PN-ABM-935

U.S. AGENCY FOR
INTERNATIONAL
DEVELOPMENT

Office of Energy and Infrastructure

Indonesia
Demand-Side Management

Volume I:
Action Plan

Report Number 92-06
October 1992

Bureau for Research and Development
U.S. Agency for International Development
Washington, D.C. 20523-1810

PN-ABM-935
ISN 80228

Report No. 92-06

A Report of the

Office of Energy and Infrastructure
Bureau for Research and Development
United States Agency for International Development

INDONESIA DEMAND-SIDE MANAGEMENT
VOLUME I: ACTION PLAN

Final Report

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Energy Policy Development and
Conservation Project, 936-5728
Energy Conservation Services Program
DHR-5728-Z-00-7014-00

November 1992

ABSTRACT

This study has been sponsored by the Agency for International Development, Office of Energy and Infrastructure, as a first step towards helping Indonesia reduce the cost and improve the reliability of electricity supply through demand-side management (DSM). The report proposes an eight year program consisting of (i) the development of a DSM Master Plan; (ii) pilot programs; and (iii) full-scale program implementation. In addition to describing each of the proposed program components, the report provides an overview of DSM program elements, an analysis of DSM objectives for the Java-Bali system, and an assessment of the potential costs and benefits of implementing the proposed DSM program. The report concludes that the $170 million program could save 1.4% of total generation and 4.6% of peak demand in the year 1999/00. Taking these costs and benefits into account, the net present value of the program would be $364 million. The proposed DSM program appears to be an excellent candidate for follow-up support from multi- or bi-lateral aid agencies.

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EXECUTIVE SUMMARY

The purpose of this study is to take the first step in assisting the Government of Indonesia chart a course toward more efficient use of electricity. It is intended to present a possible course of action, and the associated costs and benefits, in sufficient detail to provide a basis for follow-on funding from potential donor agencies and the Indonesian government. The study is part of a larger effort of the Agency for International Development's Office of Energy and Infrastructure to help Indonesia improve the efficiency of its energy sector and to promote demand-side management (DSM) in developing countries.

Given the current lack of DSM experience and relevant data in Indonesia, the report draws heavily from DSM experience in the United States and other countries. This experience suggests that with proper planning, DSM can serve as a least-cost utility resource. Although differences in Indonesian consumer behavior, institutional relationships, and other factors will necessitate that DSM strategies are tailored to Indonesia (resulting in program impacts that differ from other countries), the fundamentals of DSM strategy formulation remain applicable. The experience in other countries is a useful foundation upon which to build an accelerated DSM program in Indonesia, and suggest the benefits which DSM can provide. This report provides a guide to developing a DSM program appropriate to Indonesia based on lessons learned elsewhere in the world.

Over the past decade, power demand grew rapidly in Indonesia. Perusahaan Umum Listrik Negara (PLN), the Indonesian utility, quadrupled in size; sales grew from 4.3 TWh in 1978/79 to 27.7 TWh in 1990/91 and installed capacity increased from 2.3 GW to 9.3 GW. The number of customers grew from 1.8 million to around 11 million.

Total consumption and peak demand are expected to continue this relentless growth through the 1990's. High growth rates are forecast for all sectors: between 1992/93 and 2000/01, residential demand is expected to grow at 9.1% annually, commercial and service demand at 13.3%, and industrial demand at 13.2%. This growth may be limited by the ability of supply to keep up with demand.

Increasing supply on this scale will create new financial, economic, and environmental pressures for Indonesia. PLN will face heightened financial difficulties as the gap between revenues and debt service for new capacity widens. Load shedding and, consequently, the use of captive generation will escalate, with negative economic consequences for the entire Indonesian economy. The accelerated use of natural resources for electricity production, and expanded reliance on thermal generation will increase both local and global environmental hazards.

DSM can complement supply-side strategies to help meet Indonesia's growing electric service demands. DSM is the planning, implementation, and monitoring of utility activities designed

to encourage customers to modify their electricity consumption patterns, both with respect to the timing and level of electricity demand. Section I of this report describes the elements of a DSM program, and how these elements can be organized for maximum impact and economic benefit. Although DSM is not a panacea for problems of the Indonesian power sector, experience in the United States, Canada, and elsewhere suggests that it deserves a role in Indonesia's power sector strategy for the 1990's. Annex I summarizes some results of DSM programs elsewhere in the world.

As pointed out in Section II of the report, because both potential capacity deferral and energy reduction benefits are so great in Indonesia, peak clipping and strategic conservation should be pursued vigorously through DSM in all sectors, wherever it is cost effective. Section III presents a comprehensive eight year DSM program for Indonesia. The first phase of the program would entail the preparation of a DSM Master Plan which would create an institutional framework for DSM implementation, provide training, collect necessary data, and design specific DSM programs. It would provide a roadmap for subsequent DSM activities, and would be conducted during the first year of the program, assumed here to be 1992/93[1]. The cost of this phase of the program is estimated to be US$1.5 million.

The second phase consists of pilot programs to help reduce the risk associated with full-scale implementation of the proposed programs, facilitate program improvements before full-scale implementation, and demonstrate the effectiveness of the proposed programs. This phase of the work would be conducted over the course of one year, here assumed to be 1993/94, and is estimated to cost US$2.2 million.

The third phase covers full-scale implementation and evaluation; it will be guided by the DSM Master Plan and will build upon the experience gained through pilot programs. It would be conducted over the third through the eighth years of the program, here assumed to be 1994/95 through 1999/00.

The specific programs to be implemented during the third phase of the project will be formulated over the course of the preceding two phases. However, as a starting point for further discussion, and to illustrate the potential benefits of a DSM program in Indonesia, Section IV describes ten possible DSM programs, their costs, and their impacts. The following ten programs are considered based on their success elsewhere and their suitability for Indonesia:

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[1] Eighteen months may be a more realistic estimate of the time required for the first phase. Comments provided by the World Bank and others on an earlier version of this report suggest that the duration of the first phase should be extended to account for additional time which may be necessary to implement institutional changes and coordinate DSM activities in Indonesia. However, since increased duration of the first phase changes neither the basic scope of recommended DSM development activities nor the potential benefits of DSM implementation, and because only limited time was available for the revision of this report, the reports retains a nominal estimate of one year for the first phase of the project.

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Industrial Programs
Improved Motors
High Efficiency Lighting
Time of Use (TOU) Tariffs
Interruptible and Curtailable (I&C) Tariffs
Energy Management Audits

Commercial and Public Sector Programs
Improved Air Conditioning
High Efficiency Lighting
Efficient New Construction

Residential Programs
Improved Refrigerators
High Efficiency Lighting

Pricing is a key element of any DSM program. Volume II of this study, "Electricity Pricing Incentives", discusses in further detail the importance and potential impacts of pricing changes. It also describes specific DSM programs for load management in Indonesia which entail purchases of excess captive generation during peak hours. The report suggests a pilot program to demonstrate the technical concept as well as the regulatory, economic, and financial issues involved. This pilot program would help optimize key program elements for subsequent widespread implementation of the peak shaving program.

Section V summarizes the potential scope, costs, and benefits of these ten DSM programs. This analysis concludes that full-scale implementation of these programs would cost US$166 million over the six years of implementation (approximately $170 million including the costs of Master Plan preparation and pilot programs), and would reduce peak capacity requirements by 4.6% and total generation by 1.4% in 1999/00. Taking into account these program costs and the benefits of avoiding generation and capacity additions, the net present value of the program would be US$364 million.

Whether or not the specific programs described in Section IV are ultimately implemented in Indonesia, there is a clear need for and substantial benefits to be realized from a comprehensive DSM program. This report spells out the first steps necessary to capture this potential. Given the relentless growth of power demand in Indonesia, there is little time to lose.

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CHAPTER I: OVERVIEW OF DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) is the planning, implementation, and monitoring of utility activities designed to encourage customers to modify their electricity consumption patterns, both with respect to the timing and level of electricity demand[1].

Utility efforts to influence customer demand date back to the first generating station, Thomas Edison's Pearl Street facility in New York City. In the 1890's, when nighttime lighting was the only load, Edison hired people to promote electric motors and other daytime uses of electricity[2]. By encouraging round-the-clock electricity consumption, Edison was able to increase the utilization of generation capacity and reduce unit production costs. DSM has re-emerged as an important tool for utility planning and operation, although the emphasis these days is seldom on encouraging consumption. On the contrary, DSM now typically aims to reduce utility capacity requirements and total generation so that electricity services can be offered at least cost. In doing so, DSM yields both economic as well as environmental benefits for the nation, the utility, and consumers.

DSM is a *resource* that can be planned, measured and used by a utility to satisfy customer demand for electric services. Utilities which rely solely on conventional resources, such as power plants, often view themselves as commodity producers. Conversely, utilities which tap the potential of DSM must view themselves as service providers, i.e. that they are in the business of meeting consumer needs rather than producing kilowatt-hours.

DSM encompasses a broad range of measures to encourage consumers to modify their consumption. Tariffs can be designed to stimulate a shift in consumption to off-peak periods. End-use energy efficiency can reduce both energy and peak power demand. Direct load control can likewise limit peak power demand. The key to the success of these measures is that they are implemented for less than what it would cost to add another unit of capacity or provide another unit of energy.

The Motivation for DSM

It may seem irrational for a utility to try to sell less of its product. In fact, load-reducing DSM may be an important strategy for providing electric services at least cost, since it is often cheaper to save energy than to produce it. For instance, if a utility manages to reduce electricity demand, it can postpone the construction of expensive new power plants or

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1 Impact of Demand Side Management on Future Customer Electricity Demand: An Update, Electric Power Research Institute, Report CU-6746, September, 1990.

2 "Shaping DSM as a Resource", EPRI Journal, October/November 1991.

increase reliability. This consideration is particularly relevant in Indonesia, where average tariffs are below long run marginal costs (LRMC) of production. Regulatory authorities in many jurisdictions have recognized the economic benefits of improved energy efficiency and have created incentives for utilities to implement DSM programs.

Capacity-constrained utilities in the United States, Canada and western Europe have taken the most initiative in implementing load-reducing DSM. The results of some of these programs are discussed in Annex I. However, developing countries such as Indonesia may have the most acute need for DSM because they face the most rapid demand growth and a limited ability to finance additional capacity.

Developing countries have long recognized the critical role of energy in development. Generation, transmission, and distribution have traditionally been among the highest investment priorities in many developing countries. Power loans have generally accounted for about 25% of total public sector foreign debt service in developing countries during the 1980's, and as much as 40% in certain countries[3]. In addition, prices frequently have been set as low as possible, often below the cost of production and distribution, to encourage energy consumption, stimulate economic activity and improve household welfare. However, the rapid increase in energy demand in many countries, due to factors such as increasing economic activity and high population growth, has imposed growing capital requirements to finance utility capacity. The growing gap between debt burden and revenues has resulted in a financial crisis for many developing country utilities. This crisis has obliged many governments and utilities to seek alternatives to the strategy of ever-increasing capacity and subsidized pricing. DSM can assist utilities avoid or delay costly capacity additions by slowing demand growth.

By reducing capacity requirements and generation, DSM may help to reduce utility financing requirements. This of course is only one dimension of the utilities' financial predicament. Revenues often need to be increased through major changes in the tariff structure, far beyond the scope of tariff adjustment for better load management alone. Nonetheless, DSM remains a key element of any program to help utilities achieve *financial* viability.

As a likely component of any least-cost power supply strategy, DSM can also bring *economic* benefits to the country as a whole. This is particularly true in Indonesia, where DSM may not only help reduce capacity needs but, more immediately, may help reduce costly captive generation, load shedding, and its associated economic costs.

DSM responds to *environmental* concerns as well as to the financial difficulties in which many developing country utilities find themselves. DSM strategies such as improved end-use

[3] Schramm, G., "Electric Power in Developing Countries: Status, Problems, Prospects", *Annual Review of Energy*, vol. 15, 1990.

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efficiency can reduce the amount of undesirable generation emissions or by-products per unit of useful energy. Reduced ash and sulphur dioxide emissions are examples of local environmental benefits of energy efficiency, while lower carbon dioxide emissions are globally desirable. The scope for DSM to improve environmental quality is large. It is estimated, for instance, that about half of all global greenhouse gas emissions (on a CO_2 equivalent basis) originate from energy consumption, much of it in the power sector. These environmental benefits have made DSM attractive not only to governments throughout the world, but to bilateral and multilateral funding agencies as well.

Institutional Requirements and Incentives

Most developing countries have not yet initiated DSM programs. To do so requires the development of new capabilities as well as the regulatory provision of incentives to the utility, consumers, and trade allies[4] to promote and participate in DSM programs. Assuming DSM is indeed part of a least-cost plan, the purpose of incentives is to make this least-cost plan the most profitable plan for all parties. Because DSM programs must mobilize all three of these groups to succeed, crafting a package of incentives which motivates all can be a complex task. It is also one which must be completed prior to embarking on DSM program design and implementation.

Integrated resource planning (IRP) is a technique which generates the least-cost utility plan by considering both supply- and demand-side resources. It determines whether DSM is in fact part of a least-cost plan by comparing DSM program options to supply side options, and selecting the mix which is least costly to meet customer needs. IRP extends the supply-side least cost planning long advocated by organizations such as the World Bank to include demand-side resources.

In many countries, the first step towards the use of DSM will be a presidential or ministerial decree, or a public law, which directs the utility to introduce IRP and DSM, and sets the foundation for building and appliance standards. The IRP requirement is important because it places supply-side and demand-side resources on an equal footing in terms of utility planning.

In Indonesia, legislation has been enacted to promote energy conservation, but does not yet go as far as DSM. Presidential Decree No. 43 of 1991, for example, was issued to promote

[4] DSM programs are sometimes more effective if they are delivered through intermediaries who in turn sell goods and services to consumers, rather than delivered directly by the utility to consumers. *Trade allies* are enterprises such as builders or equipment distributors who can help to implement DSM programs through their normal business activities. Utilities typically offer incentives to trade allies to sell higher efficiency equipment or construct energy-saving buildings.

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energy conservation. To promote the appropriate use of DSM, the law or decree would also have to specify changes in the utility's accounting, performance, and project evaluation procedures. These additions would stipulate the use of IRP, would make DSM attractive to the utility from an accounting and incentive standpoint, and would empower the utility to conduct direct installation programs, offer the necessary incentives to consumers and trade allies, or contract with energy service companies to deliver a specified amount of energy or capacity savings. Specific building codes or appliance standards may also be outlined, which may be enforced by other agencies. The Indonesian presidential decree does not delve into these details, but empowers the Minister of Mining and Energy to do so.

Assuming that DSM programs are economically justified and that a country therefore wants to encourage introduction of DSM programs, financial incentives to the utility are particularly important, especially since the consumer and trade ally incentives (such as rebates or innovative tariffs) are generally offered through the utility.

Utility incentives must encourage utilities to transform from commodity producers into service providers. Until recently, tariffs were the primary power sector policy issue, as they often were formulated to balance the economic efficiency of long run marginal cost (LRMC) pricing with the government's broader socio-economic and political considerations. Utilities were, in effect, regulated on a cost of service basis, and utility success was measured by power sales. Revenue collection, usually a direct function of sales, was thought to be the only incentive utilities needed for operation. Utilities had to maximize their sales to maximize their revenues (although in cases in which certain tariff classes are subsidized, the utility has an incentive to limit sales). Existing regulatory arrangements in these countries seldom recognize that saving energy and reducing demand can be economically less costly that generating electricity and adding capacity. Consequently, incentives are seldom provided for utilities to introduce DSM programs which aim to *reduce* sales. Regulation must therefore provide incentives for utilities to implement DSM if the economic benefits of DSM are to be captured.

In Indonesia, for example, Law No. 15 of 1985 stipulates that the price of electricity is controlled by the government. The tariff is set on the basis of financial targets for the power subsector, but not necessarily at the economic cost of supply or the cost of providing service. Under prevailing arrangements, these financial targets, as well as other measures of performance, are established and evaluated by a Supervisory Board under the Ministry of Mines and Energy.

However, to provide incentives for implementation of least cost plans which consider both demand- and supply-side options, the criteria for utility success must change. Utility profits (or other measure of success) must be de-coupled from power sales. Consumers and trade allies must be encouraged to participate in the transition to new end-use technologies and consumption behavior. Such a transition naturally entails risk for all parties. Changes in utility, consumer, and trade ally incentives are not simply money "give-aways", but are

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critical to help each group overcome its risk aversion, and to give each group a stake in adopting the least-cost plan.

In Indonesia, non-tariff financial incentives are needed in addition to an IRP requirement to stimulate DSM implementation. Financial incentives for DSM should provide the utility with:

- Full recovery of all costs associated with DSM programs, including interest and adjustments for under-recovered fixed costs resulting from:
  - program participation and/or costs exceeding budgeted amounts;
  - lack of carrying charges on deferred expenditures; and
  - lack of authorized return on amortized program expenditures; and
- Bonuses in addition to cost recovery to offset risks and encourage performance.

Cost recovery mechanisms can include:

- Ratebasing DSM costs as they are incurred;
- Balancing account recovery, i.e. decoupling revenues from electricity sales by allowing the utility to collect sufficient revenues regardless of costs or sales;
- Directly offsetting revenues lost through DSM implementation, either on a program-specific or comprehensive basis.

Bonuses can be included through several means including:

- Providing ratebased DSM costs with a bonus rate of return for the purposes of tariff calculations;
- Allowing a utility markup on DSM expenditures;
- Granting unit savings bonuses, i.e. per kW or kWh saved (the "bounty system" approach); and
- Providing the utility with a percentage share of the total savings, i.e. avoided costs less program costs (the "shared net resource savings" or simply "shared savings" approach).

Of course, these utility incentives also should be reflected among the performance incentives for utility staff.

Capabilities to administer and deliver DSM programs must also be developed, and responsibilities for program implementation allocated. While the utility is ultimately responsible for the design of an optimal program delivery strategy, and always retains substantial administrative control of DSM activities, delivery of utility-designed programs may be delegated to private contractors. Alternatively, private energy service companies (ESCOs) can contract with the utility, or bid competitively, to provide energy savings from opportunities they have identified independently of the utility.

The selection of an appropriate approach will depend in part on the match between capabilities which already exist within the utility and the private sector, and the types of measures and delivery mechanisms to be used. For instance, direct installation of high efficiency lighting could allow for either the use of contractors or utility staff, while rebate programs could be handled by the utility alone. New construction efficiency programs, on the other hand, could be handled by trade allies with incentives provided by the utility. In any case, it is likely that utility personnel will require hands-on familiarization with DSM program design, implementation, and evaluation through workshops, training courses, and interaction with personnel from utilities which have already introduced DSM. An overview of delivery mechanisms is given in Box 1.1.

Key DSM Objectives

As described in Table 1.1, there are six principal ways in which DSM programs can influence consumer demand. Some of these entail a reduction in peak demand or total consumption, while others increase demand or consumption. The desired effects depend on the utility in question; clearly, not all of these objectives (such as load building) are relevant to Indonesia. The primary objective in any case is to manipulate the timing or level of customer demand so as to achieve the financial, economic, and environmental benefits of the least-cost plan. In cases of underutilized capacity, such as in Edison's first utility, valley filling would be desirable. On the other hand, in countries with rapidly growing demand, peak clipping or strategic conservation may be used to help defer costly new capacity additions, improve customer service, reduce environmental impacts, and maximize national economic benefits.

