No.

Japan International Cooperation Agency (JICA)

Ministry of Energy and Mineral Resources (MEMR),
The Republic of Indonesia

Study on The Optimal Electric Power Development and Operation in Indonesia

FINAL REPORT

(Main Report)

August, 2002

Chubu Electric Power Co,. INC.
The Institute of Energy Economics, Japan

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Preface

In response to the request from the Government of Republic of Indonesia, the Government of Japan decided to conduct the Study on The Optimal Electric Power Development and Operation in Indonesia, and the study was implemented by the Japan International Cooperation Agency (JICA).

JICA sent to Indonesia a study team headed by Mr. Akihisa MIZUNO of Chubu Electric Power Co., INC. and organized by Chubu Electric Power Co., INC. and The Institute of Energy Economics, Japan four times from July 2001 to August 2002.

The team held discussions with the officials concerned of the Government of Republic of Indonesia and conducted related field surveys. After returning to Japan, the study team conducted further studies and compiled the final results in this report.

I hope this report will contribute to the promotion of the plan and to the enhancement of friendly relations between our two countries.

I wish to express my sincere appreciation to the officials concerned of the Government of Republic of Indonesia for their close cooperation throughout the study.

August 2002

川上隆朗

Takao KAWAKAMI
President
Japan International Cooperation Agency

August 2002

Mr. Takao KAWAKAMI
President
Japan International Cooperation Agency
Tokyo, Japan

Dear Mr. KAWAKAMI,

Letter of Transmittal

We are pleased to submit to you the report of Study on The Optimal Electric Power Development and Operation in Indonesia. This study has been implemented by Chubu Electric Power Co., INC. and The Institute of Energy Economics, Japan from July 2001 to August 2002 based on the contract with your Agency.

This report presents the comprehensive proposal, such as the countermeasures against the power deficit anticipated for the near future, the Optimal Power Development Plan for the medium and long term considering political issues, Transmission Plan considering appropriate placement of power plants and measures from technical, organizational and institutional aspects in order to realize the above plans.

We trust that realization of our proposal will much contribute to sustainable development of electric power sector, and will contribute strengthening of economic fundamentals of Indonesia and improvement of the public welfare as well.

In view of the urgency to increase efficiency of power sector, we recommend that the Government of Indonesia implement our proposal by applying result of technology transfer in the study as a top priority.

We wish to take this opportunity to express our sincere gratitude to your Agency, the Ministry of Foreign Affairs and the Ministry of International Trade and Industry. We also wish to express our deep gratitude to the Ministry of Energy and Mineral Resources, PT-PLN (Persero) and other authorities concerned of the Government of Indonesia for the close cooperation and assistance extended to us during our investigations and study.

Very truly yours,

Akihisa Mizuno

Akihisa MIZUNO
Team Leader
Study on The Optimal Electric Power Development and Operation in Indonesia

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Abbreviation

(1) Organizations *: Indonesian

ASEAN	Association of Southeast Asian Nations
ADB	Asian Development Bank
BAPPENAS	Badan Perencanaan Pembangunan Nasional*
	National Development Planning Agency
BATAN	National Atomic Energy Agency, Indonesia
BHP	(Australia's) Broken Hill Proprietary
BP	British Petroleum
BPS	Biro Pusat Statistik*
	Central Bureau of Statistics
BPPT	Agency for the Assessment & Application of Technology
CGI	Consultative Group on Indonesia
DOC	Directorate of Mineral and Coal Enterprises, MEMR
DOE/EIA	U.S. Department of Energy / Energy Information Administration
DGEEU	Directorate General of Electricity Utilization, MEMR
EATM	Electricity Tariff Adjustment Mechanism
IBRA	Indonesia Bank Restructuring Agency
IEA	OECD / International Energy Agency
IMF	International Monetary Fund
JBIC	Japan Bank for International Cooperation Agency
JETRO	Japan External Trade Organization
JICA	Japan International Cooperation Agency
MEMR	Ministry of Energy and Mineral Resources
MIGAS	Direktorat Jenderal Minyak dan Gas Bumi
	Directorate General of Oil and Gas, MEMR
OECD	Organisation for Economic Cooperation and Development
P3B	Penyaluan dan Pusat Pengatur Beban*
PJB	PLN Java Bali Power Company
PLN	Perusahaan Umum Listric Negara PERSERO*
WB	The World Bank
WEC	World Energy Council

(2) Terms *: Indonesian

a. Facilities

AC	Available Capacity
AVR	Automatic Voltage Regulator
cct	circuit
CF	Capacity Factor
ESR	Essential Spinning Reserve
EVA	Early Valve Actuation
FEC	Final Energy Consumption
GATT	General Agreement of Tariffs and Trade
GIL	Gas Insulated Transmission Line
GRF	Gas Recirculating Fan
HSD	High speed Diesel Oil
HP(E)HTR	High Pressure feed water Heater
IC	Installed Capacity
IDO	Intermediate Diesel Oil
LFC	Load Frequency Control
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LOLP	Loss Of Load Probability
MFO	Marine Fuel Oil
OSR	Operational Spinning Reserve
PER	Primary Energy Requirement
PLC	Power Line Carrier communication
PM	Particulate Matter
PSS	Power System Stabilizer
RUKN	Rencana Umum Kelistrilcan Nasional*
	National Electricity Development Plan
SEDF	Social Electricity Development Fund (SEDF)
SDR	System Dumping Resistor
TSC	Transient Stabilizing Controller
T/D losses	Transmission and Distribution Losses
VAT	Value Added Tax

b. Miscellanea

AMDAL	Analisi Menegenai Dampak Lingkungan*
CPI	Consumer Price Index
EATM	Electricity Tariff Adjustment Mechanism
GDP	Gross Domestic Product

HGI	Hardgrove Grindability Index
EIA	Environment Impact Assessment
IPPs	Independent Power Producers
IRR	Internal Rate of Return
LP	Linear Programming
NPV	Net Present Value
NCV	Net Calorific Value
PM	Particulate Matter
PPA	Power Purchase Agreement
PSCs	Production Sharing Contracts
RGDP	Regional Gross Domestic Product
R/P ratio	Reserve / Production ratio
SEDF	Social Electricity Development Fund (SEDF)
SB	Single Buyer market
WASP-IV	Wien Automatic System Planning
WPI	Wholesales Price Index

c. Unit

kV	kilovolt
kVA	kilovolt-Ampere
MVA	Megavolt-Ampere
kW	kilowatt
kWh	kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
GW	Gigawatt
GWh	Gigawatt-hour
kmc	kilometer circuit
bbl	barrel
bbl/d	barrel per day
BTU	British Thermal Unit
BOE	barrel of oil equivalent
toe	ton of oil equivalent
ktoe	kilo (thousand) tones of oil equivalent
SCF	Standard Cubic Foot
BSCF	billion Standard Cubic Foot
MMSCF	million Standard Cubic Foot
mmscfd	million standard cubic foot per day
TFCF	trillion Standard Cubic Foot

Chapter 1 Preface

1.1 Background

Since the economic crisis in 1997, Indonesia has been regarded as needing reform in many fields. Structural reform has been under way in the electrical power sector to enable efficient electrical supply. This restructuring process was laid out in the “Power Sector Restructuring Policy” adopted by the Indonesian government in 1998. It aimed to use deregulation of the power sector and the introduction of market mechanism through the creation of a competitive market in order to achieve electrical power supply of high quality and efficiency. The New Electricity Law is to be enacted as soon as possible as the legal basis of this policy. Within three years of the new law coming into effect, it is to establish Single Buyer (hereinafter referred to as SB) market within the Java – Bali system. Within seven years it is to completely liberalize the operation of the Java – Bali system in the Multiple Buyers/ Multiple Sellers market (hereinafter referred to as MB/MS).

In the SB market and the MB/MS market, private generation companies are expected to take part in power development than before. The Optimal Power Development Plan, reflecting the issues faced by the sector, is essential as a development indicator in order to reconcile future participation of the private sector in power development with efficient and stable power supply. On the other hand, government participation is needed for the attainment of public-interest goals such as environmental preservation, supply stability and the best mix of energy to make effective use of national coal and natural gas reserves. Therefore the government must also be capable of power development planning and policies.

As the economy recovers from the 1997 economic crisis, the power demand is growing steadily. Demand in the Java – Bali system grew by 8.8% on the preceding year in 1999, by 9.9% in 2000 and by 6.35% in 2001. Steady demand growth is expected in future, prompting concerns that the system could reach a power deficit by as early as 2003~04, without the construction of new power stations, or measures to rehabilitate existing power stations and ease restrictions on their operation. In this situation, the examination of the probability of power deficit and preparing short-term countermeasures are current urgent issues to be solved.

1.2 The Target Regions and Purpose of the Study

This situation prompted JICA to begin a "Study on the Optimal Electric Power Development and Operation in Indonesia" (referred to below as "the Study") in July 2001. The scope of the study was limited to Java and Bali. The purpose of the study is as follows;

- To examine the probability of the power deficit anticipated for the near future (around 2005) and prepare countermeasures.
- To examine the Optimal Power Development Plan for the medium and long term (to 2015), taking generation costs, the effective use of primary energy sources, environmental conservation and other issues, and a Transmission Plan considering appropriate placement of power sources.
- To examine measures from technical, organizational and institutional aspects in order to realize the above plans.
- To transfer to the Indonesian counterpart the technologies and know-how for implementing the optimal power development plan and transmission plan during the progress of the study.

1.3 Study Content

This study comprises the following two phases:

[1] Verification of the power deficit which is anticipated for the near future, and preparation of the necessary short-term measures

[2] Examination of the Optimal Power Development Plan and Transmission Plan for the medium and long term, and advice on the technical, organizational and systematic aspects in order to realize the plans

These phases are summarized below.

(1) Verification of the power deficit which is anticipated for the near future, and preparation of the necessary short-term measures

First, past trends in power demand will be analyzed to make a detailed demand forecast using an econometric model. The model will comprise demand functions using income (GDP), electricity tariff and household electrification rates as the explanatory variables. The characteristic feature of this examination is that pricing effects will be considered in the demand forecast, reflecting the trend in the period before 1997, in which power demand increased as the real price declined. The two forecast cases are as follows:

- The JICA/LPE Case 1 scenario, in which the power price is raised to the 6~7c/kWh level by 2005, approximately doubling the current nominal price.

- The JICA/LPE Case 2 scenario, in which the power price is tied to the inflation rate, thus maintaining the real price at the current level.

This examination is the first stage of a study intended to verify the power crisis. Therefore the forecast period extends to 2010.

Next, to verify the capacity of power supply, the study will confirm the development timing in the existing power development plan, the available capacity of existing power plants, and the restrictions on them, to review the supply capacity which can be anticipated in each year. The impact of transmission constraints of the southern 500kV transmission line is examined by system analysis. These studies will envisage a number of scenarios considering the operation schedule and practicability of power plants that are now in development or at the planning stage. The probability of power deficit will be verified for each scenario.

Short-term measures, which at present appear to include coordination of the repair schedules of thermal power generators, rehabilitation of those generators, and the utilization of captive power, will be examined and their anticipated effects gauged to estimate the impact of such measures on the power deficit.

(2) Examination of the Optimal Power Development Plan and Transmission Plan for the medium and long term, and advice on the technical, organizational and institutional aspects in order to realize the plans

The model constructed for the short-term demand forecast will be used as the basis for a medium and long-term demand forecast, extending the forecast period to 2015. For the medium and long-term Optimum Power Development Plan, WASP-IV will be used to study a minimum-cost plan taking into account policies for the stable and effective use of energy, environmental preservation and other issues. The minimum-cost power development as the base case will be analyzed for sensitivity to influences such as rising fuel prices, development lead time and environmental policies and evaluated from the point of view of primary energy supply. The issues identified in the above process will be examined, and then recommendations for the realization of the Optimal Power Development Plan will be presented.

For the Transmission Plan, to match the Optimal Power Development Plan by 2015, distribution scenarios of new power sources (balanced distribution, western bias, eastern bias) will be assumed. Then, power flow, stability and short-circuit capacity of each scenario will be examined by system analysis, and the Optimal Transmission Plan will be proposed.

In parallel with the above analyses, the technical, organizational and institutional issues and recommendations in order to realize the Optimal Power Development Plan and to contribute stable power supply will be examined.

On the technical side, based on the field study of thermal power plants, measures for improving the thermal efficiency of existing power plants will be analyzed in technical and economic terms, and effective measures will be proposed.

The current status of environmental measures will be studied. And environmental countermeasures to improve environmental conditions will be examined and further environmental measures in order to increase the utilization of coal in future will be proposed.

On the organizational and systematic side, measures from Indonesia and abroad which illustrate the realization of power development plans and stable power supply will be gathered and analyzed. Measures apparently applicable to Indonesia's current situation will be identified from these cases and analyzed.

Issues and recommendations will be examined for the utilization of DSM to contribute to stable power supply in the short, medium and long terms, and for the utilization of captive power, which are expected to have a large impact on Indonesia's Power Development Plan because of their large capacity.

Measures to assist the introduction of renewable energy, the introduction of CDM, and a power source bidding system with a view to the power supply composition will also be raised, with examples from overseas, as measures to support the optimal power development.

In addition, measures will be examined and proposals made on enhancement of the PLN's financial condition, which is most important to the realization of optimal power development plan, and on promoting private investment, which is the key to future power development.

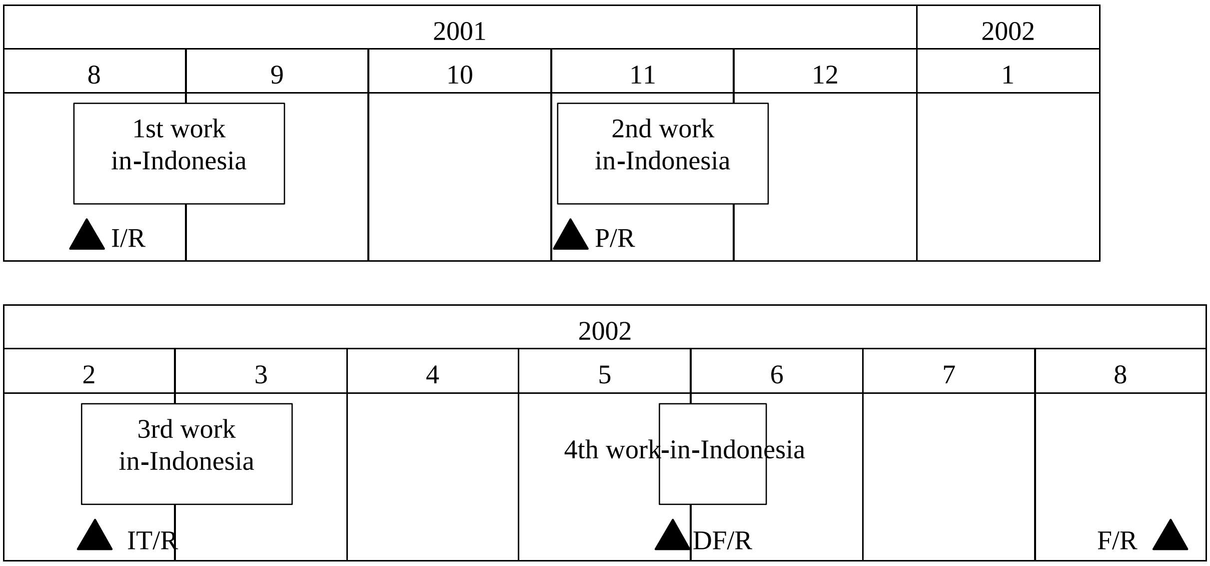
1.4 Procedure of the Study

Procedures of this study are summarized as follows.

Procedure	Activities
Phase 1: Examination of probability of power deficit and planning of short-term countermeasures	
Review of power demand forecast	- Analysis of data and information - Review of existing short-term power demand forecast by using model
Review of power supply capacity	- Review of existing power development plan
Examination of the probability of power deficit and short-term countermeasures	- Verification of short-term demand and supply balance - Planning short-term countermeasures
Phase 2: Preparation of comprehensive and realistic medium-to-long term power development plan	
Long-term power demand forecast	- Analysis of long-term power demand forecast by using model
Drawing up the optimal power development plan	- Drawing up the optimal power development plan by using WASP-IV - Evaluation of energy available for power sector
Drawing up the power transmission plan	- Power flow analysis and stability analysis - Drawing up the transmission plan
Proposal to implement the plans on technical aspects	- Drawing up the rehabilitation plan for the existing thermal power plants - Review of the environmental policy - Examination of environmental measures
Proposal to implement the plans on institutional and organizational aspects	- Study for institutional and organizational recommendations for the optimal power development plan and stable power supply

1.5 Study Schedule

The Study is scheduled for 12 months, from August 2001 to July 2002. The overall work schedule in Indonesia is shown below.



I/R: Inception Report DF/R: Draft Final Report
P/R: Progress Report F/R: Final Report
IT/R: Interim Report

1.6 Working Group, PLN Study Team and JICA Study Team

(1) Working group

Activities	Member
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Project co-leader (Director of Planning, PLN)	Ir. Hardiv H. Situmeang, MSc,. DSc
Demand forecast, Supply plan, Policy/Institutional Issues (DGEEU)	Ir. Mohamed Nur Hidayat, MSc
Finance, Reform (DGEEU)	Ir. Jarman, MSc
Policy, Finance (DGEEU)	Ir. Bambang Adi Winarso, MSc
Coordinator (DGEEU)	Ir. Ris Wahyuti
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Policy (Macro economy), Reform (DGEEU)	Ir. Madrianto Kadri, DSc
Policy (Macro economy) (BAPPENAS)	Ir. Rizal Primana, MSc
Finance, Supply plan, Demand forecast (PLN)	Ir. Eden Napltupulu, SE
Transmission (P3B)	Ir. E. H. Gultom
Transmission (P3B)	Ir. Susanto Wibowo
Environment (DGEEU)	Ir. Elidar Bahar

According to the reassignment in MEMR, Mr. Mardrianto Kadri who assumed Director of DGEEU as the successor to Mr. Suharto Satibi became the Project Leader from the 3rd work-in-Indonesia.

(2) PLN study team

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Chapter 2 Indonesian Economy and Energy Demand

2.1 Indonesian Economy

2.1.1 Background

In the years of Suharto's government, Indonesia's economy grew from a per capita GDP of US$70 in 1965 to more than US$1,000 by 1996. Prudent monetary and fiscal policies have succeeded to hold inflation in the 5%-10% range; the rupiah was stable. Much of the development budget was financed by concessional foreign aid, avoiding domestic financing. In the mid-1980s, the government began eliminating regulatory obstacles to economic activity. They succeeded to keep annual real GDP growth nearly 7% for years1987-97, and most analysts recognized Indonesia as a newly industrializing economy and emerging major market.

There is a number of structural weakness, however, behind the high levels of economic growth of 1987-97. The legal system was very weak, and there was and is no effective way to enforce contracts, collect debts, or sue for bankruptcy. Banking sector was infiltrated by widespread violation of regulations, including limits on connected lending. Furthermore, the economy has been distorted by non-tariff barriers, inefficiency of state-owned enterprises, domestic subsidies, and restrictions to domestic trade and export.

The Asian currency crisis in late 1997 quickly became an economic and political crisis. Indonesia responded by floating the rupiah, raising key domestic interest rates, and tightening fiscal policy. An economic reform program was prepared aimed at macroeconomic stabilization in October 1997 as an agreement with International Monetary fund (IMF). It eliminated some of the country's most damaging economic policies, such as the National Car Program and the monopoly. However, the rupiah could not stabilize in May 1998. In August 1998, new agreement with the IMF was made under President Habibie that included significant structural reform targets. As President Abdurrahman Wahid took office in October 1999, Indonesia and the IMF renewed the agreement in January 2000. The new program also has a range of economic, structural reform, and governance targets.

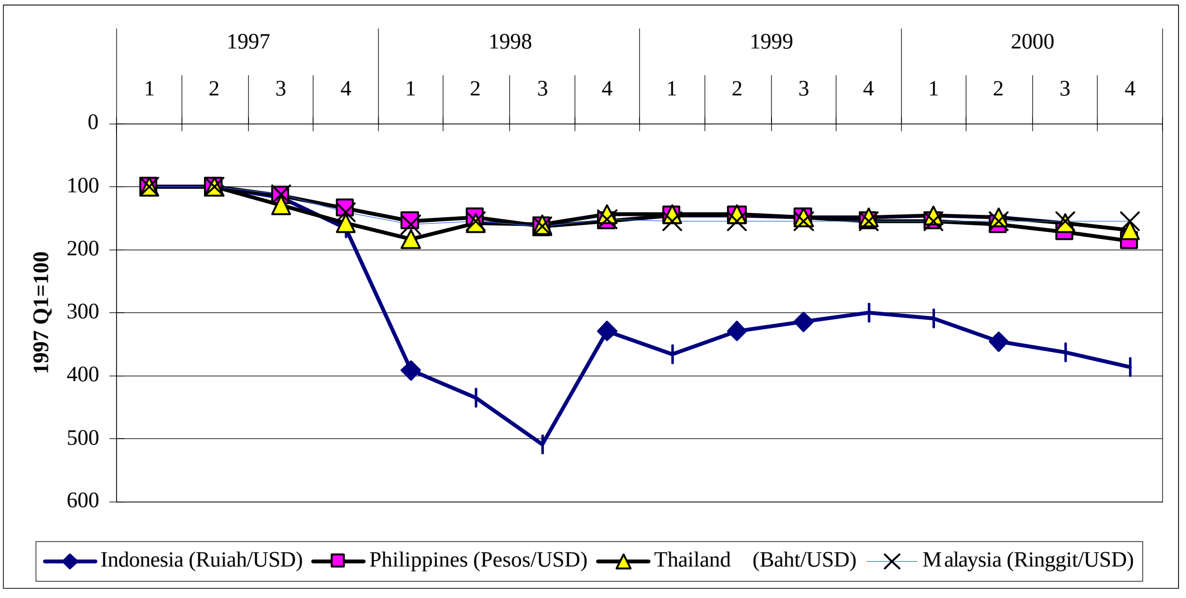
2.1.2 Asian Crisis and the Change in Economic Structure

(1) Asian Crisis: the devaluation of Rupiah

The Asian financial crisis devastated the Indonesian economy and precipitated the fall of President Suharto. The rupiah, which had been in the Rp. 2,400/US$ in 1997 reached Rp. 17,000/US$ at its peak in the 1998, returned to the Rp. 6,500-8,000/US$ in late 1998. Now the rupiah is approximately Rp. 10,000/US$. The real GDP contracted by an estimated 13.7% in 1998. The economy bottomed out in mid-1999 with the real GDP growth of 0.3%. Inflation reached 77% at its peak in 1998 but slowed to 2% in 1999. The unfavorable exchange rate reduced imports in the early stage of the crisis with reduction in domestic demand and absence of new investment, although a severe drought in 1997-98 forced Indonesia to import record amounts of rice.

Figure 2.1.1 compares the magnitude of currency depreciations of four countries of Indonesia, Philippines, Thailand, and Malaysia. The exchange rate of the first quarter of 1997 was based to be 100. The period of each year in X axis was separated by quarter. The impact on Indonesia is prominent in comparison with other countries. Even after the crisis, in 2000 the exchange rate is three to four times higher than the level of before crisis means the value of Rupiah has fell to one third to one fourth.

