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Volume II: Electricity Pricing Incentives

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INDONESIA DEMAND SIDE MANAGEMENT
VOLUME II:
ELECTRICITY PRICING INCENTIVES

Final Report

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ABSTRACT

This report is the second volume of a two-volume study of demand-side management (DSM) in Indonesia. The report focuses on electricity pricing incentives for purchasing power from captive generators. PLN's (the national electric utility) electricity sales have been growing at 16.3% annually for the past 15 years. The ability to meet new capacity requirements is so constrained that many new industrial customers are being told they must supply their own power. At present, 42%, or 6,922 MW, of the installed capacity on Java and Bali is captive industrial generation. Very little power is currently purchased from these generators by PLN, although in many instances it represents a cost-effective means of meeting future peak demand needs.

The study begins by identifying the load management objectives for incentive pricing. The objectives were determined to be to reduce peak load on a daily basis during the period 1800 to 2200 hours. PLN's long-run marginal capacity and energy costs were estimated to establish the maximum purchase price based solely on economic considerations. Based on the load shape objectives, three DSM tariff options were analyzed: interruptible rates, buy back from PLN customers and buy back from non-PLN customers. Considering only captive diesel generation capacity of 5 MVA or more, the technical potential for these generators was estimated to be 792 MW in Java. The economic and market penetration potentials represent successively smaller subsets of this amount. They depend upon the power purchase tariff ultimately offered by PLN, the cost of self-generation specific to each generator as well as non-economic factors.

Analysis of PLN's long-run marginal cost and an analysis of the cost structure of a typical captive generator provided the basis for establishing a two-part incentive tariff design to purchase power during the peak periods. Two potential candidates for a pilot load management program were identified and it is recommended that such a pilot program be implemented to demonstrate and test the technical, economic, financial, and regulatory issues involved. Overall, the report stresses that development of a captive power purchase program be seen in the larger context of the development of a clear and equitable regulatory and policy framework for private power in general.

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY

S.1 BACKGROUND AND STUDY OBJECTIVES[1]

PLN's national energy sales increased from 2,444 GWh in 1974/1975 to 27,741 GWh in 1989/90, at an average growth rate of 16.3 percent. Over the same period, the number of customers showed an average annual growth rate of 16.2 percent.

These growth rates do not show signs of abating. The electrification ratio is still below 28 percent even in Java, the most heavily electrified island. Further, the per capita electricity generation, which is estimated to be about 250 kWh per year, is low when compared with other developing countries with similar or lower income levels.

In spite of such high growth rates, PLN has historically not been able to supply all industrial demand. Therefore, many industrial enterprises have installed captive generation plants. At present, captive generation capacity is estimated to be about 7,000 MW, of which about 3,200 MW are located on Java. On a national basis, captive generation accounts for approximately 42 percent of total installed capacity.

PLN projects load growth -- under the medium scenario -- at an annual rate of 12 percent in Java and 13 percent outside Java. In reality, these forecasts are best interpreted as supply forecasts. Because of resource constraints -- manpower and financial -- PLN has not only deferred the takeover of existing captive power in industry but is also signalling to potential new industrial customers seeking grid supply that such connections may not be forthcoming. Thus, the amount of captive generation plant in industry is expected to grow even more than at today's levels.

The capital requirements -- even for the managed demand growth case -- are estimated to be on the order of US $2+ billion a year, or US $25 billion through 2003/04, excluding price escalation and interest during construction. A substantial portion of this amount represents foreign exchange-related capital requirements.

Furthermore, the total national capital expenditures for electricity generation and network capacity are an order of magnitude higher than the US $25+ billion figure just noted, because this figure does not reflect capital expenditures that must be made by industry to expand captive generation capacity.

[1] The RCG/Hagler, Bailly team members responsible for undertaking this study (Arun P. Sanghvi, team leader and pricing economist, and Toan Ngyuen, utility load management engineer) would like to express their sincere gratitude for the cooperation and assistance received from DGENE and PLN staff throughout the conduct of this study.

Capital expenditures of such magnitude will impose a heavy burden (opportunity cost) on the economy, in that less capital investment will be available to the productive sector as well as for social development -- health, education, nutrition. Indeed, the news in recent months indicates that Indonesia has temporarily deferred some "mega" projects because of financial resource constraints.

Most immediately, however, the pressing problem facing PLN's Java-Bali grid operations, and that is projected to continue for the mid-term, is the potential inability to meet peak load for the four+ hours that define the evening system peak hours on weekdays.

It is vital, therefore, that PLN leave no stone unturned to ensure that it pursues a least-cost expansion strategy for the power sector. A critical dimension of such a resource development strategy, and one that has gained significant ground in the U.S. during the last decade, is demand-side management (DSM). DSM involves actions taken by the utility, such as customer energy end-use efficiency improvement and load control -- direct load control as well as indirect load modulation via a tariff design -- that are cost-effective when compared with the cost of supply-enhancing measures that would be required, absent the change in customer consumption levels and/or patterns.

With this as background, the specific *objectives of this report* are to:

- review relevant and available information on PLN's Java-Bali grid system with a view to identifying priority objectives for load management and incentive pricing mechanisms for achieving such objectives
- review PLN's most recent long-run marginal cost study and adjust it as appropriate to develop up-to-date estimates of the economic cost of grid supply
- review PLN's existing tariffs in light of the economic cost structure and recommend incentive pricing schemes that can be offered as an optional basis to achieve the desired customer response
- examine the potential for using existing captive generation capacity as a load management strategy
- conduct a prefeasibility analysis for a pilot load management project centered around the concept of utilizing existing captive power generating capacity.

This report is the second of a two-volume study on demand-side management (DSM) in Indonesia. Volume I of this set presents an action plan for Indonesia to begin establishing a DSM program.

S.2 ECONOMIC COST OF POWER GRID POWER SUPPLY

Estimates of the long-run marginal cost of supply (LRMC) for the Java-Bali grid system were developed in the study and are summarized in Exhibits S-1 and S-2.

To illustrate, Exhibit S-1 shows that the marginal cost for PLN to supply incremental demand of 1 kW at medium voltage (MV) is Rp. 11.97/ckW-mo, of which amount, Rp. 6.98/ckW-mo represents generation capacity cost and the balance is accounted for by the network capacity.

Exhibit S-1
Long-Run Marginal Capacity Costs
(1992 $/ckW-mo)[1]

Delivery Voltage	Generation Capacity	Network Capacity			Total
		HV	MV	LV	
HV	6.39	0.67	--	--	7.06
MV	6.98	0.72	4.27	--	11.97
LV	8.81	0.85	5.07	8.57	23.30

[1] ckw denotes coincident kW.

Marginal energy costs are shown in Exhibit S-2. For example, a unit of incremental energy supplied on-peak at MV has an economic cost of 6.17¢/kWh, whereas incremental off-peak supply has an economic cost of 3.68¢/kWh.

Exhibit S-2
Marginal Energy Costs By Delivery Voltage
(¢/kWh)

Delivery Voltage	Peak	Off-Peak
Busbar	5.42	3.33
HV	5.65	3.44
MV	6.17	3.68
LV	7.78	4.40

The significance of these numbers is that if PLN can buy energy, and capacity from captive power plants, its opportunity cost -- i.e., PLN's maximum willingness to pay based on economic considerations solely -- are the estimates shown in Exhibits S-1 and S-2, net of any interconnection costs.

S.3 DSM PROGRAM OPTIONS

Based upon a careful review of available information, the following peak load management program in the near- to mid-term is recommended:

- a DSM program to "purchase" daily, excess capacity from captive power generators during the peak hours: 18:00 p.m. to 22:00 p.m.

The proposed DSM program comprises three options:

- **Interruptible:** Under this option, PLN would interrupt service during peak hours to customers who sign up for the program. Such customers could meet their load from excess self-generation capacity, if they so chose.
- **Buy Back from PLN's Customers:** Under this option, PLN would purchase excess capacity from captive power generators during the peak hours.
- **Buy Back from Non-PLN Customers:** Under this option, peaking capacity would be purchased from captive power generators owned by electricity consumers who are currently not PLN customers.

Program Potential

Estimates of program potential were derived utilizing information from PLN's captive power database for industries with installed captive diesel generation capacity of at least 5 MVA.[2]

Exhibit S-3 summarizes the peak load management potential by each of the three DSM options. A total (technical) potential of 792 MW is estimated in Java; 123 MW can be tapped through an interruptible service program. In addition, 318 MW of on-peak capacity can potentially be purchased from existing PLN customers, and the potential exists for purchasing another 336 MW of peaking capacity from non-PLN customers.

[2] Since the focus of this analysis is on peak load management, only diesel generators were considered because of their quick start-up ability. Steam generators were not considered because their start-up time is substantially longer than diesel generators.

To illustrate, consider the estimate of interruptible load in Exhibit S-3. This was derived as follows. For PLN customers whose load is lower than their captive installed capacity, as per the data base, the connected load is viewed as interruptible since in the event all supply is interrupted, the customer can self-generate to meet load. In addition, the surplus captive capacity (installed less load) can be purchased by PLN under the buyback option. It is relevant to note that the estimate of interruptible load in Exhibit S-3 understates the true potential in that it does not include actual load interruption potential by the customer rescheduling plant operations.

Exhibit S-3
Peak Load Management Potential

Option	Region	MW	On-Peak Generation (MWh/Year)
1. Interruptible	East Java	50	87,600
	Central Java	11	16,060
	West Java	29	42,340
	Jaya & Tangerang	38	55,480
	Subtotal	138	201,480
2. Buy Back Option # 1: PLN's Customers > 10 MVA	East Java	128	186,880
	Central Java	38	55,480
	West Java	60	87,600
	Jaya & Tangerang	92	134,320
	Subtotal	318	464,280
3. Buy Back Option #1: Non-PLN Customers >10 MVA	East Java	0	0
	Central Java	81	118,260
	West Java	189	275,940
	Jaya & Tangerang	66	96,360
	Subtotal	336	490,560
	Total	792	1,156,320

S.4 INCENTIVE TARIFFS

The pricing framework proposed later in this section draws upon the economic theory of efficiency pricing as the primary guiding philosophy. Based upon the analysis of PLN's long-run marginal cost, and an analysis of the indicative cost structure of captive generation (Chapter 4), a two-part incentive tariff structure is proposed to "purchase"[3] captive power generation, especially during peak hours, under the proposed incentive tariffs in Exhibit S-4. It should be noted that the tariff structure in Exhibit S-4 emphasizes economic efficiency considerations. The direct application of this tariff -- in the case of a firm contract where even the minimum suggested capacity payment in Exhibit S-4 is offered -- will require upward adjustments to PLN's current system-wide average tariff yield of Rp. 135/kWh, as discussed further subsequently. If such financial adjustments are not forthcoming, then the capacity payments in Exhibit S-4 will need to be lowered accordingly.

In the case of a non-firm power purchase, the purchase price is significantly higher than the seller's variable cost of supply, and should provide adequate financial incentives for participation in the program (e.g., a 5 MVA customer on Tariff I-4 will save nearly 8 percent of his monthly electricity bill per equivalent MW of non-firm energy provided to the grid on-peak). The analysis in Chapter 3 of this report reveals that the variable cost of generation for captive plant of the type likely to participate in the proposed program is around Rp. 70/kWh. Thus, any payments received in excess of this amount will help cover the generator's fixed cost.

For firm power purchases, Exhibit S-4 indicates that in addition to energy payments, the seller should receive a capacity-related payment as well. At this stage, it is recommended that this component of the payment be negotiated by PLN with the seller. The primary reason for this approach is grounded in the fact that the capacity and related costs of self-generation tend to vary substantially and are customer-specific.[4] Therefore, the suggested strategy of negotiation, with lower capacity payments being given initially and progressively increasing capacity payments in later stages of the program, will simulate a market-based "bidding process" that orders supplies over time in order of increasing resource acquisition cost. This will help provide an economically efficient ordering of the power purchases secured, and with no one receiving a payment that equals or exceeds full avoided cost other than the marginal -- i.e., highest-cost -- captive generation resource selected.

The intent underlying the negotiated payment recommendation for capacity valuation is that PLN attempt to first secure the lowest-cost supplies and as these are exhausted, move up the

[3] The purchase may involve a supply of captive power to the grid via an interconnection, or may simply be accomplished by a reduction in demand imposed on the grid, with the demand reduction met by captive power generation.

[4] They depend upon unit size, performance characteristics, existing levels of utilization, etc.

Exhibit S-4
Economic Tariff Structure for Peak Load Management DSM Programs

Contract	Voltage	Tariff Component	Peak	Off-Peak
1. Non-Firm Purchase	HV	Energy (Rp./kWh)	116	71
		Capacity (Rp./ckW-mo.)	--	--
2. Firm Purchase	HV	Energy (Rp./kWh)	116	71
		Capacity (Rp./ckW-mo.)	Minimum Suggested: 3,637 Maximum: 14,546	--
1. Non-Firm Purchase	MV	Energy (Rp./kWh)	127	76
		Capacity (Rp./ckW-mo.)	--	--
2. Firm Purchase	MV	Energy (Rp./kWh)	127	76
		Capacity (Rp./ckW-mo.)	Minimum Suggested: 6,156 Maximum: 24,624	--
1. Non-Firm Purchase	LV	Energy (Rp./kWh)	160	91
		Capacity (Rp./ckW-mo.)	--	--
2. Firm Purchase	LV	Energy (Rp./kWh)	160	91
		Capacity (Rp./ckW-mo.)	Minimum Suggested: 11,998 Maximum: 47,993	--

* To be structured in equivalent Rp./ckWh terms. See text for explanation.
Exchange rate: 20-to-1.

supply curve to higher-cost supplies. For example, in the early stages, PLN should attempt to register those participants and secure capacity from those self-generators who are willing to accept, say, 25 percent of the full avoided capacity cost. Once supply from these generators is exhausted, the capacity value in the tariff could be increased to, say, 50 percent of the full avoided capacity cost, with increases thereafter at appropriate times. Ultimately, it is in PLN's self-interest to pay up to the full avoided capacity cost,[5] if necessary, to secure on-peak firm power purchases. However, it is not necessary, or to the financial advantage of PLN and its ratepayers, to pay full avoided capacity cost to participants who would "come to the table," even if this capacity payment is lower than this maximum.

To illustrate the financial incentive under a capacity value of Rp. 6,156/ckW-mo. (i.e., 25 percent of full avoided capacity cost), consider again the example before wherein a 5 MVA contract demand customer offers to sell 1 MW of firm capacity on-peak. In this case, the captive power seller will receive an additional benefit of Rp. 12,321,000/month, for a total bill reduction of nearly 11 percent each month. As a percentage of the company's profit margin, this would typically represent a much higher amount.

Financial Implications for PLN

PLN's projected tariff yield for the system, i.e., billed revenue per unit of billed sales, averaged over all tariff categories, is approximately Rp. 135/kWh. By comparison, the power purchase tariffs proposed in Exhibit S-4 are higher for firm purchases, even under the minimum suggested capacity payment. For example, under the minimum suggested capacity payment of Rp. 6,156/ckW-mo. at HV, the effective cost of a firm purchase to PLN would be Rp. 178/kWh.[6] By contrast, PLN is only collecting Rp. 135/kWh, system-wide. Thus, large-scale implementation of the proposed DSM program will result in revenue erosion and deterioration of PLN's financial performance.

To avert this situation, as well as remove this disincentive for PLN, it is necessary that the costs of the power purchase, and other program costs incurred by PLN, in excess of the system-wide average tariff yield of Rp. 135/kWh, be treated as a legitimate cost in PLN's cost structure. PLN should recover these costs, as it does all other legitimate costs (fuel, salaries, investment, A&G, etc.), by adjusting its tariff yield of Rp. 135/kWh upward.[7]

[5] Net of any transaction costs, e.g., if PLN incurs the capital cost for interconnection, then these costs, which are really the responsibility of the seller, must be recovered from the seller.

[6] [6,156 Rp./121.6 peak kWh per month] + Rp. 127/kWh.

[7] Clearly, PLN would be allowed to make this adjustment if additional peaking generation is built as a substitute for the power purchase from the captive generator.

S.5 PILOT LOAD MANAGEMENT PROJECT PRE-FEASIBILITY

Two potential candidates for a pilot load management project involving on-peak power purchases from captive generators were identified. In close consultation with PLN, several potential candidates were initially screened, and two cement plants were identified for site visits. Of the two plants selected, one is a PLN customer, whereas the other is not a PLN customer.

The overall conclusion that emerged from the site visits and discussion with the plant facilities managers at the two plants indicated that given a favorable on-peak purchase tariff, PLN may be able to acquire up to 25 MW of on-peak power. This would be accomplished by: 1) providing a connection between the PLN grid and the non-PLN customer to purchase up to 20 MW of on-peak power and 2) interrupting approximately 5 MW of the manufacturing plant load that is a customer of PLN.

Next Steps

Chapter 5 describes the pre-feasibility analysis, and contains technical recommendations for configuring the interconnection. A cost-benefit analysis indicates that it is economical for PLN to purchase excess power from the captive power producers to serve PLN's system demand during the on-peak hours of 18:00 p.m. to 22:00 p.m. instead of adding peaking generating capacity.

Today, there are many captive power generators who do not seem to be interested in engaging in such a program at any price. Therefore, the basic concept needs to be demonstrated and marketed more aggressively. It is recommended that a pilot load management project be implemented so that a detailed study of the economic benefits and demonstration of technical feasibility of using captive power to serve PLN's on-peak load can be achieved. This pilot project will also enable PLN to "fine tune" the purchase tariffs for a broader implementation of the proposed DSM program concepts for peak load management. The project should take approximately 12 months to complete.

This report is part of a broader effort to chart a course towards the more efficient use of electricity in Indonesia through DSM. A companion report, *An Action Plan for Demand-Side Management in Indonesia,* presents an overall strategy for DSM in Indonesia, including a possible course of action. The associated costs and benefits of the plan -- a component of which is the pilot load management project developed in this report -- are presented in the companion document in sufficient detail to provide a basis for follow-on funding from donor agencies and the Indonesian Government.

S.6 DEVELOPMENT OF A FRAMEWORK FOR PRIVATE SECTOR PARTICIPATION

The DSM program for peak load management that is the focus of this report essentially involves the purchase of power from the private sector. Therefore, the design and implementation of this program should be consistent with the principles and framework that more broadly guide the development of the "private power market" in Indonesia. A recently completed study under USAID funding [7][8] represents a step in that direction. It proposes a framework and implementable methodology for rationalizing the pricing of a range of power purchase transactions that PLN potentially can engage in, including the transactions that are the focus of this report.

However, the success as regards the efficient and sustainable development of the private power program in general and the captive power purchase program in particular will hinge critically upon the GOI creating and implementing a market transactional structure and environment in which the rules of the game -- economic, regulatory, oversight, contractual, financial, and legal recourse -- are clearly defined and transparent, fair and equitable, and provide efficient, unambiguous, strong signals to all potential entrants (sellers) as regards the potential risks and rewards.

Since the enactment of the Law on Power Sector in 1985 and especially within the last two years with the creation of the "Private Power Team" in the Directorate General for Electricity and New Energy (DGENE), a beginning has been made. However, considerably more work remains in defining and clearly articulating the policy framework in detail, including pricing principles and mechanisms, the institutional and regulatory framework, standardized contract documents, and a host of other issues related to project and contractor selection, project financing, risk sharing, and guarantees and commercial details.

[8] Numbers in brackets denote references in Chapter 6.

CHAPTER I: INTRODUCTION

1.1 BACKGROUND AND STUDY OBJECTIVES

PLN's national energy sales increased from 2,444 GWh in 1974/75 to 27,741 GWh in 1989/90, at an average annual growth rate of 16.3 percent. Over the same period, the number of customers showed an average annual growth rate of 16.2 percent. Comparable growth rates have been achieved in Java.

PLN's record in achieving a high connection rate for new customers is remarkable. Over the decade 1979/80 to 1989/90, PLN added over 8 million new customers, or over 800,000 connections per year. In spite of this impressive record, the potential for electricity sales growth in the future remains high.

For one, the electrification ratio is still below 28 percent even in Java, the most heavily electrified island. Further, per capita electricity generation, which is estimated to be about 250 kWh per year, is low when compared with other developing countries with similar or lower income levels.

Indeed, load is projected to grow at an annual rate of about 12 percent in Java under the medium scenario. PLN forecasts are best interpreted as supply forecasts and not demand forecasts. Because of resource constraints on PLN -- manpower and financial -- the electrification ratio of substantially below 100 percent will prevail throughout the end of the forecast horizon. In addition, PLN has reduced, if not completely deferred, for a four-year period, the takeover of captive power in industry. The latter capacity is projected to rise significantly in the decade because of PLN's inability to meet new demand, let alone the takeover of existing capacity.

PLN's least-cost generation expansion program, under the medium growth scenario, beyond the committed plant, consists of the following major additions (12,000 MW) by the year 2003/2004:

- 3,200 MW of coal-steam at Paiton (units 5 through 8)
- 4,200 MW of coal-steam in Central Java (7 x 600 MW)
- 1,800 MW of coal-steam in West Java (2 x 600 MW)
- 1,500 MW of coal-steam in East Java (3 x 500 MW)
- 960 MW of gas turbines (8 x 120 MW)
- 570 MW of hydro.

The capital requirements for the national power development plan -- generation and network -- are estimated to be on the order of US $2+ billion per year, or US $25 billion through 2003/04, excluding price escalation and interest during construction. A substantial portion of this represents foreign exchange-related requirements.

In reality, the total national capital expenditures for electricity generation and network capacity are an order of magnitude greater than the US $25+ billion figure just noted, because this figure does not reflect capital expenditures that must be made by industry to expand captive generation capacity.

Capital expenditures of such magnitude will impose a heavy burden (opportunity cost) on the economy, in that less capital investment will be available to the productive sector as well as for social development -- health, education, nutrition. Indeed, within the last year the Government of Indonesia (GOI) has temporarily deferred some "mega" projects because of insufficient financial resources.

It is thus vital that PLN leave no stone unturned to ensure that it pursues a least-cost expansion strategy for the power sector. A critical dimension of such a resource development strategy, and one that has gained significant ground in the U.S. during the last decade, is demand-side management (DSM), which is also sometimes referred to as demand management.

PLN also recognizes the importance of pursuing DSM more aggressively. DSM involves actions taken by the electric utility to help consumers make energy end-use efficiency improvements and implement load management-enhancing measures that would be cost-effective, but would not be undertaken absent the DSM program.

Demand management can be defined as the deliberate control or influencing of customer electrical loads (levels and time-of-use patterns). The ultimate goal of demand management is to lower the average cost of electricity. To realize this goal, customer load shapes must be altered to bring about an improvement in load factors, a reduction in the need for peaking capacity, and higher utilization of more efficient baseload generation.