The Framework for DSM Program Design and Implementation

Since Indonesia does not yet have experience with DSM implementation, it is a chicken-and-egg question whether to proceed first with IRP or DSM: IRP would identify cost-effective DSM resources, but requires information such as estimated costs, benefits, and market penetration for DSM options under consideration. This type of information is typically only available through actual DSM experience. An accelerated DSM program

Box 1.1: Delivery Mechanisms for DSM Programs

Delivery mechanisms for DSM programs range from a centralized approach in which the utility is responsible for the identification of opportunities and installation of measures on the consumer's side of the meter, to a decentralized approach in which the utility only provides incentives for consumers, who are then responsible for identifying DSM opportunities and deciding whether or how they wish to take advantage of those incentives.

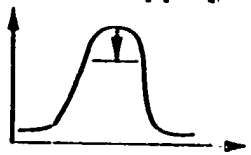
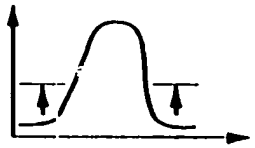
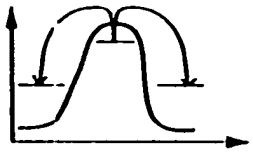
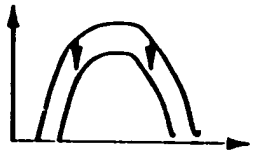
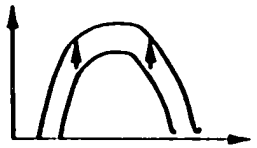
Direct installation is the most centralized approach. In its simplest form, direct installation entails utility staff visiting consumers and physically installing equipment that will modify consumer load shapes. Alternatively, a utility may hire a contractor to carry out this work.

Closer to the middle of the spectrum are delivery mechanisms which rely on third parties to identify DSM opportunities. **Energy service companies (ESCOs)** may contract with utilities in much the same way as an independent power producer, but will instead be expected to provide a certain level of reduction in peak demand and total annual energy consumption. ESCO staff are responsible for identifying the DSM opportunities and gaining the cooperation of the consumer. **Trade allies** are typically equipment vendors or builders who come in contact with DSM opportunities in the course of their primary business. For example, utilities might pay air conditioning retailers for each high efficiency unit they sell, or might provide property developers to adopt high efficient designs which may be more expensive on a capital cost basis.

Finally, utilities may offer **direct incentives to consumers**. **Tariff options**, such as time of use rates or interruptible and curtailable rates are the most direct incentives. **Rebates** can also be used to motivate consumers to purchase more efficient end-use equipment which the consumer might not have otherwise purchased because of its higher capital cost. Alternatively, a utility can offer **loans** to consumers to purchase more efficient equipment, or **lease** such equipment to them at attractive rates. Utilities can also offer consumers **shared savings programs** in which the utility would make payments to consumers commensurate with the benefits that accrue to the utility as a result of changes in consumer consumption patterns. Finally, utilities can provide **information only programs** in which the utility simply describes how the consumer can modify his or her consumption and the benefits that will accrue to the consumer under existing tariffs with these modifications.

These financial incentives for consumers may be packaged with personal marketing contact and/or technical assistance from either the utility or a contractor to help the consumer take advantage of particular DSM opportunities. Similarly, delivery may be administered, and consumer actions verified, by either the utility itself or a contractor acting on its behalf.

Table 1.1: The Effects of DSM on Load Shape

Effect on Load Shape	Description	Means of Implementation
Peak Clipping 	**Peak clipping** refers to the reduction of utility loads during peak demand periods. This can defer the need for additional generation capacity. The net effect is a reduction in both peak demand and total energy consumption.	Direct utility control of consumer appliances or end-use equipment.
Valley Filling 	**Valley filling** entails building of off-peak loads. This may be particularly desirable when the long-run incremental cost is less than the average price of electricity. This is often the case when there is underutilized capacity that can operate on low cost fuels. The net effect is an increase in total energy consumption, but no increase in peak demand.	Creation of new off-peak electric loads that previously operated on non-electric fuels, such as overnight charging of electric cars and thermal energy storage.
Load Shifting 	**Load shifting** involves shifting load from on-peak to off-peak periods. The net effect is a decrease in peak demand, but no change in total energy consumption.	Time of use rates and/or the use of storage devices that shift the timing of conventional electric appliance operation.
Conservation 	**Strategic conservation** refers to reduction in end-use consumption. There are net reductions in both peak demand (depending on coincidence factor) and total energy consumption.	End-use efficiency.
Load Building 	**Strategic load growth** consists of an increase in overall sales. The net effect is an increase in both peak demand and total energy consumption.	Increased energy intensity and/or the addition of new customers.
Flexible Load Shape	**Flexible load shape** refers to variations in reliability or quality of service. Instead of influencing load shape on permanent basis, the utility has the option to interrupt loads when necessary. There may be a net reduction in peak demand and little if any change in total energy consumption.	Interruptible and curtailable rates.

is proposed for Indonesia which does not rely on the outputs of an IRP evaluation for the following reasons:

- Load growth is so rapid in Indonesia that all potential means of providing electric services must be considered as quickly as possible.

- There is no experience with DSM in Indonesia or in similar countries which could be used as input to an IRP evaluation. The only way to accurately evaluate DSM within an IRP framework for Indonesia is to first conduct pilot programs which will provide information on the costs and benefits of DSM programs. IRP can be carried out as the results of initial DSM programs become available.

- Since no DSM programs have been conducted in Indonesia, the most promising efficiency opportunities have yet to be tapped. DSM will undoubtedly be part of any least-cost plan for the country; the key is identifying the most cost-effective programs. IRP will provide a framework to assess DSM programs as they are implemented.

In the near term, the results of the pilot DSM programs can be used to conduct the IRP analysis. In the longer term, IRP can optimize the selection and mix of DSM programs and supply-side options. DSM and IRP should proceed in parallel, the results of one feeding into the other. For example, once there are some successful DSM programs, resistance to IRP may diminish as demand-side resources are shown to be real. Conversely, IRP can create a policy and regulatory framework which legitimizes DSM.

DSM program design and implementation follow several steps described below. These steps are typically conducted iteratively, e.g. the results of the pilot program may suggest changes to the program design, and the results of the program evaluation may guide the formulation of objectives for subsequent DSM programs. These activities presuppose that an institutional environment conducive to DSM implementation has already been established.

1. **Select appropriate DSM objectives.** Based on utility requirements, load shape objectives (as described in the preceding section) should be established for the utility as a whole as well as for each target customer class or market segment. These objectives will guide program design and facilitate evaluation. Specific objectives should be derived from broader objectives regarding, on the primary level, financial performance of the utility, and on a secondary level, specific operational needs of the utility, such as increased system utilization, capacity deferment, or reduced dependency on critical fuels.

2. **Acquire data and identify market segments.** DSM aims to modify consumer behavior. DSM programs must therefore focus on the technologies used by consumers, and must stimulate consumers to act. For instance, even if there were considerable scope for efficiency improvements in residential air conditioners, a sufficient number of residential consumers must use this technology before it is worthwhile to target it. If a sufficient number of consumers in fact use the

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technology, then a DSM program targeting that technology can only be effective if it takes into account consumer considerations regarding technology selection, as well as the actual patterns of use.

DSM program design and marketing must clearly identify the target population and take into account the values, actions, consumption patterns and perceptions of that population. The required data can be acquired through a combination of customer surveys and focus groups, billing data analysis, and load research. In addition, this data can be used to establish a baseline against which net program impacts can be estimated.

3. **Design program.** Based on load shape objectives and the characteristics of each target market segment, various DSM measures can be put forward and evaluated with respect to their technical and economic potential. Technical potential refers to the impact of the measure if it were adopted wherever technically feasible. Economic potential refers to the impact of the measure if it were adopted wherever economically justified (in this case, economically justified from the societal perspective using the Total Resource Cost (TRC) test described in Annex II).

   Measures with promising technical and economic potential can be packaged with delivery strategies and utility and participant incentives to constitute program concepts. The market potential of a program concept can then be assessed. Market potential is generally less than economic potential because of logistical considerations associated with program delivery. Delivery strategies and institutional arrangements are frequently selected to maximize market potential. Pilot programs and administration, tracking, and evaluation plans are then developed for promising program concepts. Other screens of cost-effectiveness may be applied at this time to ensure that adequate incentives for participation exist. This phase should incorporate the following considerations:

   - **Explicit recognition of uncertainty.** DSM in developing countries is relatively new. Consequently there is a great deal of technical, economic, and market uncertainty related to the impact of particular DSM programs. These sources of uncertainty are discussed in Box 1.2. Program design should recognize uncertainty explicitly, and should include measures, such as pilot programs, to reduce the resulting risk and increase the likelihood of program success.

Box 1.2: Types of Uncertainty in DSM Program Design

There are four sources of uncertainty in DSM program design, each of which ultimately reduces the accuracy of estimates of program impacts. Inaccurate estimates of program impacts can lead to the allocation of resources to or design of programs which ultimately prove to be ineffective. Risk reduction strategies can be used, however, to mitigate the potential impacts of this uncertainty in program design.

Technical uncertainty arises due to many contributing factors, predominant among which is the lack of detailed, accurate information on the targeted applications and the variability of operational factors that characterize those applications. For example, suppose we were to attempt to estimate the technical potential of an industrial motive power optimization program which consisted of motor replacements, installation of variable speed drives, power factor correction, line-balancing, use of synthetic lubricants and improved maintenance of conveyors, fans and other driven equipment. Ideally, to accurately estimate savings potential we would like to know the age and size distributions of the existing inventory of motors; their nominal efficiencies; their duty cycles (in terms of hours of operation, fixed versus variable speed/torque operation, part-load performance, etc.). We might also want to know something about current maintenance practices, and the ability to affect savings by modifying driven equipment (e.g., trimming pump impellers). All of these variables represent a distribution of values; and in selecting point estimates to reflect "average" or "typical" values to perform our savings analysis, we may or may not choose values that closely approximate their true means, let alone capture their variability.

Economic uncertainty results from the variability or lack of understanding regarding factors which determine the financial attractiveness of participation in DSM programs. For example, discount rates may vary widely among market segments, so that measures that appear attractive to some consumers do not appear worthwhile to others.

Market uncertainty results from the range of potential consumer responses to DSM programs. Knowing the technical impact of a DSM measure among all consumers for whom it would be economically attractive to participate is insufficient to accurately estimate program impacts. For instance, it may take time for consumers to find out about or understand DSM programs. Or, only limited resources may be available for program delivery, so that not all consumers who wish to participate can. Such factors can slow the market penetration or consumer acceptance of DSM programs.

Uncertainty regarding the persistence of measures may be thought of as the temporal dimension uncertainty. Adoption of a measure does not ensure its consistent use. There is no assurance that a consumer will not revert to prior consumption patterns when a program expires or a piece of high efficiency equipment is replaced.

Since each of these factors influence savings potential with different degrees of importance, the value of having more detailed or accurate information on each can be correspondingly higher or lower. Decision analysis techniques allow one to assess the value of additional information; pilot programs provide the opportunity to collect it.

- **Attention to the institutional environment.** DSM program planning and implementation requires the involvement and commitment of a broad range of

groups, including regulatory bodies, utilities, trade allies, and consumers. Each of these groups must have the capabilities and incentives to implement their portion of a given DSM program if it is to be successful. With respect to incentives, regulatory bodies must ensure that the least-cost plan should be the most profitable plan from the standpoint of each party. The savings generated by program implementation must be distributed in some way among all groups to ensure their participation and support.

4. **Conduct pilot programs.** If technical and economic potential and market penetration of DSM measures were known with certainty, there would be no risk associated with DSM program implementation. Utilities would be informed on program impacts and could compare the value of these impacts to the cost of the program, prior to implementation, to determine its cost-effectiveness. However, as pointed out in Box 1.2, these parameters are quite uncertain.

   Risk reduction strategies aim to decrease the variance of the prior probability distributions of technical, economic, and market parameters. Risk may be reduced by acquiring further information about key parameters, which may decrease the uncertainty associated with these parameters. Pilot programs are effective in gaining further information when needed; in effect, they serve as additional market research. Pilot programs do not remove all uncertainty, but decision analysis techniques can identify the most sensitive parameters and suggest the maximum amount one should be willing to pay to gain even imperfect information. These "value of information" assessments are an important part of pilot program design.

   Pilot programs include not only the implementation of a program on a limited basis, but the means of monitoring and evaluating performance of the pilot program as well. Pilot programs typically involve additional load research, customer surveys, and billing data analysis to facilitate evaluation and yield the additional information originally sought.

   Pilot programs also provide an important demonstration function. Successful pilots can convince utilities, regulatory bodies, and consumers alike of the effectiveness and value of DSM programs under consideration.

5. **Implement full scale programs.** Based on the evaluation of pilot programs, it is possible to re-design the program to make it more cost-effective. As with pilot programs, full scale programs include marketing, monitoring and administration along with the actual delivery of various DSM measures. Programs can be implemented by utilities alone, although it is common to have the participation of private sector contractors, ESCOs, or trade allies.

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6. **Evaluate programs.** If DSM programs are to be utilized as true utility resources which defer conventional capacity and reduce generation, program impacts must be quantified in terms of energy and demand savings. Evaluation is also critical to establish the exact level of incentives for program implementation or participation. *Impact evaluation* determines the change in energy consumption patterns as a result of the program. *Process evaluation*, on the other hand, examines the way in which programs are marketed and delivered to determine how programs may be improved. *Market evaluation* is sometimes distinguished from process evaluation as a specific assessment of why consumers choose to participate or not in a particular program, leading to a re-estimation of the program market potential and impacts, and program design and marketing techniques.

   Program evaluation also provides an important feedback, or course correction activity. It should include on-going monitoring and program tracking to suggest adjustments to components as well as to verify program impacts.

The interaction of steps is depicted in Figure 1.1.

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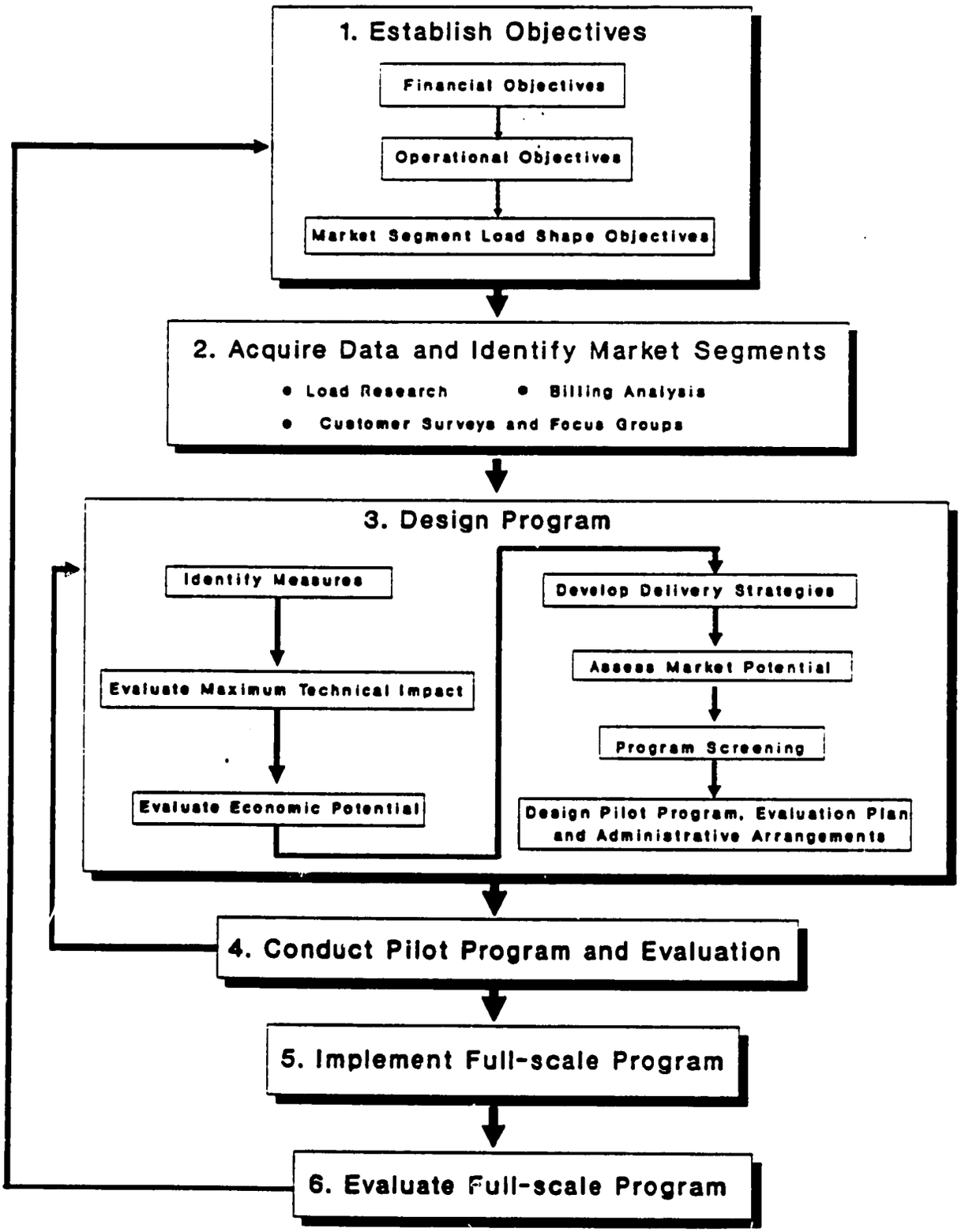
Figure 1.1
The Framework for DSM Program Design and Implementation



CHAPTER II: DSM OBJECTIVES FOR THE JAVA-BALI SYSTEM

The Composition of Electricity Demand on the Java-Bali System

In the absence of rigorous load research, end-use load curves for the principal sectors and end-uses have been estimated based on the disaggregation of total sales by tariff class, knowledge of Indonesian consumption patterns, and experience in other countries. One of the first activities of a DSM development program would be to carry out load research and collect data that would help to better determine the composition of electricity demand by end-use in the Java-Bali system. A power demand analysis project has recently been initiated with funding from the Asian Development Bank (ADB). This study should improve the results give below, and help identify the most promising areas for DSM intervention.

The following sectors and end-uses have been included in the analysis:

Sector/Subsectors	Tariff Classes	End-Uses
Industrial	I-1, I-2, I-3, I-4	▸ Motors ▸ Lighting ▸ Other
Commercial		
Hotel	I-1/H, I-2/H, I-3/H	▸ Lighting ▸ HVAC ▸ Residual
Office	Office and Retail based on U-1, U-2, U-3, U-4 together	▸ Lighting ▸ HVAC ▸ Residual
Retail		▸ Lighting ▸ HVAC ▸ Residual
Public	S-1*, S-2, S-3, G-1, G-2, J	▸ Building Lighting ▸ HVAC ▸ Street Lighting ▸ Residual
Residential	R-1, R-2, R-3, R-4	▸ Lighting ▸ Refrigerator ▸ Television ▸ Residual

* The S-1 class includes some low income/low consumption residential users.