Figure 2.1.1 The Asian Crisis and the Devaluation of Currency by Country



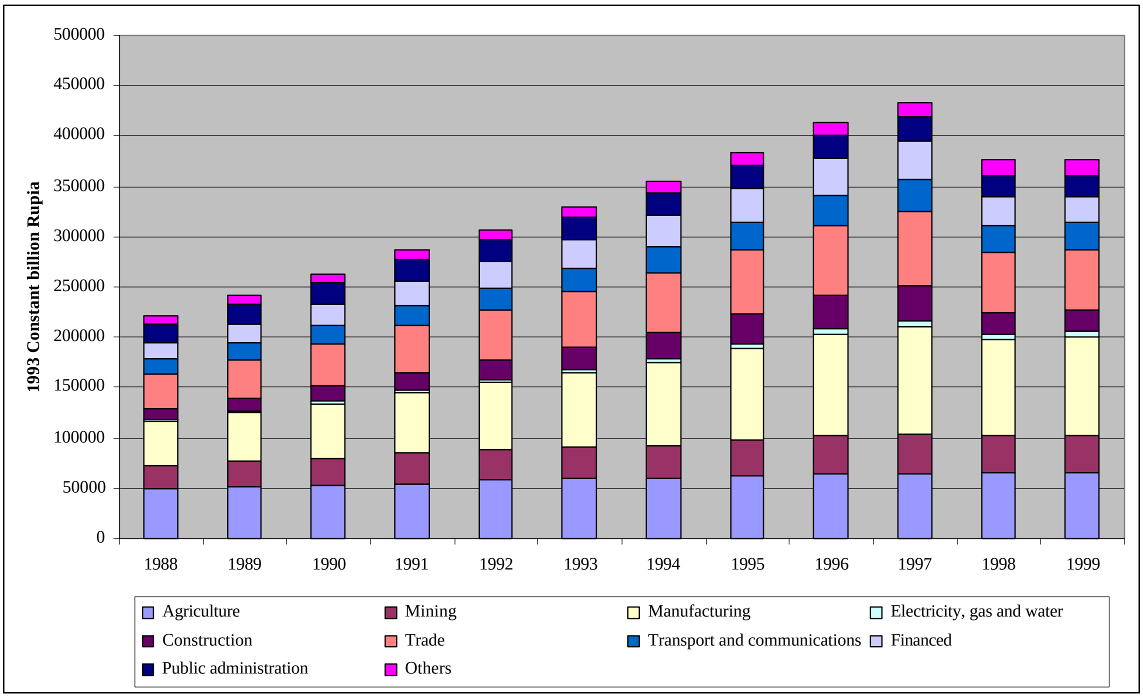
(Source) IMF

(2) GDP by industry and the impact of the Asian Crisis

Despite the continued policy disarray, Indonesia's real economy began to recover in 2000, led largely by consumer demand and surging exports. In the first seven months of 2000, Indonesia's exports were up 34 percent over the same period of 1999. The country retains its solid export foundation of oil, gas, minerals and agricultural commodities such as coffee, tea, rubber, timber, palm oil and shrimp. Regions such as Sumatra and Sulawesi that have strong, agricultural commodity-based economies survived the crisis with only minor disruptions.

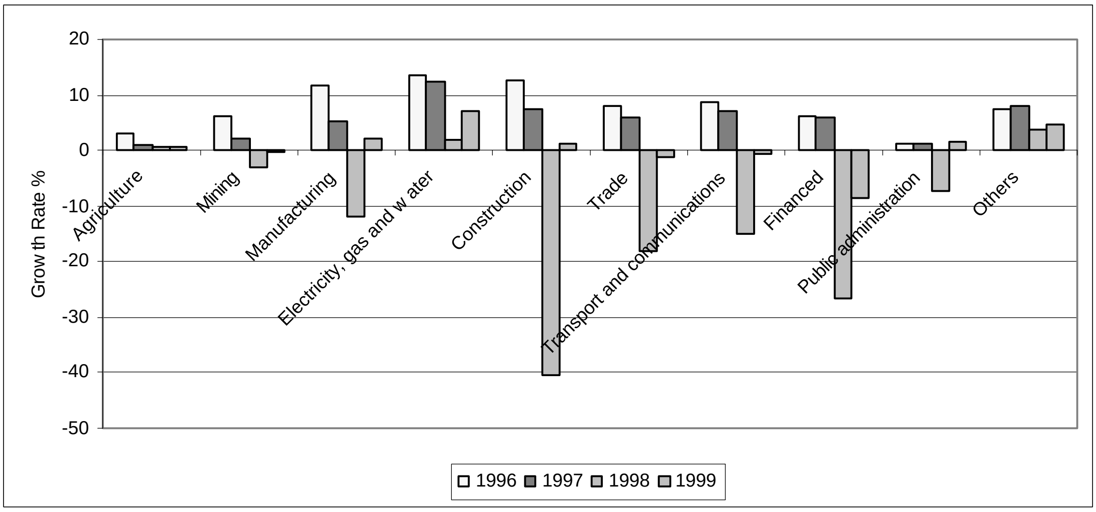
The Figure 2.1.2 shows the real GDP with its factor cost components. The Figure 2.1.3 shows the growth rate of each sector to see the difference of the impact by sector. From Figure 21.2, the shrunk of GDP in 1998 and 1999 was clear. The Figure 2.1.3 indicates that the impacts were especially severe for such sectors of construction, finance, and trade, while the impacts of the sectors of agriculture and electricity, gas and water were less severe.

Figure 2.1.2 Real GDP and the Components by Industry



(Source) ADB

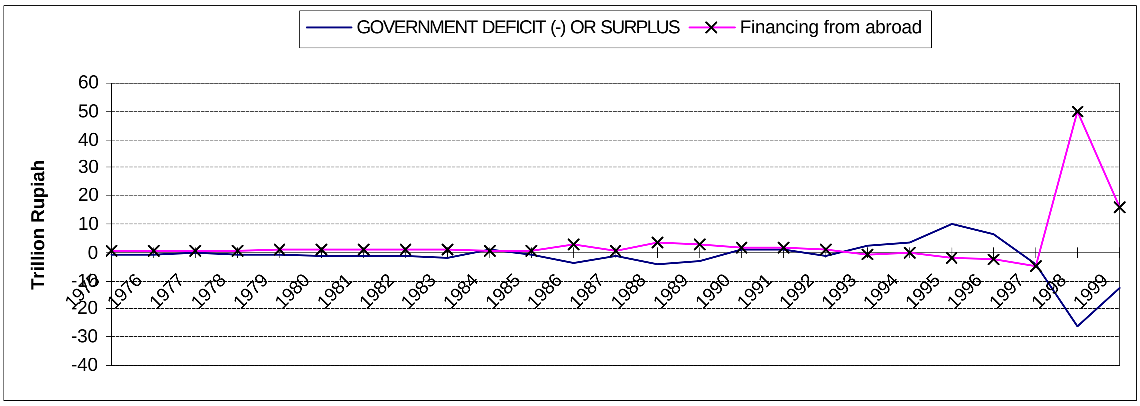
Figure 2.1.3 The Impact of Asian Crisis on Indonesia by Industry



(3) Governmental budget and debt

As shown in Figure 2.1.4, the Indonesian government has historically maintained a "balanced" budget: expenditures were covered by the sum of domestic revenues and foreign aid and borrowing, without resort to domestic borrowing. However, the financial crisis, especially the bank recapitalization program, has placed a heavy burden on government finances. The crisis left the government deeply in debt. After completing the bank recapitalization program the debt will add up to a 94% of GDP, up from a pre-crisis level of 23% of GDP. Interest payments on domestic debt, which before the crisis was almost zero, are estimated to reach Rp. 55 trillion (US$6.4 billion) or 19 percent of total spending in FY-2001. The government expects the gap between domestic revenues and expenditures to remain for several years although the rise in oil prices starting in late 1999 relieved budgetary pressure in 2000. The budgetary gap in the FY-2001 is targeted at approximately 3.7 percent of GDP.

Figure 2.1.4 Governmental Deficit/Surplus



(4) Inflation and electricity prices

Figure 2.1.5 shows the consumer price index and the inflation rate. As shown in this figure, in parallel with its fiscal policy, the Indonesian government had a reputation for prudent monetary policy that helped keep consumer price inflation below 10%. However, the extraordinary depreciation of the rupiah that began in mid-1997 and huge governmental intervention (liquidity injections) into the banking system contributed to significant inflation.

Figure 2.1.6 shows the comparison of the inflations of CPI and average electricity price with measure in the left side axis. Also it shows the average electricity price in US$/kWh with its measure on right side axis.

Figure 2.1.5 Consumer Price Index and the Inflation

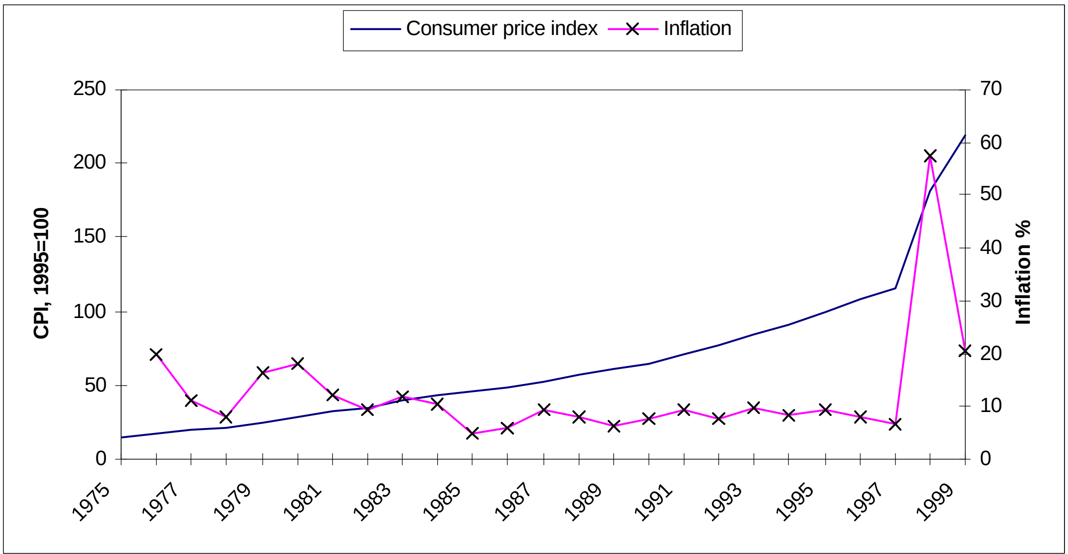
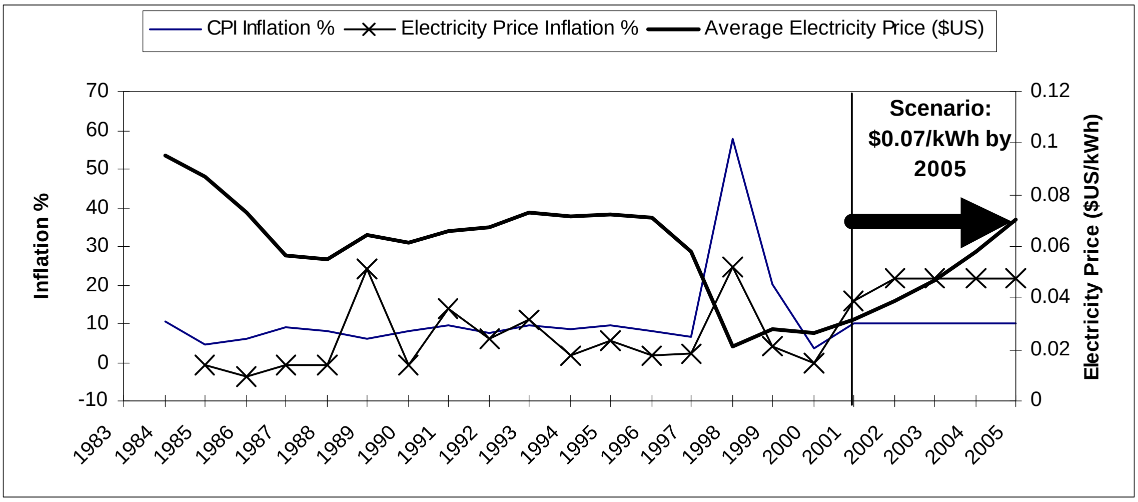


Figure 2.1.6 CPI vs Electricity Price and the Scenario up to 2005



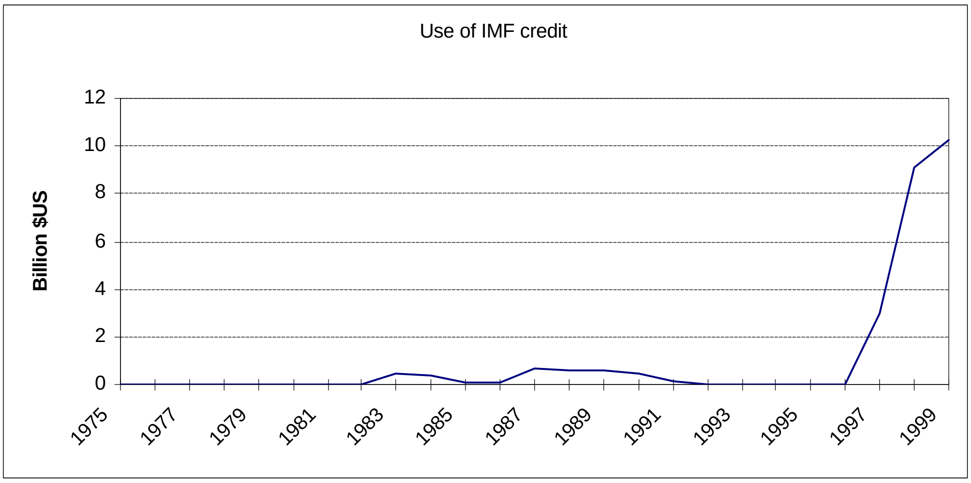
The electricity prices are controlled by the government. Therefore, without major increase during the crisis, the effect was the sharp downfall of the price in real term. Actually, in 1998, the inflation of CPI or the peak is much higher than the peak of electricity price inflation. At the same time, the sharp downfall is in the price in US$ in 1998. Except 1989, 1991, and 1993, the CPI inflation is higher than the inflation of electricity price, means that the electricity price has been decreased substantially. In fact the price in 1998 was about a half of the price of 1984.

The graph beyond 2001 shows the PLN scenario to increase the electricity price up to 7 cents by 2005. The scenario was calculated based on the assumptions—CPI inflation 10% and the exchange rate 8000 rupiah/US$. This scenario shows that the relationship between the inflation of CPI and that of electricity price have to be reversed. The inflation of electricity price has to be 20% or more if CPI inflation is about 10%.

(5) Structural policies

Pressured by the deteriorating conditions, Indonesia requested support from the International Monetary Fund (IMF) to have signed its first Letter of Intent (LOI) with the IMF on October 31, 1997. The letter called for a three-year economic stabilization and recovery program, supported by loans from the IMF (US$10 billion), the World Bank, the Asian Development Bank, and bilateral donors (See below Figure 2.1.7).

Figure 2.1.7 Use of IMF Credit



Indonesia's agreement with the IMF has been revised repeatedly because of the deteriorating macroeconomic conditions and political changes. The result is a complex program to tackle macroeconomic imbalances, financial weaknesses, real sector inefficiencies, and the loss of private sector confidence. Accordingly, the government has introduced several measures to improve governance. These include a Competition Commission that was inaugurated in September 2000 and various bodies to investigate and prevent corruption, collusion and nepotism.

With such an injection of external debt, Indonesia's foreign debt totaled about US$162 billion as of July 2000, which includes about US$80 billion owed by the public sector and US$82 billion by the private sector.

(6) Imports & Exports

In recent years, Indonesia has liberalized its trade regime and taken steps to reduce protection. Namely, since 1996, the government has issued a series of deregulation packages that have reduced overall tariff levels, simplified the tariff structure, removed restrictions, replaced non-tariff barriers with more transparent tariffs, and encouraged foreign and domestic private investment.

For example, import tariffs on vehicles were lowered in June 1999 to 65 to 80 percent (depending on engine size) for completely built-up sedans, 5 to 40 percent for trucks, and 35 to 65 percent for motorcycles. Rates for parts were also reduced to a maximum 15 percent. Luxury taxes for sedans range from 35 to 50 percent.

Export-loan interest subsidies were eliminated since Indonesia joined the GATT Subsidies Code in 1990. As part of its drive to increase non-oil and gas exports, the government permits restitution of VAT paid by a producing exporter on purchases of materials for use in manufacturing export products. Free trade zones and industrial estates are combined in several bonded areas.

Figure 2.1.8 shows the historical change of imports and exports. The depreciation of rupiah during the crisis combined with improved trade environment contributed to the surge of both imports and exports since 1998. The export is relatively large because of the rupiah devaluation and this was the primary factor, which led the recent recovery.

Figure 2.1.8 Import/Export

2.1.3 Latest Development with IMF and Subjects for the Future

The Indonesian economy stabilized in 1999, following the sharp contraction and high inflation of 1998. By following tight monetary policy, the government reduced inflation from over 70% in 1998 to 2% in 1999. Although interest rates spiked as high as 70% in response to the monetary contraction, they fell rapidly to the 10% to 15% range. The economy stopped its free-fall as GDP showed some growth in the second half of 1999, although GDP for the year as a whole showed no growth. The government managed to recapitalize a handful of private banks and has begun recapitalizing the state-owned banking sector. New lending, however, remains almost unavailable as banks continue to be wary of issuing new debt in an environment where little progress has been made in restructuring the huge burden of outstanding debts. IMF payments were suspended late in 1999 as the result of evidence that a private bank had illegally funneled payments it received from the government to one of the political parties.

The new government of the President Megawati Soekarnoputri seems more pro-reform than the predecessor. Thus the LOI of August 2001 between IMF and the government of Indonesia paved the way for the IMF to disburse its long-delayed US$400 million loan tranche to Indonesia. The agreement revealed that the IMF is easing some economic reform targets in support for President Megawati Soekarnoputri’s request. In the agreement, the inflation rate is now targeted at between 9 and 11 %, extending the range from earlier target of 9.3%. The GDP was revised downward from 4.8% to between 3 and 3.5%. The base money target has also been raised from 108 trillion to 110.5 trillion, although it is still lower than the current level of Rp. 112 trillion. Also, Indonesia agreed to raise Rp. 27 trillion from the sales of assets under the Indonesian Bank Restructuring Agency (IBRA) and Rp. 6.5 trillion from the privatization of state-owned enterprises.

The new government is trying to receive more loans from Donor countries under the Consultative Group on Indonesia (CGI). The government has expressed hope of the CGI increasing its loans to Indonesia to help finance a 2002 state budget deficit. The government is relying on foreign investment and loans to help contain this year’s state budget deficit at 3.7% of GDP. Without these, it must seek alternative sources of revenue. That could translate into the imposition of higher taxes and an increase of fuel and power prices.

The followings are the primary points in the LOI of August 2001.

- GDP growth set at 3% to 3.5%, inflation at 9% to 11% by the end of this year, and base money supply growth at 12.5% by March 2002.
- Introduction of treasury bills by year end to gradually replace Bank Indonesia’s

promissory notes.

- Bank Mandiri privatization through an initial public offering of up to 30% by the end of this year.
- IBRA revenue target at 27 trillion, of which Rp. 19.8 trillion must be collected in cash by end of September 2001.
- Announcement of performance audits of key state firms including PT Telecom and PT Garude Indonesia.
- Target to issue bonds to replenish funds for the government's blanket bank guarantee scheme.
- Restructuring corporate debts totaling US$14 billion to US$15 billion under the Jakarta Initiative Task Force.
- Targeting privatization proceeds of Rp. 6.5 trillion this year (2001).

2.1.4 Summary

To summarize, Indonesia's economy has been deeply dependent on foreign aid. The dollar or yen denominated loan made Indonesia made its economy very sensitive to the fluctuation of exchange rate. Moreover, the exchange rate can easily fall and rise in response to the political turmoil of the country. Thus, the Asian crisis, which began in 1997, was accelerated by the political upheaval for the case of Indonesia. The spread of sectarian violence and continuing dissatisfaction with the pace of bank and debt restructuring is another factor, which disturb to attract the private investment

At this moment, the critical macroeconomic problem is the governmental budget and debt. The subsidies for food and fuel are the primary burden for the government. Until recently, the income from the sales of crude oil was somewhat a relief for the government. However, without promising crude oil development in Indonesia, the government has few option but to shrink its spending with less subsidy—meaning more pain for the recipients of public in general. Now the economy is pressed to be self-sustainable with increased investment into a productive sector.

The event of terrorist attack of September 2001 against USA would deteriorate the recovery of Indonesian Economy. The GDP estimate was adjusted to lower than before. According to the World Bank the GDP growth of Indonesia would recover to 4% by 2004, but continued to be around 4% until the year 2010.

Table 2.1.1 shows Economic indicators of WB

Table 2.1.1 Economic indicators (source WB)

YEAR	1991	1992	1993	1994	1995	1996	1997	1998	1999*	2000**	2001**
									*Preliminary	**Very Preliminary	
CURRENT GNI PER CAPITA (US$)	680	740	810	890	1,000	1,110	1,110	670	580	570	
Population (millions)	181	185	188	191	194	197	200	204	207	210	
USE AND ORIGIN OF RESOURCES				(Trillions of Indonesian rupiah)							
Gross national income (GNI)	239.1	269.9	317.2	372	441.1	518.3	609.3	935.7	1,040.50	1201.43	1051.5
Net income from abroad	-10.9	-12.5	-12.6	-10.2	-13.4	-14.3	-18.4	-53.9	-78.9	-89.3	-49.9
Gross domestic product (GDP)	250	282.4	329.8	382.2	454.5	532.6	627.7	989.6	1,119.40	1290.7	1101.4
External balance on goods and services	4.2	8.3	9.8	4.4	-6.1	-3.3	-1.7	93.2	88.9	101.3	91.4
Exports of goods and services	64.5	78.8	88.2	101.3	119.6	137.5	174.9	506.2	390.6	497.5	475.8
Imports of goods and services	60.2	70.5	78.4	97	125.7	140.8	176.6	413.1	301.7	396.2	384.4
Gross national expenditure	245.7	274.1	319.9	377.8	460.6	535.8	629.4	896.4	1,030.50	1271.7	1080.6
Household consumption expenditure	146.1	163.3	193	228.1	279.9	332.1	393.1	574.2	692.6	867	734.5
General government consumption expenditur	20.8	24.7	29.8	31	35.6	40.3	43	54.4	72.6	90.8	78.7
Gross capital formation	78.9	86.1	97.2	118.7	145.1	163.5	193.4	267.8	265.3	313.9	267.4
Fixed capital formation	67.5	72.8	86.7	105.4	129.2	157.7	177.7	243	237.4		
Net taxes on products	15.1	18	21.2	24.7	31.4	33.8	39	26.9	24.8		
Total value added at factor cost	234.8	264.4	308.6	357.5	423.1	498.8	588.7	962.7	1,094.70		
Agriculture	45.6	52.7	59	66.1	77.9	88.8	101	173.9	218		
Industry	101	112	130.9	155.3	190	231.4	278.3	444.4	484.2		
Manufacturing	53.4	62	73.6	89.2	109.7	136.4	168.2	238.1	284.8		
Services	103.3	117.7	140	160.8	186.6	212.3	248.4	371.3	417.2		
Gross domestic savings	83.1	94.4	107.1	123.1	139.1	160.2	191.6	361	354.3		
Gross national savings	72.7	83	95.6	114.2	127.9	148.1	176.3	320.5	290.4		
				(Index 1995=100)							
Gross national product (GNP)	73.75	79.09	85.31	92.75	100	107.92	112.35	93.83	95.71		
Gross domestic product (GDP)	74.72	80.12	85.93	92.41	100	107.83	112.89	98.21	98.51		
Resource balance											
Exports of goods and services	72.03	82.98	85.68	94.2	100	109.14	117.66	130.82	89.46		
Imports of goods and services	66.25	72.06	75.41	90.72	100	117.25	134.5	127.38	75.57		
Gross national expenditure	73.16	77.18	83.16	91.47	100	110.02	117.45	97.36	94.73		
Household consumption expenditure	77.71	82.59	89.42	96.42	100	119.1	124.94	113.41	117.3		
General government consumption expenditur	89.25	94.37	94.54	96.72	100	100.65	100.71	85.23	85.83		
Gross capital formation	62.32	64.74	70.72	82.52	100	97.9	109.53	74.95	61.36		
Fixed capital formation	68.84	71.3	76.01	86.46	100	112.87	122.54	82.09	65.68		
Total value added at factor cost	76.46	81.7	87.59	94.09	100	107.85	111.89	99.33	100.26		
Agriculture	88.2	93.73	95.28	95.81	100	103.14	104.17	103.46	105.62		
Industry	68.55	74.16	81.47	90.56	100	110.69	116.41	100.15	101.35		
Manufacturing	65.41	72.07	80.27	90.19	100	111.59	117.45	104.02	106.71		
Services	75.7	80.83	86.79	92.95	100	106.77	112.73	94.25	92.96		
Memo Items:											
Capacity to import	74.5	84.61	89.19	99.62	100	120.32	139.94	164.04	102.8		
Terms of trade adjustment	11.57	43.02	0	-38.19	100	-163.68	-426.11	-680.1	-236.19		
Gross domestic income	75.4	80.52	86.85	93.8	100	110.72	118.65	106.52	102.08		
Gross national income	74.44	79.49	86.25	94.19	100	110.91	118.28	102.36	99.36		
DOMESTIC PRICES/DEFLATORS				(Index 1995=100)							
Overall (GDP)	73.6	77.55	84.43	91	100	108.67	122.33	221.7	250.02		
Gross national expenditure	72.93	77.11	83.53	89.68	100	105.75	116.35	199.9	236.18		
Agriculture	66.42	72.25	79.45	88.53	100	110.52	124.48	215.78	265.03		
Industry	77.54	79.45	84.55	90.28	100	110.05	125.81	233.55	251.48		
Manufacturing	74.4	78.45	83.54	90.21	100	111.46	130.54	208.65	243.32		
Consumer price index	71.39	76.77	84.21	91.38	100	107.97	115.24	181.66	218.89		
Inflation	9.409962	7.536069	9.691286	8.514428	9.433136	7.97	6.733352	57.63624	20.49433		
MONETARY INDICATORS				(Trillions of Indonesian rupiah)							
Money and quasi money	99.41	119.06	143.14	171.74	218.39	277.75	347.86	568.65	639.79		
Net foreign assets	17.28	29.54	28.49	24.39	30.26	50.91	54.82	97.37	106.17		
Net domestic credit	114	130.03	157.4	193.46	235.36	288.79	362.95	557.86	677.03		
Claims on private sector	115.41	128.52	161.27	198.31	243.07	295.2	381.74	508.56	225.24		
Claims on government, etc.	-3.01	0.5	-5.09	-7.3	-10.53	-11.38	-25.21	2.28	426.8		

2.2 Energy Policy in Indonesia

2.2.1 Transition of Energy Policy

(1) Traditional energy policy

The objectives of the traditional energy policy in Indonesia are summarized as follows.

