PART I

OVERVIEW AND CURRENT SITUATION

Chapter 1

Introduction

THE STUDY ON MASTER PLAN OF URBAN GAS DEVELOPMENT
IN THE REPUBLIC OF INDONESIA — FINAL REPORT

PART I OVERVIEW AND CURRENT SITUATIONS

1. Introduction

1.1 Background and Objectives

(1) Overview

This Final Report of the Study on the Master Plan of Urban Gas Development ("the Study") presents the proposed master plan of gas network development in the Jakarta area and the results of feasibility studies for selected areas. PART I describes our findings and analyses on current situations and sets forth most common assumptions for the Master Plan ("M/P") and Feasibility Studies ("F/S") to follow in PARTs II and III respectively. Conclusions and recommendations are re-assembled in PART IV.

Regarding this, The Government of Indonesia ("GOI") and the Japanese Government agreed that the Japan International Cooperation Agency ("JICA") would conduct this Study on Master Plan of Urban Gas Development for the Jakarta area. Formerly, GOI and PGN had asked the Japanese Government to conduct feasibility studies of the possibility of gas distribution to residential customers in Jakarta, Bogor and Medan areas. After discussions among the concerned and preparatory missions, both countries agreed upon the Jakarta Branch area of PGN as the Study area.

Under the circumstances, it was also intended that the procedures and the results of the Study be a model for the application of similar methods to other areas by PGN itself. The Study, therefore, is presented in detail, sacrificing conciseness to some extent, as well as technical transfer programs were built in during the course of study.

(2) Background

Although the Republic of Indonesia ("RI") has been a major exporter of oil and gas in the world, recent rapid economic and industrial growth has spurred the increase of domestic oil consumption with a forecast that the country will become a net oil importer early in the next century. The country's gas resource base is considerably large on the other hand. While the RI is expected to continue as the largest LNG exporter in the world by using the gas from large gas fields, it has equally been a mandate to promote domestic use of gas from smaller gas fields as a solution to conserving oil resources and for improving the environment and promoting various benefits for the people.

Domestic use of gas has been developed by both Pertamina and PT. Perusahaan Gas Negara (Persero), or "PGN". The use of natural gas used to be limited to areas close to gas fields and prioritized for strategically important industries like power generation, fertilizers, cement, steel, etc., and mostly handled by Pertamina. On the other hand, PGN, having more than 130 years in the history of gas distribution to urban customers, formerly based on manufactured gas, embarked on natural gas distribution two decades ago. It has successfully expanded natural gas distribution in Jakarta, Bogor and Cirebon using the gas from Pertamina's West Java Transmission Lines, and also in Medan and Surabaya, mainly targeting large industrial customers. Total national domestic gas utilization either through Pertamina or PGN is increasing and approaching 50 % of the total national gas production.

Further expansion of gas use will have to involve more and more general industries, including smaller ones, and even commercial and residential customers. Market development activities are more important in such smaller customer market and have to timely match upstream development. As pipelines are being planned to transport gas from Sumatra to Java, it is high time to consider how to newly develop the smaller customer market in a way that the RI has never experienced.

Looking at demand, this Study has found that economic development in the Jakarta area is at a level that qualifies it for an urban gas system. Urban gas will even be necessary as a streamlined energy infrastructure in the modern capital area. This can be demonstrated by considering the status of energy efficiency, energy transportation, traffic congestion, environment, safety, affordability and residents' desire for more convenience in the urban areas.

This Study is thus significant at least in two ways: to contribute to the national energy policy to promote the domestic use of non-oil energy to liberate as much oil for export and to modernize the urban energy infrastructure in the capital area of the country. The Study is to clarify the ways both in national policy and PGN's management strategies to accomplish such purposes.

(3) Objectives

The objectives of the Study in response to the foregoing are to:

① formulate a master plan comprising the optimum development plan of an urban gas distribution system in the household (residential), commercial and industrial market sectors in the Jakarta area, and to conduct feasibility studies in the selected districts;

② propose appropriate plans for improving institutional and administrative systems of urban gas supply service; and

③ transfer the technical and administrative expertise to PGN, in the course of conducting the study.

1.2 Focus of the Study

The Study focuses on the potential gas market in the east-west belt zone from Balaraja, Tangerang, to Cikampek, Karawang, in PGN's Jakarta Branch service area in West Java as was initially agreed. Therefore, in order to project the whole Jakarta Branch area, one will have to additionally take in the potentiality of the gas market in Kabupatens Serang and Purwakarta as well as the results of this Study. Those separated areas are mainly for the industrial market which the Team understands PGN already has examined.

The Study defines a proposed master plan ("Master Plan") of gas distribution to new customers, generally smaller than current large industrial customers, including residential, commercial, industrial and new technology gas market sectors. New technology markets include gas air-conditioning, cogeneration and natural gas vehicle (NGV) markets. District cooling is discussed in a chapter of Feasibility Studies (F/S).

The feasibility studies were conducted in two selected areas: Perumnas Bekasi Baru, a government sponsored residential estate in Kabupaten Bekasi, and the Bumi Serpong Damai (BSD) in Kabupaten Tangerang, a private sector-led residential and commercial estate.

1.3 Major Contents

In Part I, after examining the findings and data, the Team set national and regional economic development scenarios including three cases, i.e., base, high and low cases, as the basis for demand projections. This Part also includes all the findings and analyses on the current situation regarding energy and gas market except the procedures and results of the gas demand survey.

Part II describes the proposed Master Plan as well as the analyses on direct demand assumptions. It includes detail survey procedures and results on the gas demand fundamentals to determine necessary parameters for gas pipelines and demand projections. Policy and management improvement plans are presented and are the basis for economic and financial analyses. Environmental and social assessment is also included.

Part III presents the results of feasibility studies in Perum Perumnas Bekasi Baru, a residential estate, and Bumi Serpong Damai (BSD), a large residential and commercial estate. The Study includes detail economic and financial analyses as well as detailed assumption reviews.

Conclusions and recommendations are in Part IV. The most crucial issue is the gas price either in the Master Plan or in the Feasibility Study results. Recommendations include how to achieve proper gas price levels in the smaller customer markets.

1.4 Work History of the Study

A team of JICA ("JICA Team") consisting of 13 members in aggregate worked for this Study in the period of 1996-1997. The Team[1] worked together with the Working Group established for this Study in PT. Perusahaan Gas Negara (Persero) ("PGN"). The Team from time to time consulted the "Counterpart Team" comprising the officials from BAPPENAS, the Ministry of Mines and Energy ("MME"), the General Directorate of Oil and Gas ("MIGAS"), Pertamina and PGN which was headed by Ir. Rohali Sani, Director of Development of PGN. The Study was overseen by the "Steering Committee" headed by Dr. Rachmat Sudibjo, Dierctor of Exploration and Production of MIGAS, and comprised ranking officials from BAPPENAS, MME, MIGAS and PGN.

The Study began in late June 1996 immediately after a relevant contract was awarded by JICA, and the initial work was devoted to preparing the Inception Report, gathering pre-mission information and conducting various preparations including scheduling. In gathering such information, the Team has considered that a smooth continuity from any former and existing plans and policies are important in PGN's operations.

The First Field Work, as defined in the Inception Report for the first mission, was conducted in July 15-August 13, 1996 for information gathering and preparation for the demand survey. The Second Field Work was carried out in the period of September 24-November 21, 1996 for conducting the demand survey, preparing for the Master Plan, selecting feasibility study areas and for implementing technical transfer.

After the Second Field, early in January 1997, the Team prepared the Interim Report

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integrating all the former field work and home work in Japan conducted in between the field works. It included all the findings to that date, additional work results especially of preliminary demand projections, outline of the proposed Master Plan and directions for feasibility studies.

The Third Field Work was conducted from January 15 to February 16, 1997. It was devoted to gathering all the remaining data for the Master Plan and to conducting feasibility studies in the two areas, as well as implementing economic and environmental assessment.

The 4th Field Work, from June 23 to July 1, 1997, was to present the draft final report to the Counterpart and the Steering Committee and to hold a one-day seminar to present the content of the work before potential investors and financiers as well as the guests from the counterpart side. The seminar involved intensive discussions on the viability of the gas distribution to the smaller customer market promoting much understandings.

The Team prepared a Progress Report at the end of each mission. This Final Report integrates the results of all those reports as well as the Interim Report and other analyses conducted in Japan.

1.5 Future Steps

This Study includes recommendations involving policy changes both at national and PGN levels which are prerequisite for the implementation of the Master Plan and of the feasibility study results. Establishing policies or the direction of policies on gas prices and PGN's policies for organizational and managerial improvement will be crucial for future development from this Study. In addition, there will be more steps before implementation as is discussed in Part IV.

All projections and analyses in this Study are based on the assumption that policy changes and preparations for implementation be made in the year of 1997 and implementation take place in 1998. A delay of one year in policy formulations means a one year delay of all plans in this Study.

Chapter 2

Economic, Energy and Social Situations and Scenarios

2. Economic, Energy and Social Situations and Scenarios

2.1 Macro-Economic Situations

2.1.1 Overview

The Indonesian economy has grown at a rate of 6 to 7 % per annum in real terms of the Gross Domestic Product (GDP) in recent years and this high growth trend is considered to be likely to continue in the coming 5 to 10 years. Reflecting the high growth of population which is at 1.66 % per year currently, the growth of GDP per capita has been at 5 to 6 % per year. In US dollar terms, the GDP per capita of Indonesia recently passed the $1000 line according to the International Monetary Fund (IMF) statistics. Capital inflow into non-oil and gas industry has contributed to much of this growth (Table 2-1).

Table 2-1 Economic Growth of Indonesia

Year	GDP 1990P bil. Rp	Growth rate %/yr.
1983	132.8	8.8
1984	142.1	7.0
1985	145.6	2.5
1986	154.1	5.8
1987	161.7	4.9
1988	171.0	5.8
1989	183.8	7.5
1990	196.9	7.1
1991	209.9	6.6
1992	223.6	6.5
1993	238.1	6.5
1994	255.9	7.5
1995	276.7	8.1

Soure: IMF (except for 1995)

The growth on Java Island is especially high and the Gross Regional Product (GRP) per capita in the Jakarta area is now over 3,000 US dollars even at the current exchange rate. The region displays characteristics typical of a newly emerging industrial economy. This discrepancy between Java and non-Java regions is a national issue and the government's policy is to reallocate the industry and population to other regions. Nevertheless the growth of Java is expected to continue.

2.1.2 Government Projections

The government in 1994 released the "Second 25 Year Plan (or PJPTII)" as well as the 6th Five Year Plan, or "Repelita VI", for the years starting in 1994. The Plan projects the economic (GDP) growth at 6.2 % per year with accelerated rates in later years and at 8.7 % per year in the five years between 2013 to 2018 (Repelita X) (Table 2-2).

On the other hand national population growth is projected at 1.57 % in Repelita VI, gradually decreasing thereafter and at 0.88% per year in the Repelita X. Consequently the projection of GDP per capita is at more accelerated rates.

Table 2-2 GDP Growth Target by Sector in Second 25 Year Plan

		Repelita 5	Repelita 6	Repelita 7	Repelita 8	Repelita 9	Repelita 10
		Estimate ending in:		average over 5 years ending in:			
	unit	1993	1998	2003	2008	2013	2018
GDP total	% per year	6.6	6.2	6.6	7.1	7.8	8.7
1 Agriculture	% per year	2.4	3.4	3.5	3.5	3.5	3.5
2 Industry	% per year	10.0	9.4	9.4	9.4	9.1	8.7
of which non-oil a	% per year	11.0	10.3	10.2	10.0	9.5	9.0
3 Other	% per year	7.2	6.0	6.3	6.8	8.0	9.5

Source: Indonesian Government

2.2 JICA Team's Projections

2.2.1 Principle

In formulating our long term gas demand projection, we consider that the Replita and the 25 Year Plan are an important target in Indonesia although there are other economic forecasts for Indonesia, at lower growth rates in the later years. The Repelita projection tends to give a steep growth line in the later years in the 25 year period.

Besides this Study, JICA has conducted, or is conducting, several studies involving economic projections necessary for assumptions and we will also consider those projections. Those of JICA tend to give lower long term economic growth projections. The best method has been to combine those figures to create scenarios; that is, base, high and low cases, rather than create everything from scratch.

More effort has been made to create scenarios for the Jakarta area where the Study is targeted. Subtle differences may not be significant, since a long term projection always involves much uncertainty and is often just a reference for future thinking or scenarios in our philosophy.

2.2.2 Population

We use the national population projection of the Repelita as well as the 25 Year Plan for our base since the use of it, or others close to it, is versatile. It forecasts the growth at 1.57%/y from 1994 through 1998 and at 1.17 %/y thereafter through 2018.

The growth of the population of the Jakarta area (different from DKI itself) is much higher than the national average, and the Repelita forecasts it at 5.2 %/y through 1998 and 2.54 %/y (approximately half) thereafter through 2018. This assumes the current trend of high growth will continue for the time being in spite of population reallocation plans which will be effective after 2000.

The Team's common base for the growth of population in Jakarta and vicinity areas is set out in a simple form in Table 2-3 based on the Repelita projection from which the growth rate numbers appear a little different due to difference in axis years employed. The growth

Table 2-3 Projection on Population

Growth rate %/yr

	1996 - 2000	2000-2010	2010-2020	2000 - 2020 aggregate
National	1.52	1.28	0.94	1.11
Jakarta Area	5.0	2.5	2.5	2.5

Source: Restructured from Repelita by JICA Team

in each Kabupaten (prefecture) in the Jakarta area, however, is considerably different from this table and will be cited as necessary later.

2.2.3 National GDP

Our projection of the GDP takes into consideration preceding forecasts, the Repelita and the 25 Year Plan ("Repelita") and the 1995 JICA study in the Indonesian electricity sector. We have considered that:

1) The Repelita projects near term growth at a low level (6.2%/y) but very high growth for the long term (8.7%/y for 2014-2018).

2) The growth for the current Repelita period (1994-98) was set at 6.2%/y but actual growth was 8%/y in 1994 and higher in 1995. The inflow of industrial investment and the pressure for growth has been strong despite policies for lower growth rates to maintain the stability of inflation and real interest rates to maintain international currency balances. This trend may continue for the time being and we consider that the Repelita projection for a short-term period should be taken as our Lower Case.

3) The high growth projection in the long term in the Repelita over more than 20 years may indicate a national target and it is understandable in this regard. The Team will take it as the Higher Case.

4) Looking into other recent JICA studies, on the other hand, they foresee the long term growth at lower rates than in Repelita possibly employing a later part of a logistic curve toward saturation. A 1995 JICA study predicts growth through 2000 at 6.9%/y and thereafter at 5.7%/y. This study seems to have formulated the projections before the release of Repelita VI. If we assume that the statement of "5.7%/y for the years after 2000" in the said JICA study of 1995 as meaning a rate for the period of 2000-2010, it means a decrease by 1.2%/y in a decade. Another JICA study of 1996

employs the same values of Repelita.

5) We consider that, since the Counterpart possibly relies on Repelita in many occasions of planning work, it will be more convenient if our study is consistent with the Repelita as much as possible, if not a base or standard case.

6) On the other hand, while the Repelita growth rates seem to be rather high in the later stages of the 25 years, a little lower rates will be on the safe side of our projection.

7) Summarizing the above, we project the GDP growth rate as the assumption in our Study as follows:

a. For the short period through 2000: the projection of the Repelita is set as the Lower Case and 1995 JICA projection is taken as the Higher Case. We see that both cases will be easily surpassed by actual growth in the immediate future but hope they will be recognized as the mere reference assumptions for various scenarios.
b. For the long term perspective through 2010 and up to 2020, the Repelita will be used as the Higher Case. For the Lower Case we will assume a further 1.2%/y decrease in the growth rate in this period from the period of 2000-2010 supposed in the 1995 JICA projection; thus 4.5 %/y.
c. For the period of 2000-2010, the Higher Case is taken from the Repelita and the Lower Case from the said JICA study.
d. The average of Higher and Lower will be our Base Case.

The result is a rather large discrepancy between the High and Low cases in the later years,

Table 2-4 National GDP Growth Rate - JICA Team Projection %/yr.

year	Base	High	Low
up to 2000	6.5	6.9	6.2
2000 - 2010	6.4	7.1	5.7
2010 - 2020	6.7	8.7	4.5

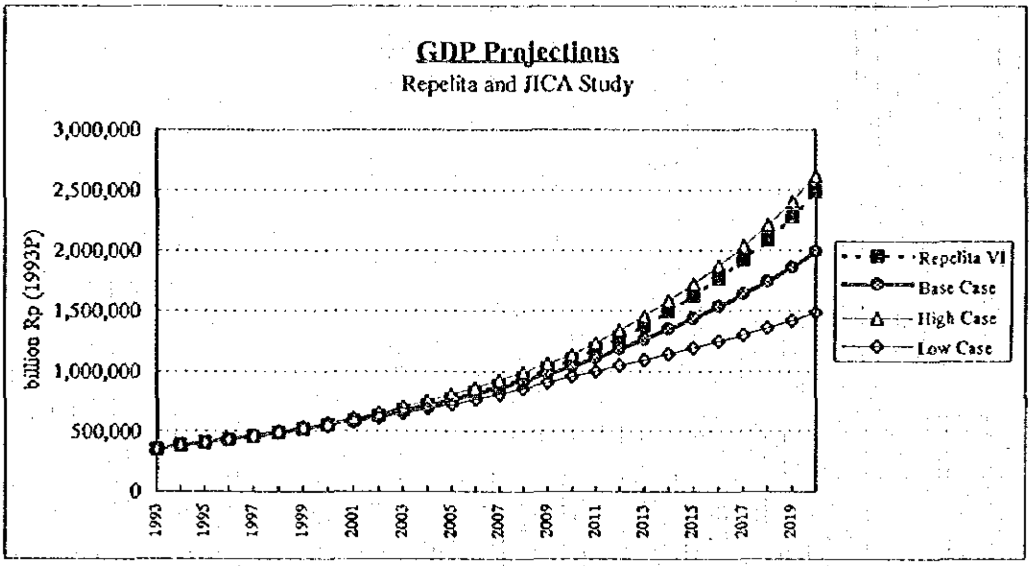
Source: JICA Team

implying uncertainty in the long term as well as rather representing a broad minded view for the future, since no long term economic prediction has proved to be completely accurate. We have rearranged the rates for each case in the brackets divided by 2000, 2010 and 2020 (Table 2-4).

2.2.4 GRP - Gross Regional Product in the Jakarta Area

The regional economic growth projection in the Jakarta area will be determined by the combination of the national projection and the historical ratio of the gross regional and national products. Table 2-8 in a later page shows historical gross regional domestic product (GRDP) of all provinces in Indonesia. This makes it apparent that DKI Jakarta + West Java make up 30% of the national domestic product (GDP), of which

Fig. 2-1 National GDP Scenario for the JICA Study



Source: Repelita VI and JICA 1996

52% is shared by the DKI+nearby 3 Kabupatens in the latest 5 year average.

The growth rate is also high in the DKI+West Java area. The ratio of the growth rate of DKI+West Java to that of national GDP (i.e., elasticity) is 1.18, meaning 18% faster in the growth. This higher growth seems to continue regardless of the industry reallocation policy and therefore the Team will use this ratio for general projection of GRDP in the area.

This projection is arranged in the table below (Table 2-5).

Table 2-5 GRP in Jakarta Area - JICA Projection

growth rate %/yr.

year	Base	High	Low
up to 2000	7.7	8.1	7.3
2000 - 2010	7.6	8.3	6.7
2010 - 2020	7.9	10.3	5.3

Source: JICA Team

2.2.5 GRDP Per Capita

Per capita national GDP growth is currently approximately at 6%/yr, reflecting the population growth. The projection of GDP per capita by Repelita VI is set at a lower rate due to the reason that we have seen. The JICA Team will project it by combining the GDP and population projections as follows (Table 2-6).

Table 2-6 National GDP per Capita Projection for JICA Study %/yr.

year	Base	High	Low
up to 2000	4.90	5.30	4.61
2000 - 2010	5.06	5.75	4.37
2010 - 2020	5.71	7.69	3.53

Source: JICA Team

The GDRP per capita in the Jakarta area is at a sky scraping level (6.2 million Rp. in 1994) compared to the national average (1.8 million Rp. in 1994). The per capita growth rate, however, is recently close to the national level, reflecting the high population growth in the area. The national statistics offer two sets of GRDP numbers by including added values in the oil and gas sector and excluding them. The difference does not affect Jakarta but there are some minor effects in West Java.

The average of Jakarta and West Java's per capita GRDP growth is almost comparable to the national average in recent years due to the population growth stated above. The trend of local population growth, however, is more uncertain in the long term because of more influencing factors. Therefore the Team will apply the local GRP per capita indicators similar to, but not necessarily the same as, the national growth rate of per capita GRDP in its projections, except in very local cases.

The projection of GRDP per capita can be related to residential energy estimates but is not directly used in gas demand projection in our Study because the residential demand is discussed in terms of household units. Instead the population and GRP are directly used.

