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# PRIVATE SECTOR POWER GENERATION IN INDONESIA: OPPORTUNITIES AND IMPEDIMENTS

MARCH 1988

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ENERGY / DEVELOPMENT INTERNATIONAL

# PRIVATE SECTOR POWER GENERATION IN INDONESIA: OPPORTUNITIES AND IMPEDIMENTS

Philip F. Palmedo (E/DI), Betsy Amin-Arsala (USAID), Mark Bagdon (Energy Resources Development Corp.), Stimson Eveleth (Consultant to Arthur Young & Co.), Macon Faulkner (LSU), Marcia Gowen (USAID) and Elmer Hall (E/DI)

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ENERGY/DEVELOPMENT INTERNATIONAL
100 North Country Road
Setauket, N.Y. 11733

# FORWARD

The issue of private power generation in Indonesia is highly complex, involving many technical, institutional and financial issues. Some of these issues, furthermore, are under active consideration. This report was written following an intensive but brief (three week) team visit to Jakarta in July, 1987. While the report profited from the experience and advice of a large number of people, its analysis and conclusions must be considered as preliminary and are intended as contributions to current debate.

We, as others working on the energy sector in Indonesia, own a substantial intellectual debt to the World Bank. In a series of reports over recent years the Bank has provided invaluable factual material and thoughtful analysis upon which we have drawn heavily in this report.

Many of those consulted in Indonesia and the U.S. provided useful advice in the course of this study. A relatively complete list is given in Appendix C. Robert Archer, also of USAID, not only guided the study but also made extensive contributions to its content. The suggestions of Robert Ichord and Eric Nelson of USAID were also very helpful. We profited greatly from the interest and efforts of Andres Liebenthal of the World Bank. Finally, we would like to express our appreciation for their guidance and help to our colleagues in Jakarta, Dr. A. Arismunandar, Dr. A. Surjadi, Ir. M. Andoyo, Mr. D. Tombeg and Mr. Purwono, all of the Direktorat Jenderal Listrik dan Energi Baru.

## UNITS AND CONVERSION FACTORS

| | | |
|---|---|---|
| US$1 | = | Rp1644 (July, 1987) |
| Rp 1 million | = | US$ 606.06 |
| Fiscal Year | = | April 1 - March 31 |
| 1 megawatt (MW) | = | 1000 kiiowatts (kW) |
| 1 gigawatt (GW) | = | 1 million kW |
| 1 Terawatt (TW) | = | 1,000 million kW |

## ABBREVIATIONS

| | |
|---|---|
| ADB | Asian Development Bank |
| ADO | Automotive Diesel Oil |
| ASEAN | Association of South East Asian Nations |
| BAKOREN | National Energy Board |
| BATAN | National Atomic Energy Agency |
| BI | Bank Indonesia (the central bank) |
| BOT | Build, Operate and Transfer (form of project development) |
| BPS | National Statistical Office |
| CPUC | California Public Utilities Commission |
| DJLEB | Directorate General for Electric Power and New Energy, Ministry of Mines and Energy |
| E/DI | Energy/Development International |
| FERC | Federal Energy Regulatory Commission (U.S.) |
| GDP | Gross Domestic Product |
| IER | Incremental Energy Rate |
| LNG | Liquified Natural Gas |
| LRMC | Long Run Marginal Cost |
| MME | Ministry of Mines and Energy |
| OPIC | Overseas Private Investment Corporation |
| PEP | Power Enterprise Permit |
| PG&E | Pacific Gas and Electric Co. |
| PLN | State Electricity Company |
| PURPA | Public Utilities Regulatory Policies Act (U.S.) |
| QF | Qualifying Facility under U.S. PURPA legislation |
| TWh | Terawatt hours |
| USAID | U.S. Agency for International Development |
| WAPDA | Water and Power Development Authority (Pakistan) |

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# I. EXECUTIVE SUMMARY

## A. BACKGROUND

This report examines in a preliminary way the potential for and implications of private investment in the power sector of Indonesia.

Investment in power production, which in recent years has represented about 10 percent of total national investment, should grow even faster than GDP if economic growth and social development is to continue. A sharp reduction in foreign exchange earnings from oil and gas exports has led to strong pressure to reduce Government expenditures whenever possible. Expenditures on electricity in 1985/86 were only 50 percent of the amount originally planned.

While in sectors such as health and education there are few opportunities for effective private investment, there is a significant potential in the power sector to replace public investment by private production of electricity.

It is the Government policy to encourage private investment generally, even to the extent of the privatization of selected state-owned entities. In the power sector, Law No. 15 of 1985 sets out a clear policy to allow cooperatives and private entities to produce power.

## B. THE POWER SECTOR

In 1986 PLN had an installed capacity of 5403 MW; a roughly equal amount of capacity was installed in (private and state-owned) industry. Projections of long term growth in electricity consumption range from 6 - 8 percent per year. There are literally thousands of very small private power producers throughout Indonesia. While they don't

represent a significant amount of total capacity, these micropower companies do demonstrate both a willingness of villagers to pay more than PLN rates for small amounts of power and widespread entrepreneurial skill on the part of producers.

A variety of countries including the United States, Turkey and Pakistan have found that, with proper structures and incentives, private entities will invest in power production to the mutual benefit of their owners and of the country.

## C. THE POTENTIAL

In Indonesia, three general approaches to private power production have been investigated.

### 1. New Large Scale Power Plants Based on Indigenous Coal or Natural Gas

A major impact on future power production in Indonesia will be made only if the private sector invests in medium to large-scale power plants. Four international proposals for private investment in such plants are now in front of the Government. The first, and most advanced, is by Union Geothermal for a 147 MW geothermal power plant at Salak. Fossil fueled plants in the 600 MW range have been proposed by a German-French consortium, a Japanese-U.S.-Italian group and a Canadian firm. These proposals follow the BOT concept.

Because it would be based at least in part on commercial financing a privately built power plant may have somewhat higher capital-related costs than the same plant financed by PLN. However, for the financial reasons discussed above, capital needed for PLN's expansion may simply not be available through traditional Government channels. Furthermore, private large scale power has the potential of introducing new power technology faster than would otherwise be the case and also of demonstrating more effective management techniques.

## 2. Cogeneration in Industry

Many industries which have need for steam and electricity can produce both, with excess electricity made available to the PLN grid. Because both the thermal and electrical outputs of power generation are used, the system is more efficient and thus the power produced is cheaper than for systems producing only power.

A small amount of cogeneration now exists in Indonesia. The fertilizer, textile, LNG, oil refining and wood products industries present major opportunities for new cogeneration and excess power production. In total, the potential excess power that could be made available from these and related industries for sale to the grid could be on the order of 4 billion kWh (compared to current PLN production of 14.6 billion kWh). New petroleum processing and chemical plants present particularly attractive cogeneration opportunities.

## 3. Biomass/Renewable Energy Systems

Private investment in power production in rural areas has the potential of extending rural electrification at much reduced cost to the Government. Although most rural electrification would still be based on diesel generation or extension of the grid, a variety of renewable energy sources are suitable for private power investment in rural areas. Proposals are now before the Government for the use of wood waste (in one instance in combination with peat). Indonesia has a major small scale hydro program and the start of a program in wood and rice husk gasification. This study examined power production from rice husk and straw.

The potential for rice residue fueled power production in Indonesia is limited by the mismatch between the scale of commercially proven efficient power units and the scale of rice milling operations. Trends on both sides, however, may make the technology viable in the future. If Indonesia follows the pattern of other countries where a higher value luxury rice market expands with increasing per capita income, more efficient mills will be

required. Capital costs associated with more efficient milling necessitates a move to larger mills. At the same time efforts to produce smaller scale but highly efficient power systems are also underway.

## D. REQUIREMENTS AND NEXT STEPS

Although the basic Government policy exists for private power investment, several steps should be taken to encourage its implementation:

1. A more detailed policy framework should be developed including principles of pricing of purchased power, general contractual terms and the continued role of PLN in integrating privately produced power into an efficient national system. Power purchase prices should be based on PLN's costs of producing power of the same reliability at the same site. Private investors should be encouraged to submit proposals based on these guidelines.

2. A firmer factual and analytical base needs to be developed for the policy framework. Actual long run marginal costs and the financial/economic criteria for major private power investments need further clarification.

3. Beneficial links should be explored between existing energy sector entities and power production. For example, companies developing coal and natural gas resources may, in a favorable climate, be interested in producing power from those resources. Companies in the fuel conversion business - e.g. LNG production and petrochemicals - may be interested in exploiting their potential for cogeneration and sale of power to the grid.

4. Several pilot projects should be initiated. Proposals for such projects already exist which would require very little outside support. The aim would be not so much a demonstration of technology as a demonstration of the institutional and financial structure of private power. These first projects would serve as a model and an encouragement for others.

5. Several modifications in the financial regulatory structure should be considered to encourage private power investment. They include:

a. Re-aligning the tax system so that different investment alternatives are taxed at the same rate;

b. Eliminating discrimination against foreign companies regarding availability of local credit;

c. Establishing incentives for investment in power production - e.g. investment credits, lines of credit, tax holidays - consistent with the benefit to the country of replacing Government foreign exchange debt financing.

6. Least cost power production, including non-Government financing should be examined as an integral part of industrial development. Low cost power production from hydro resources, in association with the energy industry and through cogeneration can represent a significant comparative advantage in Indonesia's industrial development strategy.

7. In order to create a more informed and productive environment for increased private investment in the power sector, a workshop should be held bringing together, in an atmosphere of open discussion, private power investors, manufacturers, Government policy makers and representatives of the financial community. The workshop should produce specific recommendations for a policy framework for private power and specific proposals for demonstration projects.

# II. INTRODUCTION

## A. BACKGROUND

The provision of affordable electric power is a central concern of the Government of Indonesia. Indonesia's industrial development and the social/economic advancement of its population, particularly those in rural areas, depend on increasing supplies of electricity. Since independence, both the planning and management of the power sector and the actual supply of electricity has been, in principle, a governmental activity. For one reason or another, however, private industry has installed a significant amount of generating capacity for its own use. This "captive power", as well as large numbers of extremely small scale private power producers, have grown up spontaneously, with no consideration of power system optimization.

A new interest has arisen in private investment in the power sector in Indonesia. There are four primary reasons for this:

One strong motivation for stimulating private investment in the power sector is the combination of the very high capital needs in the sector with sharply declining resources available to the Government. In recent years, the power sector has consumed about 10 percent of total government expenditures. From 1968 to 1983, total PLN generation increased an average of 14 percent per year. To accomplish this rate of growth, generating capacity has to double every five years.

The Indonesian economy is still at an early stage of industrialization, a stage in which each percent increase in GDP requires significantly more than a one percent increase in electricity consumption. The World Bank has estimated that investment in the energy sector should grow from about US$1.27 billion in 1980 to about $10 billion in 2000[49]. Roughly one half of that investment will be for the power sector.

The growth of electricity demand relative to the future growth of the economy will depend on the sectoral structure of economic growth. Nonetheless it is likely that electricity demand will grow anywhere from 10 percent to 30 percent faster than the overall economy. Thus the electricity sector will require a larger and larger share of total national investment.

At the same time, particularly because of the world oil situation, Government resources have dwindled. Foreign exchange earnings from oil and gas exports this past fiscal year (ending March 31, 1987) dropped 43 percent from a year earlier. The country's foreign debt increased by $9.3 billion between 1984 and 1986, leading to an increase in the debt service ratio from 18 percent in 1985/86 to 29 percent last year. That ratio is expected to increase significantly again this year - to around 40 percent. If private capital (separate from Government guarantees) can be used to finance a part of power sector investment, the pressure to cut back on socially important programs such as health and education will be relieved.

A second reason for encouraging private investment in the power sector is that there are major opportunities for increasing the overall efficiency of the system which can best be accomplished through private investment. These opportunities exist through the production of power for sale to the grid as an integral part of cogeneration in certain industries.

Thirdly, because of the small scale of many private power opportunities it is possible for PLN to bring on new capacity - through contracts with private producers - more quickly than would otherwise be the case and in a way which matches load growth.

Finally, through private investment in diesel power systems and in power systems using resources such as agricultural wastes and waste from the wood products industry, power can be brought to rural areas more rapidly than currently planned. Rural electrification can be accomplished in certain areas at very low cost to the Government and, if renewable energy sources are used, without use of exportable fossil fuels.

Indonesia is not the only country in which there is new interest in private investment in the power sector. In some parts of the U.S., particularly in California and Texas, a significant fraction of the additions to generating capacity over the last eight years has been through private investment in plants which sell their power to the local (generally privately-owned) utility. Other countries with significant private power programs are Ireland, Turkey, Chile, Pakistan, New Zealand and the Philippines. The British Government is moving towards the privatization of the generating side of its national power company.

Nor is the power sector unique in seeing a shift from debt to equity financing. Because of the general financial conditions of many developing countries, commercial banks in the U.S. have written off large amounts of Third World debt holdings. Equity investment, on the other hand, has remained strong, with the result that last year, according to IMF figures, such investment was four times as large as new loans.

There are also potential disadvantages of private investment in the power sector. Private capital usually costs more than the capital made available to PLN and, other things being equal, prices must eventually reflect that difference. Available, reliable low cost electricity is an important need of the society. The Government must have the final obligation to see to it that the power sector fulfills its critical role in national development. The issue, therefore, is not all private or all public power, but rather whether the total cost of providing power to the people of Indonesia can be reduced by making selective use of private investment.

Government policy clearly supports the concept of independent power production. Law No. 15 of 1985 on the Power Sector specifically stipulates that "the widest possible opportunity shall be given to cooperatives and other enterprises to provide power" for public use. Thus far, however, little benefit has accrued from the application of this provision of Law No. 15. The general purpose of the study reported here was to investigate benefits that could accrue to Indonesia from a fuller application of Law No. 15 and the factors which have inhibited its application to date.

## B. STUDY OBJECTIVES

This report is the result of a three week preliminary investigation of these issues carried out during July 1987. The specific objectives of the study were to:

- identify the potential benefits of private investment in the power sector;
- identify in a preliminary way the technical potential for cogeneration and private sector power production from renewable energy resources;
- analyze the economic and financial climate and its implications for private investment in power production;
- identify the policy, regulatory, institutional and other impediments to non-utility private power generation;
- develop a series of recommendations and an action plan for addressing the impediments to non-utility generation.

The study was initiated by the Directorat Jenderal Listrik dan Energi Baru (DJLEB), Ministry of Mines and Energy. Funding was provided by the U.S. Agency for International Development. The study was carried out by a team managed by Energy/Development International (E/DI) working in close collaboration with senior staff of DJLEB.

The next section of the report briefly summarizes the energy situation in Indonesia and, in particular, the power sector. It also provides a concise review of independent power generation in the U.S. and other countries. Chapter IV presents the results of the assessment of the potential for private investment in large scale power production in Indonesia and in cogeneration and biomass energy systems. An examination of the financial and investment climate follows in Chapter V. The report concludes with a set of conclusions and recommendations.

# III. THE ELECTRIC POWER CONTEXT

## A. ELECTRIC POWER IN INDONESIA

### 1. The Institutional Structure

PLN (Perusahaan Umum Listrik Negara) is a public corporation (Perum) in the power sector. It was created in 1961 from three Dutch owned power companies on Java. In 1972 it was given its present form and the objective "to supply electric power and its related services in adequate quantity and quality and at the proper time, in order to improve the rural and urban standard of living and to promote economic activities".

The power subsector is regulated by the Ministry of Mines and Energy (MME) through the Director General of Electric Power and New Energy (DJLEB). MME is the body which reviews tariff proposals and proposals by cooperatives and private power producers.

The basis for private investment in the power sector is established in Law No. 15, 1985 on The Power Sector. Until promulgation of this law, the power sector was regulated under an ordinance dating to 1890. That ordinance had been updated several times, of course - the latest in 1934. A series of Presidential Decrees, have, over the years, also guided the development of the power sector.

Law No. 15 of 1985 clearly provides for private investment in the power sector. Article 7, section (2) states:

> In an effort to meet power needs in a more equal manner and to further improve the capability of the Government to provide power as referred to in Article 6 paragraph (2), for public use as well as own use, insofar as the

interests of the Government are not harmed, the widest possible opportunity shall be given to cooperatives and other enterprises to provide power based on the PEP (Power Enterprise Permit).

Law No. 15 is reproduced in Appendix B.

## 2. The Current Situation

Power consumption has grown rapidly over the last several years as an integral and necessary element in Indonesia's economic growth. Between 1980 and 1986 electricity consumption (including captive power) grew at an effective compound rate of 18 percent per year. This figure includes captive power but does not include small private producers which have grown even faster. During this same period GDP grew at a compound rate of "only" 12 percent per year(46).

In 1986 the total electric power consumption in Indonesia was estimated as 32.6 TWh (TWh = terawatt-hrs = $10^9$ kWh)(11). Of this PLN provided 14.6 TWh (a reasonably accurate number), and captive power users produced about 18 TWh for their own use (a rough estimate). Cooperatives provided 0.02 TWh. The distribution by type of consumer is given in Table 1. Note that an estimated 73 percent of industrial power consumption is provided by the industries themselves.

Approximately 38 percent of PLN-supplied power on Java is consumed by industry. Households account for 40 percent. Off-Java, the industrial fraction of PLN sales is only 22 percent, with households consuming 52 percent. This difference is a major reason for the low average system load factor outside Java, 58 percent, compared with 68 percent for the Java system. The load factor difference, in turn, contributes to the higher cost of supplying power off Java.

**TABLE 1**

**Electricity Consumption by Source and Sector - 1986**

**(TWh)**

| Sector | PLN | Others[c] | Total TWh | Total % |
|---|---|---|---|---|
| Households | 5.5 | 0.9 | 6.4 | 19.7 |
| Industry | 6.3 | 17.1 | 23.4 | 71.7 |
| Commerce[a] | 1.2 | small | 1.2 | 3.7 |
| Public Uses[b] | 1.6 | small | 1.6 | 4.9 |

Notes:

a. offices, shops, hospital, etc.

b. government buildings, street lighting, etc.

c. estimated

Source: A. Arismunandar, Reference 11

Table 2 indicates how PLN and non-PLN sales are distributed by region. Note that, in 1986, 79 percent of PLN's sales were on Java. (Java holds 61 percent of the population.)

In 1986 PLN had an installed capacity of 5240 MW. Table 3 gives the fuel mix of that generation. As shown there, oil steam plants account for 32 percent of capacity. Nearly 64 percent of the PLN capacity relies on petroleum fuels. When captive power plants, which mostly use diesel fuel, are included, the petroleum fraction increases to around 79 percent. Cooperatives had an installed capacity of 5.7 MW while other entities (mostly private and state-owned industries) had an installed capacity of 5379 MW. Table 4 indicates how these capacities are distributed regionally. In addition, it is estimated that small, private entities selling power for local public use owned generators totalling about 58 MW.[11]

**TABLE 2**

**Electric Power Consumption by Source and Province - 1986**

| PLN REGIONS | PROVINCE | PLN TWh | PLN % | NON-PLN TWh | NON-PLN % | TOTAL TWh | TOTAL % | POPULATION Million | kWh/CAP |
|---|---|---|---|---|---|---|---|---|---|
| I | Aceh | 0.09 | 0.61 | 0.75 | 4.19 | 0.84 | 2.58 | 3.08 | 272.73 |
| II | Sumatera Utara | 0.84 | 5.74 | 2.37 | 13.23 | 3.21 | 9.86 | 9.66 | 332.18 |
| III | Sumatera Barat | 0.34 | 2.32 | 0.96 | 5.36 | 1.30 | 3.99 | 3.85 | 202.18 |
| | Riau | | | | | | | 2.58 | |
| IV | Sumatera Selatan | 0.50 | 3.42 | 0.89 | 4.97 | 1.39 | 4.27 | 5.58 | 93.92 |
| | Bengkulu | | | | | | | 0.98 | |
| | Lampung | | | | | | | 6.42 | |
| | Jambi | | | | | | | 1.82 | |
| V | Kalimantan Barat | 0.08 | 0.55 | 0.26 | 1.45 | 0.34 | 1.04 | 2.82 | 120.57 |
| VI | Kalimantan Selatan | 0.33 | 2.25 | 0.31 | 1.73 | 0.64 | 1.97 | 2.33 | 123.55 |
| | Kalimantan Tengah | | | | | | | 1.16 | |
| | Kalimantan Timur | | | | | | | 1.69 | |
| VII | Sulawesi Utara | 0.14 | 0.96 | 0.06 | 0.33 | 0.20 | 0.61 | 2.41 | 49.88 |
| | Sulawesi Tengah | | | | | | | 1.60 | |
| VIII | Sulawesi Selatan | 0.33 | 2.25 | 0.76 | 4.24 | 1.09 | 3.35 | 6.67 | 139.92 |
| | Sulawesi Tenggara | | | | | | | 1.12 | |
| IX | Maluku | 0.05 | 0.34 | 0.13 | 0.73 | 0.18 | 0.55 | 1.66 | 108.43 |
| X | Irian | 0.06 | 0.41 | 0.02 | 0.11 | 0.08 | 0.25 | 1.36 | 58.82 |
| XI | Bali | 0.28 | 1.91 | 0.18 | 1.00 | 0.46 | 1.41 | 2.71 | 48.47 |
| | Nusa Tenggara Barat | | | | | | | 3.11 | |
| | Nusa Tenggara Timur | | | | | | | 3.05 | |
| | Timor Timur | | | | | | | 0.62 | |
| | Jawa | | | | | | | | |
| | Jawa Timur | 2.74 | 18.72 | 1.75 | 9.77 | 4.49 | 13.79 | 31.64 | 141.91 |
| | Jawa Bagian Barat | | | | | | | | |
| | Jawa Tengah & Yogja | 1.74 | 11.89 | 1.34 | 3.08 | 3.08 | 9 46 | 30.66 | 100.46 |
| | Jakarta Raya | 4.57 | 31.22 | 2.52 | 7.09 | 7.09 | 21.78 | 8.16 | 868.87 |
| | Jawa Barat | 2.55 | 17.42 | 5.62 | 8.17 | 8.17 | 25.09 | 31.88 | 256.27 |
| | Indonesia | 14.64 | 100.00 | 17.92 | 100.00 | 32.56 | 100.00 | 168.62 | 193.10 |

Source: DJL, PLN, BPS as quoted in Arismundar, Reference 11.

**TABLE 3**
**PLN's Generating Capacity**
**(March 31, 1986)**

| Type | Java | Outside Java | Total | Percent |
|---|---|---|---|---|
| Steam (coal) | 800 | - | 800 | 15.3 |
| Steam (oil) | 1500 | 180 | 1680 | 32.0 |
| Gas turbines | 630 | 300 | 930 | 17.7 |
| Diesel | - | 740 | 740 | 14.1 |
| Hydro | 881 | 185 | 1066 | 20.3 |
| Geothermal | 30 | - | 30 | 0.6 |
| TOTAL: | 3841 | 1399 | 5240 | 100.0 |

Source: PLN, quoted in reference 20

Currently there is some excess capacity on the Java system. This results from two factors. The first is lower electricity demand growth rates compared to recent projections due to the slow-down in the economy. The second reason is the coming on line of a Saguling hydro unit of 350 MW and the 400 MW coal-fired Suralaya unit #2. Even optimal construction schedules will lead to periods of excess capacity when large plants are being brought on line.

**TABLE 4**
**Installed Capacity by Owner and Province - 1986**

| PLN Regions | Province | PLN MW | PLN % | NON-PLN MW | NON-PLN % | Cooperatives MW | Cooperatives % | TOTAL MW | TOTAL % |
|---|---|---|---|---|---|---|---|---|---|
| I | Aceh | 47.20 | 0.87 | 264.10 | 4.61 | | | 311.30 | 2.78 |
| II | Sumatera Utara | 398.40 | 7.31 | 828.70 | 14.47 | | | 1227.10 | 10.97 |
| III | Sumatera Barat | 198.00 | 3.63 | 336.60 | 5.88 | | | 534.60 | 4.78 |
| | Riau | | | | | | | | |
| IV | Sumatera Selatan | 235.90 | 4.33 | 313.90 | 5.48 | | | 549.80 | 4.91 |
| | Bengkulu | | | | | | | | |
| | Lampung | | | | | | | 1.70 | 0.02 |
| | Jambi | | | | | 1.70 | 29.82 | | |
| V | Kalimantan Barat | 48.00 | 0.88 | | | | | 138.30 | 1.24 |
| VI | Kalimantan Selatan | 136.30 | 2.50 | 90.30 | 1.58 | | | 245.90 | 2.20 |
| | Kalimantan Tengah | | | 109.60 | 1.91 | | | | |
| | Kalimantan Timur | | | | | | | | |
| VII | Sulawesi Utara | 80.70 | 1.48 | 24.90 | 0.43 | | | 105.60 | 0.94 |
| | Sulawesi Tengah | | | | | | | | |
| VIII | Sulawesi Selatan | 170.50 | 3.13 | 268.10 | 4.68 | 2.10 | 36.84 | 440.70 | 3.94 |
| | Sulawesi Tenggara | | | | | | | | |
| IX | Maluku | 30.80 | 0.56 | 48.10 | 0.84 | | | 78.90 | 0.71 |
| X | Irian | 32.80 | 0.60 | 8.10 | 0.14 | | | 40.90 | 0.37 |
| XI | Bali | 137.70 | 2.53 | 62.10 | 1.08 | | | 199.80 | 1.79 |
| | Nusa Tenggara Barat | | | | | | | | |
| | Nusa Tenggara Timur | | | | | 1.90 | 33.33 | 1.90 | 0.02 |
| | Timor Timur | | | | | | | | |
| | Jawa | 650.40 | 11.93 | 522.60 | 9.12 | | | 1173.00 | 10.48 |
| | Jawa Timur | 3274.90 | 60.06 | | | | | 3274.90 | 29.27 |
| | Jawa Bagian Barat | 7.10 | 0.13 | 402.60 | 7.03 | | | 409.70 | 3.66 |
| | Jawa Tengah & | | | 758.20 | 13.23 | | | 758.20 | 6.78 |
| | Yogja | 4.30 | 0.08 | 1691.00 | 29.52 | | | 1695.30 | 15.15 |
| | Jakarta Raya | | | | | | | | |
| | Jawa Barat | | | | | | | | |

Source: DJL, PLN, BPS as quoted in Arismundar, Reference 11.

## 3. The Future Development of the System

Per capita electricity consumption is still low in Indonesia compared with other developing countries at comparable levels of economic development and in comparison with other ASEAN countries. Furthermore, Indonesia is at a stage of industrial development in which growth of electricity consumption is expected to continue to exceed the growth of GDP. Over the long term (to 2015) "low growth" scenarios imply annual growth rates of consumption of 6 - 8 percent or a doubling of installed capacity about every 10 years. Near term growth rates, however, because of the above factors, are expected to be considerably higher.

Tables 5 and 6 show current "base case" electricity demand projections for the PLN Java system and for all of Indonesia, respectively. The projections are based on sectoral economic growth projections and assumptions about the rates of investment in rural electrification. These projections are somewhat lower than those used in the most recent five year plan, Repelita IV (starting in April 1, 1984) because of the recent slow-down in economic growth; budgetary constraints on new investment; and delays in project implementation (see Section 3.1.12).(20) For the overall system the projected average growth rate is 13 percent per year.