Energy consumption data by tariff class for 1989/90 was used to estimate sectoral consumption. End-use consumption shares within each sector were estimated from work already carried out in Indonesia, or were derived from other countries using the sources listed in the bibliography. This analysis is discussed further in Annex III. For each end-use, total consumption was apportioned by hour based on known consumer behavior in Indonesia. Therefore, these load curves represent *average* daily load profiles at 1989/90 consumption levels.

The end-use load curves generated for each sector are shown in Figure 2.1. "Total estimated" is the sum of estimated end-use load curves; "measured total" is the total average sectoral load curve estimated by the Indonesian utility, Perusahaan Umum Listrik Negara (PLN). Differences between the total estimated and measured total load curves may be a result of errors in the end-use models used here as well different definitions of the consumers belonging to each customer class. For example, as noted on the preceding page, PLN considers hotels as part of the industrial tariff category, and not the commercial category as assumed here.

As shown in Figure 2.2, these calculated load curves correspond well to the actual 1989/90 peak day system load curve, as well as to sectoral load curves estimated independently by PLN. This correspondence validates the approach used.

Load Shape Objectives for the Java-Bali System

During the 1980's, the power sector of Indonesia expanded rapidly. PLN quadrupled in size; sales grew from 4.3 TWh in 1978/79 to 27.7 TWh in 1990/91 and installed capacity increased from 2.3 GW to 9.3 GW. The number of customers grew from 1.8 million to around 11 million. Java still represents most of PLN's sales (about 78% of total consumption in 1988/89).

Despite PLN's efforts, Indonesia's current electrification ratio of under 28% is low by regional standards. PLN is only able to serve a little more than half of urban households and about one in seven rural households, whereas it is estimated that at least three-quarters of urban households and half of those in the rural areas can afford to purchase electricity[1]. Furthermore, energy intensity among users of about 2,300 kWh/yr (about 4,400 kWh year including industrial captive power) is relatively low when compared to other developing countries with similar income levels as shown in Table 2.1. The extensive use of captive generation in industry, which is generally more costly than grid-supplied electricity, is in itself the most tangible evidence of the inadequacy of current supply. In 1990/91 there was

[1] Indonesia Power Sector Institutional Development Review, World Bank, Rep. No. 7927-IND, December, 1989.

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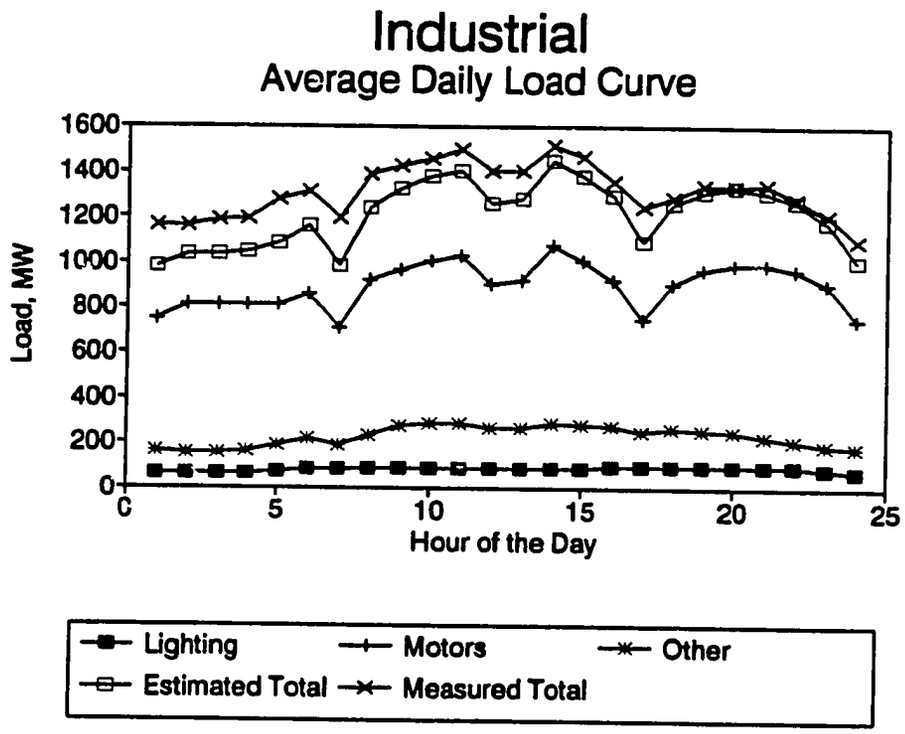
Figure 2.1: End-Use Load Curves by Sector



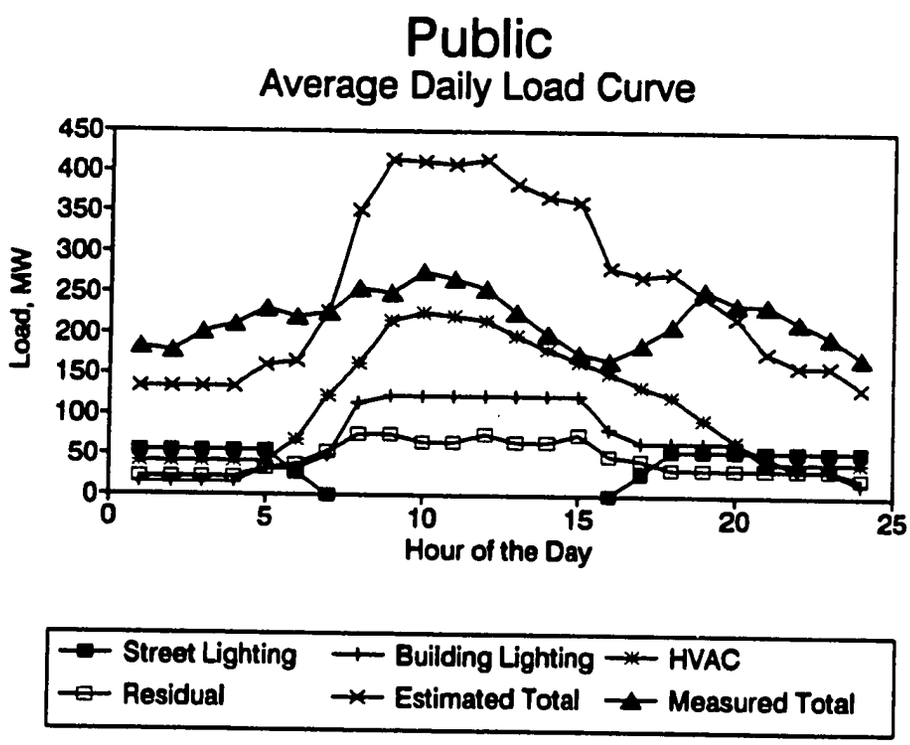
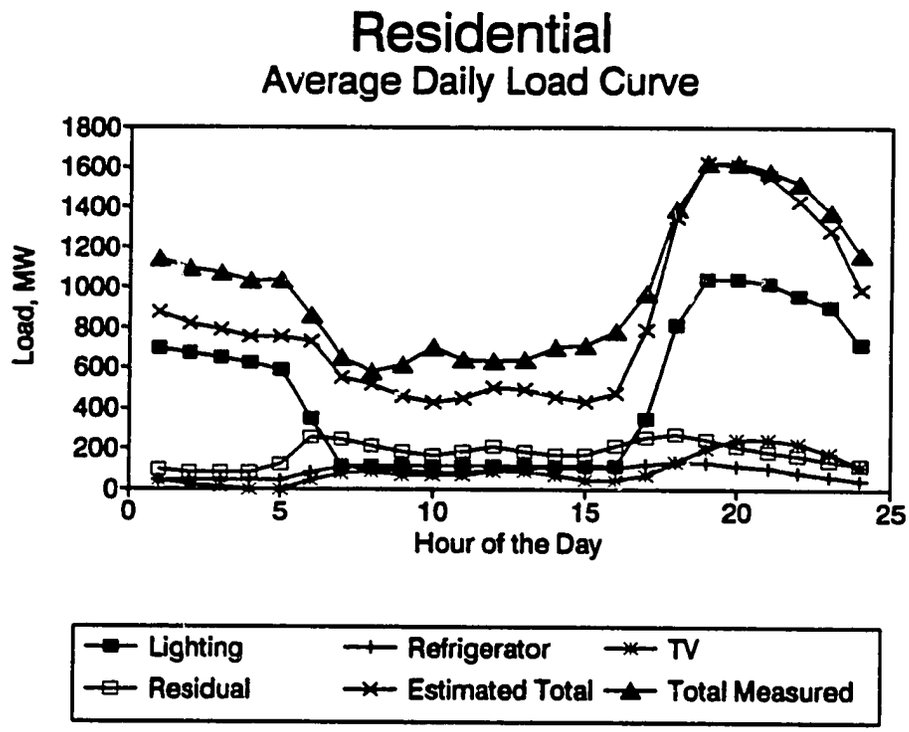


Fig. 2.1: End-Use Load Curves by Sector (contd)



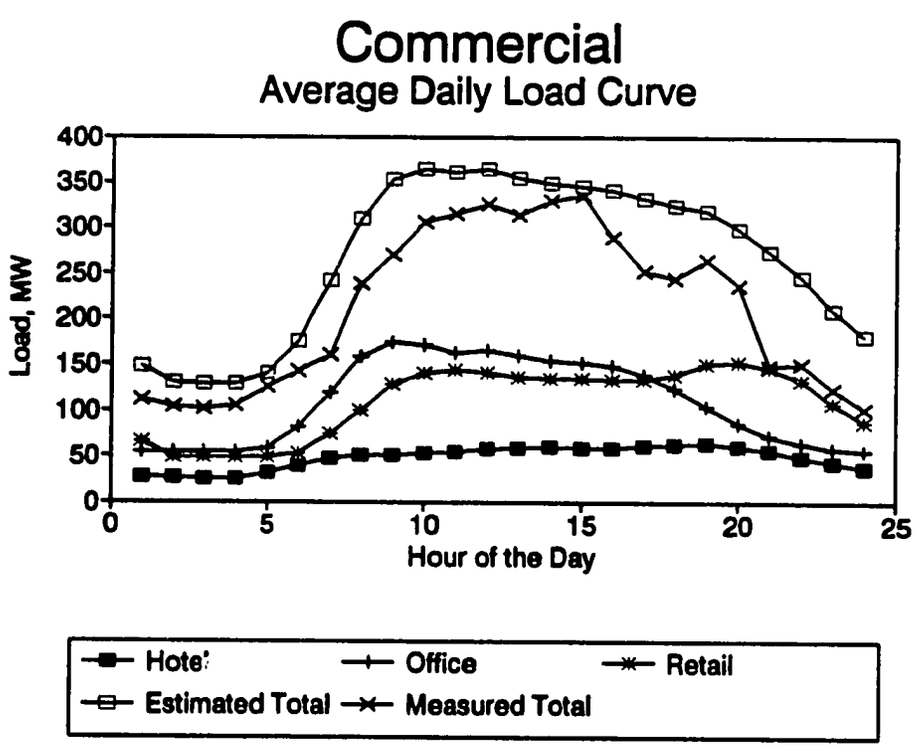
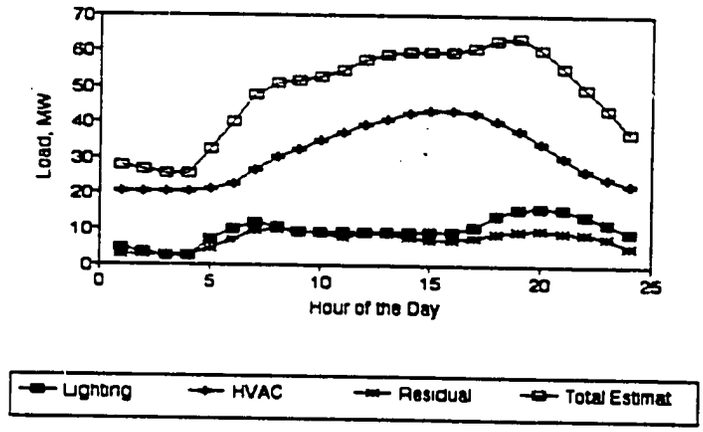


Fig. 2.1: End-Use Load Curves by Sector (contd)

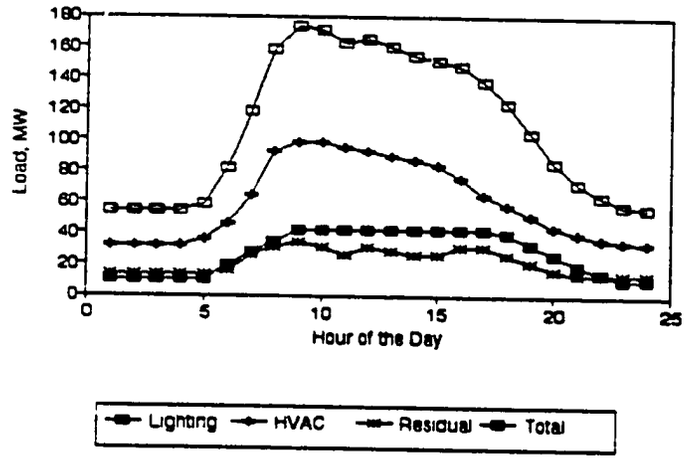
Hotels

Average Daily Load Curve



Offices

Average Daily Load Curve



Retail

Average Daily Load Curve

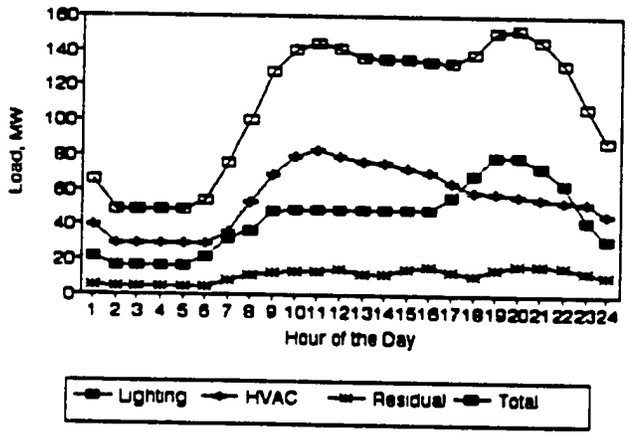
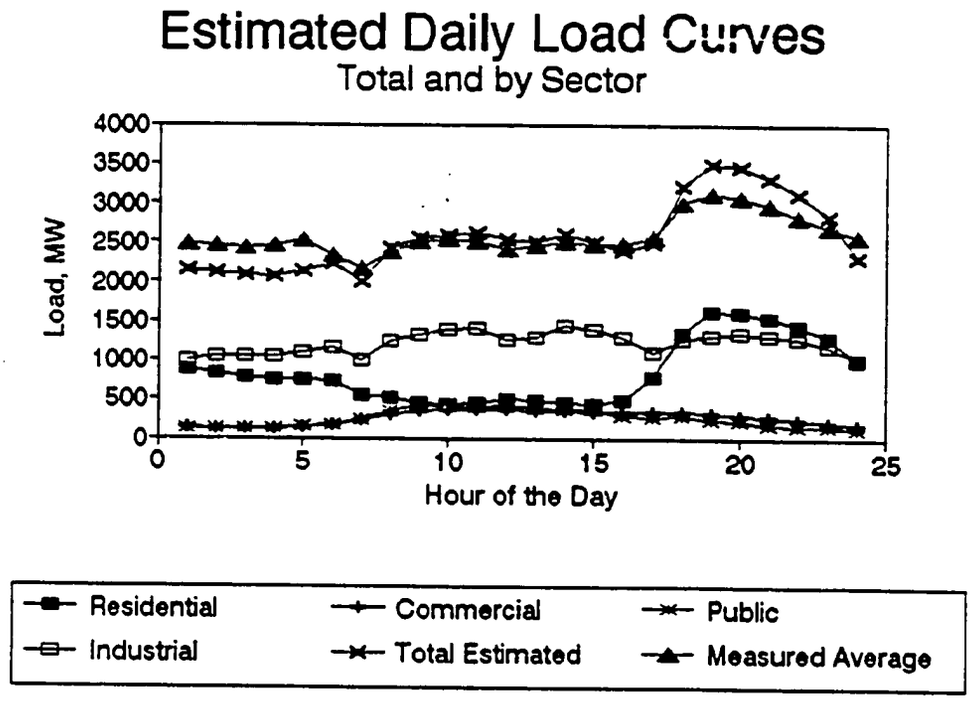


Figure 2.2: Sectoral and System Load Curves



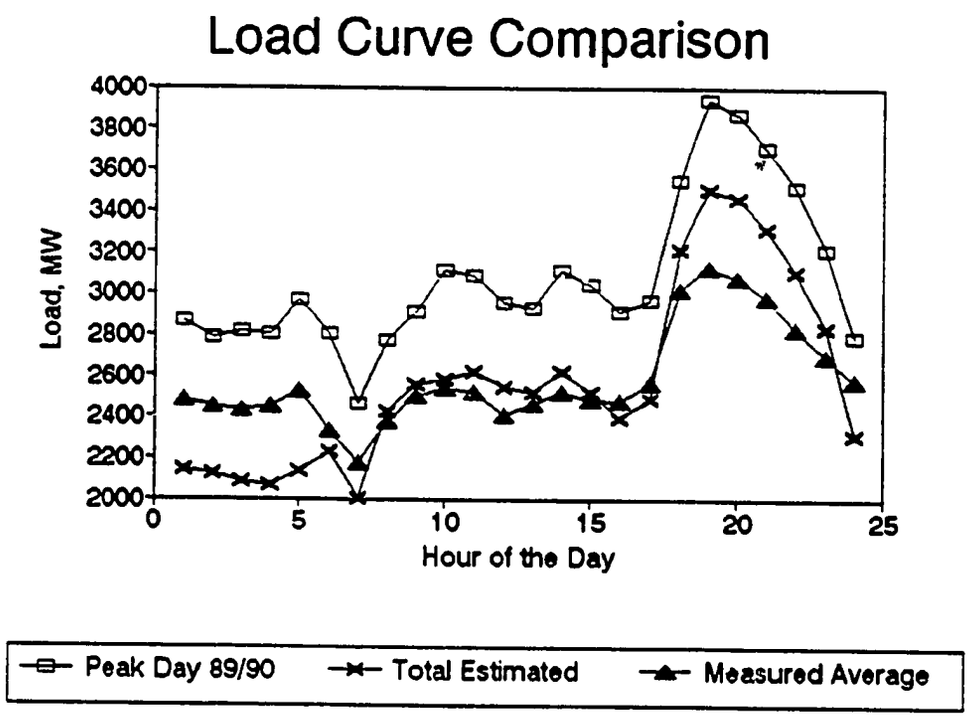


Table 2.1: Comparative Energy Intensities

	Indonesia (1989/90)	Thailand (1990)	Malaysia (1987)	Philippines (1987)
Number of Customers	10,317,000	7,248,504	2,701,270	4,510,257
Total Sales (GWh)	23,435 (45,335)*	39,368	13,715	30,247
Intensity (KWh per Consumer)	2,271 (4,394)*	5,431	5,077	6,706

* Figures in parentheses include 5 GW of captive generation operating at 50% capacity factor.

approximately 3.2 GW of captive generation on Java, and about 3.7 GW outside of Java. Only about 2 GW of the total installed captive generation is used for standby power; the rest is used on a regular basis.