Table 2-7 GRP In Jakarta Area and Comparison to National

1983 Constant Prices in billion Rp

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	Five year average (1989-93
DKI 5 districts	7,819	8,648	7,917	9,464	10,758	11,469	12,586	13,710	14,721	15,897	17,185	
Tangerang (Reg.)	583	673	762	877	914	1,041	1,145	1,168	1,278	1,380	1,513	
Bekasi	307	389	471	619	636	712	778	809	910	1,052	1,221	
Karawang	185	250	316	441	451	479	505	625	736	785	860	
Area Total	8,894	9,961	9,467	11,401	12,759	13,702	15,013	16,312	17,645	19,114	20,778	
Growth rate %/yr.		12.00	-4.96	20.44	11.91	7.39	9.57	8.65	8.17	8.32	8.71	8.69
Ratio to National Total %	14.4	14.6	13.0	14.5	15.4	15.3	15.5	15.6	15.8	16.0	16.2	15.8
Elesticity to National		1.19	-0.73	2.65	2.07	0.93	1.17	1.13	1.16	1.14	1.28	1.18
Ratio to W. Java+Jakarta %	51.2	51.1	44.5	48.2	51.5	51.4	51.8	51.6	52.0	52.3	52.9	52.1
Elasticity to W. Java+Jkt		0.97	-0.55	1.81	2.51	0.99	1.08	0.95	1.12	1.08	1.15	1.08

Note) Data of 1983-1985 except for Jakarta are by retroactive extrapolation; Tangerang includes municipality.

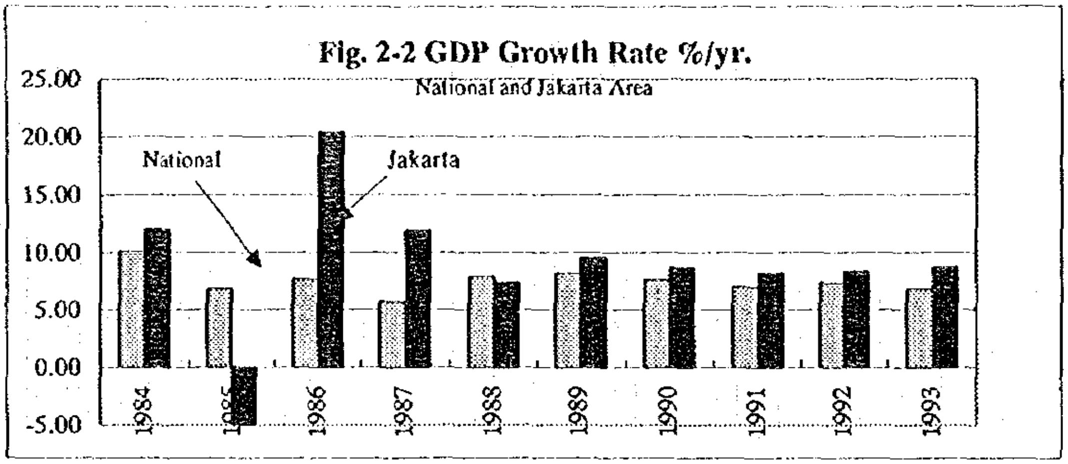
Source: BPS and JICA Team

Table 2-8 Historical Gross Regional and Domestic Products

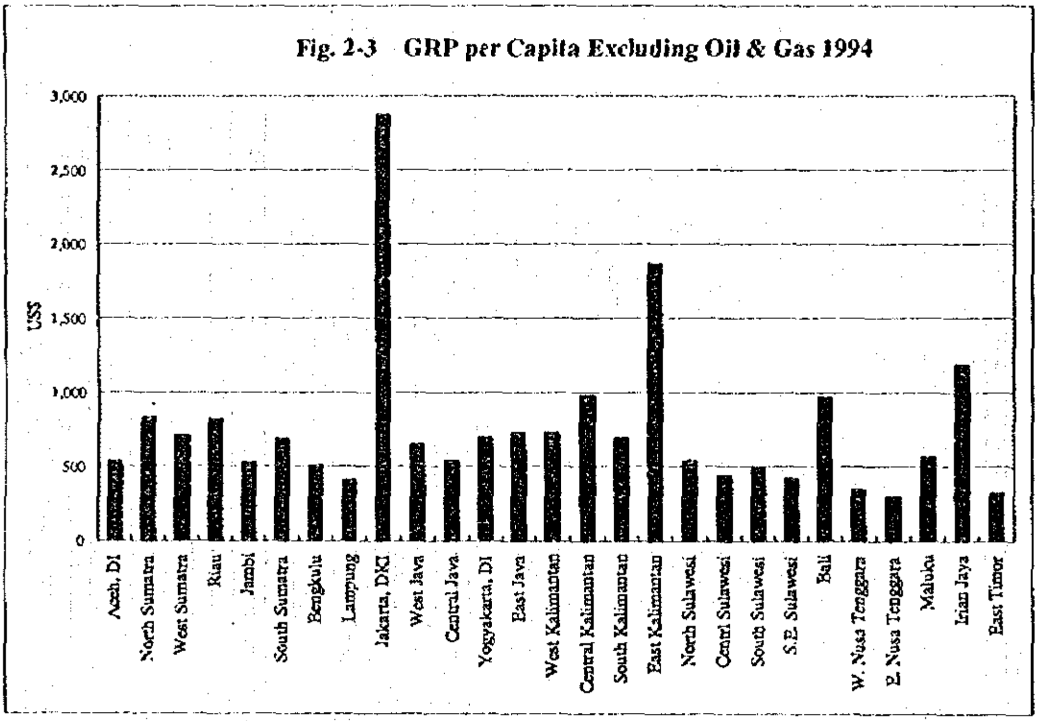
1983 Constant Prices in billion Rp	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	In 1993 Prices 1993	In 1993 Prices 1994	Share 1994%
1 Aceh, DI	3,425	4,098	4,210	4,230	4,593	5,010	5,418	5,715	6,020	6,270	6,699	7,056	11,192	11,788	3.40
2 North Sumatra	3,275	3,544	3,697	3,948	4,309	4,825	5,298	5,737	6,160	6,646	7,179	7,859	18,215	19,940	5.74
3 West Sumatra	1,234	1,300	1,356	1,424	1,498	1,597	1,712	1,832	1,948	2,078	2,222	2,386	6,027	6,471	1.86
4 Riau	977	1,035	1,102	1,177	1,274	1,374	1,522	1,629	1,791	1,993	2,135	2,226	17,254	17,988	5.18
5 Jambi	492	519	556	586	629	697	774	845	892	954	1,025	1,109	2,463	2,664	0.77
6 South Sumatra	3,438	3,857	4,061	4,249	4,248	4,509	4,864	4,879	5,058	5,308	5,576	5,995	11,309	12,158	3.50
7 Bengkulu	261	278	300	332	357	396	425	457	495	532	575	610	1,390	1,475	0.42
8 Lampung	1,057	1,183	1,270	1,396	1,529	1,645	1,780	1,919	2,003	2,233	2,354	2,521	5,368	5,749	1.66
9 Jakarta, DKI	8,348	9,205	9,679	10,164	10,758	11,469	12,586	13,665	14,730	16,002	17,350	18,815	51,000	55,305	15.93
10 West Java	9,014	10,302	11,590	13,505	14,036	15,168	16,409	17,959	19,196	20,541	21,956	23,501	52,675	56,382	16.24
11 Central Java	7,300	8,232	8,920	9,460	10,016	10,652	11,340	12,134	13,003	13,970	14,822	15,770	33,979	36,153	10.42
12 Yogyakarta, DI	764	810	821	885	921	976	1,038	1,085	1,141	1,221	1,299	1,404	4,058	4,387	1.26
13 East Java	10,848	11,513	12,147	12,896	13,524	14,420	15,495	16,737	17,924	19,184	20,511	21,991	49,114	52,658	15.17
14 West Kalimantan	851	899	962	1,104	1,206	1,404	1,407	1,575	1,679	1,798	1,928	2,073	5,148	5,536	1.59
15 Central Kalimantan	478	504	536	590	633	687	719	773	838	912	959	1,029	3,095	3,322	0.96
16 South Kalimantan	901	960	988	1,017	1,105	1,198	1,283	1,375	1,474	1,604	1,755	1,884	3,974	4,265	1.23
17 East Kalimantan	3,147	3,528	3,909	4,289	4,670	5,050	5,447	5,814	6,189	6,614	6,789	7,441	16,022	17,561	5.06
18 North Sulawesi	402	423	439	456	480	874	926	1,015	1,046	1,139	1,248	1,342	2,820	3,032	0.87
19 Centrl Sulawesi	364	371	393	419	449	487	529	576	626	679	739	792	1,653	1,772	0.51
20 South Sulawesi	1,752	1,830	1,966	2,094	2,227	2,250	2,609	2,785	3,050	3,286	3,540	3,773	7,512	8,006	2.31
21 S.E. Sulawesi	294	322	335	367	386	421	465	526	585	613	652	695	1,289	1,374	0.40
22 Bali	902	989	1,073	1,154	1,252	1,355	1,473	1,604	1,737	1,888	2,056	2,210	5,591	6,009	1.73
23 W. Nusa Tenggara	519	575	593	629	649	690	751	818	879	954	1,005	1,068	2,537	2,695	0.78
24 E. Nusa Tenggara	498	536	556	585	608	632	667	714	763	822	899	974	2,068	2,241	0.65
25 Maluku	479	516	539	601	674	734	783	858	925	962	1,018	1,076	2,369	2,504	0.72
26 Irian Jaya	852	791	775	821	848	924	1,020	1,098	1,269	1,377	1,455	2,696	2,746	5,089	1.47
27 East Timor	82	88	94	99	107	117	125	140	155	172	185	204	515	567	0.16
National Total (GDP)	61,955	68,208	72,867	78,477	82,986	89,561	96,865	104,264	111,576	119,752	127,931	138,499	321,383	347,091	100.0
Growth rate %/yr.		10.09	6.83	7.70	5.75	7.92	8.15	7.64	7.01	7.33	6.83	8.26		8.00	
of which:													Five year average		
West Java + Jakarta	17,362	19,507	21,269	23,669	24,794	26,637	28,995	31,624	33,926	36,543	39,306	42,316	(1990-94)		
Growth rate %/yr.		12.35	9.03	11.28	4.75	7.43	8.85	9.07	7.28	7.71	7.56	7.66	7.86		
Ratio to National Total %	28.0	28.6	29.2	30.2	29.9	29.7	29.9	30.3	30.4	30.5	30.7	30.6	30.5		
Elesticity to National		1.22	1.32	1.47	0.83	0.94	1.09	1.19	1.04	1.05	1.11	0.93	1.06		

Note) West Java 1983-85 and E. Kalimantan 1983-88 are given estimates by retroactive extrapolation. Data for 1993 and 1994 are preliminary (BPS).

Source: Original data: BPS 1996; Analysis: JICA Team



Source: BPS and JICA Team

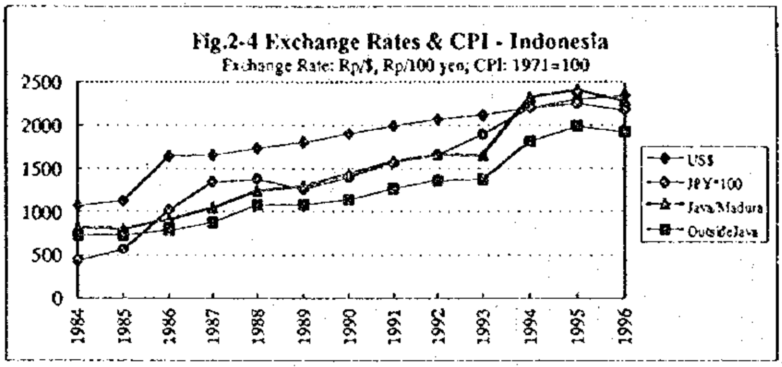


Data source: BPS 1996; Analysis & graph: JICA Team

2.2.6 Inflation

Real constant prices will be used in formulating the Master Plan; therefore inflation rate may not be used in our study for long term projections. Short-term studies and initial facility price adjustment, however, may require the use of inflation rates.

The inflation rate for consumer prices (CPI) has been at 9.3 %/y on average from 1986 to 1996. Contribution of food prices to the index elements is considerable. Inflation rate is 1 to 1.5 % higher in Java Island (Fig. 2-4).



Note) At each year end except 1996 being at end May. Data source: Indonesian Government Statistics; Graph: JICA

Source: JICA Team/BPS 1996

Recent inflation rates are given in the box to the right (Table 2-9), showing rather higher rates than Repelita VI which had targeted at 5 %/y. The price of food was increasing at a high, two-digit rate, seriously affecting the whole inflation rate. The increase in prices in housing, garment, services and others, instead, has been maintained at more reasonable rates of 5.6 to 7.0 %/y. On February 5, 1997, the Government announced that the food price hike was now under control and the inflation for 1996/1997 would be under 6%.

Table 2-9 Recent Price Increase

Inflation:	1986 to 1996 (%/y)
Consumer Price (food weight high):	
Java	9.63
Outside Java:	9.34
Wholesale Price:	
(assume common)	7.00

Source: various media 1996

We see the necessity of increase in energy prices in the future at least and so rates of inflation may continue for the time being.

2.2.7 Wage Increase

Tale 2-10
Household Income per Capita by Household

Household Group (Rp 1000 in current prices.)	1975	1990	1975 to 1990 ave.%/y	GDP per capita elasticity*
Agricultural laborers	40	438	17.29	0.94
Agricultural operators owning less than 0.5 ha of land	43	567	18.70	1.02
Agricultural operators owning less than 0.5 - 1 ha of land	58	683	17.91	0.97
Agricultural operators owning more than 1 ha of land	85	1,053	18.29	0.99
Agriculture average	56	685	18.11	0.98
Rural lower level non-agriculture households	54	640	18.00	0.98
Rural l non-labor force households	71	936	18.80	1.02
Rural higher level non-agricultural households	153	1,049	13.69	0.74
Rural non-agricultutre average	92	875	16.17	0.88
Urban lower level non-agricultural households	98	830	15.33	0.83
Urban non-labor force households	111	951	15.41	0.84
Urban high level non agricultural households	260	1,882	14.12	0.77
Urban average	156	1,221	14.70	0.80
National average	78	871	17.41	0.95

Note*) GDP per capita growth rate in current price in 1975-1990 was 18.403 %/y in the average.

Data Source: Welfare Indicators 1995, BPS; Analysis by JICA Team

In the current phase of the strong real economic growth of Indonesia, the real growth in GDP per capita suggests wage increases in real terms. This may affect price and cost elements in our economic and financial analyses in later chapters. Table 2-10 shows that the household income per capita has been growing in line with GDP per capita at a rate of 0.8 (as elasticity) for urban non-agricultural workers.

2.2.8 Exchange Rates

Foreign currency exchange rates have been closely following the trend of inflation as shown in Fig. 2-4. The rate is periodically depreciated to follow the U.S. Dollar within a currency band. In July 1997, following the floating of Thai Baht, the Bank Indonesia widened the band from 2% to 8 % to allow more fluctuation of Indonesian Rupiah. This reflects a trend of Indonesian economy becoming more international and strengthened as well as following the ASEAN countries.

Since the upstream side of natural gas business is governed by the U.S. Dollar currency, even including the trade between Pertamina and PGN, PGN taking the currency risks, it has an awful effect on all domestic gas distribution planning. Recent depreciation of Rupiah and widening of the currency band may be having a strong psychological effect on the personnel concerned. In such circumstances, relevant domestic contracts may be better designed to have some room of maneuvering in currency changes, and all business plans be cautious about such international changes. Most other countries are affected similarly.

Nevertheless, we stick to the notion that the exchange rate will basically follow the difference in inflation rates between the two countries for the long term perspective. It clearly does not represent a purchase power parity (3 to 4 times difference by the assessment of IMF or the World Bank) but an overall economic balance may be reflected. Consequently we use the current rate as of beginning 1997, i.e., 2350 Rp/$ for our real term price projections.

2.2.9 Interest Rates

The current rate in Indonesia comparable to a central bank discount rate is about 16.5%. The rate of loans from local commercial banks is about 20%. Considering the current inflation rate, the real interest rate is approximately 10%. Long term loans are non-existent, however, with domestic commercial banks and the interest rate for economic analyses will have to be separately considered.

2.3 Energy Situation and Projections

2.3.1 National Energy Resource Base

Although RI has been a famous oil exporting country, Table 2-11 shows that it is in fact a large coal country as well as a gas country. New coal mines have been aggressively developed in the last decade reflecting the size of the resource. The large share of the coal in the resources may cause misperception of hydro and geothermal potentials, shown in Fig. 2-5, which are also very large compared to other countries. The potential 25 year capacity of these renewable resources is taken as the resource potentials to compare the size with fossil fuels here.

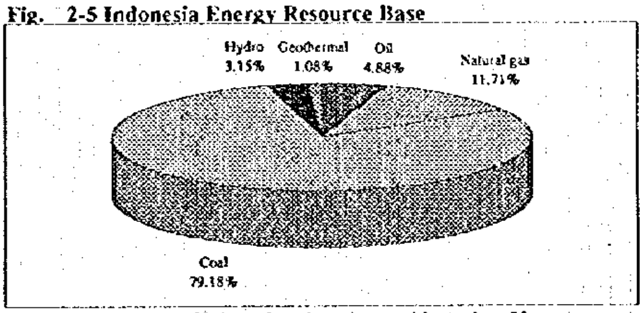
Table 2-11 Energy Resource Base of Indonesia

	Oil		Natural Gas		Coal		Hydro Potential		Geothermal
Resource category	proven reserves	potential reserves	proven reserves	potential reserves	Deposit of: Anthracite+ Bituminous	Subbituminous Lignite brown	Potential capacity	Annual potential production	Potential
units	million bbl		Tscf		million ton		MW	GWh	MW
Sumatra					782	23,893	15,587	64,110	9,562
Jawa						6,940	4,200	18,024	5,331
Kalimantan					4,560		21,581	107,202	
Other							33,608	192,290	4,765
Total	4979.7	4117.9	72.27	51.31	5,342	30,833	74,976	401,626	19,658
Proven + potential	9997.6		123.58		36175.0		mil. GJ/year	1,445	496
Proven + potential	million GJ		million GJ		million GJ		for 25 years: -		
in common unit	55,950		134,331		908,535		milGJ/25y:	36,146	12,399

Note) JICA conversion:
1bbloe=6150 MJ, 1 Tscf(NG)=1.087*10^12 MJ, 1 ton-coal(6000kcal/kg)=25115 MJ
1GWh(hydro)=3600 GJ, for Geothermal in 80% load: 1 MW for a year=25,229 GJ/y

Source: MME 1996 and JICA Team

Fig. 2-5 Indonesia Energy Resource Base



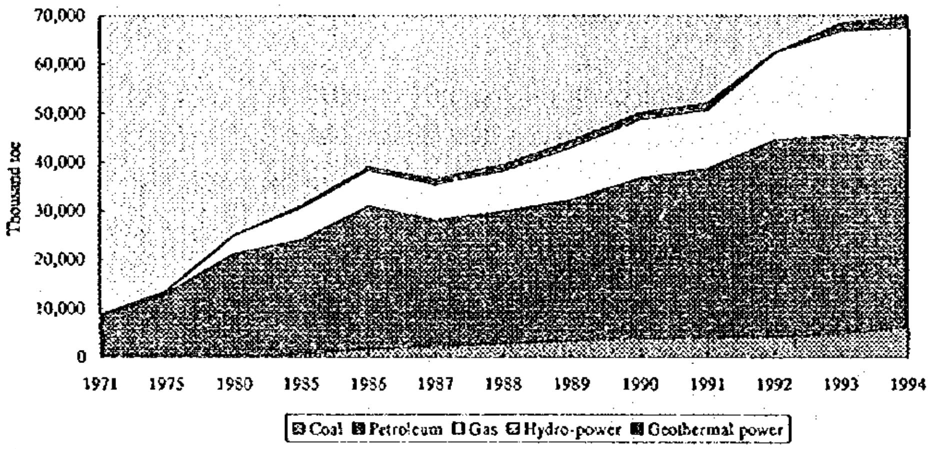
Note) potential resources; Hydro and geothermal: potential capacity x 25 years.
Source: JICA Team; original data: MME 1996

Most of natural gas reserves are located near the current LNG export areas, i.e., in East Kaklimantan, Aceh and North Sumatra as well as Natuna Island areas, the share of the reserves in these areas being about 82% of national proven reserves in 1993. Near term supply potential to Java may be from Java onshore and offshore, and South and Central Sumatra. The share of these areas of proven reserves was 16 % in 1993. This means that any long term plan of domestic gas use development has to take into consideration eventual utilization of large and remote gas fields for domestic market sustainability unless new large gas reserves are found near the large demand areas of Java.

2.3.2 Historical Primary Energy Supply

Indonesia's primary energy supply was 69.74 Mtoe (million tons of oil equivalent) in 1994 compared to 31.72 Mtoe in 1985, representing an average annual growth rate of 9.15 percent according to IEA.

Fig. 2-6 Total Primary Energy Supply



Source: IEA Energy Statistics and Balances of Non-OECD Countries 1985 to 1995

The supply of natural gas increased noticeably from 6.53 Mtoe in 1985 to 22.42 Mtoe in 1994 while that of crude oil from 23.49 Mtoe in 1985 to 41.25 Mtoe in 1994 (Fig.2-6).