- To secure the continuity of energy supply for domestic use at prices affordable to the public in order to enhance the quality of life of the people and to stimulate economic growth.
- To save an adequate supply of oil and gas for export so that these can remain an important source of foreign exchange for funding the national development program.

The energy development policy in order to meet the above objectives is also summarized as follows.

1) Energy Intensification, i.e., to increase and expand the survey and exploration of energy resources available in the country.
2) Energy Diversification, i.e., to reduce dependency on oil in overall energy consumption by a substitution of the other available resources for oil in the country.
3) Energy Conservation, i.e., to economize energy and to use it efficiently.

(2) Restructuring of energy policy

Indonesia, one of the energy-resource rich countries of Asia, has made a drastic turnaround in its second long term national plan. Namely, its first long-term plan (LTD-1, 1969/70-1993/94) stated; 1) Indonesia is rich in usable energy resources, 2) fossil fuel resources can satisfy both exports to earn foreign currency and domestic demand, and 3) energy prices are maintained lower than the economic values.

The second long-term plan (LTD-2, 1994/95-2018/19), however, revealed a different understanding of these basic matters and stated; (a) Indonesia is not necessarily rich in energy resources, (b) fossil fuel resources need to be earmarked for exports, and also are positioned as fuels and materials necessary for manufacturing products, and (c) energy prices must be set to reflect the economic values. Accordingly, Indonesia changed its energy diversification policy from a "conventional one designed to reduce domestic oil dependence in an effort to secure oil exports" to a "new one designed to maximize the national earnings and to delay depletion of its fossil fuel resources." The second long-term plan declares that the goal of energy development is to increase the added value of Indonesia as a whole and to ensure the energy security and elasticity for the country. Figure 2.2.1 shows the main changes related to the energy development policy.

Figure 2.2.1 Restructuring of Energy Policy in Indonesia

Basic Recognition

First Long-term Development Plan
(LTD-1, 1969/70～1993/94)

1. Energy resources are considered to be abundant in availability
2. Fossil fuel resources are in response to both
   ①Earning of foreign currency by export, and
   ②Supply for domestic energy requirement
3. Energy price is kept below its economic value

Second Long-term Development Plan
(LTD-2, 1994/95～2018/19)

1. Energy resources are scare resources
   ①Oil reserve is 1.1 ％ of the World
   ②Natural gas is 1～2 ％ of the World
   ③Coal reserve is 3.1 ％ of the World
2. Oil, Gas and Coal are positioned as fossil fuels and raw materials for domestic energy need to produce export goods for foreign currency
3. Energy price is set according to its economic value and market mechanism

Main Changes of Energy Policy

First Long-term Development Plan
(LTD-1, 1969/70～1993/94)

1. Diversification of energy source

Diversification for decrease of oil dependency ratio in domestic energy supply in order to keep oil export

2. Energy Conservation

Energy conservation policy is focused on down-stream

Second long-term Development Plan
(LTD-2, 1994/95～2018/19)

1. Diversification of energy source
   ①to gain maximum benefit of the nation
   ②to delay the depletion of fossil fuel resources
2. Energy Conservation

Energy conservation policy is adopted to both up-stream and down-stream

Strategy of Energy Development

Optimum allotment & utilization of energy resources

1. Optimum use of energy resources
2. Commercialization of new and renewable energy
3. Selection of moderate technology
4. Even (Equal) energy distribution & utilization
5. Export of technology & services/expertise
6. Development of energy industry
7. Efficient and environment-friendly energy use in transport sector

Goal of Energy Development

Increase of total value-added in the nation

1. Stable supply of energy and ensuring of energy security
2. Establishment of optimum energy use
3. Support of environment-friendly energy development
4. Increase of the national resilience

Energy development policy in the second long-term plan stresses the following items.

1) Energy diversification

Energy diversification policy aims at maximizing the net benefit of the nation and at supporting sustainable development by diversifying the use of energy resources. This policy is to ensure an optimum and economic utilization and supply of energy to reduce the depletion rate of hydrocarbon resources.

(Past Policy): Aimed at diversifying the use of energy resources to reduce dependence on certain resources (especially oil) in order to enable the country to secure oil supply for export.

(New Policy): Aimed at diversifying the use of energy resources and at ensuring on optimum & efficient utilization of energy in order to enable the country to achieve a maximum net benefit from energy utilization.

2) Energy intensification

Intensification policy of survey and exploration activities is to identify the potentials of economically exploitable energy resources (especially oil, gas and coal) in order to guarantee a sustainable supply of energy.

3) Energy conservation

Energy conservation policy is to stipulate the efficient and rational utilization of energy, which is adopted the whole process of energy utilization covering the demand and supply side.

(Past Policy): Implementation of energy conservation especially focused on downstream.

(New Policy): Energy conservation is applied to downstream and upstream activities.

4) Energy pricing

The energy price is designed to gradually reflect the real economic value, following the market mechanism.

- Enhancing economic competitiveness,
- Protecting consumers,
- Ensuring even distribution of energy.

5) Environment

An environmentally benign energy development policy aims at reducing the destruction and degradation of ecosystems for supporting sustainable development.

2.2.2 Policy Issues of Energy Sector

Recently, various problems in the energy sector have been highlighted, just as in the power sector. In this section, these issues are summarized.

(1) Pricing mechanism and subsidy

The oil product price is kept lower than the international market price with a subsidy of US$ 3billion (calculated by domestic price - production cost) to promote domestic development and to protect low-income groups and the residents of remote areas. This situation is a factor in the reduced international competitiveness of existing industries and the pressure on the national budget.

In addition, revenue from oil exports represents an economic loss for Indonesia, because the domestic oil product price is not linked with the international market price and is kept lower than the international market price.

(2) Monopoly system by Pertamina

According to the Indonesian constitution, the rights and interests of natural resources belong to the state. Pertamina has enjoyed a monopoly of upstream and downstream activities in the oil and gas sectors through a commission between it and the State based on the Law 8/1971.

However, obstacles related to Pertamina, Indonesia's state oil and gas company, are becoming remarkable. The main obstacles are summarized below.

1) During the exploration and exploitation phase, production cost tends to be high and productivity tends to be low, because of the length of time for exploration and exploitation and/or the time it takes to get an exploration license from Pertamina.
2) Pertamina's supervising role in upstream activities is focused more on control than on gaining added value for the Government.
3) Inefficient system in downstream activities, from refining to retailing of petroleum products, without incentives for cost reduction in each process.

2.2.3 Present Status of New Oil and Gas Law

In response to the above-mentioned policy and issues, a New Oil and Gas Law was developed to improve the efficiency of the energy sector. This draft law was already approved by the House in Oct 2001 and was promulgated after the President's signature in Nov 2001.

This law focuses on liberalization and splitting of the upstream and downstream activities of the oil and gas sector, i.e., 1) to split the function of oil and gas sector into upstream activities (exploration and exploitation) and downstream activities (processing, transportation, storage and/or trading), 2) to transfer the authority monopolized by Pertamina in both activities to an Implementing Body and a Regulatory Body, and 3) to install a market mechanism to the downstream activities.

1) Main provisions related to the upstream activities

- Implementing Body shall be responsible for the upstream activities. All existing rights, obligations and consequences of the Production Sharing Contracts (PSCs) between Pertamina and other parties shall be transferred to the Implementing Body.
- Main rights in the upstream activities are to conduct the execution of the Cooperation Contract and to supervise and monitor the implementation of upstream activities.
- Business Entity (domestic capital) and Permanent Establishment (foreign capital) can conduct the upstream activities based on the Cooperation Contract with the Implementing Body.
- Pertamina will be transformed into a State-owned Limited Liability Company (Persero). Therefore, Pertamina has to contract with the Implementing Body in order to continue the upstream activities.
- Until the establishment of the Implementing Body after the time this law comes into effect, Pertamina has to continue to perform its duties and functions of upstream activities.

2) Main provisions related to the downstream activities

- Regulatory Body shall be responsible for the downstream activities.
- Main rights in the downstream activities are to make policy, to regulate and supervise on the implementation of downstream activities based on the Business License.
- Business Entity (domestic capital) can conduct the downstream activities after receiving Business License from the Government, but Permanent Establishment (foreign capital) cannot receive Business License.
- Oil and gas price will be set through competition based on the market mechanism.
- Pertamina will be transformed into a State-owned Limited Liability Company (Persero). It will have the required Business License for downstream activities after its transformation.
- Until the establishment of the Regulatory Body after the time this law comes into effect, Pertamina has to continue to perform its duties and functions of downstream activities.

2.2.4 Electric Power Policy

The government has consistently been expanding access to an affordable and reliable electricity supply as a vital element of its strategy for rapid economic growth and equitable social development. The government established PLN in 1950 as a national electricity utility responsible for electricity generation and distribution throughout the country. In response to the continuous power deficit, the 1985 Law No.25 allowed private enterprises and cooperatives to participate in the electricity business as complements to PLN in areas where PLN was not able to supply electricity. In addition, public financing of power development was insufficient to meet the increasing demand so the government, through the 1992 Presidential Decree No.37, allowed the private sector to participate in power generation projects as Independent Power Producers (IPPs).

The policy for the use of primary energy is to increase the utilization of non-oil energy sources. Accordingly, coal is increasingly utilized. The same is true for geothermal although its use is not increasing as rapidly. The abundance of the coal supply has rapidly led to an increased number of coal steam power plants. In contrast, the uncertainty of the geothermal supply is an obstacle to increasing its development. Priority is actually given to renewable energy such as hydropower. However, the isolation of hydropower sites, the need for large space, and the high costs involved are obstacles to the development of hydropower. Efforts are always taken to utilize hydropower at the micro-scale for rural areas that are far from PLN's grid or fuel oil distribution networks.

In order to create a competitive market and to improve the efficiency of the power sector, the government developed a power sector's restructuring program. The Power Sector Restructuring Policy was released in August 1998 and it's Implementation Plan in December 1998. Unbundling and privatization of PLN is in progress. In the Java-Bali system, there is transmission, distribution, and generation, so there are many commercial business opportunities. To facilitate competition, generation, transmission and distribution are separated and multiple players are created in generation and distribution. In 1994, PLN converted to public company status (Persero) of which 100% of shares were owned by the government. In 1995, the PLN Java-Bali generation assets were unbundled into two power generation companies: Indonesia Power and PJB.

In the Java-Bali system, PLN unbundling and privatization are carried out systematically. First, Strategy Business Units are established in PLN to prepare for unbundling. Next, the generation and distribution sectors are separated from PLN. A Single Buyer system will be introduced where PLN buys power from generation companies and IPPs and sells it to distribution companies. Finally, a Multiple Buyer /Multiple Seller (MSMB) market for a completely competitive market will be created. The electricity bill, which is the basis for power restructuring and is now under deliberation in the House of Representatives.

The development of rural electricity will be carried out to achieve the goal of electrifying all rural areas; either by expanding the network or installing isolated systems such as solar power for households (Solar Home System). At present, PKUK (PLN) has a significant role in implementing the rural electricity program by expanding the network. The cooperatives also have a role in implementing this program, but it is small compared to PLN. Almost all the financing for the PKUK (PLN) program is from the State budget so PLN's rural electrification project is regarded as a Government project.

Outside Java, the power sector consists of a number of small systems and sometimes an isolated power system. The costs are high and the electrification ratio is low. Therefore, electricity business cannot be conducted for profit in these areas and government support is still needed. In these areas a Rural Electricity Company (REC) will be established, directly owned by the government. This will allow restructuring at a slow pace.

2.2.5 Outline of Energy related Laws and Regulations

(1) New electricity law

The Electricity Bill was submitted to the House of Representatives in February 2001. Since then discussion of the Bill has been going on and it is expected to be approved as soon as possible. The new electricity law aims at providing sustainable and affordable power to improve the public welfare and prosperity of the nation. Power development needs to be undertaken through competition and transparency, in a sound business climate by means of an arrangement which provides fair treatment to all business players and which benefits consumers. Therefore, business opportunities are given to state enterprises, regional enterprises, cooperatives and the private sector. The power development will take into account environmental preservation, energy conservation, and energy diversification in line with the national energy policy.

The new law will replace Law No.15 of 1985. The key points of the law are:

1) PLN will lose its monopoly over the country's power industry
2) The private sector will be allowed to do business in power generation and retailing, as well as with PLN

3) The government will control power transmission and distribution networks, and charge producers a fee to use them
4) All power producers will sell power to the public through competitive bidding. Producers that offer the cheapest price will be allowed first access to the government-owned network.

Under the new law, the central government will be responsible for making general power policy, such as, power demand forecasts, supply plans, transmission plans, finance plans, subsidies and new & renewable energy utilization. On the other hand, local government will be responsible for local business planning, such as, local demand forecasts, primary energy studies and transmission planning considering the regional development plan.

Electricity will be supplied based on market competitiveness. A regulatory body will be established in order to ensure the electricity industry introduces a competitive market. Its focus will be guaranteeing fair competition, introducing an efficient electricity supply, promoting sustainable new investment, ensuring reasonable profits for market players, and protecting the interests of the community. The Social Electricity Development Fund (SEDF), managed by a separate entity, will allocate subsidies to low-income consumers, underdeveloped areas and to rural electrification. After enactment into law, there will be a seven (7) year transition period: within a year of enactment, an executive body for SEDF will be established; within two years, an independent regulating body will be established; within three years, a single buyer market will be established; and within seven years, a fully competitive market will be established.

(2) Electricity tariff and policy

The electricity tariff is to be approved by the President. PLN submits an application to MEME and after arrangement with related agencies, it is submitted to the President. Before the economic crisis, the Electricity Tariff Adjustment Mechanism (EATM) was applied. Under this system, the tariff was set every three (3) months in response to fuel price, IPP price, inflation ratio and exchange rate to US$. However, the Rupiah devaluation in 1997 meant higher tariff increases and the tariff was not increased as planned due to political considerations. In addition to this, the dollar linked power purchase price from IPPs and the fuel price (coal and gas) meant that PLN finances remained in the red.

In order to generate profits, PLN will increase the tariff from the current 3.5 ₵ /kWh to 7 ₵ /kWh by 2005. The electricity tariff was increased by 30.1% in July and October 2001. The tariff increase did not apply to low-income groups to protect these customers. In 2002, it will be increased every three (3) months including low-income groups. Table 2.2.1 shows the electricity-pricing schedule.

Table 2.2.1 Electricity Pricing Schedule (Average Tariff :Rp./kWh)

	1999	2000	2001	2002	2003	2004	2005
Industrial	210.3	299.6	365.2	429.3	480.8	533.7	587.1
Residential	197.7	210.9	311.0	395.1	442.5	485.8	535.4
Commercial	317.2	378.6	447.7	506.2	566.9	623.5	686.0
Public	265.8	265.8	460.6	507.1	568.0	624.7	687.3
Average	221.9	276.9	360.2	429.8	481.4	532.0	585.4

(Source) PLN

Although consumers in the same categories have paid the same charge for electricity even though they are in different areas, a differential charge system will now be introduced. For example, the tariff system in Irian Jaya should be different from Batam because of the different income levels. In fact, PLN established a subsidiary company (Regional Electric Company) and set its own tariff.

Rural areas are not profitable because of high generation costs and because they are dominated by low tariff groups. Revenue generated in Java island is allocated to rural areas as a cross subsidy. All costs cannot be recovered under this tariff because of the low incomes in rural area. The government is going to continue to allocate a subsidy to support undeveloped areas, by subsidizing electricity for low-income groups. The subsidy should be transparent. The Social Electricity Development Fund (SEDF) will be created to finance the subsidy. Through the fund, the difference between allowable costs and sales revenue will be made up for to five distribution/retail companies in Java-Bali, and to REC outside Java. The allowable costs should be set based on assumptions of efficient operation, not based on actual costs.

2.2.6 Outline of Electric Power related Agencies

The Ministry of Energy and Mineral Resources (MEMR) has the combined government role of owner, policy-maker and regulator. It is necessary to separate these different roles. Policy-making will be the responsibility of the Directorate General of Electricity and Energy Utilization (DGEEU) under MEMR. The ownership role of PLN is transferred to the Ministry of Empowerment of State-Owned Enterprises. In order to separate the regulatory role, the Electricity Business Supervision was created in DGEEU and will be developed as an autonomous agency responsible for the regulatory roles of the energy sector. Figure 2.2.2 and 2.2.3 show the organization chart of MEMR and PLN.

Figure 2.2.2 Organization Chart of MEMR

- Minister
  - Directorate General of Electricity & Energy Utilization
    - Directorate of Electricity Program Supervision
      - Supply Program
      - Investment & Finance
      - Social Electrification
      - Cooperation
      - Information, Analysis and Evaluation
    - Directorate of Power Enterprise
      - Electric Power Industry
      - Price Analysis
      - Business service
      - Consumer Protection
      - Commercial Relation
    - Directorate of Electric Power Technology
      - Electric Power Standard
      - Electric Power Utilization Plan
      - Electric Power Environment
      - Electric Power Technology
      - Technology Application
    - Directorate of New, Renewable Energy and Energy Conservation
      - Energy Utilization
      - New & Renewable Energy Business
      - Energy Conservation
      - Rural Energy
      - Supporting Industry
  - Directorate General of Oil & Gas
  - Directorate General of Geology & Mineral Resources
  - Mineral Resources Education & Training Agency
  - Mineral Resources Research & Development Agency

Figure 2.2.3 Organization Chart of PLN

- President Director
  - Vice President
    - 1.Planning 2.Restructuring 3.Business Development
    - 4.Environment 5.Tariff and Commercial
    - 6.Business Performance 7.Law
    - 8.Information Technology 9.Communication
    - 10.Renegotiation IPP contract 11.Procurement
  - Planning Director
    - Secretariat
    - System planning team
    - Corporate planning team
    - Analysis and Evaluation team
    - Information technology team
  - Operation Director
    - Secretariat
    - Operation team
    - Construction team
  - Marketing & Distribution Director
    - Secretariat
    - Customer service team
    - Distribution team
    - Tariff commercial team
    - Rural electrification team
    - Business development team
  - Finance Director
    - Secretariat
    - Casher team
    - Accounting team
    - Budget team
    - Loan financing team
  - Human Resources & Organization Team
    - Secretariat
    - Human resources and organization team
    - Office facilities team
    - Law and regulation team
    - Public relation team

2.3 Energy Supply and Demand in Indonesia

2.3.1 Resources and Reserves

Indonesian primary energy resources and the reserves are published by MIGAS, BP Amoco Statistics, WEC (World Energy Council) and other international institutions. Taking into consideration of the published data synthetically, Indonesia has crude oil proven reserves of 5.2 billion bbl (barrels), the natural gas proven reserves of 72.3 trillion standard cubic feet, and coal reserves of about 5.3 billion short tones, at the end of 1999.

(1) Oil

According to BP Amoco Statistics 2001, the reserves and production of crude oil is shown in Table 2.3.1.

Table 2.3.1 Reserves and Production of Crude Oil

Proved Reserves	At the end of 1979	At the end of 1989	At the end of 1998	At the end of 1999			
	billion barrels	billion barrels	billion barrels	billion barrels	billion tones	Share	R/P ratio
Indonesia	**9.6**	**8.2**	**5.0**	**5.0**	**0.7**	**0.5%**	**9.7**
Asia Pacific Total	39.4	46.6	43.1	44.0	5.9	4.3%	16.3
World Total	650.1	1011.7	1052.0	1033.8	140.4	100.0%	41.0

Production Million tones	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Growth 98/99	Share in 1999
Indonesia	**71.9**	**78.3**	**74.1**	**74.3**	**74.3**	**73.9**	**74.1**	**73.1**	**71.6**	**68.2**	**–4.7%**	**2.0%**
Asia Pacific Total	322.9	332.4	332.4	334.8	344.0	350.1	362.5	367.8	367.0	364.5	–0.7%	10.5%
World Total	3164.1	3151.9	3184.1	3184.2	3225.2	3272.0	3370.9	3468.5	3533.1	3452.2	–2.3%	100.0%

(Source) BP Amoco 2001

In the Table, the proved reserves of Indonesian crude oil are estimated 5.0 billion barrels at the end of 1999, accounting for 0.5% of world total and 11.4 % of Asia Pacific total. Reserve/Production (R/P) ratio is 9.7, while that of world average is 41.0. The oil production in 1999 was 68.2 million tones, with the decrease of 4.7% from the previous year.

Much of Indonesia's proven oil reserve base is located onshore. Central Sumatra is the country's largest oil producing province where Duri and Minas oil fields are located. Other significant oil field under development or production is located in accessible areas such as offshore of northwestern Java, East Kalimantan, and the Natuna Sea. Table 2.3.2 shows the regional distribution of hydrocarbon (oil and natural gas) reserves, and Table 2.3.3 shows the oil and natural gas reserves and resources in whole Indonesia (by MIGAS).

Table 2.3.2 Distribution of Hydrocarbon Reserves

	Oil (million bbl)			Natural Gas (TSCF)		
Location	Proven	Potential	Total	Proven	Potential	Total
Aceh	53.3	19.7	73.0	4.1	6.7	10.8
North Sumatra	162.1	59.5	221.6	1.2	0.3	1.5
Natuna	127.0	180.2	307.2	30.5	19.0	49.5
Central Sumatra	2,732.0	2,973.1	5,705.1	0.3	1.0	1.3
South Sumatra	428.6	319.8	748.4	6.3	3.8	10.1
West Java	621.9	487.4	1,109.4	4.5	2.3	6.7
East Java	232.2	91.7	323.9	2.8	3.1	5.9
East Kalimantan	760.9	475.9	1,236.7	27.7	20.1	47.8
South Sulawesi	-	-	-	0.7	0.2	0.9
Irian Jaya	85.3	15.7	101.0	14.5	9.4	23.9
Total	**5,203.2**	**4,623.1**	**9,826.3**	**92.5**	**65.8**	**158.3**

(Source) MIGAS, January 1, 1999

Table 2.3.3 Reserves and Resources of Oil and Natural Gas

	Oil (billion bbl)	Gas (TSCF)
Reserves		
Onshore	7.7	113.1
Offshore	2.1	45.2
Total	**9.8**	**158.3**
Resources		
Onshore	19.3	73.0
Offshore	19.2	141.4
Total	**38.4**	**214.4**

(Source) MIGAS, January 1, 1999

Except for Exspan, Pertamina and Total companies, most of the country's major producers have experienced a downward trend in the output in recent years. Officials said that low production levels would continue in 2000 since no large oil fields had been discovered in recent years, and new oil-field development would be concentrated in smaller fields (on and offshore) in the relatively well explored provinces of Sumatra, Java, and Kalimantan. The oil production by major producers is shown in Table 2.3.4.

Table 2.3.4 Oil and Gas Production by Major Producers

Oil and Condensate (1000 bbl/d)				Gas mmscf			
Company	1998	1999	2000 Jan-May	Producers	1998	1999	Share (%)
Caltex	759.5	746	719.3	Mobil Oil	921,865	794,299	25.9
Maxus	148.2	140.1	126.2				
Total Co.	79.2	81.2	86.4	Total Co.	604,447	684,565	22.3
Arco	74.4	71.5	65.7	Arco	165,937	298,327	9.7
Exspan	26.6	37.5	61.9	Pertamina	270,330	259,132	8.4
Conoco	84.4	64.4	57.4	Gulf Res.	75,076	166,449	5.4
Unocal	75.6	63.9	59.9	Unocal	143,764	162,903	5.3
Vico	60.8	54.7	49.2	Vico	456,954	477,368	15.6
Others	247.9	241.0	216	Others	340,479	225,306	7
Total	**1,556.6**	**1,500.3**	**1,442.0**	Total	2,978,852	3,068,349	100.0

(Source) MIGAS

(2) Natural Gas

The reserves and production of natural gas is shown in Table 2.3.5 (BP Amoco Statistics).