These observations indicate that both the number of consumers as well as energy intensity per consumer will continue to grow at a high rate in Indonesia. This will result in rapid growth in both total consumption and peak demand. PLN is responding to this continued demand growth with an aggressive expansion plan which includes 5,800 MW of committed capacity additions over the coming decade. Table 2.2 lists these projects and expected commissioning dates.

Clearly, with such high levels of load growth (12% on Java and 13% off Java; if supply could keep pace, demand growth would likely be far higher), both peak clipping and strategic conservation are needed for Indonesia. An IRP evaluation is unnecessary to reach this conclusion (although it can optimize over time the mix of supply- and demand-side resources needed to respond to this situation). Furthermore, these high growth rates are expected across all sectors: between 1992/93 and 2000/01, residential demand is expected to grow at 9.1% annually, commercial and service demand at 13.3%, and industrial demand at 13.2%. Because both potential capacity deferral and energy reduction benefits are so great, peak clipping and strategic conservation should be pursued vigorously in all sectors, wherever it is cost effective.

This conclusion is also confirmed in the companion report to this study, "Electricity Pricing Incentives to Promote Demand Side Management in Indonesia". Based upon discussions

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with PLN staff, that report identifies the potential inability to meet peak load in the near- and mid-term as the most pressing problem facing the Java-Bali system. This situation translates into a DSM objective of peak shaving for the four hours that define the evening system peak.

Subsequent sections of this report evaluate the impacts of future DSM programs on demand. It is assumed that total and sectoral load curves retain their current general form, but that the overall level of consumption and peak demands grow at the sectoral rates estimated by PLN on a year-by-year basis. This assumption is validated by a review of average load curves from past years which is also presented in the companion report to this study.

Nonetheless, growing economic prosperity and urbanization may eventually affect the system load curve. Although the entire Java-Bali system peaks in the evening, a pattern of daytime peaks is beginning to emerge in the Jakarta area. This trend may portend a possible shift in the system peak as air conditioning, refrigeration, industrial process, and motor drive loads increase relative to lighting loads in all sectors. Load research and other survey efforts will be critical to determine whether this structural shift in electricity consumption patterns is indeed underway.

Table 2.2: Committed Capacity Additions and Commissioning Dates for the 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

CHAPTER III: THE FOUNDATION FOR DSM PROGRAM IMPLEMENTATION IN INDONESIA

A comprehensive, 8-year DSM program is proposed below for Indonesia to reduce capacity additions and generation. The first phase of the program, the preparation of a DSM Master Plan, entails the creation of an institutional framework for DSM implementation, the collection of necessary data, and the design of specific DSM programs. The second phase consists of pilot programs to help reduce the risk associated with full-scale implementation of the proposed programs, facilitate program improvements before full-scale implementation, and demonstrate the effectiveness of the proposed programs. The third phase covers full-scale implementation and evaluation; it will be guided by the DSM Master Plan and will build upon the experience gained through pilot programs. The scope, costs, and benefits of potential DSM program components are summarized in Section V.

Phase I: The DSM Master Plan - Charting the Course

The Indonesia DSM Master Plan will be prepared over the course of approximately one year[1] and will provide a roadmap for DSM implementation. As proposed in Section I, Indonesia's DSM program should proceed despite the lack of an IRP evaluation, which can be conducted later to optimize the mix of DSM and supply additions. The preparation of the Master Plan will include both institutional development and program design components.

The Current Institutional Setting

Establishing an effective institutional framework will be critical for the success of Indonesia's national DSM program. DSM is a multi-faceted endeavor requiring the active involvement of both the public and private sectors. With the exception of energy service companies (ESCOs) (which can be an important though not essential DSM participant), potential public and private sector DSM participants in Indonesia appear to be sufficiently sophisticated to develop and undertake DSM. The challenge in Indonesia will not be to create new institutions, but to introduce existing institutions to DSM and motivate them to implement DSM programs. The history of energy conservation legislation, the creation of KONEBA, and the relatively rapid introduction of private power generation are three examples which attest to the maturity of energy sector institutions in Indonesia.

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[1] Eighteen months may be a more realistic estimate of the time required for the first phase. Comments provided by the World Bank and others on an earlier version of this report suggest that the duration of the first phase should be extended to account for additional time which may be necessary to implement institutional changes and coordinate DSM activities in Indonesia. However, since increased duration of the first phase changes neither the basic scope of recommended DSM development activities nor the potential benefits of DSM implementation, and because only limited time was available for the revision of this report, the reports retains a nominal estimate of one year for the first phase of the project.

Within the public sector, the active participation of national utilities is key, but coordination must also exist with other governmental agencies responsible for energy planning, electric power, and energy efficiency programs, as well as with agencies with line responsibilities for industry, the buildings sector including housing, equipment standards, and energy efficiency-related research activities. Within the private sector, cooperation will be important on the part of equipment manufacturers, trade and professional associations, and most importantly, consumers. The nascent energy service industry will take on an increasingly important role in implementing DSM programs as incentives and programs are set in place which take advantage of market forces and private sector capabilities.

Indonesia has already made significant progress in energy conservation, both in the area of institutional development and in program implementation. Indonesia launched its first national energy conservation program in early 1980 with a national awareness campaign. In 1982, under Presidential Instruction No. 9, all government ministries and agencies were directed to undertake energy conservation measures. At the end of 1983, the second phase of Indonesia's energy conservation program was initiated with in-depth audits of energy-intensive industries.

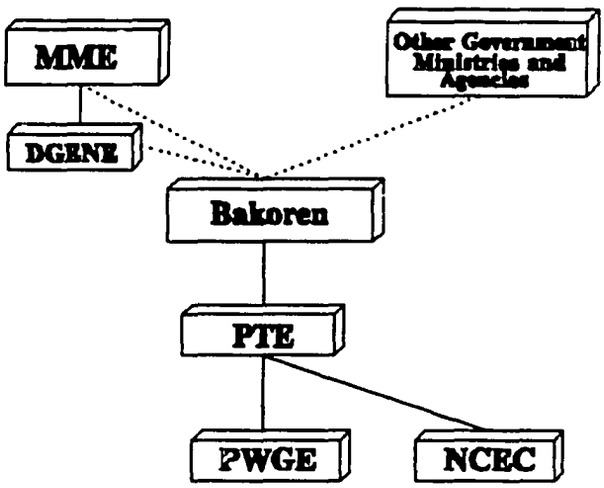
In 1987, with financial assistance from the World Bank, the Government of Indonesia established PT. Konservasi Energi Abadi (KONEBA), Indonesia's National Energy Conservation Company. KONEBA has made significant accomplishments in the past five years, including detailed energy audits of over 30 large industrial facilities, energy conservation planning activities, data base development, training, information dissemination, and the procurement and installation of energy saving equipment. KONEBA was established as a for-profit institution, the first such donor-funded effort in a developing country. By 1990, KONEBA was operating at a profit on a cash-flow basis. More recently, however, KONEBA has been unable to maintain self-financing operation. Nonetheless, it will provide an excellent resource for the design and implementation of a national DSM program. In fact, by becoming the first Indonesian ESCO, KONEBA would have an opportunity to revitalize itself.

In September, 1991, President Soeharto issued a Presidential Decree on Energy Conservation (Decree No. 43), directing that a broad program in energy conservation be undertaken aimed at the efficient use of energy and environmental sustainability. This decree is discussed in further detail in Chapter I.

The evolution of energy conservation regulation in Indonesia has involved several government agencies. The Ministerial Energy Coordination Board (Bakoren)[2] issues general

[2] Bakoren is chaired by the Minister of Mines and Energy, and comprises the Ministers of Public Works, Finance, Industry, Defence, Development Planning, Communications, Research and Technology, Population and Environment, Forestry, Directors General of Atomic Energy, Oil and Gas, and

Figure 3.1: Organization of Government Energy Agencies



policy guidelines on energy matters. The Technical Committee on Energy (PTE)[3] reports to Bakoren and provides an active forum for consideration of energy-related policy and technical issues. The Permanent Working Group on Energy (PWGE) [4] conducts analysis of energy supply and use on a quarterly basis, serves as a forum for exchange of data and information, and prepares technical reports for PTE. In June, 1990, a permanent National Committee on Energy Conservation which also reports to PTE was established with the responsibilities of formulating energy efficiency-related laws, regulations and guidelines, implementing campaigns, and taking other actions to promote energy efficiency. The relationship between these various groups is depicted in Figure 3.1.

Within the Ministry of Mines and Energy, the Directorate General for Electric Power and New Energy (DGENE) has developed substantial capability to conduct energy planning and analysis in electricity, energy conservation and renewable energy. In the late 1980's, DGENE worked with the USAID-funded ASEAN Building Energy Conservation Program to conduct energy audits and surveys. This work has resulted in the preparation of a document, Guidelines for Energy Conservation in New Buildings, which will soon be published by the Department of Public Works. This work could lay the foundation for the subsequent promulgation of a national building energy code.

PLN is also implementing programs to study the impact of improving end-use efficiency, particularly lighting, but these efforts need to be increased substantially in order to provide a foundation for a national DSM program. Within PLN, coordinating mechanisms will need to be set up to integrate the various divisions and subdivisions involved - from tariffs to load forecasting and end-use load research.

Electricity, and the President Director of Pertamina.

[3] PTE members include the Directors General and Directors of the agencies represented in Bakoren.

[4] The Permanent Working Group on Energy consists of energy experts from numerous government institutions.

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Other supporting activities include the World Bank-funded ESMAP Urban Household Energy Strategy Study which examined electricity efficiency opportunities in households, and the World Bank-funded Country Market Study under the FINESSE Program. The Country Study included, among other things, the analysis of a financing scheme on market expansion of efficient fluorescent lamps. In the private sector, Philips is planning the construction of a plant to manufacture compact fluorescent lamps, which should significantly accelerate their penetration into the market.

The above activities, and many others, provide a broad foundation and substantial momentum on which to base a national DSM program. They suggest that the inputs and activities of a wide range of organizations and agencies will need to be coordinated to give maximum impetus to the DSM program. The develop of this institutional framework will be the first task in developing a DSM Master Plan for Indonesia.

Institutional Development Activities

The first steps towards realizing the potential benefits of DSM are to create a supportive regulatory framework and to enhance the capabilities of the government, PLN, and other public and private institutions to plan, implement, evaluate, and sustain DSM programs. This work will further define DSM objectives for Indonesia, as well as the roles of and incentives for relevant agencies or groups. In addition, key utility and government personnel will participate in international training courses, workshops, and study tours to learn first-hand about DSM program design, implementation and evaluation. The following tasks should be carried out as the first activities under the Master Plan preparation:

- **Prepare and issue a DSM policy statement** from the Ministry of Mines and Energy (MME) which spells out the guiding principles for program development and specifies program objectives. This statement would ensure that the DSM program is consistent with broader central planning objectives in Indonesia. It would also delegate institutional responsibilities and establish a DSM Steering Committee.

  The Steering Committee could consist of representatives from PLN, MME, and other members of Bakoren. MME would most likely be represented by DGENE. The Steering Committee could be established as a subcommittee or extension of responsibility of NCEC. It should include representatives from industry, consumers groups, and trade allies --- all groups which will be expected to participate in program implementation. The Steering Committee would draft regulations regarding DSM program design, implementation and evaluation, would assess PLN performance in implementing DSM, and would authorize the award of incentives to PLN. A similar organizational approach has been adopted in Thailand for the design and implementation of DSM activities there.

- **Formulate regulations** regarding DSM implementation, including:
  - mandating the use of integrated resource planning (IRP) at PLN;
  - defining economic screening tests for assessing proposed DSM programs;
  - specifying PLN incentives for DSM implementation, both in terms of cost recovery and bonuses, taking into account the existing planning and operation of PLN. Issues to be considered may include whether PLN's incentives will be based simply on the rate-basing of DSM program costs, or will be based on shared savings;
  - authorizing PLN to offer incentives to customers and trade allies, or conduct mandatory programs involving, for example, direct installation;
  - specifying linkages with building codes and appliance standards; and
  - determine the financial impacts of potential regulations on PLN and consumers.

  Because these regulations will be tailored to the Indonesian institutional setting, they will differ from regulations introduced in other countries. Nonetheless, in order to give an example of the scope and level of detail typically included in regulations, a model IRP law and model regulations from the National Association of State Utility Consumer Advocates (NASUCA) in the United States are given in Annex III.

- **Develop Steering Committee expertise** through courses, workshops, and study tours for Steering Committee members. By learning from the experience of utilities and regulators in other countries who have already implemented DSM programs, the Steering Committee can avoid mistakes made elsewhere and hasten the implementation of DSM in Indonesia.

- **Train trainers** who can work through PLN or private contractors to train installation and marketing staff required for program implementation.

- **Develop indigenous private sector capabilities** to support DSM program installation by identifying competent local firms, and providing them with necessary training, technical assistance and financing.

Subsequent DSM program design and implementation activities will provide valuable opportunities for Indonesian participants from both the public and private sectors to develop the capabilities to sustain and expand DSM activities, and to cultivate a sense of ownership of these activities (which would enhance the effectiveness and benefits of DSM programs).

While program design and implementation activities should maximize the involvement of local public and private sector groups, the involvement of these groups in specific activities will depend in part upon the particular interests and willingness of each group, as well as the agreed allocation of roles among groups. Since these factors are to be determined in the course of program design, the following sections of this report do not specify in detail the involvement in local groups pending the initiation of program design activities.

Program Design Activities

Following the description of DSM program development activities described in Chapter I, program design activities could follow the structure proposed in Figure 3.2. It is anticipated that the Steering Committee would play a key role in each of these program design tasks. This will ensure that the resulting Master Plan is effective, and provides additional training for Steering Committee members.

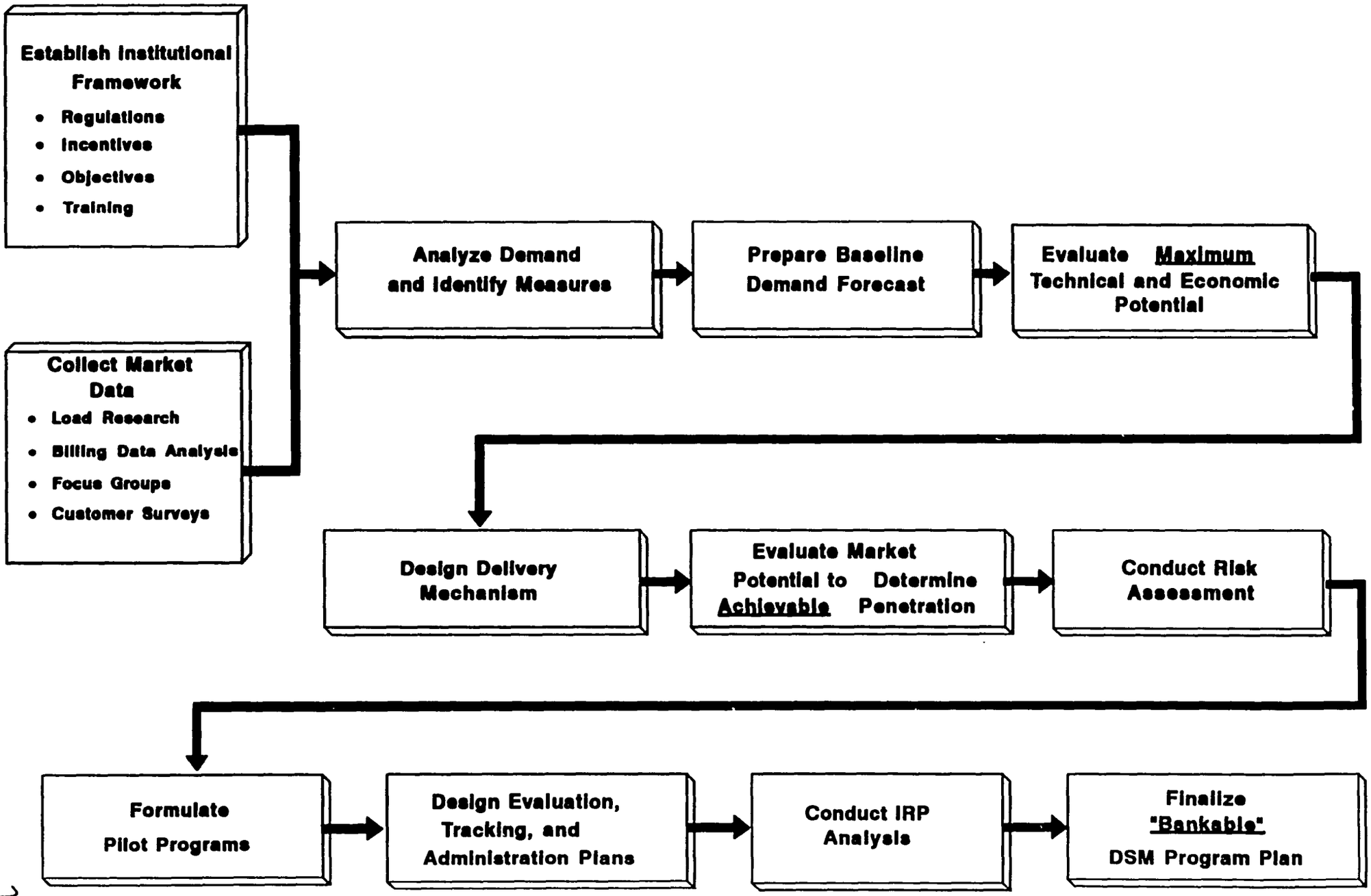
More needs to be known about Indonesian electricity consumers. In addition to a sound regulatory framework, data on consumer behavior, perceptions, and values are required for the identification of promising DSM measures and programs. The results of the ADB-financed Power Demand Analysis Study, the ESMAP Urban Household Energy Strategy Study, and the National Social and Economic Survey (SUSENAS), will be critical inputs to this data collection effort. Further load research, focus groups, analysis of billing data, customer surveys and other market research will be carried out during the early stages of Master Plan preparation to complement data already available. Surveys of end-use equipment stocks and utilization, as well as equipment availability and marketing, would be included in this work. Data collection efforts will be initiated in parallel with the institutional development activities so as to accelerate the completion of the Master Plan.

Because end-use and whole premise load research can be costly, data collection methods will employ advanced techniques to leverage this high quality data with less costly data sources[5]. The data collected during this task will be used to characterize the principal market segments to be targeted by DSM programs.

This data will also improve the disaggregation of current demand by sector and end-use to help identify candidate DSM measures. Because these measures will be implemented over

[5] "Load research" refers to the acquisition of load data over time, typically through the use of load profilers or data loggers, to generate diurnal load profiles for different days of the week or seasons of the year. Load research is often carried out with complementary customer surveys or appliance stock surveys. End-use load research provides load profiles of particular end-use equipment, while whole premise load research entails the acquisition and processing of data regarding a customer's entire load. One way of leveraging load research is to use it to calibrate engineering models, which rely on less costly data derived from sources such as customer surveys.

Figure 3.2: Overview of the DSM Master Plan Preparation



time, expected changes in demand patterns must also be taken into account. Therefore, a baseline demand forecast will be prepared, building upon the analysis of current load. In addition to helping distinguish the most promising DSM measures, this will provide a benchmark against which program impacts can be estimated. These tasks will build upon existing studies, such as the most recent load forecast developed by PLN.