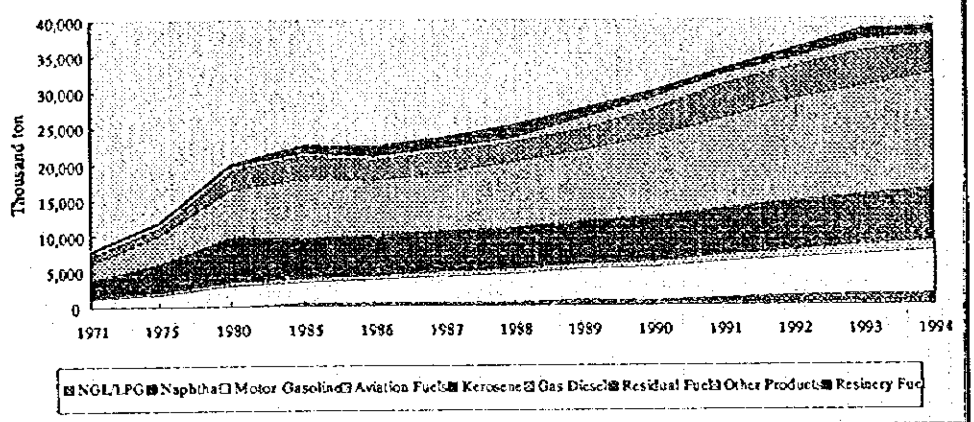
The GDP elasticity of primary energy, in terms of the ratio of the growth of energy consumption to that of GDP, during the same period, exceeded 1.4, indicating a large energy increase over the GDP growth. The reason for the increase is not only the high pace of industrialization but also the shift from non-commercial to commercial energy and the subsequent increase in fundamental energy consumption. Also, the fact that energy prices, particularly the domestic prices of petroleum products, were kept low by subsidies, cannot be overlooked as a contributing factor.

2.3.3 Final Energy Consumption

Total final energy consumption in 1994 was 47.25 Mtoe. This figure is 2.03 times that of 1985 and 1.4 times that of 1990, the average annual rates of increase being 7.7% in 1985-90 and 8.7% in 1990-94 periods. The GDP elasticity was 1.24 in 1985-90 and 1.30 in the 1990's indicating a further increase.

Looking at energy consumption in 1994, petroleum products accounted for 72.04%, gas 16.88%, electric power 8.13%, and coal 2.95%. The share occupied by oil of the primary energy supply for the same year is 59.14%, and is 12.9 points smaller than the final energy consumption. (Fig. 2-7)

Fig. 2-7 Oil Products Consumption (Thousand toe)



Source: IEA Energy Statistics and Balances of Non-OECD Countries 1985 to 1995

Looking at shares by demand sector, the industrial sector accounted for 32.43%, the transport sector 31.33%, the commercial and public sector 2.33%, the residential sector 21.18% and others 12.73% (1994). The industrial and public sectors have shown an increase in shares since 1985 and the transportation sector a decrease. However, as demand has greatly increased in all sectors, the change in shares may be a minor phenomenon (Table 2-14 in a later page).

2.3.4 Natural Gas Status

Proven + potential natural gas reserves in Indonesia are 123.6 TCF (trillion cubic feet) in 1996, the reserves to production ratio being 41 years based on the 1995 production volume of 8,220 mmcfd. Gas field developments are going on and reserves are being added every year recently. Recent large findings in Riau and Irian Jaya seem not reflected in the reserves yet and more reserves are expected in South Sumatra according to media reports.

Certain reserves are already committed for export LNG and domestic sales in long term contracts and they expect own use and losses of about 27.5 % of reserves. Net available reserves are shown in Table 2-12.

Use of natural gas in 1995 is broken down into demand sectors in Fig. 2-8. Domestic use has grown year by year and is expected to match the amount of export in the form of LNG in a few years.

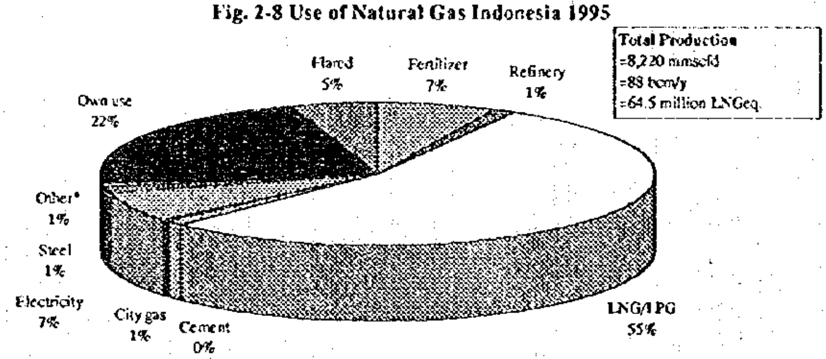
Table 2-12 Natural Gas Reserves Uncommitted

trillion cubic feet (TCF)

	Proven	Potential	Total
Reserves	72.3	51.3	123.6
Committed under contracts:			
LNG	16.7		16.7
Domestic distribution	7.0		7.0
Total	23.7	0	23.7
Own use or loss expected (27.5%)	19.9	14.1	34.0
Net uncommitted and available	28.7	37.2	65.9

Source: PGN 1996

Fig. 2-8 Use of Natural Gas Indonesia 1995



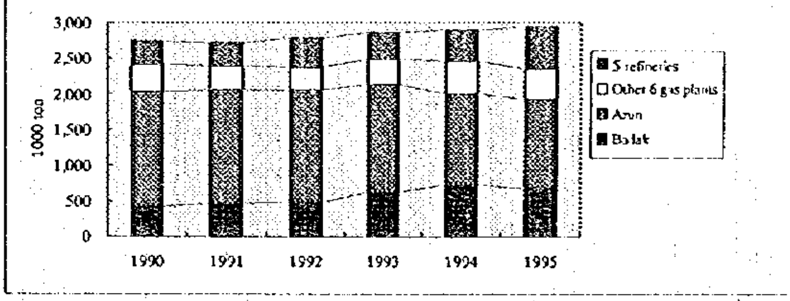
Data source: Pertamina 1996

2.3.5 LPG Status and Perspective

Large volume LPG production began in the late 1970s and the growth of its domestic use thereafter has been significant especially for residential purposes on Java Island. Recent LPG production is at the level of 2.7 to 2.9 million tons a year and has been gradually increasing for the past several years. Two thirds of Indonesian LPG is produced at LNG plants at Arun and Badak. Of the total production of 2.94 million tons in 1995, Badak produced 23% and Arun 42.6%, totaling 1.93 million tons. The other six gas processing plants produced 14.2 % (418,000 tons) and the rest, 20.2% (594,000 tons), came from five oil refineries. (Fig. 2-9). Since a large amount of LPG comes from LNG plants, the production is eventually subject to LNG trade. A portion of LPG coming from refineries will show some increase also since Indonesia is expected to have more refineries in the future.

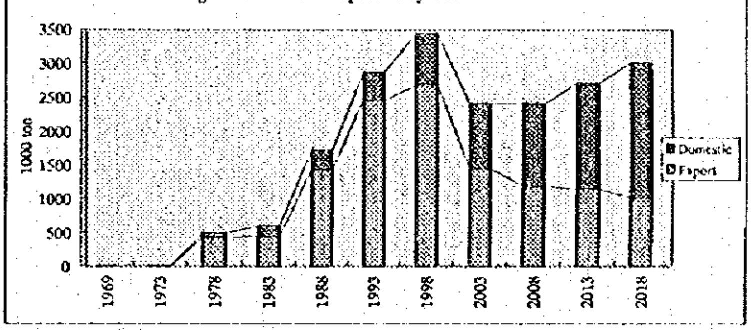
Domestic use of LPG is increasing. More than 80 % of LPG produced in Indonesia is exported to Asian countries. Domestic use is small but has been showing a steep increase over the last few years. Up to 1993, about 200,000 tons of LPG was used domestically of which 69% was for household use. The domestic consumption increased to 430,000 tons in 1995. The Jakarta area consumes a large amount of this for residential use. The transportation use is also increasing as the fuel is used mainly for buses and taxi cabs.

Fig. 2-9 LPG Production



Source: MIGAS

Fig. 2-10 LPG Perspective by Use



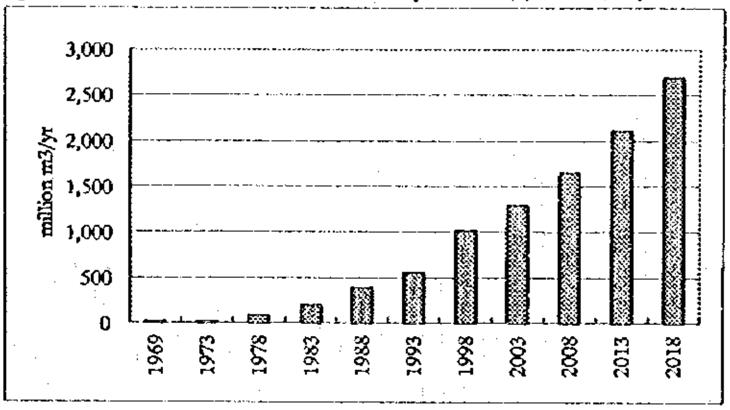
Note) Actual up to 1993, thereafter 25 Year Plan (PJPII)

Data source: MIGAS; Graph: JICA Team

Future domestic use of LPG is expected to increase, too, and LPG will now be the main competitor of natural gas for residential use. The production of LPG is constrained by the production of natural gas and oil, since it is a by-product, and therefore future uncertainty exists. However since most LPG is exported, Indonesia may turn such LPG to domestic use as the current 25 Year Plan projects (Fig. 2-10). Domestic use of LPG in the country is projected to reach 2.7 billion m3 per year in the Repelita X (2014-2018) in terms of natural gas equivalent of 8,800 kcal/m3 as shown in Fig. 2-11. LPG storage, bottling, transportation and delivery infrastructures have been installed in and around Jakarta area and most residential fuel in the suburban areas is now LPG. We will consider this in planning natural gas introduction in the Jakarta area.

2.3.6 Future Energy Outlook

Fig. 2-11 Domestic LPG Use in Natural Gas Equivalence (8,800 kcal/m3)



Source: JICA Team based on RI's 25 Years Plan / actual through 1993

For future projections we simply review energy outlook from a few sources since forecasting national energy supply and demand at large is not in our objectives but is mainly necessary in finding constraints in regional gas supply and determining the right directions in the overall framework. We have a projection from Repelita and modified ones from the Indonesian side and another one from a recent separate JICA study on hand.

The Repelita VI formulates the primary energy supply through 1998 as in Table 2-13. It projects a moderate growth in oil supply, and eventual consumption, and high growth of the use of coal, hydro and natural gas to reflect the national oil replacement policy. For the long term, Fig. 2-12 shows the most recently released outlook on the primary energy presented by Pertamina in a conference. According to this, energy use will grow from approximately 500 million bbloe (barrel oil equivalent) (approximately 73.5 Mtoe) in 1996 to 1,450 million bbloe (213 Mtoe) in 2010. The average growth is equivalent to 7.9 %/y. Compared to our base case scenario of GDP growth, the elasticity will be 1.22 in the period of 1996 to 2010, which is an improvement.

Table 2-13 Primary Energy Supply Outlook in Repelita VI

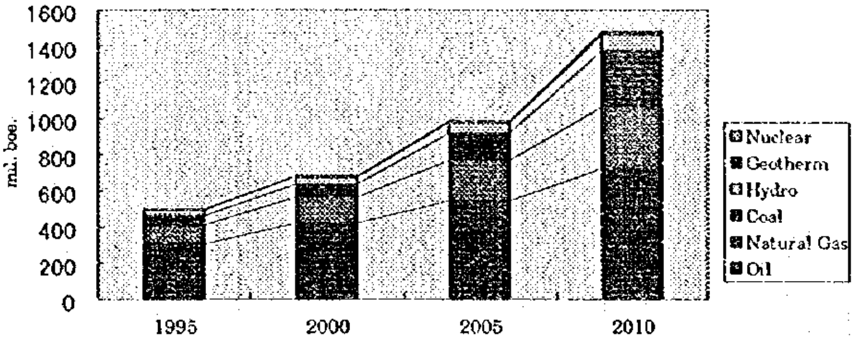
million bbl oe

	Actual	REPELITA VI					Growth %/y	
	1992	1994	1995	1996	1997	1998	98/94	98/92
Oil	263.1	296	311.7	331.6	337.5	360	5.02	5.37
Natural gas	82.3	117.2	132.1	137.8	157.3	162.6	8.53	12.02
Coal	32.4	46.9	61.3	84.2	99.4	120	26.47	24.39
Geothermal	2	4.4	4.4	6.3	8.6	12	28.51	34.80
Hydro	26.2	29.1	29.4	29.9	31.3	33.6	3.66	4.23
Total	406	493.6	538.9	589.8	634.1	688.2	8.66	9.19

Shares %	1992	1994	1995	1996	1997	1998
Oil	64.8	60.0	57.8	56.2	53.2	52.3
Natural gas	20.3	23.7	24.5	23.4	24.8	23.6
Coal	8.0	9.5	11.4	14.3	15.7	17.4
Geothermal	0.5	0.9	0.8	1.1	1.4	1.7
Hydro	6.5	5.9	5.5	5.1	4.9	4.9
Total	100.0	100.0	100.0	100.0	100.0	100.0

Source: Indonesian Government

Fig. 2-12 Projected Primary Energy Supply



Data source: Nasoyon, Conference on Integrated Gas Transmission System in Indonesia 1996

Another projection, from a JICA team of 1995, expects the total energy demand of Indonesia to reach 240.11 Mtoe (million tons of oil equivalent) in 2010 and 503.79 Mtoe in 2020 compared to 97.39 Mtoe consumed in 1995. The average growth rates will be 6.2% from 1995 to 2010 and 7.7 percent from 2010 to 2020. This outlook is from the Master Plan Study of Electric Power Development of Indonesia conducted by JICA (see Table 2-14, Table 2-15).

Table 2-14 Energy Demand by Sector

thousand toe

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Industrial	9,004.1	9,227.7	9,304.1	9,414.8	12,180	12,767	14,534	14,319	12,585	15,326
Coal	195.3	199.3	205.9	488.9	892.6	1,142	891	978	1,106	1,394
Oil	3,395.7	2,985.4	3,083.1	3,475.9	5,235.8	5,155	6,810	7,232	8,148	8,050
Gas	4,642.0	5,188.8	5,077.7	5,450.0	5,069.5	5,252	5,472	4,582	1,449	3,950
Electricity	771.1	854.2	937.4		982.0	1,218	1,361	1,527	1,882	1,932
Commercial	129.6	111.8	120.4		427.2	547	601	911	993	1,100
Oil					256.7	319	362	408	450	479
Gas								229	238	243
Electricity	129.6	111.8	120.4		170.5	228	239	274	305	378
Transport	7,243.4	7,666.2	8,434.4	9,133.3	9,945.7	11,108	11,838	13,224	13,861	14,802
Coal	19.7									
Oil	7,223.7	7,666.2	8,434.4	9,133.3	9,945.7	11,108	11,838	13,224	13,861	14,790
Gas										12
Residential	5,592.7	5,809.1	5,829.9	5,473.0	6,981.8	7,433	7,864	8,571	9,273	10,008
Oil	5,113.1	5,206.3	5,205.7	5,437.2	6,261.9	6,655	6,983	7,338	7,522	8,063
Gas	30.8	30.0	22.2	35.8	36.5	4	4	229	595	641
Electricity	448.8	572.8	602.0		683.4	774	877	1,004	1,156	1,304

Source : IEA Energy Statistics and Balances of Non-OECD Countories 1985,1986,1987,1988,1989,1990,1991,1992,1993,1994,1995

Table 2-15 Total Energy Demand in Indonesia

Mtoe

Year	1980	1985	1990	1995	2000	2005	2010	2015	2020
Oil	19.75	20.75	29.25	38.45	47.02	62.59	84.93	119.02	174.3
Natural Gas	1.64	2.68	4.14	13.31	17.21	22.12	34.31	53.69	85.07
Coal	0.1	0.94	4.55	5.28	17.96	28.78	45.1	73.61	117.98
Hydro	0.12	0.26	0.49	1.3	1.64	3.94	5.28	6.88	8.48
Geothermal	0	0.02	0.1	0.34	0.77	1.15	1.54	1.92	2.24
Bionass	16.23	17.66	26.53	31.34	33.89	35.27	38.11	41.33	45.3
Nuclear	0	0	0	0	0	0	0.38	0.38	0.38
LPG	0.08	0.19	0.39	0.3	0.52	0.89	1.28	1.5	1.79
Others	0.28	0.32	0.26	0	0	0	0	0	0
Electricity	1.29	2.23	4.17	7.07	12.07	18.76	29.18	45.16	68.25
Total	39.49	45.05	69.88	97.39	131.08	173.5	240.11	343.49	503.79

Note : electricity 869kcal/kWh; M=million

Source : The Master Plan Study of Electric Power Development in the Repubic of Indonesia by JICA 1995

Table 2-16 Forecasting Energy Demand by Sector

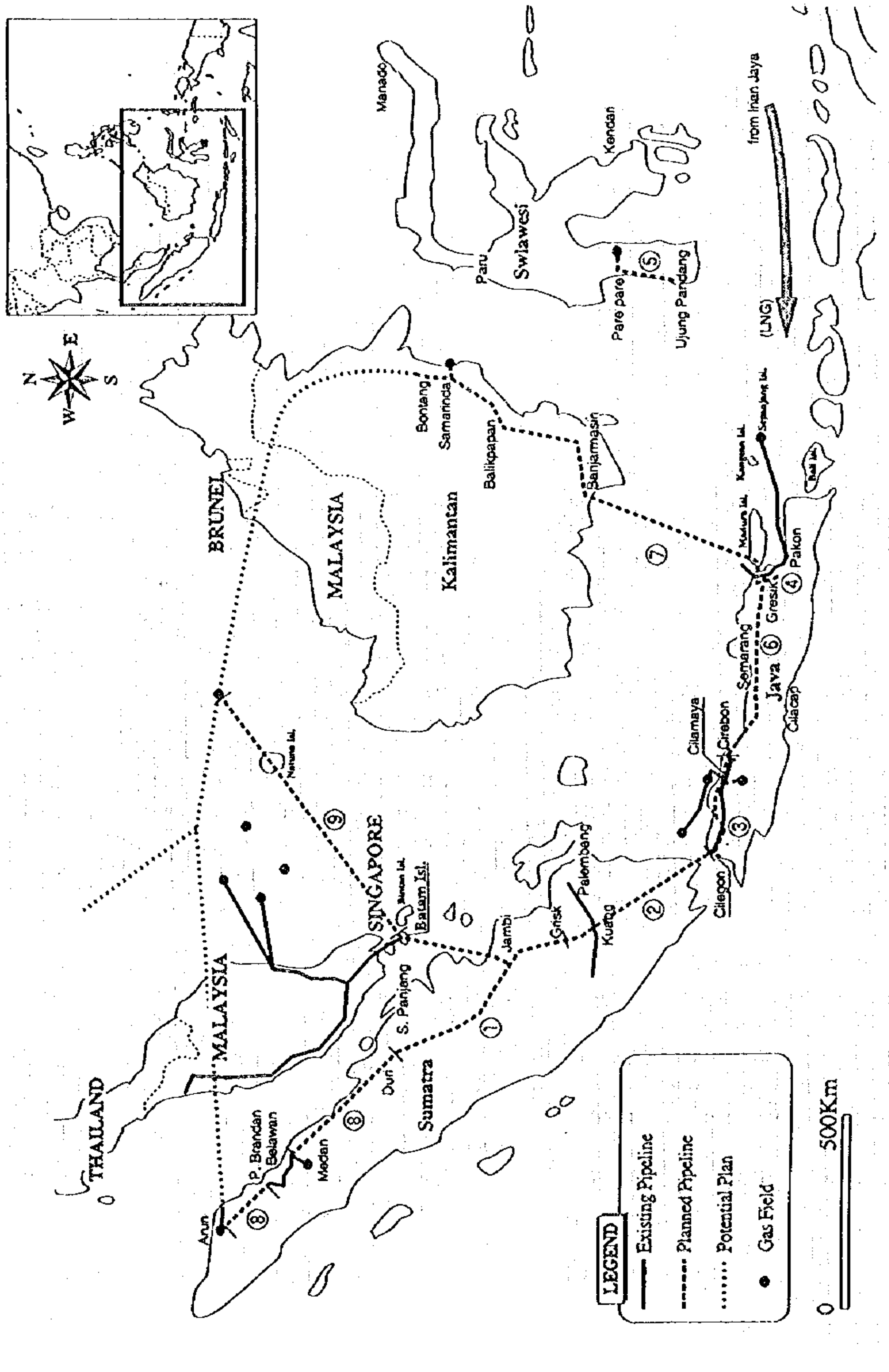
Mtoe

Year	1980	1985	1990	1995	2000	2005	2010	2015	2020
Industrial	7.32	9.04	21.04	28.72	39.85	55.5	79.37	116.91	177.36
Commercial	1.69	1.59	1.86	2.63	3.62	4.98	6.67	10.01	14.87
Public	0.26	0.14	0.19	0.32	0.45	0.64	0.91	1.31	1.84
Transport	6.34	7.5	12.47	17.04	23.02	31.69	44.66	65.02	98.67
Urban Households	5.68	5.78	7.12	10.96	13.95	17.15	21.44	26.26	32.33
Rural Households	16.03	16.99	18.84	20.7	21.58	21.41	21.85	22.26	22.37
Power Generation	2.26	4.01	8.36	17.42	29.24	42.89	65.98	103.2	158.74
Total	39.58	45.05	69.88	97.79	131.71	174.26	240.88	344.97	506.18

Note: M=million

Source : The Master Plan Study of Electric Power Development in the Republic of Indonesia by JICA 1995

Fig. 2-13 Indonesia Integrated Gas Transmission Pipelines



Source: JICA Team

2.4 Natural Gas Supply and Transmission Plans

The RI has many natural gas fields, and major gas fields and their production rates are shown in Table 2-17.