**TABLE 5**

**PLN Electricity Sales, Projections and Capacity Expansion**

**Java System**

| | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|---|---|
| Sales, GWh | 10,052 | 11,661 | 13,477 | 15,438 | 17,421 | 19,450 | 21,619 | 24,029 | 26,672 |
| Peak Load, MW | 2,245 | 2,527 | 2,918 | 3,306 | 3,688 | 4,067 | 4.472 | 4,970 | 5,517 |
| Installed Capacity, MW | | | | | | | | | |
| Hydro | 881 | 1,231 | 1,231 | 1,760 | 1,940 | 2,052 | 2,052 | 2,052 | 2,552 |
| Oil/Steam | 1,500 | 1,700 | 1,850 | 1,850 | 1,800 | 1,800 | 1,800 | 1,800 | 1,800 |
| Coal/Steam | 800 | 800 | 800 | 1,200 | 1.600 | 1,600 | 1,600 | 2,400 | 2,800 |
| Geothermal | 30 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| Gas Turbine | 630 | 630 | 630 | 630 | 545 | 520 | 520 | 480 | 440 |
| TOTAL | 3,841 | 4,651 | 4,651 | 5,580 | 6,025 | 6,112 | 6,112 | 6,872 | 7,732 |

Source: PLN/World Bank

Reference 20

**TABLE 6**

**PLN Electricity Sales, Projections and Capacity Expansion**

**Total System**

| | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|---|---|
| Sales, GWh | 12,705 | 14,694 | 16,967 | 19,430 | 21,983 | 24.656 | 27,560 | 30,762 | 34,280 |
| Peak Load, MW | 2,978 | 3,321 | 3,814 | 4,309 | 4,808 | 5.337 | 5,884 | 6,530 | 7,279 |
| Installed Capacity, MW | | | | | | | | | |
| Hydro | 1,060 | 1,416 | 1,433 | 1,963 | 2,200 | 2.438 | 2,437 | 2,437 | 3,077 |
| Oil/Steam | 1,680 | 1,880 | 2,030 | 2,030 | 2,110 | 2,110 | 2,110 | 2,110 | 2,110 |
| Coal/Steam | 800 | 800 | 930 | 1,330 | 1,730 | 1,730 | 1,780 | 2,630 | 3,130 |
| Geothermal | 30 | 30 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| Gas Turbine | 930 | 930 | 930 | 930 | 845 | 820 | 805 | 701 | 607 |
| Diesel | 740 | 1,139 | 1,444 | 1,570 | 1,588 | 1,655 | 1,667 | 1,722 | 1,725 |
| TOTAL | 5,240 | 6,195 | 6,907 | 7,963 | 8,613 | 8,893 | 8,939 | 9,740 | 10,789 |

Source: PLN/World Bank

Reference 20

Table 5 also shows the projected additions to capacity between now and 1994. These additions take into account current excess capacity and correspond to the least-cost capacity expansion plan. Capacity is assumed to grow somewhat slower than demand due to reductions in transmission and distribution losses, and, some improvement in load factor off Java (from 58 percent in 1987 to 61 percent in 1994). Table 7 gives the generation mix projected for 1994. Note that the dependency on petroleum fuels is projected to fall to 41 percent (from 64 percent in 1986).

Table 8 shows the investment required to fulfill this capacity expansion program. The total is over $12 billion, of which $6.6 billion is foreign exchange. Approximately half of the total is for generation ($6.4 billion), the remainder for transmission and distribution expansion and upgrading.

**TABLE 7**
**Projected PLN Generating Capacity, March 31, 1994**
**(MW)**

| Type | Java | Outside Java | Total | Percent |
|---|---|---|---|---|
| Steam (coal) | 2800 | 330 | 3130 | 29 |
| Steam (oil) | 1800 | 310 | 2110 | 20 |
| Gas Turbines | 400 | 167 | 607 | 6 |
| Diesel | | 1725 | 1725 | 16 |
| Hydro | 2552 | 525 | 3077 | 28 |
| Geothermal | 140 | | 140 | 1 |
| TOTAL | 7732 | 3057 | 10,789 | 100 |

**TABLE 8**
**Investment Program**
**$Million**

| | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|
| Generation | | | | | | | | | |
| Foreign Exchange | 502.8 | 450.7 | 441.1 | 443.7 | 523.2 | 637.3 | 662.7 | 698.7 | 4,360 |
| Local Currency | 219.1 | 234.4 | 204.6 | 199.2 | 249.7 | 279.6 | 315.7 | 339.7 | 2,042 |
| Total | 721.9 | 685.1 | 645.7 | 642.9 | 772.9 | 916.9 | 978.4 | 1,038.4 | 6,402 |
| Transmission, Distrib. | | | | | | | | | |
| Foreign Exchange | 277.9 | 220.9 | 267.4 | 327.1 | 372.1 | 304.5 | 286.9 | 217.2 | 2,274 |
| Local Currency | 383.8 | 398.8 | 462.3 | 524.6 | 551.1 | 550.9 | 577.2 | 389.9 | 3,839 |
| Total | 1,384. | 1,305. | 1,375. | 1,495. | 1,696. | 1,772. | 1,843. | 1,646. | 12,515 |

Source: PLN/World Bank
Reference 20

## 4. The Rural Electrification Program

In Indonesia, as in most developing countries, the electrification of rural areas is a high national priority. It is a program, however, in which social and political objectives are constantly confronted by financial limitations.

Despite major investment in extension of the PLN grid between 1976 and 1986, estimates of total households with access to electricity range from 8 to 14 percent. A more significant number in terms of the potential for private investment is the fraction of villages that are supplied with electricity. It has been estimated that 44 percent of villages are electrified. Of those, less than one half (about 18 percent) have been electrified by PLN.

In Repelita IV, rural electrification was to receive 19 percent of PLN's budget, or 2 percent of total public investment funds. The Government also has plans for rural electrification to expand from a targeted 14 percent (1985/86) to 21 percent of all households by 1994.

## 5. Financial Constraints

Expansion of the electricity sector in Indonesia requires heavy investment. The investment problem is made more difficult by the policy of the Government to keep tariffs uniform throughout the system. This requires a subsidy of the power sector - or at least of the rural electrification portion of the power sector. It should be noted that this is not an uncommon policy, and is a relatively straight-forward means of accomplishing equity objectives and subsidizing rural development. Indonesia currently is shackled by a set of economic constraints that include the temporary decline in government revenues, limited access of PLN to financing due to the country's reluctance to take on further international debt, and substantial operating losses incurred by the PLN system.

Given Indonesia's repressed economy, the Government has had little choice but to curtail part of its ambitious expansion plans for the electricity sector. The substantial reduction in government revenues in the first two years of Repelita IV resulted in actual expenditures on electricity of only 75 percent of the planned levels and 50 percent for 1985/86. This has caused major delays in project implementation.

## 6. Power Purchases by PLN

In addition to a large number of captive power installations that are independent of the PLN grid, several major facilities are connected to the grid and sell power to PLN on a regular basis. These include:

| | Installed Capacity |
|---|---|
| Larona Hydro Power Plant | 165 MW |
| Krakatau Steel Steam Plant | 400 MW |
| Asahan Hydro Power Plant | 603 MW |
| Juanda Hydro Power Plant | 150 MW |
| Aneka Tambang Diesel Power Plant | 32 MW |
| Indocement Diesel Power Plant | 90 MW |
| Total | 1440 MW |

From all evidence at hand the PLN dispatch system has no difficulty accepting power from these plants. This is an important point relative to future investment in new power facilities. The prices paid for power from these facilities vary widely. In general they are based on the cost of production at the plant.

## 7. The PLN System and Private Investment

From the perspective of private investment in the power sector it is useful to distinguish two aspects of PLN's system:

1. That portion, or subsystem which depends on large scale central station power plants which supply power to large and small consumers through a highly interconnected grid. This portion of the PLN system has long-run marginal production costs determined by the lowest cost of new, central station (probably gas or coal-fired) power plants.

   The growth of demand in this portion of the system is determined primarily by economic factors: population, incomes and growth of the economy, as well as the price and reliability of electricity supplied. Reliability particularly affects the amount of "captive" generation installed by industry and the replacement of that capacity by PLN. Because of the nature of the supply system and the density and characteristics of demand, PLN's costs per kWh sold are comparable to its revenues.

   This portion of the system can be termed the urban/industrial portion and to some degree can be identified with the Java interconnected system.

2. That portion intended to supply electricity to rural areas either by extension of the central grid or by isolated, small scale power units. This portion of the system often has long run marginal production costs which are considerably higher than the first, often related to new diesel generation.

The growth of consumption is, to a large degree, determined by the rate of investment in new generation and distribution facilities. There is a higher fraction of residential (rather than industrial and commercial) customers. The demand is more dispersed in both space and time. Since the tariff structure is the same for the urban/industrial portion, average revenues per kWh sold are lower; costs are higher.

This is the rural electrification portion of the PLN system.

Quite different considerations apply to private investment in these two " subsystems". In the urban/industrial, interconnected portion, privately-financed additions to the system would most likely be highly integrated and under the dispatch control of PLN. Presumably these would be entities selling power to the PLN grid. There is also the possibility in industrial areas to create industrial parks with independent power systems with emphasis on reliable, high quality supply. In rural areas, it is possible to conceive of a private entity electrifying a new area (as agreed to by PLN or the Ministry of Mines and Energy). There are also extensive PLN grids in areas off Java, of course, and sales to PLN in those areas is another option.

There is an important principle which applies to the evaluation of private power proposals in both of these subsystems. From the point of view of the national welfare, the basic investment criterion should be whether the private producer can supply power at a cost which is equal to or lower than PLN's long run marginal cost. In the past, two other criteria seem to have dominated the consideration of rate proposals from cooperatives or purchase agreement by PLN: the PLN tariff structure and the producer's cost of production. Although the latter is a legitimate concern, neither of these should be dominant.

Other considerations enter the picture if, as now appears to be the case, lack of capital is a significant constraint on the growth of power supply. In that case, PLN's marginal costs of supply may be purely theoretical and a more basic - and more difficult -

calculation must be made, namely what is the value to the economy of incremental power supply. The more general criteria then become the supply of power at reasonable cost and the overall mobilization and efficient allocation of private and public resources.

It is Government policy to maintain uniform electricity tariffs throughout the country. This policy derives from equity considerations, developmental objectives (e.g. rural development) and political considerations. These objectives are, of course, generally in conflict with marginal cost pricing objectives and trade-offs are necessary. In Indonesia, the result is that, although tariffs are reasonably close to long run marginal costs on the Java interconnected grid, tariffs in the rural electrification portion of the system are far from those required to cover costs.

In the rural electrification subsystem, where PLN's marginal costs are well above revenues (as determined by tariffs), it is often possible for private entities to produce power at comparable, or even lower cost than PLN. The latter is possible when power production is connected to some industrial activity, e.g., in the case of cogeneration, or when fuel is available at low cost, for example at a rice mill or saw mill. It would be virtually impossible, however, for most private producers to sell power at a profit at the current PLN tariff structure.

This situation presents an issue for Government policy. Let us assume that the Government decides to encourage private investment in power production in rural areas. Such investment would occur only if they allow rates higher than current PLN tariffs (as is now the case both for electric cooperatives and for small private producers). Such a policy would accelerate the pace of rural electrification at the cost of somewhat higher rates but with little incremental cost to the Government. For reasons mentioned above, however, the Government may want to maintain rural tariffs close to current PLN tariffs. In this case a subsidy scheme will have to be developed. This could be implemented in a variety of ways, for example through operational subsidies or through a contribution to the financing of generation or transmission/distribution.

## 8. Electricity Prices

Since 1972 the basic principle of electricity pricing has been that sufficient revenue be earned by PLN to defray all costs, including proper maintenance and depreciation costs, payment of interest and taxes, as well as having reasonable surplus to finance part of the expansion work and debt repayment.

The present basic tariff is the Basic Tariff Schedule (Tarip Dasar Listrik) 1986, which has been effective since August 1986, following the local fuel price increases in July 1986.

The TDL's tariff structure was set with the objectives of subsidizing low income families, enhancing the growth of the industrial sector and coping with PLN financial requirements in FY 1986/1987.

The tariff comprises 17 consumer categories and 6 consumer groups as follows:

| | | |
|---|---|---|
| 1. | Small consumers and social institutions | (S1 and S2) |
| 2. | Residential use | (R1, R2, R3 and R4) |
| 3. | Commercial use | (U1, U2, U3 and U4) |
| 4. | Industrial | (I1, I2, I3 and I4) |
| 5. | Government offices | (G1 and G2) |
| 6. | Street lighting | (J) |

The tariffs are shown in Table 9.

**TABLE 9**
**Tariff Schedule 1986**
**(effective August 1986)**

| No. | Code | Contracted Power | Demand Charge Rp/kVa | Energy Charge Rp/kWh |
|---|---|---|---|---|
| 1. | S1 | to 200 VA | * | - |
| 2. | S2 | 250 VA - 200 kVA | 2.100,00 | 43.50 |
| 3. | R1 | 250 VA - 500 VA | 2.100,00 | 70.50 |
| 4. | R2 | 501 VA - 2,200 VA | 2.100,00 | 84.50 |
| 5. | R3 | 2,201 VA - 6,600 VA | 3.680,00 | 126.50 |
| 6. | R4 | 6,601 VA and over | 3.680,00 | 158.00 |
| 7. | U1 | 250 VA - 2,200 VA | 3.680,00 | 134.00 |
| 8. | U2 | 2,201 VA - 200 kVA | 3.680,00 | 150.00 |
| 9. | U3 | 201 kVA and over | 2.300,00 | P = 158.00 |
| | | | | OP = 99.00 |
| 10. | U4 | 450 VA and over | - | 307.00 |
| 11. | I1 | to 99 kVA | 2.300,00 | P = 97.50 |
| | | | | OP = 60.50 |
| 12. | I2 | 100 kVA - 200 kVA | 2.300,00 | P = 92.50 |
| | | | | OP = 57.50 |
| 13. | I3 | 201 kVA and over | 2.100,00 | P = 90.50 |
| | | | | OP = 56.00 |
| 14. | I4 | 5,000 kVA and over | 1.970,00 | P = 77.00 |
| | | | | OP = 48.50 |
| 15. | G1 | 250 VA - 200 kVA | 3.680,00 | 96.00 |
| 16. | G2 | 201 kVA and over | 1.970,00 | P = 99.00 |
| | | | | OP = 65.00 |
| 17. | J | - | - | 76.50 |

*= Tariff S1 = 60 VA = Rp. 1.550,00/month
75 VA = Rp. 1,940,00/month
100 VA =

The basic tariff is set in terms of a demand charge which relates to the installed capacity of the service (VA) and an energy charge which related to kWh consumption, with the exception of S1 (fixed VA connection) and J and U4 (energy charge only).

Industrial and large consumers (U3 and G2) are charged time of day rates through peak and off-peak tariffs. The peak rate is about 1.6 times the off-peak rate and the peak period is between 18:00 and 22:00 hrs.

Electricity prices have been raised by some 130 percent since 1981 to the current "average price" (revenue per kWh sold) of 96 Rp/kWh (5.6 cents/kWh). Before the devaluation of September 1986 the World Bank estimated that that price was some 15 percent lower than long run marginal costs. The devaluation has increased that difference to over 20 percent.

Current policy development is leading to a system of financial requirements for PLN which differentiates between their Java and their off-Java operations. On Java the objective will be to attain an 8 percent annual rate of return. Off-Java the objective will be to produce total revenues at least equal to total operating expenses plus debt service less depreciation.

In 1985/86 PLN's operation on Java was profitable showing a rate of return of close to 5 percent. It is estimated that the rate has increased to over 6.5 percent in 1986/87. Thus the objectives of an 8 percent return appears attainable with expected efficiency improvements and modest tariff increases. Off Java, however, the situation is more difficult. In 1985/86 operating revenues were Rp 282 billion and expenses were Rp 386 billion, for a loss of Rp 104 billion. That loss increased to around Rp 160 billion in 1987 on estimated revenues of Rp 319 billion. Thus, simply to cover expenses off-Java, rates off-Java would have to be increased by 50 percent.

## 9. Rural Energy Cooperatives

In 1978 a pilot program on rural energy cooperatives was launched by the Government of Indonesia with support from USAID. The program had two components: a group of electrification projects in Central Java tied to the PLN grid and three electrical cooperatives on other islands. It is the latter which are of most interest for this study.

The rural electrical cooperatives are located at Lampung (southern Sumatra), Lombok (West Nusa Teuggara) and Luwu (South Sulawesi). Each cooperative owns and operates its own diesel generators. The purchase and installation of this equipment, along with distribution and house wiring were financed through a combination of USAID and government loans, and were supported by USAID-funded technical assistance.

Not surprisingly, this somewhat innovative project experienced considerable delays in implementation. The original intent was to have the cooperatives in operation by 1983; when USAID project financing was ended at the end of December 1984, the combined projects were estimated to be only 35% complete(22).

These projects have been financed by a combination of Government of Indonesia and USAID soft loans. The average revenues per kWh received by the cooperatives range from 162 Rp/kWh in Lombok to 201 Rp/kWh in Luwu. Currently, even with concessional financing, and tariffs considerably higher than PLN's the cooperatives are not financially viable. In part this is due to a customer base much lower than projected. The National Rural Electric Cooperative Association (of the U.S.) has analyzed the rates required to achieve financial break-even if customers continue to expand, increased financing is forthcoming from the Government and the grace period on the Indonesian loan is extended to 9 years(27, 28, 29). Those rates are given in Table 10.

**TABLE 10**
**Cooperatives Revenue Requirement Per kWh Sold**
**1989 Projections**

| | Average Tariffs, Rp/kWh | | |
|---|---|---|---|
| | | Total | |
| Cooperative | Residential | 1985 | 1989 |
| Lampung | 181 | 163 | 171 |
| Lambok | 183 | 162 | 174 |
| Luwu | 244 | 201 | 230 |

The World Bank has suggested several other reasons for the inefficiency of the rural electrical cooperatives(9):

- o Complex budgetary and procurement procedures
- o Shortage of technical and managerial expertise
- o Lack of of base-load or industrial consumers.

## 10. Rural Private Power Production

In addition to the official rural electrification program of PLN and the Ministry of Cooperatives there are literally thousands of unregulated private electricity producers throughout Indonesia providing small amounts of power to villagers. By law, if it operates at a power level below 5 kVa, a private producer needs no license and can set its own tariffs. According to surveys by Biro Pusat Statistik in 1982-1984, although there is a wide range of prices being charged by these "mini-power companies", their average rates in that period were roughly twice that charged by PLN to small residential customers(42).

A more recent survey by Biro Pusat Statistik provides very useful information on some 10,000 non-PLN power producers throughout Indonesia(23). These companies sold an aggregate of 29,162 MWh in the three months of 1985 preceding the survey. This corresponds to an annual sales level of some 117,000 MWh per year or 1 percent of PLN's sales.

Total revenues from these sales were 6,822 billion Rp, corresponding to a revenue per unit of sales of 234 Rp/kWh (calculated by taking the total revenues divided by the total sales). As shown in Table 11, however, there were large variations around that aggregate. In fact, if one calculates the average over regions of revenue per kWh sold (by calculating that quantity for each region and then taking the average) one arrives at a figure of 293 Rp/kWh. The difference results from the fact that in several regions in which there were high sales, such as Central Java and South Sumatra, tariffs were relatively low.

**TABLE 11**

**Average Unit Revenues for Private Power Producers**

| Province | No. of Companies | Sales, ('000)Kwh | Revenues Rp('000) | Rp/ KWh |
|---|---|---|---|---|
| Aceh | 755 | 1,478 | 402,397 | 272 |
| North Sumatra | 170 | 327 | 193,379 | 591 |
| West Sumatra | 451 | 5,844 | 815,912 | 140 |
| Riau | 695 | 1,134 | 405,002 | 357 |
| Jambi | 471 | 698 | 192,708 | 276 |
| South Sumatra | 1,473 | 3,501 | 740,362 | 211 |
| Lampung | 371 | 873 | 249,608 | 286 |
| North Java | 210 | 810 | 232,438 | 287 |
| Central Java | 195 | 3,681 | 546,578 | 148 |
| Jogjakarta | 32 | 62 | 21,449 | 346 |
| EastJava | 2,000 | 5,812 | 1,660,536 | 286 |
| East Nusa Tenggara | 104 | 136 | 29,262 | 215 |
| North Kalimantan | 390 | 560 | 199,468 | 356 |
| Central Kalimantan | 247 | 579 | 201,425 | 348 |
| South Kalimantan | 327 | 561 | 120,759 | 215 |
| East Kalimantan | 336 | 1,241 | 304,732 | 246 |
| North Sulawesi | 404 | 293 | 110,551 | 377 |
| Central Sulawesi | 91 | 181 | 39,660 | 219 |
| Southeast Sulawesi | 41 | 192 | 92,192 | 480 |
| South Sulawesi | 643 | 1,193 | 263,467 | 221 |
| TOTAL | 9,606 | 29,162 | 6,821,885 | 5878 |

If one considers total revenues derived from sales to households in the sample, unit revenues were 267 Rp/kWh. For industry, the figure is 225 Rp/kWh. The distribution of these figures by region is shown in Table 12.

**TABLE 12**

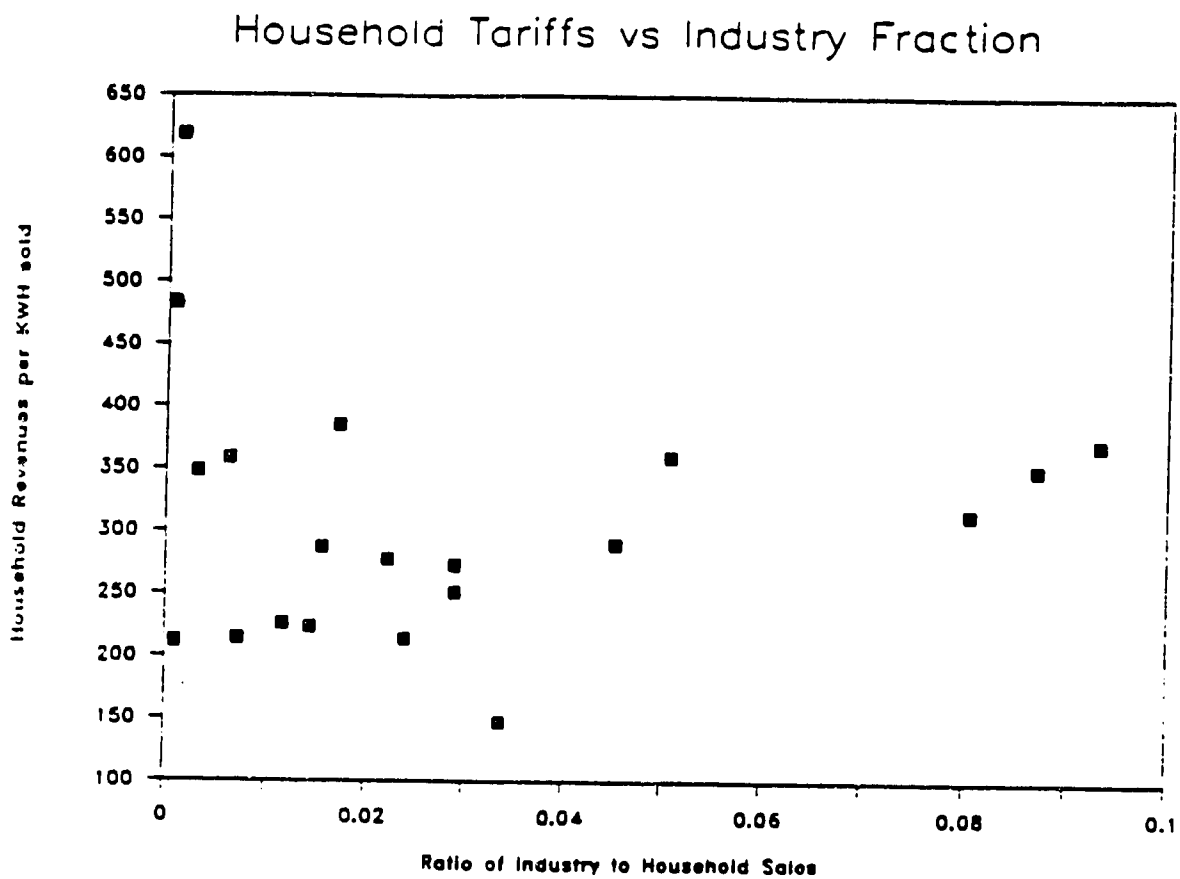
**Unit Revenues from Sales to Households and Industry from Private Power Producers**

| PROVINCE | KWH Household | KWH Industry | Rp(000's) Household | Rp(000's) Industry | Rps/KWH Household | Rps/KWH Industry | KWH Ind/Hld |
|---|---|---|---|---|---|---|---|
| Aceh | 1,321,910 | 29,354 | 367,599 | 8,830 | 278.08 | 300.81 | 0.0222 |
| North Sumatra | 278,917 | 332 | 172,582 | 195 | 618.76 | 587.35 | 0.0012 |
| West Sumatra | 407,229 | 33,453 | 142,998 | 11,433 | 351.15 | 322.48 | 0.0871 |
| Riau | 884,303 | 44,873 | 318,942 | 14,368 | 360.67 | 320.19 | 0.0507 |
| Jambi | 629,378 | 18,241 | 172,164 | 9,000 | 273.55 | 493.39 | 0.0290 |
| South Sumatra | 3,296,552 | 23,565 | 705,661 | 5,391 | 214.96 | 228.77 | 0.0071 |
| Lampung | 766,969 | 34,677 | 222,902 | 9,165 | 290.63 | 264.30 | 0.0452 |
| North Java | 665,600 | 10,378 | 191,642 | 2,673 | 287.92 | 257.56 | 0.0156 |
| Central Java | 3,294,627 | 110,590 | 487.330 | 14,746 | 147.92 | 133.34 | 0.0336 |
| Jogjakarta | 57,454 | 176 | 20,010 | 103 | 348.28 | 585.23 | 0.0031 |
| EastJava | 4,761,463 | 383,751 | 1,500,390 | 70,245 | 315.11 | 183.05 | 0.0806 |
| East Nusa Tenggara | 130.446 | 3,123 | 27,934 | 933 | 214.14 | 298.75 | 0.0239 |
| North Kalimantan | 444,260 | 41,393 | 165,129 | 14,942 | 371.69 | 360.98 | 0.0932 |
| Central Kalimantan | 520,782 | 3,244 | 186,787 | 1,463 | 358.67 | 450.99 | 0.0062 |
| South Kalimantan | 470,478 | 434 | 99,660 | 169 | 211.83 | 389.40 | 0.0009 |
| East Kalimantan | 1,058,197 | 30,701 | 266,233 | 9,802 | 251.59 | 319.27 | 0.0290 |
| North Sulawesi | 270,682 | 4,651 | 104,387 | 1,613 | 385.64 | 346.81 | 0.0172 |
| Central Sulawesi | 160,473 | 2,317 | 33,923 | 234 | 223.86 | 100.99 | 0.0144 |
| Southeast Sulawesi | 184,378 | 109 | 89,216 | 41 | 483.88 | 376.15 | 0.0006 |
| South Sulawesi | 1,088,757 | 12,675 | 246,586 | 2,087 | 226.46 | 164.65 | 0.0116 |
| TOTAL | 20,692,855 | 790,037 | 5,526,075 | 177,433 | | | |
| Average | 1,034,643 | 39,502 | 276,204 | 8,872 | 310.70 | 324.22 | 0.0286 |
| Standard Deviation | | | | | 104.53 | 130.56 | 0.0281 |

Source: E/DI, based on BPS, Reference 23

The data reveal little about the reasons for the wide variations in apparent tariffs. One might expect that regions with greater industrial demand would have lower average cost of supply due to better load factors. However, as shown in Figure 1, there is no correlation between revenues per kWh and the ratio of industry to household sales.