Table 2.3.5 Reserves and Production of natural Gas

Proved Reserves	At the end of 1979	At the end of 1989	At the end of 1998	At the end of 1999			
	Trillion cubic meters	Trillion cubic meters	Trillion cubic meters	Trillion cubic meters	TSCF	Share	R/P ratio
Indonesia	**0.68**	**2.46**	**2.05**	**2.05**	**72.3**	**1.4%**	**30.8**
Asia Pacific Total	4.35	8.03	10.17	10.28	363.4	7.0%	40.4
World Total	72.87	112.91	146.39	146.43	5171.8	100.0%	61.9

Production Million toe	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Growth 98/99	Share in 1999
Indonesia	**40.8**	**46.4**	**48.9**	**50.6**	**56.6**	**57.4**	**60.4**	**60.8**	**57.5**	**59.8**	**4.0%**	**2.9%**
Asia Pacific Total	134.9	147.5	157.7	165.9	180.4	190.8	206.6	215.1	218.2	229.4	5.1%	11.0%
World Total	1792.4	1822.0	1831.9	1862.2	1881.3	1917.4	2008.8	2007.3	2046.1	2096.8	2.5%	100.0%

(Source) BP Amoco 2001

The proved reserves of Indonesian natural gas are estimated 72.3 trillion cubic feet at the end of 1999, which accounts for 1.4% of world total and 19.9% of Asia Pacific total. Reserve/Production (R/P) ratio is 30.8, while that of world average is 61.9. The natural gas production in 1999 was 59.8 million toe (tones of oil equivalent), with increase of 4.0% from the previous year.

On the other hand, the Government of Indonesia estimates Indonesian gas reserves of 158.3 trillion standard cubic feet (TSCF) or about 27 billion barrels of oil equivalent, of which 92.5 TSCF are proven and 65.8 TSCF are probable (See Table 2.3.2). This corresponds to around three times of Indonesia's oil reserves and can supply the country for 50 years at the current production rate. Over 71 percent of natural gas reserves are located offshore, in which the largest reserve is Natuna Island accounting for the share of 33.3 percent, followed by East Kalimantan (30.2 percent), Irian Jaya (15.1 percent), Aceh (6.8 percent) and South Sumatra (6.4 percent). The discoveries by Arco, now BP, in the Wiriagar and Berau gas fields located offshore of Irian Jaya is expected to be one of the most promising finds of late.

"Country Brief" by U.S. DOE/EIA, Dec. 2000 said that Indonesia has proven natural gas reserves of 72.3 trillion cubic feet (tcf). Most of the country's gas reserves are located near the Arun field in North Sumatra, around the Badak field in East Kalimantan, smaller offshore fields of Java, the Kangean Block in the offshore of East Java, a number of blocks in Irian Jaya, and the Natuna D-Alpha field that is the largest field in Southeast Asia. Despite its significant gas reserves and its position as the world's largest exporter of liquefied natural gas (LNG), Indonesia still depends on oil about 50% of its energy needs.

(3) Coal

The reserves and production of coal is shown in Table 2.3.6 (BP Amoco Statistics).

Table 2.3.6 Reserves and Production of Coal

Reserves at the end of 1999 Million tones	Anthracite and Bituminous	Sub-bituminous and Lignite	Total	Share	R/P ratio
Indonesia	**770**	**4450**	**5220**	**0.5%**	**80**
Asia Pacific Total	184450	107895	292345	29.7%	164
World Total	509491	474720	984211	100.0%	230

Production Million toe	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Growth 98/99	Share in 1999
Indonesia	**6.4**	**8.7**	**14.2**	**17.0**	**19.1**	**25.5**	**31.0**	**33.7**	**37.1**	**40.1**	**8.2%**	**1.9%**
Asia Pacific Total	815.3	829.7	859.9	885.7	927.7	977.7	1040.0	1031.0	999.2	884.3	–11.5%	42.0%
World Total	2269.1	2197.6	2189.5	2131.8	2182.8	2221.4	2285.6	2289.8	2238.9	2103.5	–6.1%	100.0%

(Source) BP Amoco 2001

The reserves of Indonesian coal are estimated 5.22 billion tones at the end of 1999, which accounts for 0.5% of world total and 1.8 % of Asia Pacific total. Reserve/Production (R/P) ratio is 80, while that of world average is 230. The coal production in 1999 was 40.1 million tones, with the increase of 8.2% from the previous year.

On the other hand, the Directorate of Mineral and Coal Enterprises (DOC) Ministry of Energy and Mineral Resources (MEMR) has identified 38.8 billion tones of coal deposits, of which 11.5 billion tones are classified as the measured resources and 27.3 billion tones as the indicated, inferred and hypothetical resources, and 5.4 billion tones is classified as the commercially exploitable reserves (See Figure 2.3.7). Major coal resource areas are Kalimantan and Sumatra, estimated at 21.1 billion tones and 17.8 billion tones, respectively.

Coal deposits in Sumatra are located largely in the area surrounding Tanjung Enim, South Sumatra. These deposits are mined by a state-owned coal company, Perusahaan Tambang Batubara Bukit Asam (PTBA). Kalimantan has high quality coal deposits. Coal contractors operating in Kalimantan have the rights to exploit a total of 6.5 billion tones of the measured reserves. Kaltim Prima Coal possesses the largest measured reserves estimated at 1.3 billion tones, followed by Arutmin Indonesia and Adaro Indonesia with one billion tones each.

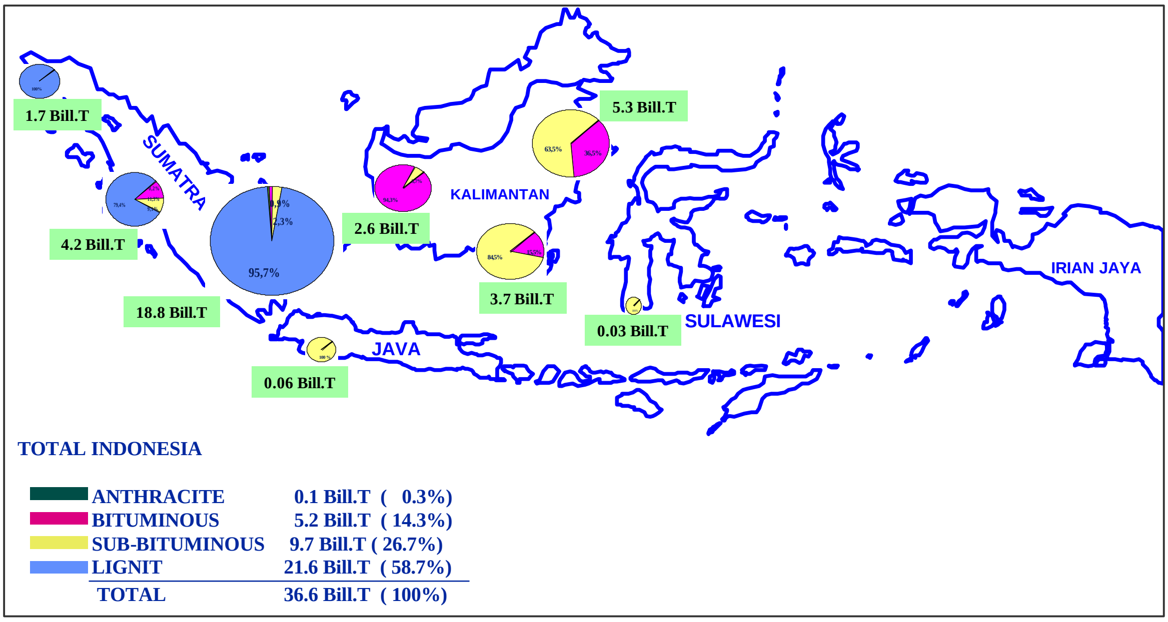
Regarding coal production, Indonesia plans to double coal production over the next five years, mostly for exports to other countries in East Asia and India. The new capacity will come primarily from private mines. The Clough Group of Australia was awarded a US$215-million contract for improvements at the Indonesian firm GBP's Kutai mine in East Kalimatan. Another foreign firm with major interests in Indonesian coal mining is Australia's Broken Hill Proprietary (BHP).

Table 2.3.7 Indonesian Coal Resources

Company (Million tones)	Resources			Mineable
	Measured	Indicated	Total	Reserves
PTBA	1,902	4,657	6,559	2,804
Contractors	8,998	22,185	31,183	2,054
Others	584	442	1,026	504
TOTAL	11,484	27,284	38,768	5,362

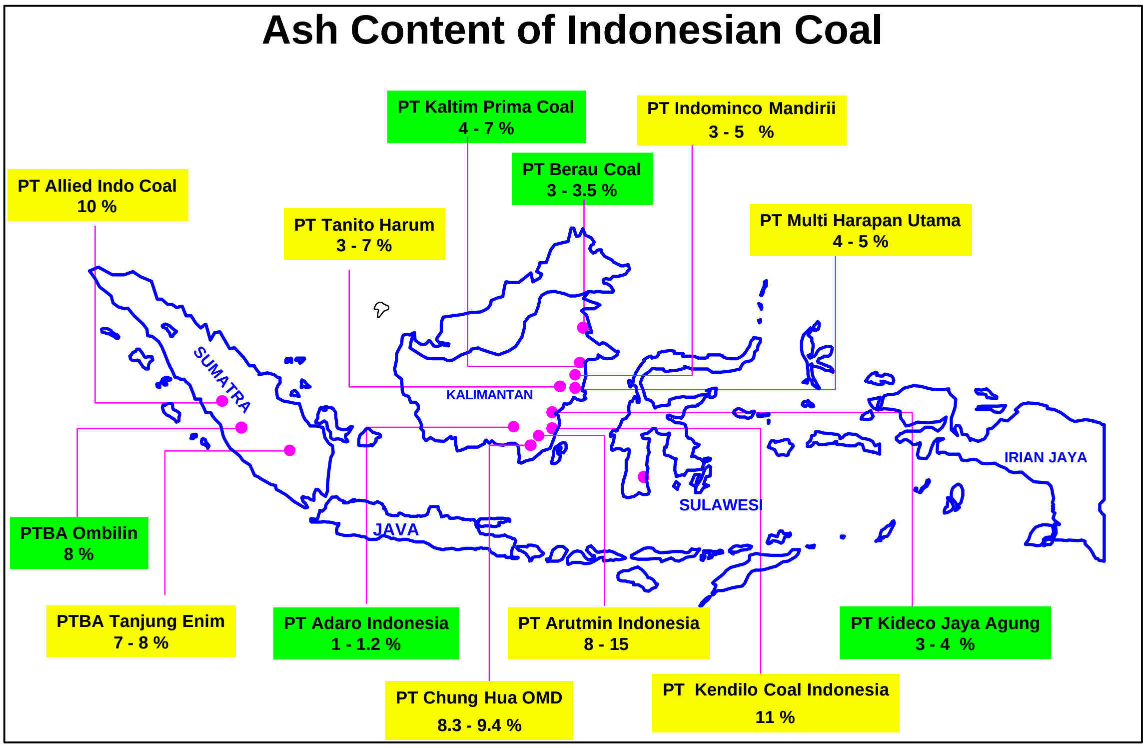
(Source) Directorate of Mineral and Coal Enterprises

Figure 2.3.1 Distribution of Coal Reserves in Indonesia



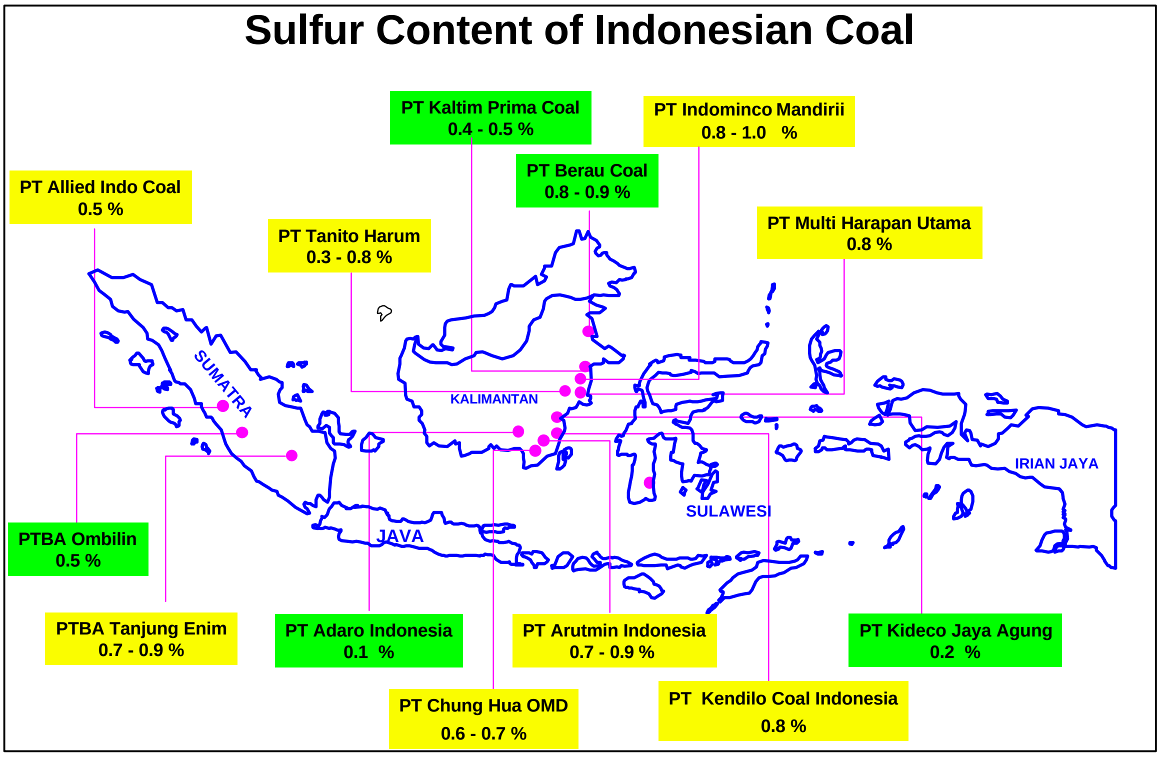
(Source) Directorate of Mineral and Coal Enterprises

Figure 2.3.2 Ash Content of Indonesian Coal



(Source) Directorate of Mineral and Coal Enterprises

Figure 2.3.3 Sulfur Content of Indonesian Coal



(Source) Directorate of Mineral and Coal Enterprises

2.3.2 Exploration of Primary Energy Resources

The Government of Indonesia tries to enhance the production from existing fields and makes effort to discover new fields.

In 1999, Indonesian oil production, including condensate, declined by 3.6 percent to an average of 1.50 million bbl/d from 1.56 million bbl/d in 1998. Crude oil production, excluding condensate, peaked at 1.391 million bbl/d in February 1999. Condensate is mainly produced at the Arun field in North Sumatra as a by-product of the oil and natural gas production process. However, because of dwindling gas reserves in the Arun field, the reduction of gas production resulted in the less produced condensate. Production of condensate fell to 149.1 thousand bbl/d in 1999 from 155.3 thousand bbl/d in 1998 and 162.8 thousand bbl/d in 1997.

Indonesia's recent oil production has remained relatively flat as the result of the introduction of crude streams from new and smaller fields, which has helped to compensate for declines at many of the country's mature oil fields. To meet its goal of oil production, Indonesia has stepped up efforts to sign new oil exploration contracts. Seven new production-sharing contracts (PSCs) were awarded in May 2000, up from only four in the 1999 bidding round. The majority of Indonesia's producing oil fields are located in the central and western sections of the country. Therefore, the focus of new exploration has been on frontier regions, particularly in eastern Indonesia. Sizable, but as of yet unproven, reserves may lie in the numerous, geologically complex, pre-tertiary basins located in eastern Indonesia. These regions are much more remote and the terrain more difficult to explore than areas of western and central Indonesia (“Country Brief” by U.S. DOE/EIA, Dec. 2000).

Of the estimated 60 oil basins, over 22 have been extensively explored. Most oil exploration is currently being carried out in the basins of Western Indonesia under PSCs. The bulk of Indonesia’s oil reserves are located onshore and offshore in Central Sumatra and Kalimantan. The Government has placed increased emphasis on developing oil reserves in remote locations, such as Papua, where proven reserves are estimated at 85 million barrels (“Petroleum Report” by US Embassy in Jakarta).

A total of 22 wildcat and appraisal gas wells were drilled in 1999. Oil companies, however, do not actively explore for gas in Indonesia, due to disincentives in the pricing for domestic gas. Rather, as the ratio of gas to oil accumulations is high in Indonesia, most gas fields have been discovered during oil exploration (“Petroleum Report” by US Embassy in Jakarta).

Table 2.3.8 New Discoveries and Fields Coming on Line

Contractor	M/Y	Location	Discovery or Production
UNOCAL	June 1999	Kutai Basin, Rapak Block PSC, Janaka North 1, the Makassar Straits, West Seno field	Reserves, 210 to 320 (MMBOE). Oil and gas production 70,000 bbl/d
	Oct. 1997	the Merah Besar structure	
	Mar. 1998	Seno structure	
EXXON MOBIL	June 1999	North Sumatra offshore	Natural Gas Production
MAXUS		PGD-3 Bayung Lincir Musi Banyuasin block, South Sumatra	Reserves Gas, 230 (BSCF) NGL, 7.0 million bbls Production Gas, 11.3 mmscfd NGL, 522 bbl/d
CALTEX	Feb. 1999	(LOSF) project, Minas, Central Sumatra	Enhanced Production
CONOCO	1998	West Natuna Block "B"	Strike Oil
GULF INDONESIA RESOURCES		Suban field onshore Sumatra	Crude and Condensate flow rate of 272 bbl/d Gas 27.8 mmscfd
MEDCO	1999		Reserves Oil 181.2 bbl Gas 169.8 billion cubic feet

(Source) "Petroleum Report" by US Embassy in Jakarta

With more competitive fiscal terms and a market-based pricing system, there would be an incentive to exploit more of Indonesia's natural gas reserves. Four key areas have been identified by the private sector to enhance the gas development in Indonesia:

- To increase incentives to find and produce natural gas;
- To promote private investment and ownership, as well as stability and cost recovery for those firms that invest in major gas facilities;
- To encourage multi-buyer and multi-seller gas marketing; and
- To establish incentives for domestic gas usage.

According to MIGAS, the Indonesia oil and gas resources are buried underneath sixties' (60) Tertiary sedimentary basins, covering an area of more than two millions square kilometers. So far thirty-six (36) basins have been explored in detail. The hydrocarbon reserves have been found largely in the Western part of Indonesia where most exploration activities have taken place. Physiographically, the Indonesia archipelago can be divided into Western and Eastern regions, which are separated by 200 m isobaths starting from offshore Kalimantan in the Makassar Strait to offshore Bali in the Lombok Strait.

The Western Indonesia covers the islands of Sumatra, Java, Kalimantan and the smaller islands in between. This region is often referred as the main part of Sunda Shelf. Prolific hydrocarbon's Tertiary-basins in this area are principally confined to the perimeter of the continental margins in the Sunda Shelf. The Eastern Indonesia covers the principal island of Sulawesi, Maluku, and Irain Jaya, Arafura Sea, Banda and Timor Sea. This region lie on the Sahul Shelf, which stretches Northwards of the Australian Continent presently, oil and gas discoveries in the Eastern Indonesia are from both of Tertiary and pre-Tertiary reservoir rocks.

Sedimentary basins in Western Indonesia are mostly located onshore or in shallow water while in Eastern Indonesia are mainly located in deep water depth. Roughly, 30% of the offshore basins in Western Indonesia and 80% in Eastern Indonesia are classified as deep-sea basins. Many of the prolific Tertiary basins in Sumatra, Java, and Kalimantan can be classified as mature stages in the exploration, whereas productions of some of their fields are declining. On the contrary, most sedimentary basins in Eastern Indonesia are poorly explored. These under explored basins are located in remote areas, in deep sea or other geologically complex regions. Eastern Indonesia, presently, can be considered as frontier area.

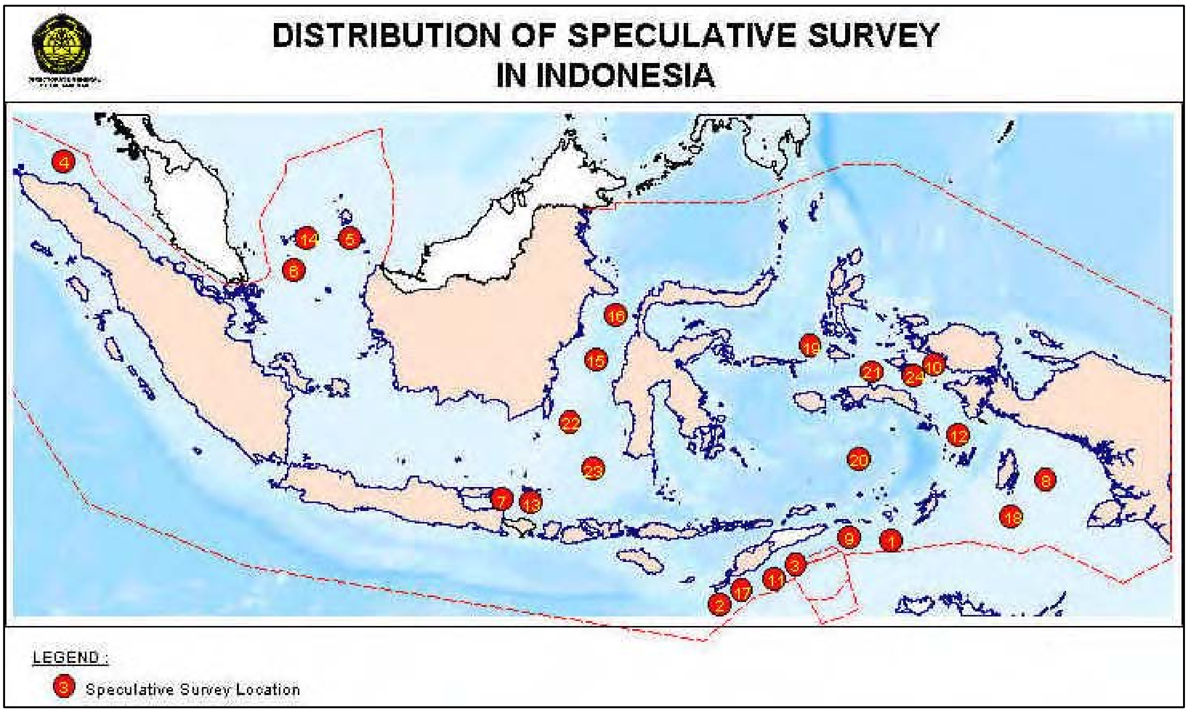
Table 2.3.9 Discoveries and Production of Oil and natural Gas Field

Contractor	**M/Y**	**Location**	**Discovery or Production**
Indonesia Total	Dec. 1999	Tunu and Mahakam, Peciko gas field, East Kalimantan	Proven Gas Reserves 19.5 TSCF Production 100 mmscfd started 400 mmscfd expected 800 mmscfd in 2000 Daily Total 470 million BOE 60% of Bontang LNG
EXXON MOBIL	2001	Merah Besar, offshore East Kalimantan, Makassar strait PSC	Gas Reserves 100 & 200 million BOE
BP, Nippon Oil Kanematsu Occidental, BG, Cairn, Nissho Iwai		Wiriagar, Berau, Muturi, Tangguh, Ilian Jaya	Proven Gas Reserves 14.4 TSCF
BP	2004	Terang-Sirasun, Kangean PSC, Ilian Jaya	1 TSCF
Exxon-Mobile Pertamina		TAGP from East Natuna	AL field 46 TSCF Sales 2400 mmcfd, 15 million tons/y LNG for 40 years
Pertamina SembGas	Mid 2001	West Natuna to Malaysia, TAGP	325 mmscfd for 22 years
Pertamina Conoco Gulf Ind.	July 2002	West Natuna to Malaysia, TAGP	100 mmscfd 250 mmscfd in 2004
SantaFe Devon	mid-2003	South Sumatra Gas Project	Reserves 2.36 Tcf 150 mmscfd 350 mmscfd in 2009
PGN		Gas pipe line to Singapore via Batam	
East Timor Australia		Timor Gap	Exploiting contract

(Source) “Petroleum Report” by US Embassy in Jakarta

Current exploring areas in Indonesia are shown in the Figure 2.3.4 and 2.3.5.

Figure 2.3.4 Speculative Survey Area



(Source) MIGAS

Figure 2.3.5 Oil and Gas Exploration Area

(Source) MIGAS

<Reference>

The main fields and major facilities concerning oil and gas are as follows.