Table 2-17 Gas Production by Location in 1995 (mmscfd)

#	Location	Production	Utilization	Flared (F/P)
1	Aceh	3,234.4	3,233.9	1.3 (0.4%)
2	North Sumatra	137.9	122.4	15.5 (11.2%)
	Central Sumatra	107.7	86.0	21.7 (20.2%)
3	South Sumatra	500.8	364.7	136.2 (27.2%)
4	West Java	953.9	833.7	120.1 (12.6%)
5	East Java	317.9	309.6	8.3 (2.6%)
6	E.Kal - Bontang	2,660.3	2,639.4	21.0 (0.8%)
7	E.Kal - Bunyu	34.4	21.3	13.1 (38.1%)
8	Balikpapan/Smr	36.2	35.1	1.1 (2.9%)
9	South Sulawesi	0.0	0.0	0.0 (0.0%)
10	Irian Jaya	40.9	28.3	12.7 (31.0%)
11	Natuna	192.0	78.5	113.5 (59.1%)
	Total	8,217.1	7,752.7	464.3 (5.7%)

Note) F/P = (Amount Flared) / (Amount Produced)

Source : Pertamina, 1996

Among these gas fields, only Bontang, Ache and Natuna have more than 10 TSCF of gas reserves each. Bontang and Ache fields have been already utilized for LNG exports. Currently Pertamina is making an effort to develop the Natuna gas field both for export and domestic use. Reserves of most of other gas fields are less than 10 TSCF, which are and will be exploited mainly for domestic use.

As for the transmission system which connects these gas fields and various gas markets, PGN has a long term master plan called "Trans Indonesia Pipelines" shown in Table 2-18 and Fig. 2-13. The Trans-Indonesia pipeline project consists of 3 parts; short-, mid- and long-term. The plan aims at connecting gas reserves and high demand density areas all around Indonesia. Among 5 short term projects in Table 2-18, PGN is currently preparing 2 projects, the Central Sumatra Project and the South Sumatra Project.

The main line of the Central Sumatra Project transmits gas from Gerisk to Duri and a branch line extends from Jambi to Batam Island. Currently this project is in the stage of "contractor bid and selection" and expected to be completed at the end of September 1998. As for the section between Gerisk and Duri, PGN is to transmit gas for Caltex to obtain a toll fee. After completion, the line is expected to contribute to the development of small- and mid-size gas reserves along the line. PGN is to buy gas at Jambi from Pertamina for the branch line and sell to PGN's customers in Batam Island where large industrial estates exist. This project is supported by ADB, JEXIM and other institutions.

The South Sumatra Project aims at responding to the rapid gas demand increase in West Java. Originally this project consisted of 3 parts ; (1) gas reserve development, (2) a 370 km transmission pipeline, and (3) the high pressure distribution system. But the first part was eliminated from the project and currently the project consists of the latter two parts. Construction of the transmission line will start in December 1998 and will complete in September 2000. The operation is expected to start in November 2000. The South Sumatra Project is to be financially supported by The World Bank.

Table 2-18 Existing PGN Plan of Transmission Systems

Term	No.	From	To	Length (km)	Demand (MMFCD)	Cost US$M
Short	1	Asamera	Duri	524	220	530
		Jambi	Batam Is.	378	90	
	2	Palembang	Cilegon	500	250	500
	3	West Java		150	220	115
	4	East Java		227	240	110
	5	Sengkang	Ujung Pandang	270	51	84
Mid	6	East Java	West Java	300		300
	7	East Java	Kalimantan	600		600
	8	Duri	Medan	400		400
Long	9	Batam	Natuna	500		500
Total				3800		3800

Source : PGN, 1995

2.5 Team's Considerations on National Energy and Urban Gas

2.5.1 Characteristics of Resources

Indonesia is rich in oil and gas, and coal as well, and has been an important oil and gas exporter in Asia, feeding the country and high economic growth. Oil among all, has long been the major source of domestic primary energy, supplying more than 60 % of the country's need. The country's significant industrial growth in these decades has spurred the increase of domestic oil consumption while Indonesian oil fields are rather small, partly depleted. Due to this, the country is expected to become a net oil importer early next century.

On the other hand, many sedimentary basins are dominated by gas; large fields have been fully developed mainly for LNG with domestic use lagging a little behind. The country is the largest LNG exporter in the World. International LNG projects require large gas reserves dedicated to them due to the size of the investment in a project chain, and to secure feasibility and financing. Exporting LNG naturally is very important for Indonesia for foreign revenue and consequently large gas fields used to be prioritized for full exploitation. Domestic use of smaller gas fields, though it has also been much developed, was limited to exploitation for nearby power stations, fertilizers and other large industries strategically important to the country without long haul pipelines except for the West Java Transmission Pipeline which extends 200 km from Cilamaya to Krakatau Steel. Now the policy has changed toward full domestic exploitation of gas by constructing the Trans-Indonesian Gas Transmission Pipelines.

Coal is also targeted on for development. Development of coal in Indonesia is very impressive since the production is going to reach 40 million tons per year, while it was almost none 20 years ago. Much of it is for export but many IPP projects are being developed to use the coal for domestic power plants. The use of coal, however, will be constrained in and around large cities due to environmental and infrastructural factors. The recent technologies have almost solved the air pollution problems caused by the use of coal but the cost of environmental measures and global environment issue remain.

Hydropower and other renewable energy sources are also receiving full attention for prompt development. Ideal energy sources especially in rural areas, they are, however, constrained by geographical limitations and remoteness from large cities and energy demand centers.

The current Indonesian energy policy is to fully develop small gas fields for the country's domestic growth as well as to improve environment and social conditions, replacing more oil for export. The Team considers that such a policy is fully legitimate to make the most suitable energy resource available to large centers of population and economy. Starting from small gas fields which are located comparatively near to the demand centers, gradual extension of pipelines will eventually connect with other gas fields more remotely located and finally reach large, remote gas fields which were originally considered for export.

2.5.2 Importance of Efficiency and Environment

Efficiency is very important in long term energy planning. It is important since resources are not unlimited even in Indonesia and many years in terms of Resource to Production Ratio never mean eternity. People may now be feeling it from declining oil trade surplus. Efficiency is also important for the environment. Reduction of pollutants and CO_2 to some extent may be easily attained by using energy more efficiently.

2.5.3 Urban Gas Priority

Use of gas in urban areas should be given priority. A second thought should be given to the direct use of gas for thermal purposes, which is the most efficient way for heating with the least conversion and transmission losses. It also will be a kind of final urban energy in the ultimate desirable energy mix in a very long term perspective. In the hundred years to come, for example, suppose a large sophisticated city with sufficient energy infrastructure versus energy resources. Oil may be already reliant on import. Abundant coal energy may be supplied to cities only in the form of electricity from remote stations with less efficiency. Gas combined cycle power generation is good in locations comparatively near to large cities but not fully ideal if waste heat is properly utilized. Full use of inherent energy in gas can be attained when gas is in the midst of a city. This enables the use of gas for transportation in cities, too. Thus one cannot suppose a city dependent only on electricity in a gas producing country. Gas pipelines should be built in cities as urban infrastructure in the long term perspective.

Large national gas transmission pipelines, the Trans-Indonesian Integrated Gas Transmission Lines, are envisaged in the long term to connect small as well as major gas fields to Java and other industrial areas. The publicized ring pipelines are to encircle the Indonesian archipelago spanning Sumatra, Java, Kalimantan, Brunei, Natuna, Malaysia or Singapore and Batam with 5000 km in length. The first phase pipeline is being constructed from Asamera to Duri and Batam, and the second phase for the Sumatra-Java connection is in actual planning.

The domestic gas promotion policy has already been steadily implemented in Indonesia. Domestic gas formerly was mainly used by nationally strategic industries located near gas fields with dedicated pipelines. The gas use by general industries started in Cirebon in 1974 and has been expanded to include Jakarta, Bogor, Medan and Surabaya since 1987 with the financial and technical assistance of the World Bank. While the majority of gas produced in Indonesia has been exported in the form of LNG, the share of domestic use of gas in the total gas production in the country is going to reach 50 % soon.

Domestic gas use, however, has so far targeted industrial customers only. The development of residential and commercial customer markets was left aside due to the economics unattractive in the past. PGN has maintained residential customers as inherited from old town gas era but avoided aggressively seeking out new customers in a captive market. This is good time to review the captive market in the metropolitan area with a long term perspective when the support of the government and new transmission gas lines are envisaged.

2.5.4 Urban Gas and LPG - Comparative Considerations

In these few years, use of LPG in the suburban areas has dramatically increased and we have found that the urban gas distribution to be planned now faces competition from LPG in most areas. The Team already made LPG price study in the Interim Report. There are also non-price and qualitative comparative issues in this regard.

(1) Economics

- National and international economics: LPG is much more easily liquefied than natural gas and so is easy for transportation, meaning a more tradable commodity nationally and internationally. It has a higher value as a commodity than natural gas. Indonesia has intentionally extracted LPG from liquefied natural gas (LNG) to export for almost 20 years. Smaller gas fields in Indonesia are more costly to develop and market and liquefaction there is too expensive to compete in the international market, disallowing exploitation. Therefore LPG has more value for export and foreign revenue. Indonesian LPG is welcomed in the international market since the world heavily depends on Saudi Arabia for LPG, and security of supply and price instability have been issues.
- Consumers: LPG is expensive in the domestic market; currently about 2.5 times the price of natural gas in the suburban areas. Though there is a government set price of LPG, it is often sold at higher prices, partly due to de facto monopoly and partly due to actual cost. Natural gas thus contributes to consumer economics through bringing in the competition in the residential market.
- PGN: PGN also can have the opportunity to sell LPG by installing interior piping in the potential customers house to be ready for future installation of gas distribution network.
- Transportation: LPG needs truck transportation and automotive fuels for this purpose. Trucks for this purpose worsen the situation of urban transportation.

(2) Environment

- Transportation: The truck transportation of LPG consumes automotive fuel products discharging pollutant emissions and adds to urban traffic load which in turn again increase pollution. LPG distribution also needs storage and bottling stations within urban areas. LPG should be more suitable for rural areas.
- Carbon dioxide (CO2): LPG emits more CO2 than natural gas. This contributes to global warming. Based on the same thermal quantities consumed, propane (C3H8) emits 17% more of CO2 and butane (C4H10)

emits 21% more of CO_2 than the natural gas of current quality.

(3) Safety

Recently large explosions caused by the use of LPG have been reported by commercial facilities like restaurants. The Team wants to reiterate the comparative safety issues regarding LPG and natural gas. In this regard, too, LPG should be considered as fuel for rural areas.

- LPG is heavier than air (C_3H_8: by 1.5 times; C_4H_{10}: by 2 times) and easy to sink on the floor when leaked in the room, leading to an explosion. Even if LPG is odorized, people may not sense a leak since LPG often stays at a low altitude. Natural gas on the other hand is lighter than air (0.6 as air-specific gravity) and moves upward to any openings and dissipates into the outside. Odorization of natural gas is also effective for a leakage to be detected by residents.
- Systematic safety education of dealers and customers may be insufficient since LPG is often handled by small enterprises. Natural gas distribution is often operated by a comparatively large utility which can observe strict safety rules and promote safety education to customers.
- The lower flammability limit (minimum concentration in the air to cause explosion) of LPG is lower than natural gas, thus increasing the likelihood of an explosion.
- LPG requires more air for burning with higher gas pressure required at the burner or the appliance; thus there is higher probability of leakage. The same volume of leakage into the air may cause more damage in the case of LPG than in the case of natural gas, because LPG has more thermal value per volume (2.5 to 3.1 times).

2.6 Financial Conditions and Implication on Energy Financing

2.6.1 General National Financial Conditions

(1) Three features of the Indonesian financial market

The financial market in Indonesia can be characterized by three features: relatively free access to the overseas market, weak domestic market (in particular long term prospects are not good), and strict Governmental restrictions on financing public sectors by foreign institutions due to large accumulated public deficit.

(2) Access to the overseas loan market

Changing Rupiah to foreign currencies is quit easy and the exchange rate is determined on the currency exchange market. Thus, together with Indonesian natural resources, the inexpensive labor force benefits and encourages foreign investment. It may not be very hard to find financial sponsors in terms of debt financing from overseas, if the project itself is feasible. However, we must remind ourselves at this point that offshore loans would require the project to break even in less than ten years.

Normally overseas loans are dollar dominated, but there exists a market to exchange dollar to Rupiah in Singapore. Even though the offer-bid spread is quite wide, it is possible to obtain finance in the long term, of about five years, in Rupiah using the Singaporian swap market.

(3) Domestic financial market

The financial market in Indonesia is quite weak for a long term project. There exists no market for long-term financing. Commercial banks mostly offer only short-term financing. BAPINDO (PT. Bank Pembanguan Indonesia (Persero)) seems to offer long-term loans, however it is not clear how much they can afford to lend. Long term projects including city gas development would need to obtain finance mostly from overseas.

(4) Governmental restriction on debt for public sectors

To prevent increase of the deficit of public sectors, it is fundamentally prohibited for any public sectors to obtain finance from overseas without permission from PKLN (Pinjaman Komersial Luar Negeri). This restriction will hold if the Government has the slightest stake in the equity of any company. There may be exceptions if the amount of debt from overseas is reasonably small, below some twenty millions of dollars. If we consider avoiding getting this permission for quick investment, it will be safe to organize equity investors for a gas utilization project without PGN.

2.6.2 Availability of Financing for Gas Utilization Projects

(1) Debt financing

As was stated before, whether a gas utilization project could be financed or not depends totally upon the economic feasibility of the project. An equivalent of project financing may not be suitable for an urban gas development project when gas customers are the mass public, and it may be quite hard to make contracts to secure cash flow for project financing.

Consumer loans which are definitely recourse money to equity investors are available instead. As we need long term loans, resorting to the Singapore financial market will be an inevitability.

(2) Equity financing

Equity financing has the least hurdles in view of international debt restriction. An equity sponsor, however, for a customer gas use project may not be PGN because it is still owned by the government and hence a target of governmental examination.

The key is economic feasibility and viability which make the project attractive to investors. Pricing will be the most important given efficient operation is assured. The aggregate gas price of a utility should cover all the costs of gas supply and the attainment of such price status is desired before inviting private sector financing. Long range marginal costs (LRMC) or average incremental costs (AIC) should be considered as an indication of the minimum price for utility services and the expected rate of return should be clear.

A normal project period for an infrastructure is twenty years. Equity investors must be those who could take commercial and country risks in Indonesia for such a time and some assurances should be given in this regard. Domestic investors might be considered from construction or real estate companies for energy service projects (supposing we are going to choose new industrial estates in a suburban area of Jakarta). International financial institutions like IFC or OECF, etc., also accommodate limited shares of equity depending on conditions and equities from such institutions are treated like private sector equities in view of national international debt.

Chapter 3

Policies, Energy Costs and Prices

3. Policies, Energy Costs and Prices

3.1 Energy Policy and Regulatory Framework

3.1.1 Team's Concerns in Regulation

The Team considers that to promote the smaller customer market, including residential and commercial, the possible necessity of regulatory changes may have to be investigated and implemented for PGN to go ahead to such markets.

Natural gas is superior to most other fuels in view of energy efficiency, safety and environment, and is a premium urban fuel. The Government of Indonesia desires to develop more use of natural gas in urban areas to replace kerosene, and LPG, thereby contributing to improved environmental conditions and to add convenience for the residents, and eventually to improve the national energy trade balances.

Most of the domestic natural gas use, i.e., 98%, is for industrial customers and the distribution network for residential and commercial customers is not yet fully developed. PGN has been given a status of the major natural gas transmission and distribution entity in Indonesia by the government since 1992 and envisages to construct major transmission pipelines in Sumatra first and then from Sumatra to Java. It desires to extend the natural gas service to all the market sectors including residential and commercial sectors if such businesses are feasible economically and "on legal and regulatory basis".

3.1.2 Current Laws and Regulations

(1) Statutes Affecting Oil and Gas and Specifically PGN

There is no one consolidated law or regulation to specifically regulate the operation of gas distribution, but rather an aggregate of past laws and decrees of the related ministries jointly define the nature of the energy entities and the content of regulation. The most prominent law has been the Law No. 8 of 1971 that legislatively established P.N. Pertamina and Production Sharing (P/S) Contract schemes, and related regulations have been issued since to amend the content of P/S schemes. PGN has been directly under several regulations since 1984 mainly to define the form of the enterprise and basic functions.

Major (virtually all) energy related laws and regulations are listed below:

1) Article 33 of the 1945 Constitution: "Natural resources are owned by the State and to be used for the prosperity of people."

2) Law No. 44 of 1960 : "The exploitation of oil and gas can only carried out by the State which has the power to undertake such activities by giving the Authority to a State-owned Company."

3) Law No. 8 of 1971 (Pertamina Law): " establishes Pertamina which is also responsible for the domestic supply and services for oil and gas fuels in accordance with further regulations to be established".

4) Government Regulation No. 27 of 1984 (not effective any more): "establishes PERUM GAS NEGARA, a national corporation, from the former Peruhasaan Gas Negara, enabling PGN to survive and expand to develop the use of natural gas and city gas." The responsibility stipulated above was a source of certain conflict of interest with the Pertamina Law. Although PGN has distributed natural gas since 1974, this regulation made formal PGN's task as distributor of natural gas. This regulation was later superseded or replaced by the MME Decree No. 785 of 1992 and the Government Regulation No.37 of 1994 (next items).

5) Decree of MME No. 785.K/02/M.PE/1992: "to ensure the continuity and reliability of gas supply and to widen the scope of PGN's businesses, vests PGN with additional responsibility to undertake the natural gas transmission for domestic needs. The scope of the transmission business should not endanger the interest of Pertamina to supply gas for bulk consumers."

6) Government Regulation No. 37 of 1994: "converts the legal status of PGN from a Perum to that of Limited Liability State-owned Company, PT. PGN (Persero), to enhance the efficiency and reliability of gas supply operation and management." This company undertakes:

- planning, construction, production development, provision, supply and distribution of hydrocarbon gas;
- planning, construction, transmission network development, and distribution of natural gas in accordance with the Government Policy;
- Other related businesses which support the company undertakings.

(2) Function of Pertamina and PGN

Laws and regulations listed above stipulate basic function of both Pertamina and PGN, and together define the integrated oil and gas industrial structures, roles of PGN being clearly defined. How their operations are regulated, however, is not necessarily clear on a legal basis and are subject to national energy policies and governmental directions that are less transparent. As the domestic use of natural gas increases incurring various issues, the Government feels to need and has been studying more consolidated regulatory framework for the future gas industry as well as restructuring the industry toward privatization.

While upstream operations remain the responsibility of Pertamina and the general gas distribution is that of PGN, the gas transmission and sales to large customers are shared by both entities without a strict border, the situation having been historically a natural consequence. By laws of 1960 and 1971, Pertamina has had overall legal authority to exploit, supply, and service all oil and gas in Indonesia, domestic and international, while PGN has over a 130 year history of distributing city gas, originally manufactured gas and later natural gas bought from Pertamina, and has aggressively expanded the downstream operation to serve large customers, successful operations leading to authorization of PGN for an additional role as a major domestic gas transmitter.

As for large customer sales practice, Pertamina is committed to very large nationally strategic customers in, e.g., electricity generation, steel, fertilizer and cement industries. PGN targets all other domestic natural gas customers along its transmission and distribution lines as well as LPG distribution in its traditional service areas.

3.1.3 Regulatory Changes Being Expected

Now launching new oil and gas regulatory framework is on the agenda in the government and the legislature, and a transparent system will come out in the public not too long after the general election of 1997 according to the media. Pertamina may be reborn as streamlined entities and PGN may have clear-cut regulations with which to do business more openly.

In the gas distribution area, we are concerned with inter-fuel price competition, distribution cost and gas pricing mechanisms, business entry constraints, conditions to make financing available to both the gas distributor's and customer's sides, safety standards and regulatory framework. We recommend all policies be favorable to encouraging quick gas customer connection to maximize efficient gas use in the market as well as encouraging development in the upstream sector.

We, at the moment, will wait for the final result of an ongoing consultant work for the gas regulatory framework to come out to MIGAS. It came to the Team's knowledge that some relevant items in the draft may appear to affect gas distribution business as follows:

- A bundled gas supply service on a local basis
- gas prices on a negotiated basis for larger customers
- Any subsidy, if applicable, directly from Government and on a fixed sum

- No exclusivity in distribution territories
- prices to small customers to be under simple ceiling price control

While the framework will be eventually in the hand of legislature, the government is taking the leadership toward the right directions. This is because necessary policy direction has to be in public before potential international investors for various near-term projects.

The trend is already coming out of the surface as in the recent energy price revision. Gas prices have been improved by the recent revision for the first time since 5 years ago. It is welcomed as a beginning toward more rational gas pricing to assure investment in all the streams of natural gas as well as for the gas to remain competitive in the market. In view of the future smaller customer market, the price rise is clearly not yet enough and also we expect more strategic price structures to be gradually worked out in the future when more market categories are explored.