**FIGURE 1**


Household Tariffs vs Industry Fraction
Household Revenuss per KWH sold
650
600
550
500
450
400
350
300
250
200
150
100
0
0.02
0.04
0.06
0.08
0.1
Ratio of Industry to Household Sales

One might also expect that the availability of small scale hydropower might lead to lower costs. Only in West Sumatra did private producers made significant use of hydro resources, however (installed hydro capacity was greater than diesel) and tariffs there were apparently about average.

All of this not withstanding, the existence of these systems - and their continual growth in numbers - provides evidence of wide-spread entrepreneurial skill on the part of the producers; of the availability of capital to invest in small private power schemes; and of the willingness of villagers to pay more than PLN rates for at least small amounts of power. It would be very useful to determine more about the experience of these private power companies including customer satisfaction, their performance, and longevity as a basis for designing an expanded, enlarged and more professional private power industry for rural areas.

In view of the financial constraints on PLN's rural electrification program, the World Bank has suggested basing a new approach to rural electrification on the "willingness and ability of many villagers to devote substantial resources of their own to supply themselves with electricity".(54) As described by the Bank,

> "This will require the implementation of a strategy to mobilize village resources by providing financial incentives for local investors or cooperatives to invest in rural electrification, upgrade their operations and cater to as many customers as possible. It is postulated that the mobilization of village resources can be accomplished through the establishment of village electric organizations (VEOs) owned and operated by villagers, whose main objective would be to supply electricity to a village on a financially self-supporting, administratively autonomous basis. As the VEOs would establish their local systems or take over from PLN the responsibility for the supply of electricity at the village level, PLN's role would be progressively limited to the supply of electricity in bulk."

The implementation of this concept, which has not been accepted by the Indonesian Government, would require a considerably strengthened regulatory and technical support

structure for private power operators in rural areas. Economies of scale and efficiency of operation would suggest systems serving at least 10,000 customers. Thus, new financial facilities would probably be required to mobilize capital beyond the village scale.

## 11. Power Production Costs

As stated above, the first criterion with which to judge the viability of a private power concept is whether the price of delivery, net of taxes, is equal to or less than PLN's long run marginal cost of production. This criterion must then be qualified by other advantages of outside investment and constraints on PLN's ability to add to its system. Clearly the industrial sector, for example, has judged that reliability of supply is of value - indeed of more value than the difference between their own cost of generation and PLN's rates.

Even the basic criterion of cost competitiveness, however, is not straight-forward. It is beyond the scope of this study to evaluate the economics of alternative power fuels and technologies except to note wide differences of opinion on the matter. Five key factors create major differences in relative electricity production costs in Indonesia. First, important variation exists between the relative costs of production from different fuels. Table 9 shows that the ranking of fuels based on unit costs shifts between different studies, depending upon the inclusion or exclusion of important cost components. With the Government trying to assess the least-cost fuel option for PLN, the focus is on coal, nuclear and natural gas cost rankings. In the view of most analysts the main choice is between coal and natural gas (Table 13). Geothermal power is a contender, but with resource and locational constraints.

A second factor, inherent in Table 13 but often overlooked, is the effect of price distortions due to market price subsidies on natural gas and the omission of pollution externalities for coal. It appears that pollution abatement equipment costs are often ignored for coal (not in the World Bank figures cited above), but that the "taxed" price of natural gas for PLN ($US3.00/MMBtu for PLN versus estimated LRMC of $US1.40/MMBtu) are used in most analyses. While such prices may reflect current private market costs, the Government needs to also assess relative energy prices by their long run

economic rather than financial costs. It may be that fuel choices do not change if the Government wants to export natural gas for foreign exchange and insists on minimal coal pollution equipment, but such pricing considerations need overt recognition in the studies.

**TABLE 13**
**Cost of Production vs. Long Run Marginal Cost (LRMC) Estimates by Fuel Source (1987 prices)**

| | Production Costs* PLN/DJLEB | | LRMC** World Bank | |
|---|---|---|---|---|
| Fuel | (Rp/kWh) | (USc/kWh) | (PR/kWh) | (USc/kWh) |
| Diesel (IDD) | 82 | 5.0 | na | na |
| Diesel (HSD) | 82 | 5.0 | na | na |
| Gas Turbine (HSD) | 129 | 7.8 | | |
| Combined Cycle (Nat. Gas) | 80 | 4.9 | 37 | 2.2 |
| Geothermal | 73 | 4.4 | 72 | 4.3 |
| Hydro | 38 | 2.3 | na | na |
| Nuclear | - | - | 84 | 5.1 |
| Steam - | | | | |
| Coal - imported | 53 | 3.2 | | |
| - domestic | 42 | 3.2 | 45 | 2.7 |
| Natural Gas | 53 | 3.2 | na | na |
| RESID | | | 59 | 3.6 |

Assume 1US$ = 1,644 Rp (July 1987): CPI 1,157 (1984-1987) inflating factor for 1984 prices. Revisions based on 1984 prices

na = not available

* includes: Capital, fuel + O&M Costs; p. 413-4. DJLEB, Ministry of Mines and Energy.

** World Bank Report, Indonesia Energy Options Review. Report No. 6583 IND. Energy Division, 1987

Third, on-grid versus off-grid connection also plays a major factor affecting costs of production. A recent study of power alternatives for rural areas, summarized in Table 14, shows that total production costs can be significantly higher than current PLN tariffs[52]. A fourth factor, location, helps to reinforce grid versus off grid gaps. Long run marginal costs are lower on Java than off Java, mainly due to differences in load factor and transmission costs. Finally, another major cost difference can be found between user groups, due in part to economies of scale and location relative to the grid (Table 15). Taken together, these factors suggest that, for Indonesia, costs of production may vary significantly, for valid reasons, due to a variety of geographical and generation characteristics of the electricity sector.

Long run marginal costs are often an appropriate economic criterion for setting the price at which a utility should purchase power from a private producer (see Section B below), then current tariff rates shown in the above tables substantially underestimate the value against which private power costs should compete (see Table 16). Yet such latter values are often given as the yardstick to determine PLN's purchase price. While it generally is accepted that rural electrification rarely pays for itself, PLN's subsidies due to operating losses, sometimes up to 40 percent of its LRMC[24] for rural electrification off-Java, limits its ability to expand service in rural areas. Concurrent with trying to reduce these losses through continued increases in its tariff structure, the Government can encourage private power that will meet rural needs and reduce the pressure on PLN and the Government budget to provide such power.

## 12. The Past Performance of PLN

In judging the performance of PLN it should be recognized that not only is the job of supplying electricity to the Indonesian archipeligo a very difficult one, but also that the modern PLN is a relatively young institution. World Bank and IDA lending to Indonesia began only in 1968. Before about 1973, PLN's financial records were described as "essentially meaningless" and there was no basis for conventional project analysis[55]. The huge job of creating adequate organizational structures, modern management, operational efficiency and an entirely new planning capability was initiated only in the early and mid seventies at the same time that the system was under pressures of rapid growth.

**TABLE 14**

**Estimates of Cost of 50 KW of Power Delivered to Rural Villages[a]**

| Source | Note | Investment $10^6$ Rp/kW | Fuel Cost Rp/kWh | Electricity Cost Rp/kWh |
|---|---|---|---|---|
| Gasifier & Dual Engine | | | | |
| Wood | (b) | 3.45 | 30 | 270 |
| Charcoal | (c) | 2.25 | 77 | 289 |
| Rice Husks | (d) | 2.65 | 38 | 288 |
| Microhydro | | | | |
| Low | | 2.5 | | 164 |
| High | | 3.1 | | 187 |
| Diesel | (e) | 1.8 | 120 | 253 |
| Grid Extension | (f) | 2.87 | 126 | 309 |

Source: BOOM-E/DI; Reference 52

Notes:

a. All cases assume 2400 operating hours per year; 500 households; 120,00 kWh per year at peak operation.

b. Rp 3500/staple meter delivered

c. Rp 87/kg delivered

d. Rp 10/kg delivered

e. Assumes delivered diesel price in remote areas of Rp 300/liter

f. Assumes extension of a single phase 20 kV line for 5 km; load factor of 0.25

**Table 15**

**Long-Run Marginal Costs for Various Consumer Groups**

| | LRMC | |
|---|---|---|
| | (Rp/kWh) | (USc/kWh) |
| Indonesia | | |
| Social | 69-145 | 4.2- 8.8 |
| Residential | 157-260 | 9.6-16.0 |
| Commercial (sm to lg) | 136-240 | 8.3-15.0 |
| Industrial | 88-224 | 5.4-13.6 |
| Government | 146-209 | 8.9-12.7 |
| Java | | |
| Social | 69-142 | 4.2- 8.7 |
| Residential | 116-263 | 7.1-16.0 |
| Commercial (sm to lg) | 138-243 | 8.4-14.8 |
| Industrial | 89-243 | 5.4-14.8 |
| Government | 147-207 | 8.9-12.6 |

Source: BAPPENAS. Analysis of Electricity Pricing. p.176 and 291.

* includes demand and energy changes

**TABLE 16**

**PLN's Estimated Long-Run Marginal Costs of Electricity Production by Time of Day (1987 Prices)**

| | Demand Charge | | Energy Charge | | | |
|---|---|---|---|---|---|---|
| | | | Peak | | Off-Peak | |
| User Level/Category | (Rp/kWh/mo) | (US$/kWh/mo) | (Rp/kWh) | (USc/kWh) | (Rp/kWh) | (USc/kWh) |
| High Voltage | 2,660 | 1.60 | 124 | 7.5 | 76 | 4.7 |
| Medium Voltage | 5,200 | 3.20 | 166 | 10.0 | 87 | 5.3 |
| Low Voltage | 10,900 | 6.60 | 248 | 15.0 | 110 | 6.7 |

Source: BAPPENAS. National Development Planning Agency. Analysis of Electricity Pricing. 1986. p. 172.

The financial performance of PLN improved rapidly in the mid-70's. As a direct result of major increases in tariffs (143 percent between 1973 and 1976), a set of financial targets agreed to with the World Bank in 1973 were actually exceeded. "The financial recovery of PLN from its disorganized situation in 1969 to a position of considerable financial strength by 1976" has been called "one of the most rapid institutional improvements in the (World) Bank's experience of power lending".(55) Several factors, however, have led to a worsening financial situation over the last several years. One of the most important of these has been increased governmental and public concern about increasing tariffs. At the same time, an ambitious rural electrification program has increased the cost per incremental customer supplied. In 1981/82 the self-financing ratio of PLN was 26.5%. This decreased to 18.3% in 1983/84 and further decreased to 14.9% in 1984/85(24).

Since the early 80's, the requirements on management - including financial management - have increased rapidly with the increased complexity of the Indonesian power system. In recent years there has been a rapid increase in the complexity of new plants due to their scale and multiple sources of finance. The interconnected Java grid, with several large plants and a 500 KV line has required sophisticated system management techniques. At the same time, the requirements of rural electrification have led to a large number of (over 630) isolated systems outside Java with attendant complexities of spare part and fuel logistics, management, customer service and financial accounting.

Several factors related to PLN's technical efficiency are shown in Tables 17 (for the entire system) and 18 (for Java). The first two factors, Load Factor and Demand Density, are, at least in part, outside PLN's control. Increases in those factors tend to increase the possible efficiency of the system. Despite a rapidly growing system and the increase in the average unit size (particularly on Java) the average thermal efficiency of the system has not increased as much as might be expected.

Steam plants on the PLN system also have a poor record in terms of plant availability. In the period 1979-83 the average plant availability factor was 74 percent. The long

downtime for scheduled and emergency maintenance have been attributed to a lack of skilled manpower, poor maintenance planning, and cumbersome procedures for procuring spare parts.

**TABLE 17**
**PLN Technical Efficiency Indicators**
**Total System**

| Year | Load Factor (%) | Demand & Density (mWh/km2) | Trans. Distr. Losses (%) | Thermal Effi-ciency (%) | Average Unit Size* (MW) | Thermal Generation Share (%) | Capacity Factor (%) |
|---|---|---|---|---|---|---|---|
| 1965 | 62.3 | 1.05 | 20.4 | na | 25.0 | 49.5 | 30.8 |
| 1966 | 63.5 | 1.11 | 21.8 | na | 25.0 | 43.6 | 30.3 |
| 1967 | 63.7 | 1.12 | 26.0 | na | 25.0 | 41.6 | 28.6 |
| 1968 | 62.4 | 1.22 | 29.1 | na | 25.0 | 35.5 | 29.4 |
| 1969 | 63.5 | 1.59 | 20.0 | 25.8 | 25.0 | 36.7 | 29.8 |
| 1970 | 64.2 | 1.84 | 21.3 | 26.6 | 25.0 | 40.2 | 33.9 |
| 1971 | 63.9 | 2.02 | 21.4 | 27.5 | 20.8 | 39.5 | 34.9 |
| 1972 | 62.0 | 2.17 | 21.3 | 27.7 | 28.1 | 49.1 | 32.9 |
| 1973 | 66.0 | 2.46 | 22.9 | 28.6 | 28.1 | 47.2 | 33.7 |
| 1974 | 66.2 | 2.98 | 23.8 | 27.8 | 25.0 | 46.0 | 32.6 |
| 1975 | 67.6 | 3.65 | 22.8 | 27.3 | 25.0 | 47.7 | 30.2 |
| 1976 | 67.1 | 4.02 | 22.7 | 26.7 | 25.0 | 56.6 | 28.5 |
| 1977 | 64.7 | 4.37 | 22.9 | 26.5 | 25.0 | 62.3 | 24.9 |
| 1978 | 63.2 | 4.95 | 21.8 | 27.1 | 32.6 | 61.6 | 24.4 |
| 1979 | 63.0 | 5.65 | 19.5 | 29.8 | 44.6 | 68.2 | 27.9 |
| 1980 | 60.9 | 6.37 | 19.1 | 30.2 | 44.6 | 73.2 | 33.5 |
| 1981 | 61.7 | 7.08 | 18.7 | 30.1 | 57.8 | 76.6 | 32.4 |
| 1982 | 59.8 | 7.90 | 19.1 | 19.1 | 64.6 | 83.0 | 35.4 |
| 1983 | 63.8 | 8.76 | 20.8 | 32.6 | 70.7 | 79.7 | 35.1 |
| 1984 | 62.1 | 9.54 | 20.6 | 32.6 | 85.0 | 78.0 | 34.4 |
| 1985 | 64.8 | 11.11 | 19.8 | 32.6 | 99.5 | 75.4 | 34.2 |

* For steam power plants only
Source: PLN[56]

**TABLE 18**
**PLN Technical Efficiency Indicators**
**Java System**

| Year | Load Factor (%) | Demand Density (MWh/km2) | Trans. & Distr. Losses (%) | Thermal Effi-ciency (%) | Average Unit Size* (MW) | Thermal Generation Share (%) | Capacity Factor (%) |
|---|---|---|---|---|---|---|---|
| 1974 | 69.7 | 26.5 | 24.2 | 27.8 | 33.3 | 36.8 | 37.4 |
| 1975 | 71.0 | 32.8 | 22.8 | 27.2 | 33.3 | 38.7 | 32.9 |
| 1976 | 70.4 | 36.3 | 22.3 | 26.6 | 33.3 | 49.6 | 31.7 |
| 1977 | 67.9 | 39.7 | 22.2 | 26.0 | 33.3 | 55.9 | 27.7 |
| 1978 | 66.0 | 46.2 | 20.8 | 26.6 | 40.6 | 54.7 | 29.9 |
| 1979 | 65.8 | 53.5 | 18.5 | 30.0 | 54.3 | 62.5 | 29.0 |
| 1980 | 64.5 | 60.8 | 18.2 | 30.8 | 54.3 | 71.7 | 34.9 |
| 1981 | 63.7 | 69.5 | 17.7 | 31.4 | 69.1 | 73.1 | 32.4 |
| 1982 | 60.4 | 78.0 | 18.2 | 32.2 | 76.8 | 80.6 | 36.7 |
| 1983 | 66.2 | 90.4 | 20.6 | 33.9 | 83.7 | 76.8 | 38.4 |
| 1984 | 65.0 | 95.6 | 19.9 | 34.0 | 100.3 | 76.5 | 39.2 |
| 1985 | 68.9 | 106.4 | 19.4 | 33.5 | 120.3 | 73.4 | 34.7 |

* For steam power plants only

Source: PLN(56)

The levels and trends in transmission and distribution (T&D) losses are also of concern. The most important factor cited by industrial power users for generating their own electricity was the lack of reliability of PLN supply. This lack of reliability results more from the inadequacies of the T&D system than lack of, or down-time of, generation (particularly considering the excess capacity now on Java).

As shown in Table 18, the period 1974-1981 saw a reduction in T&D losses on the Java system from a level of 24 percent to a level of 18 percent. Since that time losses have increased. It should be noted that losses of 18-20 percent are very high in comparison to other countries. The U.S. and other industrialized countries typically have T&D losses of 9 - 11 percent. In 1983, the losses in Korea, Thailand and Malaysia were 7 percent, 10 percent and 8 percent respectively.

Several factors contribute to the high level of T&D losses in Indonesia. They include high levels of theft and avoidance of payment ("non-technical losses"), an increasingly dispersed system, a preponderance of low voltage customers and the lack of high voltage transmission networks. Of particular importance, however, is PLN's recent poor record of distribution - project implementation.

Some of the most reliable, and revealing, statistics in this regard relate to PLN's record of implementing investments during REPELITA III (1979/80 - 1983/84). Table 19 summarizes that record. Implementation delays are not unusual in developing country power programs. What is most important about the figures shown in Table 19 is the relative figures for the components. Hook ups of new customers, measured either in terms of households or villages were significantly higher than targeted. However, implementation of generation investments fall 31 percent below targets. Even more telling is the fact that high voltage transmission and low voltage distribution investments both fell more than 50 percent below targets. Assuming that the planned investments had an appropriate balance between generation, transmission and distribution, the record of actual investment goes far towards explaining the combination of excess capacity on Java and the lack of reliability of PLN supply invoked by investors in captive power to explain their investments.

**TABLE 19**
**PLN's IMPLEMENTATION RECORD DURING REPELITA III**

| | Unit | Target | Realiz-ation | % of Target |
|---|---|---|---|---|
| Generation | (MW) | 2,859 | 1,983 | 69 |
| HV transmission | (km) | 10,402 | 4,505 | 43 |
| MV transmission | (km) | 25,803 | 18,704 | 72 |
| LV distribution | (km) | 56,765 | 20,304 | 36 |
| New customers | (1,000) | 1,625 | 2,623 | 161 |
| New Rural Villages | (No.) | 3,700 | 5,771 | 156 |

Source: World Bank (9)

Recent studies by BAPPENAS(24) and the World Bank(9) cite several factors to explain the shortfall in implementation, including:

- delays in finalizing financing arrangements;
- cumbersome procedures for the appointment of consultants, award of contracts, and opening of letters of credit;
- rigid budgetary authorization procedures;
- scarcity of local funds - particularly in 1983 and 1984;
- unsatisfactory performance of local contractors;
- problems in land acquisition; and
- a shortage of trained manpower within PLN.

Of particular concern is the shortfall in realizing targets for distribution investments. In addition to the reasons cited above, distribution projects have shorter project cycles and are thus more vulnerable to budget cutting exercises. They are also subject to procurement delays due to the requirement of using local suppliers(9). The BAPPENAS study underlined the problems resulting from delays in implementation of distribution projects(24):

"In reality, the expansion of a distribution system is sometimes delayed, causing an excessive overload to occur in the system. This in turn is the major cause of many outages (interruption of supply), voltage dips and excessive voltage drop in that network."

These factors have been recognized and efforts are being made to improve performance. Nonetheless, if private investment in power generation can relieve both the financial and managerial pressures on PLN, the contribution to reliable power supply in Indonesia may be even greater than indicated by the incremental capacity thereby installed.

### 13. Administration of the Power Enterprise Permit

Recently, procedures have been established by the Ministry of Mines and Energy to administer the review and granting of Power Enterprise Permits to private sector entities. Figure 2 summarizes the activities allowed under Law 15 for Power Enterprises.

Figure 3 illustrates the procedures for reviewing applications from Power Enterprise Permits. As shown by the figure, while the Directorate General of Electric Power and New Energy has the decision authority, important input is provided by PLN both at the local (district) level and at headquarters. The Provincial Office of MME (Kanwil) has an important role in recommending a decision.

FIGURE 2

FORMS AND PERMITTED ACTIVITIES OF POWER ENTERPRISES

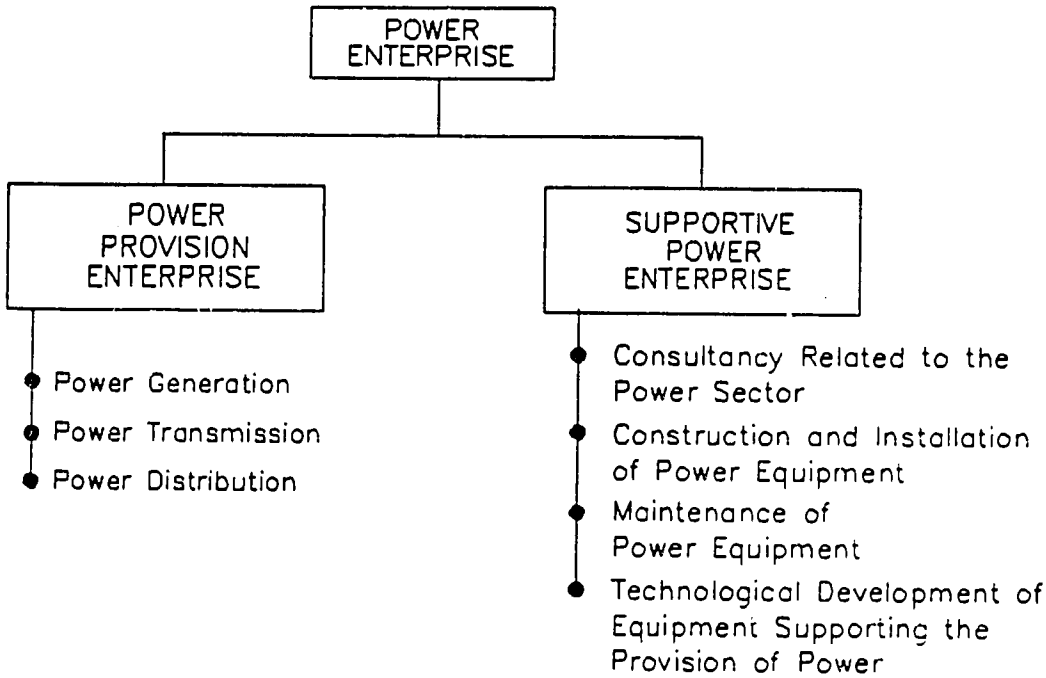
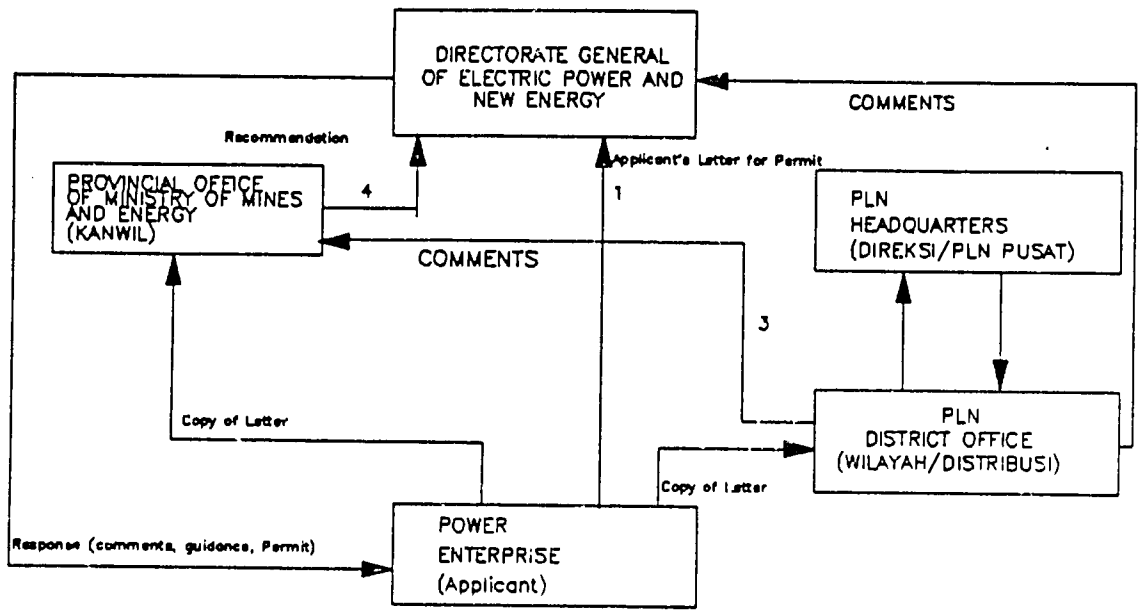


FIGURE 3
PROCEDURES FOR POWER ENTERPRISE PERMIT



## B. U.S. EXPERIENCE IN PRIVATE POWER

### 1. History

Following the "oil crisis" of 1973-74 and the major oil price increases that followed, widespread concerns developed in the United States over the country's heavy dependence on imported oil. Over the next several years a variety of strategies were developed to decrease this dependence and to foster the utilization of other fuels. Hundreds of Federal programs costing billions of dollars were initiated to accomplish those objectives. In retrospect, the action which may have had the greatest benefit - at essentially no cost to the Government or to the public - was the passage by Congress of the Public Utility Regulatory Policies Act of 1978 (PURPA). The intent of PURPA was to encourage a more efficient use of fuel through cogeneration and a more diversified fuel mix, particularly through use of renewable resources.

PURPA represented a remarkably radical, and to some a retrogressive, change in national power policy. While for decades the historical trend had been toward larger ("more cost effective") and more centralized power facilities, PURPA encouraged small scale technologies and decentralized production. While the historical trend was toward large, highly regulated, monopolistic power utilities, PURPA encouraged small, independent, essentially unregulated power companies.