(1) Oil

Major Producing Oil Fields:

Duri, Minas, Belida, Ardjuna, Arun, KG/KRA, Widuri, Nilam, Attaka

Oil Refineries (operating capacity-bbl/d, December 1999):

Cilacap, Central Java	(380,000);
Pertamina-Balikpapan, Kalimantan	(240,920);
Musi, South Sumatra	(109,155);
EXOR-1, Balongan, Java	(125,000);
Dumai, Central Sumatra	(114,000);
Sungai Pakning, Central Sumatra	(47,500);
Pangakalan Brandan, North Sumatra	(4,750);
Cepu, Central Java	(3,420)

Product Pipelines:

Trans-Java (serving the Surabaya market)

(2) Natural Gas

Major Gas Fields:

Sumatra: Arun, Alur Siwah, Kuala Langsa, Musi, South Lho Sukon, Wampu

East Kalimantan: Attaka, Badak, Bekapai, Handil, Mutiara, Nilam, Semberah, Tunu

Natuna Sea:

Natuna Java: Pagerungan, Terang/Sirasun

Irian Jaya: Tangguh

Major Gas Pipelines:

Sumatra: Pangkalan Brandan-Dumai

LNG Plants:

Arun, Bontang

2.3.3 Renewable Energy

(1) Hydropower potential

The hydropower potential study was carried out by PLN in 1999. Table 2.3.10 shows the results of the study. The total hydropower potential including undeveloped, planned, under construction, and developed potential is estimated to be 81,859 MW in Indonesia. The total hydropower potential in the Java Bali area is estimated to be 5,795 MW.

Table 2.3.10 Hydropower Potential in Indonesia (MW)

Area	Undeveloped	Planned and Under Construction	Developed	Total
Java Bali	2,238	1,552	2,005	5,795
Wilayah I (Aceh)	6,367	1,059	0	7,426
Wilayah II (Sumatra)	3,077	921	603	4,601
Wilayah III (Sumatra)	4,094	707	79	4,880
Wilayah IV (Sumatra)	4,277	497	16	4,790
Wilayah V (Kalimantan)	5,469	257	0	5,726
Wilayah VI (Kalimantan)	10,492	780	30	11,302
Wilayah VII (Sulawesi)	4,163	150	31	4,344
Wilayah VIII (Sulawesi)	6,814	947	291	8,052
Wilayah IX (Maluku)	599	66	0	665
Wilayah X (Irian Jaya)	23,109	72	0	23,181
Wilayah XI (Nusateggara)	988	109	0	1,097
Total	71,687	7,117	3,055	81,859

(Source: PLN)

There is much-undeveloped hydropower potential in Indonesia. Most of the potential is located in Sumatra, Kalimantan and Irian Jaya, outside Java Bali. In these areas, it is expected that hydropower will be an available primary energy, in addition to coal and gas. However, in these areas, hydropower is not being developed due to the small and scattered demand and inadequate transmission lines.

Hydropower sites have been developed mostly on Java Island. In addition, there are some potential sites of conventional hydropower in the Java-Bali area. Table 2.3.11 shows the 2001 development plan for the Java-Bali area. At the minimum a pre-feasibility study has been conducted on these development sites. However, most of these sites are difficult to develop due to economic and socio-environmental reasons, such as high construction costs and resettlement of communities. Due to this, they have not been promoted to develop conventional hydropower stations. Nevertheless, pumped storage power stations are considered for future peak demand in Java-Bali area.

Table 2.3.11 Hydropower Development Plan in Java-Bali Area

Name		River	Type	Installed Capacity (MW)
West Java	Ciliman	Climan	RES	5.3
	Rajamandala	Citarum	ROR	55.0
	Cipasang	Cimanuk	RES	400.0
	Jatigede	Cimanuk	RES	250.0
	Cibuni 3	Cibuni	RES	172.0
	Cibuni 4	Cibuni	RES	71.1
	Cikaso 3	Cikaso	RES	29.8
	Cimandiri	Cimandiri	RES	352.0
Central Java	Maung	K..Serayu	RES	360.0
	Gintung	K.Serayu	RES	19.2
	Rawalo 1	K.Serayu	LHD	0.6
East Java	Grindulu 2	K.Grinau	RES	16.3
	Kesamben	Brantas	ROR	37.0

(Source: PLN)

RES; Reservoir Type

ROR; Run of river Type

LHD; Run of river Type with a low head dam

(2) Geothermal power potential

The geothermal power potential was studied by Pertamina in 1995. Table 2.3.12 shows the results of the study. The geothermal power potential is estimated to be 19,658 MW in Indonesia. The geothermal power potential in Java Bali is estimated to be 5,681 MW.

Table 2.3.12 Geothermal Power Potential in Indonesia

Area	Potential (MW)
Java Bali	5,681
Aceh & North Sumatra	3,705
Central & South Sumatra	5,857
Lombok	0
Sumbawa	250
Frores	1,850
North Sulawesi	815
Other Sulawesi	750
Maluku Islands	750
Total	19,658

(Source: PLN)

As Indonesia is an island country with many volcanic areas, there is much geothermal power potential. The geothermal power potential distributed in Indonesia is expected to be a primary energy, in addition to coal and gas.

A total installed capacity of 727 MW of geothermal power has been developed in Indonesia by PLN and IPPs, most of it is located in Java island. In addition, there is much undeveloped geothermal potential. Table 2.3.13 shows the 2001 development plan in the Java-Bali area. However, many sites are difficult to develop due to economic and environmental reasons. Geothermal power development by PLN is not progressing. It is expected that development will be promoted under the IPP scheme in the future.

Table 2.3.13 Geothermal Power Development Plan in Java-Bali Area

Name	Area	Installed Capacity (MW)
(Java-Island)		
Kamojang 4	West Java	60
Salak 7	West Java	55
Wayag-Windu 2	West Java	110
Karaha	West Java	220
Cibuni	West Java	10
Patuha	West Java	220
Dieng	Central Java	95
(Bali-Island)		
Bedugul Bali	Bali	220

(Source: PLN)

2.3.4 Outline of Current Situation of Energy Supply and Demand

(1) Primary energy

According to an annual report “Statistik dan Informasi Ketennagalistrik dan Energi” by DGEEU, the Primary Energy Requirement (PER, domestic primary energy supply/ consumption) in 1999/2000 is 635,745.2 thousand BOE (86,271 thousand tones of oil equivalent, ktoe) comprising 365,205.1 thousand BOE (49,558 ktoe) of oil (share of 58%), 170,770.6 thousand BOE (23,174 ktoe) of natural gas (27%), 65,315 thousand BOE (8,863 ktoe) of coal (10%), 27,138 thousand BOE (3,683 ktoe) of hydropower (4%) and 7,316.5 thousand BOE (993 ktoe) of geothermal (1%).

The Final Energy Consumption (FEC) by sector in 1999/2000 was 411,408.6 thousand BOE (55,828 ktoe), consisting of 148,763.6 thousand BOE (20,187 ktoe) for an industrial sector (36%), 155,462.3 thousand BOE (21,096 ktoe) for a transportation sector (38%) and 107,182.7 thousand BOE (14,545 ktoe) for a residential sector (26%).

Regarding the final energy consumption by type in 1999/2000, oil accounts for 75 % (307,819.7 thousand BOE, 41,771 ktoe), natural gas for 8 % (34,464.7 thousand BOE, 4,677 ktoe), coal for 4 % (16,292 thousand BOE, 2,207 ktoe), and electricity for 11 % (45,118.2 thousand BOE, 6,123 ktoe).

Figure 2.3.6 Share of PER by Source

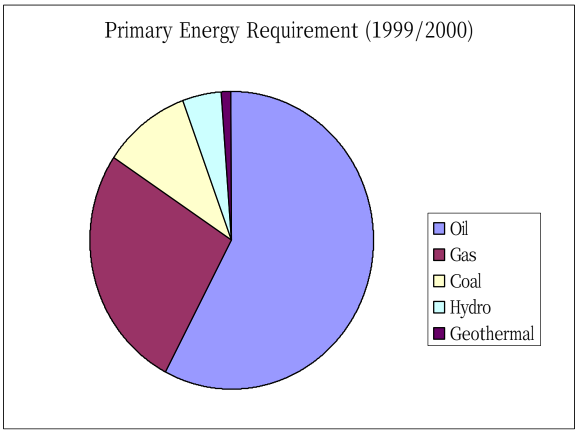
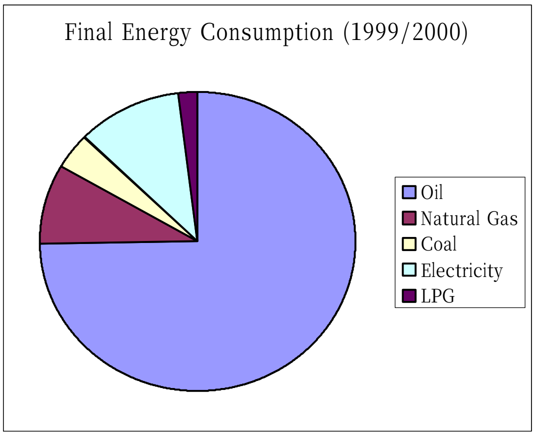


Figure 2.3.7 Share of FEC by Source



(Source) DGEEU

(2) Electricity

In 1999/2000, the capacity of the national power system was 38,599 MW, consisting of the installed PLN power system 22,732 MW, non-PLN 15,215 MW and private sector 651.8 MW. Compared to the year 1998/99 (35,676MW), the capacity of the national power system was the increase of 2,923 MW (8 % up).

The transmission lines increased from 23,860.91 to 24,388.74 kmc (527.83 kmc up). JTET (extra high voltage transmission lines) was the increase of 102.2 kmc, and JTT (high voltage transmission lines) was the increase of 426 kmc. The sub-stations increased from 45,361 MVA to 46,783 MVA. In distribution, JTM (Medium Voltage Lines) was the increased of 21,524 kmc. JTR (Low Voltage Lines) 21,995 kmc and distribution sub stations 385 MVA.

The supply of electricity in 1999/2000 was 87,999,212 MWh, consisting of PLN's production of 83,164,466 MWh and a purchase of 4,834,746 MWh. The sale of PLN electricity was 73,560,041 MWh, with an increase of 693,882 MWh over 1998/99. Sales to an industrial sector were 32,412,088 MWh (44%), while that to a residential sector 26,015,859 MWh (35%), to a commercial/business sector 9,569,216 MWh (13%) and to a public sector 3,382,801 MWh (4.6%).

The number of customers reached 27,726,932 with an increase of 953,288 (3.56 %). The residential sector was the largest group of customers, numbering in 26,015,859 with the share of 93.8 % to total customers. Rural residential customers totaled 18,683,181 equivalent to 67.38 % of the residential group. Until 1999/2000 the electrification ratio has realized 56.75 % from 56.2 % of 1998/99. The electrified villages in 1999/2000 reached 48,675 villages. The total number of villages is 61,975 consisting of 39,317 villages outside of Java and 22,658 villages in Java. The village electrification ratio is 78.54 %, while the ratio of outside Java was 67.49 % and in Java 97.71 %.

Transmission losses decreased by 2,116,563 MWh, and distribution losses decreased by 7,862,392 MWh. This represents the ratio of 2.52 % and 9.12 % in overall transmission and distribution losses respectively.

As of March 31, 2000, the capacity of independent power plants is 1,586.3 MW comprising of South Sulawesi of 220 MW, Irian Jaya of 120 MW, Central Java of 26 MW, and West Java of 800 MW. The installed capacity of the non-PLN was 15,215.02 MW, while the captive power permitted was 8,979.79 MW.

2.3.5 Energy Balance Table and Energy Flow

Table 2.3.14 shows a simple example of Energy Balance Table. Energy flow is from energy production, to primary energy supply, to energy conversion and to final energy consumption. Figure 2.3.8 shows the schematic energy flow chart and Figure 2.3.9 shows the energy flow by energy carrier in the block diagram.

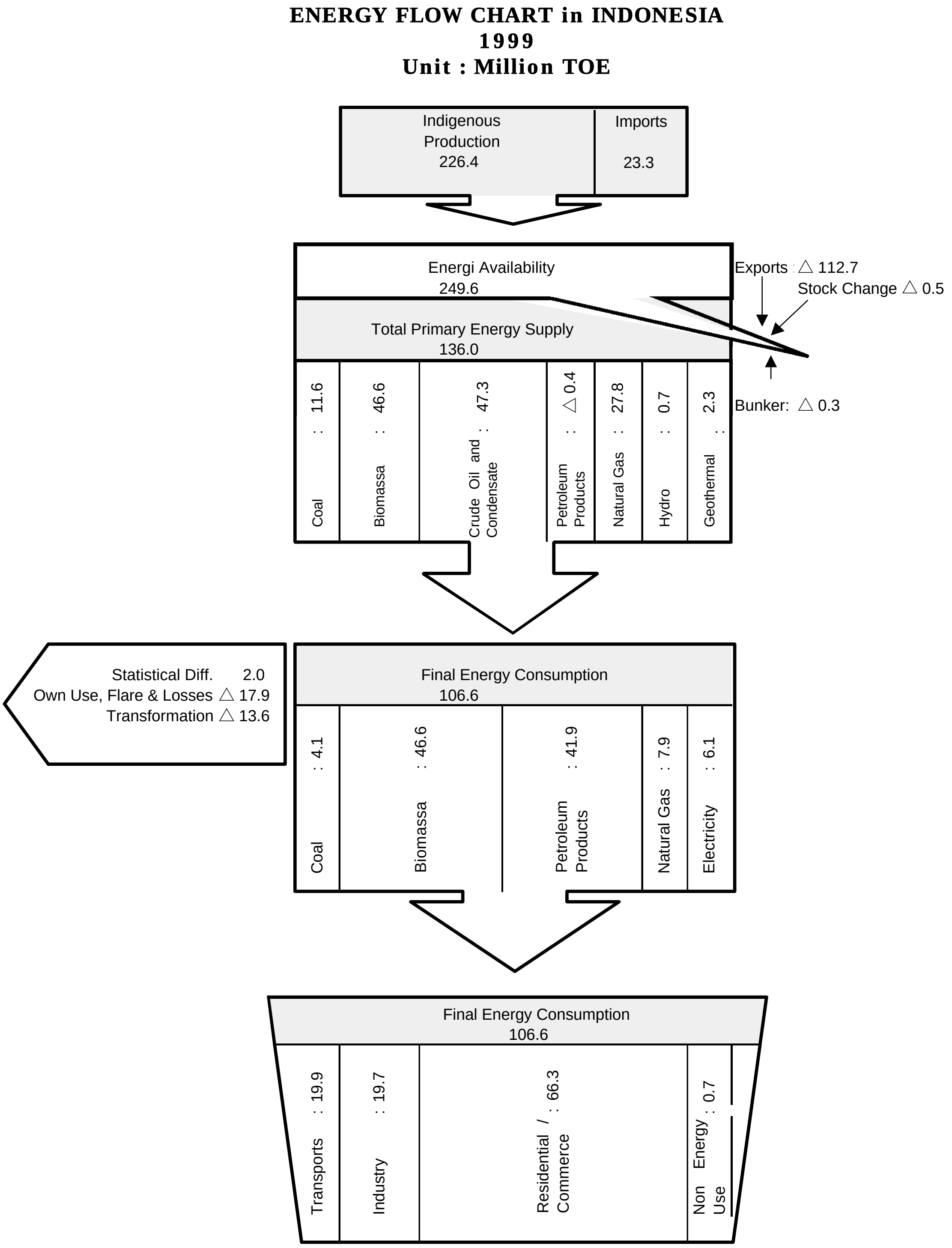
Indonesia, the representative energy producer in Asia, is an energy export country of coal, crude oil, petroleum products and natural gas. However, petroleum products such as kerosene and gas oil (diesel oil) are dependent on import at present.

Table 2.3.14 Energy Balance Table in 1999

1999	Thousand tonnes of oil equicalent								
	Coal	Crude Oil	Petroleum Products	Natural Gas	Hydro	Geothermal	Combustible and Waste	Electricity	Total
Indigenous Production	44,282	70,312	0	61,884	806	2,346	46,748	0	226,378
Imports	302	11,726	11,242	0	0	0	0	0	23,270
Exports	-33,528	-34,738	-10,246	-34,055	0	0	-104	0	-112,671
International Marine Bunkers	0	0	-308	0	0	0	0	0	-308
Stock Changes	517	0	-1,066	0	0	0	0	0	-549
Total Primary Energy Supply	**11,573**	**47,300**	**-377**	**27,829**	**806**	**2,346**	**46,644**	**0**	**136,121**
Transfers	0	-1,828	1,551	0	0	0	0	0	-277
Statistical Differences	-303	3,094	-740	-2	0	0	0	0	2,049
Public Electricity Plants	-7,151	0	-3,129	-5,198	-806	-2,346	0	6,882	-11,749
Autoproducer Electricity Plants	0	0	-369	-656	0	0	0	366	-660
Public CHP Plants	0	0	0	0	0	0	0	0	0
Autoproducer CHP Plants	0	0	0	0	0	0	0	0	0
Public Heat Plants	0	0	0	0	0	0	0	0	0
Autoproducer Heat Plants	0	0	0	0	0	0	0	0	0
Heat pumps	0	0	0	0	0	0	0	0	0
Electric boilers	0	0	0	0	0	0	0	0	0
Gas Works	0	0	0	800	0	0	0	0	800
Petroleum Refineries	0	-48,566	46,985	0	0	0	0	0	-1,580
Coal Transformation	-1	0	0	0	0	0	0	0	-1
Liquefaction Plants	0	0	322	-386	0	0	0	0	-64
Other Transformation	0	0	0	0	0	0	-71	0	-71
Own Use	0	0	-2,331	-14,488	0	0	0	-255	-17,075
Distribution Losses	0	0	0	0	0	0	0	-858	-858
Total Final Consumption	**4,117**	**0**	**41,912**	**7,897**	**0**	**0**	**46,573**	**6,135**	**106,634**
Industry Sector	**1,850**	**0**	**8,608**	**6,571**	**0**	**0**	**0**	**2,695**	**19,724**
Iron and Steel	127	0	1,197	721	0	0	0	0	2,045
Chemical and Petrochemical	0	0	1,227	5,488	0	0	0	0	6,715
Non-Metallic Minerals	1,108	0	1,386	57	0	0	0	0	2,551
Machinery	0	0	67	0	0	0	0	0	67
Mining and Quarrying	0	0	1,096	0	0	0	0	0	1,096
Food and Tobacco	0	0	771	0	0	0	0	0	771
Paper, Pulp and Printing	0	0	0	0	0	0	0	0	0
Wood and Wood Products	0	0	0	0	0	0	0	0	0
Construction	0	0	333	0	0	0	0	0	333
Textile and Leather	0	0	1,270	0	0	0	0	0	1,270
Non-specified Industry	616	0	1,261	305	0	0	0	2,695	4,877
Transport Sector	**0**	**0**	**19,901**	**0**	**0**	**0**	**0**	**0**	**19,901**
International Civil Aviation	0	0	465	0	0	0	0	0	465
Domestic Air Transport	0	0	0	0	0	0	0	0	0
Road	0	0	17,750	0	0	0	0	0	17,750
Rail	0	0	0	0	0	0	0	0	0
Pipeline Transport	0	0	0	0	0	0	0	0	0
Internal Navigation	0	0	1,685	0	0	0	0	0	1,685
Other Sectors	**2,267**	**0**	**12,710**	**1,326**	**0**	**0**	**46,573**	**3,440**	**66,316**
Agriculture	0	0	1,784	0	0	0	0	0	1,784
Commercial and Public Services	0	0	333	400	0	0	0	802	1,536
Residential	2,267	0	10,593	926	0	0	46,573	2,312	62,671
Non-specified Other	0	0	0	0	0	0	0	325	325
Non-Energy Use	**0**	**0**	**692**	**0**	**0**	**0**	**0**	**0**	**692**

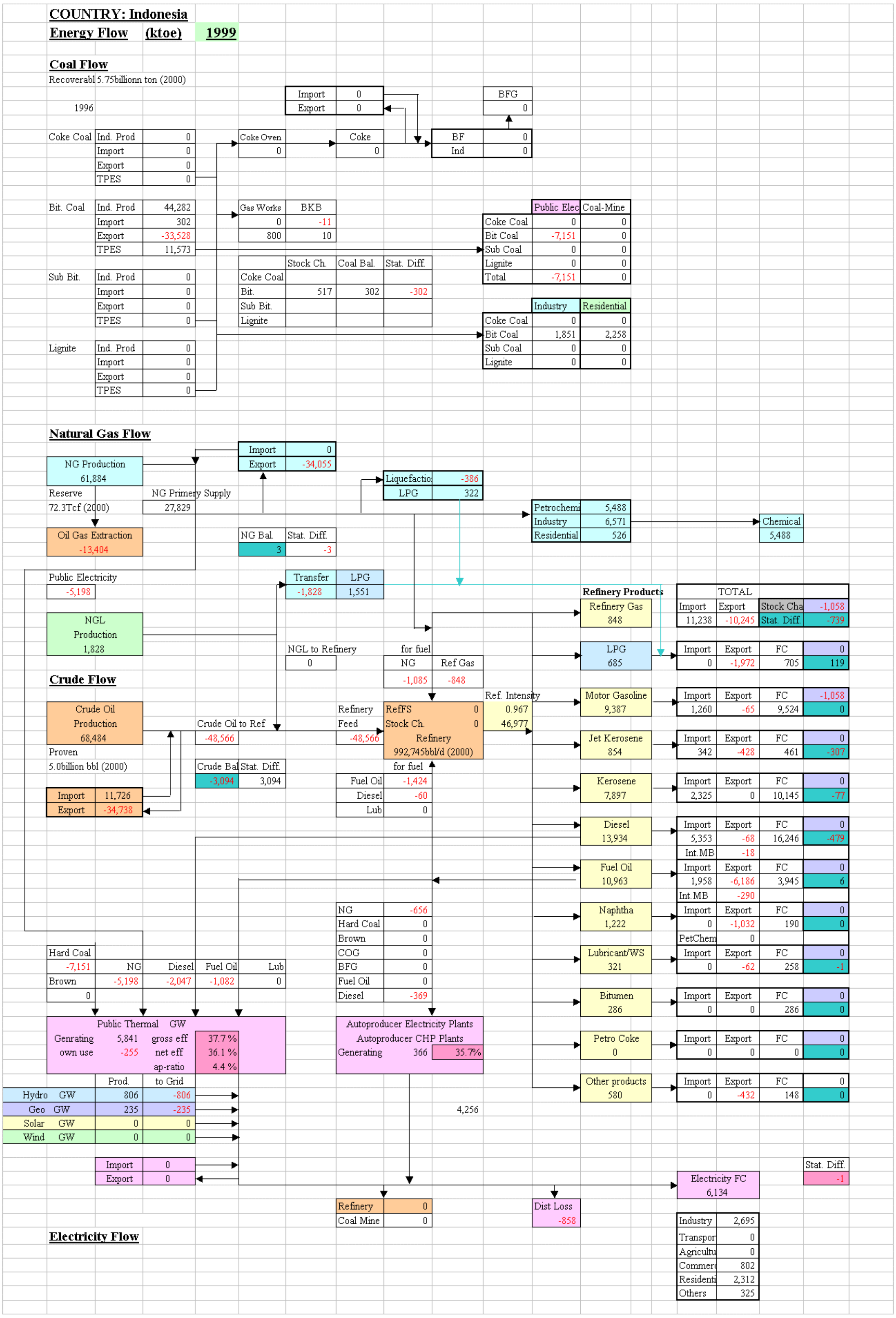
(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

Figure 2.3.8 Schematic Energy Flow in Indonesia



(Source) IEA, “Energy Balances of Non-OECD Countries, 2001”

Figure 2.3.9 Block Diagram of Energy Flow by Energy Carrier (1999)

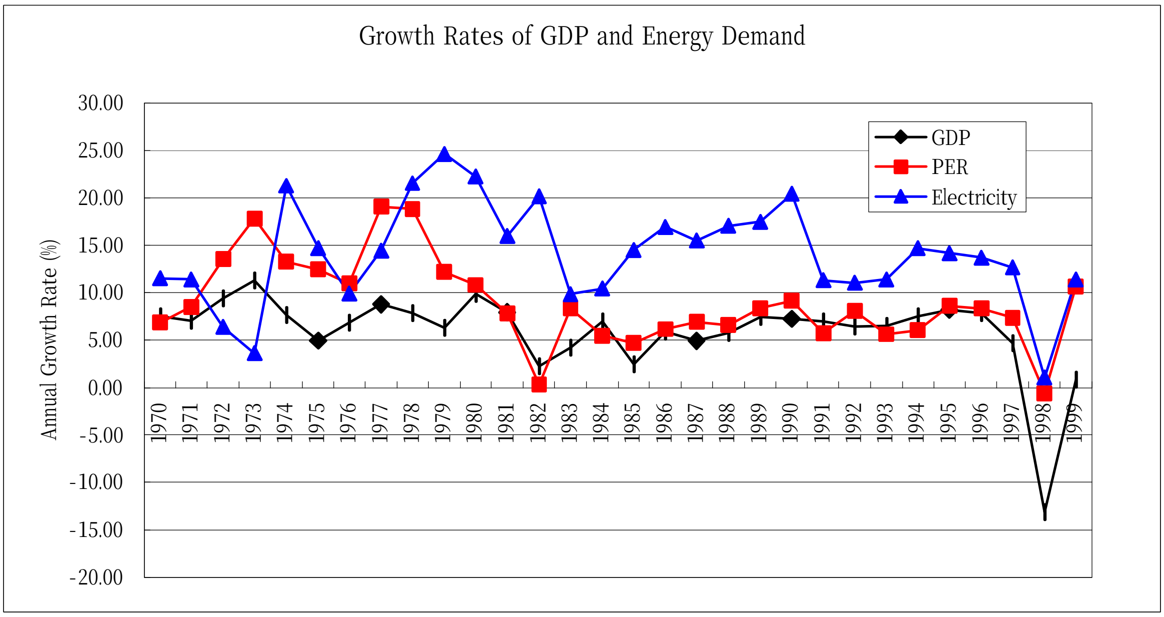


(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

2.3.6 Historical Trend of Energy Supply and Demand

Firstly we describe the outline of economic activities and energy demand. Figure 2.3.10 shows the historical trends of Indonesian economy and energy. In the Figure, polygonal line means annual average growth rates (%) of GDP, Primary Energy Requirement (PER), and Electricity Consumption (Electricity) respectively. As shown in the Figure, Primary Energy Requirement keeps a stable relationship with GDP growth rate in the period 1984/85 – 1997/98. Entering 1998/99, these energy indicators drastically decreased linked with minus (-) growth of GDP. After 1999/00, recovery of GDP growth pushed up energy growth rates. GDP growth rate recorded 4.0 % in year 2000 comparing 0.23 % of year 1999. The growth rate in year 2001 was 3.4 %.