3.1.4 Recommendation

We recommend to treat natural gas as an urban energy infrastructure with public encouragement and endorsement. Regulations should allow to ensure profitability for a private utility, and investors, under efficient and safe operations. The smaller customer market generally requires more advance investment and longer term orderly planning. Investors in this sub-sector usually expect sure returns instead of high risky returns and the regulatory framework should consider this. Natural gas to smaller urban customers may be a little expensive in thermal value terms in the future but should be a premium fuel to attract them in view of convenience, cleanliness, safety and efficiency even at a bit higher price than competing fuels.

3.2 Energy Prices and Subsidy

The Indonesian tax system is composed of national tax and local tax. National tax can be classified into two categories, direct tax and indirect tax. Direct tax includes income tax for corporations and individuals. Indirect tax includes value added tax etc. By the amendment of the Tax Law in January 1995, the corporate tax rate has been lowered as the table below shows :

Table 3-2-1 Corporate Tax Rate in Indonesia

	previous tax rate	new tax rate (1995)
up to 25 million Rp	15%	10%
25 million Rp to 50 million Rp	20%	15%
50 million Rp and upper	35%	30%

source:PGN

In addition to the corporation tax, state companies like PGN have to make contributions. 55% of the profit after tax has to be contributed to the government (DPS), 5% to social funds to support the growth of small business and pensions for employees.

The Indonesian government has long adopted a cheap oil policy. Especially, kerosene has been most heavily subsidized because it is the most popular cooking fuel particularly for low income households. But as the income level of Indonesian people rises as a result of high economic growth, the neccessity to subsidize kerosene is decreasing. It is important to send them a fair economic signal from the market and to promote efficient energy usage which energy policy aims at. The government fully recognizes this and is gradually eliminating some of the direct or cross subsidies to petroleum products.

Table 3-2-2 Fuel Subsidy / Total Domestic Revenue

Year	Revenue from Oil and Gas / Domestic Revenue(%)	Fuel Subsidy / total Domestic Revenue(%)
1979	64	8
1984	66	3
1989	39	2
1990	27	2
1991	29	3
1992	30	2
1993(*1)	29	2

source:Petroleum Report of Indonesia, 1993

Table 3-2-3 Subsidies and Taxes on Petroleum Products in 1990

	Aviation gas	Aviation turbo	Gasoline	Kerosene	Automobile diesel	Industrial diesel	Fuel oil
Price (Rp/l)	330	330	450	190	245	235	220
Tax/(subsidy) (Rp/l)	39	6	115	(124)	(127)	(59)	28

source:PGN

Gas prices, fertilizers and steel plants have been low due to fixed price contracts and implied subsidy. In general, subsidy is used by the government to achieve particular purposes such as developing domestic industries and protecting weak industries. In principle, a price should be determined on economic basis. Subsidy distorts price structures and hampers economic efficiency. Therefore, subsidy has to be limited to the minimum. Even if the industries need continuous subsidy, it should be paid by the government directly, not by lowering energy prices.

Table 3-2-4 Natural Gas Prices for Industry 1994

(US $/MMBTU)

fertilizer	steel	cement	paper	PLN	PGN
1.00~1.50	0.65(*1)	2.70~3.00	1.50	2.45~3.00	2.16~2.85

note:(*1)KRAKATAU STEEL

source:PNN

3.3 Competing Fuel Market

In this section, we will review current prices of competitive fuels firstly, then analyze economic prices of them.

3.3.1 Overview of Petroleum Product Prices

All fuel prices in the end use market are controlled by the government in Indonesia and a one-price policy basically goes throughout the country except in certain sectors. Table 3-3-1 shows the current set of prices of petroleum products.

In the residential market for natural gas use, a major competitive fuel is LPG. In 1970's, LPG utilization was limited just for residential and small industrial customers. In late 1980's, LPG demand has grown rapidly due to the strong growth of economy. At the same time, domestic production of LPG also increased drastically as a by product of gas fields such as Arun in North Sumatra, and Badak in East Kalimantan.

The current domestic price of LPG is 1,000Rp/kg officially set in 1995. The domestic balance of supply and demand of LPG will not really be tight in the near future. While steady growth of LPG in Asian countries such as China, India, Vietnam, etc., may bring some price increase, more LPG production associated with LNG development is expected in the Middle East for the future.

Table 3-3-1 Prices of petroleum products and LPG

	Btu/l	kcal/l	Rp/l 1993	Rp/ mmBtu	US$/ mmBtu	(reference) Rp/l 1990
PREMIUM	31,111	7,840	700	22,500	9.78	-
AVIGAS	33,532	8,450	420	12,525	5.45	330
AVTUR	33,532	8,450	420	12,525	5.45	330
IDO	36,786	9,270	360	9,786	4.25	235
ADO/HSD	35,964	9,063	380	10,566	4.59	245
FO	38,754	9,766	240	6,193	2.69	220
KEROSENE	35,079	8,840	280	7,982	3.47	190

note: valid from January 1993

	Btu/kg	KCAL/KG	Rp/kg 1995	Rp/ mmBtu	US$/ mmBtu	Rp/kg 1993
LPG	47,222	11,900	1000	22,500	9.78	750

note: valid from December 1995
source: PGN and JICA

3.3.2 Current Electric Prices

The electricity tariff has to be approved by the government. In 1994 a new tariff was set reflecting inflation and increase of fuel prices. Table 3-3-2 is the current electric tariff table of PLN. It is characterized by its numerous tariff categories depending on usage and contracted capacity. It is composed of two parts, the demand charge and the energy charge. The demand charge is determined by contracted capacity in Rupiah per kW per month. Energy charge is determined according to the consumption of electricity per month. This kind of tariff structure, so called two-part tariff, contributes to stable recovering the fixed cost.

Table 3-3-2 Basic Tariff of Electricity 1994

	Category Tariff	Contracted Power	Demand Charge	Energy Charge	
Social welfare	S-1/LV	up to 200VA	(*1)	—	for very small customer
	S-2/LV	250VA to 2,200VA	3,360	56.00	for small social institution
	S-3/LV	2,201VAto200kVA	4,640	76.00	for medium social institution
	S-4/MV	201kVA and upper	5,020	P=158.50 OP=117.50	for large social institution
	SS-4/MV	201kVA and upper	6,060	P=194.50 OP=144.00	for private-large social institution for commercial service
Residential	R-1/LV	250VA to 500VA	3,980	(*2)	for simple residential service
	R-2/LV	501VA to 2200VA	4,020	(*3)	for small residential service
	R-3/LV	2201VA to 6600VA	8,080	227.50	for medium residential service
	R-4/LV	6601VA and upper	8,760	309.00	for large residential service
Commercial	U-1/LV	250VA to 2,200VA	6,260	179.50	for small commercial service
	U-2/LV	2,201VAto200kVA	7,320	239.50	for medium commercial service
	U-3/MV	201kVA and upper	5,180	P=240.50 OP=178.50	for large commercial service
	U-4/LV	—		622.00	temporary connection
Hotel	H-1/LV	250VA to 99kVA	4,600	118.00	for small hotel
	H-2/LV	2,100VAto200kVA	6,220	171.00	for medium hotel
	H-3/MV	201kVA and upper	5,400	P=212.00 OP=157.00	for large hotel
Industry	I-1/LV	450VA to 2,200VA	4,080	80.50	for home industry
	I-2/LV	2,201VAto13.9kVA	4,760	93.50	for small industry
	I-3/LV	14kVAto 200kVA	5,760	P=169.50 OP=125.50	for medium industry
	I-4/MV	201kVA and upper	5,060	P=(*4) OP=117.50	for medium/large industry
	I-5/HV	10,000kVA and upper	4,780	109.50	for large industry
Government	G-1/LV	250VA to 200kVA	8,500	118.50	for small to medium government office building
	G-2/MV	201kVA and upper	4,560	P=176.50 OP=130.50	for large government office building
Street	J/LV	—	—	165.00	for street illumination

*note:*LV, MV, HV stand for low voltage, medium voltage, high voltage respectively.
(*1)For Tariff Category S-1, Monthly charge is fixed depending on Contracted Power as follows.
60VA=Rp2,150, 75VA=Rp2,750, 100VA=Rp3,550, 125VA=Rp4,500, 150VA=Rp5,300, 175VA=Rp6,100, 200VA=Rp6,750.
(*2)<60 hours utilization per month = 81.00/kWh, >60 hours utilization per month = 109.50/kWh
(*3)<60 hours utilization per month = 96.50/kWh, >60 hours utilization per month = 147.00/kWh
(*4)<350 hours utilization per month = 142.00/kWh, >350 hours utilization per month = 117.50/kWh
source:PLN

Another characteristics of electricity tariff in Indonesia is the system of review or adjustment in every 3 months introduced in 1994. The adjustment mechanism is as follows.

$$d(SR)=A\cdot dF+B\cdot dP+C\cdot dL+D\cdot dEr$$

d(SR)=adjustment on sales revenue(%)
dF = adjustment on fuel price(%)
dP = adjustment on purchasing of electricity power(%)
dL = adjustment on rate of inflation(%)
dEr= adjustment on middle currency rates of US $ to Rp(%)
A =charging coefficient of fuel against sales revenue
B =annual charging coefficient of electricity power purchasing against sales revenue
C =annual charging coefficient of operation cost of local components against sales revenue
D =annual charging coefficient of operation cost for imported component against sales revenue

Cogeneration potential in the gas distribution market may automatically involve the policies in the electric sector. The "General Plan of National Electrification" published by the Ministry of Mines and Energy in 1996 stipulates that gas is the main alternative to oil and coal for generation when the policy is to decrease oil consumption and the coal for power generation faces ceilings due to environment. According to the document, " the technologies utilized in gas power generation are relatively cost-effective. Gas and steam-fired power plants can be built in relatively shorter periods. The available gas reserves, however, cannot be tapped as yet because there are no effective systems to transport natural gas. Presently natural gas is transported only to dedicated electric generating plants. Consequently, the lack of gas distribution lines affects efforts at supplying electric power". The "Plan" also points out that (1) lines are needed to connect Java, Sumatra and Kalimantan; the availability of gas pipelines allows determination of sites for power plants, and (2) once gas supplies are determined, reviews are needed for conversion of generation sources.

From the view point of gas industry, a power generation station usually requires quite large volume of gas and the existing, or even planned, distribution network often cannot suffice the required capacity unless gas market network and power generation are jointly developed; such joint pipeline development is also recommended, while inter-agency adjustment efforts will be necessary. It will be wrong if the electric side is simply waiting for, e.g., a Kalimantan-Java pipeline without being involved in specifying the capacity of the pipelines.

In the Master Plan, however, we have studied smaller power generation through cogeneration, which is highly energy-efficient, setting a side economic viability.

Table 3-3-3 shows electricity tariff of PT.Cikarang Listrindo. PT.Cikarang Listrindo has the exclusive service area in Jababeka, MM21 Bekasi Fajar, Lippo City and East Jakarta Industrial Park, and PLN. The power plant is, however, grid-connected to PLN and supplied with power if trouble happens in the plant.

Table 3-3-3 Electricity Power Tariff of PT. Cikarang Listrindo

Customer Category			Capacity Charge	Usage Charge
			Rp / kVA / month	Rp / kWh
Industry	I-3/LV	14-200kVA	12,000*A/2060	140*(0.54*B/2.45+0.46) *A/2,060
	I-4/MV	>201kVA		
Light Industry	U-1/LV	501-2200VA	effective PLN tariff	effective PLN tariff
	U-2/LV	2201VA-200kVA		
	U-3/MV	>201kVA		
Hotel	H-2/LV	100-200kVA	effective PLN tariff	effective PLN tariff
	H-3/MV	>201kVA		
House	R-2/LV	501-2200VA	effective PLN tariff	effective PLN tariff
	R-3/LV	2201-6600VA		
	R-4/LV	>6601VA		

note:

A: The average exchange rate of Rp to one US $ on the month of billing. A=2,344 in OCT.1996

B: Price of natural gas in TEGAL GEDE in US $ / mmBtu according to the price determined by PERTAMINA. B=2.45 (no change after operation)

Source: PT. Cikarang Listrindo

3.3.3 Economic Fuel Prices

Long-term planning and assessment are often better done by using economic prices without distortion assuming that the distortion will be gradually eliminated or pointing to desirable pricing policy directions. Adopting the prices close to economic levels in businesses usually assures higher economic efficiency in a market economy and beneficial to consumers. Economic prices are not always easy to determine, but we will try at least to show what levels the prices should be in. The prices studied here will be used in economic analyses as assumptions in the later chapters.

(1) Oil Products

While most economic prices of energy are determined in between the cost and a theoretical or an international market price, that of each oil product is never determined by the cost since various oil products come from one refinery plant at the same time. International market prices only are significant in this regard since crude and petroleum products are fully internationally traded. Only debatable costs are average price or average cost of petroleum products.

Under the circumstance, we can only refer to the general refinery cost with regard to the average cost. Though we do not have domestic refinery cost data for Indonesia, Table 3-3-4 shows typical refinery costs in other Asian countries based on existing and old plants. Considering that a new 125,000 bbl/d refinery, for example, is said to cost 1.5 to 2.5 billion US dollars as of 1996, depreciation cost may be twice as that of Singapore in the table. Judging from this, an average cost of oil products in South East Asia may be in the range of 3 to 4 US$/bl fob above crude oil prices.

Table 3-3-4 Refinery Costs

Forex: JPY/US$=100

US$/bl

	Japan		Korea		Singapore	
Cost elements	1993	1996	1993	1996	1993	1996
Fuel	1.44	1.49	0.50	0.48	0.38	0.41
Overhead	1.43	1.60	0.30	0.41	0.20	0.21
Maintenance	1.38	1.39	0.19	0.41	0.50	0.65
Depreciation	1.72	1.80	0.94	1.76	0.92	0.94
Chemicals	0.33	0.34	0.12	0.11	0.12	0.14
Utility	0.29	0.30	0.11	0.10	0.16	0.16
Other	0.92	1.01	0.25	0.25	0.20	0.32
Total (US$/bl)	7.52	7.93	2.40	3.52	2.49	2.83
Converted toUS$/ton*	55.3	58.3	17.7	25.9	18.3	20.8
US$/mmBtu	1.28	1.35	0.41	0.60	0.42	0.48

Note: Numbers in US$ are re-converted from JPY by using the assumed exchange rate given at top right for simplicity.
*Property at API 34 degrees is assumed for conversion: sp.gr.=0.8553, thermal value=5.8603mmBtu/bl

Source: Institute of Energy Economics, Japan; an Internal study for cost comparison January 1996

(2) LPG

LPG (priced at 1,000 Rp/kg in the end-use market) is the most competing with gas in suburban residential market. The price of LPG may be justified by two ways: domestic costs and international prices. The LPG in Indonesia is domestically produced but at the same time much of it is exported and therefore it has a value based on international opportunity costs. International LPG prices, around US$ 210 to 220 per ton at CIF East Asia in the Fall 1996, has soared since 1995 due to Saudi Arabia's contract price (CP) policy and spot prices are often US$300/ton. Such price hike, however, may be suppressed by international market forces in the near future in the light of past experiences. Domestic cost at refinery is hard to determine but if average refinery cost is applied, we can start from international or Indonesian crude oil price. Such relationship is demonstrated in Fig. 3-3-1

Fig. 3-3-1 shows that the current LPG price of Rp1000/kg is in the range of economic prices derived either from international market prices or from domestic refinery costs. LPG prices are heavily affected by handling cost at storage and bottling terminals and distribution cost. Past data of investment cost for distribution terminals proves that such costs are in the ranges shown in this table.

In actual LPG markets in suburban areas higher prices such as 1,200 or 1,500 Rp/kg are sometimes illegally applied by dealers with alleged reason of final distribution cost added. A part of these extra charges may be deemed as market premium prices but may be due to de facto monopoly of this clean residential fuel that certain people strongly want.

In the first sale of LPG to a customer, an amount of 100,000 Rp for a 12 kg or 50 kg bottle is charged. When urban gas is newly subscribed by a customer who was using LPG and he now needs no more LPG, he can sell this "right of bottle" in the market. This should be taken in account in the economic analysis of urban gas to residential customers as well as the indoor piping cost of gas.

Fig. 3-3-1 LPG Price Structure

1996

For Conversion: LPG: 12,000 kcal/kg
Crude Oil: 34 deg. API= 5.8603 mmBtu/bl= 0.1357 t/bl
Forex: 2,350 Rp/US$

Price Unit	Middle East LPG Production: Saudi Arabia fob CP	Transp/storage cost	Singapore fob	Transp/storage cost	Major Market: Far East (Japan) CIF
$/ton	200	34.00	234.00	16.00	250.00
$/mmBtu	4.20	0.714	4.91	0.34	5.25
$/bl oe	24.61	4.184	28.80	1.97	30.77

Export netback

Freight cost	Premium*	Net freight ($/ton)
12	0	12

*Premium for Japanese market 31$/t ignored here.

Export netback

	Transp/storage	Java Island: Port (T. Priok)	Port (T. Priok)	Transp/storage	Kalimantan LPG fob	Jakarta Port (T. Priok)	LPG Transp/Storage and handling	Domestic LPG Production: Refinery	Transp.	Crude Oil fob
$/ton	20	254.00	250.00	12	238.00	221.3	15	22.1	22.1	162.1
$/mmBtu	0.420	5.33	5.25	0.25	5.00	5.1	0.315	0.5	0.5	3.754
$/bl oe	2.461	31.26	30.77	1.48	29.29	29.8	1.8	3	3	22
Rp/kg	47.00	596.90	587.50	28.20	559.30	520.1	35.3	52.0	52.0	381.0
Rp/8800kcal	34.5	437.7	430.83	20.68	410.15	417.9	25.9	42.0	42.0	308.1

1. int'l market driven prices

2. domestic cost driven price

2

	CIF Average Port (T. Priok)	Bulk Distr. Stn. Transp/handling	fob	Bottling Stn. Transp/handling	fob	Distribution	End Consumer Delivered
$/ton	221.34	50	271.34	90	361.34	50	411.34
$/mmBtu	4.65	1.05	5.70	1.89	7.59	1.05	8.64
$/bl oe	27.24	6.15	33.39	11.08	44.47	6.15	50.62
Rp/kg	520.14	117.50	637.64	211.50	849.14	117.50	966.64
Rp/8800kcal	381.44	86.17	467.60	155.10	622.70	86.17	708.87

Sensitivity:	Delivered Rp/kg	
1	1,039	internationally dri
2	967	domestically driv

Source: JICA; Original data: Various sources and JICA Team judgment

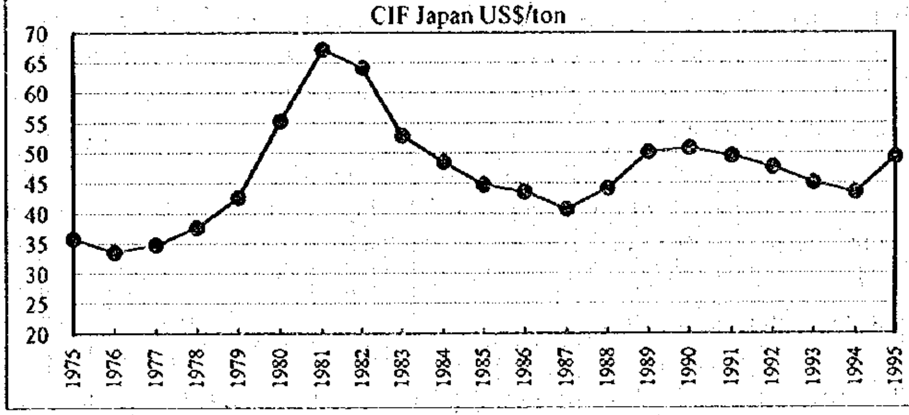
3.3.4 Price of Coal for Power Generation

(1) International Coal Prices and Freights

We discuss steam coal prices as the assumptions for estimating economic or future electric prices. Historical international steam coal prices in the Far East are shown in Fig. 3-3-2 in terms of US dollars per ton CIF Japan. The CIF coal prices are purely affected by market forces and freight, and closely linked to thermal values. Average prices in the last decade have been fluctuated in between 40 to 50 dollars per ton.

Fig. 3-3-2 Average Steam Coal Import

CIF Japan US$/ton



Data source: Japanese Ministry of Finance (MOF)

Compared to theses average prices, the price of Indonesian coals imported to Japan is about 9% lower in an average as in Table 3-3-5 below.

The freight of coal is US$5/ton from Tanjung Barat, Kalimantan, to Japan currently based on using Panamax boat. It thus varies with the size of ships used and other factors including transportation market forces.

Table 3-3-5
Compare Indonesian Steam Coal to Average

CIF Japan $/ton

Year	Average	Indonesia	Indo./Ave.
1994	43.74	39.88	0.912
1995	49.35	45.43	0.920

Source: MOF Japan

Indonesian steam coal price FOB Kalimantan is therefore estimated at about US$35 to 40 per ton. In fact the bench mark price in 1996 was US$40.30 per ton f.o.b. for a rather high quality steam coal of 6,700 kcal/kg in the thermal value according to a trader.