The potential technical impacts of each measure, as well as the maximum amount of economically justified applications, must then be assessed to determine the most promising measures. This will build upon work already carried out in Indonesia by groups such as KONEBA and will involve discussions with Indonesian builders, manufacturers and importers to ensure that subsequent estimates of technical potential are realistic. Estimates of the maximum potential technical and economic impact of each measure will then be used to prioritize measures and furnish an upper bound on potential impacts.

In order to convert economically attractive and technically feasible *potential* into captured *savings*, a comprehensive program delivery strategy must be developed. This strategy must take into account market imperfections and barriers as well as the adequacy of existing institutions and market infrastructure to enable large fractions of this savings potential to be realized.

The design of effective delivery mechanisms is perhaps the most challenging component of the Master Plan preparation. Many of the same implementation issues which pertain to North America and western Europe are also relevant in developing countries --- but more so. Considerations of financing and affordability, for instance, take on greater importance. A compact fluorescent bulb, for example, costs roughly the same in Indonesia as it does in the United States, but Indonesian household income may be less than one-tenth of what it is in the U.S. Direct installation of DSM measures by the utility will likely play a much larger role in Indonesia than it has in other countries.

This task area will develop delivery mechanisms for each program concept to maximize its penetration and likelihood of savings persistence under the *existing* institutional arrangements and market infrastructure. At the same time, initiatives would be identified which over a *longer term* may alter institutions and accelerate DSM implementation. Part of this work will focus on how to bring about the strategic partnerships between consumers, utilities, government and trade allies that are necessary for long term DSM program success.

In the residential sector, for example, direct installation programs for lighting retrofits may be the most effective delivery mechanism to compensate for lack of customer understanding of conservation benefits or their inability to cost-share investment. Over the long term, increased customer awareness or education, or a general rise in affluence may enable other approaches that rely more on incentives or, indeed, may even lead to major changes in market behavior and the technology delivery infrastructure that entirely obviate the need for subsidized DSM.

Measures which offer acceptable technical and economic potential would be bundled with selected delivery mechanisms and institutional arrangements to form the basis of "program concepts". The market potential for each of these program concepts would then be estimated, and the program concepts screened with respect to their economic value and financial attractiveness to each of the parties involved, i.e. the utility, consumers, trade allies, etc. Program concepts would then be prioritized on the basis of the screening results.

There is no DSM experience in Indonesia that can be used to determine the actual impacts of program implementation. Simply applying results from DSM programs in other countries ignores the unique characteristics of Indonesian society and energy consumption patterns. Despite the substantial market research and technical information that will have been compiled by this point of the study, significant technical, economic and market uncertainty will remain. Each element of uncertainty introduces an element of risk to program design in that the program may not achieve its expected results.

An important dimension of the Master Plan is risk assessment of the technical, economic and market uncertainties associated with each program concept. This risk assessment will attempt to both: (a) quantify expected program impacts by explicitly considering the ranges within which technical, economic, and market potential may lie as well as the likelihood of reaching different levels of each; and (b) help to establish priorities for and value of future pilots or other field activities which can reduce risk. Activities such as pilot programs can narrow the uncertainty around the most influential variables and lead to higher precision estimates of savings potential. Once the priorities and value of specific pilot programs have been established, the pilot programs themselves can be designed in detail.

Timely and accurate information on program impacts is likewise required if PLN is to use DSM as a true utility resource. Formal DSM program evaluation activities are critical to measure the savings of DSM programs (impact evaluations) and to identify potential improvements in program delivery (process evaluations). These activities typically entail advanced statistical analysis of consumer surveys and load research. Program evaluation activities will be planned concurrently with the pilot projects. In addition to the periodic impact and process evaluations, the evaluation plan will spell out monitoring and administration mechanisms that will enhance program management on a continuing basis.

As shown in Figure 3.2, the DSM Master Plan will combine the formulation of all the foregoing elements: a supportive institutional framework, appropriate technical measures, effective delivery mechanisms, and pilot and evaluation programs. The technical and institutional assessments upon which the Master Plan will rest ensure that it is *achievable*. Further work is required, though, to mold this Master Plan into a project which is *bankable*. Therefore, program concepts will be evaluated within an integrated resource planning (IRP) framework using both economic and utility financial prices to determine the attractiveness of each component of the Plan. This evaluation will be comprehensive in that it will take into account all program elements simultaneously, so that programs can be compared to each

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other as well as to all supply options currently under consideration by PLN. This analysis will also determine the financial impacts of the proposed DSM program on PLN.

The local and global environmental benefits of the Master Plan will also be calculated as part of this analysis. This environmental analysis framework may serve as the basis for an environmental accounting system for PLN. Priority program concepts will be selected and the Master Plan will then be finalized based on the findings of the IRP analysis. The Master Plan will conclude with the presentation of a proposed program implementation package for financing consideration by multilateral and bilateral funding agencies.

Master Plan Timetable and Budget

The proposed timetable and budget for the Master Plan preparation is based on the following assumptions. This phase of the work is broken down by the tasks shown in Figure 3.3.

1. **Develop institutional framework.** The preparation of a policy statement and regulations would be the first Master Plan tasks and would be carried out over the first few months of the Master Plan preparation. Steering Committee instruction would be on-going, starting as soon as the Steering Committee was convened. Training of trainers would begin later in the project, after specific programs have been designed.

   It is assumed that the staff and office costs of the Steering Committee would be met through an in-kind contribution of the Government. However, external costs would be incurred for three person-months of a DSM regulatory specialist, one person-month of a utility financial analyst, two person-month of a local legal expert, ten study tour/course/workshop trips for Steering Committee members, and two person-months of trainers for preparation of training materials followed by actual instruction. Assuming an average cost of $25,000 per person-month (including travel and per diem), and $4,000 per Steering Committee trip, the total cost of these activities is $240,000.

2. **Collect market data.** Because of the time required to organize and conduct surveys, this task will commence as early as possible in the Master Plan preparation, and will be carried out in parallel with the institutional development activities. The data to be collected includes end-use load profiles by market segment, socio-economic or financial characterization of each market segment, information on equipment stocks (such as age, make, utilization, and efficiency), billing data, and receptivity and responses of consumers from principal market segments to possible DSM strategies. Local organizations with energy data collection experience, such as KONEBA and SUSENAS, will be involved in the design and execution of this activity to the maximum possible extent.

Although this work will be coordinated with the ADB Power Demand Analysis study, it is assumed that considerable primary data collection efforts must be conducted under this project. A local firm or group of firms is expected to be involved in all aspects of this data collection activity. There will be four data collection activities: customer surveys to detail equipment stocks, focus groups to assess customer attitudes, load research to generate load profiles, and billing analysis to complement the load research and customer surveys. For each of these activities there will be subtasks for sample design (1 person-week), survey instrument preparation (2 person-weeks), field testing (except for billing data) (2 weeks of the local enumeration contractor plus a survey specialist), data acquisition (2 months of the local enumeration contractor), and data processing (1 month of the local enumeration contractor). Assuming $25,000 per person-month for individual specialists, $100,000 each for the customer survey enumeration and focus groups, $20,000 for the billing data analysis, and $150,000 for the load research (including monitoring hardware), the total cost of data collection comes to $482,500.

3. **Analyze demand and identify measures.** The data collected in the preceding task will help identify principal market segments, their end-use load profiles, their socio-economic or financial characteristics, and equipment saturation and characteristics. This information can be used in turn to identify candidate DSM measures. It is assumed this task requires three person-months of work plus $25,000 of local contractor assistance, for a total cost of $95,000. It is expected that KONEBA and PLN, which have evaluated and implemented numerous energy efficiency measures in the past, will play a key role in this task.

4. **Prepare baseline demand forecasts.** Building upon the analysis of end-uses in the preceding task, this task will provide a baseline assessment of changes over time for each end-use in the absence of any DSM program. This analysis may incorporate probabilistic evaluation to capture the uncertainty of these demand forecasts. These forecasts will also build upon forecasts already prepared by PLN; it is expected that PLN or their load forecasting contractor will participate in this task. It is assumed this task will require one and one-half person-months plus $10,000 of local contractor assistance, for a cost of $47,500.

5. **Evaluate maximum technical and economic potential.** These evaluations would be carried out by technical specialists in each principal end-use area, with assistance from an economist. Principal areas might include lighting, buildings, industrial processes, motors, and tariff design. Four person-months of expertise are assumed. A local contractor, along with PLN or DGENE staff, would help compile the necessary cost and performance data and carry out the evaluation at a cost of $20,000. The total cost of this task would be $120,000.

6. **Design delivery mechanisms.** Having identified promising measures and customer attitudes, one can begin to formulate program delivery mechanisms. This will entail two person-months of program design expertise, plus $20,000 of local marketing expertise to help tailor the delivery mechanisms to local conditions, for a total cost of $70,000.

7. **Evaluate market potential.** The type of delivery mechanisms which have been proposed will help determine market potential. For example, programs involving direct installation will have a higher market potential than information-only programs. Delivery mechanisms and measures found to have promising technical and economic potential will be bundled into program concepts and screened in terms of economic and financial attractiveness. The market potential evaluation and screening will require one and one-half person-months of expertise at a cost of $37,500. Part of this cost may be applied towards local contractors.

8. **Conduct risk assessment.** The models developed to assess market potential will be modified to incorporate probabilistic assessments of the various parameters which determine market potential. Additional analysis will be conducted to determine the range and likelihood of potential outcomes as well as the value of additional information. One person-month of expertise will be required at a cost of $25,000.

9. **Formulate pilot programs.** Based on the results of the risk assessment, pilot programs will be designed, including monitoring, administration and evaluation. This will require two person-months of a program designer at a cost of $50,000 plus $20,000 for local contractors such as KONEBA with experience in energy efficiency program implementation.

10. **Design evaluation, tracking, and administration plans.** Two person-months of expertise at a cost of $50,000 will be required to establish an evaluation plan and to specify the framework for administration and monitoring of the DSM programs. The agency expected to administer the DSM programs, most likely PLN, will have a key role in this task.

11. **Conduct IRP analysis.** The results of the preceding tasks will be compiled to provide a fully costed DSM implementation program along with the expected impacts of that program. To determine whether this program is indeed least-cost, an IRP analysis will be carried out. As noted earlier, this will provide environmental, economic and financial justifications for the program as a whole. As a result of this evaluation, individual program concepts may require revision. The total cost of this component would be $75,000, corresponding to three person-months of expertise. Staff from PLN and the government will be expected to participate in this activity.

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12. **Finalize "bankable" DSM program plan.** The foregoing elements will be combined into a "bankable" plan that will specify funding requirements, timetables, etc. This plan will be circulated among multilateral and bilateral financing agencies for consideration. Two person-months will be required for this task at a cost of $50,000, plus $10,000 for local contractor assistance.

The Master Plan schedule and budget is shown in Figure 3.3. The total estimated cost of the Master Plan preparation is $1.5 million, including contingency. It is expected that these tasks would be carried out by a core team of consultants residing in Indonesia for the duration of the Master Plan preparation, working closely with local contractors and agencies such as PLN and DGENE. This is similar to the approach taken by the DSM development project in Thailand with funding from the Global Environmental Facility. This team should have experience conducting similar assignments in other countries, and would define and execute the individual tasks in consultation with the Steering Committee. Because of the breadth of expertise required, core team expertise would be supplemented by short-term visits of experts specializing in particular aspects of individual tasks.

The Government of Indonesia would provide in-kind contributions to the Master Plan preparation, such as the salaries of the Steering Committee and support staff, office space, etc. These in-kind contributions are not reflected in the attached budget. By involving government and PLN staff in each step of the Master Plan preparation, this phase will provide a unique hands-on training opportunity.

Phase II: Pilot Programs - Reducing Uncertainty

Proposed Pilot Program Activities

The Master Plan will specify pilot programs to be conducted during the second year of the program. These programs will carried out either by PLN or a contractor such as KONEBA, under the auspices of the Steering Committee. Although this phase will include technology demonstration, it will serve as a miniature version of the full-scale program to confirm judgements about the obstacles, costs, and benefits of implementing specific DSM programs. Pilot programs may be clustered on a regional basis to reduce costs, or to target certain markets.

This phase of the program will include the following tasks for each of the pilot programs specified in the Master Plan:

- Selection of a sample from each target market segment for participation in the pilot program;
- Marketing of the pilot program to the selected sample of consumers;

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Figure 3.3: Budget and Timetable for Preparation of the DSM Master Plan

Task	Budget	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12
1. Institutional Development													
Prepare Policy Statement	$25,000												
Formulate Regulations	$125,000												
Develop Steering Comm. Expertise	$40,000												
Train Trainers	$50,000												
2. Collect Market Data	$482,500												
3. Analyze Demand & Identify Measures	$95,000												
4. Prepare Baseline Demand Forecasts	$47,500												
5. Evaluate Technical & Econ. Potential	$120,000												
6. Design Delivery Mechanisms	$70,000												
7. Evaluate Market Potential	$37,500												
8. Conduct Risk Assessment	$25,000												
9. Formulate Pilot Programs	$70,000												
10. Design Evaluation, Tracking, and Administration Plans	$50,000												
11. Conduct IRP Analysis	$75,000												
11. Finalize "Bankable" DSM Program	$60,000												
Contingency	$127,500												
Total	$1,500,000												

- Implementation of a management information system (MIS) to track pilot installations;
- Installation of the measures for participating customers;
- Impact and process evaluations at the conclusion of the pilot programs; and
- Revision, if necessary, of the program design and delivery strategy for full-scale implementation.

To prepare a preliminary estimate of the scope and cost of pilot programs, it is assumed that pilot programs will be proposed for the following sectors and end-uses. These programs have been selected on the basis of the analysis of system load and DSM objectives described in the preceding chapter, as well as experience in other countries. This program list only illustrates the types of programs that may be considered; a final determination will be made on the basis of the Master Plan:

<u>Industrial Programs</u>
Improved Motors
High Efficiency Lighting
Time of Use (TOU) Tariffs
Interruptible and Curtailable (I&C) Tariffs
Energy Management Audits

<u>Commercial and Public Sector Programs</u>
Improved Air Conditioning
High Efficiency Lighting
New Construction

<u>Residential Programs</u>
Improved Refrigerators
High Efficiency Lighting

Pilot Program Timetable and Budget

The timetable and budget for the pilot program phase is based on the following tasks and assumptions:

1. **Implement Administration System.** An administration system based on the specifications spelled out in the Master Plan will first be implemented. This task will include establishing the organizational structure for DSM activities and a computer-

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based management information system (MIS). The MIS facilitates marketing, financial reporting, and retention of the data necessary for performance monitoring, evaluation, and redesign. It is assumed that additional computer resources must be procured, and that five person-months are required for MIS design and installation for a total cost of $200,000.

2. **Procure Load Management and Efficiency Hardware.** A number of the proposed measures utilize load management or high efficiency hardware to accomplish DSM objectives. PLN (or the designated local contractor) will purchase the hardware required for programs which rely on direct installation for delivery. In addition, the availability of hardware for rebate programs must be guaranteed. One way of doing so, at least at the pilot stage, is for PLN to purchase the necessary equipment itself and resell it directly to customers. This will not only ensure availability, but will demonstrate the market for this equipment so that retailers, importers, and manufacturers would be more favorably disposed to introducing these new products. It may even be possible for PLN to work directly with manufacturers or importers to develop high efficiency equipment, as is being done by EGAT in Thailand with refrigerator manufacturers, as well as by several utilities in the United States. Pilot program hardware cost assumptions are given in Table 3.1. The number of installations or participants will vary by program. Using the equipment unit costs given in Annex IV, the implied sample size for each pilot program can be derived.

3. **Hire Marketing and Installation Staff.** Whether utility personnel or contractors are used, qualified staff must be identified and hired. It is assumed this hiring process costs $25,000 to cover the preparation of job descriptions, advertising and interviewing.

4. **Train Marketing and Installation Staff.** Once staff have been hired, they must be trained by those who received instruction during the master plan preparation. It is assumed that 50 local marketing and installation staff are retained at a cost of $1,000 per staff member per month and that training requires one month. The total cost of the activity is therefore $50,000 (the cost of trainers is an in-kind contribution of the Government).

5. **Market Program and Select Participants.** Program marketing and selection of pilot program participants is assumed to require three months. Marketing will rely principally on personal contact with consumers. Only marketing staff, who are assumed to represent half of the new staff, are involved. Additional promotional expenses are also incurred. The resulting cost is $100,000.

6. **Install Measures.** Installation of the measures is assumed to take place over three months and involves all installation staff on a full time basis, for a total cost of

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Table 3.1: Hardware Cost Assumptions for the Pilot Programs

Programs	Equipment to be Procured	Cost
Industrial Programs		
Improved Motors	High efficiency motors & VSDs	$150,000
High Efficiency Lighting	Improved lamps, reflectors, ballasts, and occ. sensors	$30,000
TOU Tariffs	TOU meters	$40,000
I&C Tariffs	Load control equipment	$50,000
Energy Management Audits	Analyzers and monitors	$75,000
Commercial & Public Programs		
Improved Air Conditioning	Resized pumps, compressors, motors; Improved controls	$150,000
High Efficiency Lighting	Improved lamps, reflectors, ballasts, and ccc. sensors	$25,000
New Construction	Hardware & software for design evaluation; improved equipment and materials	$75,000
Residential Programs		
Improved Refrigerators	High efficiency refrigerators	$50,000
High Efficiency Lighting	Improved lamps, reflectors, ballasts, and occ. sensors	$20,000
New Construction	Hardware & software for design evaluation; improved equipment and materials	$40,000
Additional monitoring equipment	Load monitors and other data collection instruments such as surveys	$100,000

$100,000 (which includes $25,000 for tools, transportation, and other direct costs).

7. **Evaluate Pilot Programs.** Installers and marketing personnel (since they have already had extensive contact with these customers) will return to the sites to collect the technical and consumer information required for evaluation. The evaluation itself will be conducted by PLN staff, under the supervision of the Steering Committee. This task will require one and one-half months of the installation and marketing staff, for a total cost of $100,000 (which includes $25,000 for other direct costs besides labor).

It is assumed that two consultants would serve as resident advisors to assist PLN and/or the local contractor(s) with the management and execution of all aspects of the pilot program over the course of the year. The cost of these advisors would be $600,000. These advisors would assist with the preparation of the final plan for full-scale implementation.

Figure 3.4 summarizes the timing and budget for these activities. The total cost of the pilot program amounts to $2.2 million, including contingency.

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Figure 3.4: Budget and Timetable for DSM Pilot Programs

Task	Budget	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12
1. Implement Administration System	$200,000												
2. Procure Load Management and Efficiency Hardware	$805,000												
3. Hire Marketing & Installation Staff	$25,000												
4. Train Marketing & Installation Staff	$50,000												
5. Market Programs and Select Participants	$100,000												
6. Install Measures	$100,000												
7. Evaluate Pilot Programs	$100,000												
8. Prepare Plan for Full–Scale Implementation													
Consulting Advisors (2 person–years)	$600,000												
Contingency	$220,000												
Total	$2,200,000												

Phase III: Implementation - Capturing the Benefits

Implementation of the programs will be carried out during years three through eight. Based on the results of the pilot programs, implementation will including the following tasks:

- Program marketing;
- Improvement and expansion of the MIS for tracking installations;
- Installation of the measures;
- On-going tracking of performance of the programs included under the program;
- Periodic impact and process evaluations of the programs; and
- Revision of the load shape objectives or program designs, as appropriate.