Broadly speaking, there are two classes of strategies for carrying out load management: direct load control and indirect load control.[1] Direct load control involves the physical on-and-off switching of end-use devices/loads by the utility. Indirect load control involves customer control of loads in response to price signals and is the primary focus of this report. The most common examples of indirect load control are:

- demand charge tariffs, where billing demand is measured coincident with system peak
- time-of-use (TOU) tariffs
- interruptible tariffs
- incentive buy-back rates
- dynamic tariffs.

[1] A third approach is energy storage.

16

Simple demand charge tariffs do not provide a sufficiently strong signal for customers to shape their load in accordance with overall demand management objectives. Clearer and strong signals for load modification are provided by coincident demand charges and more generally, by time-of-day (TOD) or TOU tariffs.

Time-of-use (TOU) tariff options can provide substantial financial incentives for load reduction on-peak as well as load shifting. Low load factor customers can realize bill savings primarily by virtue of the capacity price differentials, whereas high load factor customers can realize such savings through the capacity as well as energy price differentials. The differential between peak and off-peak period energy price essentially reflects the cost differences associated with the marginal generating units that would typically be required to provide incremental power supplies in those periods. In addition, to the extent losses tend to be a quadratic function of load, costs are higher during peak hours.

Interruptible service (IS) is a demand-side option that is widely used and accepted by electric utilities and utility customers in many countries. Interruptible service allows a utility to interrupt load to a customer in accordance with specified provisions. For this privilege, the utility reduces the customer's bill by a specified amount each month. In regard to the daily operations of generation facilities, IS improves reliability and operating flexibility. In the longer term, IS allows the utility to build less generating capacity. A well designed IS tariff provides substantial benefits to both the utility and the customer.

Under an IS tariff, the customer contracts with the utility for an amount of load the customer is willing to remove from the system when requested to do so. This load is then considered to be non-firm. This tariff specifies an advance notice period that may be as long as 24 hours to as little as 15 minutes. While the utility may, in some cases, have direct control over the customer's load, most often the interruption is triggered by a phone call from the utility to the customer. This requires a constantly manned, dedicated phone line to ensure timely communication. Special metering equipment that records usage on a continuous basis is also required to ensure compliance with the magnitude and time of requested interruption. An interruptible tariff is particularly well suited for customers who have standby generation capacity available.

Incentive buy-back rate programs are geared to the purchase of power from those customers who have on-site generation, in order to help meet the utility's load management objectives -- typically, peak shaving. This type of tariff design is based upon establishing a power purchase tariff that provides a financial incentive for the customer to engage in the transaction -- i.e., the tariff should be higher than the customer's cost of self-generation, and simultaneously, does not exceed the utility's avoided cost.

Dynamic pricing refers to tariffs that have one or more parameters which are determined on a "real time" basis. In contrast to the classical TOD or TOU tariffs that are based upon the utility's long-run marginal cost structure, dynamic pricing is based upon the short-run marginal cost structure. Dynamic tariffs are typically offered on an optional basis to large customers that have the response capability to react to such tariffs to the mutual benefit of themselves and the utility.

Objectives

The objectives of this report are to:

- review relevant and available information on PLN's Java-Bali grid system with a view to identifying priority objectives for load management and incentive pricing mechanisms for achieving such objectives

- review PLN's most recent long-run marginal cost study and adjust it as appropriate to develop up-to-date estimates of the economic cost of grid supply

- review PLN's existing tariffs in light of the economic cost structure and recommend incentive pricing schemes that can be offered as an optional basis to achieve the desired customer response

- examine the potential for using existing captive generation capacity as a load management strategy

- conduct a prefeasibility analysis for a pilot load management project centered around the concept of utilizing existing captive power generating capacity.

1.2 ORGANIZATION OF REPORT

This report is organized as follows. Chapter II presents a review of relevant and available information on customer electricity usage characteristics and patterns, and concludes with an assessment of the load shape objectives of high priority to PLN with respect to the Java-Bali grid.

Chapter III develops estimates of PLN's economic cost of supply at various delivery points on its Java grid system. This provides the basis for evaluating the existing tariffs vis-a-vis their effectiveness in helping achieve the load management objectives identified in Chapter II. Recommendations for optional incentive pricing schemes are presented as well.

Chapter IV focuses on the potential for utilizing existing captive power installed capacity as a load management program. It establishes the technical and economic potential of such a program; the latter under different incentive mechanisms. Finally, Chapter V contains a prefeasibility analysis of a pilot load management project at two specific sites based upon the utilization of captive power generation as a load management option.

CHAPTER II: POWER SECTOR OVERVIEW

Section 2.1 of this chapter presents an overview of historical information about the PLN system that is of relevance to the task at hand. Section 2.2 reviews the limited available information that sheds insights on the broad characteristics of electricity usage patterns. Finally, Section 2.3 establishes the load management objectives of relevance for PLN's grid system into the foreseeable future.

2.1 PLN SYSTEM CHARACTERISTICS

The National Electricity Authority of Indonesia, PLN, was legally established in 1972 as a public corporation under Presidential Decree No. 18, elevating its earlier status as a department of the Ministry of Public Works and Electric Power. PLN is responsible for the generation, transmission, and distribution of electricity as well as the planning, construction, and operation of facilities required to provide electricity. Beginning in the early 1980s, the Ministry of Mines and Energy (MME), through the Directorate General of Electricity and New Energy (DGENE), has granted licenses to a few rural electric cooperatives to generate and distribute power in areas not connected to PLN's network. In addition, during the late 1970s and early 1980s, because PLN was unable to meet a significant portion of industrial demand, a large number of such establishments were given permits by MME and installed captive generation plant to meet their electricity needs.

With a share of almost 60 percent in the country's total power generation and about 55 percent of national installed capacity, PLN has the dominant role in the sector. Specifically, the ownership of generation is distributed as follows:

- the government-owned PLN with an installed capacity of about 8,800 MW as of October 1990, of which 6,300 MW are connected to the Java-Bali grid

- a large number of captive plants (approximately 10,000) installed and operated by industries for their own use (6,700+ MW); of this capacity, more than 45 percent is located in Java

- a small number of electric cooperatives in rural areas (about 20 MW).

Installed Capacity and Mix

Exhibit 2-1 indicates that as of the end of fiscal year 1990/91 (March 31, 1991), PLN had a total installed capacity of 9,275 MW.[1] Energy generation of 34,012 GWh supported final sales of 27,741 GWh. The system-wide annual load factor has hovered around 65 percent in recent years. Network losses for the most recent year for which data were available were around 17 percent of gross generation and 18 percent of net generation.

Exhibit 2-2 provides a breakdown of the generation capacity mix, which can be seen to be predominantly (55 percent) oil based. However, the present situation represents a considerable improvement over the situation in the 1970s and early 1980s. Since that time, substantial amounts of coal-fired generating capacity have been commissioned, consisting of the 4 x 400 MW oil-fired Suralaya units (commissioned in August 1984, June 1985, February 1989, and November 1989, respectively). In addition, during 1985 and 1989, respectively, the hydro plants at Saguling (700 MW) and Cirata (500 MW) were commissioned.[2] As a consequence, during FY 1990/91, oil-fired plants accounted for 46 percent of total generation (compared with 75 percent four years ago), while coal- and gas-fired plants had a combined share of 27 percent. Twenty-four percent was derived from hydropower and geothermal plants, and the remaining 3 percent was purchased.

Regional statistics on power system operation shown in Exhibit 2-3 indicate that PLN's operations are concentrated in Java, which accounts for over three-fourths of total capacity, generation, and sales, and two-thirds of all customers.

Power Market

PLN's national energy sales increased from 2,444 GWh in 1974/75 to 27,741 GWh in 1989/90, at an average growth rate of 16.3 percent. Over the same period, the number of customers showed an average annual growth rate of 16.2 percent.

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[1] In addition, PLN purchased 265 MW from three large captive plants, namely, the Asahan and Juanda hydropower stations and the Krakatau steam power plant.

The high operating capacity margins -- on the order of 45 percent -- appear to reflect PLN's operating environment: a substantial amount of capacity derating of older generating units coupled with the reality that PLN is responsible for operating over 600 isolated power systems over the entire archipelago.

[2] Three large existing oil-fired power plants with a combined installed capacity of about 1,600 MW are also being converted to natural gas, and about 30 old medium-sized hydropower, steam, and diesel power plants are under rehabilitation. All of these measures are intended to reduce PLN's dependance on oil-fired generation. Finally, the implementation of the EHV transmission lines in Java (almost completed) and the establishment of interconnected grids in Sumatra (planned) and Bali (ongoing) will allow a more economic operation of the new large power generating units.

Exhibit 2-1
PLN Installed Capacity, Generation, Sales, and Losses

Fiscal Year	Installed Capacity			Peak Demand **	Capacity Margin		Energy Generation ++	Station Use		T&D Losses		Energy Sales	Load Factor	No. Consumers	Connected Load
	PLN	Pur.	Total												
	MW	MW	MW	MW	MW	% +	GWh	GWh	% †	GWh	% †	GWh	%	10^3	MVA
1974/75	922	100	1,022	602	420	41.1	3,345	96	2.8	807	24.1	2,444	63.4	1,806	1,253
1975/76	1,129	100	1,229	638	591	48.1	3,770	106	2.8	861	22.8	2,804	67.5	1,141	1,426
1976/77	1,377	100	1,477	734	743	50.3	4,127	114	2.8	932	22.6	3,082	64.2	1,209	1,594
1977/78	1,863	100	1,963	835	1,128	57.5	4,725	137	2.9	1,061	22.5	3,527	64.6	1,413	1,934
1978/79	2,288	100	2,388	1,033	1,355	56.7	5,723	186	3.3	1,250	21.8	4,287	63.2	1,784	2,449
1979/80	2,536	100	2,636	1,276	1,360	51.6	7,004	358	5.1	1,303	18.6	5,343	62.7	2,247	3,063
1980/81	2,555	260	2,815	1,577	1,238	44.0	8,420	343	4.1	1,517	18.0	6,560	61.0	2,745	3,744
1981/82	3,032	285	3,317	1,876	1,441	43.4	10,138	395	3.9	1,898	18.7	7,845	61.7	3,232	4,503
1982/83	3,406	285	3,691	2,285	1,406	38.1	11,846	528	4.5	2,217	18.7	9,101	59.2	4,406	5,270
1983/84	3,935	285	4,220	2,413	1,807	42.8	13,392	580	4.3	2,812	21.0	10,000	63.4	5,135	6,127
1984/85	4,515	265	4,780	2,715	2,065	43.2	14,777	694	4.7	3,042	20.6	11,041	62.1	5,133	7,122
1985/86	5,635	265	5,900	2,966	2,934	49.7	16,899	855	5.1	3,338	19.7	12,706	65.0	5,953	8,150
1986/87	6,200	265	6,465	3,403	3,062	47.4	19,455	855	4.4	3,814	19.6	14,786	65.3	6,966	9,282
1987/88	7,237	265	7,502	3,890	3,612	48.1	22,306	1,051	4.7	4,178	18.7	17,077	65.5	8,203	10,711
1988/89	8,529	*265	8,794	4,497	4,297	48.9	25,623	1,269	4.9	4,327	16.9	20,027	65.0	9,276	12,234
1989/90	9,088	265	9,353	--	--	--	29,567	--	--	--	--	23,435	--	10,312	13,951
1990/91	9,275	265	9,540	--	--	--	34,012	--	--	--	--	27,741	--	--	--

Source: Reference [1] and PLN.

* 125 MW from the Juanda Hydropower Station, 90 MW from Krakatau Steel Steam Power Station in West Java, and 50 MW from the Asahan Hydropower Station in North Sumatra

** Arithmetic sum of not necessarily coincident peak demands in the individual systems

\+ As percentage of installed capacity (not reserve margin)

++ Including purchase

† As percentage of gross energy generation

Exhibit 2-2
PLN's Capacity and Generation Mix in 1990/91

Plant Type	Fuel	Installed Capacity		Energy Generation	
		MW	%	GWh	%
Steam	Oil	2,081	22	10,284	30
	Coal	1,730	18	10,910	31
	Gas	130	1	235	1
Gas Turbine		1,230	13	2,175	6
Diesel	Oil	1,870	20	3,608	10
Hydropower	-	2,095	22	5,675	16
Geothermal	-	140	1	1,125	3
Purchase	-	265	3	856	3
Total		9,541	100	34,868	100

Source: PLN.

The data in Exhibit 2-4 reveal that the overall sales growth was caused by the increase in the number of connections rather than in average usage per customer. Indeed, the slight drop in average usage is a result of expanded rural electrification program coverage.

Exhibit 2-3
PLN's Regional Operations, 1988/89

	Java	Outside Java	Total
Installed Capacity (MW)*	6,201	2,593	8,794
Peak Demand (MW)	3,372	1,125	4,497
Energy Generation (GWh)**	20,066	5,557	25,623
Energy Sales (GWh)	15,692	4,335	20,027
Energy Losses (%)***	21.8	22.0	21.8
Annual Load Factor (%)	67.9	56.4	65.0
Number of Customers (million)	6.2	3.1	9.3

* Including a purchase of 265 MW
** Including a purchase of 683 GWh
*** As percentage of energy generation, including power station use

It is interesting to note that the GDP growth over the period 1975/75 to 1988/89 was 8.1 percent per year. This implies an extremely high "income elasticity" of electricity demand at 2.7.

The data also show (Exhibit 2-5) that PLN's sales in Java have traditionally represented the overwhelming share of national sales (on the order of 80 percent), but that this share has shown a declining trend because of the emphasis on the electrification of other islands. Further, the data reveal that sales growth rates have been marginally higher outside Java.

Exhibit 2-6 indicates consumption shares by major consuming categories. The residential share of consumption has fallen from 48 percent in 1974/75 to 32 percent of all sales in 1990/91. At present, industry's consumption share of total PLN sales is the highest at 51 percent. Further, sales to industry have risen at the fastest rate (20.0 percent) and well over the average system-wide sales growth rate of 16.2 percent (Exhibit 2-7).

PLN's record in achieving a high connection rate for new consumers is remarkable. Over the decade 1979/80 to 1989/90, PLN added over 8 million new customers, or over 800,000 connections per year. In spite of this impressive record, the potential for electricity sales growth in the future remains high.

For one, despite the record noted above, the electrification ratio is still below 28 percent even in Java, the most heavily electrified island. Further, the per capita electricity generation, which is estimated to be about 250 kWh per year, is low when compared with other developing countries with similar or lower income levels.

Exhibits 2-8 and 2-9 present, respectively, historical data on energy sales and customer accounts by consumer classes for the Java-Bali grid system. In many respects, the Java-Bali system data -- e.g., growth rates, energy shares -- largely parallel the characteristics of PLN's national sales data discussed earlier. However, average system consumption in the Java-Bali system is higher than the national average (2,609 kWh/consumer in 1989/1990 for Java-Bali versus the national average of 2,217 kWh/consumer). Furthermore, the average sales per account has increased significantly on the Java-Bali system (2,818 kWh/account in 1990/91 versus 2,408 kWh/account in 1986/87) in contrast to the national average consumption per account over the same period (Exhibit 2-4). This increase has occurred despite the fact that average residential consumption in the Java-Bali system has declined over the period 1986/87 - 1990/91 (1,051 kWh/household down to 906 kWh/household), signalling strong industrial demand.

Exhibit 2-4
PLN's Sales and Consumer Growth

Fiscal Year	Energy Sales		No. of Customers		Average Consumption	
	GWh	% p.a.	'000	% p.a.	kWh/con.	% p.a.
1974/75	2,444		1,086		2,250	
1975/76	2,804	14.7	1,141	5.1	2,457	9.2
1976/77	3,082	9.9	1,209	6.0	2,549	3.7
1977/78	3,527	14.4	1,413	16.9	2,496	(2.1)
1978/79	4,287	21.5	1,784	26.3	2,403	(3.7)
1979/80	5,343	24.6	2,247	26.0	2,378	(1.0)
1980/81	6,560	22.8	2,745	22.0	2,390	0.5
1981/82	7,845	19.6	3,232	17.7	2,427	1.5
1982/83	9,101	16.0	3,802	17.6	2,394	(1.4)
1983/84	10,000	9.9	4,406	15.9	2,270	(5.2)
1984/85	11,041	10.4	5,133	16.5	2,151	(5.2)
1985/86	12,706	15.1	5,953	16.0	2,134	(0.8)
1986/87	14,786	16.4	6,966	17.0	2,123	(0.5)
1987/88	17,077	15.5	8,203	17.8	2,082	(1.9)
1988/89	20,027	17.3	9,276	13.1	2,159	3.7
1989/90	23,435	17.2	10,317	11.2	2,217	5.2
1990/91	27,741	18.4	--	--	--	--
Average						
74/75 - 89/90	--	16.3	--	16.2	--	0.0
74/75 - 79/80	--	16.9	--	15.7	--	1.1
79/80 - 84/85	--	15.6	--	18.0	--	(2.0)
84/85 - 89/90	--	16.2	--	15.0	--	1.1

Source: PLN.

24

Exhibit 2-5
Regional Breakdown of Energy Sales

Region	1974/75		1988/89		Average Growth Rate % p.a.
	GWh	%	GWh	%	
Java	1,988	81	15,692	78	15.9
Outside Java	456	19	4,335	22	17.5
Total	2,444	100	20,027	100	16.2

Source: PLN.

Exhibit 2-6
Energy Shares by Consumer Category
(PLN Sales)

Customer Category	1974/75		1990/91	
	GWh	%	GWh	%
Residential	1,163	48	9,004	32
Industrial	738	30	14,166	51
Commercial	225	9	2,328	9
Public	318	13	2,224	8
Total	2,444	100	27,741	100

Source: PLN.

15

Exhibit 2-7
Historical Energy Sales of PLN by Consumer Category

Fiscal Year	Residential		Commercial		Industry		Public		Total	
	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)
1974/75	1174		226		732		307		2439	
1975	1306	11.2	280	24.1	854	16.6	338	10.1	2777	13.9
1976	1420	8.7	318	13.5	928	8.7	366	8.4	3031	9.2
1977	1609	13.4	352	10.9	1142	23.1	413	12.8	3517	16.0
1978	1962	21.9	421	19.5	1443	26.4	452	9.5	4279	21.7
1979	2428	23.7	509	20.9	1910	32.3	487	7.7	5333	24.7
1980	2909	19.8	771	51.6	1874	-1.9	1007	106.6	6560	23.0
1981	3425	17.8	841	9.0	2469	31.8	1110	10.3	7845	19.6
1982	3933	14.8	941	11.9	3017	22.2	1210	9.0	9101	16.0
1983	4292	9.1	1003	6.6	3436	13.9	1270	4.9	10000	9.9
1984	4567	6.4	1054	5.1	4011	16.8	1408	10.9	11039	10.4
1985	5023	10.0	1151	9.3	4937	23.1	1596	13.4	12707	15.1
1986	5649	12.5	1297	12.7	6183	25.2	1657	3.8	14786	16.4
1987	6370	13.1	1491	14.9	7402	19.7	1795	8.3	17077	15.5
1988	7275	13.9	1700	14.1	9052	22.3	1966	9.6	19993	17.1
1989	7946	9.2	1982	16.6	11418	26.1	2088	6.2	23434	17.2
1990/91	9004	13.3	2328	17.5	14166	24.2	2224	6.5	27741	18.4
Average Growth (%)		13.6		15.6		20.1		13.6		16.3

Source: PLN.

Exhibit 2-8
Historical Data on Energy Sales, Java-Bali (MWh)

Year	Res.	G (%)	Comm.	G (%)	Public	G (%)	Industry						Total	G (%)
							Hotel	G (%)	Manuf.	G (%)	Total	G (%)		
1981/82	2606136		647324		855490		--	--	--	--	2234186		6343135	
1982/83	3003174	15.2	714259	10.3	934019	9.2	--	--	--	--	2732293	22.3	7383745	16.4
1983/84	3270762	8.9	768322	7.6	972647	4.1	--	--	--	--	3032550	11.0	8044282	8.9
1984/85	3488548	6.7	814504	6.0	1090735	12.1	--	--	--	--	3507825	15.7	8901612	10.7
1985/86	3818651	9.5	896493	10.1	1245689	14.2	--	--	--	--	4334796	20.7	10195629	14.5
1986/87	4258777	11.5	1009320	12.6	1270233	1.9	196417	--	4966200	--	5227876	23.5	11766206	15.4
1987/88	4817639	13.1	1177663	16.7	1378966	8.6	222550	13.3	5941106	19.6	6243811	19.4	13618079	15.7
1988/89	5494337	14.0	1356592	15.2	1511035	9.6	244324	9.8	7248413	22.0	7587777	21.5	15949741	17.1
1989/90	5998664	9.2	1595252	17.6	1582921	4.8	357891	46.5	9224883	27.3	9582774	26.3	18759611	17.6
1990/91	6795272	13.3	1872658	17.4	1693771	7.0	421122	17.7	11618992	26.0	12040113	25.6	22401815	19.4

G = Growth

Source: PLN.

Exhibit 2-9
Historical Data: Number of Customers, Java and Bali

Year	Residential	Growth (%)	Delta R	Commercial	Growth (%)	Delta C	Public	Growth (%)	Delta P
1986/87	4582992			182725			103734		
1987/88	5372457	17.2	789465	196672	8.7	15947	122895	18.5	19161
1988/89	6091848	13.4	719391	215485	8.5	16813	141420	15.1	18525
1989/90	6780980	11.3	689132	226571	5.1	11086	159163	12.5	17743
1990/91	7500342	10.6	719362	244481	7.9	17910	178556	12.2	19393

Year	Industry								Total	Growth (%)
	Hotel	Growth (%)	Delta H	Manufactur.	Growth (%)	Delta M	Total	Growth (%)		
1986/87	1634			14305			15948		4885399	
1987/88	1703	3.7	60	16103	12.6	1798	17806	11.7	5711830	16.9
1988/89	1778	4.4	75	18195	13.0	2092	19973	12.2	6468726	13.3
1989/90	2775	56.1	997	20844	14.9	2649	23619	18.3	7190333	11.2
1990/91	3138	13.1	363	24066	15.5	3222	27204	15.2	7950583	10.6

Source: PLN.

Captive Power Development

During the 1970s, industrial enterprises installed captive generation on a large scale because of inadequate supply and the poor reliability of grid supply. Captive plant capacity of about 6,922 MW accounts for approximately 43 percent of the nation's total installed capacity.