(2) Domestic Coal Prices for Power Generation

Domestic steam coal market prices are not fully established since IPP plants have just begun only, but such coal prices for power plants could be assumed as very close to international prices or a little less. Indonesian coal is produced in central parts of Sumatra and East Kalimantan and the production is about 40 million tons per year, which is growing year by year. PLN uses about 6 million tons as the fuel for power generation and most of the rest are currently exported. While many of new power generation plants being planned by "independent power producers" (IPPs) in Indonesia are based on coal, almost no one of them have reached commercial operation to date; thus no substantial and competitive domestic steam coal market exits so far.

The bench mark price, which was US$40.30 per ton f.o.b. for a 6,700 kcal/kg coal in 1996 as is stated above, has deteriorated to $37.70 in early 1997 possibly due to delayed implementation of power generation plants. Actual prices greatly vary from $25 to $40 per ton depending on quality, i.e., thermal values. The price is not necessarily proportionate to the thermal value and as the value decreases it tends to deteriorate acceleratedly. When a thermal value decreases to 5,000 to 5,500 kcal/kg, the price may easily decrease to $21 to 25 per ton.

(3) Team's Assumption of Coal Price

We consider that the standard coal for domestic power generation has the thermal value of 6600 kcal/kg. We will take the bench marl price as $38/ton FOB Kalimantan, consider a domestic premium due to abundance of coal as -$2.00, assume the freight of $5.00 within the archipelago based on a bit smaller boats than for international trade and adjust the calorific value effect as "-$1.20/ton". For the future electric generation cost estimate, we assume the domestic coal price as around $40/ton CIF or a little less in Java area based on the situation stated above.

3.3.5 Price and Cost of Electricity

The electricity rates of PLN have been basically unchanged since the revision in 1994. A new three month review system was installed then, but has not affected the actual rates. Average electric prices together with amount of sales in 1994/1995 are tabulated in the following Table 3-3-6:

Table 3-3-6 Average Electric Prices of PLN

Subsectors	Electric sales: Amount MWh	Revenue mil.Rp	No. of customers	Consump-tion per customer kWh/mon.	Average price Rp/kWh Indonesia	Rp/kWh West Java	Rp/kWh DKI	Rp/US$: 2300 In US cent per kWh Indonesia	per kWh DKI
Industrial	22,465,083	3,143,468	42,613	43932	139.93	134.46	147.92	6.084	6.431
Residential	15,161,904	2,275,389	16,473,051	77	150.07	132.47	180.66	6.525	7.855
Business	4,391,533	1,134,959	571,770	640	258.44	264.40	249.13	11.237	10.832
Public	2,650,593	460.386	435,584	507	173.69	171.20	177.69	7.552	7.726
Total	44,669,113	7,014,202	17,523,018	212	157.03	139.45	180.07	6.827	7.829

Source: Ministry of Mines and Energy 1996

The national average electricity rate as derived from the statistics above was 6.8 cent /kWh in 1994/95. The tariff table based on the two part tariff system is common to all regions but is broken down into many customer categories; thus the average rate changes from region to region according to the shares of consumption by market category having a different tariff table each. The average rate in Jakarta is higher than the national average especially because the rate for business, i.e., the commercial sector, is large compared to other areas. The electric rate for the commercial sector is set high at around 11 US cent /kWh while residential customer is charged 6.5 to 7.8 cent and the industrial sector is charged 6.1 to 6.4 cents per kWh.

Since many facilities in PLN accounted for in price setting are based on past investments, this average price level has been able to accommodate PLN's operation so far, but will have to be re-valued for future due to large investment required for generation plants and transmission and distribution network expansion. But where a right level of price will be is uncertain at the moment. The electricity purchase from an IPP (independent power producer) coal power that is to cover about 10% of the power requirement in Java is priced at 8.2 cents/kWh which is said to produce a limited internal rate of return (IRR). Another coal power contracted later and recently (April 1997), however, is priced at 5.6 cent/kWh. Construction costs seem to be on a downward trend. Table 3-3-9 shows an example of generation costs based on a domestic coal price level stated elsewhere. As the electricity sector in Indonesia is still on an building-up stage, the rates should be on a level to reflect the costs of future investments, at least partly, to sustain the development.

Table3-3-9 also includes the calculation of power generation costs by other type of plants, suggesting that the current average electric rates may not accommodate most future generation costs. Therefore, despite of the decreasing coal power costs, we suppose the rates to end customers will have to be increased sooner or later and the size of the increase may be 4 to 7 U.S. cents per kWh at present price in 2000 - 2010 when many new IPP plants are expected to come on surface together with transmission and distribution network expansion.

We will tentatively assume that the average electric rate in the commercial sector, which is already set at a level higher than in other sectors, will be around 14.5 cents/kWh, in the residential sector at 15.5 cents/kWh and in the industrial at 11 cents/kWh. These price levels will be still well affordable in the future considering the expected economic growth at 6 to 7 % per year and income per capita at 4 to 5 % per year.

Table 3-3-7 Electricity Rate Assumption US cents/kWh

sub-sector	current average (1994/95 DKI)	future average (after 2000)
Residential	7.8	15.5
Commercial	10.8	14.5
Industrial	6.4	11.0
Average	7.8	13.5

Source: JICA Team Assumption *Assumed at 1997 prices*

Table 3-3-8 Breakdowns of Power Generation Costs (c.f. Table 3-3-9)

			1 Comb. Cycle Gas (C.C.) Natural gas	2 St/Trbn-Coal with FGD Coal	3 St/Trbn-Oil Oil Heavy oil	4 Hydro - -
Total Period Present Values						
Power Output		GWh	10,095	14,878	9,394	2,248
Fuel Consumption ('000mmBtu)		GBtu	76,586	149,393	84,394	0
Capital Cost		US$'000	213,101	685,195	273,987	160,903
Fixed Cost		US$'000	46,095	171,782	59,265	15,669
Variable Costs		US$'000	20,190	89,268	28,181	4,495
Tot. Oper. Cost (excl. fuel)		US$000	279,385	946,245	361,433	181,068
Fuel Cost		US$'000	229,757	216,755	235,569	0
Total Costs		US$'000	509,142	1,163,000	597,001	181,068
Average fuel cost (leveled)		$/mmBtu	3.000	1.451	2.791	0.000
Average Leveled Power Cost:		$/MWh	50.436	78.169	63.554	80.558
		cents/kWh	5.044	7.817	6.355	8.056
Shares of cost:	Capital	%	41.85%	58.92%	45.89%	88.86%
	Fixed	%	9.05%	14.77%	9.93%	8.65%
	Variable	%	3.97%	7.68%	4.72%	2.48%
	Fuel	%	45.13%	18.64%	39.46%	0.00%
Fuel+Variable Costs:		cents/kWh	2.476	2.057	2.808	0.200
	Same converted to:	Rp/8800kcal	595.322	494.551	675.091	48.087

Source: JICA Team

Table 3-3-8 indicates that the "fuel + other variable" costs or running costs of these power plants converted to the unit of gas price (Rp/8800 kcal or m3) are in the range of 495 (coal power) to 595 (gas C.C.) Rp/m3. The economic analyses in later chapters use a value in this range interpolated with appropriate rates of power energy mix as an economic value of the running cost of future power.

Table 3-3-9 Power Generation Costs and Gas Netback Values

Starting year= 1997 Interest rate: 15.0%

Gas Power Plant = 1 =Comb. Cycle
Target Plant= 2 =St/Trbn-Coal

				3 and 4 for reference	
Plant No.		1	2	3	4
Type		Comb. Cycle Gas (C.C.)	St/Trbn-Coal with FGD	St/Trbn-Oil Oil	Hydro -
Table (1) Technical Assumptions	Fuel	Natural gas	Coal	Heavy oil	-
Fuel thermal value	kcal	252000	6600	9200	860.1
value unit	per	mmBtu	kg	1	kWh
value unit to trade unit factor		1	1000	1050	1000000
Fuel trade unit		mmBtu	ton	ton	GWh
Facility	Unit				
Installed capacity	MW	400	600	400	200
Load factor	%	70%	85%	70%	45%
Thermal efficiency	%	45%	34%	38%	100%
Construction period	Years	3.0	4.0	3.0	5.0
Economic life of project	Years	20	20	20	30
Period till plateau reached	Years	1	2	2	3
Hours in a year	Hours	8760	8760	8760	8760
Table (2) Economic Assumptions					
Real interest rate	%	15%	15%	15%	15%
Investment cost per capacity	US$/kW	700	1600	900	1200
Other ancillary investment	US$000	0	0	0	0
O & M fixed cost factor (yearly)	% of Inv.	4.00%	5.00%	4.00%	2.00%
O & M variable cost factor (yearly)	USc/kWh	0.2	0.6	0.3	0.2
Fuel price ($/trade unit)	$/unit	3.00	38.00	107.00	0.00
Escalation on fuel price	%/year	0%	0%	0%	0%
Gross heat value of fuel (mmBtu/fuel unit)		1.00	26.19	38.33	3,413.10

Table (3) Summary of Results	Plant code	1	2	3	4
Ave. Levelized Generation Cost	USc/KWh	5.044	7.817	6.355	8.056
	US$/mmBtu	14.777	22.903	18.621	23.603
Gas Netback Values for: Comb. Cycle Gas (C.C.)					
present value	$/mmBtu	3.000	6.655	4.729	6.970
Code= 1 Same in GJ	$/GJ	2.727	6.050	4.299	6.337
Same in Rp	/8800kcal	246	546	388	572
1997 Currnt value	$/mmBtu	3.000	6.655	4.729	6.970

Source: JICA estimates and judgments- preliminary; Plants 3 & 4 are not fully examined and for reference only.

Country: **Indonesia**

Foreign exchange rate for:		Rp
Rp/US$=	2350	
Compared gas:	8800	kcal/m3

Fuel prices:

Bunker C:		240	Rp/l
	=	108	$/ton
	=	16.2	$/bl
	=	2.797	$/mmBtu
Steam coal:		99100	Rp/ton
	=	42.2	$/ton
	=	1.610	$/mmBtu

Sensitivity Analysis on Coal Power

Impact of Coal Cost

Coal cost: US$/ton	Power cost c/kWh	Gas netback $/mmBtu
30	7.510	6.251
35	7.702	6.504
40	7.894	6.757
45	8.085	7.009

Impact of Interest (discount) Rate

Interest %/Yr.	Power cost c/kWh	Gas netback $/mmBtu
10.0%	6.286	5.469
11.0%	6.563	5.681
12.0%	6.855	5.905
13.0%	7.162	6.142
14.0%	7.482	6.392
15.0%	7.817	6.655

3.4 Gas Supply and Purchase Cost Situation

3.4.1 Domestic Gas Prices

Indonesian domestic gas prices to end users are set by the Government from the view point of national strategies. Most of these prices are US Dollar and fixed price contract based and have been unchanged for many years since once set for each customer; price ranges being as in Table 3-4-1.

Table 3-4-1 Domestic Gas Pricing

				Rp/US$=	2350
		Rp		US$/mmBtu	
		min	max	min	max
1 Fuel					
	Fertilizer			1.00	1.50
	Steel Industries			2.00	2.00
	Electricity			2.45	3.00
	Cement Industries			3.00	3.00
	Paper			1.50	1.50
	Refinery			1.49	1.49
	Wood Industries			0.97	0.97
	City Gas*	2500	4150	2.16	2.16
2 Feedstock					
	Fertilizer			1.00	1.50
	Steel Industries			0.65	0.65
3 New Contracts					
	Based on economics of field development and transmission facilities				

*Price to PGN defined partly in Rp and partly in US$; is about 2 US$/mmBtu in 1997.

(Source: MME1996)

The pricing policy has been to prioritize nationally important industries; highest priorities are given to steel, fertilizer and wood industries to contribute to increased export. How economics and market principle are reflected and how city gas is positioned in this framework, however, are not clear to us.

According to PGN officials, a regulation of 1994 has a clause that PGN has to apply the same gas price to end-customers regardless of its service area. The current residential gas prices are different from branch to branch of PGN, but it is true that such difference only reflects standard thermal values of gas.

The regulation is also said to mention a "distribution charge" in addition to the gas price for the case of, e.g., large apartment buildings. By such a system for apartment buildings, PGN has only to read the meter of the property owner and the allocation of gas bills and collection can be left to the property owner, functioning as a kind of small whole-selling. But actual application of such a system is limited to small properties, and not "areas", and a different gas price has never been charged to end customers. We consider that if the concept of a distribution charge is allowed, it can be used to reflect the different distribution costs and apply a new rate to a newly developed residential market area recovering a justified cost.

It is considered that any proposed change in a price in a sector has to be examined by the government in view of the national gas pricing policy.

3.4.2 PGN Jakarta's Purchase Cost and Future Gas Options

PGN currently buys gas from Pertamina at the city gates at about 167 Rp/m3 (8800 kcal), for the volume within a contractual limit, which is comparable to approximately 2.0 US$/mmBtu. The price is mostly US dollar based and PGN takes the foreign exchange rate risks. The price is considered as based on the existing gas transmission facilities including the West Java trunk lines, and we will assume it for the moment as an economic, or economically justifiable, price at a starting point.

The trunk line itself, 20 years old, is said to be sound but with the growth of gas distribution pipelines connected to the line and the growth of gas quantities, many problems like pressure insufficiency and bottlenecks exist. They consider the necessity of additional compressors and loops along the lines as well as additional connections to new gas fields. These will surely require additional costs setting aside who will pay. We do not, however, include such costs in the smaller customer market study.

For the future expansion of domestic gas use, PGN needs new sources of gas and new infrastructure, or gas transmission lines, since the current gas sources and facilities are near full capacity. Regarding this as of summer 1997, (1) PGN has secured a new gas from Arco Jakarta North gas fields. Also (2) a new transmission line from South Sumatra is being planned by the support of the World Bank, as the second phase project of Sumatra Transmission Lines. This will be in operation in 2001, and, considering the large cost of the project, new prices will have to be determined. Considering the limited gas reserve potential in South Sumatra, (3) an additional connection between the first and the second phase lines of 183 km will be implemented and the cost will be again reviewed to bring the gas from Asamera Corridor gas fields. For the future after 2010, we will assume that further new gas sources may be required for Java gas distribution networks. There are options in such assumed new sources: (4) the gas from Natuna via Sumatra pipelines and (5) an LNG from Irian Jaya. The Trans-Java Pipeline to connect East Java and West Java will be for the supply to the mid-Java cities and industries; so we will set it aside in the study for the Jakarta area.

In consideration of the cost of gas from Natuna, for example, even if Natuna is connected eventually to Jakarta via the Indonesia Integrated Transmission Lines which is being proposed by PGN for long term perspective, it is not practical to directly apply the whole transmission cost to Jakarta area. An LNG scheme may be cheaper in that case or sharing the costs with exported LNG could give complicated resultant costs unless an opportunity cost of export LNG f.o.b. price parity is applied to the pipeline inlet. Rather the gas from Natuna will push the pipeline gas southward and much gas may be consumed in strategic industries in northern regions, or in Singapore, and eventually Riau and South Sumatra gases will be directed southward to the Jakarta area. Therefore we will consider only the cost of marginal pipes from Natuna in our study period and mostly consider the gas from South Sumatra only.

3.4.3 Future Gas Supply Costs

How future gas prices to PGN will be determined is not clear, but we consider that economic principles and costs will eventually rule them since the privatization of oil and gas sector is on agenda. And the prices will have to reflect the gas supply costs in the upstream at least.

The following supply cost research is mostly conceptual as we have not had enough opportunities to access upstream information in detail this time:

A. West Java: Existing gas supply of 160 mmscfd. The price in the current arrangement is assumed fixed at $2.03/mmBtu as of 1997. Since future costs in our Study are all treated in 1997 real prices, this fixed price will be deflated by an inflation rate (6 % per annum is assumed for the wholesale price inflation) in our future gas purchase cost calculations.

B. Arco Gas: The gas of 60 mmscfd or more from Arco Jakarta North gas fields has recently been secured for supply to PGN after negotiations. The price is set at \$3.40/mmBtu, which is unexpectedly high considering it is comparable to the current LNG prices c.i.f. in Japan. If this is a fixed price, however, the price will be deflated for our future considerations as in the foregoing paragraph. We have projected that the current price of \$3.40 will be \$0.82 in 2020 in the 1997 price.

C. Sumatra - West Java: The South Sumatra Gas project is for the length of 370 km from Pagar Dewa to Cilegon and targeted for operations beginning in 2001. The capacity is 350 mmscfd. The upstream gas price is considered at 1.8 to 2.2 dollars per million Btu at the gate station in South Sumatra. The present value transmission cost is calculated in a separate table in detail and estimated as about 0.95 \$/mmBtu at 12% discount rate. (Table 3-4-3). This unit gas cost is a levelized one in real terms throughout the study period, and will not be inflated or deflated in our cost study. This concept applies to all other gases hereafter.

D. Grisik - Pagar Dewa Connection: This 180 km connection is to bring the gas from the Asamera-Duri area to the Jakarta area after 2008. The capacity is 175 mmscfd. The transmission cost is roughly calculated as 0.59 cents/mmBtu at the 12% discount rate. There may be argument that all this marginal cost may not fully apply to the Jakarta area service since the gas could be used for fertilizer plants in Palembang area. (Table 3-4-4)

E. Natuna Gas: We conceptually assume that the Asamera - Batam Island Pipeline will be extended to Natuna and the cost of the portion of existing plan is covered by existing scheme customers. The extension is about 600 km offshore in concept and the total cost of this gas at Batam is estimated as \$4.70/mmBtu, of which the transmission cost is \$3.20/mmBtu. Again to apply the whole of this cost to the Jakarta area will not be practical as stated before. The marginal supply cost to Batam may be deemed as the cost to Jakarta. (Table 3-4-5)

F. LNG from Irian Jaya: If the 3000 km long LNG scheme from Irian Jaya to Java is materialized, the cost will have to be borne by the Java customers. A tentative estimate of the cost is \$4.35/mmBtu (though we use \$4.50/mmBtu with an allowance) at a receiving terminal outlet as is shown in Table 3-4-6.

3.4.4 JICA Supply Cost Assumption

Without knowing detail gas reserve and availability positions in each relevant gas field, we estimate the weighted average gas supply costs tentatively as in Table 3-4-2 as an indication of economic costs at the current constant price. The gas purchase costs increase in real terms to about 278 Rp/m3 in 2020. We have smoothed out these yearly gas costs by a simple line toward 2020 in the actual application in our economic and financial analyses.

Table 3-4-2 Gas Supply Cost Assumption (weighted)

January 1997 Prices — Rp/US$= 2350

Case	A*	B*	C	D	E	F	JICA Assumption	
Gas Source	Existing Gas	Jkt North Arco Gas	S. Sumatra Gas	Asamera Gas	Natuna Gas	LNG from I. Jaya	Weighted average supply cost	
Transm'n			0.97	0.59	1.90			
Price('97)$/mmBtu	2.03	3.40	2.97	2.20	4.70	4.50		
Rp/8800kcal	167	279	243	181	386	369	$/mmBtu	Rp/m3
Shares (%)	Existing	Arco	S. Sumatra	Asamera	Natuna	LNG I.Jaya		
1997	100						2.030	167
1998	84	16					2.110	173
1999	82	18					2.012	165
2000	75	25					1.976	162
2001	55	17	28				2.159	177
2002	50	15	35				2.155	177
2003	44	16	40				2.176	179
2004	39	17	44				2.193	180
2005	37	16	48				2.192	180
2006	31	21	48				2.201	181
2007	32	19	49				2.153	177
2008	29	17	50	4			2.162	177
2009	26	16	50	8			2.172	178
2010	19	15	48	11		7	2.400	197
2011	9	13	49	13	6	11	2.758	226
2012		13	47	14	7	18	3.045	250
2013		12	44	16	12	17	3.106	255
2014		11	42	17	11	20	3.135	257
2015		10	43	19	10	18	3.089	253
2016		10	40	17	13	20	3.181	261
2017		9	37	17	17	20	3.268	268
2018		8	35	17	17	24	3.331	273
2019		7	32	17	19	24	3.385	278
2020		7	32	18	19	25	3.391	278

JICA Team 1997 Note* Real prices for A and B assumed to decline in general inflation (6%/yr).

Table 3-4-3 Sumatra-West Java Gas Transmission Cost Estimation

A. General Assumptions:

Starting Year=	1997	Discount Rate=	12.00%	Gas Calorific Value: at27degC	
Project Period (max 34)=	25 yrs	Life of Facility=	30 yrs	8800	kcal m3
Final Year=	2021	Std. gas temp. degC=	27	34.921	mmBtu mmcm
Operation from:	2001	Forex: Rupiah US$:	2350	1.02763	mmBtu mscf

B. Technical Assumptions

From: Pagar Dewa
To: Cilegon

Length:	370 km	max press.	80 bar
Major Size:	30 inch	Trans.Capx:	350.00 $million
Intended capacity:	350mmcfd	unit cost	31,532 $ inch km

Investment & Operation Plans

(a) & (b) are for reference only.