Private power in the U.S. is now extending well beyond the types of facilities contemplated by PURPA. There is a general trend towards deregulation and greater competition in the U.S. power industry. As an example, in June of 1987 the Boston Edison Company asked for bids on 200 MW of future capacity. The successful bidders included a company which proposed a large coal fired plant as well as a firm proposing a very small trash burning facility.

In several utility systems, including those in California, Maine and Texas, proposals from private producers can fulfill all of the requirements of the current expansion plans. Cogeneration has become such a recognized financial success that several utilities,

including Florida Power & Light Company, Atlantic City Electric Company and Dominion Resources, have set up cogeneration subsidiaries in alliance with independent power producers.

All this not withstanding, the PURPA legislation was the key first step in moving towards a more diversified power system in the U.S.

## 2. The PURPA Legislation

Two sections of PURPA are of primary concern. Section 210, the heart of the legislation, requires utilities to purchase electricity from certain types of private producers, termed "qualifying facilities". The principal which establishes the price of purchased power is that the utility's rate payers should not have to pay more as a result of the PURPA purchase. Practically this means that the utility purchases power at a price equal to or less than the cost it would have to incur if it produced the power itself - its "avoided cost". In addition, Section 210 requires that utilities provide back-up power to the private producers at non-discriminatory rates and exempts such producers from the burdensome regulatory requirements normally applied to utilities.

The other pertinent section of PURPA, Section 201, specifies the kinds of facilities that can qualify for these mandatory purchase arrangements. These "Qualifying Facilities" fall into two categories:

1. Small Power Producers

Facilities of 80 MW or less with at least 75% of their energy coming from biomass, waste, solar, wind or geothermal sources.

2. Cogenerators

Facilities producing both useful thermal energy and electricity. There are various requirements on the thermal energy used and the overall efficiency of the plant (under the Industrial Fuel Use Act) depending on fuel and technology. There is no limit on the size of qualifying cogeneration systems.

The implementation of PURPA has been the responsibility of the Federal Energy Regulatory Commission (FERC). Although FERC provides some guidance, the specific terms of generic and specific contracts are decided upon by state public utility commissions. It is these commissions which represent the public interest and which mediate between the producer and the utility. Thus implementation of PURPA varies greatly from state-to-state. In some states standard power purchase contracts have been developed, particularly for small units say up to 100 kW. In other states, contracts are negotiated on a case-by-case basis. In all cases the "avoided cost" principle is used.

### 3. Avoided Costs

The concept of avoided cost is simple in principle but often complex in practice. There are two components to avoided cost. The first, the energy component, is relatively straight-forward and includes the utility's fuel and O&M expenses (which usually vary as a function of season and time of day).

More complex is the capacity cost component which accounts for the generation, transmission and distribution investment costs that are avoided by having the private producer on line. The value of that component depends on a number of factors including:

- The rate of growth of demand served by the utility
- The structure of demand
- The utility's current excess capacity, if any

- The utility's marginal cost of new capacity
- The reliability of the private producer and the ability of the utility to dispatch that particular facility
- Cost savings in line losses and interconnection costs
- The mix of private producers on the grid.

There are large variations in the buy-back rates developed by the different state utility commissions. In 1983 the average state-wide energy payment varied between 1.3 cents/kWh in Nebraska to 6 cents/kWh in New York. The latter is the only state which has a floor rate. In some cases the price depends on time-of-day. The Pacific Gas and Electric Company, for example, is currently paying 3.0 cents/kWh on-peak and 2.6 cents/kWh off-peak.

**4. Impact**

Despite a relatively slow start, braked by challenges to PURPA legislation at both the Federal and the state level, non-utility generation now accounts for more than 4 percent of U.S. power production. In many regions of the country the effect of PURPA has been even more significant.

In northern California, for example the Pacific Gas and Electric Company in 1982 purchased 1006 MW of hydro power under long term contracts and 255 MW from other PURPA facilities. Its own installed capacity at that time was 11,337 MW. By December 1986, purchases from non-hydro PURPA facilities had increased eight-fold to 1871 MW while the company's total installed capacity increased only 4 percent to 15,233 MW. The PURPA facilities fall into the following categories:

| TYPE | CAPACITY (MW) |
|---|---|
| Biomass | 144 |
| Geothermal | 82 |
| Hydro | 184 |
| Cogeneration | 842 |
| Solar | 7 |
| Wind | 612 |
| Total | 1,871 |

About 20 percent of the electricity sold by the Houston Lighting and Power Company is produced by private companies. This includes 1,400 MW from the Dow Chemical plant in Freeport, Texas. About 12 percent of the power sold by the Central Maine Power Company comes from non-utility sources such as paper companies; the utility expects that figure to rise to 38 percent by the year 2000(38).

Private power generation in the U.S. has created a more diversified fuel base, has increased the overall efficiency of power production (particularly through cogeneration), has reduced the utilities' need for capital and has lowered the cost of electricity to the consumer.

Despite these successes, recent experience with PURPA in the U.S. leads to a number of concerns which are relevant to Indonesia. One problem has resulted from excessive incentives and tariffs built into some contracts, particularly in Texas and California. In some instances the tariff structure involved a floor price which did not contemplate the kinds of reductions in oil prices that have occurred over the past two years. This has resulted in some utilities buying cogenerated electricity at a price which is more than double their own selling price.

There is also a concern in the U.S., as private power production becomes more prevalent, that the large, high load factor, customers will be weaned from the utility systems thus increasing the cost of serving the remaining customers, leading to more defections, even higher costs and lower reliability.

Despite these concerns, and despite current world oil prices, private power generation continues to accelerate in the U.S. It is reported that private power producers currently account for the majority of orders for new power generating equipment(38).

Because of the nature of the PURPA regulations, and because of its inate cost effectiveness, cogeneration accounts for the lion's share of proposed new capacity. Not to be left behind, several utilities have themselves set up cogeneration subsidiaries or joint ventures.

As the private power production industry matures in the U.S. there are strong indications that it will play an increasingly important and more diverse role in the future. The Federal Energy Regulatory Commission is considering regulations favoring competitive bidding on new generating facilities while certain utilities, such as Boston Edison, are already proceeding in that direction. The process is for a utility to specify a site and to ask for bids on producing power at that site for a 15 - 20 year period. In other instances the site is to be specified and acquired by the bidder.

PURPA has already changed the nature of the power industry in the U.S. in a fundamental way and it appears that its full implications are yet to be experienced.

## C. OTHER COUNTRIES

### 1. Turkey

Turkey, in the early eighties, was faced with a rapidly growing economy, a history of power shortages and high system losses, the necessity to increase power production, and severely constrained national budgets. The energy share of public sector investment had risen from 25 percent in 1970 to an extraordinary 42 percent in 1985.

The Government which took office in 1983 established a clear policy the intent of which was to "develop an efficient and financially sound energy sector in which public and

private entities work together effectively to meet increasing energy needs at minimum cost"(8). The policy was explicit in its objective of meeting new energy needs not by increasing the Government's borrowing but rather by increasing the flow of foreign capital.

In 1984 a key law was passed entitled, "Respecting Authorization to the Institutions other than the Turkish Electricity Authority for Generation, Transmission, Distribution and Trade of Electricity". This law also allows for the creation of new regional utilities. The Ministry of Energy and Natural Resources has the authority to grant permission to power companies to construct and operate power plants. The Council of Ministers must approve the creation of new regional utilities. In 1985 a set of regulations was promulgated setting forth the principles for evaluating applications, negotiating energy tariffs and granting permission(8).

In addition, Turkey has strongly endorsed the BOT (Build, Operate and Transfer) model for private investment in major infrastructure projects. Airports and port projects, as well as power plants, are being developed using this approach.

During the summer of 1987 Turkey attracted five companies or consortia to propose on its first BOT power plant. They were:

- A consortium including Bechtel of the U.S. and Kraftwerk Union of West Germany. Morgan Guarantee Bank is the leading private financial participant.

- A consortium including Brown Boveri of Switzerland and backed by three major Swiss banks.

- Seapac, a venture including Westinghouse and Chiyoda of Japan.

- Alsthom, of France, with strong support of Coface, the French export credit agency.

- A Japanese consortium led by the Electric Power Development Corporation.

Beyond this plant the Government is considering a second major plant to be negotiated later this year and a third early next year. Beyond this, Turkey is considering 40-50 smaller hydro projects also to be contracted on a BOT basis.

**2. Pakistan**

As in Turkey, in Pakistan the interest in private power generation was stimulated by a combination of power shortages, resulting in load shedding, a commitment to rural electrification, and severely restricted national budgets. In response to this situation the Government, in 1985, established a policy to encourage private power production(48).

The policy envisioned two mechanisms for developing private sector proposals. In the first, the Ministry of Water and Power (which supervises the national power company, WAPDA) would designate "in the context of agreed medium and long-term plans, the location and capacities for thermal generation suitable to system conditions, and invite (the) private sector to install and operate them." In the second mechanism, the "Ministry would entertain proposals made by private enterprise, on their own initiative, and consider them in the context of the agreed medium and long-term plans." Because of the resource situation in Pakistan the emphasis in the policy was on generation using oil or indigenous coal.

The policy stipulated that the power purchase price would be based on the cost of production if the investment was to be made by WAPDA (i.e. what we referred to above as the "avoided cost" including a capacity component). Some consideration would be given to return on the equity of the investors but the guarantee would be for price and the quantity of electricity to be purchased not on return. The bulk tariff was to be based on a 60 percent annual plant factor. Penalty clauses for both the seller and the purchaser would apply if the amount available or the amount requested, respectively, were less than 60 percent. The policy envisioned that the power purchase contract would include escalation clauses, particularly for fuel.

A full copy of the policy document is reproduced in Appendix D.

Although there had been unsolicited proposals submitted to the Government before that date, the policy was first implemented through a request for proposals for a 120 MW diesel power plant at a specific site published in April, 1986. Of the 13 proposals received for the diesel plant, 4-5 were considered to be viable. In early 1987 pro forma contracts were prepared containing guarantees for both the producers and the purchasers. After initial negotiations it appeared that, because of the quality of the proposals, the Government might accept more than the originally intended single plant.

In the meanwhile, in response to the Government's recognized receptivity to such proposals, three international joint ventures have proposed to build plants at other sites. These include a British, a Saudi Arabian and a U.S. firm, each with a Pakistani joint venture partner. These proposals total some 1320 MW of power.

To meet development targets, generating capacity in Pakistan should roughly double in the period 1987/88 - 1992/93, from 6700 MW to 13,600 MW. It was clear that the target could not be met within budget constraints without a significant investment in power by the private sector. While early estimates indicated the possibility of private investment accounting for roughly 10 percent of new capacity, it now appears that the figure could reach 20 percent.

# IV. THE POTENTIAL ROLE OF PRIVATE POWER

## A. OBJECTIVES AND PRINCIPLES

Private power generation is worthy of exploration in Indonesia not because of some theoretical advantage of private ownership or virtue of free enterprise. In fact, as mentioned in the previous chapter, the Government will justifiably want to maintain central control over the evolution of the power sector because of electricity's critical role in development. Fundamentally, the rationale for private power is that it can make a major contribution to adequate, reliable electricity supply. Under some circumstances, for example when industrial cogeneration is possible, private power can reduce the cost of electricity supply. But lower cost is not the sole criterion. As has been made clear over the last few years by the rapid expansion of captive power, reliability is also highly valued. In rural areas, the willingness of villages and cottage industry to pay much higher rates for power than PLN rates indicates a continuing need for new power.

We suggest that private power be considered as one - important - element in Indonesia's total power development strategy. The appropriate role of private power in that broader context should be determined by an evaluation of the technical and economic benefits and costs. This chapter provides a first estimate of those benefits and costs.

There is a wide variety of factors influencing the relative benefits of private power generation in Indonesia. As a developing nation, the power generation and distribution systems are expanding rapidly. From 1968 to 1983 total PLN generation increased an average of 14 percent per year, both on and off Java. However, the costs of continuing expansion is extremely high. As shown above, from 1987-94 PLN's financing requirements will average about 1600 billion rupiah (one billion dollars) per year.

Private investment in power generation facilities could significantly reduce PLN's capital requirements and possibly permit greater investment in improving the reliability of the existing transmission and distribution system.

In this chapter we investigate three categories of private power generation. The first is the possibility of private capital, local and foreign, being used to construct large, central station power plants tied into the central grid. The second, cogeneration, takes advantage of the need for both power and thermal energy in some industries to generate excess power to the grid. The third category includes the use of biomass, particularly agricultural residues, to generate power in rural areas. In the latter instances we use specific examples to illustrate the potential.

## B. LARGE SCALE PRIVATE POWER PLANTS

### 1. The Concept

The greatest potential for national economic benefit from private power will come about if the private sector invests in major new power plants. As shown above, over the next eight years, PLN expects to add some 5500 MW to its entire system to meet projected demand growth. As we shall see, cogeneration and renewable energy systems at best will be able to contribute only a fraction of that need.

One of the mechanisms used in other countries, and currently under discussion in Indonesia for private investment in the power sector, is the BOT concept. The BOT system would involve an investor/builder/vendor which builds a power plant (B), owns and operates the plant (O), selling power to PLN, and after a certain number of years, transfers (T) the plant to PLN or the Government. The period over which the builder operates the plant before transfer is typically 15 years. The BOT system is being used for power plants in other countries and for toll roads and communications systems in Indonesia.

Private investment in large scale private power in Indonesia would have several advantages:

1. Under current financing arrangements and conditions, government resources, and those available from international financial institutions through government channels, may be inadequate to meet the capital needs of power expansion. Private financing has the potential of overcoming, at least in part, this very significant constraint.

2. Private power producers provide a potential vehicle for the introduction, management and transfer of new energy conversion technology.

3. Under the assumption that private plants would be operated by highly skilled managers and operators, they could set a beneficially high standard for plant operation which could be emulated throughout the PLN system. There is an opportunity to train local workers, technicians and managers both in imported technology in management and in support services.

4. The possibility of private power generation can significantly improve the climate for energy resource development. For example, a company or consortium which can provide its own assured market for coal through power generation should be willing to invest in coal development on more favorable terms to the Government. The same would be true of natural gas.

## 2. Energy Resource Policy and Private Power

A policy for large scale privately financed power in Indonesia should be construed as an instrument for meeting broader national objectives in energy and economic development within financial constraints. In particular, large scale private power development should be strongly guided by policies on energy resource development.

A central concern of Indonesia's energy policy in recent years has been the prospect that the steady growth in internal demand for petroleum products combined with limited production capability will diminish the capability to export petroleum. Indonesia is in the fortunate, and unusual, position of having several alternatives to oil for power production. Resource utilization strategy in the power sector concentrates on the use of natural gas and coal with economics and logistical factors determining the choice between them. Hydro power, when it can compete with coal or natural gas, and where environmental considerations allow, is also an option of choice as is geothermal energy.

As suggested above, there may well be strong synergies in resource development and power production. For example, the assured market of a new large coal fired or gas fired power plant may be of significant value to the developer of the coal or gas resource. There may be a direct benefit of a large, local incremental demand for the fuel and possibly an indirect benefit of justifying infrastructure - coal transport systems or a gas pipeline - which would create an ancillary industrial market for the particular fuel.

### 3. Geothermal Energy

The total geothermal potential in Indonesia has been estimated as 10,000 MW (electric). About half of that is on Java. Pertamina and PLN have been producing 30 MW of power at Kamojang since 1982. This will soon increase to 140 MW. Pertamina sells steam to PLN at a price tied to the price of fuel oil (80% of that price and under the assumption of a 28% conversion efficiency). This comes out to a current price of 44.8 Rp/kWh as the steam "fuel" component of power produced.

One of the first private proposals for power generation in Indonesia was brought forward by Unocal Geothermal of Indonesia. In 1982 Unocal signed a contract with Pertamina to develop the Gunung Salak geothermal field and to provide steam (under a Joint Operation Contract) to PLN for power production. The original power level anticipated was 110 MW which was subsequently raised to 147 MW. Unocal to date has spent over $88 million on development of the field, including an investment in local infrastructure.

In the original contract the sale price of geothermal steam was tied to the world price of oil. The current world oil price has rendered the project financially infeasible under those original terms. Unocal then proposed a major extension of the original concept to a BOT arrangement whereby it would (with other overseas participants) build the entire system including the power plant and sell the power to PLN.

## 4. Natural Gas

Natural gas reserves in Indonesia have been estimated at 80 trillion cubic feet (TCF). Production in 1985 was 1.5 TCF, about half of which was exported as liquified natural gas (LNG). The largest gas fields are relatively remote; the Natuma field in the North China Sea has reserves of 41 TCF and the Arun Field in North Sumatra, 14 TCF. Offshore East Java has about 2.6 TCF and offshore West Java 2.3 TCF.

Future exports of gas are apt to be limited more by world demand (and the costs of liquification and transport) than by supply. Thus, natural gas is a prime candidate for future power production as well as industrial energy use. Given this situation there are plans to substitute natural gas for oil in power plants currently under construction: the 400 MW Gresik Station in East Java and the 200 MW plant at Semarang, Central Java. Either would be a potential site for a private sector financed combined cycle gas fired plant.

Unless new discoveries are forthcoming off the coast of Java, the mid-term uses of gas will commit essentially all of the easily accessible supply. Investment in further exploration off Java or in construction of a pipeline from Kalimantan will be strongly influenced by Government policy on gas pricing [49]. A link between the developer of the gas resource and a private power producer (or if they were the same entity) would transfer the issue to that of the purchase price of power. This is essentially what happened in the geothermal case in which, for economic reasons, Union Geothermal decided to propose to sell power rather than steam.

## 5. Coal

The coal reserves of Indonesia have been estimated at 20 billion tons, mostly situated in Kalimantan and Sumatra. The Bukit Asam mine in South Sumatra is scheduled to produce 3 million tons/year but considerable delays have been experienced in the facilities for rail haulage, transfer and shipping to West Java. The Government has entered into a number of production-sharing agreements with domestic and foreign companies for exploration and production of coal in Kalimantan. Three major sites for coal plants are in various stages of development, at Suralaya (West Java), Paiton (East Java) and in Central Java. These sites will accommodate a total of at least 10,000 MW, of which 800 MW is now installed at Suralaya. The Paiton site could well be appropriate for a private power initiative.

A private power plant on Java based on coal could be linked in a financial and institutional way to development of its coal supply (say in Kalimantan). This kind of linkage, if accompanied by integrated planing, could serve to avoid the situation that arose with the Suralaya plants in which supply delays forced the plants to fall back on imported coal.

## 6. Nuclear

The most ambitious private power concept thus far in Indonesia is to use the BOT arrangement to construct a 600-650 MW nuclear power plant near Jepara, Central Java. Three groups responded in 1987 to a request from the Government for expressions of interest in building the plant:

1. Kraftwerk Union (Germany) and Framatome (France).

2. Mitsubishi Heavy Industries (Japan), Westinghouse (U.S.) and Ansaldo Spa (Italy).

3. Atomic Energy of Canada, Ltd.

On examination, several doubts were raised about the financial feasibility of the nuclear option at this time. Even if the investment came from overseas the buyers of electricity would have to pay for that investment through high tariffs (or the Government would have to pay through a subsidy). Even given the "buyers market" for nuclear plants, both the World Bank and PLN estimated that a nuclear plant would cost at least $1.2 billion more than a fossil fuel plant of the same size(49). Favorable economics appears to depend on coal and natural gas prices increasing more rapidly than nuclear capital and fuel costs.

The vendors and the Government are now considering a first step in which a coal or natural gas-fired plant is built. In some versions the earnings from this fossil BOT plant would contribute to the construction costs of the nuclear plant. Others maintain that the fossil proposals should be evaluated on their economic and technical merits, while deferring a decision on the nuclear option.

**7. The Industrial Park Concept**

Another alternative, which could be very attractive for Indonesia, would be for a private entity to build and operate a power plant to primarily serve an industrial park. The evidence of the many captive power producers indicates that industrial consumers will pay higher than PLN tariffs for reliable power. Reliability will have to be assured by having more than one plant serving the park. In that case systems/economic considerations would probably lead to the desirability of also selling power to the PLN grid and purchasing power from the grid.

The economics of the power/industrial park concept would also be enhanced if the industries concerned had need of thermal energy as well as power. This would allow the private power company to operate in an efficient cogeneration mode. This, in turn, suggests that the industrial park might be built around a natural cogeneration facility such as a petrochemical plant.

## 8. Issues Regarding Implementation

Several basic issues emerge as large scale private power is considered as a serious option for Indonesia's future. The first is the pricing of power purchased from private producers. PLN's long run marginal cost of production might seem the correct starting point. However, this assumes that PLN can meet anticipated load growth by financing expansion in the same way it has in the recent past. As was shown in the past fiscal year, such financing is not forthcoming now. Thus, from a practical point of view, there may be some fraction of future demand that will be met only if new mechanisms such as private power are implemented. In that case, PLN's traditional long run marginal costs are not the appropriate measure for pricing; one must consider measures of value and willingness to pay. As discussed above, these are considerably higher than PLN's tariffs or costs, at least on Java.

The difficulties experienced by PLN and its deficiencies are not unusual for a developing country power company. Indeed management problems and financial difficulties are not exactly unknown among U.S. utilities. Even the Central Electricity Generating Board in England has been criticized recently for monopolistic inefficiencies(60). As mentioned above, PLN is still a young and developing institution. In many ways its performance is steadily improving. The various programs now under way to improve the performance of PLN are of high priority.

At the same time, a significant private power program in Indonesia has the potential of setting new standards of management, performance and efficiency. To achieve these objectives, a private power program involving large scale plants should not be viewed as competitive to PLN, but complementary.

It is to be expected that foreign and local investors in private power projects will have a number of requirements. For example:

1. The operator must be assured that he can operate the plant equipment reasonably near to maximum efficiency or, failing that assurance, is guaranteed a minimum yearly purchase on a "take or pay" basis if the plant is available.

2. The operator must be assured that he will have a continuous supply of fuel at the price assumed in his power sales contract. Plant operators usually obtain this assurance through long term supply contracts. If fuel is supplied through a Government entity, however, this may involve tying the power purchase price to fuel cost.

3. The operator must be assured that he can borrow local currency for local content purchases and working capital on an equal footing with local counterparts in terms of price and availability.

4. The operator must be assured the availability of foreign exchange for remittance of profits and he must be assured that he can remit profits or, at least, translate them into hard currency as they are earned.

5. If the operator's earnings are in local currency he must be able to insulate himself against currency devaluation.

Of the five preconditions the first is critical in terms of risk taken by investors. The last two are also critical since the ability to protect hard currency earnings are central to the profitability of the project for the operator. With current policies, currency conversion in Indonesia does not present a problem.

One of the mot difficult issues in the financing of large scale private power projects is that of Government guarantees. In Turkey, for example, the developers of the first large scale private power project sought partial World Bank financing in order to lower the risk

and increase the attractiveness to other investors. While the World Bank's charter required a sovereign guarantee the Government of Turkey's policy was to not provide such guarantees to private projects.

In Pakistan an approach to solving this impasse has been proposed through the creation of a special facility for the financing of private power projects. While the institutional structure of the facility is still under discussion, the concept is to include both donor financing and international financial institution (World Bank and Asian Development Bank, ADB) financing. In one scheme the funds would be on-lent to specific projects through government channels. The low effective cost of money through this combination would allow the Government, through a mark-up on loans, to cover its cost of providing exchange risk guarantees. The only other Government guarantee would be that required by the World Bank and ADB for their share of the financing of the window. An important contribution of the facility would be to assure a professional screening and project evaluation function on technical, financial and economic grounds. This process would provide additional assurance to project co-financers and investors.

Forward exchange contracts could be used to assure future exchange rates. Contracts to PLN could be, at least in part, in hard currency.

## C. COGENERATION

### 1. Introduction to Cogeneration

Cogeneration is defined as the use of fuel in a single system to provide both electricity and useful thermal energy. Cogeneration systems recover energy that would normally be exhausted to the environment as either hot water or steam for useful purposes.

In the conventional generation of electricity with fossil fuel fired systems, the conversion efficiencies range from 15% to 40% (heat rates from 2150 - 5734 kcal/kWh). In practice, today high speed diesel generators may achieve maximum efficiencies of

about 35%. However, under normal operating conditions, efficiencies are more likely to be closer to 30%. This is due to a variety of factors including normal deterioration of equipment between overhauls and operation under part-load conditions.

A large steam plant may achieve thermal efficiencies of up to 37% (2330 kcal/kWh). However, in practice, over the long term plant efficiencies are generally lower. For example, PLN's average efficiency on Java (where the system is primarily steam based) in 1983, was 33.9%. Gas turbine generators vary widely in efficiency depending on their size. Very small units (600 kW) have efficiencies of only 12-14%. Large units over 10 MW have efficiencies in the range of 20-30% depending on operating load and ambient temperature conditions.

Cogeneration systems can generally achieve system efficiencies in the range of 50 to 70%, sometimes higher. Taking credit for the recovered heat, the electric heat rate of cogeneration systems may be in the range of 1800-2100 kcal/kWh. Therefore, when a cogeneration system is utilized in a facility requiring both thermal energy and electric energy, substantially less fuel is required than if they were generated separately.

Cogeneration systems recover heat in different ways depending on the prime-mover utilized. With diesel generators, heat as steam or hot water can be recovered from the hot exhaust gases (which range up to 550$^{o}$ C). As well, hot water (at about 82$^{o}$ C) can be recovered from the cooling jacket and oil cooler. For diesel cogeneration systems the ratio of thermal:electric output ranges from 1:1 to 1.5:1.

With gas turbine systems, the turbine exhaust gases are run through a waste heat recovery boiler to generate steam. Pressures up to 20 bar or higher can be easily generated but the quantity of heat recovered declines with increasing pressure. The thermal:electric ratio is generally about 2:1. Thermal output can be increased significantly by firing supplemental fuel into the exhaust gases before the boiler.

For cogeneration with steam turbines, either back-pressure or extraction turbines are used to obtain process steam at a useful pressure. Thermal to electric ratios can vary widely depending on plant requirements. They generally range from 3:1 to 10:1.

## 2. Captive Power

As described above, "captive power" refers to the widespread practice of industrial entities to own and operate their own power production equipment. Currently, government policy is to encourage industrial facilities with captive power plants to switch to PLN power where available. Switching to PLN power would help to reduce the nation's consumption of automotive diesel oil (ADO) which is utilized by most captive power plants, thereby freeing up valuable exportable product. Conversion of round-the-clock industrial consumers to PLN would also tend to improve PLN's overall capacity factor which currently is only about 35% on a system-wide basis.

However, maintenance of certain types of captive power plants and, in fact, encouraging certain types of new ones, might be a preferable strategy to achieve these objectives. Installation of cogeneration equipment at existing industrial captive power sites can increase overall fuel use efficiency from 30-35% to 50-70%, thereby contributing to the national goal of reducing internal oil consumption. In particular, expansion of cogeneration with sale back to the grid at industrial facilities which use natural gas can contribute significantly to both fuel substitution and increased efficiency.