The costs and benefits of full-scale implementation are discussed in the following sections. Although these costs and benefits can be estimated more accurately as the first two phases of the project proceed, this analysis provides a "best guess" evaluation of full-scale implementation.

CHAPTER IV: POTENTIAL DSM PROGRAMS

The purpose of the Master Plan is to define candidate DSM programs and their associated costs and benefits for Indonesia. Nonetheless, based on experience in other countries and an understanding of the structure of electricity demand in Indonesia, preliminary programs are described below as a starting point for further discussion.

This section provides provisional estimates of potential benefits and costs of implementation, as well as the funding required for the implementation of likely programs. These estimates are used in Section V to determine the economic justification for an comprehensive DSM program in Indonesia. Estimates of program costs and impacts will change as programs take shape and further information is obtained during the preceding phases. Detailed technical, economic, and market assumptions for each measure are presented in Annex IV[1].

In general, the programs presented here incorporate aggressive delivery mechanisms. Extensive contact with consumers is assumed. The lack of existing market mechanisms, insufficient channels for information dissemination, and inadequate access to capital necessitates assertive program delivery. Direct installation is expected to be common, which should result in higher market potential and more rapid market penetration. The additional cost of these delivery mechanisms is reflected in both the administrative markups used in Annex IV, and are included in the program budget described in this section.

Industrial Sector Programs

The industrial sector is the largest single energy consuming sector in Indonesia, accounting for approximately 46% of PLN's electric sales. If PLN were to absorb the roughly 6,900 MW of privately-owned captive generation, this share would grow substantially. As in many countries, the industrial sector in Indonesia offers some of the largest and most immediate DSM benefits.

I.1 Improved Motors

It is assumed that motors account for about three-quarters of total industrial consumption, as discussed in Annex IV. Given this high share of consumption and the potential for industrial motor improvements, motor programs should receive high priority in Indonesia.

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[1] Annex III uses the Total Resource Cost (TRC) test to estimate economic potential. It is assumed that as long as a measure passes that test, some mix of utility, consumer, and trade ally incentives can be used to make the measure attractive to all. Costs given throughout this section, on the other hand, represent utility costs of implementation, unless otherwise specified. These costs are used to estimate the financing required for program implementation.

Program Design

High efficiency motors and variable speed drives (VSDs) can cost-effectively improve industrial energy efficiency. Annex IV describes these technology options in further detail.

Most industrial motor programs underway in other countries offer rebates that offset the additional cost of purchasing a high efficiency motor or a variable speed drive. This program will also offer rebates, but will be distinguished by personal marketing efforts directed at plant managers and others responsible for motor replacement.

Identifying good industrial candidates is an important part of program implementation. Some utilities, such as the Companhia Energetica de Sao Paulo (Brazil) (CESP), are developing extensive databases of industrial motor installations within their service territory. The CESP database, for example, is part of an expert system which determines which customers need to exchange motors with others so that everyone has an optimally sized motor.

Regardless of how potential industrial customers are identified, either PLN staff or a contractor will visit plant sites and "sell" motor replacements. These visits can, of course, be preceded by mail or telephone announcements, and will entail simple audits to determine whether the motor is optimally sized and the type of motor that may be most appropriate. The program representatives could work at least partially on a commission basis.

Given industrial growth in Indonesia, new purchases rather than retrofits will provide the predominant opportunity for use of improved motors. Consequently, motor importers and manufacturers will serve as important trade allies in this program. PLN must involve these trade allies early on, starting with the Master Plan preparation, to ensure their maximum participation.

Potential Impacts

Based on the analysis in Annex IV, the cumulative impacts of an industrial motor program are shown in Table 4.1. The estimated impacts reflect relatively low penetration rates, which are consistent with experience elsewhere.

Program Budget

Although probably more than three-quarters of motors in Indonesia are less than 5 kW, motor programs will target larger motors. If it is assumed that the average motor replaced under the program is 30 kW with a coincidence factor of 0.6, the impacts described in Table 4.1 imply that over 500 high efficiency motors and VSDs are installed over the first two years of the program (an average of about 21 per month), approximately 1,400 over the next two years (an average of about 60 per month), and about 8,400 over the last two years (an average of 350 per month). As discussed in Annex IV, much of this volume would be for

new purchases rather than retrofits. Consequently, involvement of trade allies will be critical.

Table 4.1: Industrial Motor Programs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	7	26	138
% of Sector Consmptn.	0.0%	0.1%	0.3%
Peak Reduction (MW)	1	3	17
% of Sector Demand	0.0%	0.1%	0.3%

Whereas improved motors used in the pilot phase would have been purchased outright by PLN to ensure availability to program participants, it is expected that PLN would pay a rebate that would cover only the difference in cost between a conventional and improved motor. Assuming an average rebate of $300 (reflecting the typical size of the motors involved and the fact that 25% would be more costly VSDs; see Annex IV for further cost assumptions), the total rebate cost over all six years of full-scale implementation would be $3.1 million. In addition, assuming ten dedicated staff over the first two years, 15 over the next two and 20 over the last two, manpower costs would total $1.1 million (given a labor cost of $1,000 per person-month). The total cost for industrial motor programs over the six years of the program is $4.2 million.

I.2 High Efficiency Lighting

Although lighting is assumed to account for only 7% of industrial demand, savings can reach 75% depending on the technologies used. This technical potential, as well as the relatively high program penetration rates achieved in other countries, make lighting programs far more important than lighting's share of sectoral consumption might suggest.

Program Design

The following measures are suggested for consideration:

(a) replacing incandescent bulbs with compact fluorescent lamps (CFL);

(b) replacing standard fluorescent tube lamps with energy-saving fluorescent tube lamps;

(c) replacing standard fluorescent ballasts with high-efficiency magnetic or electronic ballasts;

(d) installing optical reflectors and removing lamps that are no longer required;

(e) installing occupancy sensors; and

(f) replacing mercury vapor high intensity discharge (HID) lamps with sodium HID lamps.

Although direct installation typically achieves the highest penetration rates, the additional costs of administering a direct installation program make many of the above measures uneconomical if that delivery mechanism were to be used. Annex IV presents the economic analysis of these measures, which suggests that only measures (a) and (f) would be delivered through direct installation programs, while the other measures would rely on information and rebates for delivery. New building standards would also be an important part of ensuring that these measures are adopted.

Potential Impacts

Table 4.2 indicates the cumulative energy and peak demand impacts of the industrial lighting programs outlined above. Although lighting accounts for a smaller portion of industrial load than motors, program impacts exceed those of the motor program during the early years of the program. This reflects both higher penetration rates as well as greater savings per installation.

Table 4.2: Industr. Lighting Programs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	7	29	74
% of Sector Consumptn.	0.0%	0.1%	0.2%
Peak Reduction (MW)	1	4	10
% of Sector Demand	0.0%	0.1%	0.2%

Program Budget

These impacts imply the level of activity shown in Table 4.3. Although individual installations are relatively inexpensive, the large number of installations requires a high budget for this activity. The total cost of industrial lighting programs over the six year life of the program is $114.5 million.

I.3 Time of Use (TOU) Tariffs

Time of use (TOU) rates provide incentives to shift demand from on-peak to off-peak periods by offering the consumer lower electricity prices during off-peak periods. Even though a large portion of peak demand on the Java-Bali system is attributable to the residential sector, the industrial sector would probably be the most responsive to price structure changes designed to encourage load shifting and reflect the economic value of power. PLN has already adopted a TOU rate structure. The analysis presented here gives only a rough

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Table 4.3: Lighting Program Budget

Measure	Number of Installations During Period (rounded to nearest thousand)				Mode of Delivery	Total Program Cost to PLN*
	Units	1994/95 thru 1995/96	1996/97 thru 1997/98	1998/99 thru 1999/00		
CFLs	18 W CFLs	46,000	110,000	226,000	Direct Installation	$6,900,000
High efficiency fluorescent	34 W hi-eff tubes	240,000	502,000	1,357,000	Information/ Rebate	$2,900,000
High eff. magnetic ballasts	single lamp ballasts	136,000	278,000	442,000	Information/ Rebate	$5,100,000
Reflectors	4 tube fixtures	8,000	19,000	30,000	Information/ Rebate	$3,400,000
Occupancy sensors	2000 m^2 area @ 15 W/m^2	250	600	700	Information/ Rebate	$20,500,000
Low pressure sodium HIDs	160 W lamps	38,000	210,000	383,000	Direct Installation	$75,700,000

* For direct installation programs, program cost is the number of installations multiplied by the product of the cost of the measure and the administration/installation markup. For Information/Rebate programs, program cost is the number of installations multiplied by the sum of the amount of administrative markup and the difference between the cost of the measure and the cost of conventional equipment. Cost details are given in Annex III.

approximation of the impacts that might be expected from an enhanced TOU tariff structure. The companion report to this study, "Electricity Pricing Incentives to Promote Demand-Side Management in Indonesia", develops a TOU tariff for purchase of power from captive generation, and discusses innovative TOU tariff options such as real time pricing and peak activated rates.

Program Design

The design of a TOU tariff structure can be complex. Rather than specify one here, it is assumed that a tariff structure can be designed which will achieve results similar to those implemented in other countries.

PLN's tariffs for industrial classes I-3 and higher already incorporate a TOU element in their energy prices. Experience in other countries, however, suggests that the introduction of well-designed TOU pricing in itself may be insufficient to induce significant load shape modification. Many consumers initially need help in understanding the impact of pricing revisions on their bills, and in developing and implementing the appropriate responses. Thus, TOU programs, particularly those with innovative components such as real-time or peak-activated pricing, require marketing and technical assistance to consumers to make them effective DSM measures. The DSM program proposed here includes technical assistance to help firms shift load and reduce their costs under the new tariff structure. With respect to the design of the new TOU rate, PLN should consider shifting from a contract demand charge to a coincident demand charge.

Potential Impacts

Demand savings are estimated to be 5% of industrial motor demand over peak periods, and annual energy savings are estimated to be 0.5% of total annual industrial energy consumption. These impacts are consistent with the experience in the United States and Mexico[2]. Table 4.4 summarizes the estimated impacts of the assumed TOU rate program. This program is among those described here which offer the greatest impact.

Program Budget

Implementation of the TOU tariff program described above assumes the installation of time of use meters to measure coincident maximum demand as well as the assignment of technical support staff who can help plants take advantage of the new rate structure to reduce their bills. Meters are assumed to cost $500 each and are installed in 4,000 establishments during the six year program. Ten technical assistance staff members are assumed over the course of the program at a total cost of $1,000 per person-month. The total cost of this program would be $2.7 million.

I.4 Interruptible and Curtailable (I&C) Tariffs

Interruptible and curtailable (I&C) rates allow the utility to interrupt or reduce service to those consumers using the rate in order to reduce system peak demand. Consumers using the rate benefit from rate discounts. These programs typically require consumers to offer a minimum interruptible load of 500 kW. I&C tariffs are discussed further in "Electricity Pricing Incentives to Promote DSM in Indonesia".

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[2] USAID (Office of Energy), Mexico: Demand-Side Management in the Industrial Sector, Washington, D.C., September, 1991.

Program Design

As with TOU rates, the design of I&C rates can be complex. Therefore, a specific I&C schedule is not proposed, but it is assumed that a set of rates can be implemented which would achieve results similar to those in other countries. Whereas it may be possible to implement mandatory TOU rates, I&C rates should remain voluntary because of the potential disruptions to industrial processes. As with the TOU rate program previously proposed, this program includes marketing and customer technical assistance. Load interruption is generally implemented through a phone call from the utility's load dispatch center to the consumers on the I&C tariff.

Table 4.4: Industrial TOU Tariffs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Net Energy Saved (GWh)*	133	171	214
% of Sector Consumptn.	0.5%	0.5%	0.5%
Peak Reduction (MW)*	107	138	176
% of Sector Demand	3.3%	3.3%	3.3%

* Because TOU rates shift some load to other periods, impacts are expressed in terms of net energy reductions and power reductions during peak periods only.

Potential Impacts

I&C rates will not result in as much load shifting as TOU rates since firms will not have the advance notice necessary to reschedule industrial processes. It is assumed here for simplicity that I&C rates result in a 5% reduction in motor loads during curtailment periods and that they do not result in any load shifting. This impact is consistent with the experience in the United States. Table 4.5 summarizes these impacts.

Program Budget

The principal costs associated with implementation of I&C rates are the metering equipment (to measure consumer compliance with curtailment periods) and program marketing and administration. Assuming that approximately 650 firms adopt the I&C rate over the six years of the program at an average cost of $2,000 each, and that two staff are required to market and administer the program over its life, the total cost would about $1.4 million.

I.5 Energy Management Audits

Energy management audits entail site visits by utility personnel or contractors who typically review DSM potential in the various electric systems at that facility. Audits often consider the full range of end-uses, and may be used to stimulate participation in other DSM programs. KONEBA already has extensive experience in conducting energy audits.

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Program Design

KONEBA currently conducts audits on a for-profit basis. The proposed audit program could build upon this expertise as follows:

Table 4.5: Industrial I&C Tariffs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	293	375	481
% of Sector Consumptn.	1.1%	1.1%	1.1%
Peak Reduction (MW)	107	138	176
% of Sector Demand	3.3%	3.3%	3.3%

(i) PLN could share the cost of the audit with the firm being audited commensurate with the benefits PLN derives from the audit. KONEBA could offer an electric-only audit, or a comprehensive audit under this arrangement;

(ii) KONEBA could review the potential for load management as well as conservation; and

(iii) additional funds could be committed for a revolving fund to help finance adoption of the recommended measures.

Audits could be conducted using a "mass production" approach in which generic energy measures (GEMS) are identified on the basis of data collected during the Master Plan preparation. Instead of conducting comprehensive audits of a limited number of facilities, the "mass production" approach targets a limited number of generic measures which can be replicated across an entire industry. This approach has been successfully implemented in Pakistan, Egypt, and Morocco.

Potential Impacts

It is assumed that 200 audits are conducted during the first two years, 500 during the next two years, and 600 during the last two years of the program. Table 4.6 summarizes the impacts of these audits based on experience with industrial audits in the United States.

Program Budget

Assuming the cost to the utility of each audit is $500, including marketing and administration, and that a $5 million loan fund is established to implement recommended measures, the total budget for the audit program would be $ 5.7 million over its life.

I.6 Other Potential Industrial Programs

Several other industrial programs may be worthwhile in Indonesia, but there is insufficient information to assess the prospects for these programs at this time. A few of these programs are described below.

Table 4.6: Industrial Audit Programs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	31	110	204
% of Sector Consumptn.	0.1%	0.3%	0.5%
Peak Reduction (MW)	0.2	0.8	1.5
% of Sector Demand	0.1%	0.3%	0.5%

Power Factor Correction

Power factor reductions result from reactive loads which in effect use up generation, transmission and distribution capacity. Inductive loads, such as motors, often reduce power factor to the range 0.8 to 0.9. Some inductive loads, such as certain types of electric furnaces, may have power factors as low as 0.3. The most commonly used means of correcting low power factor are:

(a) On-site capacitor banks. Capacitors can be installed at any point in the electrical system and will improve the power factor between the point of application and the power source. However, the power factor between the load and the capacitors will remain unchanged. Capacitors are usually added at each piece of offending equipment, ahead of groups of motors or at main services.

(b) On-site switched capacitors. Plants equipped with very large intermittent inductive loads, such as large motors, may require switched capacitors which are utilized only when the motor load is on. Such capacitors may be controlled from the substation depending on the measured power factor. The switching feature is only required if the capacitors needed are so large that they cause an undesirable leading power factor during times when inductive loads are off.

(c) Utility distribution line capacitors. Utilities can install capacitors on their own lines where it is not practical to measure power factor or to assess charges to owners. For instance, capacitor banks are often installed on utility poles in residential neighborhoods.

The cost and effectiveness of capacitor use depends on prevailing power factor in different parts of the system, the locations where capacitors are to be installed, and the mounting, enclosure, voltage and capacitance required. Evaluation of maximum potential technical

impact and economic viability requires detailed engineering and economic studies of particular consumers and portions of the distribution system.

Captive Generation, Interfuel Substitution, and Cogeneration

Self-generation of electricity is common throughout Indonesian industry; it is estimated that there are currently about 7000 MW of installed captive generation capacity in the country. Moreover, there may be considerable cogeneration potential which could be tapped to cost-effectively reduce load growth on the PLN system, or at least to add capacity to the system. PLN and the Government can encourage the development of this potential by adopting a clear power purchase framework and encouraging the use of cogeneration.

The companion report to this study, "Electricity Pricing Incentives to Promote Demand-Side Management In Indonesia" considers the potential for the use of captive generation as a DSM strategy in further detail. The report presents and analyzes three program options for peak shaving:

- **Interruptible**: 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 choose. This is a variation of the interruptible and curtailable tariff structure discussed earlier.

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

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

In addition to estimating program potential, the report presents incentive tariffs for captive power purchases as well as a pre-feasibility study of a pilot load management program based on this concept. Additional data on the utilization of captive power could be collected in the course of the Master Plan preparation to assist with program design.

Abundant natural gas offers extensive fuel substitution opportunities, although further pricing adjustments and distribution system expansion are required to stimulate interfuel substitution. Further analysis of these opportunities is required to determine the economics and potential load impacts of cogeneration and interfuel substitution.

Direct Load Control

The companion report to this study, "Electricity Pricing Incentives to Promote Demand-Side Management in Indonesia" discusses direct load control (DLC). Opportunities may exist for

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load control such as residential air conditioning or water heating. However, there does not appear to be sufficient saturation of these appliances in Indonesia at this time to warrant the implementation of a residential DLC program. Experience in the United States and elsewhere suggests that commercial and industrial consumers are reluctant to participate in such programs; I&C pricing programs may be more appropriate since the customer retains the option to continue to consume power during the curtailment period and simply pay a penalty. DLC does not permit such flexibility. Furthermore, remote control technologies face considerable problems. Power line carriers cannot be transmitted through transformers, dedicated phone lines may be impractical, and radio transmitters are costly. Consequently, DLC programs are not considered further.

Improved Industrial Processes

Arc furnaces, smelters, and electrolytic processes are often promising candidates for DSM measures. Indonesia produces significant amounts of iron and steel as well as several non-ferrous metals, including aluminum, copper, gold, tin and nickel. Frequently there is substantial DSM or energy efficiency potential associated with metal mining and processing. However, measures to realize this potential are not considered here because (i) many of these installations are off PLN's Java-Bali system, and (ii) further information on the processes used is required to assess DSM potential.

Commercial and Public Sector Programs

The commercial and public sectors each account for about 10% of electricity sales in Indonesia. Of the public sector share, approximately 13% is for street lighting. Because virtually all commercial and public electricity demand is for buildings (excluding that which is used in street lighting), programs for these two sectors are combined.