(a) Wellhead Gas Price: 1.200 $ mmBtu

(b) Gas Field (assumed)

	Year of Investment	Investment $million	Fixed O&M % Invst.	Variable O&M $ mmBtu 0.00	Salvage Value in 2021 $million
1	1999	100.0	1.20	1.20*	26.67
2	2000	200.0	1.00	1.07*	60.00
3					
	Total/Ave	300.00	1.07		86.67

*% of accumulated investment for Fixed O&M

(c) Transmission

	Year	$ million	% Invst.	$/mmBtu 0.01	$million
11	1998	50.00	1.30	1.30*	11.67
12	1999	120.00	1.20	1.23*	32.00
13	2000	130.00	1.00	1.13*	39.00
14	2001	50.00	1.00	1.11*	16.67
	Total/Ave	350.00	1.11		99.33

*% of accumulated investment for Fixed O&M

(d) Market Prices given (for ROR calculation):

	$/mmBtu	Rp/8800kcal
Wholesale price:	2.800	229.77778

(e) Gas Transmission Plan

Year	mmcm/year	mmscfd
1997	0.000	
1998	0.000	
1999	0.000	
2000	0.000	
2001	500.000	47
2002	676.471	63
2003	852.941	79
2004	1029.412	96
2005	1205.882	112
2006	1382.353	129
2007	1558.824	145
2008	1735.294	162
2009	1911.765	178
2010	2088.235	194
2011	2264.706	211
2012	2441.176	227
2013	2617.647	244
2014	2794.118	260
2015	2970.588	277
2016	3147.059	293
2017	3323.529	309
2018	3500.000	326
Hereafter	1.000	%/year up
Peak Load	in 2018	423.609
Peak to Ave ratio=		1.30

C. Summary Cost Results

NPV in 1997		Wellhead	Gas field	Transmission	Total
Capital Cost	US$million	na	193.184	230.419	423.603
Fixed O&M	US$million	na	16.141	20.202	36.343
Variable	US$million	na	0.265	2.654	2.919
Total (NPV)	US$million	na	209.590	253.274	462.865
Overall Cost to Gas	$/mmBtu(gas)	1.200	0.790	0.954	2.944
at8800kcal	Rp/m3	98	65	78	242

RORs based on the given market price

ROR Overall= 11.10%   Payback= 9.053 yrs

Table 3-4-4 South Sumatra Interconnect Cost Estimation

A. General Assumptions:

Starting Year=	1997	Discount Rate=	12.00%	Gas Calorific Value: at 27degC	
Project Period (max 34)=	32 yrs	Life of Facility=	30 yrs	8800	kcal m3
Final Year=	2028	Std gas temp. degC=	27	34,921	mmBtu mmcm
Operation start	2008	Forex: Rupiah US$	2350	1.02763	mmBtu mscf

B. Technical Assumptions

From: Grisik
To: Pagar Dewa

Length	183 km	max press	80 bar
Major Size	24 inch	Trans. Cost:	135.00 $million
Intended capacity:	175mmcfd	unit cost	30.738 $ inch km

Investment & Operation Plans

(a) & (b) are for reference only.

(a) Wellhead Gas Price: 1.500 $ mmBtu

(b) Gas Field (dummy)

	Year of Investment	Investment $million	Fixed O&M % Invst.	Variable O&M $ mmBtu 0.00	Salvage Value in 2028 $million
1	2000	1.0	1.50	1.50*	0.07
2					
3					
	Total Ave	1.00	1.50		0.07

*% of accumulated investment for Fixed O&M

(c) Transmission

	Year	$ million	% Invst.	$/mmBtu 0.01	$million
11	2005	10.00	1.20	1.20*	2.33
12	2006	50.00	1.20	1.20*	13.33
13	2007	55.00	1.00	1.10*	16.50
14	2008	20.00	0.90	1.07*	6.67
	Total/Ave	135.00	1.07		38.83

*% of accumulated investment for Fixed O&M

(d) Market Prices given (for ROR calculation):

	$/mmBtu	Rp/8800kcal
Wholesale price:	2.200	180.53968

(e) Gas Transmission Plan

Year	mmcm year	mmscfd
1997	0.00	
1998	0.00	
1999	0.00	
2000	0.00	
2001	0.00	
2002	0.00	
2003	0.00	
2004	0.00	
2005	0.00	
2006	0.00	
2007	0.00	
2008	154.55	14
2009	309.09	29
2010	463.64	43
2011	618.18	58
2012	772.73	72
2013	927.27	86
2014	1081.82	101
2015	1236.36	115
2016	1390.91	129
2017	1545.45	144
2018	1700.00	158
Hereafter	1.000	%/year up
Peak Load	in 2018	174.099
Peak to Ave ratio=		1.10

C. Summary Cost Results

NPV in 1997		Wellhead	Gas field	Transmission	Total
Capital Cost	US$million	na	0.634	39.616	40.250
Fixed O&M	US$million	na	0.076	3.352	3.428
Variable	US$million	na	0.074	0.741	0.815
Total (NPV)	US$million	na	0.784	43.709	44.493
Overall Cost to Gas	$/mmBtu(gas)	1.500	0.011	0.590	2.100
at 8800kcal	Rp/m3	123	1	48	172

RORs Based on Given Market Prices

ROR Overall= 13.67% Payback= 7.457 yrs

Table 3-4-5 Natuna to Batam via Pipeline

An imaginary case: extension from Batam only

A. General Assumptions:

Starting Year=	1997	Discount Rate=	12.00%	Gas Calorific Value: at 27degC	
Project Period (max 34)=	34 yrs	Life of Facility=	25 yrs	8800	Kcal/m3
Final Year=	2030	Std. gas temp. degC=	27	34.921	mmBtu/mmcm
		Forex: Rupiah/US$	2350	1.02763	mmBtu/mscf

B. Technical Assumptions

From: Natuna Is. (offshore)	Length	600 km	max press	90 bar	min 45 bar
To: Batam	Major Size	28 inch	Trans. Cost:	750.00	$million
	Intended capacity:	350mmcfd	unit cost	44.643	$/inch/km

Investment & Operation Plans

(a) & (b) are for reference only.

(a) Wellhead Gas Price: 1.200 $/mmBtu

(b) Gas Field

	Year of Investment	Investment $million	Fixed O&M %Invst.	Variable O&M $/mmBtu 0.00	Salvage Value in 2030 $million
1	2010	1.0	1.00	1.00*	0.20
2					
3					
	Total/Ave	1.00	1.00		0.20

**% of accumulated investment for Fixed O&M

(c) Transmission

	Year	$ million	% Invst.	$/mmBtu 0.01	$million
11	2007	100.00	1.20	1.20*	8.00
12	2008	200.00	1.20	1.20*	24.00
13	2009	250.00	1.20	1.20*	40.00
14	2010	200.00	1.20	1.20*	40.00
	Total/Ave	750.00	1.20		112.00

**% of accumulated investment for Fixed O&M

(d) Market Prices given (for ROR calculation):

	$/mmBtu	Rp/8800kcal
Wholesale price:	4.700	385.7

(e) Gas Transmission Plan

Year	mmcm/year	mmscfd
1997	0.000	
1998	0.000	
1999	0.000	
2000	0.000	
2001	0.000	
2002	0.000	
2003	0.000	
2004	0.000	
2005	0.000	
2006	0.000	
2007	0.000	
2008	0.000	
2009	0.000	
2010	0.000	
2011	300	28
2012	400	37
2013	700	65
2014	700	65
2015	700	65
2016	1,100	102
2017	1,600	149
2018	1,700	158
Hereafter	1.000	%/year up
Peak Load	in 2018	166.185
Peak to Ave ratio=		1.05

C. Summary Cost Results

NPV in 1997		Wellhead	Gas field	Transmission	Total
Capital Cost	US$million	na	0.200	175.924	176.125
Fixed O&M	US$million	na	0.015	16.239	16.254
Variable	US$million	na	0.060	0.598	0.658
Total (NPV)	US$million	na	0.276	192.762	193.037
Overall Cost to Gas	$/mmBtu	1.500	0.005	3.221	4.725
at 8800kcal	Rp/m3	123	0	264	388

RORs Based on Given Market Prices

ROR Overall= 12.88% Pay back= 6.784 yrs

Table 3-1-6 LNG Cost Estimation

A Case Study

A. General Assumptions:

Starting Year=	1997	Discount Rate=	12.00%	Gas Calorific Value: at 27degC	
Project Period (max 34)=	34 yrs	Life of Facility=	40 yrs	8800	kcal/m3
Final Year= 2030		Std. gas temp. degC=	27	34,921	mmBtu/mmcm
Local currency:	Rp	Rp/US$=	2350	1.02763	mmBtu/mcf
Operation start:	2010	note: m=1000, mm=million		13,210	kcal/kg
				52.41952	mmBtu/ton

B. Technical Assumptions

Scheme Outline

From: Irian Jaya	Distance:	3130 km	Ship speed	19 knot	Cargo Size:	30 mton
To: Java	Intended throughput	280mmcfd	=2.003515mmt/a		Load & unload	20 hrs.
	Req'd voyages:	70.3	round trips/yr.	Dry dock	1.5	months/y
	Ave. per voyage:	8.2	days	No. of ships	1.81503 = 2 ships	
	Rec'ving storage:	stockpile	12.0	days, dead=	10.0	%
Planned investment	105 mton req'd. thus		35 mton	x 3	tanks	
	Liquefaction	940	US$million	LNG Ship	150	$million/ship
	Receiving terminal	180	US$million			

Investment & Operation Plans:

(a) Wellhead Gas Price: 0.500 $/mmBtu

(b) Liquefaction

	Year of Investment	Investment $million	Fixed O&M % Invst.	Variable O&M $/mmBtu 0.00	Salvage Value in 2030 $million
1	2006	150.0	5.00	5.00*	60.00
2	2007	300.0	5.00	5.00*	127.50
3	2008	260.0	5.00	5.00*	117.00
4	2009	230.0	5.00	5.00*	109.25
	Total/Ave	940.00	5.00		413.75

*% of accumulated investment for Fixed O&M

(c) Shipping

	Year	$ million	% Invst.	$/mmBtu 0.01	$million
11	2006	50.00	7.50	7.50*	20.00
12	2007	100.00	7.50	7.50*	42.50
13	2008	100.00	7.50	7.50*	45.00
14	2009	50.00	7.50	7.50*	23.75
	Total/Ave	300.00	7.50		131.25

*% of accumulated investment for Fixed O&M

(d) Receiving

	Year	$ million	% Invst.	$/mmBtu 0.01	$million
11	2006	20.00	3.00	7.35*	8.00
12	2007	60.00	3.00	6.97*	25.50
13	2008	60.00	3.00	6.65*	27.00
14	2009	40.00	3.00	6.46*	19.00
	Total/Ave	180.00	3.00		79.50

*% of accumulated investment for Fixed O&M

(e) Market Price given (for ROR calculation):

	$/mmBtu	Rp/8800kcal
Wholesale:	4.400	361.07937

(f) LNG Buildup Plan

Year	mton/yr.	mmscfd	mmcmy
1997	0.0		0
1998	0.0		0
1999	0.0		0
2000	0.0		0
2001	0.0		0
2002	0.0		0
2003	0.0		0
2004	0.0		0
2005	0.0		0
2006	0.0		0
2007	0.0		0
2008	0.0		0
2009	0.0		0
2010	200.0	28	300
2011	400.0	56	600
2012	800.0	112	1,201
2013	1000.0	140	1,501
2014	1200.0	168	1,801
2015	1300.0	182	1,951
2016	1600.0	224	2,402
2017	1800.0	252	2,702
2018	2000.0	280	3,002
Hereafter	7.000	%/year up	
Peak Load	in 2018	307.460	
Peak to Ave ratio=		1.10	

Sensitivity Analysis:

Gas Price $/mmBtu	ROR%	Payback yrs
2.0	#NUM!	17.939
2.5	#NUM!	14.381
3.0	7.63%	12.060
3.5	9.42%	10.424
4.0	10.99%	9.233
4.5	12.40%	8.322
5.0	13.68%	7.607

C. Summary Cost Results

NPV in 1997		Wellhead	Liquefaction	Shipping	Receiving	Total
Capital Cost	US$million	na	245.208	79.188	46.569	370.965
Fixed O&M	US$million	na	97.519	47.256	24.144	168.918
Variable	US$million	na	0.141	1.409	1.409	2.958
Total (NPV)	US$million	na	342.867	127.853	72.121	542.841
Overall Cost to Gas	$/mmBtu	0.500	2.434	0.908	0.512	4.354
at 8800kcal	Rp/m3	41	200	74	42	357

RORs Based on Given Market Price

ROR Overall= 12.13% Payback= 8.484 yrs

3.5 Urban Gas Prices and Pricing Policy Considerations

3.5.1 Urban Gas Prices

Indonesian economy has kept steady growth these 10 years and the growth has been accelerated after 1985. Accordingly, the income level of the people has also increased as well as affordability for energy bills. Compared to the income increase, energy price relatively stayed lower.

Table 3-5-1 Economic Growth and Energy Prices

		Year				Annual growth rate(%)			
		1980	1985	1990	1993	85-80	90-85	93-90	93-85
Avturbo	(Rp/l)	145	330	330	420	17.9	0.0	8.4	3.1
IDO	(Rp/l)	45	220	235	360	37.4	1.3	15.3	6.3
Premium gasoline	(Rp/l)	220	440	450	700	14.9	0.5	15.9	6.0
LPG	(Rp/kg)	269	370	400	750	6.6	1.6	23.3	9.2
Natural gas	(Rp/m3)	55	190	230	300	28.1	3.9	9.3	5.9
Nominal GDP	(billion US$)	78	87	106	145	2.2	4.0	11.0	6.6
Population	(million)	151	164	178	187	1.7	1.7	1.7	1.7
GDP/capita	(US $/capita)	517	530	596	775	0.5	2.3	9.2	4.9

note:Prices are in nominal terms.

source: World Bank, PGN

As to the gas pricing, PGN got authorization of new gas tariff structure in October 1996. Gas tariff was not changed for 5 years since 1991. The new tariff table by Branch is as follows:

Table 3-5-2 New Tariff Structure of PGN approved as of October 1996

❑ General Tariff

Branch	kcal (kcal/m³)	New Tariff (Rp/m³)	Old Tariff (Rp/m³)	Change
Medan	11,000	400	370	+ 8.1%
Jakarta	8,800	370	300	+23.3%
Bogor	8,800	370	300	+23.3%
Surabaya	9,100	335	300	+11.7%
Cirebon	7,000	300	225	+33.3%

❑ Contract Tariff

Branch	kcal	New Tariff (Rp/m³)			Old Tariff (Rp/m³)	Change (VS.K1)
		K1	K2	K3		
Medan	11,000	350	340	$Hn=Hd \times (1+g)^n$	320	+ 9.4%
Jakarta	8,800	330	315	$Hn=Hd \times (1+g)^n$	265	+24.5%
Bogor	8,800	330	315	$Hn=Hd \times (1+g)^n$	265	+24.5%
Surabaya	9,100	335	320	$Hn=Hd \times (1+g)^n$	265	+26.4%
Cirebon	7,000	Contract Tariff : 265 Rp/m³ Small industry : 160 Rp/m³			210	+26.2%

note: 1. K1 is applied to commercial and industrial customers who consume from 1,000m³ to 300,000m³ per month.
2. K2 is applied to commercial and industrial customers who consume from 300,000m³/to 5,000,000m³ per month.
3. K3 is applied to commercial and industrial customers who consume more than 5,000,000m³ per month.
4. In the formula of K3, "Hd" represents the basic price, "g" represents escalation rate set by negotiation, "n" represents the number of years.

The increase of general tariff, mainly applied to residential and small commercial and small industrial customers, ranges from 8% to 33%. In the residential gas market, natural gas will face severe competition against LPG. As a result of tariff increase this time, price competitiveness of natural gas against LPG has weakened a little, but still has an advantage.

The contract tariff, mainly applied to large commercial and industrial customers, was split into 3 categories by consumption volume. Particularly, it is characteristic that K3, which can be set without authorization, was newly introduced in the tariff menu. PGN and customers can set the price by negotiation. Flexible pricing is required for large industrial customers, because the distribution cost to such kind of customers varies greatly depending on the usage conditions such as daily load factor, seasonal fluctuation etc., as well as net-back values. K3 meets this needs. This enables PGN to acquire potential customers, which consumes more than 5 million cubic meters per month strategically.

However, from the standpoint of government, it has to be considered if the customers have bargaining power against gas companies, if too much bargaining for large customers may affect captive customers.

Chapter 4

Corporate Situation of PGN

4. Corporate Situation of PGN

4.1 Corporate Status of PGN

4.1.1 History of Gas Distribution

Since 1863 when colonial Dutch started gas distribution, the gas was manufactured by coke oven and oil cracking and was distributed to wealthy residential customers in eight major cities. After independence, the Indonesian Government took over this business. In 1958 Perusahaan Gas Negara(PGN) was established as a state owned enterprise. In 1974 natural gas distribution started in Cirebon (200km east of Jakarta). In 1976 a 280 km transmission pipeline from Cilamaya to Cilegon (west end of Jawa Island) was completed. After completion the pipeline's neighboring area (including Jakarta and Bogor) was converted from manufactured gas to natural gas. In Medan(north of Sumatra island) natural gas distribution was also started by using natural gas from neighboring gas well. In 1993 natural gas distribution started in Surabaya. In the other three cities (Bandung, Semarang and Ujung Pandang) LPG is distributed now. The PGN has traditional knowledge of gas distribution to small customers.

PGN has been expanding natural gas sale to industrial market based on a feasibility study funded by the World Bank in 1984. On the other hand, the gas sale to residential and commercial market has not been active, because the cost to distribute gas to them is deemed high.

4.1.2 Corporate Status

In 1965 PGN (Perusahaan Gas Negara) was established as a state owned gas distribution company. In 1976 PGN fell under the jurisdiction of MIGAS(Directorate General of Oil and Gas) and strengthened its relationship with Pertamina. In 1984 PGN's status was changed from Perusahaan Gas Negara to Perum Gas Negara by Government Regulation No. 27, in order to corporatize the entity. In 1992, by Decree No.785 of Ministry of Mines and Energy, Government vested PGN with the additional responsibility to undertake natural gas transmission for domestic needs. In 1994, by Government Regulation No. 37, the legal status of the state gas public corporation was converted to that of limited liability state owned company (PERSERO) i.e., PT PGN(PERSERO), to enhance the efficiency and reliability of the gas supply operation and management.

As the result of commercialization of the entity, PGN has been obtaining options to diversify its business.

4.2 Status of Operation

Highlights of the PGN are shown below.

Table 4-2-1 Highlights of PGN

Business Territories: 8 Cities
(Jawa)Jakarta, Bogor, Bandung, Cirebon, Semarang, Surabaya
(Sumatra) Medan (Sulawesi) Ujung Pandang

Financial Data as of Fiscal Year 1996

Gas Sales Revenue	444,869 million Rupiah
Profit After Tax	91,160 million Rupiah
Paid up Capital	200 million Rupiah

Number of Customers and Sales Volume: (as of 1994)

	No. of customers (as of March 1997)	Gas sales volume (as of 1995) (MMSCFD)	(%)
Residential:	42,805	1.7	1.5
Commercial:	1,311	1.3	1.1
Industrial:	600	117	97.4
Total:	44,716	120	100

Gas Sales Volume: (as of 1995)	Distribution	120 MMSCFD
	Transmission(PLN etc.)	68 MMSCFD
	Total	188 MMSCFD
Pipeline Length(as of 1995):		1,408 km
Number of Employees(as of 1995):		1,323

History of Gas Conversion

1974	NG conversion in Cirebon
1978-79	NG conversion in Jakarta
1980	NG conversion in Bogor
1985-86	NG conversion in Medan
1988-90	LPG conversion in Bandung, Semarang, and Ujung Pandang
1993	NG conversion in Surabaya

Source: PGN

The gas sales revenue is 444,869 million Rupiah (about 9 billion yen). The profit after tax is 91,160 million Rupiah (20% of the gas revenue), which seems to be a quite high rate. The number of customers is 45 thousand, amongst which residential customers are the most. However industrial usage is the most based on the sales volume.

PGN has a scenario of its future operation as shown below.