Exhibit 2-10 shows the captive generation capacity and mix in Indonesia. The predominant fuel for captive generation is diesel (82 percent in Java and 46 percent outside Java), with fuel oil's share being a mere 2 percent in Java and 3 percent outside Java. Other fuels used in significant amounts are gas in Java (14 percent) and hydro and wood outside Java (20 percent and 8 percent, respectively).

In the case of oil products, the overwhelming preference for diesel (No. 2) over residual fuel oil (No. 6 oil) can be surmised to have come about for two primary reasons: technical considerations as regards performance characteristics of available captive generation plant and the GOI's policies that historically distorted the relative prices of petroleum products by under-pricing diesel oil and over-pricing fuel oil. These price distortions have also contributed to the growth of captive power plant capacity because it was frequently cheaper for individual consumers to self-generate than to buy from PLN, whose predominant energy source was fuel oil.

Exhibit 2-10
Captive Generation: Estimated Installed Capacity and Mix

Location	Installed Capacity 1990/91 (MW)	Generation Capacity Mix (%), 1988/89							
			Steam						
		Diesel	Hydro	Coal	Oil	Gas	Wood	GT	Total
Java									
East	641								
Central	571								
West	1,154								
Jakarta	856								
Subtotal	3,224	82	--	--	2	14	1	1	100%
Outside Java	3,700	46	20	--	3	0	8	23	100%
Total	6,922	62%	11%	--	2%	7%	5%	13%	100%

Source: PLN and MME reports.

Subsequent to the domestic price adjustments in May 1990, distortions in product prices have been reduced, with automotive diesel oil (ADO) priced at Rp. 245/liter (a 4 percent premium over border prices as of June 1990), industrial diesel oil (IDO) priced at Rp. 235/liter (a 5 percent premium over June 1990 border prices), and marine fuel oil priced at Rp. 220/liter (an 83 percent premium over June 1990 border prices).

The 6,992 MVA (6,700 MW) of estimated generation capacity is spread over approximately 10,000 units split almost evenly between Java and outside Java. More than 90 percent of these installations are under 1 MVA each, and together they account for approximately 25 percent of installed captive generation capacity. On the other end of the spectrum, the 34 companies each with an installed capacity of 20 MVA or greater, together account for 3,300 MW (approximately 50 percent of national captive generation capacity). Within this segment, the generation mix is as follows: 30 percent diesel, 30 percent gas turbines, 23 percent hydro, 13 percent gas steam, and the remaining 4 percent almost evenly split between fuel oil-steam and wood-steam capacity.

Of the national total captive generation capacity of 6,922 MW, approximately 2,000 MW are estimated to be operated in a "standby plant mode," i.e., predominantly for reliability support.

The energy generation mix for 1989/1990 is estimated to be 50 percent from diesel generation, 32 percent from steam, and 15 percent from hydro, with the remainder from all other sources.

Finally, as discussed subsequently, captive power installed generation capacity is projected to increase substantially in the next few years as PLN is forced to scale back its planned program to supply new industrial load.

2.2 SYSTEM EXPANSION

Projected Power Demand

Exhibit 2-11 summarizes PLN's base case load forecast. Load is projected to grow at an annual rate of about 12 percent in Java and 13 percent outside Java. The forecasts in Exhibit 2-11 are best interpreted as supply forecasts and not demand forecasts. Because of resource constraints on PLN -- manpower and financial -- the electrification ratio of substantially below 100 percent will prevail throughout the end of the forecast horizon. In addition, PLN has reduced, if not completely deferred, for a four-year period, the takeover of captive power in industry. The latter capacity is projected to rise significantly in the decade because of PLN's inability to meet new demand, let alone the takeover of existing captive capacity.

Exhibit 2-11
Generation Load Forecast, Base Case

Year	Java-Bali		Other		Total	
	Peak Load (MW)	Energy Production (GWh)	Peak Load (MW)	Energy Production (GWh)	Peak Load (MW)	Energy Production (GWh)
1991/92	4,888	29,588	1,663	8,036	6,551	37,624
1992/93	5,684	34,406	1,881	9,162	7,565	43,568
1993/94	6,488	39,318	2,131	10,451	8,619	49,769
1994/95	7,578	45,973	2,410	11,916	9,998	57,889
1995/96	8,780	53,314	2,725	13,582	11,505	66,896
1996/97	10,129	61,555	3,082	15,474	13,211	77,029
1997/98	11,238	68,313	3,482	17,608	14,720	85,921
1998/99	12,273	74,607	3,928	19,997	16,210	94,584
1999/00	13,315	80,938	4,427	22,667	17,742	103,605
2000/01	14,443	87,793	4,976	25,619	19,419	113,412
2001/02	15,655	95,151	5,584	28,890	21,239	124,041
2002/03	16,965	103,108	6,256	32,516	23,221	135,624
2003/04	18,383	111,717	7,002	36,555	25,385	148,274
Growth Rate	11.7%	11.7%	12.7%	13.5%	11.9%	12.1%

Source: PLN (R6-Base), July 3, 1991

Power Development Program

Under PLN's expansion plan as of April 1991, there were approximately 5,800 MW of committed projects. The specific projects and the planned commissioning dates are indicated in Exhibit 2-12. The data reveal the following major PLN capacity additions by 1995/96: 9 x 120 MW of gas-fired combined-cycle plant capacity (Gresik), 2 x 400 MW of coal-steam capacity (Paiton-1 and -2), 4 x 55 MW of geothermal, and 4 x 125 MW of hydro. Beyond 1995/96, the committed plant consists of the 3 x 600 MW coal steam units at Suralaya.

PLN's least-cost generation expansion program beyond the committed plant shown in Exhibit 2-13 consists of the following major additions (12,000 MW) by the year 2003/04:

- 3,200 MW of coal-steam at Paiton (units 5 through 8)
- 4,200 MW of coal-steam in Central Java (7 x 600 MW)
- 1,800 MW of coal-steam in West Java (2 x 600 MW)
- 1,500 MW of coal-steam in East Java (3 x 500 MW)
- 960 MW of gas turbines (8 x 120 MW)
- 570 MW of hydro.

Some of these plants are to be offered to the private sector for development.

PLN's expansion plan reflects the objective of the diversification of its resource base away from oil and towards cost-effective indigenous energy resources -- natural gas, coal, geothermal, and hydro -- and where appropriate, to realize economies of scale by building large power stations and larger-sized generating units.

PLN's power development plan for outside Java calls for more than doubling the existing installed capacity of 2,500 MW by the year 1998/99. Of this increment, about half is projected to be hydro plant, 30 percent is projected to be combined cycle, and 20 percent wood-steam.

The Need for Demand-Side Management

The capital requirements for the national power development plan -- generation and network -- are estimated to be on the order of US $2+ billion per year, or US $25 billion through 2003/04, excluding price escalation and interest during construction. A substantial portion of this amount represents foreign exchange-related capital requirements.

Exhibit 2-12. Committed Projects and Commissioning Dates: Java-Bali System

Project Name		Capacity (MW)	Commissioning Date
1. GTPP ex Tosan Prima		3 x 20	December 1991
2. HEPP Tulung Agung		2 x 18	March 1993
3. CCPP Open Cycle Muara Karang	#1	1 x 100	September 1992
	#2	1 x 100	October 1992
	#3	1 x 100	November 1992
4. CCPP Steam Cycle Muara Karang		1 x 150	September 1994
5. CCPP Open Cycle Gresik	#1	1 x 120	March 1992
	#2	1 x 120	April 1992
	#3	1 x 120	May 1992
	#4	1 x 120	June 1992
	#5	1 x 120	July 1992
	#6	1 x 120	August 1992
	#7	1 x 120	September 1992
	#8	1 x 120	October 1992
	#9	1 x 120	November 1993
6. HEPP Tulis		2 x 6.5	1993/94
7. HEPP Ciliman		1 x 10	1993/94
8. HEPP Kedung Ombo		2 x 11.5	May 1993
9. Geothermal PP Salak		2 x 55	1993/94
10. CCPP Steam Cycle Gresik I		1 x 166	July 1993
11. CCPP Steam Cycle Gresik II		1 x 166	January 1994
12. CCPP Steam Cycle Gresik III		1 x 166	July 1994
13. STCPP Paiton 2		1 x 400	January 1994
14. STCPP Paiton #1		1 x 400	July 1994
15. Geothermal PP Drajat		1 x 55	1994/95
16. Geothermal PP Dieng		1 x 55	1994/95
17. HEPP Kesamben		1 x 33	1995/96
18. HEPP Cirata II		4 x 125	1995/96
19. STCPP Suralaya #5		1 x 600	March 1996
20. STCPP Suralaya #6		1 x 600	December 1996
21. STCPP Suralaya #7		1 x 600	September 1997

In reality, the total national capital expenditures for electricity generation and network capacity are an order of magnitude higher than the US $25+ billion figure just noted, because this figure does not reflect capital expenditures that must be made by industry to expand captive generation capacity.

Capital expenditures of such magnitude will impose a heavy burden (opportunity cost) on the economy, in that less capital investment will be available to the productive sector as well as for social development -- health, education, nutrition. Indeed, the news in recent months indicates that Indonesia has temporarily deferred some "mega" projects because of tight financial resources.

It is vital, therefore, that PLN leave no stone unturned to ensure that it pursues a least-cost expansion strategy for the power sector. A critical dimension of such a resource development strategy, and one that has gained significant ground in the U.S. during the last decade, is demand-side management (DSM). DSM involves actions taken by the utility, such as energy end-use efficiency improvement and load control -- direct load control as well as indirect load modulation via a tariff design -- that are cost-effective when compared with the cost of supply-enhancing measures that would be required, absent the change in customer consumption levels and/or patterns.

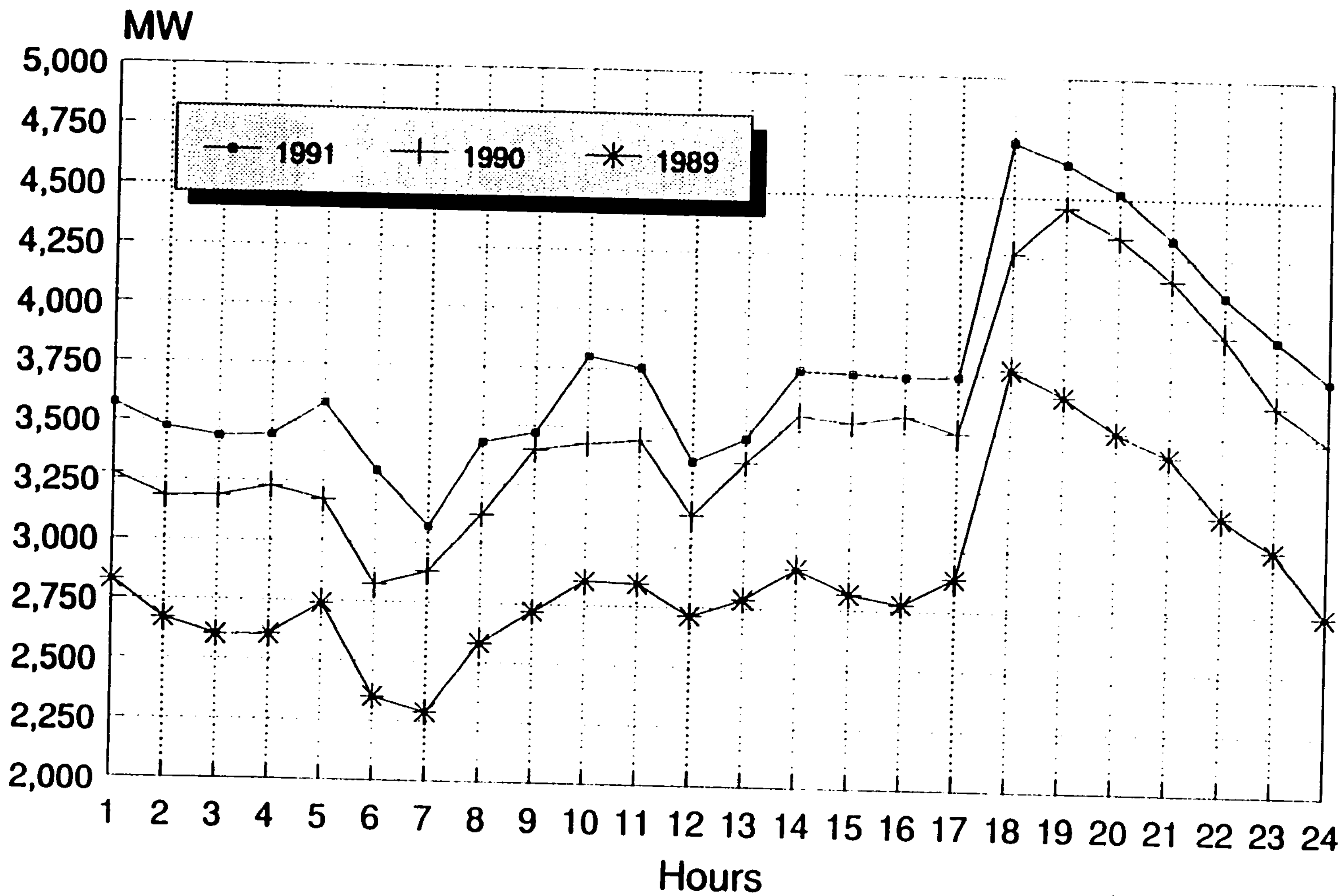
2.3 LOAD SHAPE CHARACTERISTICS AND OBJECTIVES

Exhibits 2-13 and 2-14 depict the recent evaluation of the system peak day and average workday load shape for the Java-Bali system. The load shape is characterized by an evening peak (from 6 p.m. to 10 p.m.), with a daytime "shoulder" and a mid-day dip. Average weekday and weekend load shapes are not very different (Exhibit 2-15). Furthermore, the general load shape has remained unchanged in recent years (Exhibit 2-16).

PLN has undertaken sporadic load research activities in recent years on a selective basis to support system expansion planning, tariff setting, and distribution planning.[3] These limited data reveal that the major contributors to the evening peak load are the residential lighting load, street lighting, and the commercial retail load. The industrial load exhibits the highest daily load factor and is fairly flat (Exhibits 2-17 and 2-18).

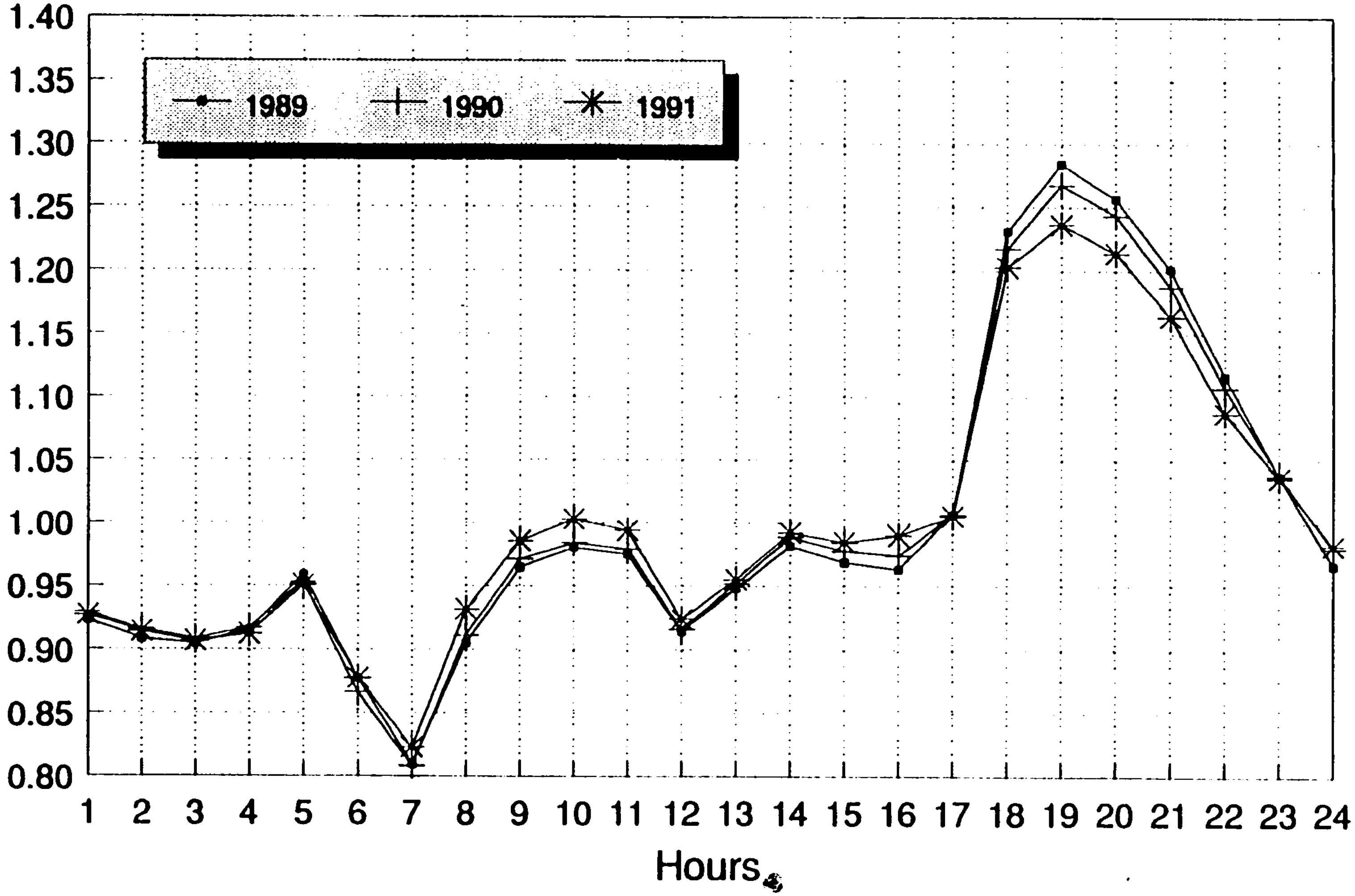
[3] Recently, under an ADB-financed technical assistance project, a load monitoring study is underway for the Java-Bali grid system. However, end-use load research is not a focus of that study.

Exhibit 2-13
Peak Day Load Curves



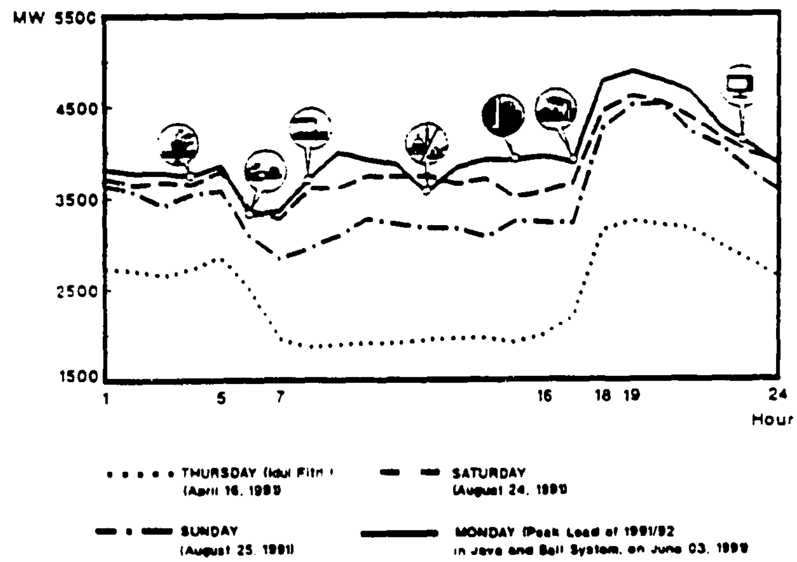
Source: RCG/Hagler, Bailly, based upon data provided by PLN.

Exhibit 2-14
Normalized Average Workday Load Curves



Source: RCG/Hagler, Bailly, based on data provided by PLN.

Exhibit 2-15
Characteristics of Daily Load in Java and Bali System, 1991/92



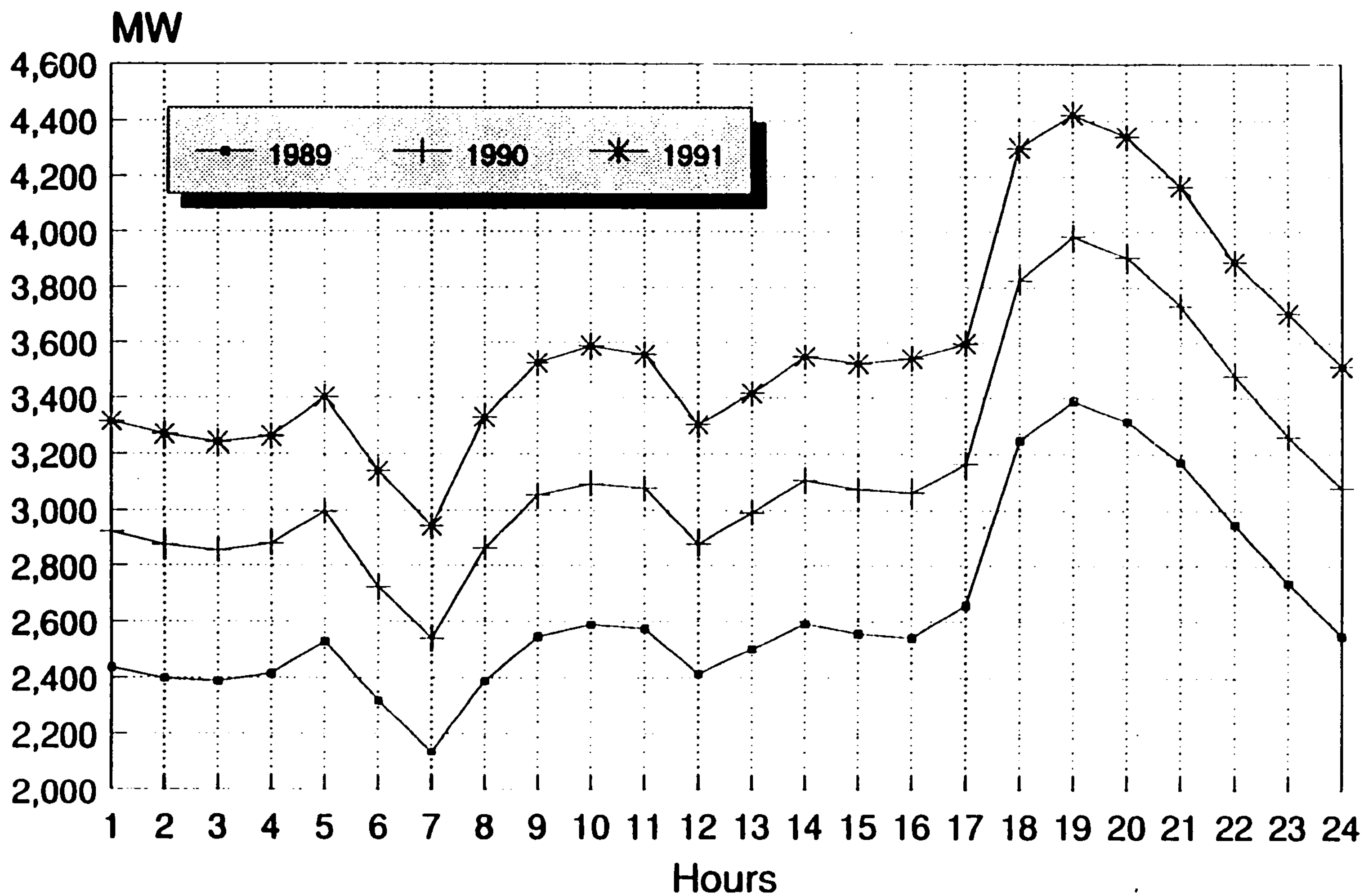
The predominance of the industrial load in the Jakarta area can be seen from Exhibit 2-19, which shows a relatively flat daily load curve between 10 a.m. and 6 p.m.