C&P.1 Improved Air Conditioning

Audits of commercial buildings in Jakarta[3] suggest that air conditioning accounts for 50 to 65% of total commercial consumption. Hotels are at the higher end of this range, while office and retail are at the lower end. This program is assumed to target building heating, ventilating and air conditioning (HVAC) systems rather than window air conditioning units. The potential measures described below have been identified in the audit work cited.

[3] These audits were conducted by the Surabaya Energy Audit Group, and were sponsored by USAID under the ASEAN-USAID Buildings Energy Conservation Project.

Program Design

The proposed program entails the implementation of the following measures:

(a) proper sizing of cooling tower pump;

(b) using enthalpy control to reduce chiller loads;

(c) increasing set point temperatures;

(d) reducing air leakage and infiltration;

(e) operating fans according to loads; and

(f) using more efficient compressors, pumps, and motors.

These measures could be delivered through trade allies, such as vendors and architects, who would be marketed personally and who would receive rebates for sales of high efficiency and properly sized HVAC components. Alternatively, or in addition, rebates could be paid to equipment manufacturers or importers. DSM program staff could also provide information to building managers as well as building audits. This is particularly critical for the low cost/no cost measures such as increased set point temperatures.

Potential Impacts

A number of sources referenced in Annex IV suggest that economically justified reduction in HVAC load could average around 20% per installation. Assuming penetration rates similar to much narrower HVAC programs in the United States which focus on high efficiency replacement of HVAC units, approximately 40 facilities would participate during the first two years of the program, 125 during the next two years, and 775 during the last two years. Table 4.7 summarizes the impacts expected with this level of participation.

Table 4.7: C&P HVAC Programs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	2	11	62
% of Sector Consumptn.	0.0%	0.1%	0.5%
Peak Reduction (MW)	0.3	1.1	6.6
% of Sector Demand	0.0%	0.1%	0.4%

Program Budget

The principal costs for this program would be marketing and audit staff and equipment rebates. Assuming a staff of three for the first three years of the program, increasing to six for the remainder of the program, results in a staff requirement of 27 person-years and a staff cost of about $325,000 over the life of the program. In addition, assuming rebates of $5,000 per installation, rebate costs would total $4.7 million over the life of the program. The total lifetime cost of the program would therefore be around $5 million.

C&P.2 High Efficiency Lighting

As with industrial lighting, savings of up to 75% for individual installations and high participation rates make commercial and public sector lighting programs attractive. The potential impacts are even greater than in the industrial sector because lighting accounts for a larger share of sectoral consumption. It is assumed that lighting represents 13% of office and public building consumption, 20% of hotel consumption and 25% of retail building consumption, compared to 7% for the industrial sector.

Program Design

The following measures are suggested candidates:

(a) replacing incandescent bulbs with compact fluorescent lamps (CFL);

(b) replacing standard fluorescent tube lamps with energy-saving fluorescent tube lamps;

(c) replacing standard fluorescent ballasts with high-efficiency magnetic or electronic ballasts;

(d) installing optical reflectors and removing lamps that are no longer required; and

(e) installing occupancy sensors.

Low pressure sodium lighting was included in industrial programs, but is not included here because of it unsuitable color rendition and lower incidence of use in the commercial sector. Future data collection may reveal that in fact there is significant scope for this measure or high pressure sodium lamps, which offer better color rendition.

Although direct installation typically achieves the highest penetration rates, the additional costs of administering a direct installation program make many of the above measures uneconomical if that delivery mechanism were to be used. Annex IV presents the economic analysis of these measures, which suggests that only measure (a) would be delivered through

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direct installation programs, while the other measures would rely on information and rebates for delivery. New building standards would also be an important part of ensuring that these measures are adopted.

Potential Impacts

Table 4.8 indicates the cumulative energy and peak demand impacts of the C&P lighting programs outlined above. For participating facilities, lighting intensities are expected to fall from 17 W/m^2 to 10 W/m^2, a reduction in consumption of 41%. Penetration rates are consistent with those assumed for the industrial lighting program.

Table 4.8: C&P Lighting Programs Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	9	35	66
% of Sector Consumptn.	0.1%	0.3%	0.5%
Peak Reduction (MW)	1.4	5.2	9.8
% of Sector Demand	0.1%	0.4%	0.6%

Program Budget

These impacts imply that approximately 260,000 m^2 of floorspace is covered during the first two years of the program, that 740,000 m^2 are achieved during the next two years, and 880,000 m^2 in the final two years. Assuming a total cost of $2 per m^2 (labor plus rebates or direct installations) results in a lifetime cost of $3.8 million.

C&P.3 New Construction

The greatest efficiency gains can be had at least cost when measures are incorporated into building designs before the onset of construction. New commercial construction is a major source of load growth throughout the dynamic economies of Southeast Asia, and offers a one-time opportunity to achieve considerable savings with high persistence. DSM programs which target the efficiency of new construction are critical if these opportunities are not to be lost.

DSM new construction efficiency programs in the United States are typically programs which encourage trade allies such as builders to exceed mandatory building energy performance standards for new construction. Although considerable capability has been established in Indonesia through such projects as the ASEAN-USAID Building Conservation Project, building energy standards have not yet been established in Indonesia. Presidential Decree 43 issued in 1991 provides a foundation for such standards to be implemented.

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Program Design

This program will establish minimum building energy standards which all new construction must meet. Incentives for exceeding those standards exist in the commercial and public sector programs for high efficiency lighting and HVAC described above. The standards will be applied during the construction permitting process. Architects will file compliance plans along with other site plans in much the same way that Title 24 building energy standards are applied in California.

It is not suggested that PLN manage this program, but that authorities currently responsible for approval of building projects take on this responsibility. It is nonetheless in PLN's interest to see this program implemented. The program would consist of establishing a technical directorate which would: (i) establish standards and the means of compliance; (ii) enforce implementation of the standards; and (iii) provide training and technical assistance to architects and others who will need to conform to the standards. PLN would nonetheless be in a position to evaluate program response and compliance.

Potential Impacts

The stringency and level of enforcement of the standards will determine the impacts of this program. Although the ASEAN-USAID Building Energy Conservation study has considered these details in depth, it is simply assumed here that this program will save 10% of commercial and public sector lighting and HVAC demand growth which otherwise would have occurred. It is assumed compliance increases from 40% of new facilities in the first two years, to 60% in the second two years and 70% in the last two years. The impacts of this program are given in Table 4.9.

Table 4.9: C&P New Construction Program Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	57	103	271
% of Sector Consumptn.	0.7%	1.0%	2.1%
Peak Reduction (MW)	7.0	12.5	32.9
% of Sector Demand	0.7%	1.0%	2.0%

Program Budget

The budget for this activity includes $120,000 per year for directorate staff and $100,000 for training and promotional activities. Initial set-up costs include $600,000 for expatriate advisors and $200,000 for computer hardware and software, and other office equipment. Although this program will presumably remain in effect indefinitely, the total cost over the six year time horizon of the DSM program will be approximately $1.5 million.

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C&P.4 Other Potential Commercial & Public Programs

Although the three programs proposed above will likely incorporate most of the cost-effective DSM measures relevant to the commercial and public sectors, work carried out during the Master Plan preparation may point to additional opportunities. For instance, thermal storage, fuel substitution, and audits have been used elsewhere for commercial and public buildings, but there is insufficient data at the present time to determine whether separate programs would be worthwhile in Indonesia.

Thermal Storage

Thermal storage in Indonesia would be limited to cooling storage, which involves producing chilled water or ice during off-peak periods, and then using this stored water or ice to help meet building cooling requirements during peak periods. This is a load management measure which allows the primary cooling system to be turned off or reduced during peak periods.

For existing buildings, the potential for thermal storage will depend in part on the cost of retrofitting these systems, and whether or not there is even sufficient space at sites for these systems. Thermal storage is typically easier to implement and more cost-effective when incorporated in new building designs. This measure requires further engineering pre-feasibility studies, including building surveys.

Fuel Substitution

As in the industrial sector, other fuels such as natural gas may be used to substitute for electricity for certain end-uses. In particular, air conditioning can utilize natural gas. One type of gas air conditioner uses a natural gas-powered motor which in turn drives the compressor of a standard air conditioning system. Another type uses heat to drive an absorption cycle cooling system in which a binary working fluid is used and a compressor is replaced by an absorber and a gas-fired generator. Gas absorption systems are probably the most common type of thermal air conditioner; the American Gas Association estimates that gas systems cool 5% of all buildings in the United States.

Gas air conditioning programs in the United States have combined marketing, education, technical assistance, special tariffs, and equipment rebates. Before such programs are introduced in Indonesia, it is necessary to ensure that the distribution system is adequate, natural gas prices are conducive to these programs, and that a capability to install and service the technology exists.

Energy Management Audits

Energy management audits can be performed for commercial and public buildings, just as they have been proposed for the industrial sector. However, the range of electric end-uses in commercial and public buildings is much smaller than in industry. The relative homogeneity of end-uses may allow the three programs proposed above to exploit the majority of DSM opportunities in the commercial and public sectors and obviate the need for a distinct audit program. Nonetheless, commercial end-uses such as refrigeration and water heating may offer significant DSM opportunities and may be amenable to general audit programs. Information collected during the data acquisition activities of the Master Plan will help determine whether there is scope for a separate program of energy audits in the commercial and public sectors.

Residential Programs

Households consume about one-third of all electricity in Indonesia. In addition to representing a significant portion of total consumption, the residential sector is particularly critical because the residential peak is coincident with the system peak. The two end-uses targeted here, refrigeration and lighting, together account for approximately two-thirds of total household electricity consumption, and three-quarters of peak household demand. Annex IV provides further information on the composition of residential electricity demand.

R.1 Improved Refrigerators

Most refrigerators in Indonesia, particularly entry-level models, are assembled domestically. Relatively simple changes in domestic refrigerator construction, such as the use of rotary compressors and increased insulation, would add only a small amount to the cost of a refrigerator, but would decrease consumption by at least 20%.

Program Desi[illegible]

The [illegible] entail three components to encourage the use of the more efficient domes[illegible]ators:

- testing and labelling of all refrigerators to be sold, so consumers would be aware of the energy costs associated with that particular model, both in absolute terms and relative to other models in that class;
- rebates to trade allies, e.g. appliance retailers, to help encourage the sale of these improved models; and

- incentives to manufacturers and assemblers in Indonesia to incorporate more efficient designs in their production.

Potential Impacts

Based on assumptions described in Annex IV, the estimated energy and demand impacts of a refrigeration program are shown in Table 4.10. These impacts imply that approximately 160,000 high efficiency refrigerators are disseminated during the first two years of the program, 290,000 during the next two years, and 380,000 during the last two years.

Table 4.10: Res. Refrigerator Prgm. Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	24	66	121
% of Sector Consumptn.	0.2%	0.4%	0.7%
Peak Reduction (MW)	4.1	11.4	20.9
% of Sector Demand	0.1%	0.3%	0.5%

Program Budget

The Indonesian household energy strategy study conducted by the World Bank/ESMAP recommended the creation of a testing and labelling program for household appliances which would cost approximately $25 million over 10 years and cover air conditioners and televisions as well as refrigerators. It is assumed that a program for refrigerators alone would cost about half this amount, or $1.25 million per year. In addition, rebates to trade allies, or other incentives to manufacturers, of $25 per refrigerator would add nearly $21 million over the life of the program.

R.2 High Efficiency Lighting

Although perhaps 40% of household lighting fixtures are fluorescent, the remaining 60% are incandescents which appear to be used more often. The use of compact fluorescent lamps (CFLs) in place of these standard incandescent bulbs can save up to 75% of the energy that would have otherwise been consumed by those bulbs.

Program Design

This program entails the direct installation of CFLs to replace incandescent bulbs in households. Installation would be paid for by PLN, and would be conducted by either PLN or a subcontractor. It is assumed that PLN covers part of the cost of the lamp and that the rest is recovered through the customers' bills. PLN's pilot CFL replacement program

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underway in one part of Jakarta will provide valuable guidance on the design and effectiveness of these programs. Further details on this program are given in Annex IV.

Potential Impacts

Even using conservative assumptions, the potential impacts of a residential lighting program could be significant. Impacts are given in Table 4.11. These impacts correspond to 310,000 installations over the first two years of the program, 420,000 over the next two years, and 520,000 over the last two years.

Table 4.11: Res. Lighting Program Energy and Demand Impacts by Year

	1995/96	1997/98	1999/00
Energy Saved (GWh)	51	120	206
% of Sector Consumptn.	0.4%	0.8%	1.1%
Peak Reduction (MW)	12.5	29.5	50.7
% of Sector Demand	0.4%	0.9%	1.3%

Program Budget

Assuming a labor and administration cost of $2 per installation, plus a rebate or subsidy of $3 per lamp, the total cost of the program over its six year life is $6.25 million.

R.3 Other Residential Programs

Improved Televisions and Air Conditioners

Televisions currently account for about 10% of household electricity consumption. Air conditioners represent about 3%. As with refrigerators, ownership of these appliances is increasing rapidly. Also like refrigerators, these appliances offer opportunities for significant efficiency improvements. The best available air conditioners would reduce electricity consumption by 40% when compared to standard window air conditioners assembled in Indonesia. The most efficient color TVs currently available would use 25% less energy than the average sets in use today in Indonesia. The World Bank/ESMAP report previously cited goes into considerable detail regarding the potential for these programs to increase the efficiency of these appliances.

New Construction

Residential new construction programs can be designed similar to the program described for the commercial and public sectors. Such programs may focus on multi-family dwellings, or could encompass single-family housing as well. However, even rudimentary proposals for a residential new construction program require additional information regarding the current and

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forecast housing stock. Residential new construction programs can be considered in the course of the Master Plan preparation when the necessary information will be more readily available.

CHAPTER V: SUMMARY OF POTENTIAL DSM PROGRAMS AND BENEFITS

The combined impact of the ten DSM programs described in detail in Section IV is depicted in Figure 5.1. This figure shows the effect of the programs on the average daily load curve estimated for the year 1999/2000. Peak capacity requirements are reduced by 613 MW (assuming peak line losses of 20.75%, but not taking into account capacity derating as a result of availability characteristics or reserve margin requirements). This corresponds to approximately 4.6% of the peak demand which would have been expected in the absence of the DSM program. Total annual generation (assuming 15.2% line losses) is reduced by 2,024 GWh, corresponding to a reduction of approximately 1.4% of the total generation that would have been expected in the absence of the DSM program.

Table 5.1 shows the cumulative costs and benefits of the entire DSM program proposed in the preceding sections. The following assumptions have been made in the preparation of this summary:

- The costs reported here correspond to the expenditures PLN would have to make for program implementation and generation, net of any taxes.

- Revenue effects are not included in these budget estimates. However, if the average tariff continues to be less than the long run marginal cost of supply, the DSM program would look even more attractive if revenue effects are included. In any case, financial impacts will depend upon the incentives put into place for PLN. An analysis of financial impacts has been included as part of the proposed Master Plan preparation.

- 100% persistence of measures is assumed over a ten year period beginning with the first year of project implementation. In reality, persistence will be less (the exact number will vary from program to program), resulting in lower benefits that stated here. This assumption is balanced by excluding project benefits which continue to accrue after the ten years. For instance, new construction programs will typically yield benefits for the entire life of the building.

- All monetary values are given in constant 1992 terms. The net present value was calculated using a 10% real discount rate and the net "cash flow" stream indicated. The internal rate of return, on the other hand, was calculated assuming that the gross benefits and Master Plan and Pilot Program costs occur in the years indicated, but that the total cost of full scale implementation is incurred in 1994/95, the first year of implementation.