Figure 2.3.10 Historical Trends of GDP and Energy Indicators



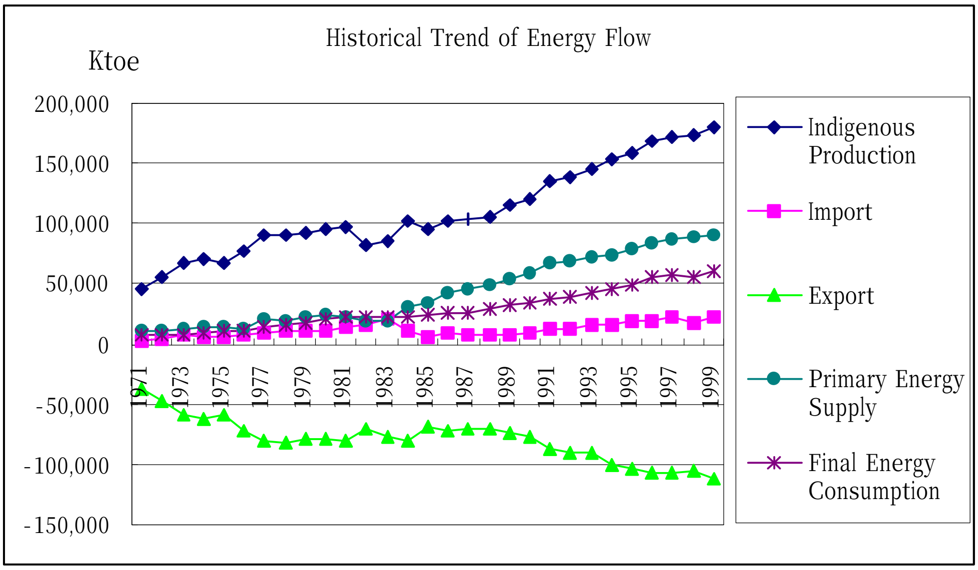
(Source) IMF, DGEEU

(1) Energy supply and demand

Figure 2.3.11 shows the historical trends of energy supply/demand (commercial energy) from energy production to final energy consumption. In the Figure, plotted lines show indigenous production, primary energy supply (domestic), final energy consumption, import and export from upper side.

Since after the half of 1990's, primary energy production has been progressing with an increasing tendency. On the other hand, the energy import also has increased by crude oil import for domestic refineries and the secondary energy import such as diesel oil, kerosene and gasoline (See Figure 2.3.9). As for export and import of crude oil, Indonesia earns hard currency by the export of high quality crude oil and meets the domestic demand by the import of comparatively low price crude oil for throughput to refineries (See Figure 2.3.9).

Figure 2.3.11 Historical Trends of Energy Supply and Demand in Indonesia

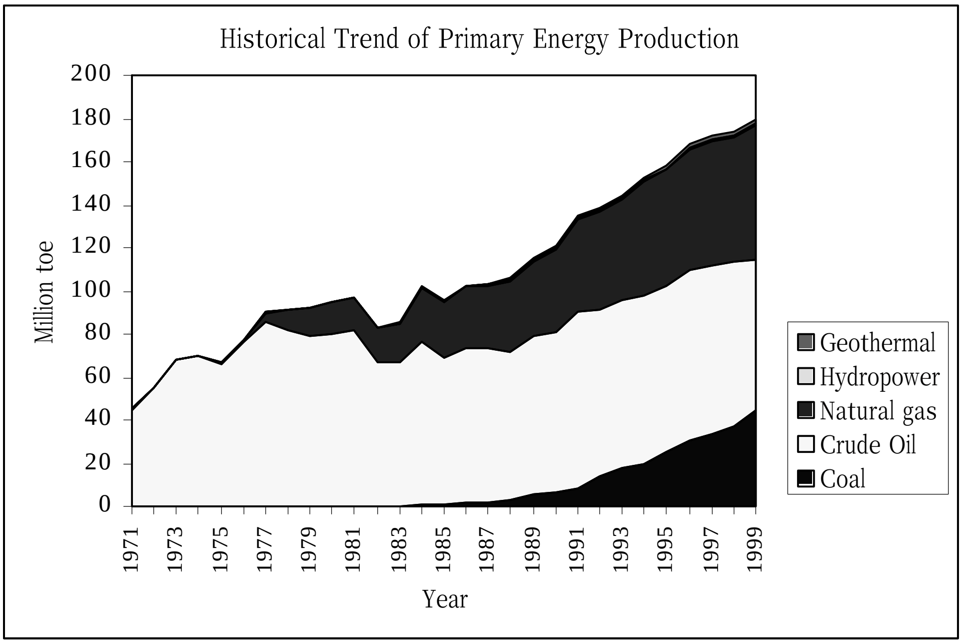


(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

(2) Energy production

Figure 2.3.12 shows the breakdown of the indigenous production shown in Figure 2.3.11. As shown in the Figure, coal and natural gas has been expanding their share through the 1990's.

Figure 2.3.12 Historical Trend of Primary Energy Production by Energy Carrier



(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

According to IEA (International Energy Agency) Statistics, the commercial energy production in 1999 was 179.63 Mtoe (million toe), in which oil accounted for 70.31 Mtoe (39.1 %), natural gas for 61.08 Mtoe (34.5 %), coal for 44.28 Mtoe (24.7 %), hydropower for 0.81 Mtoe (0.4 %), and geothermal for 1.3 Mtoe (1.3 %).

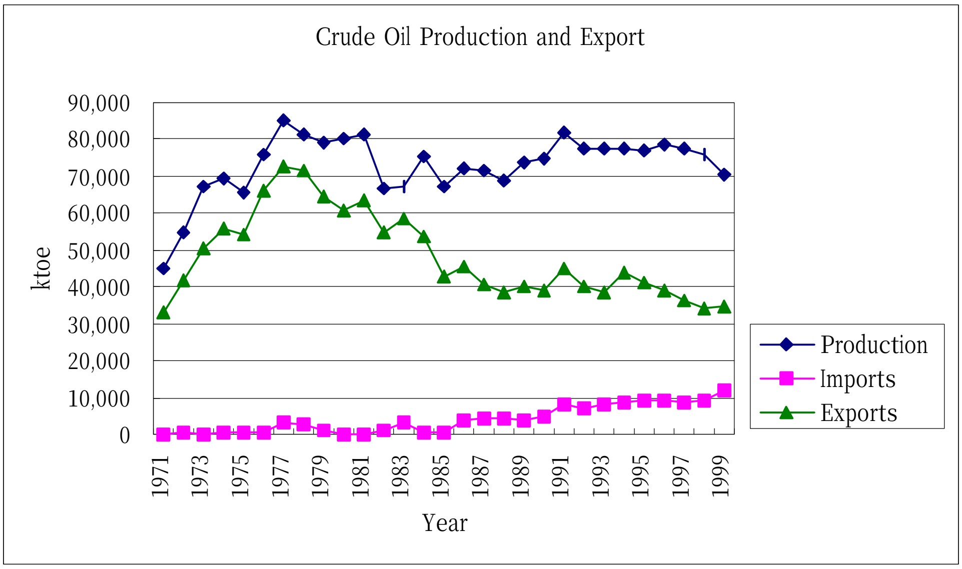
(3) Energy export and import

Figure 2.3.13, 2.3.14 and 2.3.15 show the historical trends of export/import of crude oil, natural gas and coal respectively. In these figures, each production is also plotted to point out clearly the relationship between production and export/import.

Export of crude oil has a decreasing tendency since 1977 because of the increase of domestic energy requirement. On the other hand, natural gas export was increasing from 1977 until 1994 and afterwards, the export remains the level of 30,000 ktoe (thousand tones of oil equivalent). As for coal, the export has rapidly increased after 1990. At present, the exports of crude oil, natural gas and coal are similar level of about 30,000 ktoe in terms of oil equivalent. Recent growth rates are –6 % of crude oil, almost +/- 0 % of natural gas, and +16 % of coal.

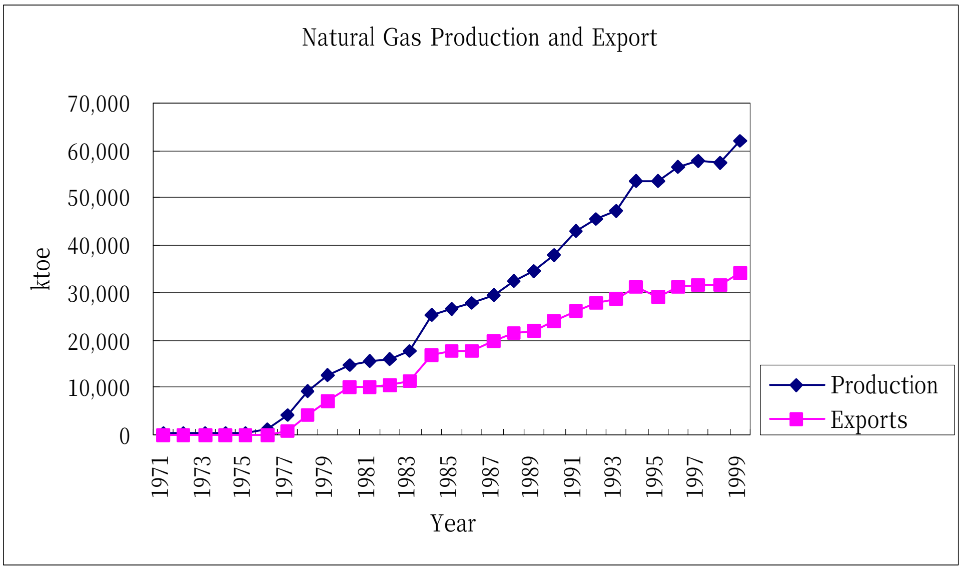
As for petroleum products, fuel oil and LPG are exported. On the other hand, gasoline, kerosene and diesel oil are imported to meet the domestic demand. Total balancing of petroleum products is the import over of about 10 %. In 1999, the total import of petroleum products was 11,238 ktoe and the total export was 10,245 ktoe.

Figure 2.3.13 Historical Trend of Crude Oil Production and Export/Import



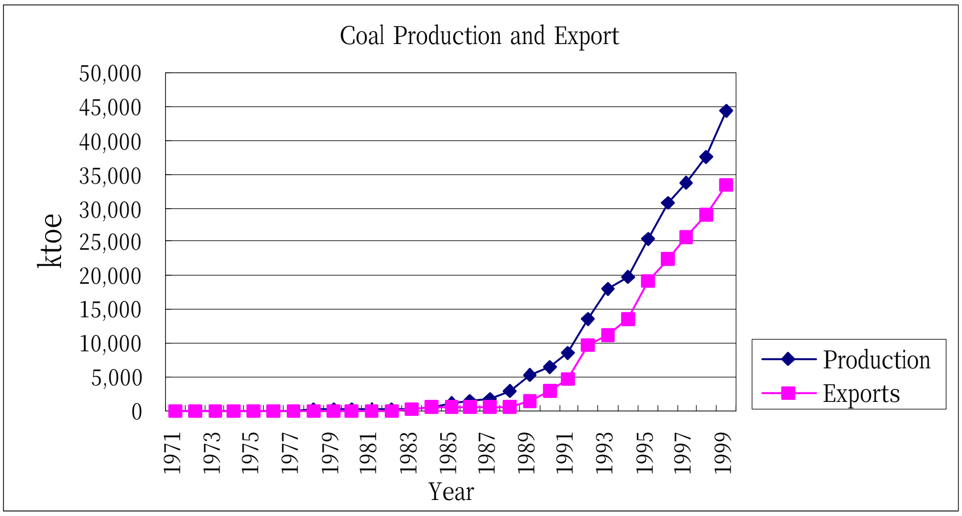
(Source) IEA, “Energy Balances of Non-OECD Countries,2001”

Figure 2.3.14 Historical Trend of Natural Gas Production and Export



(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

Figure 2.3.15 Historical Trend of Coal Production and Export

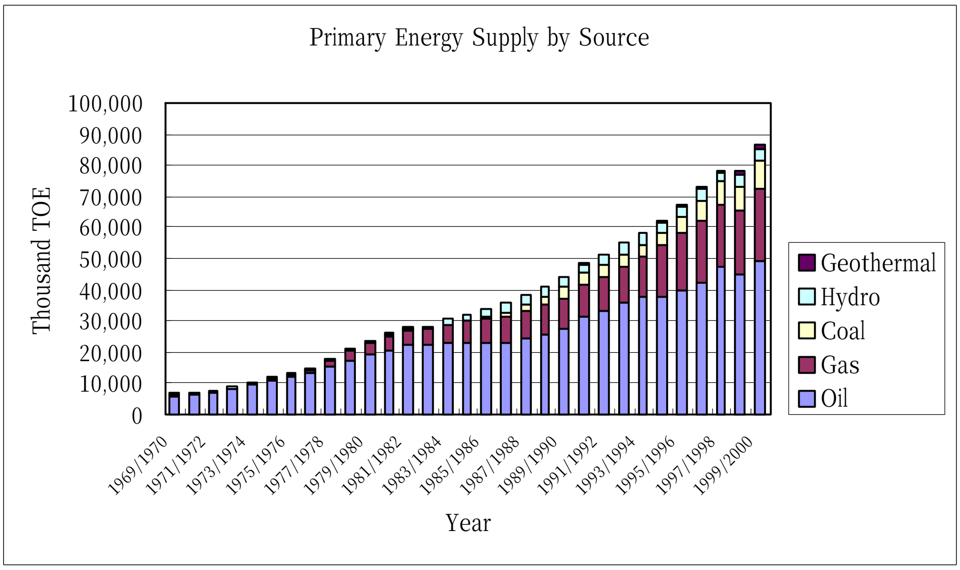


(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

(4) Primary energy supply

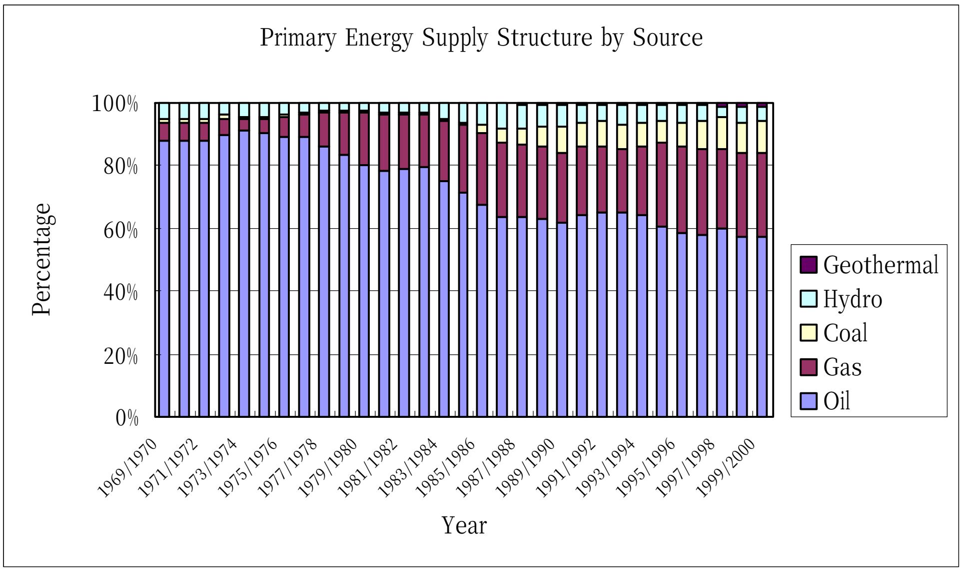
Figure 2.3.16 (a) and (b) show the historical trends of primary energy supply (requirement) and its supply structure by source. The primary energy requirement grew at the pace of 13.7 % annual average growth in the 1970's, 6.4 % in the 1980's and 6.6 % in the 1990's. The biggest source of primary energy supply is oil, however, the share of oil in the total primary energy supply has decreased from 90 % in the 1970's to 50 % level in the 1990's.

Figure 2.3.16 (a) Historical Trend of Primary Energy Supply by Source



(Source) DGEEU

Figure 2.3.16 (b) Historical Trend of Primary Energy Supply Structure

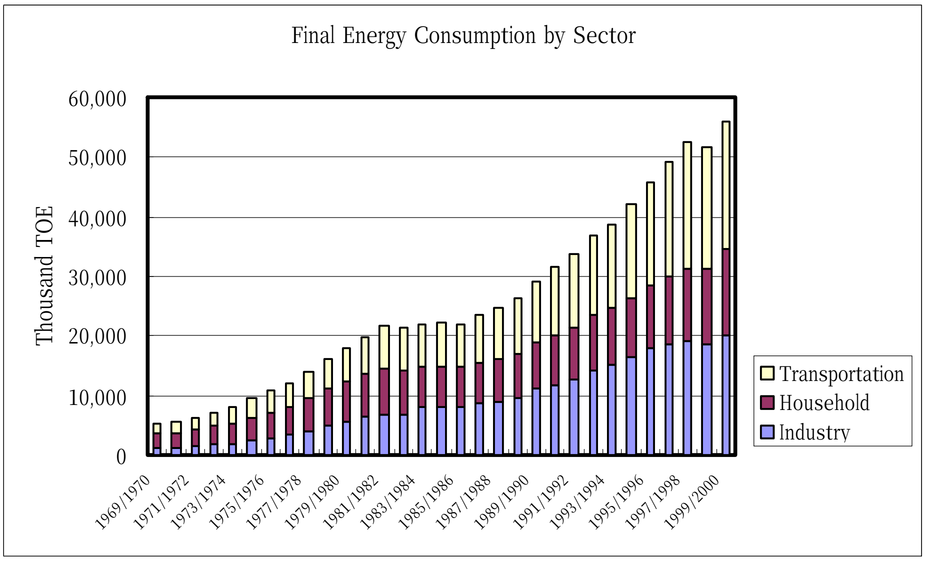


(Source) DGEEU

(5) Final energy consumption

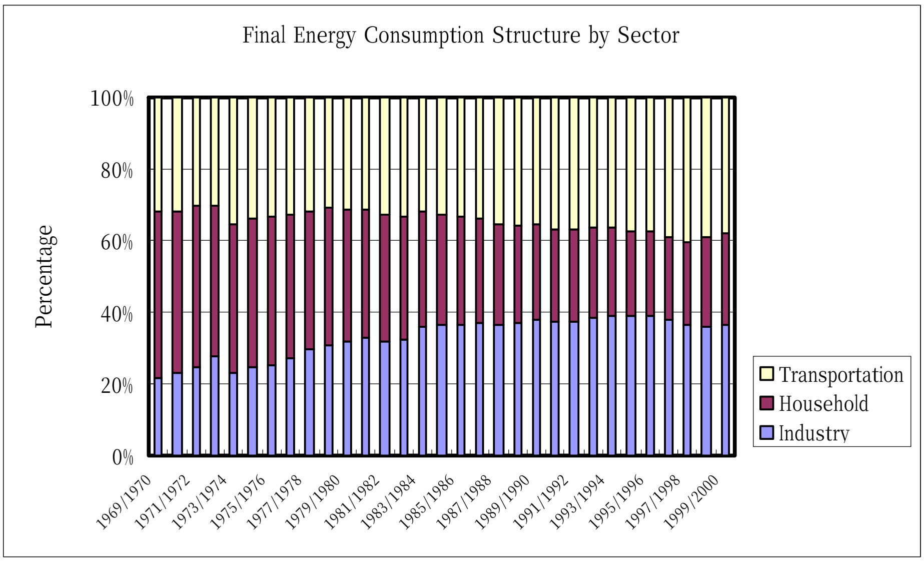
Figure 2.3.17 (a) and (b) show the historical trends of final energy consumption and its consumption structure by sector. The final energy consumption grew at the pace of 13.6 % annual average growth in the 1970's, 4.7 % in the 1980's and 6.6 % in the 1990's. In the 1970's, major energy consumer was the residential and commercial sector. And entering the 1980's, the transportation and industrial sectors expanded the share in the final energy consumption total. This tendency is still now continuing.

Figure 2.3.17 (a) Historical Trend of Final Energy Consumption by Sector



(Source) DGEEU

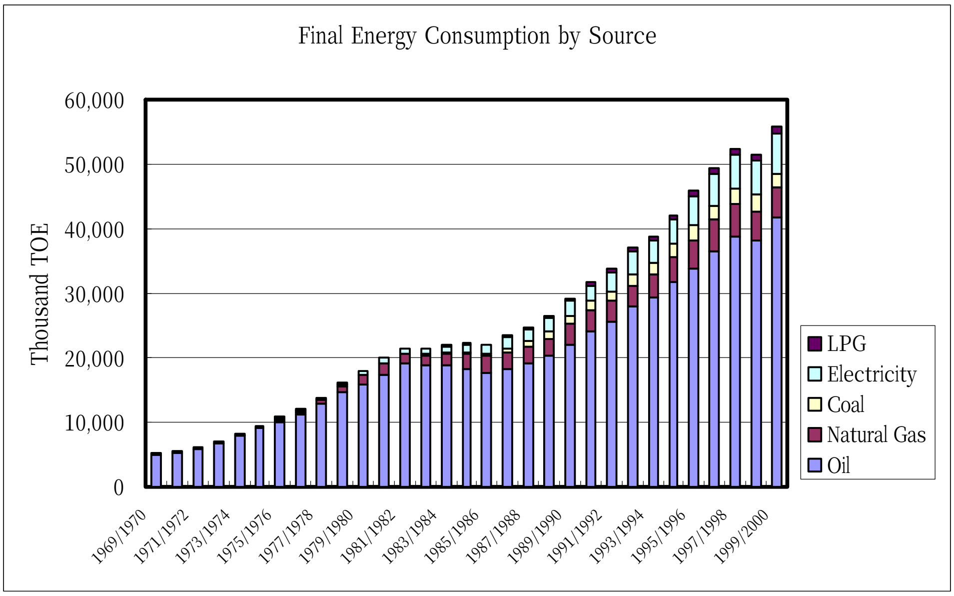
Figure 2.3.17 (b) Historical Trend of Final Energy Consumption Structure by Sector



(Source) DGEEU

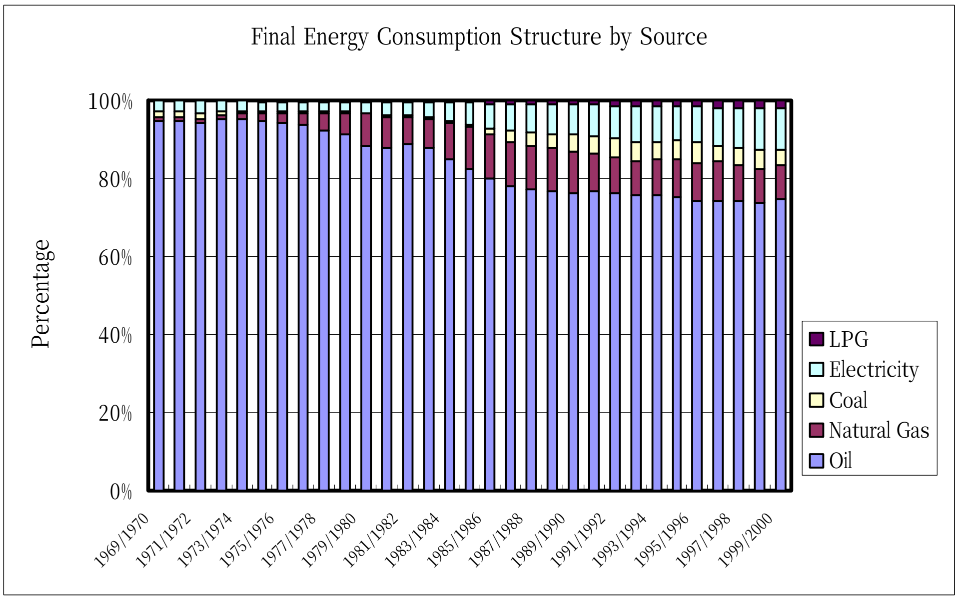
As for the historical trends of final energy consumption by energy source and its structure (See Figure 2.3.18 (a) and (b)), the major energy source is oil, and the share decreased from 95 % level in the 1970's to 75 % level in the 1990's as shown in Figure 2.3.18 (b). However after 1990, we cannot identify the decreasing tendency of oil dependent energy consuming structure.