One of the fundamental building blocks of "production grade" DSM programs is detailed information about how, why, and when electricity is consumed and the efficiency of such consumption. This understanding requires collecting data on, updating, and monitoring trends as regards a very large number of variables such as saturation, appliance stock vintages and efficiencies, how decisions are made about new appliances when choices are available to consumers, what are the major determinants (i.e., end-uses) of electricity consumption profiles, and indeed, as a first step, what is the typical daily usage pattern at the premise level (e.g., house, building, factory, shop), etc.

Collecting such information requires designing and implementing a load monitoring and customer survey program. PLN has undertaken some residential surveys on appliance saturation and household usage.

Exhibit 2-16

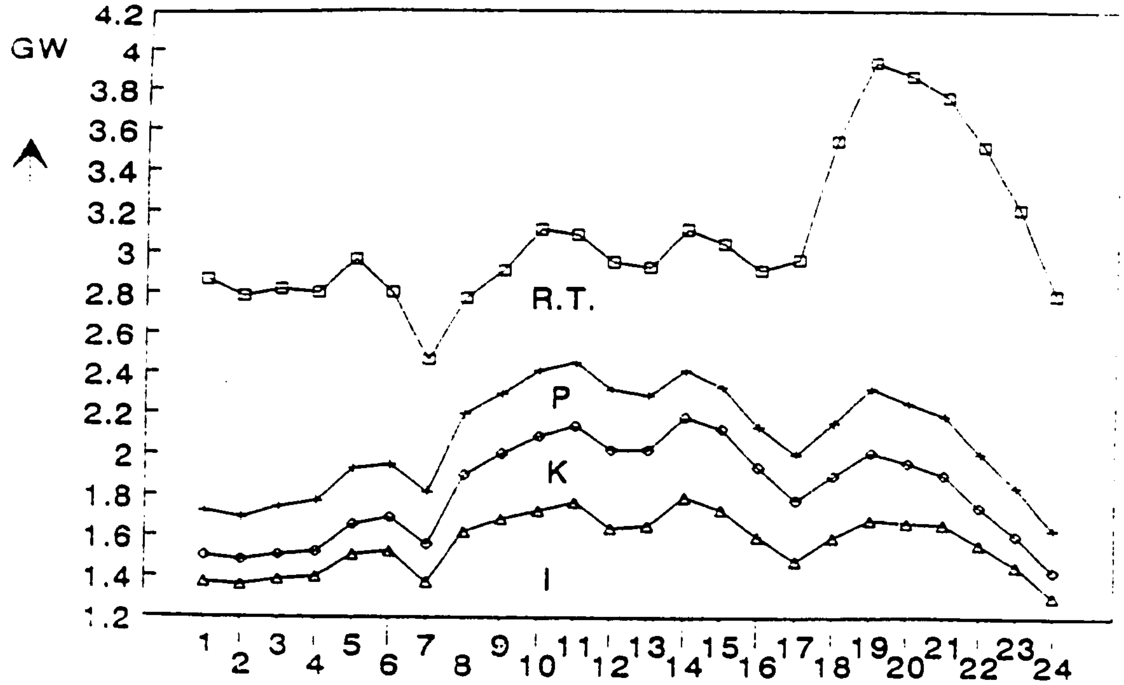
Average Workday Load Curves



38

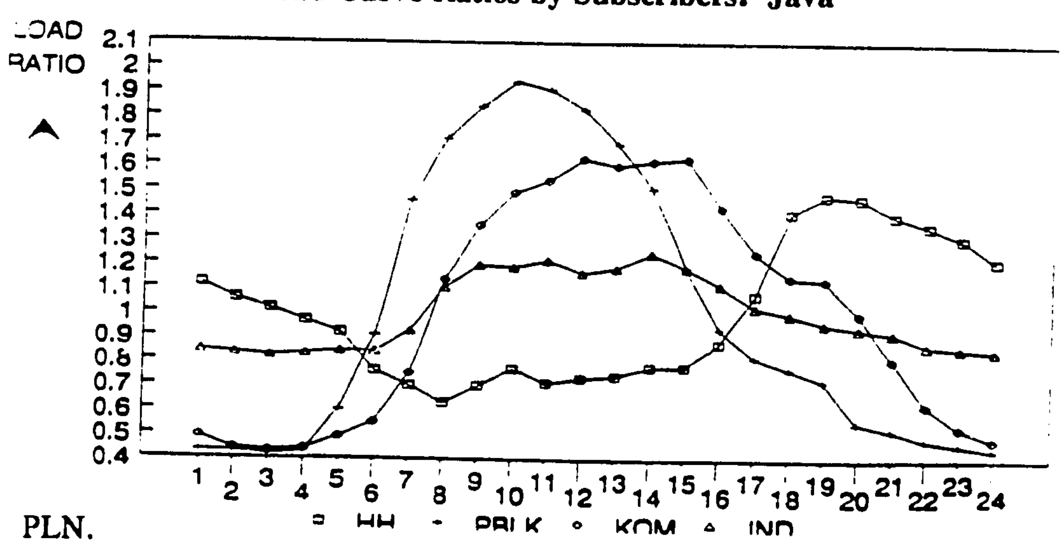
Source: RCG/Hagler, Bailly, based on data provided by PLN.

Exhibit 2-17
Sector Contribution to the Daily Load Curve, Java-Bali System, 1989/90



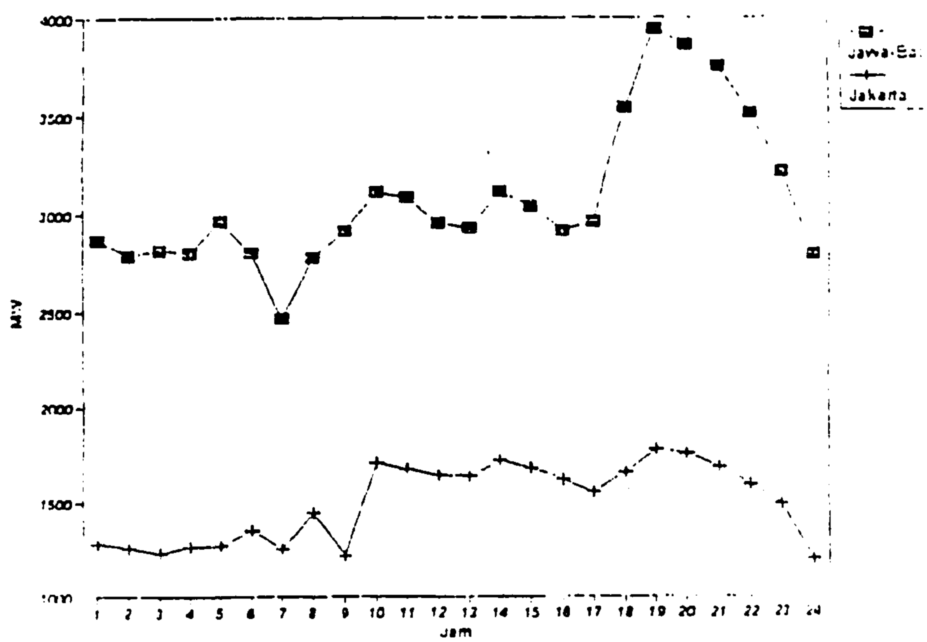
Source: PLN.

Exhibit 2-18
Load Curve Ratios by Subscribers: Java



Source: PLN.

Exhibit 2-19
Daily Load Curve, March 1990, Java-Bali and Jakarta



Load Shape Objectives

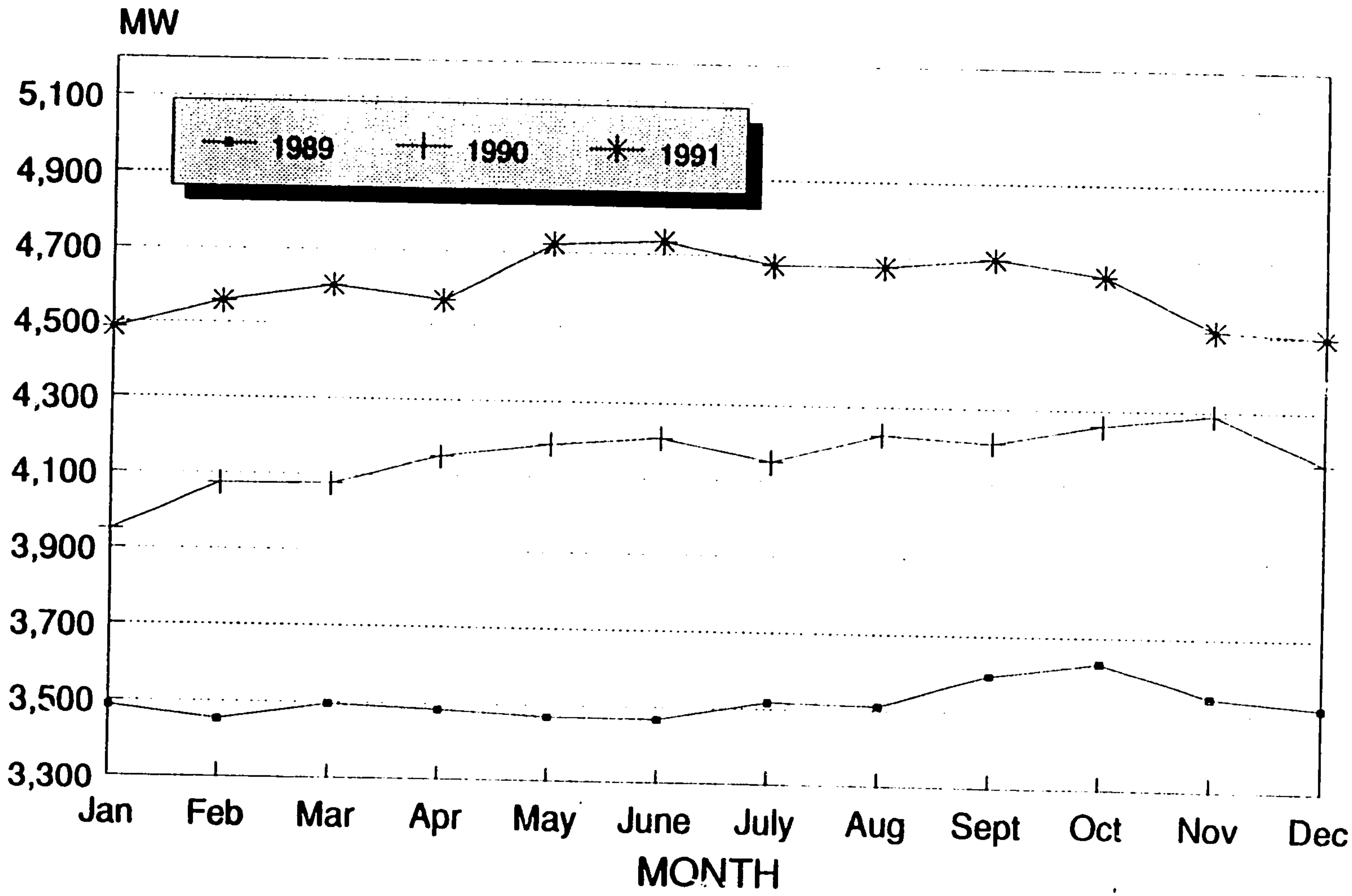
During the course of our mission to Jakarta, available data on load characteristics were reviewed with PLN operations and planning staff in light of the current and emerging power demand balance. A general consensus emerged that the most pressing problem facing PLN's Java-Bali grid operations projected for the mid-term and starting almost immediately is the potential inability to meet peak load. Given the lack of significant seasonality in load shape (e.g., see Exhibits 2-20 and 2-21), this situation translates into a DSM objective of peak shaving (clipping) for the four+ hours that define the evening system peak hours on weekdays.

Thus, a consensus was reached in discussions with PLN that this report will focus exclusively on a load management program directed at peak clipping during the evening hours. This, coupled with the fact that substantial amounts of installed captive power capacity exist (3,224 MW on Java alone, per Exhibit 2-10), established the basis for the analysis presented in this report: a DSM program centered around the concept of utilizing existing captive generation capacity for peak shaving. Such a program can potentially be structured as an interruptible service (IS) option directed to those customers with sufficient captive capacity to meet their

40

non-firm load when grid supply is curtailed. Under an alternate program structure -- power purchase/buyback -- power from captive generators would be injected into the grid.

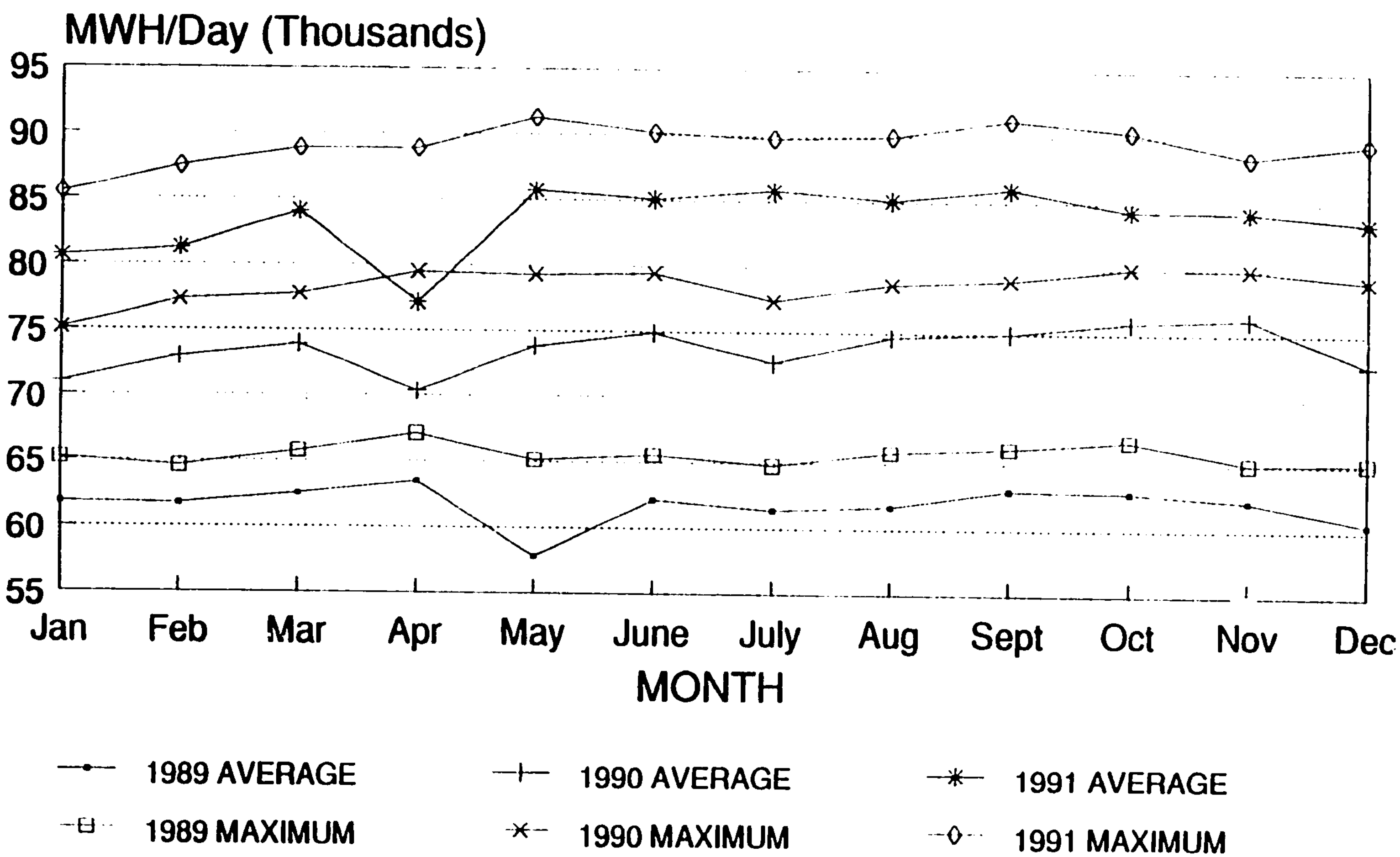
Exhibit 2-20
Adjusted Monthly Peak Load



42

Source: RCG/Hagler, Bailly, based upon data provided by PLN.

Exhibit 2-21
Adjusted Monthly Energy Consumption



Source: RCG/Hagler, Bailly, based on data provided by PLN.

CHAPTER III: ECONOMIC COST OF GRID POWER SUPPLY

Rational electricity pricing -- level and structure -- must be a central element of any strategy for bringing about efficiency improvements whereby electricity consumption and production are matched to economically efficient levels. In this regard, economic theory suggests that the economic cost of power supply, as measured by its marginal cost, provides the appropriate benchmark for efficiency pricing.

This chapter begins by developing estimates of PLN's long-run marginal cost (LRMC) for the Java-Bali grid (Section 3.1). These estimates of LRMC provide the basis (Section 3.2) for defining tariff options to help achieve the desired load management objectives identified in Chapter 2.

3.1 LRMC FOR THE JAVA-BALI GRID SYSTEM

This section establishes estimates of the long-run marginal cost (LRMC) of supply for the Java-Bali grid system. Since a full-scale and independent LRMC analysis was outside the scope of this effort, the approach utilized was to update, adjust, and adapt as appropriate, estimates of LRMC developed in PLN's most recent LRMC study.[1]

Network Capacity Cost

For estimating LRMC for the network, PLN has used the Long-Run Average Incremental Cost (LRAIC) method, which we find to be acceptable. The estimates of network LRMC shown in Exhibit 3-1 were developed by updating estimates in PLN's November 1991 report, but updated for one year of inflation.[2]

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1 "PLN Electricity Pricing 1992/93, Based on LRMC Approach," Review November 1991, PLN Tariff Department Report.

2 Based on discussions with PLN, a 4 percent escalation was used; estimated as 3 percent world inflation applied to the 70 percent foreign component of network investment, and 6 percent local inflation applied to the 30 percent local component of network investment.

Exhibit 3-1
Long-Run Marginal Network Capacity Costs
(1992 $/ckW/mo)[1]

Voltage		Voltage HV	MV	LV	Total
High	(HV)	0.67	--	--	0.67
Medium	(MV)	0.72	4.27	--	4.98
Low	(LV)	0.85	5.07	8.57	14.49

[1]"ckW" denotes coincident kilowatt

Source: RCG/Hagler, Bailly, Inc. update of PLN estimates.

Generation Capacity Cost

To establish estimates of the LRMC for generating capacity, we have employed the "peaker method." This method is not only appropriate in the PLN context but is generally speaking superior to the differential revenue requirement method used by PLN until recently.[3]

Exhibit 3-2 lists the key input parameters developed in discussions with PLN. Estimates of LRMC for generation capacity are displayed in Exhibit 3-3, and range from $6.39 per coincident kW per month at HV to $8.81/ckW/mo at LV.[4]

[3] e.g., see "PLN Electricity Pricing 1989/90, Based Upon LRMC Approach," Review April 1990, PLN Tariff Department Report.

[4] Estimates of peak period losses, as a percentage of incoming, are 4.08 percent for HV, 8.43 percent for MV, and 20.75 percent for the LV network.

47

Exhibit 3-2
Long-Run Marginal Generation Capacity Cost:
Key Assumptions for Gas Turbine
(1992 $)

Capital Cost ($/kW)	390
Life (years)	20
Reserve Margin (%)	15
Discount Rate	0.12
Standard Conversion Factor	0.9
Station Use (%)	1.5
Fixed O&M Costs (%)	1.5
LRMC ($/ckW/mo)	6.13

Source: RCG/Hagler, Bailly, PLN.

Exhibit 3-3
LRMC for Generation Capacity
(1992 $)

Voltage	$/ckW/mo
Busbar	6.13
HV	6.39
MV	6.98
LV	8.81

Source: RCG/Hagler, Bailly, Inc.

Finally, Exhibit 3-4 shows the total marginal capacity costs (for network and generation), by delivery voltage.

Exhibit 3-4
Total Marginal Capacity Costs
(1992 $/ckW-mo)

Delivery Voltage	Generation Capacity	Network Capacity			Total
		HV	MV	LV	
HV	6.39	0.67	--	--	7.06
MV	6.98	0.72	4.27	--	11.97
LV	8.81	0.85	5.07	8.57	23.30

Source: Exhibit 3-1 and 3-3.

Marginal Energy Cost

Estimates of marginal energy costs were developed by reviewing and utilizing, as appropriate, information contained in PLN's November 1991 LRMC update report and using assumptions developed during the course of discussions with PLN Tariff Department and Control Center staff.

Exhibit 3-5 summarizes the calculation of marginal energy costs by the two plant types that are typically "on the margin" during most hours of the day. The specific assumption of relevance to the energy cost calculations are shown in the exhibit, as are the results of intermediate calculations. The marginal energy costs at the busbar are estimated to be 5.92 ¢/kWh for a gas turbine and 3.12 ¢/kWh for an oil-steam plant.

These estimates are based upon economic costs of fuel of $25.20/bbl of distillate (equivalently about Rp. 317/liter at an exchange rate of Rp. 2000-to-$US 1), and $15.30/bbl for fuel oil (equivalently about Rp. 192/liter), and were derived from a projected average crude oil price of $18.00/bbl for the three-year period 1993-1995. Furthermore, the price of distillate was pegged at 1.4 times the price of crude, whereas the fuel price was pegged at 0.85 times the crude oil price.

Exhibit 3-6 shows estimates of marginal energy costs by three day-types: working day, Saturday and other days. In each case, the energy costs in Exhibit 3-5 are weighted by the percentage of time the gas turbine and oil-steam plants are projected to be on the margin. The weights are based upon production simulation studies conducted by PLN's Control Center.