PLN currently maintains gas turbine power plants on Java for peaking purposes. These plants operate at very low capacity factors - in the range of 5 to 10%. Existing surplus capacity in the captive power sector is far greater than the capacity of gas turbines used for peaking. By interconnecting captive plants to the grid PLN could take advantage of this large surplus and depend on existing diesel plants to provide peaking power. By doing this PLN would eliminate the cost of maintaining a large reserve of gas turbine peaking units which are used only a small percentage of the time.

## 3. Existing Cogeneration Facilities

An attempt was made to identify the extent to which cogeneration technology is currently being utilized in Indonesia. Discussions with personnel at DJL, the Ministry of Industry, and P.T. Koneba (a company organized for the purpose of implementing energy conservation projects) indicated that the penetration of conservation technology in the industrial sector is still fairly limited.

A handful of plants were identified that do have operating cogeneration systems. these include several fertilizer (urea) plants, two oil refineries, a textile plant, and a paper mill. Based on extremely limited data it would appear that the total capacity of existing cogeneration equipment is in the range of 200 to 300 MW. With the exception of the oil refineries, none of these plants appears to be interconnected with PLN. As discussed below, it appears that some of these plants could generate surplus power at a very low cost which could be sold to PLN if an interconnection existed.

## 4. Power Purchased by PLN

As mentioned above, Indonesia contains a large number of power plants which are owned and operated by private or government-run corporations (captive power plants). Some of the largest plants are interconnected with PLN and sell some power on a regular basis.

While some independent entities sell power to the PLN grid, a far greater capacity of captive power exists which is not interconnected with PLN. These facilities are located primarily at industrial sites. Industries commonly producing their own power include textiles, food, basic chemicals, cement, paper, fertilizer, aluminum, iron and steel, oil refining, and LNG production. The majority of these facilities generate with diesels. Gas turbines and/or steam turbines are also utilized at fertilizer plants, oil refineries and the LNG facilities.

## 5. The Potential for Cogeneration

### Total Potential

The following table summarizes the theoretical cogeneration potential in both private and government-run industries in Indonesia. The estimate for the private sector is based on 1985 fuel consumption data collected by Pertamina and BPS. The estimates for government-run industries are explained in the sections below:

TOTAL COGENERATION POTENTIAL

| | TWh |
|---|---|
| Private Sector Industries | |
| Textile Industry | 2.6 |
| Wood Waste-fired Cogeneration | 3.6 |
| Other Private Industry | 4.6 |
| Sub-Total | 10.8 |
| Government Industries | |
| Oil Refineries | 1.7 |
| Fertilizer Plants | 0.4 |
| LNG Facilities | 0.4 |
| Sub-Total | 2.5 |
| TOTAL | 13.3 TWh |
| PLN GENERATION (for comparison) | 14.6 TWh |

Thus the total cogeneration potential is of the same order of magnitude as PLN's current total generation. It should be pointed out that this is a result of calculations of technical feasibility; for various reasons, including the location of load vis-a-vis industry and the willingness of plant owners to undertake these changes, the actual impact may be considerably less. Nonetheless, the figures indicate strongly that the combination of retrofit cogeneration and the incorporation of cogeneration with sale to the grid in new plants could reduce significantly the need for PLN to build new capacity to meet future demand growth.

The following sections present estimates of theoretical cogeneration potential in six industrial sectors: fertilizer, textiles, oil refining, LNG production, enhanced oil recovery, and wood products. These sectors were selected for a variety of reasons:

- they are areas where cogeneration technology is commonly applied because of the need for large amounts of thermal energy;
- they are among the largest energy consuming sectors in Indonesia;
- data were readily obtainable to develop rough theoretical estimates (except for enhanced oil recovery);
- the plants generally operate 24 hours per day;
- payback periods for added cogeneration capacity would likely be very attractive.

There are other sectors which may also have large cogeneration potential. These include iron and steel, basic chemicals, seasonings, and sugar.

The estimates presented below are theoretical estimates only. At a particular plant there is a variety of possible reasons why cogeneration may not be feasible including:

- lack of simultaneity of thermal and electric loads;
- space constraints;
- lack of suitable power grid for sale of excess power;
- unavailability of skilled operating staff.

**Fertilizer Plants**

Indonesia has a large fertilizer manufacturing industry consisting of six government-owned fertilizer companies. These companies produce urea, triple super phosphates and ammonium sulfate. Of these three industries, the production of urea is the most energy intensive requiring the consumption of large amounts of steam and electricity. At five of the six urea plants both the chemical feedstock and the energy source are natural gas. The Petro Kimia Plant at Gresik uses fuel oil.

Indonesia's urea companies, which produced a total 4.47 million tons of in 1984, presently cogenerate electricity and steam. Fuel use efficiencies are very high at these plants, approaching 70%, yielding a net cost of electricity of about Rp. 35/kWh (assuming gas prices at $3/mcf). This can be compared to PLN's lowest industrial tariffs of Rp 48.5/kWh and Rp 77/kWh for off-peak and on-peak respectively.

At present, these plants generate power for their own use. They have sufficient steam load to almost double their cogenerated electric output (with installation of new generating equipment). A rough estimate of surplus power that could be made available in this way is 400 million kWh/yr for all urea plants combined (calculations of this figure are given in Appendix F.)

Assuming a natural gas cost of $3/mcf, the net fuel cost of this new power would also cost about Rp 35/kWh. The capital cost requirements for the added capacity would be substantial, about 130 billion rupiah ($US 80 million) industry-wide. However, the return on investment could be extremely attractive considering the low cost of generated power and the round-the-clock operation of these plants. Note also that the $3/mcf price for natural gas is considerably higher than the long run marginal cost of supply of gas which may be considerably less than $2.(49)

**Textile Industry**

The textile industry is a large, diversified industry in Indonesia, responsible for a significant percentage of national energy consumption. Certain sectors within this industry have high thermal demands for bleaching, washing, dying, and finishing and are good prospects for cogeneration. Other sectors, such as weaving and sewing have very low thermal demands in relation to electric demands and are not good cogeneration prospects.

The textile industry (industrial code 321) is a major consumer of liquid fuels. Pertamina data for 1984-85 indicate consumption of 829 million liters (ADO and IDO combined). It is likely that much of the ADO consumed is used to generate electricity using diesel generators while the other fuels are utilized to raise steam in boilers.

Using an average specific consumption of 0.3 l/kWh, the ADO consumed could generate about 1.6 billion kWh per year (see Appendix F). This figure compares favorably with BPS data on self-generation in the textile industry (1.9 billion kWh).

Using current boiler fuel consumption figures one can estimate the amount of electric power that could be produced using cogeneration systems in the industry. This turns out to be greater than the current captive power generation - about 2.6 billion kWh vs 1.9 billion kWh. Assuming a capacity factor of 65%, this represents an additional potential capacity of 455 MW. This figure represents a theoretical limit. The amount of power that could be cogenerated in practice, with financially attractive systems is undoubtedly lower.

Nevertheless, there does appear to be significant opportunity for the installation of heat recovery equipment on existing diesel generators for production of steam. A financial analysis for such an installation is shown below in Section IV.B.6. The payback is very attractive, only 0.6 years.

**Oil Refineries**

Pertamina has a total of about 400 MW of installed generating capacity at its five refinery locations. Generating units consist of a mix of steam turbine-generators, diesel generators and gas turbine generators. The refineries rely heavily on small condensing type steam turbine generators. Cogeneration technology is utilized at two plants with three new extraction steam turbines at Balikpapan and two new gas turbine generators with heat recovery boilers at Plaju. The other plants generate electricity and steam for process use separately.

In general, oil refineries are excellent candidates for cogeneration due to their high steam demand in relation to electric loads. For a typical oil refinery, the energy ratio of process steam to electricity is about 6:1. Using gas turbine/heat recovery technology a refinery could cogenerate surplus power of about 10 kWh per barrel of output. Based on a nationwide refinery output of 165 million barrels per year, the total technical potential for cogeneration at oil refineries is about 1.65 billion kWh/year. If

operated for 7200 hrs/year, this output would represent an additional 230 MW of installed capacity. Total investment required for this capacity would be about 283 million rupiah (US$ 173 million).

As in the fertilizer industry, the return on investment for such plants could be very attractive if they are sized to operate at a high capacity factor. The real cost of power, as well, would be very low due to the use of refinery by-products for fuel and the high generation efficiencies.

**LNG Facilities**

Indonesia operates two LNG processing plants which liquify natural gas for export by ship. One is located in Aceh, North Sumatra, and is operated jointly by P.T. Arun and Mobil Oil Indonesia; the other is in Kalimantan and is operated by P.T. Badak. These facilities generate very large quantities of electric power for internal plant use with gas turbines at P.T. Arun and steam turbines at P.T. Badak.

P.T. Arun operates eight gas turbines for around-the-clock generation with a total capacity of 168 MW. While all this power is utilized for internal use, it would be possible to generate excess power for sale to the grid by converting the gas turbines to combined cycle operation. This would entail installation of heat recovery boilers, steam-turbine generators and cooling towers to utilize existing waste heat from the gas turbines. The total additional capacity would be on the order of 50 MW; additional generation would be about 400 million kWh per year.

Due to the high capacity factor of these plants and since waste heat would be utilized, the cost of power generated could be very low.

**Limitations**

Although these estimates indicate a significant potential for economical cogeneration in the textiles, fertilizer, LNG and petroleum refining industries, we should emphasize that they are very preliminary.

There are many reasons why a cogeneration project might not be feasible. First, space or layout limitations at an existing plant could make installation difficult. Second, construction of a new installation might not be possible without an unacceptable level of interference with current plant operations. Third, the local utility grid might not have sufficient electric demand to utilize power available from such a project and make it financially attractive.

**Wood Products Industries**

Indonesia is a major producer of timber, plywood and other wood products. Wood production in 1985 totaled close to 15 million M3 requiring the input of 30 million M3 of sawlogs. Due to their remote locations sawmills and plywood plants frequently produce their own electricity. Mills generally operate diesel generators for power while some burn wood wastes to produce steam. Cogeneration of steam and electricity from wood waste using steam turbines is common in many countries but thus far not much practiced in Indonesia.

Many sawmills and plywood mills are located in remote areas with only small local populations and limited utility grid systems. The potential for sale of excess power in these areas is limited. However, cogeneration of electricity and steam for in-plant use using wood waste would save substantial quantities of ADO currently used in diesels.

For each M3 of wood product produced another M3 of wood waste is generally produced. Therefore, Indonesia's total wood waste production is on the order of 15 million M3 per year. The theoretical potential for electricity production from this waste is about 3.6 billion kWh which is about three times greater than the current captive generation in this sector according to BPS data (see Appendix F). This would suggest that, theoretically, at least, some 2.4 billion kWh might be exportable to the grid. Many factors would tend to limit the actual potential such as the small size of many mills, isolated locations, and lack of nearby distribution systems. However, large mills or clusters of small mills could provide most or all of this electric power using wood waste and save substantial quantities of ADO. Large mills or mill clusters could also sell power to a local electric cooperative serving local villages where mill workers live.

Wood waste power generation is not likely to be as inexpensive as other sources of cogenerated power such as fertilizer plants or oil refineries. This is because wood waste boiler/steam turbine systems have high capital costs (between $1,300 and $1,500/kW). Nonetheless these systems can provide power to a local area - or to the PLN grid - far cheaper than PLN's usual alternatives. Recent estimates for wood-based power generation are in the range of 4-5 cents/kWh. This is roughly the equivalent of PLN's cost of diesel fuel alone in Kalimantan(13).

A distinct advantage of power generation from wood waste at sawmills and wood products factories is that it is an old and established technology. Modern developments have enhanced the technology's potential for remote sites in that it can now be provided in the form of reliable, standard plants. There already exists in Indonesia the capability of manufacturing boilers of the size needed for typical 1 - 3 MW installations.

**Enhanced Oil Recovery**

Enhanced oil recovery through steam flooding offers substantial prospects for cogeneration of steam and electricity, if a suitable market exists for the power. With this technology, steam is injected into wells in heavy oil fields to heat the oil and increase recovery rates. Either gas turbine or steam turbine technology can be utilized. To date, steam flooding has been used primarily in heavy oil fields, but the technology is proving to be competitive with $CO^2$ and water flooding in lighter oil fields as well. Steam flooding is being utilized in the Duri field in Sumatra, which is operated by P.T. Caltex, Texaco, and Chevron. This project is one of the largest steam flooding projects in the world. Clearly, the technical potential for inexpensive power production from such a project would be tremendous. However, the location of the project, in the coastal swamps of East Sumatra, may severely limit the sale of power from such a project. More detailed study of this project would have to be undertaken to establish its feasibility.

While the Duri field is the largest heavy oil field in Indonesia, other heavy oil fields do exist. Steam flooding at light oil fields is also a future possibility. The feasibility for cogeneration should be investigated for oil fields located closer to more populated areas.

## 6. Financial Analysis for Installation of Cogeneration Systems

### Heat Recovery System Retrofit

In order to be more specific about the economic benefits of cogeneration, we present here a representative calculation of the return on investment for the installation of an exhaust heat recovery system. The analysis is based on the system being installed on an existing 5 MW diesel plant operating at a capacity factor of 0.7. The heat recovery equipment consists of a single water tube heat recovery boiler with a design pressure of 2 bar. The project would require the manifolding of all diesel exhausts to a single header feeding the boiler. The boiler would be equipped with necessary feedwater and control systems. The cost is based on typical costs for such equipment in the U.S. plus 25% to cover contingencies, since this equipment is not yet widely used in Indonesia.

Assumptions

| | |
|---|---|
| Plant Size: | 5MW |
| Capacity Factor: | 0.7 |
| Average Load: | 3.5MW |
| Fuel Consumption: | 1050 1/hr |
| Heat Recovered: | 5.9 MM BTU/hr |
| | 2.66 ton/hr steam |
| Fuel Value of Steam | 281 1/hr |
| Assuming 75% Boiler Efficiency: | |
| Annual Value: | Rp 407 million/year |
| | $248,000/year |
| Installation Cost: | Rp.72 million/ton for 3.6 ton/hr boiler |
| | Rp. 259 million |
| Payback Period: | 0.6 years |

The analysis assumed that only 75% of the recovered heat is utilized to account for intermittent thermal loads. Based on this analysis the system would have an installed cost of Rp. 259 million. Annual fuel saving for boiler fuel would total Rp. 407 million. The simple payback period would be about 0.6 years.

This system would boost the overall fuel use efficiency to about 46%. Far higher efficiencies (up to 65%) could be achieved if a system were installed which recovered jacket water heat as well as exhaust gas. However, each facility would have to be investigated on a case-by-case basis to determine the type and quantity of heat loads to then determine what type of heat recovery system would offer the most favorable payback.

**Wood-Fired Steam Plant**

An existing plywood mill is investigating the installation of a wood-fired steam generation system to reduce its utilization of diesel fuel, currently used for electricity generation. The plant generates 5500 M3/month of wood waste. The waste is 50 percent green and 50 percent kiln dried and has an average calorie content of 3300 kcal/kg. The plant engineer selects a 2000 kW steam turbine generator and a 20 ton/hour wood-fired boiler which generates superheated steam at 41 bar/400$^{o}$ C. The turbine exhausts steam at 1 bar pressure for process use. The turbine has a water rate of 10 kg./kWh.

If operated round the clock the turbine generator would produce an average of 1750 kW of power or 14.4 million kWh annually. Assuming the diesel plant produces power at a fuel cost of 66 Rp/kWh, the steam plant would save 950 million rupiah per year in diesel fuel (4.3 million liters).

The cost of such an installation would be about US $1800/kW or 5.9 billion rupiah. The simple payback period, based on fuel cost along would be about 6.2 years.

The economics of this project would be more attractive if it were installed at a new plant where the installation would replace both diesels and a low pressure wood boiler to generate steam for process use. In this case the incremental capital cost for the project would be about Rp 2.4 billion and the payback period for the added investment would be 2.5 years.

### 7. Further Analysis

From this preliminary analysis cogeneration appears to have a significant potential in Indonesia not only of providing additional power to the grid in a short length of time but also of reducing the cost of electricity to consumers. Clearly our evaluation has been very preliminary and further work is required. It would be advisable for future work to be undertaken by, or in close collaboration with, P.T. Koniba, the national energy conservation enterprise since their initiatives relate closely to those proposed here.

## D. BIOMASS/RENEWABLE ENERGY SYSTEMS

### 1. The Central Issues of Renewable Energy in Indonesia

Analysts have for many years noted the large amounts of energy embodied in Indonesia's biomass. Particular attention has been paid to agricultural wastes and to wood as produced in the natural environment, grown for energy purposes or as a waste product in the wood products industry(45). General studies which tally the large amounts of energy available in such biomass are of little benefit, however, unless they address the critical issue of how those resources can be mobilized and converted into useful energy.

The issue of renewable energy in Indonesia is only partially a technical issue; more critical are the policy, institutional and financial issues that must be resolved before biomass can be considered a practical energy source.

Modern energy systems depend on economies of scale and interconnected systems. A petroleum economy depends on complex production, refining and distribution networks. The growth of PLN's system is based on centralized power production and the extension of a sophisticated, integrated power grid. Renewable energy, however, is by definition decentralized. The resource is large in aggregate but highly dispersed. Biomass (mostly wood) now accounts for over 40 percent of energy consumption and is produced in the most dispersed manner possible and is processed (burned) at the smallest scale possible. Even in commercial applications, the dispersed production of biomass is not particularly

compatible with large centralized plants (at the national or provincial scale). Investment in and production of energy from biomass would, on the other hand, seem to be a natural activity for the private sector which can operate efficiently in a small and dispersed mode.

Although not considered directly in this study, other work has identified small scale hydropower as a promising technology for private power production. In a recent study of West Java, for example, small scale Hydro was found to be the technology having the most widespread potential and the highest rates of return(52).

In the previous section we discussed the use of wood waste in cogeneration systems. Here we discuss, as a further example of the potential for private investment, the direct combustion of rice residues for power production. As will be seen, there are technical and economic barriers to the immediate commercial application of this technology but its potential developmental benefits justify increased national attention.

**2. Rice Husk Combustion Technology**

Although rice husks have been used as fuel in rural brick kilns, efficient systems utilizing the full BTU potential (6200-6400 BTU/lb) of this large fuel resource have only recently been developed. The high silica content of rice husks and rice husk ash can produce serious handling problems and slagging. New systems have conquered these old problems, however. Two commercial systems currently available in the U.S. have the following characteristics:

System A: uses 3,500 lbs. husk per hour to produce 15,000 lb/hr of 125 psig steam for a rice parboiling process plus 5,000 lbs. of husk per hour to produce a 2200 degree F hot gas stream used in a rice dryer.

System B: uses 250-300 tons of husk per day to produce 11,200 lbs. per hour of 650 psig steam which runs a generator producing 10.6 MW of electricity.

**TABLE 15**
**TOTAL RICE PRODUCTION AND POTENTIAL HUSK PRODUCTION BY PROVINCE IN 1985**
**(1,000 metric tons/year)**

| Province | Total Production[a] | Potential Production[b] | | |
|---|---|---|---|---|
| | | Rice | Rice Husks Produced | |
| | | | Rough Husks | Smooth Husks |
| DI. Aceh | 716 | 915 | 229 | 16 |
| Sumatera Utara | 1,473 | 2,022 | 506 | 35 |
| Sumatera Barat | 923 | 1,354 | 338 | 24 |
| Riau | 210 | 329 | 82 | 6 |
| Jambi | 293 | 455 | 114 | 8 |
| Sumatera Selatan | 930 | 1,093 | 27[illegible] | 19 |
| Bengkulu | 116 | 247 | 62 | 4 |
| Lampung | 785 | 1,081 | 270 | 19 |
| DKI Jakarta | 25 | 35 | 9 | 1 |
| Jawa Barat | 4,537 | 8,528 | 2,132 | 149 |
| Jawa Tengah | 5,189 | 6,904 | 1,726 | 121 |
| DI Yogyakarta | 436 | 641 | 160 | 11 |
| Jawa Timur | 5,033 | 7,594 | 1,898 | 133 |
| Kalimantan Barat | 427 | 587 | 147 | 10 |
| Kalimantan Selatan | 733 | 842 | 271 | 15 |
| Kalimantan Tengah | 145 | 210 | 52 | 4 |
| Kalimantan Timur | 165 | 141 | 35 | 2 |
| Sulawesi Utara | 495 | 263 | 66 | 5 |
| Sulawesi Tengah | 226 | 260 | 65 | 5 |
| Sulawesi Selatan | 1,941 | 2,539 | 635 | 44 |
| Sulawesi Tenggara | 71 | 105 | 26 | 2 |
| Bali | 583 | 759 | 190 | 13 |
| Nusa Tenggara Barat | 56[illegible] | 952 | 238 | 17 |
| Nusa Tenggara Timur | 1[illegible] | 258 | 64 | 5 |
| Maluku | 28 | 20 | 5 | - |
| Irian Jaya | | 5 | 1 | - |

Notes: Conversion factor (sun drying)
rice = 68%
rough husks = 25%
smooth husks = 7%

Source a. Ministry of Industries
b. Central Bureau of Statistics

## 3. The Resource Base

In 1986 milled rice production in Indonesia was 26,129,000 tons. Milling of that rice also produced over 6.5 million tons of rice husk. Mobilization of 25% of this husk (1.8 million tons) and at a 1:1 ratio of available straw to husk an additional 1.8 million tons of straw could give a net available energy feedstock of 3.6 million tons. Using feedstock consumption rates of the U.S. systems (18,000 tons/year/MW for low pressure systems and 8,500 tons/year/MW for high pressure systems) the gross power potential from 25 percent

of the available husk and straw would be 200-423 MW. Given the different combustion characteristics of rice husk and rice straw, these feed stocks could probably not be used as a mixed fuel. Rather, husk would be burned during milling and straw baled and stored for off-milling season use. Combustion systems would be adjusted accordingly.

## 4. The Availability of Residues

Although the majority of rice husks and straw in the country goes unused, competing uses exist for a portion of the residue. During the dry season, husks are burned for fuel or mixed in mortar by brickmakers. If sold commercially, prices for rice husks generally run 3-4 Rp/kilo bag (US cents 0.2/kilo bag), but within a village it is often given "free" to the brickmaker. Charred rice husks also are sold at rural or urban markets as domestic cleaners, with the farm price for the husk (2-5 Rp/kilo) being one-tenth of the retail price. Rice husks may also find some use as a household fuel. Use as chicken feed, at about 5 Rp/kilo, is another. While some data suggest a higher figure, the general consensus from different Government sources and farmers is that at most only 10 percent of the available rice husk is currently used, with use being regional.

Similarly, rice straw has few but occasionally important competing uses. The primary use is for nutrient recycling and soil conditioning through returning the straw to the fields. The actual value of this use and its importance in terms of fertilizer is unknown, but agronomists are skeptical given the limited nutrient content of rice straw. A small use for mushroom growing, cattle feed, and as filler at pulp mills is reported, but prices were not found, except uncorroborated pulp prices. A full feasibility study of rice husk use for energy should include a consideration of these alternative uses.

When originally presented with the technical necessity of straw collection, some of those interviewed reported that collection and transport of straw would be a major problem. However, straw has reportedly been in use at two pulp mills, at Padalarang close to Bandung and at Magelang in Central Java, for producing low grade paper since the 1940's. Market prices and a transport system for straw collection are presumably well established in these areas. Farmers apparently collect straw in the fields and middlemen

pick up the straw and transport it to the mills. Transport by local trucking companies employs 2-3 men/truck and makes several trips per day. More information on pulp mill use of rice straw is needed by any firm attempting a transport system for straw use in rice residue energy systems.

## 5. System Considerations

To assure all villagers had access to milling, to increase national marketing potential, and to raise employment and incomes in the rural areas, over the last decade the Government encouraged the milling industry to decentralize and introduce smaller (usually Japanese) milling equipment. As a result, the average capacity of Indonesian rice mills is extremely small, 1-4 metric tons per day, as contrasted with the existence in Thailand, for example, of several 1,000 ton/day mills. The Indonesian trend towards smaller scale and decentralized mills means that few mills have sufficient on-site rice husk feedstock to meet the resource feedstock requirements of the commercialized electric generating system. These are in the 10 MW range and have husk fuel requirements of 250-300 tons per day. Unfortunately, smaller systems, in the 1-2 MW range are not yet proven commercially and will have higher capital costs per unit of capacity, perhaps by a factor of two. Thus, if rice residue energy systems are to be introduced now in Indonesia, they will need to draw upon rice straw as well as husk for feedstocks and/or be located near a cluster of the largest existing mills.

With continual increases in rice yields, the Indonesian rice market is beginning to see product differentiation and the emergence of high priced (600-900 Rp/kg. versus 300-400 Rp/kg.), high quality rice. It is possible that such product differentiation will help to reverse the decentralization trend, since larger, more modern mills are needed to produce higher quality products. With a substantial projected excess demand, more rice will need to get to market and greater pressure will be put on the industry to continue increasing yields and to centralize and modernize its processing facilities.

In certain areas, rights to the value of the rice husks and straw may be under different or questionable ownership. Normally, the landowner would be paid for the straw

and rice millers paid for the husks. In order to get crops off the field in a hurry, there has been a recent revival in some areas of an old system for harvesting rice, "cebasan", whereby a contractor buys the crop from the farmer in the field and harvests the field, making ownership of the straw questionable. If straw and husk suddenly become valuable, contractors and farmers may need to revise prices due to the increased opportunity cost of the straw and husk.

To promote small milling units, the Government also supported the development of village cooperatives (KUD's). The number of KUD's for rice milling rose dramatically from 1,600 in the early 1970's to over 7,000 on the books by the mid-1980's. Given the inherent difficulties in establishing cooperatives, only 50 percent of these are reportedly functioning cooperatives, and only 20 percent are fully equipped with mills. In addition, only 10 percent of this 20 percent are commercial - i.e., selling rice to the formal market.

The dominant organizational structure for milling, however, is not cooperative in nature. Most milling is done by extended families that own the mills and often also the transport- wholesale-retail chains. Organizing by cooperatives or attempting to form consortia of different rice mills to gain scale economies for energy systems may therefore be difficult. Given this prevailing milling pattern, interested groups of private entrepreneurs or mills associated with the Government may be the likeliest organizations for installing energy production.

### 6. Financial Considerations

As discussed in Chapter V, there is a variety of sources of investment capital in Indonesia. Compared with other power investments, rice residue energy systems would require quite small (US$2 - 5 million) investments, and could be handled by regional or possibly cooperative banks. The higher perceived risk of private power generation, particular rice residue generation, compared to alternative domestic or international investment opportunities is a potential problem, however. These issues are discussed more fully in the next chapter.

With adequate assurances, it is possible that foreign equipment manufacturers in joint venture or BOT arrangements would invest in rice energy production if economically viable. Some U.S. firms are currently in Indonesia exploring the financial feasibility of private sector involvement. Given that technical feasibility needs to be proven at small scale and that the various economic constraints mentioned above affect investment in such systems, it may be that initial investments could be sponsored by the Government at the larger rice mills.