Figure 2.3.18 (a) Historical Trend of Final Energy Consumption by Source



(Source) DGEEU

Figure 2.3.18 (b) Historical Trend of Final Energy Consumption Structure by Source



(Source) DGEEU

(6) Electric power

Figure 2.3.19 shows the historical trends of electricity by sector. Annual average growth rates of electricity consumption were 14.8 % in the 1970's, 15.8 % in the 1980's and 11.2 % in the 1990's respectively. Each growth rate by consuming sector during each period is shown in Table 2.3.15.

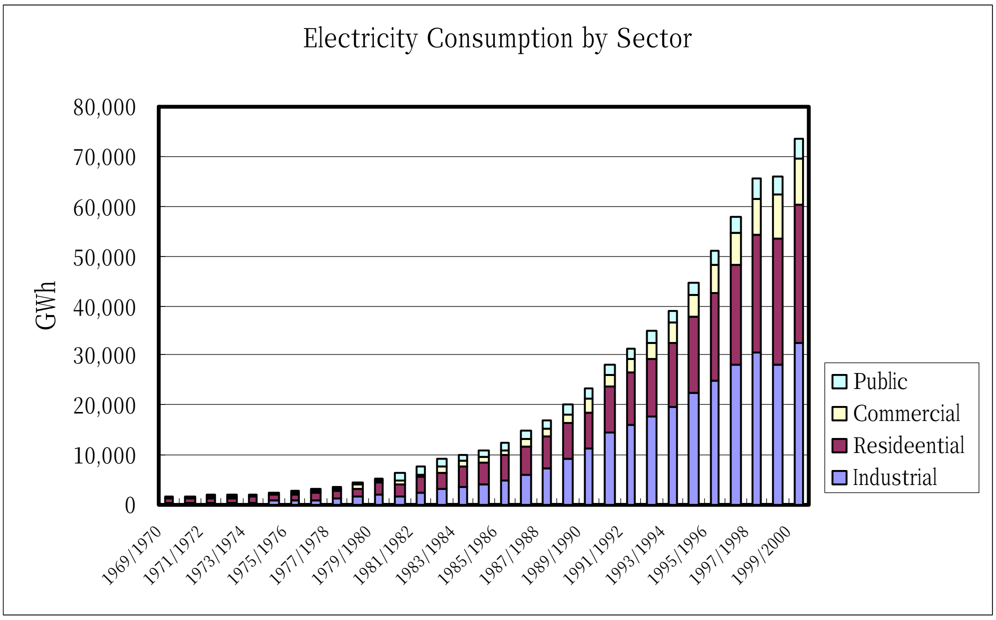
Table 2.3.15 Average Growth Rate of Electricity Consumption by Sector

	1970's	1980's	1990's
Industry	18.96	23.77	9.31
Residential	9.77	14.93	13.19
Commercial	16.80	12.34	16.91
Public/Government	20.06	2.40	5.83
Indonesia Total	14.82	15.78	11.20

(Source) DGEEU

As for the share of each sector, the industrial sector expanded the share from 30 % level to 50 % level in the 1980's and reduced the share after the later half of the 1990's. In place of the industrial sector, the residential and commercial sectors recovered the share.

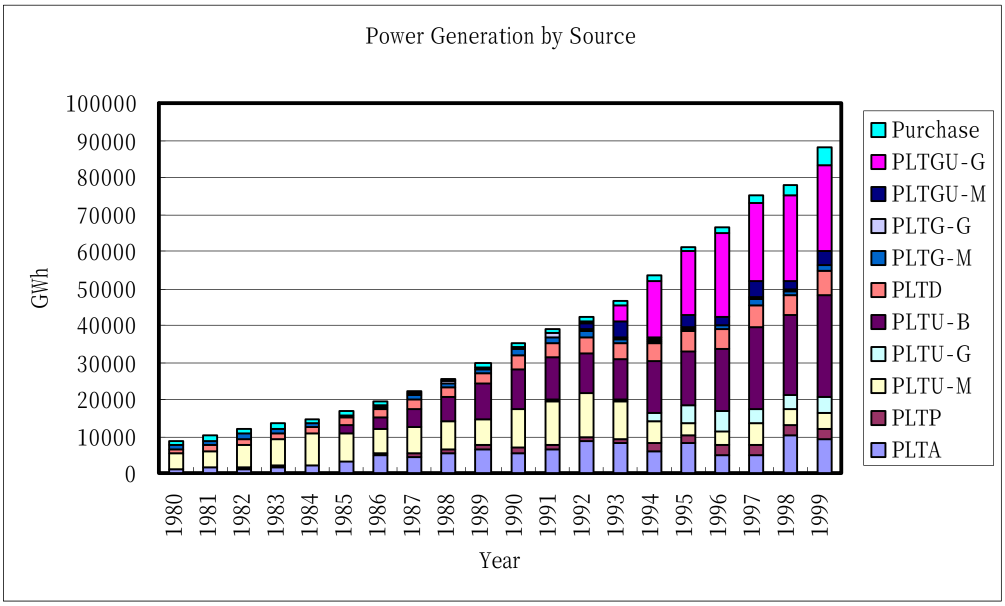
Figure 2.3.19 Historical Trend of Electricity Consumption by Sector



(Source) DGEEU

Figure 2.3.20 shows the historical trend of power generation by source (PLN). The brevity code names by power source are explained in Table 2.3.16. As shown in Figure 2.3.20, the power generation by combined cycle has rapidly increased since 1993. Steam thermal power generation (Coal and Oil) had been also gradually increasing. After 1995, the share of steam thermal, combined cycle and hydropower keep the level of 40-45 %, 30-40 % and about 10 % respectively. Regarding the generated power by source in 1999, the thermal power generation was 67,923 GWh and accounted for 85 % of total generation 80,023 GWh, followed by hydropower 9,372 GWh (12 %) and geothermal power 2,728 GWh (3.4 %).

Figure 2.3.20 Power Generation by Source (PLN)



(Source) PLN

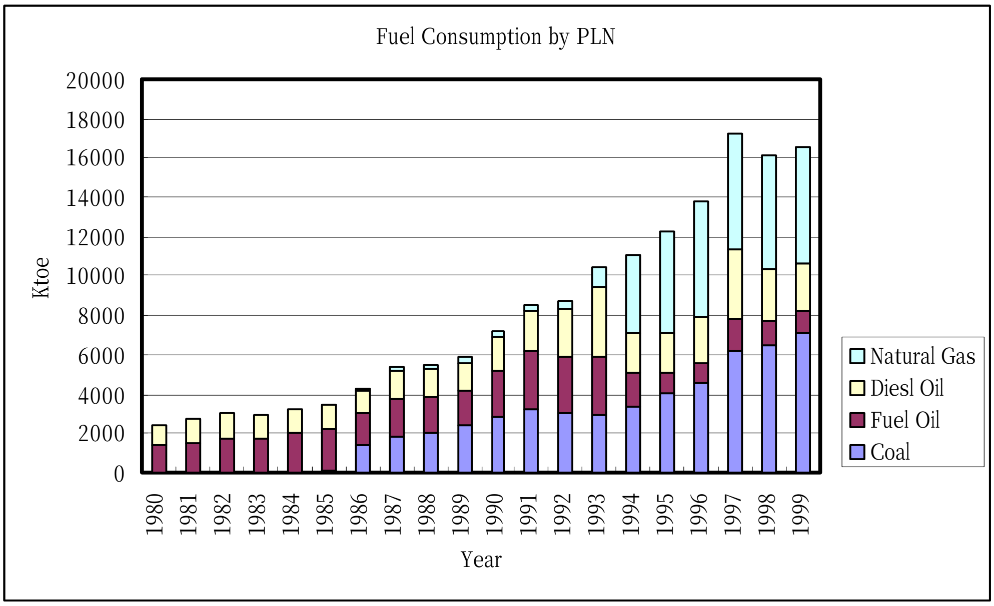
Table 2.3.16 Brevity Code Name by Power Source

	Power Source
PLTA	Hydropower
PLTP	Geothermal
PLTU-M	Steam (Oil)
PLTU-G	Steam (Natural Gas)
PLTU-B	Steam (Coal)
PLTD	Diesel
PLTG-M	Gas Tuebine
PLTG-G	Natural Gas
PLTGU-M	Conbined Cycle (Oil)
PLTGU-G	Conbined Cycle (N.Gas)

Figure 2.3.21 shows the historical trends of fuel consumption by public utility plants (PLN). In PLN, natural gas requirement has expanded from 1994 and also coal requirement has increased in recent years. Major fuels for thermal power are coal accounting for the share of 46.2 %, and natural gas of 33.6 %. The share of diesel oil is 13.2 % and that of fuel oil is 7.0 %

at 1999. As shown in Figure 2.3.21, the 1997's high fuel consumption comparatively is due to compensating thermal power for the output drop of hydropower. Gross thermal efficiency in Indonesia reached 37.7 % in 1999.

Figure 2.3.21 Historical Trend of Fuel Consumption by PLN



(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

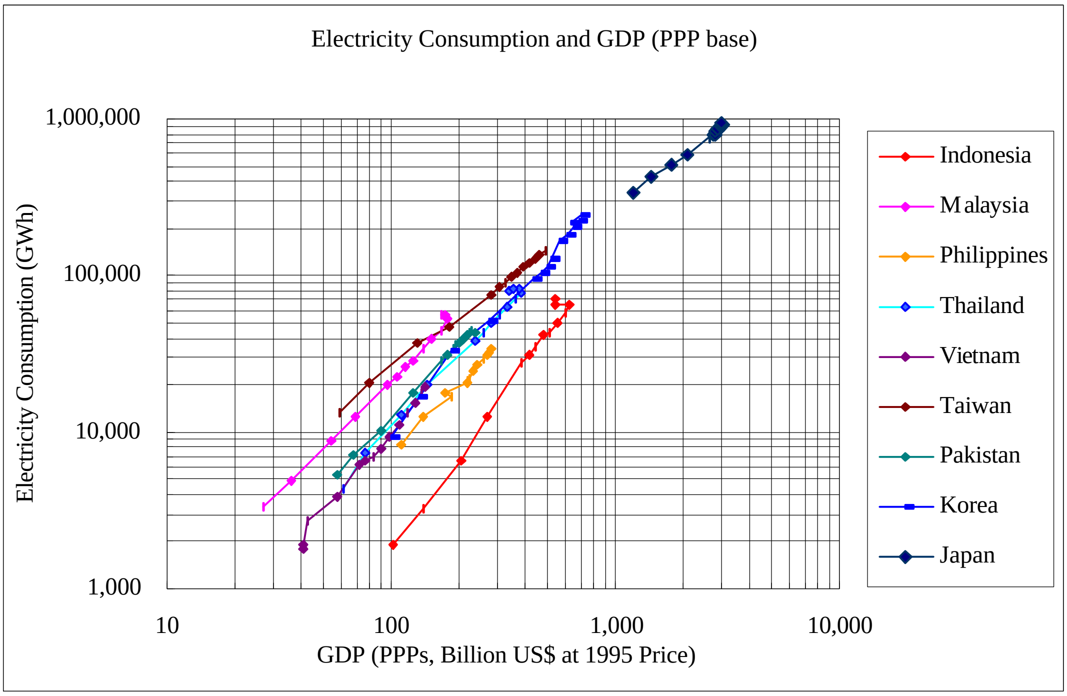
2.4 Cross Country Analysis on Electricity Consumption

2.4.1 Electricity Consumption and Economic Activities

Figure 2.4.1 shows the relationship between electricity consumption and economic size in selected Asian countries (economies) during 1971-1999, in terms of logarithmic graph. Economic size (GDP) is expressed by purchasing power parity (PPP). The polygonal line of bottom side in the Figure shows the Indonesian trend. This means that Indonesian GDP is larger than other Asian countries except Japan, Korea (South Korea) and Taiwan and that Indonesian electricity consumption relatively small in comparison with other countries.

Reasons why Indonesia consumes relatively small comparing to national economic size are guessed as follows. 1) Statistical figure deal with electricity sales by PLN. 2) Rural electrification is still now low level because Indonesia is a typical nation comprising of many islands. Indonesia, however, produces a lot of own-use electricity by private companies. In the case that own-use electricity is added to electricity statistics, Indonesian polygonal line is estimated to move upper side slightly toward the Philippines' line, which is similar islands nation to Indonesia.

Figure 2.4.1 The Relationship between Electricity Consumption and Economic Size

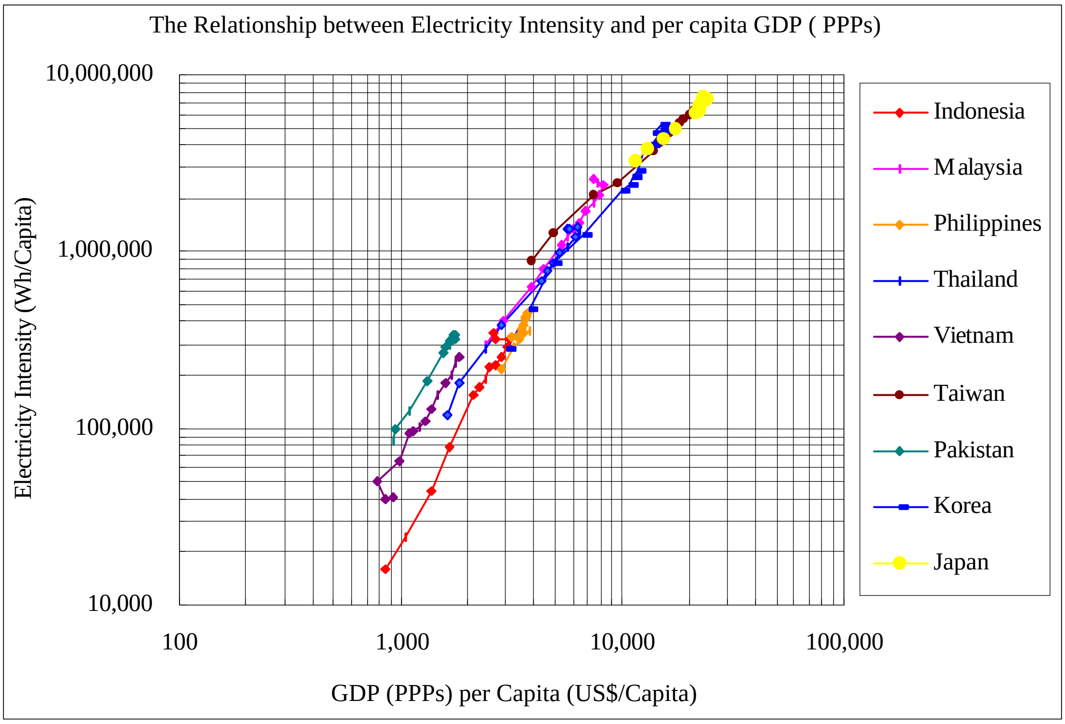


(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

2.4.2 Electricity Intensity and Economic Level

Figure 2.4.2 shows the relationship between electricity consumption per capita (electricity intensity) and economic size (GDP/Capita) in selected Asian countries (economies) during 1971-1999, in terms of logarithmic graph. GDP is also expressed by purchasing power parity (PPP) as previous section. As can you seen in the Figure, lines of Thailand – Malaysia – S. Korea – Taiwan – Japan are drawn like a straight line. And we can find that Indonesia – Philippines' line is plotted a little bit lower side of Thailand - -- - Japan line, and lines of Vietnam and Pakistan are plotted upper side respectively. Lower side countries on same level of horizontal axis means that electricity consumption per capita is comparatively low in comparison with similar life level.

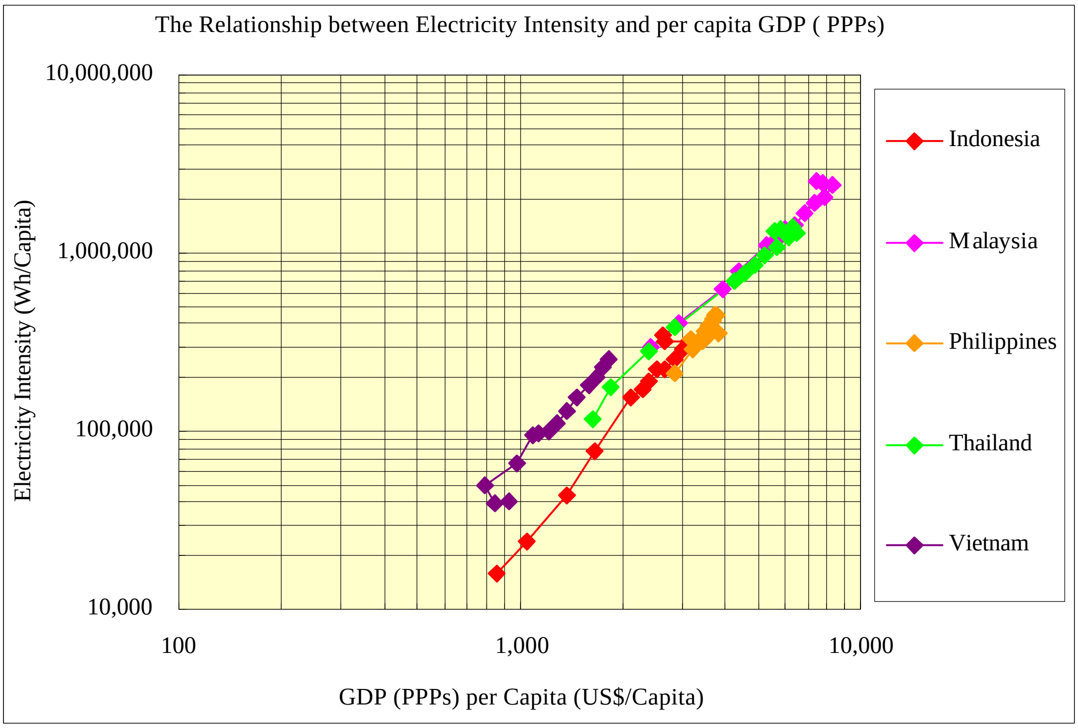
Figure 2.4.2 The Relationship between Electricity Intensity and Economic Level



(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

Figure 2.4.3 shows the trends of selected ASEAN countries derived from Figure 2.4.2. In Figure 2.4.3, we can see three (3) lines, 1) Indonesia – Philippines, 2) Thailand - Malaysia, and 3) Vietnam from the bottom side. In recent years, however, Indonesia – Philippines' line is moving close to Thailand – Malaysia's line as shown in the Figure. This trend implicates that the resemblance of economy and people's living in core ASEAN countries, Indonesia, Philippines, Thailand and Malaysia, is implied from the viewpoint of their electricity consumption.

Figure 2.4.3 Electricity Intensity and Economic Level in selected ASEAN Countries



(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

Table 2.4.1 Electricity Consumption per Capita in selected ASEAN Countries (Unit: kWh/capita)

	1980	1985	1990	1995	1999
Indonesia (PLN)	46.0	83.2	176.7	265.7	358.9
(Java-Bali, PLN)	56.1	99.7	200.6	347.3	465.3
Malaysia	669.8	870.6	1146.7	2004.8	2460.9
Philippines	366.4	347.9	362.8	407.0	473.9
Thailand	294.7	412.9	721.8	1265.6	1404.6
Vietnam	54.6	70.3	99.8	157.9	258.3

(Source) IEA, "Energy Balances of Non-OECD Countries, 2001"

Table 2.4.1 shows numeric values of electricity consumption per capita (kWh/capita). As shown in the Table, the electricity consumption per capita in Indonesia at 1999, about 360 kWh/capita, corresponds to the 1990 level of the Philippines and before the 1985 level of Thailand. That of Java-Bali Region is similarly positioned to the Philippines' level. As described before, captive power plays a large role in Indonesia, and so it is a little bit difficult to evaluate the electricity consumption itself as published statistics, which represents the public utilities' portion, in general. Taking into the consideration of such situation, for instant, if the consumption per capita could be presumed as 700 kWh/capita of around double, Indonesian per capita consumption is still now ranked to before the 1985 level of Malaysia and the 1990 level of Thailand.

2.4.3 Electricity Elasticity with respect to GDP

Table 2.4.2 shows the elasticity of electricity consumption to GDP and the elasticity of per capita electricity consumption to GDP/capita in selected Asian countries. In the Table, observation year is classified into the period of 1973-1985 and 1985-1997. The reason why year 1997 is set as an end year of observation period is that receivable results could not be obtained under the impact of Asian economic crisis after 1998.

Table 2.4.2 Electricity Elasticity in selected ASEAN Countries

Country (Economy)	Electricity Elasticity to GDP			Elasticity of KWh/capita – GDP/capita		
	-1973	1973-1985	1985-1997	-1973	1973-1985	1985-1997
Indonesia		2.17	1.99		2.39	2.78
Malaysia		1.52	1.53		1.91	1.68
Philippines		1.29	1.27		4.28	1.63
Thailand		1.61	1.54		1.96	1.61
Vietnam		1.71	1.77		2.98	2.04
Pakistan		1.52	1.66		2.02	2.33
Taiwan	(1952-1973) 1.57	1.13	1.14	(1952-1973) 1.88	1.21	1.20
S. Korea	(1962-1973) 2.27	1.66	1.64	(1962-1973) 2.76	1.85	1.70
Japan	(1946-1965) 1.22 (1965-1973) 1.29	0.89	1.20	(1946-1965) 1.26 (1965-1973) 1.33	0.92	1.25

(Source) IEA Statistics and Energy Statistic of Japan, S. Korea and Taiwan

As a reference, the past elasticity values before 1973 as to Japan, S. Korea and Taiwan are introduced in the Table. Especially, S. Korea and Taiwan have typical characteristics in the industrial structure from the viewpoint of electricity consumption and it will be suggested for developing countries as preferred precedents. S. Korea has a manufacturing (especially heavy chemical industry) oriented industrial structure, and therefore electricity elasticity is large in general. On the other hand, Taiwan is a typical economy of a light and service oriented industrial structure, and the electricity elasticity is small. Japanese industrial structure is positioned as an intermediate point of both economies.

Traditionally energy elasticity to GDP in Indonesia is relatively high, compared with other Asian countries. This historical trend might be imagined that Indonesia is one of the Korean type's industrial structures, however, this trend is practically considered that Indonesian electricity demand is still low for her population and territory. Socio-economy and industrial structure of Indonesia has an energy consuming characteristics and this trend would continue in ten (10) or fifteen (15) years when the per capita electricity consumption level will reach the current level of Thailand or Malaysia, as the case might be, although it depends on energy conservation and energy price policies.

Chapter 3 National Electricity General Plan (RUKN)

3.1 Outline of National Electricity General Plan (RUKN)

3.1.1 Objective of RUKN

The National Electricity General Plan (RUKN) is an integrated power development plan that covers the national policy, power development target and electricity infrastructure development. RUKN also includes power sector restructuring, privatization of PLN, and rural electrification according to the decentralization policy. These factors promote private investment in the power sector and support development of the national economy.

The electric power demand forecast is done based on the previous year’s record. The power development plan and transmission plan for PLN will be applied in 13 power systems in Indonesia. Power policy, a fuel plan and a financial plan are also prepared.