Exhibit 3-5
Marginal Energy Costs by Plant Type (cents/kWh)

	Marginal Plant	
	Gas Turbine	**Oil Steam**
Fuel	Distillate	Fuel Oil
Heat Content (kcal/kg)	11000	10000
Gross Heat Rate (kcal/kWh)	3340	2481
Variable O&M Costs (% of fuel costs)	3	6
Station Use (% of Gross Generation)	1.5	5
Fuel Costs (cents/kWh)	5.66	2.81
Variable O&M (cents/kWh)	0.17	0.17
Station Use Losses (cents/kWh)	0.08	0.14
Total cost at Busbar (cents/kWh)	5.92	3.12

Source: RCG/Hagler, Bailly, Inc., based upon discussions with PLN.

Finally, Exhibit 3-7 presents estimates of marginal energy costs by delivery voltage for peak and off-peak hours. During peak hours, marginal energy costs range from 7.78¢/kWh at LV to 5.65¢/kWh at HV. Corresponding estimates during off-peak hours are 4.37¢/kWh and 3.41¢/kWh, respectively, for LV and HV delivery.

Incremental Energy Costs at Financial Prices

The marginal energy costs in Exhibit 3-7 are stated in economic terms and as market efficiency prices. It is a matter of interest to compare these costs to incremental energy costs

4b

Exhibit 3-6
Marginal Energy Costs (MEC) By Day Type
(1992 ¢/kWh)

Day Type	Weight	Peak Gas Turbine %	Peak Oil-Steam %	Peak MEC ¢/kWh	Off-Peak Gas Turbine %	Off-Peak Oil-Steam %	Off-Peak MEC ¢/kWh
Working	0.69	0.91	0.09	5.66	0.09	0.91	3.37
Saturday	0.14	0.78	0.22	5.30	0.09	0.91	3.37
Sundays/ Holidays	0.17	0.50	0.50	4.52	0.00	1.00	3.12

Source: Based upon production simulation study undertaken by PLN.

Exhibit 3-7
Marginal Energy Costs By Delivery Voltage
(¢/kWh)

Delivery Voltage	Peak	Off-Peak
Busbar	5.42	3.33
HV	5.65	3.44
MV	6.17	3.68
LV	7.78	4.40

Source: RCG/Hagler, Bailly, Inc. based upon Exhibits 3-5 and 3-6.

based on the financial cost of fuel to PLN at present, i.e., at Rp. 300/liter for distillate, and Rp. 220/liter for fuel oil.[5]

Exhibit 3-8 shows the compounding estimates of incremental fuel and variable O&M costs, and utilizing an exchange rate that reflects the prevailing regime in recent months (Rp. 2,000-to-US$ 1).

Exhibit 3-8
Incremental Energy Costs at
Financial Prices for Fuel (¢/kWh)

Delivery Voltage	Peak	Off-Peak
Busbar	5.24	3.72
HV	5.46	3.84
MV	5.96	4.11
LV	7.52	4.92

The numbers in Exhibit 3-8 are not significantly divergent from those in Exhibit 3-7. Therefore, in the remainder of this report, we focus on the economic costs stated in Exhibit 3-7.[6]

3.2 SUMMARY OF MARGINAL COSTS

Exhibit 3-9 summarizes marginal costs by tariff category. Attention is restricted to the tariff categories most likely applicable to the majority of customers with captive power generation. These are the following tariff categories:

- Extra-Large Industrial Service (I-5)
- Large Industrial Service (I-4)
- Large Commercial Service (U-3)
- Large Hotel Service (H-3)
- Large Government Office Service (G-2)

[5] i.e., $23.85/bbl of distillate and $17.49/bbl of fuel oil at an exchange rate of Rp. 2,000 to U.S. $1.

[6] In situations where a large difference exists between the economic and financial costs of incremental energy, a "full avoided cost" purchase tariff could have an adverse financial implication for PLN.

- Medium Industrial Service (I-3).

Estimates of monthly load factors and daily peak energy charges are based upon load research data provided by PLN. Exhibit 3-10 presents a corresponding summary of marginal costs in Rp., utilizing a forward exchange rate of 2060-to-1.[7]

By way of illustration, Exhibit 3-9 (Exhibit 3-10) indicates that for a typical large industrial service customer (receiving service at HV with maximum coincident demand of 1 kW), the economic cost of supply is 5.15¢/kWh (Rp. 106.11), of which 3.77¢/kWh (Rp. 77.64/kWh) is the energy cost, with the balance, 1.38¢/kWh (Rp. 28.47/kWh) representing the cost of capacity. By comparison, under the present tariff structure (I-4), such a customer pays Rp. 110.00/kWh (Exhibit 3-11). Of this amount, Rp. 16.70/kWh represents capacity-related charges. Whereas this economic cost of supply -- level and structure -- for tariff I-4 customers is fairly close to the tariff, substantial differences exist between the economic cost of supply -- levels and structure -- and the present tariffs in the case of all the other tariff categories shown in Exhibits 3-9, 3-10, and 3-11.

[7] This forward rate is based upon the 1991 average exchange rate of Rp. 1968-to-US $1 escalated by 5 percent, the trend experienced in recent years. Spot rates of 2030-to-1 have been recorded in the currency futures markets during May 1992.

Exhibit 3-9
Summary of Marginal Costs (1992 $)
(For Customers with Maximum Coincident Demand of 1 kW)

Tariff Category	Voltage	Monthly Load Factor	Peak Energy Share	Capacity $/ckW-mo	Energy (¢/kWh)			Total ¢/kWh
					Peak	Off-Peak	Average	
I-5	HV	0.70	0.15	7.06	5.65	3.44	3.77	5.15
I-4/U-3/ H-3/G-2	MV	0.65	0.12	11.96	6.17	3.68	3.98	6.50
I-3	LV	0.55	0.16	23.30	7.78	4.40	4.95	10.75

Exhibit 3-10*
Summary of Marginal Costs (1992 Rp.)
(For Customers with Maximum Coincident Demand of 1 kW)

Tariff Category	Voltage	Monthly Load Factor	Peak Energy Share	Capacity Rp./ckW-mo	Energy (Rp./kWh)			Total Rp./kWh
					Peak	Off-Peak	Average	
I-5	HV	0.70	0.15	14,546	116.36	70.81	77.64	106.11
I-4/U-3/ H-3/G-2	MV	0.65	0.12	24,642	127.08	75.86	82.01	133.94
I-3	LV	0.55	0.16	47,993	160.34	90.73	101.87	221.41

* Exchange rate = 2060-to-1.

Exhibit 3-11
Power Purchase Costs by Tariff Category
(Customers with Maximum Coincident Demand = 1 kW)

Tariff Category	Voltage	Monthly Load Factor	Peak Energy Share	Contract Demand Charge Rp./nc kVA-mo	Energy Tariff (Rp./kWh)			Capacity Cost Rp./kWh	Total Power Purchase Cost Rp./kWh
					Peak	Off-Peak	Average		
I-5	HV	0.70	0.15	3,960	188.50	76.50	93.30	16.70	110.00
I-4	MV	0.65	0.12	4,200	212.00	84.00	99.36	26.46	125.82
U-3	MV	0.65	0.12	4,500	337.50	135.00	159.30	28.35	187.65
H-3	MV	0.65	0.12	4,420	274.00	109.50	129.24	27.85	157.09
G-2	MV	0.65	0.12	3,700	236.00	94.50	111.48	23.31	134.79
I-3	LV	0.55	0.16	4,500	220.00	85.50	107.02	27.98	135.00

CHAPTER IV: PROGRAM OPTIONS, POTENTIAL, AND INCENTIVE STRUCTURE

This chapter develops the DSM program options for peak load management utilizing captive power generation. Section 4.1 begins with an assessment of the peak load management potential. This is followed in Section 4.2 with an analysis of the private cost of self-generation from the perspective of industrial customers who own and operate such plant. This cost, together with estimates of PLN's "avoided cost," bracket the range within which a power purchase tariff would be set. Section 4.3 discusses the incentive tariff structure for the DSM options.

4.1 DSM PROGRAM OPTIONS

Based upon a careful review of available information, the feasibility of two peak load management programs in the near- to mid-term was assessed:

- a DSM program to "purchase" daily, excess capacity from captive power generators during the peak hours: 18:00 p.m. to 22:00 p.m.

- a direct load control (DLC) program that uses an FM radio system to control central air conditioners, electric water heaters, and miscellaneous industrial equipment during PLN's system peak hours.

After some consideration, the DLC program to control central air conditioners, electric water heaters, and miscellaneous industrial equipment was not deemed to be appropriate at this stage because this type of load control system cannot produce a large enough peak load reduction within the next few years to make any significant impact on PLN's system. However, this type of load management program should be considered in the future to moderate peak load growth in the industrial sector.

The proposed DSM program comprises three options:

- **Interruptible:** Under this option, PLN would interrupt service during peak hours to customers who sign up for the program. Such customers could meet their load from excess self-generation capacity, if they so chose.

- **Buy Back from PLN's Customers:** Under this option, PLN would purchase excess capacity from captive power generators during the peak hours.

- **Buy Back from Non-PLN Customers:** Under this option, peaking capacity would be purchased from captive power generators owned by electricity consumers who are currently not PLN customers.

The interruptible service option does not require any additional interconnection costs, other than some metering-related costs, and would be the cheapest to implement. By contrast, Options 2 and 3 will require interconnection protection, and additional metering costs, as well as costs to synchronize the captive power generation with the grid. In addition, in the case of non-PLN customers (Option 3), the transmission system may need to be extended to interconnect these customers.

Program Potential

In order to develop estimates of program potential, this study utilized information from PLN's captive power database for industries with installed captive diesel generation capacity of at least 5 MVA.[1]

There are 103 companies with a total installed capacity of 1,481 MVA (Exhibit 4-1) in the database. Of these, there are 71 companies that are also customers of PLN (Exhibit 4-2). The remaining 32 companies with a total capacity of at least 5 MVA are not PLN's customers.

Exhibit 4-1
Installed Capacity of Diesel Captive Power in Indonesia:
Companies with Total Installed Capacity of at Least 5 MVA

Region	Number of Companies	Number of Units	Installed Capacity		Contract Demand with PLN	
			(MVA)	(MW)	(MVA)	(MW)
East Java	26	34	350	280	231	185
Central Java	22	22	289	232	43	34
West Java	22	22	475	380	111	89
Jaya & Tangerang	33	33	367	294	145	116
Total	103	111	1481	1186	530	424

[1] Since the focus of this analysis is on peak load management, only diesel generators were considered because of their quick start-up ability. Steam generators were not considered because their start-up time is substantially longer than diesel generators.

Exhibit 4-2
Excess On-Peak Captive Generation Capacity Potential

Region		Number of Companies	Installed Captive Generation Capacity		Contract Demand with PLN		Estimated Demand at PLN System Peak		Excess Capacity at PLN Peak	
			(MVA)	(MW)	(MVA)	(MW)	(MVA)	(MW)	(MVA)	(MW)
PLN CUSTOMER	East Java	23	321	257	231	185	75	60	246	197
	Central Java	11	95	76	43	34	14	11	81	65
	West Java	16	161	129	111	89	36	29	125	100
	Jaya & Tangerang	21	227	182	145	116	47	38	180	144
	Subtotal	71	804	643	530	424	173	138	631	505
NON-PLN CUSTOMER	East Java	3	29	23	--	--	7	5	22	18
	Central Java	11	194	155	--	--	29	23	165	132
	West Java	6	314	251	--	--	71	56	243	195
	Jaya & Tangerang	12	140	112	--	--	29	24	111	89
	Subtotal	32	677	542	0	0	135	108	542	434
	Total	103	1481	1185	530	424	308	246	1173	939

Notes: 1. MW are calculated using a power factor of 0.80.

2. The demand at the time of PLN's system peak for PLN customers is calculated based on the responsibility factor of 0.4640 for the HV class, 0.3445 for the MV class, and 0.4050 for the LV class.

As a group, PLN customers with captive generation have a contract demand of 530 MVA. The coincident demand is estimated to be 173 MVA.[2] The latter represents about 19 percent of the total captive generation installed capacity. Thus, there is a potential for PLN to "purchase" up to 505 MW of excess captive generation capacity during the peak hours (Exhibit 4-2).

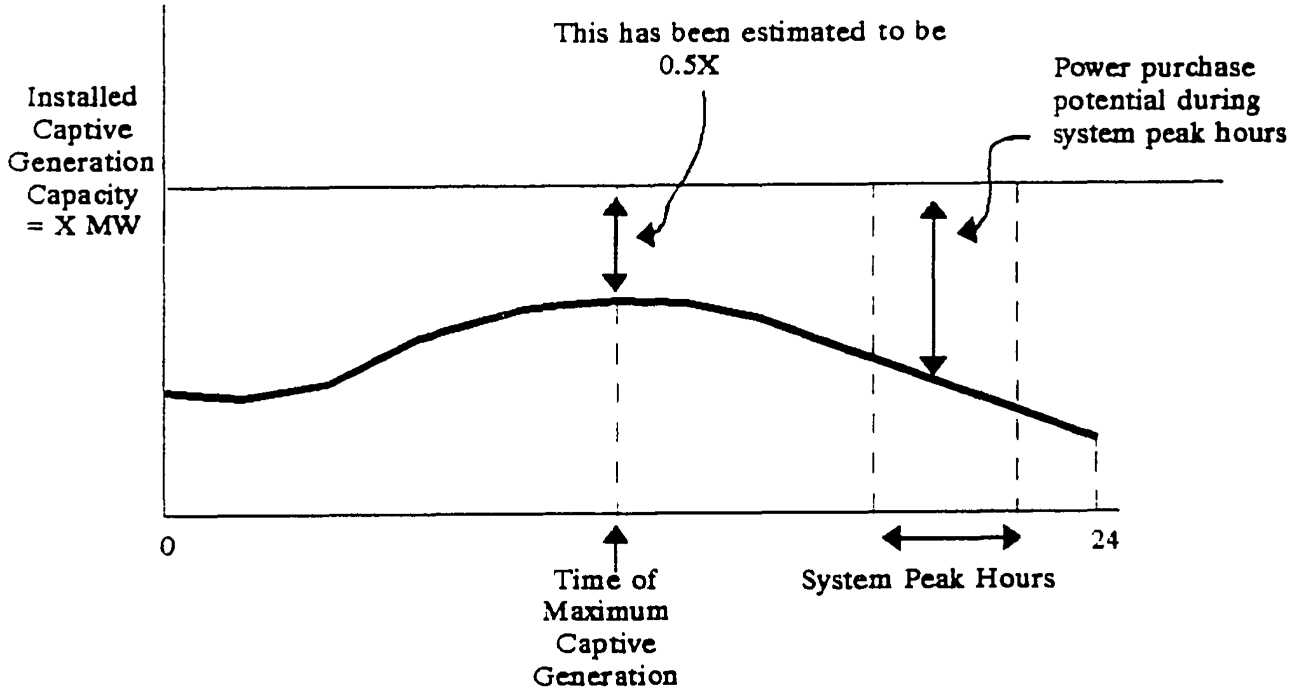
The total installed capacity of non-PLN customers is 677 MVA (542 MW). Assuming that this group of customers has the same peak responsibility factor as the first group, it is estimated that their coincident demand is 108 MW. This indicates a potential of up to 434 MW of excess capacity that could be tapped during peak hours.

Exhibit 4-3 summarizes the peak load management potential by each of the three DSM options. A total (technical) potential of 792 MW is estimated in Java, 123 MW can be tapped through an interruptible service program. In addition, 318 MW of on-peak capacity can potentially be purchased from existing PLN customers, and the potential exists for purchasing another 336 MW of peaking capacity from non-PLN customers.

To illustrate, consider the estimate of interruptible load in Exhibit 4-3. This was derived as follows. For PLN customers whose load is lower than their captive installed capacity, as per the data base, the connected load is viewed as interruptible since in the event all supply is interrupted, the customer can self-generate to meet load. In addition, the surplus captive capacity (installed less load) can be purchased by PLN under the buyback option. It is relevant to note that the estimate of interruptible load in Exhibit 4-3 understates the true potential in that it does not include actual load interruption potential by the customer rescheduling plant operations.

It should be emphasized that the estimates of technical potential developed from data in Exhibit 4-2 are best interpreted as approximate and order-of-magnitude numbers. Whereas PLN's regional offices periodically update these data, there are lags in reporting. Moreover. in many instances, the data are not independently verified or validated. In this connection, a recently completed survey [11] estimated the potential for power purchases (MW) from captive power generation in Java-Bali, with installed capacities of 5 MVA or greater. The study found that the difference between the installed captive generation capacity and the maximum generation is on the order of 50 percent of installed captive capacity. This represents an estimate of the non-coincident potential for power purchases from PLN. Clearly, the potential for power purchases will be higher than 50 percent at other times (see the figure on the next page).

[2] This estimate is derived using "peak responsibility factor" estimates provided by PLN. These are 0.4640 of HV, 0.3345 for MV, and 0.4050 for LV.



If we conservatively assume this percentage to be 60 percent of installed captive capacity, and apply this to the installed capacity estimate of 1,481 MW in Exhibit 4-2, a technical potential for about 900 MW is obtained as compared with 1,156 MW in Exhibit 4-3.

4.2 CAPTIVE POWER GENERATION COST

Data on relevant technical performance characteristics and costs of captive power generation were first assembled (Exhibit 4-4). The primary Indonesian sources were PLN's current planning studies for future diesel plants it is planning to build, PLN's operating statistics on its existing diesel stations, and vendors in Jakarta that sell diesel generator sets.[3]

In addition, these country-specific data were supplemented with comparable data from studies/reports sponsored by the World Bank (IBRD), USAID, and the Inter-American Development Bank (IDB). These data, including other key assumptions in the analysis, are displayed in Exhibit 4-4.

Exhibits 4-5 and 4-6 summarize, respectively, the fixed cost, variable cost, and total unit cost, in $ and Rp., for different plant sizes and types, and as a function of existing utilization of plant (i.e., capacity factor). The primary focus in Exhibits 4-2 and 4-3 is on unit sizes in the 1 to 10 MW range. This reflects the view that the initial DSM program design would target the

[3] Komatsu and Caterpillar.

Exhibit 4-3
Peak Load Management Potential

Option	Region	MW	On-Peak Generation (MWh/Year)
1. Interruptible	East Java	50	87,600
	Central Java	11	16,060
	West Java	29	42,340
	Java & Tangerang	38	55,480
	Subtotal	138	201,480
2. Buy Back Option # 1: PLN's Customers > 10 MVA	East Java	128	186,880
	Central Java	38	55,480
	West Java	60	87,600
	Jaya 7 Tangerang	92	134,320
	Subtotal	318	464,280
3. Buy Back Option #1: Non-PLN Customers >10 MVA	East Java	0	0
	Central Java	81	118,260
	West Java	189	275,940
	Jaya & Tangerang	66	96,360
	Subtotal	336	490,560
	Total	792	1,156,320

larger customers (i.e., those with total captive capacity of 5 MVA or greater). Whereas within the total population of customers with one or more captive generation sets, most have generation sets in the fractional MW size range, the total installed capacity of the larger customers is typically composed of individual units that are larger than 1 MW.[4] By way of illustration, for a captive power plant of type 5 -- a medium-speed

[4] As noted in Chapter 2, Section 1, over 90 percent of the installations, nationally, are under 1 MVA each, and together, they account for approximately 25 percent of installed captive generation capacity. On the other hand, 34 companies each with installed capacities of 25 MVA or greater together account for 3,300 MW, or approximately 50 percent of national captive generation capacity. Furthermore, a review of permit applications filed at the Directorate General for Electricity and New Energy (DGENE) reveals that the larger installations tend to employ unit sizes in excess of 1 MVA.

Exhibit 4-4
Typical Captive Power Plant Characteristics

Input Parameter	Unit	Captive Plant							
		1	2	3	4	5	6	7	8
Unit Size	MW	1.0	4.7	1.6	2.5	Typical Sizes	3.0	5.2	12.6
Fuel		Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel
Type		HSD	HSD	MSD	MSD	MSD	MSD	MSD	SSP
Speed	RPM	1500	1000					600	426
Data Source		Komtasu Vnd	CAT Vnd	IDB	PLN	IBRD	IDB	PLN	PLN
Capital Costs	$/kW	200	398	925	1428	1000	969	1114	1043
Equipment		187	362						
Installation		13	36						
Financing									
Life	Yrs.	10	10	20	20	20	20	20	20
Annual Fixed O&M	% of Capital	5	6	6	5	5	6	5	5
Variable O&M	% of Fuel/kWh	6	6	6	3	5	6	3	3
Heat Content	kcal/kg	11000	11000	11000	11000	11000	11000	11000	11000
Heat Rate	kcal/kWh			2688	2688	2688			
	g/kWh	180	215	255	244	250	215	213	188
Specific Gravity	g/Liter	850	850	850	850	850	850	850	850
Station Use	% of Gross Gen.	0	0	0	0	0	0	0	0
Fuel Price	$/Barrel								
	Rp./Liter	315	315	315	315	315	315	315	265
	$/Ton								
Exchange Rate	Rp./$	2060	2060	2060	2060	2060	2060	2060	2060
Interest Rate	%	12	12	12	12	12	12	12	12
CRF		0.1770	0.1770	0.1339	0.1339	0.1339	0.1339	0.1339	0.1339

Exhibit 4-5: Captive Power Generation Costs ($)*

Cost Component	Unit	Captive Plant							
		1	2	3	4	5	6	7	8
Annual Capacity Costs	$/kW-Yr	37.17	74.67	131.27	200.74	140.57	123.32	156.60	146.62
Deprec & Financing		35.40	70.44	123.84	191.18	133.88	116.34	149.14	139.64
Fixed O&M		1.77	4.23	7.43	9.56	6.69	6.98	7.46	6.98
Capacity Costs	¢/kWh								
0.15		2.83	5.68	9.99	15.28	10.70	9.39	11.92	11.16
0.17		2.55	5.11	8.99	13.75	9.63	8.44	10.72	10.04
0.20		2.12	4.26	7.49	11.46	8.02	7.04	8.94	8.37
0.30		1.41	2.84	4.99	7.64	5.35	4.69	5.96	5.58
0.35		1.21	2.44	4.28	6.55	4.58	4.02	5.11	4.78
0.40		1.06	2.13	3.75	5.73	4.01	3.52	4.47	4.18
0.50		0.85	1.70	3.00	4.58	3.21	2.82	3.58	3.35
0.60		0.71	1.42	2.50	3.82	2.67	2.35	2.98	2.79
0.70		0.61	1.22	2.14	3.27	2.29	2.01	2.55	2.39
0.80		0.53	1.07	1.87	2.86	2.01	1.76	2.23	2.09
0.85		0.50	1.00	1.76	2.70	1.89	1.66	2.10	1.97
0.90		0.47	0.95	1.66	2.55	1.78	1.56	1.99	1.86
Variable Costs	¢/kWh	3.50	4.10	4.86	4.52	4.72	4.10	3.95	2.93
Fuel		3.24	3.87	4.59	4.39	4.50	3.87	3.83	2.85
O&M		0.26	0.23	0.28	0.13	0.22	0.23	0.11	0.09
Total Costs	¢/kWh								
CF = .15		6.33	9.76	14.85	19.80	15.42	13.49	15.86	14.09
CF = .17		6.04	9.21	13.85	18.27	14.35	12.54	14.76	12.97
CF = .20		5.62	8.36	12.36	15.98	12.75	11.14	12.89	11.30
CF = .30		4.91	6.94	9.86	12.16	10.07	8.79	9.91	8.61
CF = .35		4.71	6.54	9.14	11.07	9.31	8.12	9.05	7.71
CF = .40		4.56	6.23	8.61	10.25	8.73	7.62	8.42	7.11
CF = .50		4.35	5.80	7.86	9.10	7.93	6.92	7.52	6.28
CF = .60		4.20	5.52	7.36	8.34	7.40	6.45	6.93	5.72
CF = .70		4.10	5.32	7.00	7.79	7.01	6.11	6.50	5.32
CF = .80		4.03	5.17	6.74	7.39	6.73	5.86	6.18	5.02
CF = .85		4.00	5.10	6.63	7.22	6.61	5.76	6.05	4.90
CF = .90		3.97	5.05	6.53	7.07	6.51	5.66	5.93	4.79

* Unit characteristics are defined in Exhibit 4-4.