## 7. Development Implications

With rice the main staple for most Indonesians, rice production is basic to the livelihood - jobs, income and diet - of rural and urban people. Rice production has grown by 6 percent annually between 1976-1985, shifting Indonesia from a rice importer to having a large surplus in 1985. The Government's high priority for the rice sector through substantial infusion of subsidies for farm inputs - fertilizer, credit, pesticides and extension - has been extremely successful.

By improving agricultural waste utilization with rice residue energy systems, additional off-farm incomes and jobs are created while also increasing the value-added of the product. Creation of rice reside energy systems would add jobs in collection, transport and storage/handling of the feedstock as well as operating the plant and selling the ash by-product. Building upon existing product networks, waste utilization industries can be an important component in rural industrialization. Such systems also add to the self-sufficiency of rural area.

## 8. Conclusions

While the potential benefits of rice residue energy systems are appealing from a development point of view, their viability in Indonesia depends on bridging the gap between the scale of currently economical power technology and the scale of rice milling

in Indonesia. A demonstration of the system would depend on a decision by the Government to install a modern large-scale (at least 250 T/day) mill incorporating a rice residue power system.

## E. THE IMPLEMENTATION OF PRIVATE COGENERATION AND RENEWABLE SYSTEMS

We discussed above several key issues related to the implementation of large scale private power systems. The issues related to the implementation of private cogeneration and renewable energy systems are quite different and are discussed here.

### 1. The Implementors

A practical barrier to the implementation of cogeneration systems is the simple question of who is going to do it. In many instances the operators of the facilities, whether they are refineries or LNG plants or wood processing plants, have other business interests and concerns than power production. Furthermore, they often do not have the requisite technical expertise.

A natural solution to this barrier is for a third party or parties to go into the business of cogeneration. This party may be a joint venture between an Indonesian and an overseas firm. There are a number of advantages of this kind of operation. First, it creates an entity whose primary interest is in efficient private power generation. Second, it can take advantage of economies of scale, both from a technical and a management point of view. It would be advantageous to develop standard modules for cogeneration and heat recovery systems.

These same principles apply to the development of renewable energy systems. The distributed nature of all these power production opportunities does not contradict the economic benefits of centralized manufacture, standardized equipment, common technical

repair and maintenance, etc. Indeed, the success of small scale decentralized power systems may well depend upon the existence of large scale private entities to promote, implement and service them.

## 2. The Institutional Structure

Implementation of power purchase agreements between PLN and private power producers will require resolution of a number of significant issues and the issuance of new regulations clarifying government policy. These issues are discussed below.

### Pricing

A methodology must be developed to determine appropriate prices for purchase of power by PLN. To date, proposals to sell power to PLN have been evaluated on the basis of the seller's cost of production with some consideration being given to PLN's tariffs. However, in order to give the correct economic signals, buy back rates should be based on PLN's actual marginal costs or "avoided costs". These avoided costs should be based on realistic capacity expansion and investment plans and should be calculated on a regional basis since costs vary widely across the country. They should also be updated periodically.

For instance, on Java, where excess generation capacity exists, the initial marginal cost would probably be equivalent to the energy costs (fuel and operating costs) of the most expensive plant (generally gas turbines). As growth in demand consumes the current excess capacity, however, if the cogenerator can supply power when PLN needs it, then the price paid should include a component reflecting PLN's avoided capital cost component as well.

Off Java, in areas that are capacity short, or will soon need new capacity, marginal costs should include a capacity component as well as an energy cost component. Plants which can supply power on a reliable basis should be paid a rate to reflect both energy and capacity costs. Rates should also be adjusted to reflect transformer and transmission losses or savings. Responsibility for dispatch must remain with PLN,

subject to stipulations on aggregate purchase amounts in the contract. In that context additional purchases may be negotiated on a daily basis if the seller has excess energy and PLN wishes to buy at the seller's price. This would constitute a spot market transaction.

**The Long Term Standard Offer Concept**

Establishing the framework for private power production will require compromise between the interests of PLN and the interests of private producers. It is for this reason that a strong agency representing the public interest in mediating between PLN and private producers is required.

In order to accomplish an efficient implementation of private power it is necessary to develop a regulatory system with some generic guidelines or approaches. Treating each proposal as a unique case is both inefficient and does not provide sufficient guidance to potential private producers in deciding whether or not to proceed towards a proposal.

A key element of the framework for private power production could be some kind of standard offer by PLN to purchase power. Such "standard offers" have been the basis of utility purchase of private power in the U.S. for several years (53) (see Appendix E). They provide potential private power producers with a clear set of criteria and prices over time under which power will be purchased. Associated with each standard offer is a pre-specified limit on the total amount of capacity that the utility is willing to purchase as a function of time, based on its capacity expansion plan.

One difficulty in arriving at a standard offer results from the uncertainty of the future. PLN may contract with a peat-fueled power producer based on a favorable comparison with $18/bbl oil. If oil decreases in price to $14/bbl PLN may be paying more for power than its cost. However, there is also the possibility that oil will cost $22/bbl in the future in which case PLN will be saving more money than originally calculated. The decision must be made on a risk-weighted, expected value basis.

In some cases, in which private power is produced using fossil fuels, it would be possible to include some variability in the purchase price. Normally, however, it will be required to fix the price schedule in advance in the standard offer based on projected fuel costs to PLN.

Another possible approach, appropriate for rural areas to be electrified by a private power company, would be a competitive bidding system for the entire area. This implies some form of contractual arrangement in which the supplier agrees to maintain a tariff schedule (which formed the basis for his bid) similar to a standard offer. The risk in such arrangements is that for one reason or another the supplier may find it impossible to supply power profitably at the agreed-upon rates and may withdraw. This suggests a bonding approach and a role for a regulatory body in approving tariff adjustments.

**Contracts and Interconnection Issues**

Before a private company can commit capital or obtain financing for a power project, it will probably require a long term (10-15 years) commitment for sale of power. PLN must be willing to enter into long term agreements if private investment in the power sector is to occur in Indonesia. In addition to a schedule of buy-back rates, such a contract would spell out a variety of other conditions:

- The responsibilities of each party for the costs of installation and maintenance of interconnection and metering equipment;

- Specifics regarding the type of protective relaying equipment required to protect each party from irregularities on the other system;

- Specifications for the quality of power to be required by PLN (frequency range, voltage range, harmonic distortion, reactive power);

- Standby power provisions in case of an outage on the seller's system;

- A provision permitting PLN or DJLEB to inspect a private power producer's equipment to ensure it complies with necessary codes.

The reliability of supply of privately produced power will be a central concern to the buyer, whether that be PLN, a rural area or an industrial complex. If private power is to play a major role in the future, reliability must be addressed in parallel with cost. In rural electrification reliability should be addressed through the licensing or regulatory process. For private power sales to the grid, reliability can be addressed through the contractual arrangements for the purchase of power.

**Organizational Issues**

The Ministry of Mines and Energy (MME) presently receives and processes proposals for permits to operate captive power plants. MME therefore appears to be the logical agency to review and approve applications for sale of power to PLN. MME should also be responsible for reviewing PLN's proposed buy back rates and for mediating disagreements which might arise between PLN and private power producers regarding pricing, provisions for back-up power, and technical issues.

There is a need to develop and implement standards for electricity generation, transmission and distribution by private producers. The poor quality of many of the current very small private installations raises a concern for the protection of the public. In some cases it may also be envisioned for PLN to eventually take over a local system once its transmission system is extended to the area. In that case the distribution system should be at least up to PLN's standards to avoid duplicate investment. Such standards are already under development at MME.

For stand-alone power systems which might sell power to an electric cooperative, design, operation, and maintenance standards should be developed to assure the safety of the system. Provision for periodic inspection of such systems should also be made.

# V. THE FINANCIAL AND INVESTMENT CLIMATE

## A. THE FINANCIAL SITUATION

As suggested in the introduction to this report, Indonesia's current financial situation provides a strong incentive to replace some portion of government financing of the power sector by private investment.

Largely as a result of reduced oil export revenues, Indonesia's balance of payments deficit grew from US$ 2.7 billion in 1985/86 to $5.1 billion 1986/87. The fact that a large portion of Indonesia's debt is denominated in yen, while more than 60 percent of exports is denominated in dollars along with recent declines of the dollar against the yen has also contributed to a sharp increase in the debt service ratio. This year that ratio is expected to exceed 40 percent(47) - a level at which, traditionally, lending institutions start to become concerned. This situation has even led to public discussion in Jakarta of the possibility of some form of debt rescheduling(50) a move which would itself damage the country's credit worthiness.

Foreign assistance project financing remains strong. The Inter-Governmental Group on Indonesia (IGGI), the consortium of Indonesia's main aid donors, recently increased its commitment from US$2.5 billion last year to $3.16 billion in 1987/88.

Despite the debt situation, many commercial lenders currently view Indonesia as a good credit risk. This viewpoint reflects their perception of the responsible way in which the government has managed its balance of payments problems and is supported by a favorable report by a recent mission by the Institute for International Finance. In fact, Indonesia currently has over US$2 billion of unused commercial bank credit lines available to it.

Nonetheless, the fact remains that there is a much higher concern about the level of Indonesia's debt now than any other time in recent history. As described recently by Sarwar Hobohm:

> "Given the already high debt burden facing Indonesia and the indispensability of further external funding, significant efforts to ensure a reduction of the future burden imposed by this borrowing on the balance of payments and the Government's recurrent budgetary expenditure become inevitable. This is especially true in view of the likely persistence of these resource constraints for some time to come, the Government's aversion to a rescheduling of its debt service payments and the loss of international creditworthiness it will entail, and the continuing imperative for a rapid pace of economic development imposed by the need to provide income and employment opportunities for Indonesia's rapidly growing labour force."(50)

In recent years, the power sector has constituted 9 - 13 percent of government expenditures. Several factors, beyond general budgetary constraints argue for the replacement of part of that investment by the private sector:

1. Income elasticity. Power consumption is expected to increase at 1.1-1.3 times the rate of growth of GDP. Even if the national budget increased, expenditures on power would demand an increasing fraction of the total.

2. Social Implications. Budgetary restrictions are apt to damage socially important programs in the health and educational sectors unless increased fractions of the national budget are allocated to those sectors, with resultant pressure on the power sector. Likewise, under these conditions increased emphasis is likely to be given to relatively labor-intensive programs. Power projects are typically capital-intensive rather than labor-intensive.

3. Opportunities for the Substitution of Private Investments. In other priority development areas such as health and education, and to a certain degree agriculture, there

is little possibility for private investment, because of the lack of a clear financial return. The power sector is one of the few areas in which a major substitution can be made for government investment by private investment.

Whether such investment will be forthcoming, however, depends on a number of factors including perceptions of risk, returns from alternative investments, Government incentives and regulations regarding such investments. This chapter reviews these various factors and identifies those conditions which could improve the climate for private investment in the power sector.

## B. THE FINANCIAL SYSTEM

### 1. Banks

The banking system has evolved quite rapidly since the banking sector deregulation of 1983 which replaced quantitative credit controls with market controls, eliminated interest rate ceilings on deposits and loans and began the phaseout of subsidized credit to State-owned and "priority" borrowers.

All banks are heavily dependent on self-funding due to the prohibition since 1985 on interbank borrowing exceeding 15 percent and to the immaturity of the rediscount market. Due to interest rate changes following deregulation, the share of time deposits with maturities exceeding one year has fallen from 69 percent in 1982 to 8 percent. This, in Indonesia's open foreign exchange regime, has led to runs on deposits whenever currency depreciation leads depositors to prefer to hold US dollars. As a result, banks are unwilling to make term loans.

**Central Bank**

The Central Bank, Bank Indonesia (BI), uses four principal techniques to control the supply and application of credit in the system:

1. Auction of BI debt instruments, which can be bought and sold in open market operations to regulate the money supply. BI issues its own notes because the Central Government is required to run a balanced rupiah budget; no equivalent of U.S. Treasury bills exists.

2. Money market certificates. A bank may rediscount part of its portfolio to other banks or - since 1985 - to BI, to obtain additional resources. Three factors have greatly limited the growth of this instrument. First, closely-held firms do not permit their banks to securitize their debt (revealing the extent of their borrowing). Second, the 1985 regulation limits interbank borrowing to 15 percent of a bank's deposit base. Third, BI has recently claimed the right to force banks to repurchase these certificates in order to tighten the money supply sharply.

3. Priority Sectors and Liquidity Credits. These are a holdover from before deregulation, except for a few very limited priority sectors (particularly small businesses, exports, and plantations) plus the Foodgrains Stabilization Board BULOG. They were and continue to be financed by BI liquidity credits, BI providing 75 - 80 percent of the loan amount as a subsidized credit to the lender who in turn offers preferential terms. Such credits are only available to local investors (and majority local joint ventures) through local banks. A substantial portion of non-performing loans in state bank portfolios falls under the various priority programs, which are based on political and developmental necessity more than on commercial viability.

4. Parastatal deposits with the banking system. In early 1987, faced with the need to tighten the money supply sharply in response to currency speculation, BI used its power to persuade Government entities and State-owned enterprises to withdraw their substantial deposits from the banking system.

**Government Commercial Banks**

The five government commercial banks represent roughly 71 percent of banking

system assets, down from 85 percent before deregulation. Although since 1983 these banks have a dual mandate as "agents of development" and profit-making enterprises, their loss in market share suggests that they are slow in adapting to the latter regime. These banks have large deposit bases and are the required depositories for Government enterprises, institutions and pension funds; the interbank money market channels some of their excess liquidity to the private banking sector. The largest bank is BNI-1946 being almost twice as large as the second place BBD.

**Private Local Banks**

The 70 local private banks have expanded aggressively since deregulation and now represent 21 percent of assets, despite limits on interbank borrowing. These banks provide mainly short-term working-capital credit. Ten are licensed to engage in foreign exchange transactions. Several are military related, but many more are small, primarily serving the needs of commercial and industrial enterprises under holding companies mainly owned by ethnic Chinese. The three largest private local banks, BCA, Pan Indonesia Bank, and Bank Duta, together have one-third the market share of the smallest state-owned commercial bank, BEII. They and Bank Niaga have foreign branches.

**Foreign Banks**

Foreign banks make up less than 5% of the market; their activities are limited and market share is dropping. They are limited to the Jakarta area for lending in local currency and cannot commit to a loan that exceeds one year. Nevertheless, local currency loans may be rolled over and, for all practical purposes, are evergreen. They may do foreign currency lending outside of Jakarta but under current regulations they cannot hedge their positions. However, since their deposit taking activities are limited to their liquidity positions they are at the mercy of the Central Bank and Government banks. Consequently, they maintain conservative gap positions.

Many of the current restrictions on foreign banks will be lifted under pending bank legislation. It should also be noted that many foreign banks maintain representative offices in Indonesia, with lending taking place offshore, usually in Singapore.

### Development Bank

There is only one national development bank, BAPINDO, and 27 Regional Development Banks. These latter, however, mainly concentrate on providing commercial banking services and providing treasury-type services for the provincial governments which operate them. Sources for long-term funding through these organisms include the World Bank, ADB, USAID, BI and the budget. BAPINDO has been an important source of finance for state-owned enterprises, who are responsible for most of its arrears.

### Other Banks

There is also a cooperatives bank (BUKODIN), 3 savings banks (one state-owned, 2 private), and more than 5000 secondary banks throughout Indonesia whose role in the country's financial sector is negligible due to their limited resources.

## 2. Other Financial Institutions

### Merchant Banks

Most major banks have merchant bank affiliates, usually in partnership with foreign financial institutions. Currently they are relatively inactive and, in fact, function primarily as commercial banks. With the August 10, 1987 regulations they may play a more active role in financial and capital markets.

### Leasing Companies

The number of leasing companies has been severely reduced, down to 73 at the end of 1986 from several hundred. The feeling is that the major ones are product arms of financial institutions rather than stand-alone entities.

### Finance Companies

There are seven or eight finance companies. They are small and not important players in the market. They raise funds by issuing short term promissory notes (1 to 6 months) at rates slightly higher than TD rates. They do not come under the supervision of

the central bank and therefore have no reserve requirements. They are also considered a riskier place to place money since in a liquidity squeeze they would not get Central Bank support as would the commercial banks.

**Venture Capital Companies**

There are two venture capital companies, both small and relatively inactive, PDFIC & INDOVEST. Their principal activity is managing Government issues. PDFIC is majority owned by the Government while INDOVEST has minority ownership by the Government.

### 3. Institutional and Private Investors

**Danareska**

Danareska is state owned mutual Fund (Unit Trust) established for the purpose of broadening the ownership of shares. By law they are authorized to purchase 50% of any issue of bonds or stocks. They currently own 50% of all shares and 25-30% of all bonds that are listed on the stock exchange. This authority is also a minor disincentive to the development of capital markets since, effectively, Danareska sets the offer price of an issue. Danareska certificates may not be sold to foreigners.

**Pension Funds**

The principal Government pension fund (TASPEN) has substantial funds to invest and is authorized to invest in stocks and bonds. Currently they have some funds in bonds but most investments are in time deposits. As an investor this fund is in a privileged position against other Government and private funds since its investment income is tax free.

There are currently many private pension funds with investable funds that are looking for investment vehicles. The new law will require all companies to have pension funds in addition to the state pension funds. These could be a source of investments in the power sector. It is said that oil company pension funds are actively looking for investment alternatives to bank deposits.

**Insurance Companies**

Private insurance companies are not investors in the capital markets. Their investments are primarily in time deposits because of the tax exempt status of these instruments and in Danareska certificates. These latter are provided liquidity by Danareska's willingness to repurchase. The Government Social Security Insurance Corporation (ASTEK) is authorized to hold stocks and bonds but only in local currency. It currently has a minor holding in bonds. Other insurance companies may invest in foreign deposits, shares and bonds, although private insurance companies currently are not particularly strong financially.

**Private Mutual Funds**

Private mutual funds will soon be authorized. Discussions are currently under way with five or six foreign investment houses with a view to their establishing such funds.

**Stock Market**

The stock market is small and inactive with only 20 or 25 companies listed and daily turn-over less than $10,000. The value of shares listed has dropped dramatically since it was established. The original purpose of the stock market was to facilitate divestiture by foreign firms. This has not occurred since, when divestiture occurs, the local partners usually buy out the foreign partner. It is probable that the same techniques used by foreign investors to "control" the original local equity contribution may apply to the process of divestiture. Furthermore, obtaining temporary waivers to the divestiture rules does not appear to be an overwhelming problem. Since most companies are closely held, it is unlikely that an equity market will develop rapidly. However, there is a strong possibility for a bond market. Three events need to take place before a bond market can become active:

a. Consistent treatment regarding taxation has to be created,

b. Investors will have to accept holding periods in excess of 4 or 5 years,

c. A secondary market will have to be created, so as to provide liquidity.

On August 10 a new regulation governing the operations of capital markets will be issued, considerably liberalizing the current regulations. Among the provisions of the new regulations will be the authorization for an over-the-counter market (OTC). Listing on the OTC market will be more liberal than on the stock market. The only requirements for a company to list will be to have been in operation for two years and the publication of a yearly independent audit. Profitability and other hurdles will not apply.

Market makers will be encouraged. They will include state banks, merchant banks and commercial banks. To be a market maker one must show a strong capital base and demonstrate in-house expertise. Market makers will be required to manage issues they make markets in for at least one year and, to provide liquidity, will be required to repurchase shares of issues they manage.

It is anticipated that market makers will also act as venture capital companies. The new regulations will also authorize private companies to issue bonds.

## C. THE INVESTMENT ENVIRONMENT

### 1. General

Private enterprises are closely held by small groups. The preference of these groups is to raise funding either from within the group or by bank debt. The reason for this preference is two fold;

a. Equity issues require disclosures which owners would prefer to avoid for tax and other considerations.

b. Owners are very reluctant to give up any control over the management of their organizations through dilution of ownership.

The possibility discussed above of new Indonesian mutual funds combined with the liberal rules governing the operation of an OTC market raises the interesting possibility of these mutual funds becoming a venue for small savers to invest their funds as well as vehicles through which companies will be able to raise equity.

It is the Government's intention to privatize some state run companies. The first step will be to allow competing entities to be formed in the private sector. Subsequently, shares in state owned companies will be sold. While there is some movement toward privatization it is still unclear how fast it will take place.

Currently Ministry of Finance approval is required for private companies to issue bonds. To date this approval has not been forthcoming. Only Government entities have received such authorization, the rational being that investment funds should be directed to projects of national interest. Under the OTC regulation to be issued in August private companies will be able to issue bonds without restriction.

**2. Private Investors**

Private investors can be substantial players in the capital and financial markets. They can be sources of short term financing as well as sources of equity. For the purposes of this paper the sources of short term funding are not relevant. However, large trading groups do exist such as the Astra group and the Liem S. Leone group which do make equity investments in projects together with outside investors.

Investors currently expect to get, at a minimum, a return on their investment at least equal to the after tax equivalent of the TD rate. In reality they expect to get a nominal return of 25 to 40 percent per annum. The usual maximum investment horizon is 4 years.

## 3. Disincentives

The taxability of investment income and the non taxability of bank deposit income is a serious disincentive to investment.

Regulations on foreign investment (see below) clearly are a disincentive when compared to other countries. But they may not be critical. Discrimination against foreign entities borrowing locally are a clear disincentive and may swing the balance against investment.

## 4. Statistical Data

After several years of reductions, investments appear to be on the rise again. The following are the numbers for non-oil, non-gas investments in the private sector.

Foreign Investment

| | |
|---|---|
| 1983 | $2.9 Billion |
| 1984 | $1.1 Billion |
| 1985 | $850 Million |
| 1986 | $823 Million |
| 1st Sem. 1987 | Indicated annual rate 1.24 Billion |

Domestic Investment

| | |
|---|---|
| 1983 | Rp 7 trillion |
| 1984 | Rp 2 Trillion |
| 1985 | Rp 3.7 Trillion |
| 1986 | Rp 3.8 Trillion |
| 1st Sem. 1987 | Indicated annual rate 4 Trillion |

Projected Growth In Investment

| 1981-6 | 1986-88 | 1988-90 | 1990-95 |
|---|---|---|---|
| -3.4% | 0.4% | 3.1% | 5.9% |

## D. GOVERNMENT REGULATIONS/ATTITUDES

### 1. Foreign Exchange Regulations

There are no exchange regulations which impede the free exchange of local currency into foreign currency and vice versa. The Central Bank does use monetary policy as a means of controlling the supply of credit which has, in turn, a dampening effect on speculation against the Rupiah.

### 2. Import/Export Regulations/Restrictions

In March 1985, the Government announced an across-the-board reduction in the range and level of nominal import tariffs. In April 1986, the Government completely reorganized the customs, ports and shipping operations as a means of reducing transport and handling costs, particularly of manufacturing. On May 6, 1986, the Government announced a package of measures designed to provide internationally priced inputs to manufacturers. All of these measures helped the cost structure of Indonesian industry. The import policy reforms announced on October 25, 1986 and January 15,1987 represent a fundamental shift in the direction of Indonesian import policy away from import licensing restrictions toward only tariff protection.

### 3. Investment Restrictions - Foreign/Local

Despite some liberalization the entry of foreign capital continues to suffer from several restrictions:

i. A foreign investor must have a joint venture with a local partner. Initial Indonesian participation must be not less than 20% (equity). However initial Indonesian capital can be as low as 5% if:

a. The project is designated to be in a remote area

b. Production is destined 85% for export

c. The project is greater than $10 million.

Only one of the above hurdles need be met to have the concession granted

ii. After 15 years the foreign investor must offer shares to Indonesians so that Indonesian equity rises to 51%.

iii. Minimum capital should be $1 million. Investments of less than 1 million are reserved for local investors. Some foreign investments of less than 1 million will be considered on a case-by-case basis, particularly in the service industry.

iv. Foreigners may not own a distribution facility unless equity is 75% Indonesian. There is some disagreement on how strictly or effectively these regulations are enforced.

Government entities may invest in private sector projects but must have Ministry of Finance approval.

While this is not the place for a detailed discussion, suffice it to say that the Government has substantially simplified the process and procedure for establishing a business (35).

## E. PERSPECTIVES FOR FUTURE CHANGE

Indications, both from the past and from proposed changes, tend to confirm that the Government is serious in liberalizing the conditions for the entry of foreign capital and is actively stimulating local investments. The development of capital markets is a clear agenda item with high priority. However, the same does not appear to be true of financial

markets. As long as the Central Bank can effectively control not only the supply and cost of credit but also its application, bank lending policies will be subordinate to Government development policies.

## F. CONCLUSIONS

Substantial funds are available from Indonesian interests for investment. These interests primarily are:

a. Institutional investors:

1. Pension funds - up to $6 billion available

2. Insurance companies

b. Other investors:

1. Merchant banking operations of private banks

2. Indonesian corporate investors

3. Individual investors.

Funds available from 2 and 3 above are estimated to be in the 20 to 100 billion dollar range. However, certain structural changes are required before these funds will be available for equity or term debt investments.

Local bank, local currency funding is available with terms up to 7 years. However, the availability of credit, the beneficiaries of credit and the freedom of decision exercised by lending institutions are under the effective control of the Central Bank. Commercial

banks are the only sources of substantial credit. Foreign banks cannot commit to loans with terms in excess of one year. Foreign currency funding from banks will probably not be available from international commercial sources unless the transaction can be turned into something other than Indonesian risk. Supplier credits may, however, be available particularly if extended under Exim Bank, OPIC or similar programs.

The Government has made substantial and substantive changes in order to attract and increase investment. More changes are planned and, if they continue, Indonesia will rapidly reach a regulatory environment on a par with other ASEAN countries as far as attracting foreign capital is concerned. Capital and financial markets remain underdeveloped, however. While efforts are being made to stimulate, broaden and expand capital markets little seems to be being done to improve and introduce flexibility into financial markets. For example, interest rates are managed to a high level in order to discourage capital flight. Furthermore, there continue to be three major disincentives to investment expansion:

a. In the tax system there is a clear bias against investment income since Bank deposits earn interest tax free whereas dividends, bond interest and capital gains are taxable. Furthermore, the Ministry of Finance has to date not authorized bond issues by private companies, restricting this privilege to Government concerns,

b. Foreign investors are not only not allowed to hold 100% of an equity investment, they must divest to a minority position in a certain time.

c. Foreign firms are discriminated against with regard to the availability of loan funds since they cannot get loan commitments which exceed 1 year. Furthermore, foreign banks may not lend in local currency outside of Jakarta. Finally, Government banks do not lend to foreign firms.

In terms of energy investment, from the point of view of the banking community, cogeneration appears to be of the greatest interest for the following reasons:

1. They see an opportunity to develop and expand a business relationship.

2. The transaction probably has limited foreign exchange exposure.

3. Since the transaction would be a private sector transaction there would be limited Indonesian sovereign risk.

4. Transactions would probably be small enough to be easily digestible.

5. They view stand-alone plants as probably the province of Government.

6. They view renewable energy systems, e.g. using rice husks, as experimental and the purview of venture capitalists and speculators.

There is a real question in the minds of investors as to whether the Government has the private generation of power as an objective to be achieved. If it does not then local financing in any useful quantity may not be forthcoming since the allocation of credit is largely controlled by the central bank and is directed to entities that are of "national interest". Foreign investors will naturally be wary, absent a clear policy statement by the Government, since the generation of power is a sensitive political issue.