3.1.2 Responsible Agency

The Ministry of Energy and Mineral Resources is the agency responsible for RUKN. The Directorate of Electricity Planning in the Directorate General of Electricity & Energy Utilization is in charge of the work. RUKN will serve as a guideline for PLN to make an power demand-supply plan, according to the government policy.

RUKN will be up-dated periodically according to the actual demand and power development and become effective by signature of the minister. The latest RUKN hasn't been issued officially since 1996. Therefore the draft RUKN as of October 2001 will be reviewed in this chapter.

3.1.3 Power Development

PLN is the main electricity supplier. Private companies and cooperatives complement PLN in areas where PLN is not able to supply power. The government also decided to introduce IPPs because PLN cannot secure the budget to meet the increasing demand. According to its depetrolization policy, the government put a high priority on coal, geothermal and hydropower.

Most of the rural electrification program is carried out by PLN with a government subsidy. Cooperatives are utilized to promote participation of rural communities and local energy utilization. Social Electricity Development Fund will be established to promote in the rural electrification program in the near future.

In addition to PLN's financial problem caused by the monetary crisis, there are various other problems. These include inefficiency of PLN in management and technical aspect and high purchase prices from IPPs. In the Java-Bali system, despite the IPP capacity increases being re-negotiated, it is pointed out that there still will not be enough capacity by 2003 considering the recent demand growth. In addition to the Java-Bali system, all other systems except for West Sumatra, the North Sumatra and Ujung Pandang systems will also experience a power deficit in 2003.

In case PLN does not develop sufficient power, the government will consider private sector development or power purchases from captives. In order to attract significant investment, it is necessary to solve problems such as transmission constraints, improve PLN's financial condition and change the current investment system.

3.1.4 Simulation Tool

Table 3.1.1 shows the demand- supply plan of the Java-Bali system in RUKN.

The table consists of three sections, the top section shows the demand, the middle section shows the supply capacity, and the bottom section shows the generation reserve margin.

The actual information is only about ongoing / planned projects, the rest are simulated by PLN's power development optimization program. This program, known as " Sihombing program" named after the person who developed it, is a WASP- like program written in Fortran.

NEW PLTUs and NEW PLTGs listed in Table 3.1.1 indicate the calculation result of program simulations, there are no specific plans for these power sources.

Table 3.1.1 Demand-Supply plan of RUKN as of October 2001 (Java-Bali System)

		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Demand	GWh	70,387	75,899	82,092	89,272	97,469	106,223	115,550	125,463	135,973	147,088	8,522
Growth	%	11.5%	7.8%	8.2%	8.7%	9.2%	9.0%	8.8%	8.6%	8.4%	8.2%	8.2%
Load Factor	%	70.0	70.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	
Production	GWh	81,717	87,958	94,817	102,765	111,953	121,873	132,427	143,788	155,661	168,386	9,630
Peak Load	MW	13,326	14,344	15,245	16,523	18,000	19,595	21,292	23,119	25,028	27,073	1,527
Total Loss Rate	%	13.9%	13.7%	13.4%	13.1%	12.9%	12.8%	12.7%	12.7%	12.6%	12.6%	
Capacity												
Installed	MW	18,608	18,608	18,608	18,308	18,308	18,308	18,308	18,308	18,308	18,308	
PLN Project												
P.Storage	HPP									500	500	
Rajamandala	HPP											
New PLTG						840		480	720			
Muara karang Repowering	C/C PP				720							
M.Tawar Extension	C/C PP				500	250	500	250				
Pesanggaran Extension				40								
Pemaron Extension				45								
New PLTGU												
New PLTU						1,200	1,800	1,800	1,800	1,200	3,000	
Private Project												
Tanjung JatiB	SPP				1,320							
SYSTEM CAPACITY		**18,608**	**18,608**	**18,693**	**20,933**	**23,223**	**25,523**	**28,053**	**30,573**	**32,273**	**35,773**	
Reserve	%	39.6%	29.7%	22.6%	26.7%	29.0%	30.3%	31.8%	32.2%	28.9%	32.1%	

3.2 Demand Forecasting

Table 3.2.1 shows the demand forecasted in RUKN. The terms used in the demand section are defined below:

- Demand (GWh) --- The total electric sales of industrial, commercial, residential, and public use.
- Production (GWh) --- The total of gross generation output at PLN and net generation output at IPPs. The output of captives and cooperative power is not included in the figure.
- Peak load (MW) --- The total of gross electric demand at PLN and net generation demand at IPPs.

Table 3.2.1 Demand Forecast in RUKN

Items	2000	2005 (2005/2000)		2010 (2010/2000)	
Demand GWh	63,872	97,469	(8.8%)	147,088	(8.7%)
Production GWh	74,901	111,953	(8.4%)	168,386	(8.4%)
Peak Load MW	12,231	18,000	(8.0%)	27,073	(8.3%)
Total Loss (%)	13.8%	12.9%		12.6%	

The peak load is expected to grow at the rate of 8.0% (2005/2000) and 8.3% (2010/2000). According to this forecast, peak load will increase to 27,073MW, twice as much as the present peak load (12,231MW). This table implies that large power source development will be needed if the demand increases at this rate.

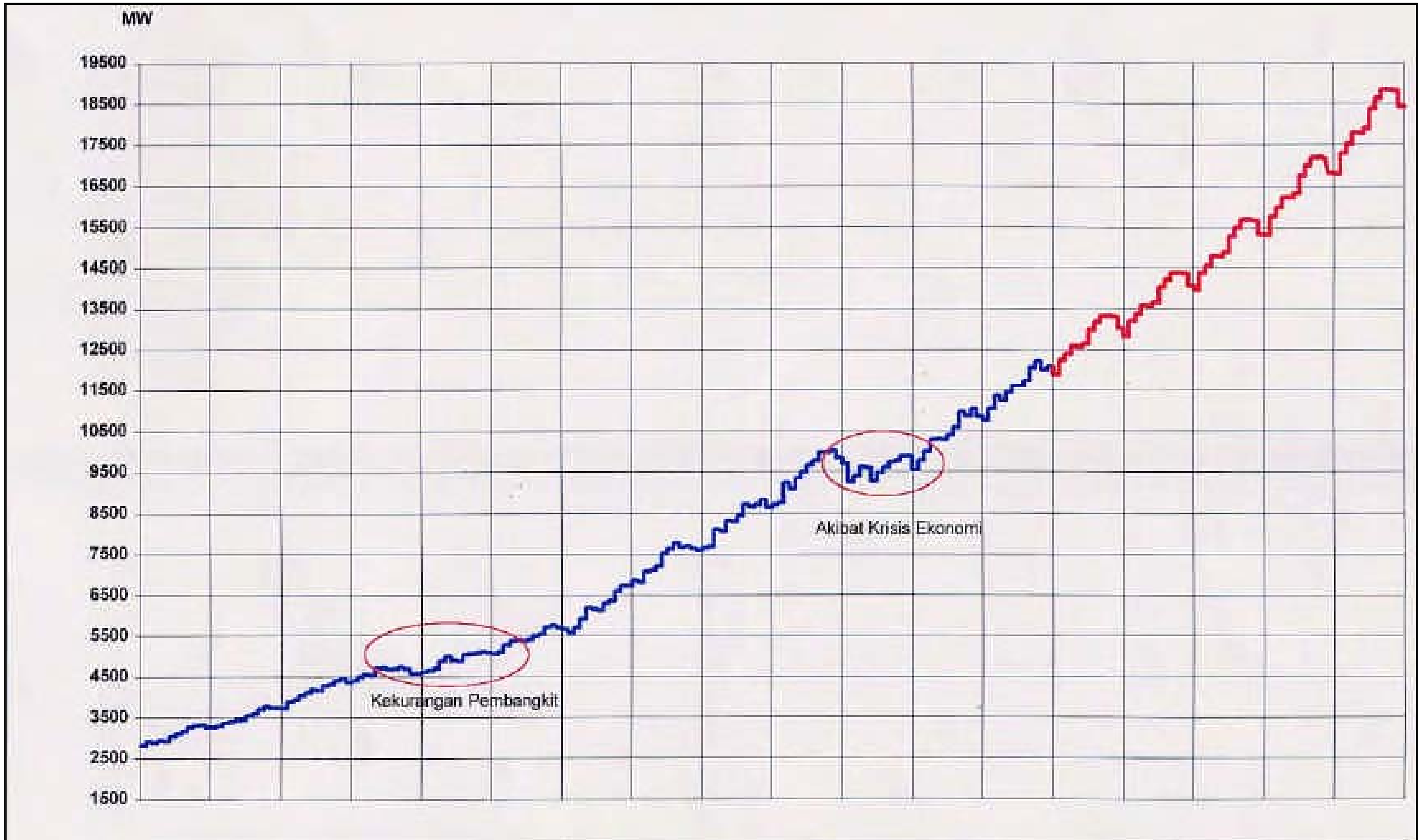
Considering that the rate of total loss is around 9% in Japan, a 13% rate in Indonesia is not so large. PLN is appropriately managing electricity loss.

Figure.3.2.1 shows the trend of electric demand from year 1988 to 2000. Except the year 1998, which was the year that economic crisis happened, the demand has been increased steadily.

Figure.3.2.2 shows the daily load curves from the year 1990 to 2000. We can see the maximum load appears in the evening. It means peak load would stem from the lighting demand.

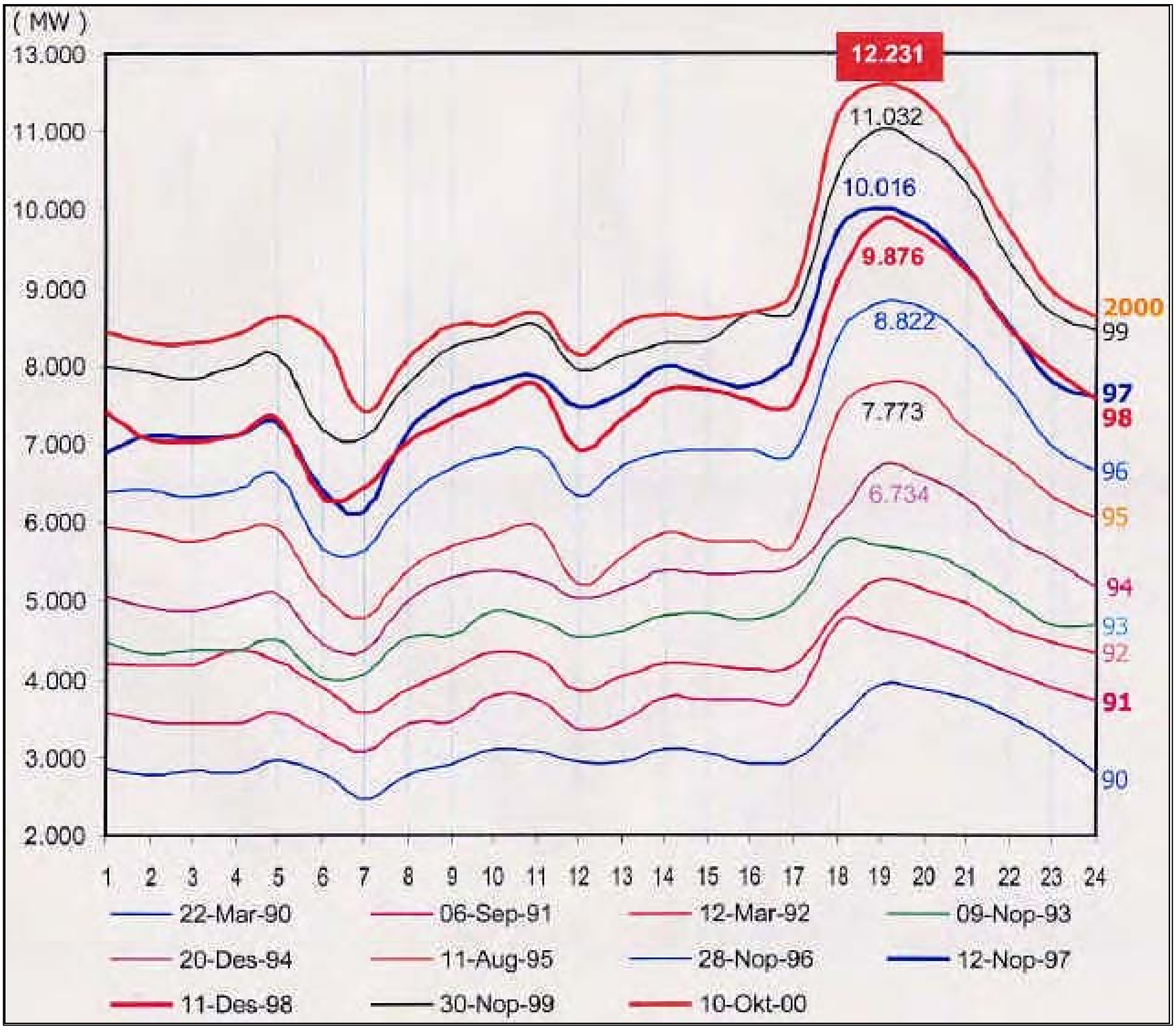
Despite of the constant temperature of tropical climate, we can see the maximum load day has been occurred in October, November or December as early wet season, since 1996. It is considered that maximum demand arises in the end of year since the maximum demand is renewed every month because of the high growth of electric demand.

Figure 3.2.1 The trend of electric demand from year 1988 to 2000 in Java-Bali



	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Peak (MW)	3311	3774	4461	4728	5117	5757	6734	7773	8822	10016	9876	11032	12231	13326	14392	15680	17200	18886
Kenaikan (%)	16.0	14.0	18.2	6.0	8.2	12.5	17.0	15.4	13.5	13.5	-1.4	11.7	10.9	9.0	8.0	8.9	9.7	9.8

Figure 3.2.2 Java-Bali Daily Load Curves on Peak Day (1990-2000)



3.3 Supply Capacity

3.3.1 Supply Capacity of Existing Power Units

According to the RUKN, the installed capacity of Java-Bali system in 2001 is 18,608MW. It is about 8.3% of the installed capacity in Japan (224,291MW as of the end of March 2001).

Table 3.3.1 shows the installed capacity by the types of power source and their locations in Java-Bali. This table shows the total installed capacity of PLN and IPPs. Captives and cooperatives are not included in the table.

Table 3.3.1 Installed Capacity by Type and Location (unit: MW)

Items	Areas				Installed Capacity Java-Bali	Capacity Percent %
	Area1	Area2	Area3	Area4		
Hydro	37	1,918	306	275	2,536	13.6
Thermal	7,108	80	1,389	6,730	15,307	82.2
Steam	(4,200)	(0)	(300)	(3,950)	(8,450)	(45.4)
C/C	(2,609)	(0)	(1,034)	(2,343)	(5,985)	(32.2)
GT	(300)	(80)	(55)	(361)	(796)	(4.3)
Diesel	(0)	(0)	(0)	(76)	(76)	(0.4)
Geothermal	330	375	60	0	765	4.1
Sub Total	7,475	2,373	1,755	7,005	18,608	100

Note: The capacity of IPPs is included

Table 3.1.2 shows that the installed capacity of hydropower is 2,536MW (13.6% of the total installed capacity), thermal is 15,307MW (82.2%), and geothermal is 765 MW (4.1%). This means that the main power source is thermal power. Conventional steam power units account for 8,450MW(45.4%) and combined cycle power units account for 5,985MW (32.2%) of this thermal power.

Regarding location, the Java- Bali area is divided into four areas: Area 1 (Jakarta and surrounding areas), Area 2 (West Java except for Area 1), Area 3 (Central Java), and Area 4 (East Java and Bali). Most of the thermal power plants are located in Area 1 and Area 4. On the other hand, most hydropower plants are located in Area 2. Most geothermal power plants are located in Area 1 and Area 2.

Table 3.3.2 shows the installed capacity by type of fuel. Coal fired power plants account for 6,650MW (35.7% of installed capacity), followed by natural gas fired power plants (4,749MW / 25.5%) and High Speed Diesel Oil (HSD) fired power plants (3,108MW / 16.7%).

It is important to point out that presently many combined cycle power plants, which are designed to use natural gas, have to be operated as HSD fired power plants, because there is no natural gas supply. Such examples include the Muara-Tower Thermal Power Plant (Block I, II), the Grati Thermal Power Plant (Block I), and the Semarang Thermal Power Plant (Block I, II).

Table 3.3.2 Installed Capacity by Fuel Type (Unit: MW)

Item	Areas				Installed Capacity Java-Bali	Capacity Percent %
	Area1	Area2	Area3	Area4		
Hydro	37	1,918	306	275	2,536	13.6
Thermal	7,108	80	1,389	6,730	15,307	82.2
(Coal)	(3,400)	(0)	(0)	(3,250)	(6,650)	(35.7)
(Gas)	(2,388)	(80)	(0)	(2,281)	(4,749)	(25.5)
(HSD)	(920)	(0)	(1,089)	(1,099)	(3,108)	(16.7)
(MFO)	(400)	(0)	(300)	(100)	(800)	(4.3)
Geo thermal	330	375	60	0	765	4.1
Sub Total	7,475	2,373	1,755	7,005	18,608	100

Note: The capacity of IPPs is included

Table 3.3.3 shows the installed capacity by owner. Most of the generation capacity is owned by PLN (Indonesia Power, PJB). PLN owns 15,453MW of the installed capacity (87% of the total) and IPP owns only 3,155MW (17%).

Table 3.3.3 Installed Capacity by Owner (unit: MW)

Item	Areas				Installed capacity Java-Bali	Capacity Percent %
	Area1	Area2	Area3	Area4		
Indonesia Power	5,031	1,035	1,695	100	7,862	42.3
PJB	2,128	1,008	0	4,454	7,591	40.8
IPP	315	330	60	2,450	3,155	17.0
Sub total	7,475	2,373	1,755	7,005	18,608	100

3.3.2 Power Development Plan

As described in 3.1.4, power development projects of RUKN can be classified into two types: ongoing / planned projects and required projects, which are based on the output of the simulation program. In this section, we will describe both types of projects in detail.

(1) Ongoing / planned projects

There are six ongoing / planned projects with a total capacity of 4,325MW.

-Repowering of Muara-Karang (Total capacity: 720MW / Actual increase 420MW)

To efficiently use the Muara-Karan power plant in Jakarta, a new gas turbine will be installed into the existing 1-3 unit in the plan. Since this power plant is one of the most important plants supplying Jakarta, installation should be carried out without shutting down the unit. The unit capacity will be about 720MW after completing the installation work. Actual increased capacity is only about 420MW. Start of operation is expected in 2004. The application for financial support for the engineering service and construction is submitted to the Japanese government under the Yen credit scheme. It was discussed in the meeting of the Consultative Group for Indonesia (CGI) in 2001.

-Extension project of "Muara-Tower Block III,IV" (Total capacity : 750MW×2)

A new combined cycle power plant (750MW×2) will be installed into the extension area in the Muara-Tower power plant (Block III,IV) in the plan. Operation is expected in 2004-2007. The application for financial support for the engineering service is submitted to the Japanese government with the Muara-Karang project, it was discussed in the meeting of the Consultative Group for Indonesia (CGI) in 2001.

-Pesanggaran power plant (Actual increased capacity: 40MW)

A new steam turbine (40MW) will be installed to be combined with existing gas turbines (42MW×2) in the Pesanggaran power plant located in Bali. Operation is expected in 2003 according to RUKN.

-Pemaron Thermal Power Plant (Actual increased capacity: 45MW)

The Pemaron power station will be a new power plant located in Bali. The existing gas turbine (48.8MW ×2) is moved from Tanjung-Priok power station and combined with a newly installed steam turbine(45MW). Operation is also expected in 2003 according to RUKN

-Tanjung-Jati B (1,320MW)

Tanjung-Jati B is an IPP power plant located in central Java and will be the largest scale coal fired thermal power plant (660MW×2) in Indonesia. Operation is expected in 2004. Construction work started in 1996 is being interrupted because of difficulty of renegotiating the PPA contract between PLN and the owner and constitution of financial scheme.

-Upper Chisokan pumped storage power plant (Total capacity: 1,000MW)

Upper Chisokan is a pumped storage power plant planned for west Java, west of the existing Shagling hydropower and near the existing 500kV transmission line. Start of operation is expected in 2009 (500MW) and in 2010 (500MW). Engineering service is now carried out under the finance of Yen credit. The total construction cost is estimated at about US$ 1,200 million.

(2) Required capacity (output of simulation program)

According to RUKN, a total installed capacity unidentified as specific projects is 12,840MW. It means that a yearly average installed capacity to be developed is 2,5000 MW from 2005 until 2010. The breakdown of this figure is shown in Table 3.3.4.

Table 3.3.4 Required Capacity by Type of Power Source (Unit: MW)

Items	2005	2006	2007	2008	2009	2010	Total	Average
Gas turbine	840	0	480	720	0	0	2,040	340
Steam turbine	1,200	1,800	1,800	1,800	1,200	3,000	10,800	1,800
Sub total	2,040	1,800	2,280	2,520	1,200	3,000	12,840	2,140

In this table, gas turbine refers to oil fired gas turbines for peaking; and steam turbine refers to conventional coal fired power plants.

3.3.3 Generation Reserve Margin (GRM)

Generation reserve margin is generally used in preparing the power development plan. GRM shows the capacity required to avoid any unpredicted risk in the future. The formula to calculate GRM is shown below.

GRM =(Installed Capacity - Peak Load) / Peak Load

RUKN is planned at a 25% GRM. The 25% GRM is recommended in the "Second Power Transmission and Distribution Project (PLTDII)" exchanged between the World Bank and PLN.

Table 3.3.5 shows GRM on RUKN. We can see from the table that GRM in 2001 is about 40%, and it looks enough to keep the stability of power system.

Table 3.3.5 Generation Reserve Margin of RUKN (Unit: MW,%)

Year	2001	2002	2003	2004	2005	2006	2010
Maximum Peak Load (MW)	13,329	14,344	15,245	16,523	18,000	19,595	27,073
Installed Capacity (MW)	18,608	18,608	18,693	20,933	23,223	25,523	35,773
GRM (%)	39.6	29.7	22.6	26.7	29.0	30.3	32.1

On the other hand, the target reserve margin proposed by P3B that operates the actual power system is 30%. The break down of this figure is shown below.

Hydro Power Deleting	5%
Maintenance (Periodic Repair)	12%
Thermal Power Deleting	2.7%
Rate of Forced Outage	6%
Spinning Reserve	4.3%
Total	30%

The difference between the 25% GRM used during planification and the 30% reserve margin proposed by P3B is explained below:

-For the purpose of system planification, efficient investment is given high priority. In other words, a lower GRM is preferred.

-For the purpose of system operation, stable power supply is given high priority. In other words, a higher GRM is preferred

By considering the actual operation, we have to examine the difference between these figures carefully and find the optimal generation reserve margin.

3.3.4 Fuel Consumption Plan and Financing Plan

(1) Fuel consumption plan

Table 3.3.6 shows the fuel consumption plan according to RUKN.

Table 3.3.6 Production plan / Fuel Consumption Plan of RUKN

	Items	2001	2005	2010
Production (GWh)	Hydro	6,976	6,976	6,976
	Coal	40,147	60,934	122,697
	Gas	21,419	36,873	30,793
	HSD	6,763	1,809	2,559
	MFD	1,051	-	-
	Geo thermal	5,361	5,361	5,361
	Sub total	81,717	111,953	168,386
Fuel consumption	Coal (10^3t)	18,096	27,465	55,304
	Gas (bcf)	182	309	258
	HSD (10^3kl)	1,768	693	981
	MFO (10^3kl)	355	-	-

c.f. Coal consumption includes IPPs.

-Since the power sector in Indonesia depends on coal, the actual amount of coal consumption is expected to be about 18,096×10^3t in 2001. This tendency continues in the future, the amount of coal consumption in 2010 is expected to be three times as much as the one in 2001.

-The amount of natural gas consumption is 182bcf in 2001. In the middle and long term, consumption is expected to increase in place of oil.

-The consumption amount of oil product consumption, such as HSD or MFO, is expected to decrease in the future.

(2) Financing Plan

Table 3.3.7 shows the financing plan according to RUKN. US$ 2,324 million is required to develop new power sources until 2005, and for the following years US$ 10,810million is required.

Table 3.3.7 Financing Plan in RUKN (Unit: US$ million)

Items	2001~2005	2006~2010	Total
Gas turbine	336	480	816
Steam Turbine	1,080	8,640	9,720
Combined Cycle	908.5	490	1,398.5
Hydro	0	1,200	1,200
Sub Total	2,324.5	10,810	13,134.5

c.f. Hydro means the pumped storage unit.

Table 3.3.8 shows that US$ 2,861 million is required for costs related to transmission and distribution lines.

Table 3.3.8 Construction cost for Transmission system (Unit: US$ million)

Items	2001~2005
Transmission System	895
Distribution System	1,966
Total	2,861