5

Exhibit 4-6: Captive Power Generation Costs (Rp.)*

Cost Component	Unit	Captive Plant							
		1	2	3	4	5	6	7	8
Annual Capacity Costs	Rp./kW-Yr	76563	153812	270412	413520	289580	254041	322592	302032
Deprec & Financing		72917	145106	255106	393829	275790	239662	307230	287649
Fixed O&M		3646	8706	15306	19691	13790	14380	15362	14382
Capacity Costs	Rp./kWh								
0.15		58	117	206	315	220	193	246	230
0.17		52	105	185	283	198	174	221	207
0.20		44	88	154	236	165	145	184	172
0.30		29	59	103	157	110	97	123	115
0.35		25	50	88	135	94	83	105	99
0.40		22	44	77	118	83	73	92	86
0.50		17	35	62	94	66	58	74	69
0.60		15	29	51	79	55	48	61	57
0.70		12	25	44	67	47	41	53	49
0.80		11	22	39	59	41	36	46	46
0.85		10	21	36	56	39	34	43	41
0.90		10	20	34	52	37	32	41	38
Variable Costs	Rp./kWh	72	84	100	93	97	84	81	60
Fuel		67	80	95	90	93	80	79	59
O&M		5	5	6	3	5	5	2	2
Total Costs	Rp./kWh								
CF = .15		130	202	306	406	318	278	327	290
CF = .17		124	190	285	376	296	258	302	267
CF = .20		116	172	255	329	263	229	265	233
CF = .30		101	143	203	250	207	181	204	175
CF = .35		97	135	188	228	192	167	187	159
CF = .40		94	128	177	211	180	157	173	147
CF = .50		90	120	162	188	163	142	155	129
CF = .60		87	114	152	172	152	133	143	118
CF = .70		85	110	144	161	145	126	134	110
CF = .80		83	106	139	152	139	121	127	106
CF = .85		82	105	136	149	136	119	125	101
CF = .90		82	104	134	146	134	117	122	99

*** Unit characteristics are defined in Exhibit 4-4.**

of unit size 1.6 MW (Exhibit 4-1) -- the annual capital cost is $131.27/kW-year. At an annual capacity factor of 40 percent, this translates to an effective cost of 3.75¢/kWh (Rp. 77/kWh). Variable costs of operation are estimated to be 4.86¢/kWh (Rp. 100/kWh).

Exhibit 4-3 shows that whereas the unit variable operating cost is typically in the 85 to 100 Rp./kWh range (with a central tendency around Rp. 90/kWh), the data show significantly more variability in the capacity costs.

Exhibit 4-7 presents a graphic representation of the cost of captive generation -- variable, fixed, and total -- as a function of plant utilization. It is based upon a "typical" captive plant configuration that is indicative of the data in Exhibit 4-6 (i.e., variable cost of Rp. 90/kWh and capital costs of $925/kW). This indicative cost structure is also used subsequently as a basis for formulating incentive tariffs for furthering the DSM goal of peak load management by procuring power from customers who have captive generator sets.

In particular, the annual capital costs of the two high-speed diesel units quoted by the two vendors (plants 1 and 2 in Exhibits 4-2 and 4-3) are substantially lower than the corresponding estimates for the medium-speed diesel units (plants 3 through 7), with the total costs for the latter being higher for all levels of plant utilization. We have not been able to reconcile these differences to our satisfaction.[5]

4.3 INCENTIVE TARIFFS

A key aspect of the DSM program design is the incentive structure. Developing the appropriate tariff for the program discussed in the preceding section is a complex exercise. In this regard, it is important to enunciate the key principles that have guided the development of the incentive tariff structure developed in this section.

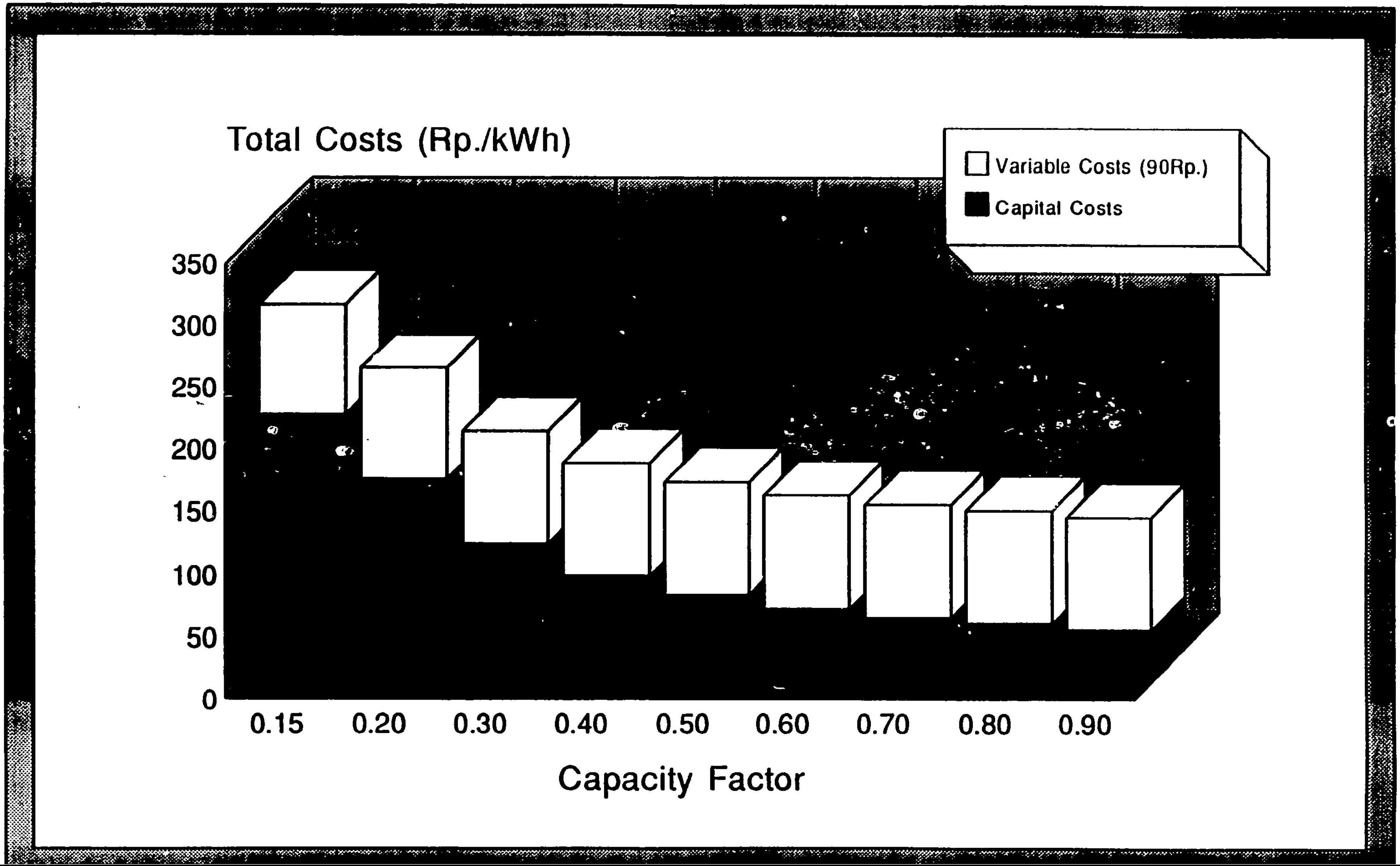
- **Economic efficiency,** which essentially requires that the power purchase price not exceed the economic cost of the least-cost alternative supply option available to PLN (i.e., PLN's "avoided cost").

- **Financial requirements** of the seller as well as financial implications for the purchaser (PLN) need to be considered.

- **Equity considerations,** which are concerned with how any financial surpluses are appropriated.

[5] It is interesting to note that a recent and major study on diesel power plant cost and efficiency comparisons across 65 countries, undertaken by the IBRD with funding from USAID's Office of Energy and Infrastructure, also experienced similar problems and noted that "much work on capital costs needs to be done." [10]

Exhibit 4-7
Unit Generation Costs
For a Typical 1.6 MVA Medium Speed Diesel Unit



64

- **Ease of implementation** of the incentive tariff structure.

Efficiency Considerations

Avoided costs are the costs that the buyer -- PLN -- can defer as a consequence of the purchase. Avoided energy costs can be estimated as the incremental fuel and O&M cost (running cost) of the displaced generation plant.

In the case of generation capacity, the linkage between capacity cost and long-run marginal capacity cost can be illustrated by the following example. If PLN can avoid (defer) building 1 kW of additional peaking capacity because of a 1 kW "power purchase," then the avoided cost to PLN is the cost it would have incurred to build that capacity itself (i.e., its long-run marginal generation capacity cost).[6]

In addition, there may be an additional benefit (avoided cost) to PLN that stems from reduced network capacity requirements.

Estimates of PLN's marginal cost are developed in Chapter 3 of this report and provide the basis for establishing its avoided cost for the purposes of this study.

Financial Considerations

The transaction price should be set such that neither party to the transaction is a financial loser. First, from the captive power supplier's viewpoint, the price he receives must be sufficiently high as to be financially attractive. This means that the price should be, at a minimum, equal to the incremental variable cost of generation (fuel, variable O&M) plus a profit adder to make it worthwhile to engage in the DSM program given the additional operational and other difficulties inevitably involved in coordinating with the utility, in operating the program, for having to make adjustments to the process, and in making adjustments t[illegible] in-plant activities, schedules, and operations management.

Based [illegible] ing considerations outlined above, the analysis of PLN's long-run marginal cost (Chapter 3), and the indicative cost structure of captive generation (Chapter 4), a two-part incentive tariff is proposed, as shown in Exhibit 4-8. This tariff primarily reflects the economic cost structure of PLN as developed in Chapter 3 (see Exhibit 3-10).

[6] This equivalence presumes that the power purchase is "firm" in nature, i.e., availability, dispatchability, and contract duration of the power purchase are predictable in magnitude and outcome, and that these parameters are consistent with the corresponding parameters for what the utility considers firm supply options.

Even in the case of a non-firm power purchase, the proposed incentive tariff discussed below is significantly higher than the seller's variable cost of supply, and should provide adequate financial incentives for participation in the program (e.g., a 5 MVA customer on Tariff I-4 will save nearly 8 percent of his monthly electricity bill per equivalent MW of non-firm energy provided to the grid on-peak).[7]

For firm power purchases, Exhibit 4-8 indicates that in addition to energy payments, the seller should receive a capacity-related payment as well. At this stage, it is recommended that this component of the payment be negotiated by PLN with the seller. The primary reason for this approach is grounded in the fact that the capacity and related costs of self-generation tend to vary substantially and are customer-specific.[8] Therefore, the suggested strategy of negotiation, with lower capacity payments being given initially and progressively increasing capacity payments in later stages of the program, will simulate a "bidding process" that orders supplies over time in order of increasing resource acquisition cost. This will help provide an economically efficient ordering of the power purchases secured, and with no one receiving a payment that equals or exceeds full avoided cost other than the marginal -- i.e., highest-cost -- captive generation resource selected, which gets the full avoided cost.

The equity implication of this simulated bidding approach[9] is that PLN -- and hence its ratepayers -- will benefit from any financial surplus generated in instances where the capacity payment is below the full avoided cost.[10]

By recommending a negotiating approach to setting capacity payments, it is not intended -- indeed, not recommended -- that PLN attempt to ascertain the fixed and variable costs of self-generation in the case of each customer who wishes to participate in the program.[11] This is a time-consuming exercise doomed to failure and will result in program failure since private industry will generally be reluctant to divulge its true cost, and many would prefer not to

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[7] The issue of interconnection costs is addressed subsequently. In the case of interruptible options, however, these costs would be minimal.

[8] They depend upon unit size, performance characteristics, existing levels of utilization, etc.

[9] A full-blown market-based bidding approach is premature at this preliminary stage because the market for power purchases from non-utility generators is underdeveloped at present and an active competitive market does not yet exist.

[10] A surplus is defined as the difference between PLN's avoided cost and the price it pays to secure supply from others.

[11] Either independently or by requiring the potential participant to provide the necessary data and/or prove their validity.

Exhibit 4-8
Economic Tariff Structure for Peak Load Management DSM Programs

Contract	Voltage	Tariff Component	Peak	Off-Peak
1. Non-Firm Purchase	HV	Energy (Rp./kWh)	116	71
		Capacity (Rp./ckW-mo.)	--	--
2. Firm Purchase	HV	Energy (Rp./kWh)	116	71
		Capacity (Rp./ckW-mo.)	Minimum Suggested: 3,637 Maximum: 14,546	--
1. Non-Firm Purchase	MV	Energy (Rp./kWh)	127	76
		Capacity (Rp./ckW-mo.)	--	--
2. Firm Purchase	MV	Energy (Rp./kWh)	127	76
		Capacity (Rp./ckW-mo.)	Minimum Suggested: 6,156 Maximum: 24,624	--
1. Non-Firm Purchase	LV	Energy (Rp./kWh)	160	91
		Capacity (Rp./ckW-mo.)	--	--
2. Firm Purchase	LV	Energy (Rp./kWh)	160	91
		Capacity (Rp./ckW-mo.)	Minimum Suggested: 11,998 Maximum: 47,993	--

Source: Exhibit 3-10.
* To be structured in equivalent Rp./ckWh terms. See text for explanation.
Exchange rate: 2060-to-1.

participate in the program rather than engage in protracted negotiations or reveal confidential information. Nor is it intended that different captive generators be paid varying purchase prices.

Rather, the intent underlying the negotiated payment recommendation for capacity valuation is that PLN attempt to first secure the lowest-cost supplies and as these are exhausted, move up the supply curve to higher-cost supplies. For example, in the early stages, PLN should attempt to register those participants and secure capacity from those self-generators who are willing to accept, say, 25 percent of the full avoided cost. Once supply from these generators is exhausted, the capacity value in the tariff could be increased, to say, 50 percent of the full avoided capacity cost, with increases thereafter at appropriate times. Ultimately, it is in PLN's self-interest to pay up to the full avoided capacity cost,[12] if necessary, to secure on-peak firm power purchases. However, it is not necessary, or to the financial advantage of PLN and its ratepayers, to pay full avoided capacity cost to participants who would "come to the table," even if this capacity payment is lower than this maximum.[13]

To illustrate the financial incentive under a capacity value of Rp. 6,156/ckW-mo. at HV (i.e., 25 percent of full avoided capacity cost), consider again the example before wherein a 5 MVA contract demand customer offers to sell 1 MW of firm capacity on-peak. In this case, the captive power seller will receive an additional benefit of Rp. 12,321,000/month, for a total bill reduction of nearly 11 percent each month. As a percentage of the company's profit margin, this would typically represent a much higher amount.

When evaluating the power purchase tariff, it is relevant to consider whether captive power generation owners will seek recovery of only the variable cost of self-generation or will expect coverage for capital cost as well. Clearly, consumers who are considering the purchase of new equipment to meet self-generation needs will include capital cost in estimating the cost of self-generation. Even consumers with existing self-generation equipment must have considered full costs in making their original purchase decisions, although it may be argued

[12] Net of any transaction costs, e.g., if PLN incurs the capital cost for interconnection, then these costs, which are really the responsibility of the seller, must be recovered from the seller. This issue is addressed below.

[13] A related issue deals with the vintaging of payments: when the avoided cost capacity payment is raised subsequently, should it be applied to the new contracts only or to all existing contracts as well? This is a matter of regulatory policy. In the U.S., for example, contract prices for large and individually negotiated contracts are typically governed by the specific provisions of each contract and prevail throughout the duration of each contract. This is also a characteristic of the growing number of power purchase contracts entered into in a bidding process. By contrast, "standard offers" are posted prices with specified duration for validity, and are uniformly applicable to anyone willing to sell under such a tariff, whether they happen to be existing or new suppliers of power. They often are updated periodically using the declared method that is transparent and whose proper application is overseen by the regulatory authority that has oversight responsibility. Standard offers are typically utilized for the smaller sized power purchases (fractional megawatt up to a few megawatts).

68

that the annual operating decisions of these consumers will be based only on annual variable operating costs. However, to the extent that operation results in physical depreciation of the generator and a reduction in its future life, it can be argued that this cost is also taken into account in the annual operating decisions of consumers with existing generators.[14] If this depreciation rate is approximately the same as the annualized capital cost, and this is a reasonable supposition, it is total cost per kWh -- including capital cost -- which is the appropriate measure of the cost of captive generation.

In reality, potential program participants will expect recovery of all variable costs plus some coverage of fixed cost. The extent of fixed cost recovery demanded will be customer-specific, with some requiring more than others. The proposed graduated capacity payments will help to order the participation of the entire spectrum of such customers.

Paying for the Firm Capacity Purchase

In connection with the proposed capacity payments for "firm" purchases, proposed in Exhibit 4-8, it is relevant to draw attention to the issue of how to ensure that the supply is indeed firm. If payments are made on a Rp./ckW-mo basis, then PLN is exposed to the risk that the availability on-peak is lower than expected. In addition, this approach leads to additional metering and verification problems.

A simple and effective approach to this problem is to pay the selected capacity value on the basis of metered kWh on-peak. By structuring the capacity payment in equivalent Rp./on-peak kWh terms, the captive power generator has a strong incentive to maximize the availability of power on-peak. This can be seen from the following example.

To implement the proposed tariff structure, two energy meters could be installed to monitor the kWh supplied to the grid during the peak and off-peak hours. The kWh purchased on-peak would be credited the on-peak energy payment of Rp. 127/kWh, whereas the kWh purchased off-peak would be credited a payment of Rp. 76/kWh (Exhibit 4-8). In addition, the on-peak kWh would be credited a capacity value of Rp. 213.05/ckWh,[15] under the maximum capacity valuation of Rp. 24,624/ckW-mo, and 53.26 Rp./ckWh under the minimum suggested capacity valuation of Rp. 6,150/ckW-mo (Exhibit 4-8).

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[14] This may be especially true in the situation faced by industry in Indonesia, where there is supply rationing by the grid and industry will have to rely on self-generation well into the foreseeable future. In other words, when a generator is retired, a replacement will need to be installed.

[15] Under the minimum.

Exhibit 4-9 shows the capacity-related payments actually received by the captive power supplier as a function of actual (metered) on-peak kilowatt hours (ckWh) supplied. To illustrate, consider the case where 115.58 kWh are actually supplied in a given month on-peak. This situation is comparable to 95 percent on-peak availability[16] and is comparable to the on-peak availability of PLN's gas turbines which provided the basis for establishing marginal generation capacity cost.

Therefore, if the capacity valuation is set at the minimum suggested in Exhibit 4-8 (Rp. 6,156/ckW-mo), the equivalent energy-based payment rate is 53.26 Rp./ckWh; calculated as 6,156/115.58).[17] What Exhibit 4-9 shows is that if the captive power supplier achieves on-peak availability (i.e., reliability) comparable to the utility's, the payment is equal to the full capacity valuation. However, if the captive power generator supplies 73 ckWh in a certain month (i.e., equivalent on-peak availability is only 60 percent), the capacity payment received that month is Rp. 3,888, which is substantially less than Rp. 6,156.

Exhibit 4-9
Capacity Payments Received by Captive Power Supplier
(HV)

Actual kWh Provided On-Peak (ckWh/mo)	Equivalent Availability On-Peak	Capacity Payment Received (Rp./mo)	
		Capacity Valuation Rp. 6,156/ckW-mo	Capacity Valuation Rp. 24,624/ckW-mo
119.23	98%	6,350	25,402
115.58	95%	6,156	24,624
109.50	90%	5,832	23,329
103.42	85%	5,508	22,034
97.33	80%	5,182	20,736
91.25	75%	4,860	19,441
85.17	70%	4,536	18,145
79.08	65%	4,212	16,848
73.00	60%	3,888	15,553
66.92	55%	3,564	14,257
60.83	50%	3,240	12,960

[16] Calculated as (1 kW x 4 hours/day x 365 days/year x 0.95 availability)/12 months.

[17] Under the maximum capacity valuation scenario (Rp. 24,624/ckW-mo), the equivalent energy-based payment rate is 213.05 Rp./ckWh, calculated as (24,624/115.58).

70

By the same token, the captive power generator can receive capacity payments in excess of Rp. 6,156. This can happen, for example, if actual supply is 119.23 ckWh in a given month. This corresponds to an equivalent on-peak availability of 98 percent (i.e., higher than the 95 percent used to establish the capacity valuation payment).

The energy-based payment approach for the capacity value, as illustrated above, is simple to implement (in a metering and administrative sense) and also provides easy-to-understand signals and incentives for the captive power generator to maximize the availability of on-peak power supplied,[18] which is the primary goal of the peak load management DSM programs of interest in the present context. Under this scheme, payment is based upon actual and easily verifiable performance as opposed to implementing a direct kW-based tariff and metering scheme.