Recommendations which derive from this analysis of the financial and investment context are contained in the next chapter.

# VI. CONCLUSIONS AND RECOMMENDATIONS

## A. GENERAL CONCLUSION

The fundamental conclusion of this study is that private investment in the power sector, if properly planned and managed, could be of significant benefit to the nation. The benefits to be obtained include an increase in the overall energy and economic efficiency of the power system; reduction in the local currency and foreign exchange burden to the national treasury (and thus in the national debt); and accelerated electrification of rural areas.

Absent private investment, economic development may be slowed due to constraints on public financing of the power sector.

While Law No. 15 of 1985 has created the legal framework for private investment in the power sector, these benefits will not be obtained if the present constellation of guidelines, regulatory procedures, incentives, investment regulations, tariffs and policies remain unchanged. The full benefits of private power will also not be achieved unless there is concerted Government action to establish a policy towards private power and to manage its integration into the energy system of the country.

## B. THE ESTABLISHMENT OF A POLICY FRAMEWORK

**A clear policy framework should be established for private power.**

The first step to be taken to encourage private investment in the power sector is to further elaborate the policies allowing private power enunciated in Law No. 15 of 1985. This would involve the development of a set of guidelines for potential investors which include the bases on which proposals for private power generation will be evaluated. As

described in Chapter III, the PURPA legislation in the U.S., as elaborated by the Federal Energy Regulatory Commission, and the utility commissions of the various States, provided such a framework for the U.S.

## C. LARGE SCALE PRIVATE POWER PLANTS

**Private financing of large scale power plants should be developed as a key integral component of national energy policy.**

It is likely that increasing needs for investment in the power sector confronting reduced Government revenues will severely hamper PLN's ability to finance planned electric capacity expansion. If private investment in the power sector is to help resolve this problem it must do so by investment in large scale power plants. The geothermal proposal before the Government would appear to provide the opportunity to take the first important step towards large scale private power.

Private investment and operation of large scale power plants holds the potential of a number of advantages. While the primary one is to reduce the financial obligation of the Government for expansion of the power sector, other advantages could be the transfer of new technology and the demonstration of efficient power plant operation. The issue is highly complex, however; quantifying the benefit of reducing Government obligations, balanced by certain conversion guarantees and possibly higher tariffs is by no means straightforward. Given the stakes involved we would suggest that a careful analysis of the costs and benefits of the BOT concept could be a useful contribution to energy policy-making in Indonesia and to the evaluation of individual proposals. In Chapter V we have identified some of the issues to be considered in such a study.

In the meanwhile, it would appear undesirable to link nuclear and fossil fueled BOT proposals. The probability of there being a significant cost associated with delay of the nuclear decision (until fuel and capital cost trends clarify) is low. Each option is sufficiently complex; each should be evaluated on its merits.

## D. THE ANALYTICAL FRAMEWORK

**A better-founded information base needs to be developed on key parameters of power costs and benefits.**

The Government of Indonesia clearly has been revising its policies regarding energy pricing and production over the past decade, with an emphasis on moving towards fewer price distortions between fuels and more efficient energy production. Major decisions regarding the promotion of private power sales in Indonesia need to reflect the full opportunity costs and benefits to the economy from optimal fuel mix, production systems, and financing options. The evaluation of private power proposals should be on the basis of the real costs of alternatives, not a pre-existing tariff structure nor primarily on the private producer's costs. The Government should identify and encourage those opportunities where the net social welfare gain from private power production is positive.

Government pricing policies are needed to provide decision rules when balancing the financial - private prices - against the actual economic costs of energy production in Indonesia. It is not clear that anyone now has a clear and coherent view of what those costs and benefits really are. An assessment is required of the full economic costs, which include: the true costs of production without market subsidies or taxes; long-run marginal costs; externalities from future pollution and environmental risk; and incremental value to the economy of reducing public sector debt through private sector energy investment. Explicit pricing guidelines are needed to help determine purchase prices paid by the utility to private energy producers. Such guidelines should reflect the utility's actual avoided costs (either full energy plus capacity or partial energy), at the private power plant location.

## E. RESOURCE DEVELOPMENT AND POWER PRODUCTION

**The Government should explore ways of involving energy producing companies in power generation.**

Large scale private power production should be construed as an integral element of energy resource development policy. In the case of Union Geothermal the resource developer found it in its interest to propose to sell power rather than geothermal steam. The Government should explore the possibilities and the implications of joint (or at least related) resource development and power production from natural gas and coal.

In the area of cogeneration, the energy companies, public and private appear to be logical leaders in developing projects to sell power to the PLN grid.

## F. COGENERATION

**A major new Government program should be developed to encourage private investment in cogeneration in industry.**

The value of cogeneration as a vehicle for private investment in power production resides in its inherent efficiency. Taking advantage of the need for both heat and power in certain industries, power produced from a cogeneration system can cost significantly less than PLN's current or future cost of production.

Significant potential for cogeneration appears to exist in Indonesia's fertilizer industry, the textile and wood products industries, in oil refineries and in LNG facilities. In total, the potential excess power that could be made available from these and related industries for sale to the grid could be on the order of 13.3 billion kWh (compared to current PLN production of 14.6 billion kWh). While it would not be practical to develop all of this potential, at least 30% should be economical and practical.

The energy industry of Indonesia itself has a great potential for inexpensive power production. Furthermore, it would seem to be a natural industry to be involved in generating power. Given the remoteness of much of the industry, however, the accessible demand may place a limit on practical production levels.

## G. RENEWABLE ENERGY SYSTEMS

**Continued attention should be paid to dispersed renewable energy systems to provide power to remote areas.**

A variety of renewable energy sources are suitable for private power production in rural areas. These include small scale hydropower, combustion of wood waste and agricultural residues and gasification of wood. While there are a number of projects in Indonesia which focus on research and demonstration of these technologies, increased attention should be given to institutional and financial aspects of their implementation. In particular, a framework should be developed whereby private firms could bid on the provision of power using renewable resources in certain defined areas of the country.

This project examined electricity production from rice residues in this light. The practical applicability of rice residue-fired steam boilers for power production is currently questionable, however, because of the mismatch between the scale of commercially available, economic systems on the one hand, and the scale of current rice milling operations on the other.

The developmental and energy benefits of this technology could materialize if, for reasons of product quality or efficiency, the Government decided to install a large (at least 250 T/day) mill or if current developments toward smaller scale husk energy technology are successful. In any event the economics of rice residue energy systems are very sensitive to location. Each application will require detailed site-specific analysis of social, economic, infrastructure and environmental factors. Project feasibility will depend on finding locations with load factors greater than 75%, firm rates for electricity sales, markets for rice husk ash and the availability of local transport and labor.

## H. THE FINANCIAL CLIMATE

**The power sector should be treated as a priority area for private investment.**

As suggested in Chapter V there is one basic change in the regulatory environment which would be beneficial in terms of all investment including that in the power sector. Consideration should be given to:

1. Re-aligning the tax system so that different investment alternatives are taxed at the same rate. Rates of return then will become a function of risk and tenure. Commercial rather than tax motives will drive investor decisions.

The following recommendations are specific to encouraging investment in private power generation:

2. Eliminate discrimination against foreign companies regarding the availability of local credit.

3. If the private generation of power is indeed a priority issue for the Government it should study the advisability of providing incentives for investments (e.g., investment credits, tax holidays, special lines of credit for power generation, etc.) to bring private companies to an equal footing with PLN.

## I. ENERGY AND INDUSTRIAL DEVELOPMENT STRATEGY

**A new power strategy should be linked with industrial development.**

It was pointed out in Chapter IV that there is a very substantial potential to generate power from cogeneration and in conjunction with other energy activities in various places in Indonesia. Many of the energy production areas and even the locations where waste (e.g., sawmill waste) is available are in remote locations with very little current demand for power.

A main thrust of Indonesian industrial development policy is to substitute increased value added products for traditional raw material and crude energy exports. In the energy and minerals sector this probably implies electricity - or at least energy - intensive processes.

In developing that higher value added industrial strategy consideration should be given to the potential availability of cheap power. This situation strongly recommends that the opportunities for cheap power (and fuels) be considered in the development of a national industrial strategy. As part of that strategy consideration should be given to privately-financed power/industrial parks.

## J. DEMONSTRATIONS

**Demonstration should be used to overcome current uncertainties and reluctance of private power producers.**

Private power production should not be based on new or untested technology. The institutional and contractual arrangements envisioned in this report, however, are new to Indonesia. Thus it would be useful to implement a small number of demonstration projects of private power production under a variety of circumstances to test and further develop those arrangements. Such demonstrations, if successful, would certainly encourage further proposals from the private sector.

The form of support for private power demonstrations which sell power to the grid could be a somewhat better purchase price or other terms than contemplated for the long run. This would compensate the producer for the risks of being first and for the additional costs of an active performance evaluation. There are proposals before the Government for private power production which could be the basis for these demonstrations.

In the large power area the current Union Geothermal proposal should also be viewed as having the potential benefits of a demonstration and should be given some "credit" for that fact.

The workshop suggested below would provide a context to further develop the concept of demonstrations of private power.

## K. A WORKSHOP ON PRIVATE POWER GENERATION

**A national workshop should be held on private power.**

If private power is to succeed in Indonesia there needs to develop a much higher level of concern, and a much more active flow of information between the Government, potential investors, entrepreneurs and the financial community. In order to further these objectives we recommend that a workshop be organized which will bring together the several communities which must be involved in such endeavors.

The specific objectives of the workshop would be:

1. Establish a consensus on the kind of policy framework which would be most conducive to the development of private power in the national interest. Attain agreement in certain elements of that framework (as suggested above).

2. Identify the major opportunities for private power production, in terms of technical potential, national benefit and benefit to the investor/entrepreneur.

3. Identify some specific projects that should be pursued on a demonstration or direct commercial basis.

A tentative agenda for such a workshop is presented in Appendix A. It is important that the workshop have an atmosphere of free and open discussion. The emphasis should be on the exploration of important technical and institutional issues and on technical, individual opinions rather than official or formal positions. Although the subjects identified for the workshop are categorized under technical headings (cogeneration, etc.) the discussion should focus primarily on the economic, financial and institutional issues involved with implementing such systems.

The workshop should emphasize the perspective of the national interest, however and the fact that it is serving to elaborate an existing national policy. Thus an appropriate title for the workshop could be: "Electric Energy Law Number 15/1985: Possibilities for Private Power Generation in Indonesia".

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# APPENDIX A

## Workshop Outline

**ELECTRIC ENERGY LAW NO. 15/1985:**
**THE POSSIBILITY FOR PRIVATE POWER GENERATION IN INDONESIA**

**Workshop Outline**

**SCHEDULE**

DAY 1. AM Background and Objectives

Greetings (MME)
Objectives of Conference and Procedures
Background Paper
- Energy, Power Background
- Investment Requirements and Constraints
- Summary of Options and Issues

PM.1 Industrial Cogeneration

Background Paper
- Concept and Technical Advantages
- Experience Elsewhere
- Potential in Indonesia
- Issues ( financing, purchase agreements)

Potential in the Wood Products Industry

Potential in the Energy Industry

Potential in Other Industries
- Fertilizer, Cement, Textiles, etc. )

PM.2 B.O.T. Concept

Background Paper
- Concept; Experience Elsewhere
- Advantages to Indonesia and Disadvantages
- Issues

Comments by Proposers
- Union Geothermal; KWU-Framatom; Canada; Mitsubishi-Westinghouse-Ansaldo

DAY 2. AM.1 Rural/ Renewable Electrification

Background Paper
- Requirements/ Goals for Rural Elec.
- PLN Program
- Potential for Renewable Energy Systems

Rice Waste Combustion
- Potential; technology; issues

AM.2 Rural/Renewable Electrification, Continued

Wood and Residue Gasification

Minihydro

Peat and Wood Combustion

PM.1 Policy, Institutional, and Financial Issues

Background Paper
- Experience in other countries
- U.S. PURPA; Ireland; Turkey
- Framework for Indonesia

Sources of Finance

Policy ; Institutional Suggestions
- PLN; MME; Private Companies

PM.2 Conclusions, Recommendations

Formulated by a working group which was convened at the beginning of the workshop and operated throughout.

PARTICIPANTS

Government/Energy
- MME, PLN, Pertamina, BPPT
- Ministries of Industry, Cooperatives, Forestry

Government, Other
- Bappenas, Min. Finance,
- BULOG, Min. Agriculture, Dalam Negeri
- Selected Bappedas ( S. Sulawesi, Kalimantan )
- Ministry of Domestic Affairs

Private Sector, Indonesia
- Proposers of Power Projects
- Equipment Suppliers
- Chamber of Commerce; Petroleum Association
- Wood Products, Cement, Textiles, Fertilizer
- Rice Mill Processing Owners

Private Sector, Overseas
- BOT Proposers
- Equipment Suppliers:
- Energy (oil) Industry

Financial Community
- Danareksa, BKPM, Capital Markets Board
- Government Banks (BI, BNI 1946, BBD, BRI, BDN)
- Foreign Banks (Citibank, Bank of Tokyo, Chase,etc)
- Local Private Banks (BLA, Bank Um Um, etc.)
- Government and Private Pension Funds
- World Bank, ADB, IFC

Academic Community
- I. T. Bandung; Bogor Ag. U, etc.

Assistance Agencies
- USAID, Other bilateral
- UNDP ?

# APPENDIX B

## Law No. 15

**THE PRESIDENT**
**OF**
**THE REPUBLIC OF INDONESIA**
**LAW OF THE REPUBLIC OF INDONESIA**
**NO. 15, 1985**
**ON**
**THE POWER SECTOR**
**BY THE GRACE OF GOD ALMIGHTY**

**THE PRESIDENT OF THE REPUBLIC OF INDONESIA**

Considering:

a. that the objective of national development are to improve public welfare and create an intelligent nation for the purpose of realizing a just and prosperous society with material and spiritual equality based on the Pancasila and the 1945 Constitution;

b. that power is very important for improving the welfare and the prosperity of the people in general and for stimulating improved economic activities in particular, and that it is thus necessary to step up the efforts to provide, utilize and process power so that it may be available in adequate and equal allocations with a good quality of service;

c. that in order to step up continued development in the power sector efforts are needed to optimize the utilization of energy sources to generate power, thereby guaranteeing its availability;

d. that in order to achieve the above-mentioned objectives and in view of the fact that the Ordinance dated September 13, 1890 on the Provisions on Installation and Utilization of Lines for Electrical Lighting and Electrical Power Transmission in Indonesia inserted in State Gazette No. 190, 1890 which has been amended several times, the latest with the Ordinance dated February 8, 1934 (State Gazette No. 63, 1934) which is no longer suitable to the situational progress and the requirements of development in the power sector, a Law on the Power Sector needs to be made.

Adhering to: Article 5 paragraph (1), Article 20 paragraph (1), and Article 33 of the 1945 Constitution;

**WITH THE APPROVAL OF**
**THE HOUSE OF REPRESENTATIVES OF**
**THE REPUBLIC OF INDONESIA**

**HEREBY DECREES:**

Enacting: THE LAW ON THE POWER SECTOR.

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# CHAPTER I

# GENERAL PROVISIONS

## Article 1

What is referred to herein as:

1. Power sector shall be everything related to the provision and the utilization of power.

2. Power shall be one of the forms of secondary energy generated, transmitted and distributed for all kinds of purposes, and not the power utilized for communication or signalling.

3. Power provision shall be the provision of power from the generating point up to the utilization point.

4. Power utilization shall be the use of power starting from the utilization point.

5. Power Enterprise Authorization (PEA) shall be the authorization given by the Government to the BUMN (state-owned enterprise) assigned the sole task of providing power for public use or to cooperatives, private entities or other government institutions to provide power for own use.

6. The Power Enterprise Permit (PEP) shall be the permit issued by the Government to cooperatives or private entities for conducting power provision operations for public use or to cooperatives, private entities or other government institutions to provide power for own use.

7. Minister shall be the minister responsible for the power sector.

# CHAPTER II

# BASIS AND OBJECTIVE OF POWER DEVELOPMENT

## Article 2

Power development shall be based on the principles of utilization, fairness and equality, self-confidence and environmental preservation.

## Article 3

Power development shall have as its objective the improvement of the people's welfare and prosperity in a fair and equal manner as well as the stimulation of improved economic activities.

## CHAPTER III

## ENERGY SOURCES FOR POWER

1. The natural resources serving as energy sources available throughout the territories of the Republic of Indonesia shall be utilized to the maximum extent possible for various purposes including guaranteeing the availability of power.

2. The policy for the provision and the utilization of energy sources as power shall be established by the Government taking into account the aspects of security, balance and environmental preservation.

## CHAPTER IV

## GENERAL POWER PLANNING

### Article 5

1. The Government shall make the general power planning in an overall and integrated manner.

2. In preparing the general planning referred to in paragraph (1) the Government shall be obliged to take into account the thoughts and views that exist in society.

## CHAPTER V

## POWER ENTERPRISE

### Article 6

1. Power enterprise shall comprise:

   a. power provision enterprise;
   b. supportive power enterprise.

2. The power provision enterprise referred to in paragraph (1) point (a) may comprise the following types of enterprise:

   a. power generation;
   b. power transmission;
   c. power distribution.

3. The supportive power enterprise referred to in paragraph (1) point (b) may comprise:

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a. consultancy related to the power sector;
b. construction and installation of power equipment;
c. maintenance of power equipment;
d. technological development of equipment supporting the provision of power.

**Article 7**

1. The provision of power shall be organized by the Government and shall be carried out by the BUMN established as the Holder of the PEA in accordance with the prevailing legislative regulations.

2. In an effort to meet power needs in a more equal manner and to further improve the capability of the Government to provide power as referred to in Article 6 paragraph (2), for public use as well as own use, insofar as the interests of the Government are not harmed, the widest possible opportunity shall be given to cooperatives and other enterprises to provide power based on the PEP.

3. The requirement for the PEP referred to in paragraph (2) shall be waived for power provision operations for own use the capacity of which shall be fixed with a Government Regulation.

**Article 8**

The issuance of the PEP referred to in Article 7 paragraph (2 ) shall be regulated with a government regulation.

**Article 9**

The stipulation on the supportive power enterprise referred to in Article 6 paragraph (3) shall be specified in a Government Regulation.

**Article 10**

In the event the operations of the power provision enterprise referred to in Article 6 paragraph (2) have not been, or cannot be, performed by the Holder of the PEA alone, the Holder of the PEA may cooperate with another enterprise after obtaining the approval of the Minister.

**Article 11**

1. For the sake of the public, the Holder of the PEA and the Holder of the PEP for Public Use in performing the power provision operations referred to in Article 6 paragraph (2) shall be authorized to:

a. cross rivers or lakes either on or under the surface;
b. cross seas, either on or under the surface;
c. cross public roads and railroads.

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2. Insofar as there is no contradiction, adhering to the prevailing legislative regulations, for the sake of the public the Holder of the PEA and the Holder of the PEP shall also be authorized to:

   a. enter public or private places and use them temporarily;
   b. use land, crossing on or under it;
   c. cross on or under buildings constructed on or under the ground;
   d. fell or cut plants that are obstructive.

**Article 12**

1. For the sake of the public, those who are in possession of titles to land, buildings and plants shall allow the Holder of the PEA and the Holder of the PEP for Public Use to implement the authorization referred to in Article 11 paragraph (2), obtaining a compensation, unless the land is Government-owned, from the Holder of the PEA.

2. The compensation referred to in paragraph (1) shall be borne by the Holder of the PEA and the Holder of the PEP for Public Use.

3. The Holder of the PEA and the Holder of the PEP for Public Use may commence operations only after the compensation referred to in paragraph (1) has been settled.

**Article 13**

The obligation to pay the compensation referred to in Article 12 shall not apply to those who construct buildings, plant trees, etc. on land that will be, or has been, used for power provision operations with the purpose of obtaining such compensation.

**Article 14**

The compensation stipulation, procedure and payment referred to in Article 12 shall conform to the provisions of the prevailing legislative regulations.

## CHAPTER VI

## RELATIONSHIP BETWEEN THE HOLDER OF THE PEA/THE HOLDER OF THE PEP FOR PUBLIC USE AND THE PUBLIC IN POWER PROVISION OPERATIONS

**Article 15**

1. The Holder of the PEA and the Holder of the PEP for Public Use shall be obliged to:

   a. provide power;
   b. provide the best possible services to the public;

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c. take occupational safety and public safety precautions.

2. The stipulation on the relationship between the Holder of the PEA, the Holder of the PEP for Public Use and the public with regard to the respective entitlements, obligations and responsibilities shall be specified in a Government Regulation.

**Article 16**

The Government shall regulate the selling price of power.

## CHAPTER VII

## PROVISION AND UTILIZATION OF POWER

**Article 17**

The conditions for the provision, exploitation, utilization, installation and standardization of power shall be specified by the Government.

## CHAPTER VIII

## MANAGEMENT AND SUPERVISION

**Article 18**

1. The Government shall conduct general management and supervision of the operations and implementation of power enterprises.

2. The general management and supervision referred to in paragraph (1) shall especially relate to occupational safety, public safety, enterprise development, and the accomplishment of standardization in the power sector.

3. The procedures for the general management and supervision referred to in paragraphs (1) and (2) shall be specified in a Government Regulation.

## CHAPTER IX

## CRIMINAL ACT CLAUSE

**Article 19**

Anyone who utilizes power that is not rightly allocated to him/her shall have committed a criminal act of theft as referred to in the Penal Code.

**Article 20**

1. Anyone who undertakes to provide power without the PEA or the PEP shall be sentenced to a maximum of 6 (six) years imprisonment or fined a maximum of Rp 50,000,000 (fifty million rupiahs).

2. The stipulation referred to in paragraph (1) shall not apply to power provision enterprises for own use as referred to in Article 7 paragraph (3).

3. Anyone who undertakes to provide power without fulfilling obligations towards those who are entitled to land, buildings and plants as referred to in Article 12 paragraph (3) shall be sentenced to a maximum of 1 (one) year imprisonment or fined a maximum of Rp 10,000,000 (ten million rupiahs) and the relevant PEP shall be revoked.

**Article 21**

1. Anyone who on account of negligence causes a person's demise by means of power shall be sentenced to a maximum of 5 (five) years imprisonment.

2. In the event the negligence referred to in paragraph (1) is committed by the Holder of the PEA or the Holder of the PEP, the maximum imprisonment shall be 7 (seven) years.

3. In addition to the punishment referred to in paragraph (2), the Holder of the PEA or the Holder of the PEP shall be obliged to pay compensation.

4. The amount, the procedure and the payment of the compensation referred to in paragraph (3) shall be specified in a Government Regulation.

**Article 22**

1. The Holder of the PEA or the Holder of the PEP for Public Use who does not comply with the implementation stipulation referred to in Article 15 paragraph (1) shall be sentenced to a maximum of 6 (six) years imprisonment or fined a maximum of Rp 5,000,000 (five million rupiahs).

2. In addition to the punishment referred to in paragraph (1), an additional punishment may be inflicted in the form of a revocation of the PEP.

**Article 23**

1. The acts referred to in Articles 19, 20 and 21 shall constitute crimes.

2. The act referred to in Article 22 shall constitute a violation.

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# CHAPTER X

# INVESTIGATION

## Article 24

1. Besides a public investigator assigned the task of investigating criminal acts, certain Civilian Government Official appointed in accordance with the prevailing legislative regulations may also conduct an investigation of the criminal acts referred to in this Law.

2. The investigator referred to in paragraph (1) shall be authorized to:

   a. verify reports or information related to criminal acts in the power sector;

   b. inspect persons or institutions suspected of committing criminal acts in the power sector;

   c. request information or evidence from persons or institutions in relation to criminal acts in the power sector;

   d. make inspection at certain places suspected to be the locations of evidence and confiscate items that can be used as evidence in cases of criminal acts in the power sector;

   e. take other actions in accordance with the provisions of the prevailing legislative regulations.

# CHAPTER XI

# TRANSITION CLAUSE

## Article 25

In view of the enactment of the Law the implementation regulation on the power sector issued in accordance with the Ordinance dated September 13, 1890 on the Stipulations on the Installation and Utilization of Lines for Electrical Lighting and Transmission of Power by Means of Electricity in Indonesia inserted in State Gazette No. 190, 1890 which was amended several times, the latest with the Ordinance dated February 8, 1934 inserted in State Gazette No. 63, 1934, is declared still effective, insofar as it is not contradictory to this Law or has been replaced or amended in accordance with this Law.

# CHAPTER XII

# CONCLUSION CLAUSES

## Article 26

At the time this Law starts to take effect, the Ordinance dated September 13, 1890 on the Stipulations on the Installation and Utilization of Lines for Electrical Lighting and Transmission of Power by Means of Electricity in Indonesia inserted in State Gazette No. 190, 1890 which was amended several times, the latest with the Ordinance dated February 8, 1934 inserted in State Gazette No. 63, 1934, shall be declared no longer effective.

## Article 27

This Law shall be effective as of the date of enactment.

To enable everyone to be aware of this Law, it is instructed that this Law be inserted in the State Gazette of the Republic of Indonesia.

Ratified in Jakarta on December 30, 1985

**THE PRESIDENT OF THE REPUBLIC OF INDONESIA**

(signed)

SOEHARTO

Enacted in Jakarta on December 30, 1985
**THE MINISTER/STATE SECRETARY**
**OF**
**THE REPUBLIC OF INDONESIA**

(signed)

SUDHARMONO, S.H.

STATE GAZETTE OF THE REPUBLIC OF INDONESIA NO. 74, 1985

# APPENDIX C

## People Consulted

## FERTILIZER PLANTS

Indonesia's six urea production plants utilize gas turbine generators with heat recovery boilers to produce electricity and steam. Additional steam is produced using natural gas-fired auxiliary boilers. If additional gas turbine/heat recovery boiler sets were installed to satisfy the full steam loads, surplus electric power could be generated at a very attractive price. The following analysis determines potential additional generation if all steam were generated with heat recovery boilers. Data used in this analysis were provided by P.T. Pusri, the nation's largest urea plant, for the year 1986.

| | |
|---|---|
| 1984 National Urea Production (5 plants) | 4,470,000 metric tons |

FOLLOWING STATISTICS ARE FOR P.T. PUSRI, PALEMBANG

| | |
|---|---|
| Production | 1,620,000 M. tons |
| Gas Turbine Generator | |
| Electric Power Production | 193,000 MWh |
| Heat Recovery Boiler Steam Production | $1.74 \times 10^6$ M.tons |
| Fuel Used in Aux. Steam Boilers | $4.18 \times 10^6$ MCF |
| Steam Generated @ 70% efficiency | $1.31 \times 10^6$ M.tons |
| Ratio of Aux. Boiler Steam Generation to Heat Recovery Boiler Steam Generation | $1.31 \times 10^6 / 1.74 \times 10^6 =$ 0.753 |
| Potential Additional Electric Generation if Aux. Boilers Replaced with new Gas Turbine/Heat Recovery Boiler Sets | 193,000 MWh x 0.753 = 145,000 MWh |

Industry-wide potential additional generation assuming other plants are similar to P.T. Pusri

$$\frac{\text{National Production}}{\text{PUSRI}} x\ 145{,}000\ \text{MWh} = \frac{4{,}470{,}000\ \text{tons}}{1{,}620{,}000\ \text{tons}} x\ 145{,}000\ \text{MWh}$$

= 400,00 MWh

= 0.4 TWh

TEXTILE INDUSTRY

Pertamina Data for Sector Boiler Fuel Consumption (1984-1985)

IDO - $262 \times 10^6$ liters

Bunker C - $77 \times 10^6$ 1.