Table 4-2-2 Scenario of Future Operation

Short Term(1993/1998)

*Construction of total 1,490 km pipelines:

Asamera - Duri - Batam island

Palembang - Cilegon

Sengkang - Ujung Pandang

Medium Term(1998/2003)

*Construction of total 1,493 km pipelines:

Cilegon - Jakarta

Cilebon - Surabaya

Arun - Duri

Long Term(2003/2008)

*Construction of total 3,177 km pipelines:

Arun - Natuna (via Malaysia)

Bontang - Natuna

Natuna - Brunei

Brunei - Bontang

*The other plans to construct 1,266 km of pipelines

Natuna - Pontianak

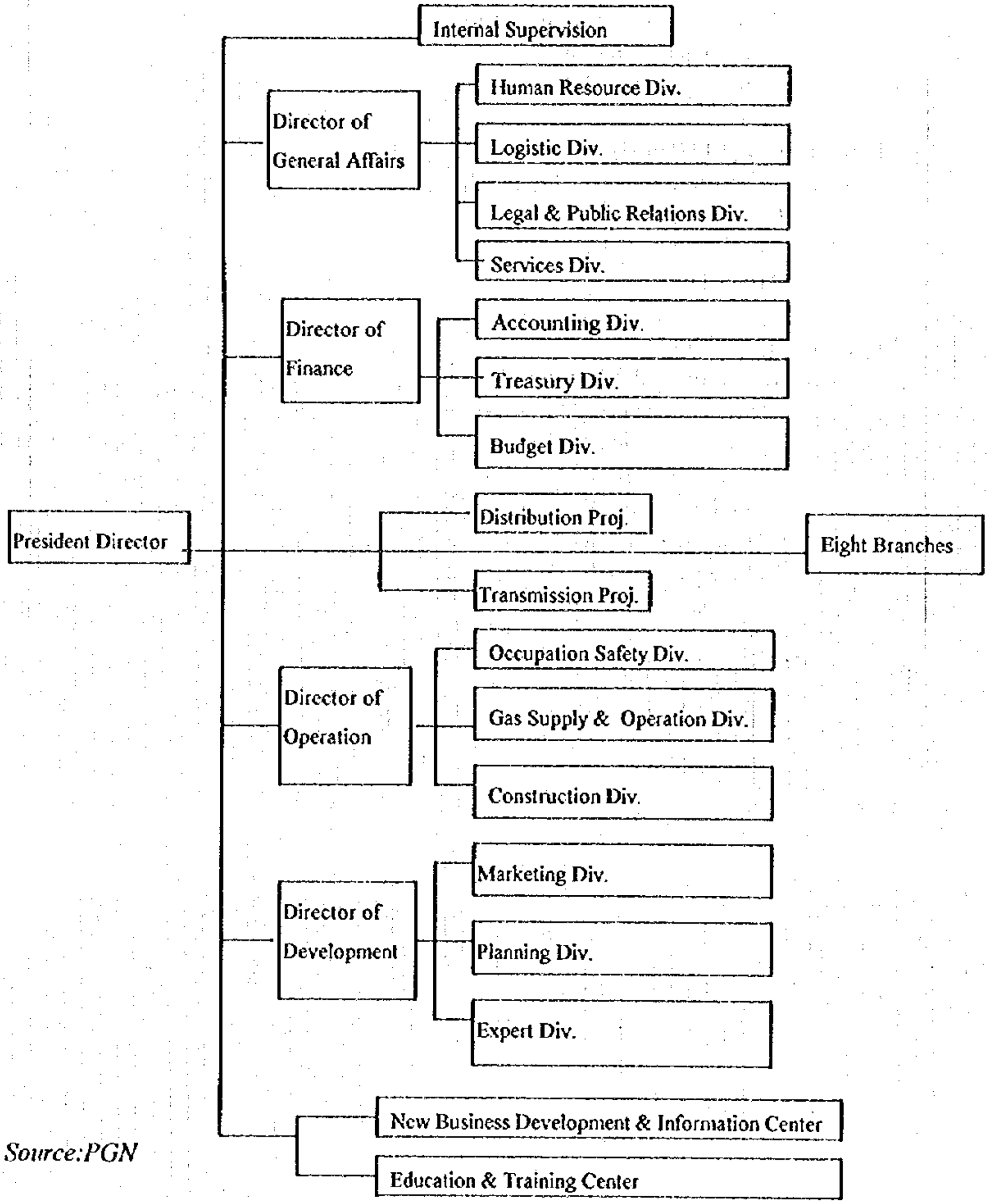
Pontianak - Semarang

Source :PGN

4.3 Organization of PGN

The current organization of PGN is shown in Fig. 4-3-1. Under the President Director PGN has four Directors supervising 11 divisions; two centers; two projects; and an internal supervision (all in the head office); and eight regional branches.

Fig. 4-3-1 PGN Organization Chart as of Oct.1996



Source:PGN

PGN has a scenario to restructure its organization according to the procedure of plans in Table 4-2-2.

After completion of Asamera-Duri-Batam transmission pipeline and South Sumatra-West Jawa transmission pipeline, operation companies are established as subsidiaries of PGN.

PGN itself may become a holding company as a state owned company. Transmission and distribution companies including current PGN business entity become subsidiaries under this holding company.

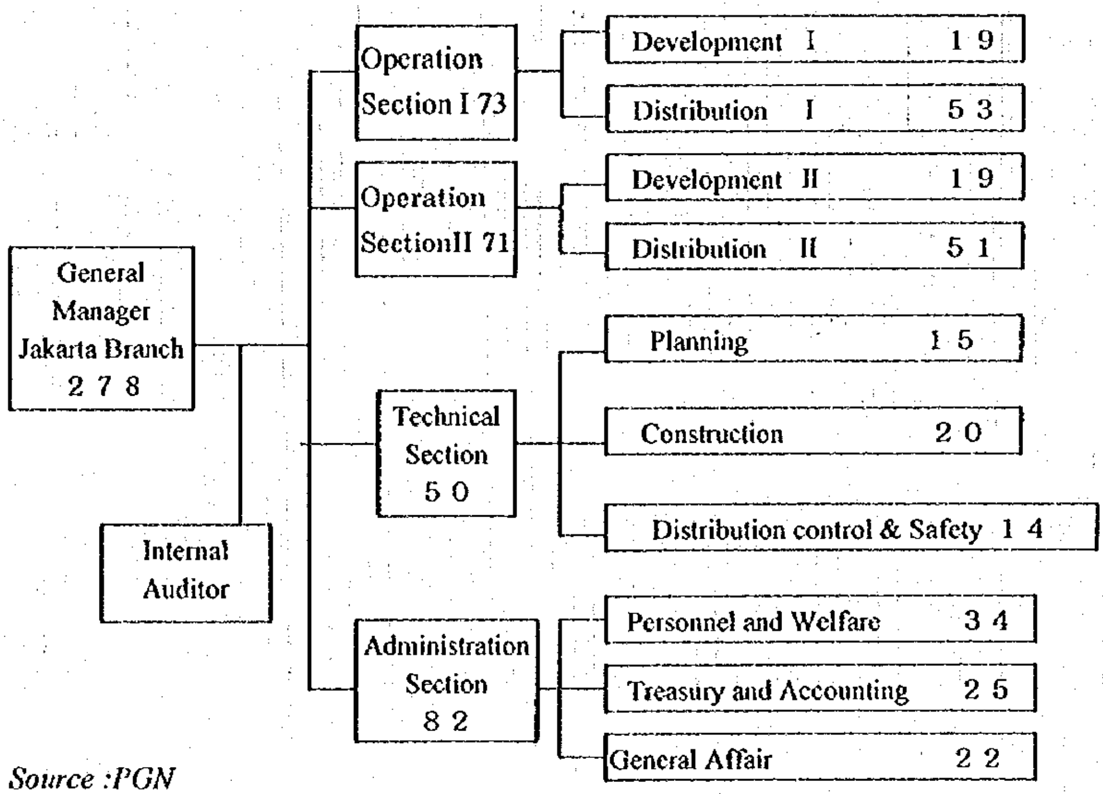
The holding company has options to establish energy related business entities including cogeneration, bio-gas and gas distribution to newly developed estates.

In order to realize this scenario recruiting additional employees as well as shifting personnel among PGN group companies will be necessary.

The organization of Jakarta Branch is shown in Fig. 4-3-2.

Fig 4-3-2 Organization Chart in PGN Jakarta Branch

as of Oct. 1996



Source :PGN

Under the General Manager it has four sections and a internal audit unit. The operation is divided into two, based on the operation areas, which are west and east. The number of employees in development sections seems to be small compared to that of developed countries.

Table 4-3-1 shows the allocation of personnel in branches with age distribution, as well as giving educational break-downs. There seems to be a generation gap because of the lack of employees aged between 35 and 45 years old. All of the management members appear to have a broad knowledge of the natural gas industry and the ability to think critically and creatively, and have the ability to expand urban gas business.

Table 4-3-1 Allocation of Personnel, Age and Education

As of Oct 1995

	H. Office	Jakarta	Medan	Bogor	Bandung	Cirebon	Semarang	Surabaya	U Pandang	Total
Total	376	284	130	104	108	85	50	160	26	1,323
Age										
<20	3	0	0	0	0	0	0	4	0	7
21-25	22	11	3	0	2	2	0	13	0	53
26-30	85	59	30	8	0	6	5	6	1	200
31-35	112	61	33	31	3	11	4	24	5	284
36-40	52	34	16	18	10	13	1	14	1	159
41-45	8	49	10	15	20	25	4	21	5	157
46-50	40	42	8	14	48	18	17	38	7	23
51-56	36	28	26	17	24	10	19	39	7	206
>56	18	0	4	1	1	0	0	1	0	25

Education Background

Master	Diploma	Bachelor	Senior High	Junior High	Elementary	Total
21	152	64	447	376	263	1,323

Source :PGN

4.4 Financial and Budget Situation

From the view point of financial and budget situation of PGN, it is now rapidly changing company by aggressively capitalizing transmission pipelines. It is on the way to construct its own transmission pipelines in Asamera-Duri and South Sumatra-West Jawa, which are part of the Trans-Indonesia Pipelines. Asamera-Duri line is planned to reach Batam Island which will be an opportunity of acquiring a new industrial gas demand. Further in the future the pipeline is expected to be connected to Natuna Island opening a way to PGN to secure a big source of gas for the future demand. The South Sumatra-West Jawa line is to transmit new source of gas to the Jakarta area from 2000 to 2008. PGN is actively financing for the investment with the help of World Bank, ADB, EIB, and JEXIM as well as domestic financial sources by MTN(Medium Term Notes) in 1997. In PGN's long term financial plan, overseas strategic partners who will invest in the convertible bonds of 100 millions US dollars are being sought.

This situation is clearly seen in the financial ratios based on 1993-1997 as shown in Table 4-4-1.

Table 4-4-1 Financial Ratios of PGN

	1993	1994	1995	1996	1997
ROE*1		23%	29%	32%	29%
Operating profit/total sales	40%	35%	30%	26%	25%
Cost of goods sold/total sales	40%	47%	53%	58%	61%
Operating expenses/total sales	20%	18%	17%	17%	13%
Profit before tax/total sales	40%	33%	30%	28%	23%
Profit after tax/total sales	25%	20%	21%	20%	17%
Annual sales growth Rate		27%	41%	26%	38%
Sustainable growth rate*2		13%	21%	8%	39%
Debt/equity ratio	70%	80%	79%	117%	247%
Total assets turnover*3		132%	154%	154%	117%
Self-financing ratio*4	129%	79%	109%	48%	13%

*1 =After Tax Profit/Average Equity
*2=Growth Rate of Equity
*3=Total Sales/Average Total Assets
*4=Total cash from operation/total cash for investment

Estimated by JICA Team from the annual report 1995 and the budget 1997 of PGN
Source: PGN

From the figures we see that Sales Growth Ratio overshoots Sustainable Growth Ratio, which together with the decline of Total assets Turn Over in 1997, results in dramatic growth of Debt/Equity Ratio in these years. PGN is expected to finance net of 89,194 millions of Rp, which is equivalent to 37 millions of dollars in 1996 and 700,990 million Rp, which is equivalent to US $ 298 millions (2350Rp/$) through The World Bank, ADB, EIB and JEXJIM, and with MTN.

This dramatic change will give PGN a profound impact on the status as natural gas distributor in Indonesia and those projects are critically important for them to succeed in the future. For the gas supplied from South Sumatra to Jakarta Area (250MMSCFD), PGN are expecting mainly industrial demand.

This study will be showing the feasibility of distributing gas to the residential and commercial sectors to enable PGN to have strategic views for developing additional demand of natural gas in the Jakarta area.

Because ROE has been stable all these years, we see profitability. However, Operating Profit/Total Sales are declining these years, because Cost of Goods Sold/Total Sales has been increasing. Behind this figures, we see the price of gas purchased from Pertamina are contracted to increase in the course of the volume increase of gas purchased. PGN has been decreasing Operating Expenses/Total Sales but it has not been catching the increase of Cost of Goods Sold.

When interests of loans that PGN borrowed these years (it will be capitalized in a few years) will be counted as cost, profitability may decline. Cost of gas per volume would be expected to keep growing to compensate the capital expenditures of transmission lines.

Again it is showing how important it is for PGN to secure the feasibility for the future demand increase of gas. It is also quite important for PGN to accelerate the development of new demand around Jakarta area in the course of the development of new gas source to pay for the interests of loans PGN is financing now.

Table 4-4-2 Income Statements of PGN

Income Statements (million Rp)

	1993	1994	1995	1996	Budget 1997
Income from basic business					
Gas sales	192,132	244,049	342,802	436,384	600,461
Pipeline transmission	4,141	5,518	9,421	8,485	11,474
Deductible	(60)	(119)	(9)	0	0
Total	196,213	249,449	352,215	444,869	611,935
Cost of Goods Sold					
Gas Purchased	81,791	121,680	190,338	264,854	367,737
Gas Lost	(3,091)	(4,728)	(4,166)	(7,902)	7,316
Total	78,700	116,952	186,171	256,952	375,053
Operating expenses					
Distribution expenses	11,128	16,949	20,244	23,488	26,292
Administrative expenses	11,046	8,988	11,908	19,033	21,298
Marketing expenses	2,333	3,264	4,653	7,232	7,757
Overhead expenses	15,196	16,908	23,579	24,426	26,383
Total	39,703	46,108	60,384	74,179	81,730
Operating profit	77,810	86,388	105,659	113,738	155,152
Profit & loss from other operation					
Income for installation	209	327	425	415	427
Expense for installation	(81)	(191)	(323)	(410)	(376)
Total	127	136	102	5	51
Profit & Loss from other activities					
Income from other activities	17,283	13,963	17,437	27,228	21,594
Expense from other activities	(16,597)	(17,876)	(18,558)	(17,285)	(37,907)
Total	686	(3,913)	(1,121)	9,943	(16,313)
Profit before tax	78,623	82,611	104,640	123,686	138,890
Tax	29,809	33,009	31,030	32,526	36,396
After tax profit	48,813	49,603	73,610	91,160	102,494

Source:PGN

Table 4-4-3 Balance Sheets of PGN

Balance Sheets

(million Rp)

(Assets)	1993	1994	1995	1996	Budget 1997
Current assets					
Cash	751	153	670	72	72
Bank accounts	22,891	27,850	38,932	3,867	21,435
Securities	83,000	94,100	111,000	101,000	140,000
Account receivable	19,939	26,386	35,277	40,873	71,326
Other receivable	1,871	2,708	2,357	2,640	1,740
Prepaid expenses	3,831	2,313	5,181	16,309	16,324
Inventories	22,445	48,623	50,486	49,146	56,517
Prepaid expenses	121	83	95	95	95
Income receivable	1,316	921	763	762	762
Total current assets	156,164	203,138	244,760	214,764	308,271
Fixed assets					
Land	24,122	24,271	24,205	23,944	24,452
Buildings, offices	13,301	16,679	19,362	25,879	38,251
Cars, vehicles	3,405	3,840	4,199	3,872	4,415
Gas facilities	120,708	142,811	177,271	206,242	277,814
Office equipment	5,483	8,973	9,563	9,181	10,747
Other inventories	6,652	9,859	11,452	8,753	11,081
Gross fixed assets	173,671	206,434	246,054	277,871	366,760
Accumulated depreciation	(50,749)	(64,054)	(80,417)	(91,545)	(110,801)
Net fixed assets	122,922	142,380	165,637	186,326	255,959
Construction in progress	11,234	11,094	25,147	170,205	766,785
Total fixed assets	134,156	153,474	190,784	356,531	1,022,744
Other assets					
Deferred charges	54,370	56,673	64,027	79,055	109,777
Others	83	5	6	1,983	1,983
Total other assets	54,453	56,678	64,033	81,038	111,760
Total assets	344,773	413,290	499,577	652,333	1,442,775

(million Rp)

(Liabilities & Equity) Current Liabilities	1993	1994	1995	1996	Budget 1997
Account payable	14,510	24,143	36,270	36,270	36,270
Tax payable	5,982	4,455	4,109	0	0
Other payable	21,934	26,325	21,192	30,845	22,279
Accrued expenses	842	1,339	2,009	2,009	2,009
Prepaid income	27	37	39	69	69
Development fund payable	21,088	24,407	24,801	7,494	11,108
Long term debt within a year	6,411	8,645	15,536	15,535	15,536
Total current liabilities	70,793	89,351	103,955	92,222	87,271
Long term liabilities					
FromWB	50,764	72,861	97,614	127,166	151,449
From JEXIM	11,444	9,918	8,392	37,761	247,803
From ADB	0	0	0	31,662	250,767
From EIB	0	0	0	5,611	129,171
By MTN	0	0	0	0	124,000
Development fund	0	0	0	47,065	35,957
Total long term liabilities	62,208	82,779	106,006	249,265	939,147
Other liabilities					
Customer deposits	444	483	523	350	395
Social fund	8,479	11,013	10,493	10,493	0
Total other liabilities	8,922	11,496	11,016	10,843	395
Equity & reserves					
Paid in capital	44,000	44,000	44,000	200,000	200,000
Fund for PGN	65,725	79,113	89,868	8,598	41,542
Donated capital	23,433	25,526	27,298	0	0
Total equity	133,159	148,639	161,165	208,598	241,542
Total reserves	20,964	31,423	43,824	35,751	71,926
Profit loss for current year	48,813	49,603	73,611	55,654	102,494
Total equity and reserves	202,936	229,664	278,600	300,003	415,962
Total liabilities and equities	344,860	413,290	499,577	652,333	1,442,775

Source:PGN

Table 4-4-4 Cash Flow Statements of PGN

Cash Flow Statement

	1993	1994	1995	Estimated 1996	Budget 1997
Cash flow from operational activities:					
Profit	48,813	49,603	73,611	91,160	102,494
Adjustment for:					
Depreciation & amortization	20,494	21,742	16,363	11,128	28,102
Long term expenditures paid					(37,824)
Others	(10,447)	(37,286)	(23,321)	(10,092)	885
Total cash from operating activities	58,861	34,058	66,653	92,196	93,657
Cash for investment:					
Additional for fixed assets	(27,543)	(32,624)	(53,673)	(176,875)	(685,469)
Others	(18,111)	(10,739)	(7,354)	(17,005)	(42,027)
Total cash for investment	(45,654)	(43,363)	(61,027)	(193,880)	(727,496)
Cash flow from fund activities:					
Bank Loans	9,462	22,187	24,753		
WB				25,552	24,283
ADB				31,662	219,105
EIB				5,611	123,560
JEXIM	(1,526)	(1,526)	(1,526)	29,369	210,042
MTN				0	124,000
PGN gas deposits	279	40	40		45
Payment for employees	(5,874)	(7,228)	(7,440)		(17,922)
Payment for small business fund	(2,109)	(2,441)	(2,480)		(2,735)
Payment for social fund	0	0	(3,000)		(10,493)
Payment for dividend					(5,565)
Payment for general reserves	(2,642)	(1,744)	0		0
Receiving government fund for project	8,438	13,388	10,755		32,944
Receive for donated capital	4,811	2,093	1,772		
Others				(36,173)	(9,317)
Total cash flow for fund activities	10,840	24,767	22,873	56,021	687,947
Additional cash for this year	24,047	15,462	28,498	(45,662)	56,568
Cash from other activities					2,460
Beginning cash of this year	82,594	106,641	122,103	150,601	104,939
Ending cash of this year	106,641	122,103	150,601	104,939	161,507

Source:PGN

4.5 Human Resource Development

Table 4-5-1 shows the training programs in 1996

Table 4-5-1 Training Program in1996

No. Title of Training	No. Courses	No. Participants	Total Period	
A Training and Employee Affairs	7	105	11 weeks	
B Marketing	7	70	10 weeks	
C Technical	9	140	15 weeks	
D Economical	7	110	8 weeks	
E Computer	5	55	4 weeks	
F Management	6	90	4 weeks	
G Audit	6	55	5 weeks	
H Legal and Public Relations	10	28	8 weeks	
I Logistic	4	40	8 weeks	
J General	8	165	20 weeks	
(Overseas Training)				
1 Gas Strategic Business Planning	1	10	4 weeks	USA
2 Gas Trans Pipeline Construction	1	5	4 weeks	Canada/UK
3 Gas Project Management	1	10	4 weeks	Australia
4 Gas Contract	1	10	4 weeks	Malaysia
(Study in University)				
1 Master Degree	1	8	1.5 years	UK
2 Master Degree	1	25	2 years	Jakarta
3 Diploma	1	50	1 year	CEPU
Grand Total	76	976		

Source:PGN

More than 70% of the over thirteen hundred employees have chances to participate in training programs. The programs cover almost a full range of subjects related to gas distribution business. The instructors of the training program are not only from PGN but also outside organizations including CEPU, I U and language schools.

However the participants are all PGN employees. Programs for the contractors are not offered. There does not seem to be enough training programs for gas utilization and gas appliances, and gas safety. There is no affiliation and tie-up with gas manufacturers and makers.

4.6 Technology Status and JICA Team's Technology Transfer

PGN has relatively high standard of technology. The engineers are well educated and are keen to adapt advanced technologies from abroad. Engineers from Britain are stationed at PGN to do a wide range of consultation including introduction of new technologies and technical standards. However indoor piping for high-rise building and safety standards for installing gas appliances and ducting their flue gas are not enough.

Followings are the technologies which are insufficient and expected to be introduced.

(1)Distribution area

1) Indoor piping materials (flexible pipes and fittings)
2) Pipe installation standards for high rise buildings
3) SCADA(Supervisory Control And Data Acquisition) system

(2) Gas utilization area

1) Sales know-how of residential and commercial gas appliances
2) Technologies for large commercial gas appliances (gas absorption chillers etc.)
3) Technologies for industrial gas appliances (cogeneration etc.)

(3)Gas safety area

1) Technical standards for installation of gas appliances and ducting flue gas
2) Intelligent gas meters
3) Safety standards for new gas appliances

In the future it seems to be expected to establish an association to qualify new gas appliances to be marketed in.