Financial Implications for PLN

PLN's projected tariff yield for the system, i.e., billed revenue per unit of billed sales, averaged over all tariff categories, is approximately Rp. 135/kWh. By comparison, the power purchase tariffs proposed in Exhibit 4-8 are higher for firm purchases, even under the minimum suggested capacity payment of Rp. 6,156/ckW-mo. Thus, large-scale implementation of the proposed DSM program will result in revenue erosion and deterioration of PLN's financial performance. To avert this situation, as well as remove this disincentive for PLN, it is recommended that the costs of the power purchase, and other program costs incurred by PLN, in excess of the system-wide average tariff yield of Rp. 135/kWh, be treated as a legitimate cost in PLN's cost structure. PLN should recover these costs, as it does all other legitimate costs (fuel, salaries, investment, A&G, etc.), by adjusting its tariff yield of Rp. 135/kWh upward.

By way of illustrating this adjustment, suppose that a utility's total sales are 1,000 kWh at an average tariff yield of Rp. 135/kWh, yielding a total revenue of Rp. 135,000. Suppose further that the utility's demand grows by 10 kWh on-peak, and this can be supplied by a gas turbine at Rp. 250/kWh. In this case, the utility must raise its system-wide tariff yield to Rp. 136/kWh.[19] Alternatively, if the utility can supply the additional 10 kWh on-peak by purchasing the power from a captive generator, then it can afford to pay up to a maximum of Rp. 250/kWh as well, in which it must also increase the system-wide tariff yield to Rp. 136/kWh. If, however, it can strike a deal to buy the additional 10 kWh at a price less than Rp. 250/kWh (the cost it would incur to build its own peaking unit), then a proportionately

[18] Ultimately, reliability and availability are essentially equivalent.

[19] [1,000 kWh x Rp. 135/kWh + 10 kWh x Rp. 250/kWh] / 1010 kWh.

lower increase in the system-wide tariff yield would be required. The point is that the utility is better off in the long run, as it pays no more than its avoided cost (Rp. 250/kWh) for the power purchase. Furthermore, it should be allowed to recover the additional cost of power purchase that represents the difference by which the power purchase cost exceeds the current system-wide average yield (Rp. 135/kWh in the example above). This is permissible because such an adjustment in cost recovery would be necessary and allowed were the utility to build a gas turbine to meet the additional peak load of 10 kWh.

CHAPTER V: PILOT LOAD MANAGEMENT PROJECT PRE-FEASIBILITY ANALYSIS

This chapter identifies potential candidates for a pilot load management project to demonstrate the technical and economic feasibility of on-peak power purchases from captive generators. In close consultation with PLN, several potential candidates were screened, and two were identified for site visits.

5.1 SITE VISITS

Site visits were undertaken to two plants in order to understand first hand, the nature of electricity usage, captive power plant characteristics, ability to exploit in-process storage, to reschedule operations, or undertake process modifications that would alter the level and/or pattern of electricity demand, extent of excess captive generation capacity available, potential interest in participating in a pilot program, etc. Of the two plants selected, one is a PLN customer, whereas the other is not a PLN customer. For reasons of confidentiality, in the following, the customers' names are not identified.

Site #1 - Non-PLN Customer

This cement manufacturing plant is currently not connected to the PLN gird. The plant is located approximately 1 km from a PLN 150 kV transmission line, and 7 km from a substation. The electricity required to operate the cement plant is being supplied by two electric generating plants owned and operated by this company. They also sell approximately 2 percent of the total outputs of the two plants to some small industrial customers who are not PLN's customers.

The first generating plant has 14 generators with a total installed capacity of 80 MW. The sizes of the generators vary from 3.5 MW to 7 MW. All are medium-speed diesel units rated at 600 rpm. This plant operates at approximately 85 percent capacity factor to produce 67 MW of continuous power when all engines are on line. The second generating plant has 9 generators with a total installed capacity of 171 MW. The engines are the same size and are rated at 19 MW. All are 428 rpm medium-speed diesel units. This plant produces a maximum of 145 MW when all engines are on line.

The outputs of the two plants are synchronized to a common 33 kW bus that supplies the cement manufacturing plant and some small industrial customers. The cement plant currently utilizes 98 percent, or 150 MW of the total output. The bus voltage level is maintained strictly at a plus or minus 1 percent level to prevent voltage-sensitive equipment from being damaged. Both plants are maintained and operated on a 24 hour a day basis by a staff of 250 people.

The plant facilities manager was receptive to the idea of his company selling excess capacity during the on-peak hours of 18:00 p.m. to 22:00 p.m. to PLN. With a favorable purchase tariff, his company may be able to sell approximately 10 to 20 MW during the on-peak hours to PLN. However, he also indicated that several important issues such as interconnection costs, on-peak purchase tariff design, and system reliability must be clearly addressed in order for his company to consider selling power to PLN. With regard to the reliability issue, there must be sufficient protection in the design to assure that voltage-sensitive equipment will not be damaged since PLN allows a voltage fluctuation of 5 percent as compared to a more stringent 1 percent voltage fluctuation allowed by his company.

Site #2 - PLN Customer

This cement manufacturing plant is connected to the PLN grid via a 70 kV transmission network. PLN is providing all of the electrical requirements to operate the plant. The contract demand for this plant is approximately 30 MVA. The load demand profile for this plant remains constant at about 18 MW most of the time. The plant is operated 24 hours a day. There are two high-speed 150 rpm diesel generators rated at 1 MW installed capacity, which are used mainly for standby power. These generators are used to provide emergency backup power to the main building and other essential load in the event of a power failure by PLN.

Because this customer has only 2 MW of installed capacity, it is not cost-effective to synchronize the output of these generators to the PLN grid to allow the sale of excess power to PLN. However, by using these generators during the on-peak hours to serve their own load and also by backing down the finish grinding mill operations, they can reduce their on-peak demand by approximately 5 MW, provided the correct financial incentive exists.

The overall conclusion that emerged from the site visits and discussion with the plant facilities managers indicated that given a favorable on-peak purchase tariff, a potential exists to acquire up to 25 MW of on-peak power. This would be accomplished by: 1) providing a connection between the PLN grid and the non-PLN customer to purchase up to 20 MW of on-peak power and 2) interrupting approximately 5 MW of the manufacturing plant load that is a customer of PLN.

5.2 ENGINEERING DESIGN

This section outlines preliminary analyses of different configurations and options that can be utilized as a framework for PLN to purchase on-peak capacity from the above-mentioned industrial customers. Based upon a careful review of relevant data gathered during the site visits, the two options discussed in the following are the interruptible option and buy-back from non-PLN customers. The buy-back option would require the customer to synchronize the output of the two generating plants to PLN's system. The interruptible option would only require the installation of load recording equipment to monitor the cut-back in demand by the customer during the on-peak hours. It is relevant to note that the intent of this report is to define a framework to determine the pre-feasibility of undertaking such a pilot project, and not conduct a detailed engineering analysis. A detailed analysis of the recommended configuration would require special follow-up studies that include the following:

- *Load flow studies* to analyze the thermal load of the transmission lines and other major system equipment during normal and contingency operations. The studies determine whether or not improvements to the utility's existing transmission system are required in order to handle the new or additional generating capacity.

- *Short-circuit studies* to assess the extent of increased fault duty on the utility's buses and the breakers due to the addition of generating capacity to the system. These studies determine whether or not existing circuit breakers in the system can still operate properly for system protection at higher fault current levels, and if improvements are required.

- *Stability studies* to determine the severity of the system disturbance that can result in generator instability and subsequent tripping. These studies enable the identification of an optimal configuration and point of connection to the utility network to minimize generator vulnerability to system disturbances. The stability study is usually performed when the size of the generator is approximately 5 MW or more.

Site #1: Non-PLN Customer Buy-Back Option

The output of the two power plants owned and operated by this captive power producer needs to be connected to the PLN grid in order for PLN to purchase excess capacity. In most cases, the design to connect the two systems depends heavily on the technical guidelines set forth by the utility for connecting the utility system to the captive power producer systems to assure adequate protections are included. For the purpose of this study, the operating guidelines are based on the guidelines commonly used by utilities in the United States. The guidelines include the following:

1. The design must include an automatic disconnecting device to isolate the customer's facility from the utility system for the following conditions:

    - a fault on the customer's equipment
    - a fault on the utility system
    - a de-energized utility line to which the customer is connected

- an abnormal operating voltage or frequency on the line
- loss of phase or improper phase sequence
- abnormal power factor.

2. The captive power producers are not allowed to energize a dead circuit on the system during a generator black start.

Based on the above operating requirements, two configurations have been developed to connect this customer to the PLN grid. The two configurations are labelled: integrated and dedicated.

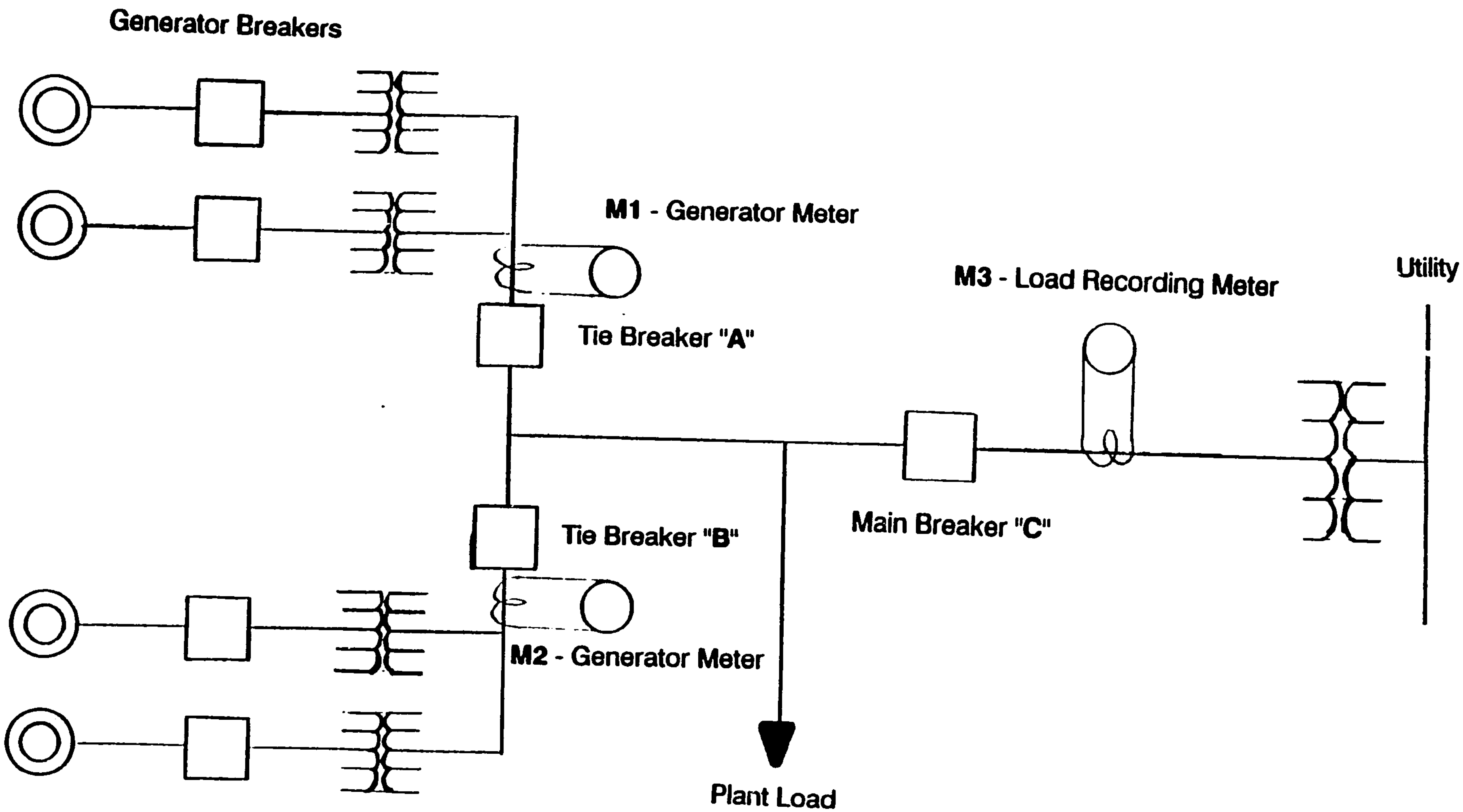
Exhibit 5-1 shows the configuration of an integrated scheme. In this configuration, PLN will have to extend the 33 kV transmission line approximately 7 km from the nearest substation to the captive power plant. The output of the two generating plants will be connected to a common 33 kW bus that will supply the plant load. During the off-peak hours, the disconnect switch will be opened so that all output from the two plants will be used to supply the manufacturing plant. During the on-peak hours, the disconnect switch will be closed and the output of the two plants will gradually synchronize to the utility system. The output of the two plants will supply the manufacturing plant and the excess capacity will be purchased by PLN via the 33 kV transmission line.

This configuration will require the installation of three demand and energy metering systems to determine the energy sold to PLN by the captive power producer. Meters 1 and 2 will be used to measure the total output of the two generating plants. Meter 3 will be used to measure the kWh consumed by the manufacturing plant. The difference between the sum of Meters 1 and 2 less the kWh consumed by the plant is the new kWh sold to PLN by the captive power producer. In the event of a fault on the PLN system, the main breaker will close to allow the output of the two generating plants to continue serving the manufacturing plant load.

Exhibit 5-2 shows the configuration of a dedicated scheme. As in configuration-1, PLN is required to extend the 33 kV transmission line by 7 km from the substation to the captive power plant distribution system. In this configuration, a fixed number of generators will be dedicated for selling power to PLN during the on-peak hours. Assuming that this customer can sell 10 MW to PLN during the on-peak period, they could assign two generators, each rated at 3.5 MW and one rated at 7 MW, from generating plant #1 for this purpose. The output of the three generators will be connected to a separate 33 kV bus, which will be tied with the utility's 33 kV system. The output of the remaining generators of plant #1 and the output of all generators from plant #2 are connected to the captive power's own 33 kV bus.

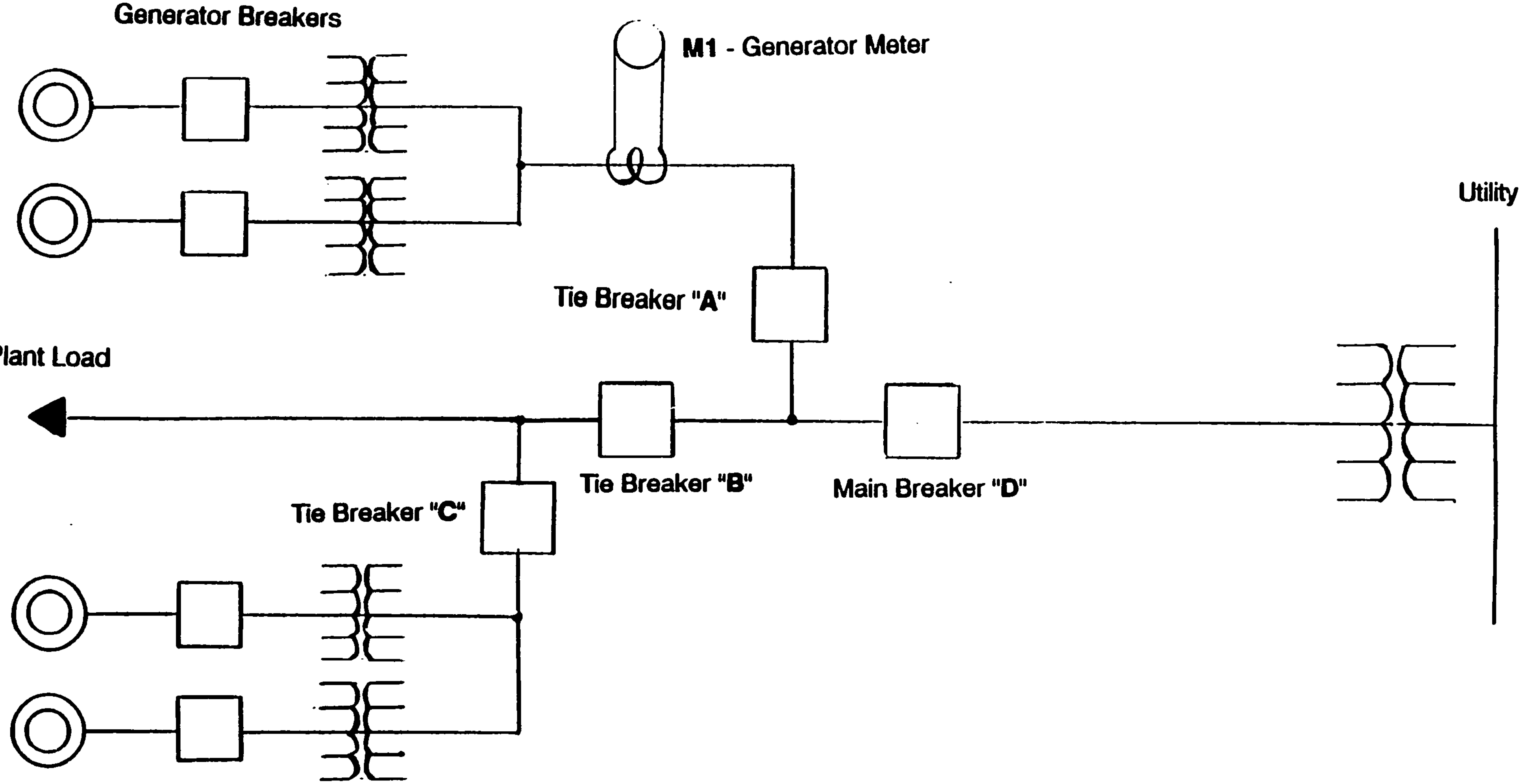
During the off-peak hours, the disconnect switch is opened and breaker B is closed to allow the output of the two plants to serve the load of the manufacturing plant. During the on-peak hours, the disconnect switch is closed and breaker B is opened to: 1) allow the output of the dedicated generators to be sold to PLN via the 33 kV tie line with the PLN system and 2) to

Exhibit 5-1
Buy Back from Non-PLN Customer
Configuration 1 - Integrated Scheme



77

Exhibit 5-2
Buy Back from Non-PLN Customer
Configuration 2 - Dedicated Scheme



78

isolate the output of the remaining generators from plant #1 and the output of plant #2 to continue to serve the manufacturing plant. This configuration would require only the dedicated generators to be synchronized with the PLN system. One meter is required to measure the output of the dedicated generators to account for kWh sales to PLN. The main breaker will provide protection to the captive power producer as well as PLN in the event of a fault on either PLN or the captive power system.

There are advantages and disadvantages associated with these two configurations. The advantage of configuration-1 is that in the event of a failure in the captive power's two generating plants, PLN may be able to provide backup to the captive power to allow normal operation of the manufacturing plant. The disadvantage is that the main breaker will trip frequently due to high voltage fluctuations in the PLN system. This is due to the fact that PLN's operating guidelines allow a plus or minus 5 percent voltage fluctuation, which is significantly higher than the plus or minus 1 percent voltage fluctuation allowed by the captive power producers. The advantage of configuration-2 is that since only the output of the dedicated generators are connected to the PLN system, the rest of the captive power producer's distribution system remains independent of the PLN system. The problem with the high voltage fluctuation in the PLN system is no longer a concern of the captive power system. The disadvantage is that PLN is not able to provide backup to the captive power system in the event of a failure to the captive power's generating system.

Of the two configurations, configuration-2 is recommended for the following reasons:

- It allows the captive power producer to operate their system very much the same as before, but have the ability to sell their excess capacity to PLN during the on-peak hours.
- The high voltage fluctuation in the PLN system will not have any impact on the captive power's own distribution system.
- Only one metering point is required for the accounting of kWh sales to PLN.

Exhibit 5-3 shows a variant of the dedicated scheme (configuration-2). This scheme relies on a bi-directional meter placed on the utility side of the customer-utility interface. This option, we understand, is consistent with PLN's current policies regarding meter location and reading responsibility.