Energy Value of Fuel Consumed

| | |
|---|---|
| IDO - $262 \times 10^6 \times 36{,}500$ Btu/1. | $= 9.56 \times 10^{12}$ Btu |
| Bunker C - $77 \times 10^6 \times 39{,}600$ Btu/1. | $= 3.05 \times 10^{12}$ Btu |
| Total | $= 12.61 \times 10^{12}$ Btu |
| Steam Generated @ 70% efficiency | $= 8.83 \times 10^{12}$ Btu |

Assume that this steam is generated with diesel cogeneration systems. Thermal/electric output ratio is 1:1

| | |
|---|---|
| Power Produced | $= 8.83 \times 10^{12}$ Btu/3413 Btu/kWh |
| | $= 2.59 \times 10^9$ kWh |
| Assume capacity factor of 65%. Then, potential additional installed capacity | = 455 MW |

For comparison, existing captive power generation according to Biro Pusat Statistik is $1.9 \times 10^9$ KWh at a capacity factor of 65%. This represents an installed capacity of 334 MW.

WOOD PRODUCTS INDUSTRIES

| | |
|---|---|
| Annual Wood Waste Production (from Apkindo) | $= 15 \times 10^6\ m^3$ |
| Assume Moisture content (wet Basis) | = 50% |
| Recoverable Energy in Steam Boiler | = 6,600 Btu/kg (3000 Btu/lb) |
| Assume Average Density of Wood | $= 640\ kg/m^3$ ($40\ lb/ft^3$) |
| Mass of Wood Available | $= 15 \times 10^6 \times 640$ |
| | $= 9.6 \times 10^9$ kg |
| Recoverable heat | $= 9.6 \times 10^9 \times 6{,}600$ |
| | $= 6.34 \times 10^{12}$ Btu |

Assume power is generated with condensing turbine w/throttle pressure of 17 bar (250 psig). Water rate is 7.3 kg/kWh (16 lb/kWh).

| | |
|---|---|
| $\Delta$ h for steam | = 2420 Btu/kg (1100 Btu/lb) |
| Total steam generated | $= 2.62 \times 10^{10}$ kg |
| Total Power Generated | $= 2.62 \times 10^{10}/7.3 = 3.6 \times 10^{9}$ kWh = 3.6 TWh |



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LNG FACILITIES

P.T. Arun installed generating capacity consists of eight General Electric Frame V Gas Turbine/Generators totaling 168 MW. Generation efficiency for these units is about 30%.

If the plant were converted to combined cycle operation through installation of heat recovery boilers and steam turbine generators, efficiency would increase to about 39%.

Additional installed capacity could be

$$9/30 \times 168 = 50.4 \text{ MW}$$

Additional potential generation @ 90% capacity factor

$$50.4 \times 8760 \times 0.9 = 397 \times 10^6 \text{ KWh} = 0.4 \text{ TWh}$$

OTHER PRIVATE INDUSTRY
(excluding textile and paper)

Boiler fuel consumption based on Pertimina Data for 1984-85

| | |
|---|---|
| IDO | - $344 \times 10^6$ l |
| Bunker C | - $245 \times 10^6$ l |
| Btu equivalent | = $2.23 \times 10^{13}$ Btu |

Using same assumptions as textile industry calculations:

Potential Power Produced = $4.6 \times 10^9$ KWh

At capacity factor of 65%
potential additional installed capacity = 805 MW

## APPENDIX D

### Private Sector Power Generation Policy Statement for Pakistan

In this document WAPDA refers to the Water and Power Development Authority, responsible for power generation throughout most of Pakistan. KESC is the Karachi Electric Supply Corporation, which supplies power in the Karachi region.

**ARCO International**

Richard A. Fuller

**Stone and Webster Indonesia Corp.**

Dr. Peter A. Jezek, Vice President

**Morrison-Knudsen Engineers, Inc.**

Huseyin Yaman, Resident Rep.

**Mitsubishi Corporation**

Masahiko Agawa, Assistant to General Manager

**P.T. Citaconas**

Ir. B. Prajogo, Director
Ir. Tjahja Wibisana

**P.T. Reffcom Nusantara Shaba**

A. J. Kristiadi

**General Electric Co.**

Ram K. Sharma

**Union Geothermal Indonesia**

Garth M. Lyon
Dick Engebretsen

**Mobil Oil Indonesia**

L. A. Denton, LNG Manager
S. D. Myers, Engineering Manager

**Exsa International**

Dr. Ot. C. Soekotjo

**Amoseas Indonesia Inc.**

Philip A. Scully, Manager, Joint Interest
Andrew J. Whittome, Geothermal Drilling and Ops.

**ConAgra International (Far East) Ltd.**

Lourdes Tanco, Business Development Mgr.

**Bogor Agricultural University**

Ir. Irawadi Jamaran, Head, Dept. of Agroindustrial Technology
Dr. R. Muljono Judoamidjojo
Ir. E. Gumbira Sa'id, Bioindustry
Dr. H. Eriatno, Ag. Engineering
Dr. Suhadi Hardjo, Food Science and Biotechnology
Dr. Basulei, Industrial Technology
Dr. Hachjuddin Jjiptah, Biotechnology and Environmental Management
Dr. Waxapto, Industrial Environmental Protection
Dr. Lukman Hidayat, Animal Products and Processing Technology

**Directorate General of Forest Utilization**

Ir. Broto Irawan Sumartomo

**P.T. Pupuk Sriwidjaja (PUSRI)**

Mrs. Sri Martati Muhammad

**P.T. Austindo Nusantara Jaya**

George Tahija, Director

**P. T. Indonesia Toray Synthetics**

R. Djumhana, Assistant Manager
Y. Ogura, Director/Factory Manager

**P.T. Konservasi Energi Abadi (KONEBA)**

Dr. Entol Soeparman, President Director
Ir. Wahyudi Sunaryo, Manager
Ir. Amir Sajat, Manager

**P.T. Semen Cibinong**

Nick P. Petroff, President Director

**P.T. Inti Karya Persada Tehknik**

Ario Damar, Marketing Manager

**P.T. Satya Raya Indah Woodbased Industries**

Darman, Maintenance Engineer

**Asian Development Bank**

Peter G. M. Smith, Project Economist

**P.T. Danareksa**

J. A. Sereh, President Director

**Algemene Bank Nederland**

Len H. Steffen, Manager for Indonesia

**Citibank**

Phil Markert, Country Corporate Officer

**Washington Capital Markets Group**

Robert Parra

**Astra**

Edward Sueriajaga

**Chase Manhattan Bank**

Laurel Pekar

**American Express Bank**

K. Balasubramanian, V.P.

**Multicorp (Multinational Finance Corp)**

Kenneth R. Wynn, President

**P. T. Aspecindo Kreasi**

Hartojo Wignjowijoto

**Stanford University Petroleum Research Institute**

Dr. Louis Castanier

## INDONESIA PRIVATE POWER PROJECT

### PEOPLE CONSULTED

**Ministry of Mines and Energy**
Direktorat Jenderal Listrik dan Energi Baru

Dr. A. Arismunandar, Director General
Dr. A. J. Surjadi, Director, New Energy
Ir.M. Andoyo, Director, Electric Power Planning
Irzal Chatab, Energy Conservation
N. Pulungan, Budget Analysis
David Tombeg, Regulation and Supporting Industries
Imam Sugandi, Planning
Merdeka Sebayang
Yugo Pratomo
Mr. Purwono

**U.S.A.I.D./Washington**

Robert Ichord, Asia, Near East/TR
Robert Archer, Asia Near East/TR
John Kadyszewski, Office of Energy
Samuel Schweitzer, Office of Energy

**U.S.A.I.D./Jakarta**

David Merrill, Mission Director
Gordon West, PRE
William Coles
Edi Setianto
William Douglas, OARD
Philip Brewer
Martin Hanratty
Robert Ruker, Economist

**U. S. Embassy, Jakarta**

James Harrison
Maria Andrews, Commercial
Jeff Lutz, Science

**U. S. National Academy of Sciences**

Rose Bannigan

**The World Bank**

Andres Liebenthal (Washington)
Priscilla Z. Urbano (Jakarta)
Sakdiyiam Kupasrimonkol, IFC

**Overseas Private Investment Corporation**

Scott Andrews

**Department of Cooperatives**

Ir. Sjoufjan Awal, Chief, Rural Electrification
Budhiman Sirod W.
Mamiet Marjono, Director for Rural Electrification

**P.L.N**

Ir. Hardiv H. Situmeang, Java Control Ctr.
Djiteng Marsudi, Chief, Subdirectorate Budget
Dr. Nengah Sudja

**BKPM: Investment Coodinating Board**

Samuel Tiwow, Director, Investment Promotion Bur.

**Ministry of Industry**

Backram Harahap, Advisor to the Minister
Trisura Suhardi, Director General, Small Scale Industries

**Ministry of Agriculture**

Sugianto Brotosusanto, Head, Food Crop Economics
Ir. Hardjanto Soercharsono, Senior Agronomist
Mr. Halim, Head, Post Harvest Rice Technology
Steven Tabor, SCDP Project Economist

**BULOG**

Ir. Sapuan, Director of National Stockpile

**BPPT: Ministry of Science and Technology**

Dr. A. B. Van Rennes, U. S. Technical Advisor to Chairman Habibie
Rahardi Ramelan, Deputy Chairman, Industrial Analyses
Ir. Totok Sulistiyanto

**BAPPENAS**

Dr. Bambang Purmono

## APPENDIX E

**Summary of Pacific Gas and Electric Company (PG&E) Standard Offers of Private Power Producers and Current Purchase Prices.**

**In the following, QF refers to a "Qualifying Facility" as described in Chapter III of this report. SCE refers to the Southern California Edison Company and SDG refers to the San Diego Gas & Electric Company. CPUC is the California Public Utilities Commission which establishes the purchase prices for private power.**

## LIST OF PARTICIPANTS

Planning and Development Division

1. Mr. V.A. Jafarey,
   Secretary General (In Chair)

2. Dr. Ghulam Rasul,
   Joint Chief Economist

3. Mr. Ashfaq Mahmood,
   Chief

4. Mr. Ghulam Haider,
   Deputy Chief

Ministry of Water and Power

5. Mr. Muhammad Akram Khan,
   Additional Secretary (Power)

Ministry of Petroleum and Natural Resources

6. Mr. Ashiq Ali,
   Director General

7. Mr. Muhammad Iqbal Qureshi,
   Director

Ministry of Labour, Manpower and Overseas Pakistanis

8. Mr. S.S. Huda,
   Joint Secretary

Enerplan Project

9. Mr. Sadaqat Hasan Mir,
   Managing Director

10. Mr. A.M. Izharul Haque,
    Deputy Managing Director

Karachi Electric Supply Corporation

11. Mr. S.M. Arshad Bokhari,
    Managing Director

12. Mr. S. Hashim Abbas,
    Project Engineer

(i) The base price for energy.
(ii) The cost of fuel.

(h) A suitable escalation will be provided for the basic price of energy, taking into consideration key inputs only e.g. labor. The fuel component will be directly linked with the cost of fuel which will be the prevalent competitive market price. A formula for this linkage, assuming certain plant efficiency, would be worked out.

III. Inviting of Bids and Acceptance of Offers

(a) Private entrepreneurs will submit bids for the capacity and location, in term of bulk price of power desired by them. Where the bulk price offered by the entrepreneur is lower or equal to the price, computed in accordance with para (II) above, the Ministry of Water and Power may accept the offer. Where the price bid is higher than the bulk price computed under para (II) above, the Ministry of Water and Power may either reject the offer or seek sanction of ECC, giving reasons for accepting the higher price.

(b) Since timely installation and proper operation of the plant is of importance, a bank guarantee will be taken from the private entrepreneur to ensure recovery of penalty in case of default.

(c) The financial position, experience and other credentials of the applicant will be examined while considering his offer.

(d) Bids will be invited by WAPDA/KESC under the aegis of Ministry of Water and Power. the agreement with the private sector will be at two levels i.e. between WAPDA/KESC and private sector party and between GOP and private sector with GOP as under-writer.

IV. Tax and Fiscal Status:

(a) The power station would be treated, as an industrial establishment, for purposes of tax, and other fiscal regulations.

(b) Concessions available for large scale industry in specified areas will be available to the power plant as well, and will be reflected in the determination of the bulk rate.

(c) The entrepreneur may raise local and foreign

finance in accordance with regulations applicable to industry, in general.

V. Labour Laws

The consensus was that the Essential Services Act may be made applicable to the labour working in the privately owned power house, since the same is applicable to the Government owned power house. The Ministry of Labour however, was not in favor of this proposal and they advocated that the existing laws applicable to industry should be applied to the privately operated power house as well.

VI. Fuels

Entrepreneurs should be restricted to two specified fuels, namely oil and indigenous coal. Other fuels may be added later. Bids can be invited for plants based on specific fuel/fuels (HSD, F.O., LDO or Coal) depending upon location and available time for construction. Infrastructure requirements for fuel transportation will be kept in view while evaluating bids.

VII. Inspection and Monitoring

In order to ensure that power plant is being properly maintained/renovated and proper standards are being observed, periodic inspection and monitoring be ensured in the contract.

5. The Summary has been prepared in consultation with Ministries of Finance, Water and Power, Petroleum and Natural Resources and Labor, Manpower and Overseas Pakistanis.

6. The proposals made in para 4 are submitted for approval.

7. The submission of the Summary has been authorized by the Minister of Planning and Development.

V.A. JAFAREY,
Secretary General

Islamabad, the 22nd August, 1985.

GOVERNMENT OF PAKISTAN

PLANNING AND DEVELOPMENT DIVISION

SUMMARY FOR ECONOMIC COORDINATION COMMITTEE

Subject: Private Sector Induction in the Power Generation

1. On a Summary submitted by the Ministry of Water and Power. the ECC decided to constitute a Committee to resolve the basic issues involved in the induction of private sector in power generation.

2. A meeting of Committee was held on 14th July, 1985 (list of participants attached).

3. Before setting out the recommendations of the Committee, it might be useful to consider the rationale of private sector participation in power generation.

Firstly, inadequate investment in power has been the principal reason for recent power shortages. As funds for public sector investment will continue to be less than the requirements, in the forseeable future, it appears desirable to mobilize private resources for development of the power network.

Secondly, WAPDA is burdened with manifold responsibilities and is examining ways of decentralization. Privately operated generation units will relieve WAPDA of some of its future day to day responsibilities.

Thirdly, power generation is a convenient point for inducting private participation. In the light of experience gained, the role of private enterprise in the development of the power system could be enlarged.

4. It was agreed to recommend the following procedure for induction of private enterprise in bulk power generation:

I. Location and Capacity

(a) The Ministry of Water and Power will determine, in the context of agreed medium and long-term plans, the location and capacities for thermal generation suitable to system conditions, and invite private sector to install and operate them.

(b) The Ministry of Water and Power may also entertain proposals made by private enterprise, on their own initiative, and consider them in the context of the agreed medium and long-term plans.

II. Bulk Price

(a) The Ministry of Water and Power will calculate the bulk purchase price of electricity for a Power Station, at a specified location, on the basis of the cost of production, if the investment were to be made by WAPDA or KESC.

(b) In determining the bulk price, a suitable return on equity will be taken into consideration. The rate of return on equity, would be fixed in consultation with Finance.

(c) No fixed return will be guaranteed to the private entrepreneur. The guarantee will be only for price and quantity of energy to be purchased.

(d) Where the station is located at a distance from the transmission system, a suitable discount for transmission costs may be provided.

(e) The bulk tariff will be worked out on the basis of 60 percent annual plant factor. A purchase at 60 percent annual plant factor would be guaranteed by WAPDA/KESC. Suitable penalty clause applicable to both the purchases as well as to the supplier of electricity will be incorporated in the contract to ensure that the purchases and sales do not fall below the minimum, except by mutual consent.

(f) WAPDA/KESC would have the "right" to purchase power, over and above the 60 percent annual plant factor, at the agreed price, and the private operator would not unreasonably withhold the supply.

(g) The bulk purchase price may be in two parts

# APPENDIX F

## Calculations of Cogeneration Potential

## DETERMINATION OF QF ENERGY PRICES

## UNDER CURRENT STANDARD OFFERS

The CPUC has two kinds of energy price offers currently available to QFs - short run energy price offers (standard offers 1, 2 and 3) and the long run energy price offer. The short run energy prices are based on the forecasted performance of the utility system for the next 2-3 years (depending on the general rate case cycle). The long run energy prices are derived from the forecasted operation of the utility system over a longer period extending up to the next 15-20 years.

### THE SHORT RUN ENERGY PRICES

In the general rate case proceeding of each of the three major California utilities, Incremental Energy Rates (IERs) are developed. These IER s form the basis of the short run energy price for QFs. The utilities forecast the price of oil/gas (their marginal fuel) for the next quarter and multiply the adopted IERs by the oil/gas price. The product is the energy price for QFs for the next quarter.

These incremental energy rates are not heat rates in the engineering sense of the term . Instead these are the factors which reflect the composite of the utility resources operating on the margin. They are divided and multiplied by the price of oil/gas only to get a single equivalent number that one can conveniently refer to.

Because the QF energy price is the product of the oil/gas price and the IER, some believe under there offers the QFs get energy prices based solely on the utility's expensive oil/gas plants. However, that is not true. (See illustration on page 3). The fact is that these prices take into account any of the non-oil/gas plants that may be operating at the margin. These prices also incorporate the economy energy that the utility expects to be available. They reflect the utility's best operation under the foreseen circumstances. If

for example, in the general rate case it is determined that the utility will have 10,000 GWH of economy energy available until the next general rate case the adopted IERs and the resulting energy prices reflect that. This can be understood by going through the computational process which determines IERs and the energy prices.

## THE LONG RUN ENERGY PRICES

The interim standard offer No. 4 has three energy price options. A QF can take fixed forecasted energy prices[1] or a levelized energy price[1] or can take a forecast of IERs for upto the first 10 years of its operation. These energy prices and the IERs have been derived assuming the future systems of the major California utilities will have a progressively lower reliance on oil/gas and that the plants operating at the margin will be non oil/gas for significant periods of time. For each year the energy price reflects the plants operating at the margin after the utility receives the expected block of QF power and after the utility has added the planned resources to optimize its operation.

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[1] The cogenerator QFs have a limited availability of this offer.



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## CALCULATION OF IERs

One must note two things about IERs and QF energy prices. The first is that these are averages of hourly costs grouped into three periods: peak, mid peak and off-peak. The off-peak energy price; for example is an average of 8-10 hours in that period. Similarly peak period energy price is an average of 6-7 hours of highest load grouped together. Secondly, the whole calculation is probablistic. Production cost models (e. g. GRASS, PROMOD, and IAM) which are used to simulate the best performance of the utility system under the foreseen circumstances look at the outage rates of various plants and calculate each plant's probability of being on the margin given the expected loads and the resources available to the utility. The following illustration would be helpful in understanding the process.

### ILLUSTRATION

1. The expected Hourly Load: 11,000 MW

2. Utility Resource Mix:

| | Capacity | Engineering Heat Rate | Fuel Cost | Running Cost |
|---|---|---|---|---|
| | MW | Blu/kWh | $/M$^2$btu | ¢/kWh |
| Oil/gas | 7,000 | 12,000 | 5.00 | 6¢ |
| Nuclear | 3,000 | 20,000 | 1.00 | 2¢ |
| Geothermal | 2,000 | 15,000 | 2.00 | 3¢ |
| Economy Energy | 2,000 | - | - | 1¢ |

3. Given the resource mix, the outage rates of each plant and the expect hourly loads the probability of each resource being on the margin:

| | |
|---|---|
| Oil/gas | 50% |
| Nuclear | 10% |
| Geothermal | 20% |
| Economy Energy | 20% |



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4. Probablistic cost at the margin (probability weighted average of cost at the margin):

$$= (6¢ \times .5) \quad \text{(oil/gas)}$$
$$+ (2¢ \times .1) \quad \text{(Nuclear)}$$
$$+ (3¢ \times .2) \quad \text{(Geothermal)}$$
$$+ (1¢ \times .2) \quad \text{(Economy)}$$

$$= 3 + .2 + .6 + 2$$

$$= 4¢/kWh$$

5. Gas cost = $\$5/M^2btu$

6. Incremental Energy Rate (Btu/kWh)

$$= ¢/kWh \div ¢/M^2btu$$
$$= 4¢ \div ¢/M^2btu$$
$$= 4¢ \times \frac{1,000,000}{500}$$
$$= 8,000$$

7. QF Energy Price = IER x expected Gas Price in the next quarter:

If expected gas price $\$4.5/M^2btu$, then QF price = 3.6¢/kWh
If expected gas price $\$5/M^2btu$ then QF price = 4¢/kWh
If expected gas price $\$6/M^2btu$ then QF price = 4.8¢/kWh

8. Had the QF price been based only on oil/gas units the IER in this illustration would not have been 8,000. Instead it would have been 12,000 which is the heat rate of oil plants operating at the margin. See (2) above.

The QF price then would have been as follows:

If oil price $\$4.5/M^2btu$ then QF price = 5.4¢/kWh
If oil price $\$5.0/M^2btu$ then QF price = 6¢
If oil price $\$6.0/M^2btu$ then QF price = 7.2¢

## ECONOMY ENERGY, CURTAILMENT AND QF PRICES

Large amounts of cheap economy energy are expected to be available to the major California Utilities for the next few years. Under PURPA, the utilities cannot refuse to buy QF power and buy cheaper economy energy but they can pay them a price which reflects the low costs avoided during such periods.

Concern is expressed sometimes that ratepayers may be losing money during some off-peak hours when the utilities pay the QFs the published energy

price for off-peak hours while they have economy energy being used at the margin for some of those hours. For example, for the month of October 1984 the off-peak energy price for PG&E is 6.3¢/kWh while for some of the off-peak hours it may have economy energy being used at the margin and thus may be rejecting cheap economy energy to buy QF power.

However, one must note that the published prices are determined by taking into account the expected economy energy available to the utility. The reason why published off-peak energy price for QFs does not directly show economy energy cost is because it is an average of several hours. This is explained in the illustration below.

ILLUSTRATION

1. Off-peak period = 10 P.M.-8 A.M.
2. Number of hours in the off-peak period = 10
3. Hourly marginal cost:

| | | |
|---|---|---|
| 10 P.M.-11 P.M. | 1st hour | 6¢/kWh |
| | 2nd | 6¢ |
| | 3rd | 1¢ |
| | 4th | 1¢ |
| | 5th | 1¢ |
| | 6th | 1¢ |
| | 7th | 6¢ |
| | 8th | 6¢ |
| | 9th | 6¢ |
| 7 A.M.-8 A.M. | 10th hour | 6¢ |



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4. Published QF energy price for the entire off-peak period:

$$= \frac{(4x1)+(6x6)}{10} = 4¢/kWh$$

As the above illustration shows a QF which gets an energy price of 4¢/kWh for the entire off-peak period has in fact been paid the economy energy price of 1¢/kWh for four hours. So it is not fair to curtail a QF or to pay it 1¢/kWh for four hours when economy energy is at the margin. It is fair to do so only if the price for the other six hours is 6¢/kWh each.

The only situation when ratepayers could be hurt by purhasing QF power and rejecting economy energy is when economy energy availability is more than the amount assumed in deriving the published energy price. If for example, the published energy price is calculated by assuming 8000 GWH of economy energy wheras the actual amount available is 10,000 GWH, the ratepayers would lose .

This can be avoided by making better estimates of how much economy energy will be available to the utility. From the QFs' point of view it may be better if the energy price is differentiated by every hour instead of being averaged. Then a QF may want to provide power to the utility only for 6 hours and get 6¢/kWh and let the utility buy economy energy for the other four hours. However, those hourly prices would be more cumbersome to administer than the current grouping of energy price into three periods. PG&E has tried to move a little bit in thhat direction under S.O #4 by offering QFs two options - a higher off-peak price with curtailment and a lower price without curtailment.



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## SUMMARY OF PG&E* STANDARD OFFERS

**STANDARD OFFER #1: As-Delivered Capacity and Energy**

The QF's energy and capacity are sold on an as-available basis, not firm, meaning that the amount and time of delivery of the energy is not guaranteed. The QF is paid full short-run avoided energy cost, plus current shortage cost, on a per kWh basis, for all energy delivered to the utility. These costs are updated quarterly by the utilities, with the energy cost based on the incremental energy rates (IERs) established in the last rate case and the expected fuel costs for that quarter. Shortage costs are based on the cost of a combustion turbine. This contract is used by all technologies, particularly wind, due to the uncertain nature of that resource.

**STANDARD OFFER #2: Firm Capacity and Energy**

The QF's capacity is sold on a firm basis, meaning that an amount of capacity is guaranteed to be available to the utility during its peak load period. The capacity payments are based on levelized, forecated shortage costs, which are stated in the contract and are fixed for the life of the contract. Energy prices are the same as in Standard Offer #1. This offer was mainly used before the development of Standard Offer #4, principally by cogenerators, biomass and small hydro QFs.

**STANDARD OFFER #3: As-Delivered Capacity and Energy From QFs Less Than 100kW**

This offer is the same as Standard Offer #1 in practice, but the contract terms and QF responsibilities are less involved, due to the small size of the facilities. All technologies use this offer.

**STANDARD OFFER #4: Long Term Capacity and Energy**

This offer provides fixed payment rates over long time spans (up to 10 years) to provide QFs with some certainty in the return on their investment. There are three energy payment options and two capacity options in this offer.

<u>Energy Option #1</u> - Energy prices are fixed and are based on forecasted avoided energy costs. The QF can choose to have a mix of forecasted and current short-run avoided costs for the energy price, with oil & gas fired cogenerators limited to 20% of the price being based on the forecasted prices.

<u>Energy Option #2</u> - This is similar to Option 1, except that the forecasted energy prices are levelized and oil & gas fired cogenerators may not use this option at all.

<u>Energy Option #3</u> - Energy prices are based on fixed, forecasted utility IERs and utility oil & gas costs. Payments are made based on short-run costs, then adjusted at the end of the year to



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reflect the forecasted prices. This option is used by cogenerators and is designed to have the energy price reflect changes in fuel costs.

<u>Capacity Option #1</u> - As-delivered: The QF can choose payments based on either short-run shortage costs, updated quarterly, or fixed, forecasted shortage costs, which are not levelized.

<u>Capacity Option #2</u> - Firm: Payments are based on fixed, forecasted, levelized shortage costs.

*SCE and SDG&E offers are similar



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