Site #2: PLN Customer - Interruptible Option

Since this customer is already connected to the PLN network, only minor enhancements and additions to the existing system are required to allow PLN to reduce power supply to this customer during the on-peak hours. Exhibit 5-4 shows the existing configuration of the

Exhibit 5-3
Buy Back from Non-PLN Customer
Variant Dedicated Scheme

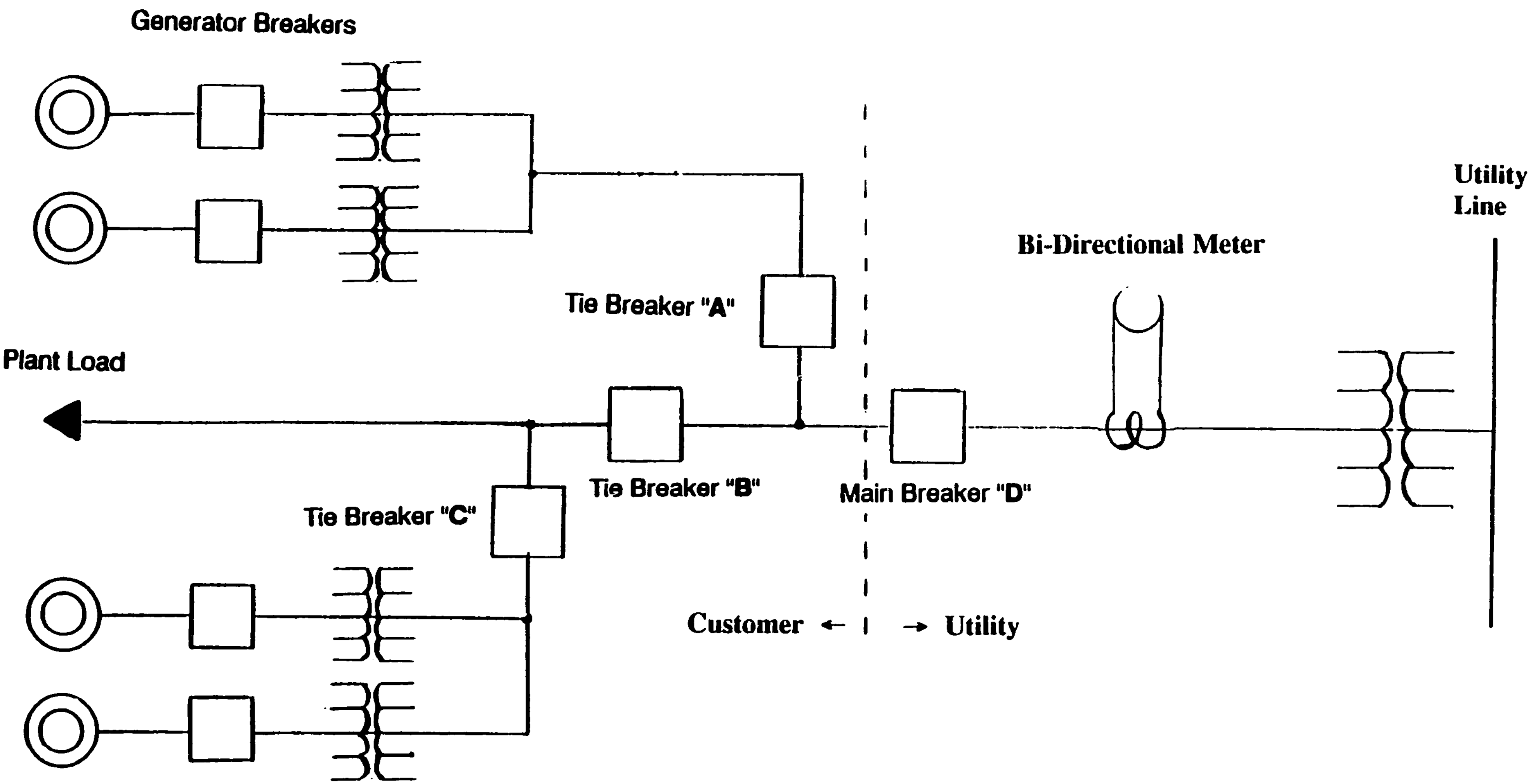
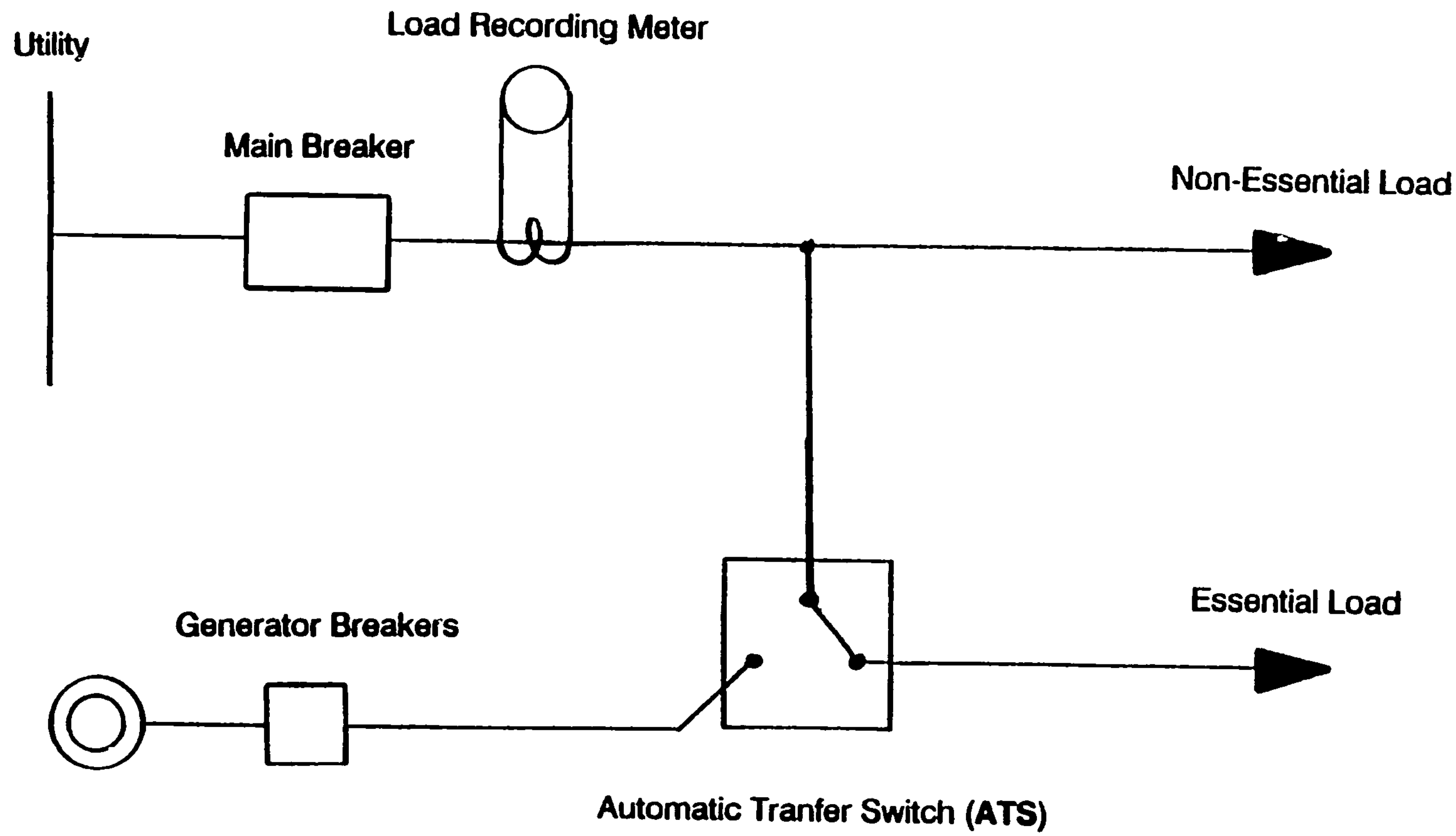


Exhibit 5-4
Configuration for Interruptible Option



system, with the exception of the load recording meter. In the existing configuration, the two backup generators are controlled by an automatic transfer switch (ATS). The load of the plant is separated into essential and non-essential load. In the event of a power failure, the ATS will open the tie to the utility network and allow the two generators to come on-line to serve the essential load. This configuration remains the same except for one modification; the backup generators will have to come on line during on-peak hours. Concurrently, this customer will have to back down the finishing mill operations to reduce the overall electrical demand of the plant. The metering equipment will record the daily load data of the plant. The data will then be analyzed by PLN personnel to determine the kW and kWh reduction contributed by the plant for accounting purposes.

5.3 COST/BENEFIT ANALYSIS

Exhibit 5-5 shows the cost/benefit to PLN and the captive power producers based on different capacity payment levels. The proposed capacity payments are based on different percentages of the total capacity credit available.

For the buy-back option, the connection costs include the equipment costs and installation costs for the main breaker "D," the tie breaker "B," and the meter to record the output from the dedicated generators. In addition, there will be another expense to PLN to extend the 33 kV transmission line from the substation to the distribution system of the cement manufacturing plant.

The equipment cost for two rebuilt 2000 amp circuit breakers and one recording meter system is approximately $350,000. This consists of two (2) rebuilt 2000 amp Westinghouse 500 kV, outdoor, 500 Hz skid-mounted, pneumatically operated, 125 V DC close and trip, 20,000 A I.C. main circuit CTs, weighing 29,500 lbs with oil, and a relay panel. The relay panel should be equipped with: (1) kW meter, (1) PF meter, (1) ammeter, (3) 67 relay, (1) 67 N relay, (1) C/S, (1) synchronous switch, (1) 43A, (1) set of synchronizing CTs, (1) metering unit, 3-CTs and 2 PTs, (1) 2000 amp, 33 kV disconnect switch, 3 pole, gang operated structure for mounting, (1) structure. The equipment will be guaranteed for one year. The installation cost is approximately $50,000. The projected total cost for this configuration is $400,000.

We recommend using rebuilt equipment for the following two reasons. First, the costs of rebuilt equipment are approximately half the cost of new equipment. Second, rebuilt equipment is very reliable and usually has the same guarantee time as new equipment. Many industries with cogeneration equipment facilities in the U.S. are choosing rebuilt equipment for their facilities over new equipment for these reasons. For the purpose of conducting a pilot study, it is practical to use the rebuilt equipment to reduce the capital costs of the project.

Exhibit 5-5
Costs/Benefits Analysis of Case Study

Option	Fuel and Variable O&M Cost of Captive Generation (Rp/kWh)[1]	Costs to PLN for System Inter-connection (Rp/ckWh)[2]	Proposed PLN Purchase Tariff[3]			Effective Tariff for On-Peak Purchase[4] (Rp/ckWh)	Payment to Captive in Excess of O&M and Inter-connection Costs (Rp/kWh)	Net Benefits to PLN (Rp/ckWh)
			On-Peak Energy (Rp/ckWh)	Capacity Payment (% of Avoided Cost)	Capacity Payment (Rp/ckWh)			
Buy-Back Option (10 MW)	90	23	127	0	0	127	14	202
				25	51	178	65	152
				50	101	228	115	101
				75	152	279	166	51
				100	202	329	216	0
Interruptible Option (5 MW)	90	1	127	0	0	127	36	202
				25	51	178	87	152
				50	101	228	137	101
				75	152	279	188	51
				100	202	329	238	0

1 Exhibit 4-7.

2 Includes costs for interconnecting captive power's distribution system with PLN's system. This cost, however, does not include the costs to extend the 33 kV transmission line (see Exhibit 5-6).

3 Exhibit 4-8.

4 Interconnection costs will be deducted from the payment to captive power producers.

Assuming that the interconnection cost would be incurred by PLN, and further assuming a three-year contract, at a 12 percent discount rate and a forward exchange rate of Rp. 2060 per $1, the annual payment is Rp. 343,071,560. Assuming the plant will produce 14,600,000 kWh annually,[1] the average capacity cost per kWh is Rp. 23.

If PLN were to provide 50 percent of the marginal capacity costs to them during the on-peak hours as capacity credit for captive power producers, the benefit to PLN would be Rp. 101 for every kWh PLN purchases from the captive power producers on-peak. The captive power producers would realize Rp. 115 for every peak kWh sold to the PLN system, in excess of their fuel and other variable costs of generation (Exhibit 5-5).

The interruption option would only require the installation of load recording equipment at a cost of approximately $6,300. The load data recorded by the meter will need to be analyzed by PLN to determine the kWh reduction achieved by the customer. Assuming the customer can reduce the on-peak demand by 5 MW, this translates to a reduction of 7,300,000 kWh of on-peak energy. By financing the cost of metering equipment over a three-year period at a 12 percent discount rate, the average cost per kWh is Rp. 1. For this option, the benefit to PLN would be Rp. 101 for every on-peak kWh reduced by the customer. The captive power producer realizes Rp. 137 per ckWh in excess of its fuel and other variable generation costs (Exhibit 5-5).

Based upon the two site visits, it appears that most potential program participants will not want to be responsible for installing the selected interconnection configuration. PLN has the expertise to undertake this, and it may also be able to procure the required equipment more cheaply if it bought in bulk. Given that PLN incurs the equipment and installation cost for metering and interconnection, it will need to recover these costs over the life of the contract. This can be achieved as a reduction in the total monthly payments made to the captive power generator for power purchases by PLN, and would be shown as a separate debit line item after tallying up credits for energy and capacity purchased. Exhibit 5-6 shows estimates of this cost component (expressed as Rp./ckWh, assuming 100 percent availability on-peak), as a function of interconnection costs, on-peak contract capacity, and life of contract. For firm power contracts, a minimum duration of three years is recommended, since that is the minimum lead time needed by PLN to install a gas turbine for peaking capacity support. In implementation, it is recommended that the interconnection cost incurred by PLN be deducted on a monthly basis from the total energy and capacity cost payments due to the captive power generator. The interconnection costs should be shown as a separate line item that is debited against the credits due from the power sold by the captive power plant in that month. Exhibit 5-7 shows the monthly payments to be debited for interconnection costs as a function of PLN's investment and contract duration.

[1] 10 x 1000 x 4 x 365.

Exhibit 5-8
Time Line for Pilot Load Management Project (Months)

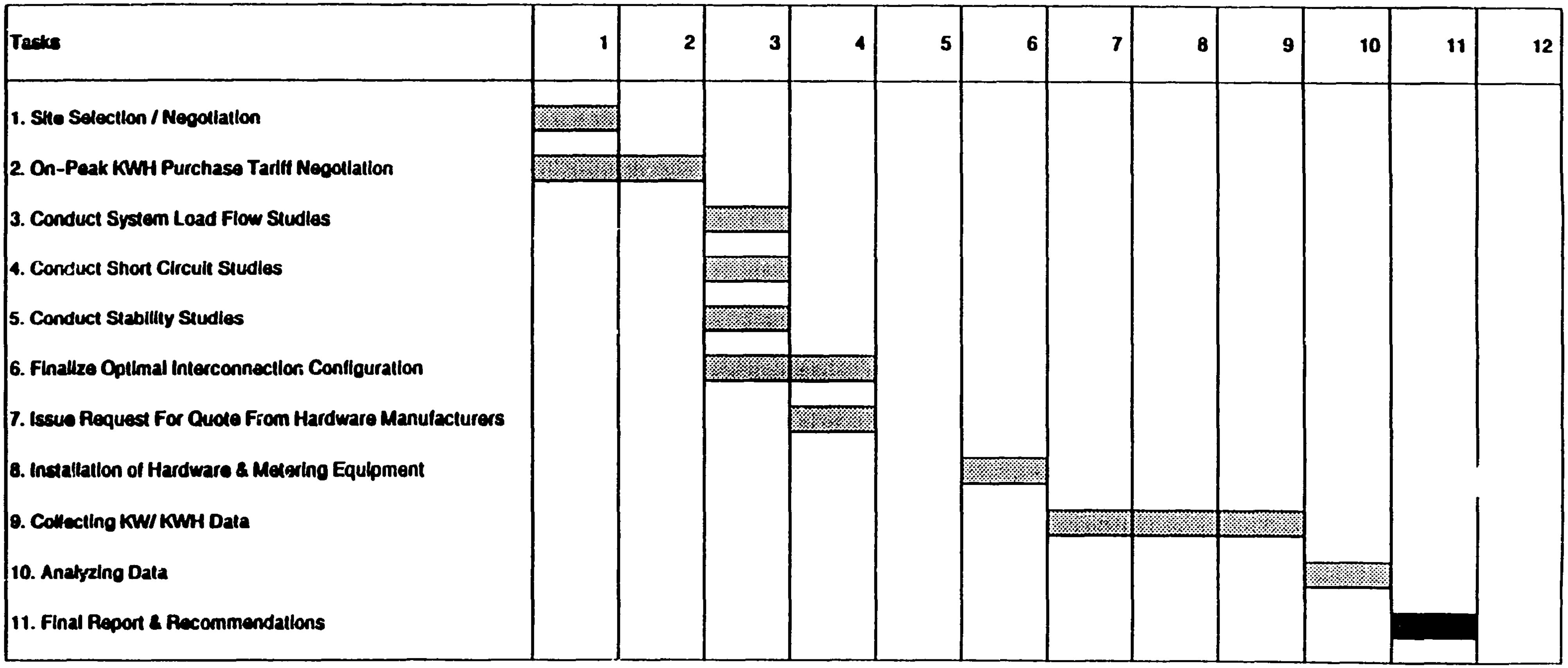


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Exhibit 5-6

Interconnection Costs in Rp./kWh Based on On-Peak Contract Capacity
(Based on Three-Year Recovery of Investment)

INTER-CONN. COSTS ($)	CONTRACT CAPACITY (KW) 1000	2000	3000	4000	5000	6000	7000	8000	9000	10000
100,000	59	29	20	15	12	10	8	7	7	6
200,000	117	59	39	29	23	20	17	15	13	12
300,000	176	88	59	44	35	29	25	22	20	18
400,000	235	117	78	59	47	39	34	29	26	23
500,000	294	147	98	73	59	49	42	37	33	29
600,000	352	176	117	88	70	59	50	44	39	35
700,000	411	206	137	103	82	69	59	51	46	41
800,000	470	235	157	117	94	78	67	59	52	47
900,000	529	264	176	132	106	88	76	66	59	53
1,000,000	587	294	196	147	117	98	84	73	65	59
1,100,000	646	323	215	162	129	108	92	81	72	65
1,200,000	705	352	235	176	141	117	101	88	78	70
1,300,000	764	382	255	191	153	127	109	95	85	76
1,400,000	822	411	[illegible]74	206	164	137	117	103	91	82
1,500,000	881	441	294	220	176	147	126	110	98	88

Note: Assumed 12 percent discount rate and 100 percent on-peak availability.

87

Exhibit 5-6 (Continued)
Interconnection Costs in Rp./kWh Based on On-Peak Contract Capacity
(Based on Four-Year Recovery of Investment)

INTER-CONN. COSTS ($)	CONTRACT CAPACITY (KW) 1000	2000	3000	4000	5000	6000	7000	8000	9000	10000
100,000	46	23	15	12	9	8	7	6	5	5
200,000	93	46	31	23	19	15	13	12	10	9
300,000	139	70	46	35	28	23	20	17	15	14
400,000	186	93	62	46	37	31	27	23	21	19
500,000	232	116	77	58	46	39	33	29	26	23
600,000	279	139	93	70	56	46	40	35	31	28
700,000	325	163	108	81	65	54	46	41	36	33
800,000	372	186	124	93	74	62	53	46	41	37
900,000	418	209	139	105	84	70	60	52	46	42
1,000,000	465	232	155	116	93	77	66	58	52	46
1,100,000	511	255	170	128	102	85	73	64	57	51
1,200,000	557	279	186	139	111	93	80	70	62	56
1,300,000	604	302	201	151	121	101	86	75	67	60
1,400,000	650	325	217	163	130	108	93	81	72	65
1,500,000	697	348	232	174	139	116	100	87	77	70

Note: Assumed 12 percent discount rate and 100 percent on-peak availability.

Exhibit5-6 (Continued)
Interconnection Costs in Rp./kWh Based on On-Peak Contract Capacity
(Based on Five-Year Recovery of Investment)

INTER-CONN. COSTS ($)	CONTRACT CAPACITY (KW) 1000	2000	3000	4000	5000	6000	7000	8000	9000	10000
100,000	39	20	13	10	8	7	6	5	4	4
200,000	78	39	26	20	16	13	11	10	9	8
300,000	117	59	39	29	23	20	17	15	13	12
400,000	157	78	52	39	31	26	22	20	17	16
500,000	196	98	65	49	39	33	28	24	22	20
600,000	235	117	78	59	47	39	34	29	26	23
700,000	274	137	91	68	55	46	39	34	30	27
800,000	313	157	104	78	63	52	45	39	35	31
900,000	352	176	117	88	70	59	50	44	39	35
1,000,000	391	196	130	98	78	65	56	49	43	39
1,100,000	431	215	144	108	86	72	62	54	48	43
1,200,000	470	235	157	117	94	78	67	59	52	47
1,300,000	509	254	170	127	102	85	73	64	57	51
1,400,000	548	274	[illegible]	137	110	91	78	68	61	55
1,500,000	587	294	196	147	117	98	84	73	65	59

Note: Assumed 12 percent discount rate and 100 percent on-peak availability.

Exhibit 5-7
Payments for Interconnection Costs Recovery
(Rp./Month)

Interconnection Costs ($)	**Recovery of Investment (Years)**		
	3	**4**	**5**
100,000	7,147,324	5,651,858	4,762,200
200,000	14,294,648	11,303,716	9,524,401
300,000	21,441,972	16,995,573	14,286,601
400,000	28,589,297	22,607,431	19,048,802
500,000	35,736,621	28,259,289	23,811,002
600,000	42,883,945	33,911,147	23,573,202
700,000	50,031,269	39,563,005	33,335,403
800,000	57,178,593	45,214,863	38,097,603
900,000	64,325,917	50,866,720	42,859,804
1,000,000	71,473,242	56,518,578	47,622,004
1,100,000	78,620,566	62,170,436	52,384,204
1,200,000	85,767,890	67,822,294	57,146,405
1,300,000	92,915,214	73,474,152	61,908,605
1,400,000	100,062,538	79,126,010	66,670,806
1,500,000	107,209,852	84,777,867	71,433,006

Note: Assumed 12 percent discount rate.

Next Steps

The results of the pre-feasibility analyses indicated that it is economical for PLN to purchase excess power from the captive power producers to serve PLN's system demand during the on-peak hours of 18:00 p.m. to 22:00 p.m. instead of adding peaking generating capacity. It is recommended that a pilot load management project be implemented so that a detailed study of the economic benefits and demonstration of technical feasibility of using captive power to serve PLN's on-peak load can be achieved. The pilot project will also enable PLN to "fine tune" the purchase tariffs for a broader implementation of the proposed DSM program concepts for peak load management. The study should take approximately 12 months to complete. Exhibit 5-8 identifies the major tasks and the projected time required to complete these tasks.

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92

The Office of Energy and Infrastructure

The Agency for International Development's Office of Energy and Infrastructure plays an increasingly important role in providing innovative approaches to solving the continuing energy crisis in developing countries. Three problems drive the Office's assistance programs: high rates of energy use and economic growth accompanied by a lack of energy, especially power in rural areas; severe financial problems, including a lack of investment capital, especially in the electricity sector; and growing energy-related environmental threats, including global climate change, acid rain and urban pollution.

To address these problems, the Office of Energy and Infrastructure leverages financial resources of multilateral development banks such as The World Bank and the InterAmerican Development Bank, the private sector and bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research, adaption and innovation. These approaches include improving power sector investment planning ("least-cost " planning) and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. Promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective, reliable and environmentally sound energy systems integral to broad-based economic growth.

Much of the Office's strategic focus has anticipated and supports recently enacted congressional legislation directing the Office and A.I.D. to undertake a "Global Warming Initiative" to mitigate the increasing contribution of key developing countries to greenhouse gas emissions. This strategy includes expanding least-cost planning activities to incorporate additional countries and environmental concerns, increasing support for feasibility studies in renewable and cleaner fossil energy technologies that focus on site-specific commercial applications, launching a multilateral global energy efficiency initiative and improving the training of host country nationals and overseas A.I.D. staff in areas of energy that can help reduce expected global warming and other environmental problems.

The Office also helps developing countries speed their economic development through promoting technology cooperation between U.S. suppliers and developing country companies, institutions and governments. This effort involves Business Opportunity Identification to define and analyze the range of commercially viable trade and investment opportunities, technologies and services that have a positive impact on the environment and are appropriate for developing countries; Venture Promotion to encourage the involvement of the U.S. private sector; Innovative Finance; and Policy Development assistance to developing counties as they pursue policy and regulatory changes to provide market incentives for environmentally beneficial technologies.

To pursue these activities, the Office of Energy and Infrastructure implements the following six projects: (1) Biomass Energy Systems and Technology Project (BEST); (2) The Renewable Energy Applications and Training Project (REAT); (3) The Private Sector Energy Development Project (PSED); (4) The Energy Training Project (ETP); (5) The Energy Technology Innovation Project (ETIP); and (6) The Energy Efficiency Project (EEP).

The Office of Energy and Infrastructure helps set energy policy direction for the Agency, making its projects available to meet generic needs (such as training), and responding to short-term needs of A.I.D.'s field offices in assisted countries.

Further information regarding the Office of Energy and Infrastructure projects and activities is available in our Program Plan, which can be requested by contacting:

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93