Figure 5.1: DSM Program Impacts

1999/00 average daily load curve

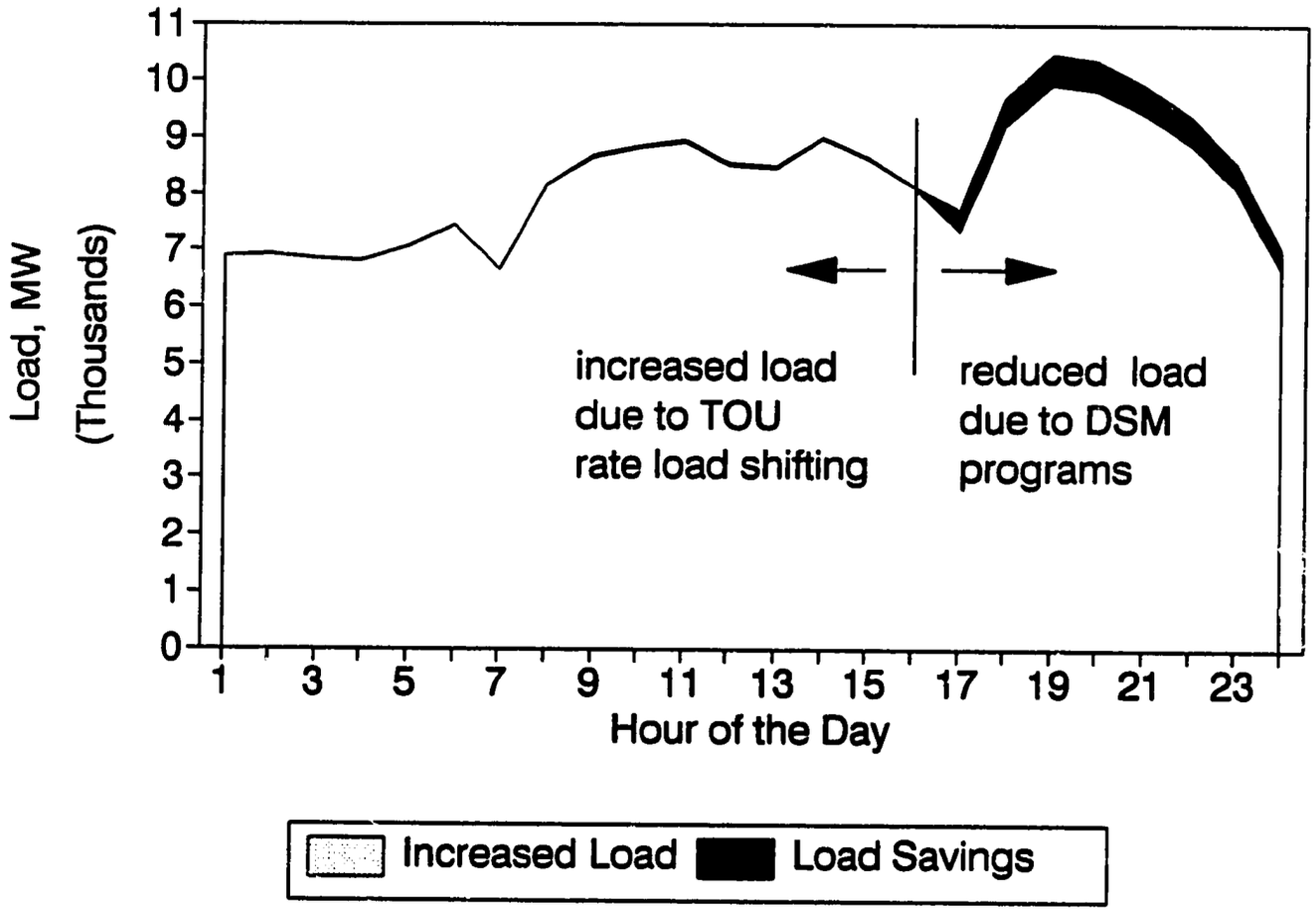


Table 5.1: DSM Program Costs and Benefits

Program	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04
Master Plan Preparation Cost:	$1,500,000											
Pilot Programs Cost:		$2,200,000										
I.1 Improved Motors												
Cost:			$195,600	$195,600	$396,000	$396,000	$1,500,000	$1,500,000				
Benefits:												
MW Saved			0.3	1	2	3	10	17	17	17	17	17
GWh Saved			2	7	16	26	82	138	138	138	138	138
I.2 High Efficiency Lighting												
Cost:			$3,436,667	$6,873,333	$12,666,000	$25,732,000	$28,110,857	$37,481,143				
Benefits:												
MW Saved			0.3	1	2	4	7	10	10	10	10	10
GWh Saved			2	7	18	29	52	74	74	74	74	74
I.3 TOU Tariffs												
Cost:			$453,333	$453,333	$453,333	$453,333	$453,333	$453,333				
Benefits:												
MW Saved			36	107	122	138	176	176	176	176	176	176
GWh Saved (net)			44	133	152	171	214	214	214	214	214	214
I.4 I&C Tariffs												
Cost:			$240,667	$240,667	$240,667	$240,667	$240,667	$240,667				
Benefits:												
MW Saved			36	107	138	138	157	176	176	176	176	176
GWh Saved			98	293	375	375	428	481	481	481	481	481
I.5 Energy Management Audits												
Cost:			$5,037,500	$62,500	$112,500	$137,500	$150,000	$150,000				
Benefits:												
MW Saved			0.1	0.2	0.5	0.8	1.1	1.5	1.5	1.5	1.5	1.5
GWh Saved			10	31	41	110	157	204	204	204	204	204
C&P.1 Improved Air Conditioning												
Cost:			$86,000	$186,000	$322,000	$447,000	$1,822,000	$2,197,000				
Benefits:												
MW Saved			0.1	0.3	0.7	1.1	3.8	6.6	6.6	6.6	6.6	6.6
GWh Saved			1	2	8	11	36	62	62	62	62	62
C&P.2 High Efficiency Lighting												
Cost:			$200,000	$320,000	$700,000	$780,000	$860,000	$900,000				
Benefits:												
MW Saved*			0.5	1.4	3.3	5.2	7.5	9.8	9.8	9.8	9.8	9.8
GWh Saved			3	9	22	35	50	66	66	66	66	66
C&P.3 New Construction												
Cost:			$620,000	$420,000	$120,000	$120,000	$120,000	$120,000				
Benefits:												
MW Saved			2.3	7.0	9.7	12.5	17.7	32.9	32.9	32.9	32.9	32.9
GWh Saved			19	57	80	103	170	271	271	271	271	271
R.1 Improved Refrigerators												
Cost:			$1,500,000	$2,500,000	$3,500,000	$3,750,000	$4,250,000	$5,250,000				
Benefits:												
MW Saved			1.4	4.1	7.7	11.4	17.2	22.9	22.9	22.9	22.9	22.9
GWh Saved			8	24	46	66	93	121	121	121	121	121
R.2 High Efficiency Lighting												
Cost:			$700,000	$850,000	$1,000,000	$1,100,000	$1,250,000	$1,350,000				
Benefits:												
MW Saved			4.2	12.5	21.0	29.5	40.1	50.7	50.7	50.7	50.7	50.7
GWh Saved			17	51	85	120	163	206	206	206	206	206
Total Cost	$1,500,000	$2,200,000	$12,488,767	$12,101,433	$19,710,500	$33,156,500	$38,756,857	$49,842,143	$0	$0	$0	$0
Total MW Saved*	0	0	80	241	305	341	427	486	486	486	486	486
Total GWh Saved*	0	0	203	608	827	1,030	1,373	1,716	1,716	1,716	1,716	1,716
Total Value of Savings	$0	$0	$17,897,060	$53,691,180	$70,987,444	$84,745,015	$110,507,138	$133,679,580	$133,679,580	$133,679,580	$133,679,580	$133,679,580
Net Annual Savings (Cost)	($1,500,000)	($2,200,000)	$5,427,293	$41,589,747	$51,258,944	$51,588,515	$71,750,282	$84,037,437	$133,679,580	$133,679,580	$133,679,580	$133,679,580

* Measured at point of consumption; line losses included in "Value of Savings".

Assumptions:

Value of Capacity:	$73,560 per coincident MW per year
Peak Period Losses:	20.6%
Value of Energy:	$43,750 per GWh (average of peak and off-peak)
Average Losses:	15.2%

Results:

Total Cost of DSM Program:	$169,537,200
Net Present Value of DSM Program:	$363,953,137
Internal Rate-of-Return of DSM Program:	51.5%

Costs include Master Plan preparation and Pilot Programs

- Values for generation and peak capacity are taken from the report on "Indonesia Demand Side Management, Volume II: Electricity Pricing Incentives", the companion report to this study.

As suggested in Table 5.1, the total cost of the project (in 1992 $) is approximately $170 million. The net present value is $364 million, and the internal rate of return is 51.5%. Even allowing for the uncertainties in this analysis, load management and energy conservation through the DSM programs described here are clearly less costly than PLN's costs of adding capacity and generating more power.

Annex I: Some Experiences with DSM in North America

Already some U.S. utilities are beginning to reap the benefits of DSM. Currently, about three dozen major North American utilities have aggressive DSM programs. Table 1, for example, shows that several of the utilities with the largest program expenditures are projecting target reductions in demand by the year 2000 which will more than halve their anticipated rates of load growth during the preceding decade. One of these utilities, the New England Electric System (NEES) has increased DSM spending by a factor of 8 over the past 5 years while at the same time increasing the level of captured savings by a factor of 18, leading to a savings high of about 450 GWh in 1991. Figures 1 and 2 summarize NEES's DSM expenditure and benefits.

Table 1 LEADING U.S. UTILITIES IN DSM

Examples	Projected 1990-2000 Annual Load Growth (%)	Projected DSM Reduction in Year 2000 Demand (%)
SoCal Edison (CA)	2.0	13.0
PG&E (CA)	1.6	6.0
WEPCO (WI)	1.7	6.2
NEES (MA, NH, RI)	1.9	6.6
NU (CT, MA)	1.7	7.0
LILCO (NY)	2.3	9.0
Duke Power (NC)	2.6	11.9
NIMO (NY)	1.2	9.1
Boston Edison (MA)	1.5	10.9

SOURCES: RCS/Hagler, Bailly, Inc., ACEEE, ORNL.

There are numerous other examples of successful DSM programs in the United States. Wisconsin Electric Power and Central Main Power (CMP) began instituting programs about five years ago. CMP's programs saved more than 45 MW in 1991, and Wisconsin Electric says it has reduced demand by about 300 MW since 1987. Pacific Gas and Electric says it cut 119 MW of its load in 1991 and plans to reduce demand growth 75% by the year 2000. In New York, Consolidated Edison and Long Island Lighting together reduced demand by 368 MW last

Figure 1 NEES DSM SPENDING

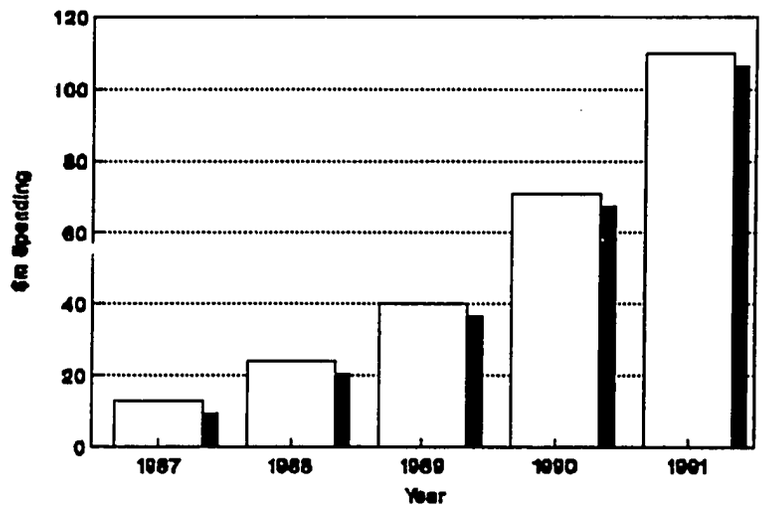
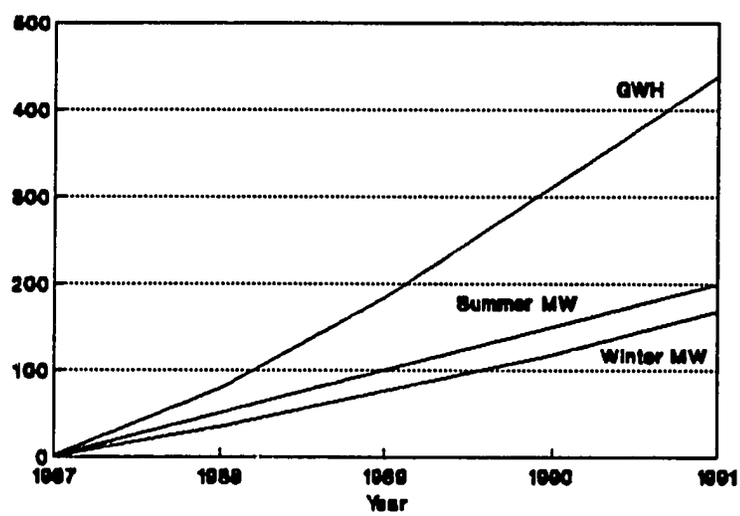


Figure 2 NEES DSM BENEFITS TO DATE



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year. Southern California Edison reduced its load by 115 MW through conservation programs. Bonneville Power Administration has reduced demand by about 350 average MW over the last 10 years, and aims to reduce it by another 600 MW over the next decade.

DSM will find even broader application in the United States, Canada, western Europe and elsewhere in the coming decade. Persistence of measures, and the evaluation of program impacts have emerged as critical issues, and will receive greater scrutiny in the future. Nonetheless, according to an Electric Power Research Institute (EPRI) report (CU-6935), DSM programs in the United States will reduce demand approximately 25,000 MW over the next decade. This is equivalent to 30% of new capacity requirements over the same time period. EPRI's calculations suggest that if DSM is in fact successful in reducing electricity use by about 200 billion Kwh in 2000, it will simultaneously reduce carbon dioxide emissions by about 150 million tons.

ANNEX II: ECONOMIC ASSESSMENT USING THE TOTAL RESOURCE COST TEST

The total resource cost (TRC) test is used here to economically evaluate each measure. This test takes into account total implementation benefits and resource requirements, regardless of the groups to which they accrue. As with economic (as opposed to financial) analysis of projects, the TRC test can be used to identify the most attractive measures from the standpoint of overall resource utilization. This requires that cost and benefits are examined in the absence of transfer payments, including subsidies and taxes. Once a measure passes the test, different financial mechanisms can be employed to allocate costs between the utility, consumers, and trade allies, with a view of making these measures attractive to both utilities and participants. Alone, this test does not determine whether a given level of incentives is adequate or fair for various program participants.

The test evaluates whether the total benefits of implementation exceed the total costs. This test may be formulated using several economic figures of merit, including net present value, benefit/cost ratio, or levelized cost. In this particular analysis, the benefit/cost ratio formulation is adopted. A measure passes the test if:

$$\frac{B_{TRC}}{C_{TRC}} > 1$$

where:

B_{TRC} = *the present value of avoided costs over the life of the measure*
C_{TRC} = *the present value of costs to both participants and the utility for implementation*

Benefits in the TRC test are the avoided supply costs, i.e. the reduction in transmission, distribution, generation and capacity costs (valued at marginal cost) resulting from implementation of the measure. In cases in which the measure entails installation of high efficiency equipment in place of conventional equipment, or cases in which the lifetime of the high efficiency equipment is longer, avoided costs also include the participants' avoided equipment costs. Since the TRC test evaluates measures at marginal avoided costs, it is important to later evaluate all passing measures simultaneously (in an IRP framework, for example) to determine whether some measures offer non-marginal benefits when taken together.

Costs in the TRC test include the program costs paid by both the utility and participants. Thus, all equipment costs, installation, operation and maintenance, cost of removal less

salvage value, and administration costs, regardless of who pays for them, are included. For measures that result in load shifting, costs also include the additional supply costs for periods in which load is increased.

Using these conventions, the TRC benefit/cost ratio may be calculated as follows:

$$B_{TRC} = \sum_i \frac{1}{(1+k)^i}[\Delta E_i \times \frac{1}{1-TD} \times MC_{Ei} + W \times S \times F \times \frac{1}{1-TD} \times (MC_{Ci} + MC_{Ti}) + ACE_i]$$

$$C_{TRC} = \sum_i \frac{1}{(1+k)^i}[PC_i + UC_i]$$

where the new variables are:

i = *index for the year, 1 through the lifetime of the measure*
k = *the real discount rate*
ΔE_i = *the amount of energy saved in year i as a result of the measure*
TD = *transmission and distribution losses*
MC_{Ei} = *the marginal cost of energy in year i*
W = *power consumption of the conventional equipment*
S = *the power savings factor for the measure*
F = *the coincidence factor for equipment operation*
MC_{Ci} = *the cost of generation capacity to be added in year i*
MC_{Ti} = *the cost of transmission and distribution capacity to be added in year i*
ACE_i = *the equipment nd O&M costs avoided by the participant as a result of the measure in year i*
PC_i = *total participant costs in year i for implementing the measure*
UC_i = *total utility costs in year i for implementing the measure*

The following assumptions are made to simplify the analysis:

- energy savings and the marginal costs of energy and capacity remain constant over the life of the measure;
- no transmission capacity is to be added over the life of the measures considered;
- the only costs associated with the measure are the cost of the equipment and a markup for program administration and marketing costs, all of which are incurred at the onset of the program;

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- the only possible avoided costs for the participant are the costs of new and/or replacement conventional equipment; and

- the present value of generation capacity costs is equivalent to the installed capital cost of a peaking unit at the onset of the program less the present value of the capital cost of the same plant installed at the end of the life of the measure, i.e. capacity value lies in capacity deferral.

Annex III

MODEL LEAST COST UTILITY PLANNING STATE STATUTE

Description: An Act relating to public utilities; requiring certain utilities which supply electricity to submit plans containing predictions of future demands for their services and appropriate measures for acquiring resources to meet or reduce those demands; and providing other matters properly relating thereto.

THE PEOPLE OF THE STATE OF _____, REPRESENTED IN SENATE AND ASSEMBLY, DO ENACT AS FOLLOWS:

Section 1. Chapter _____ is hereby amended by adding thereto the provisions set forth as sections 2 to 5, inclusive, of this act.

Section 2. The application of sections 3 to 5, inclusive, of this act is limited to any public utility in the business of supplying electricity which has an annual operating revenue in this state of $_____or more.

Section 3. 1. A utility which supplies electricity in this state shall, on or before _____ of every _____ year, submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the commission.

2. The commission shall, by regulation, prescribe the contents of such a plan including, but not limited to, the methods or formulas which are used by the utility to:

(a) Forecast the future demands; and

(b) Determine the best combination of sources of supply to meet the demands or the best method to reduce them.

Section 4. 1. Not more than _____ days after a utility has filed its plan, the commission shall convene a public hearing on the adequacy of the plan.

2. At the hearing any interested person may make comments to the commission regarding the contents and adequacy of the plan.

3. After the hearing the commission shall determine whether:

(a) The utility's forecast requirements are based on substantially accurate data and an adequate method of forecasting;

(b) The plan identifies and takes into account any present and projected reductions in the demand for energy which may result from measures for conservation and management of loads in the industrial, commerical, residential and energy producing sectors of the area being served, and

(c) The utility's plan shows an adequate consideration of the following possible measures and sources of supply;

(1) Improvements in energy efficiency;
(2) Load management;
(3) Pooling of power;
(4) Purchases of power from neighboring states or countries;
(5) Facilities which operate on solar or geothermal energy or wind or biomass; and

(6) Facilities which operate on the principle of cogeneration or hydrogeneration.

Section 5. 1. Within _____ days after a utility has filed its plan, the commission shall issue an order accepting the plan as filed or specifying any portions of the plan which it deems to be inadequate.

2. All prudent and reasonable expenditures made to develop the utility's plan, including environmental, engineering and other studies, can be recovered from the rates charged to the utility's customers.

Section 6. (The state statute pertaining to the licensing of utility facilities should be amended to require that:)

( ) The if the facility or a part thereof is intended to meet the requirements of customers of this state for electricity, it is included in the utility's plan to increase it supply of electricity or decrease the demands made on its system by its customers.

MODEL LEAST COST UTILITY PLANNING STATE REGULATION

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^^00 COMMISSION AUTHORITY AND SCOPE OF PROVISIONS

^^00.1 Consistent with (cite state statute, if applicable) each electrical corporation (hereinafter "utility") doing business within the State of _____shall be required to develop and file for review and approval by the Public Service Commission (hereinafter "Commission") a least-cost resource plan as described by these regulations. These regulations establish guidelines for the development and submission of plans, and for the procedures for a periodic regulatory review of each utility's integrated least-cost resource plan. Interim plan monitoring is established through working groups and reporting requirements.

^^00.2 The Commission will either approve the utility's least-cost resource plan, approve it subject to stated conditions, approve it in part and reject it in part, or reject the utility's resource plan as filed, only upon a finding, after a hearing conducted determines that the action is in the public interest.

^^00.3 Not withstanding the provisions of subsection ^^00.2, above, failure to substantially comply with the provisions of this chapter may result in summary rejection of an applicant's plan. Such rejection may be without prejudice to the refiling of the application.

^^01 DEFINITIONS

^^^01.1 Avoided Cost: The cost over a future period to the electric utility of marginal energy and capacity from a utility supply resource for which an alternative resource may be substituted. Avoided cost is determined utilizing a system planning methodology which incorporates the least-cost alternatives for generation capacity additions to be obtained directly by the utility, and has the ability to endogenously consider all realistic sizes of capacity additions. Marginal capacity costs must reflect the total costs of plant additions over the entire planning horizon. Data developed in the utility's integrated least-cost plan must be utilized for determining avoided cost so that realistic assumptions regarding the utility's actual anticipated operating characteristics are incorporated into the calculation. No specific avoided cost "model" is adopted in this regulation so that the utility is free to choose any methodology which conforms to the guidelines set forth above.

^^01.2 Capacity Factor: The ratio of the energy produced by a generating facility to the amount of energy that could have been produced, in the absence of any outages, in any selected time period.

^^01.3 Customer (or Participant) Contribution: The incremental cost to the customer (or to any person or entity, other than the utility serving that customer), for a demand-side measure that requires an expenditure of utility funds.

^^01.4 Demand or Demand-Side Resource or Measure: An energy efficiency or energy management device or application which is installed as a result of a program implemented by the utility or provided by a third party selected by the utility in response to an all-source bid solicitation

^^01.5 End-Use: Light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by electricity or its substitute. If equivalent amenity levels and/or productivity are maintained, the end-use service is considered constant for purposes of these regulations.

^^01.6 Energy Efficiency: The decrease of kilowatt or kilowatt-hour requirements of participating customers during any selected time period, with end-use service held constant (see definition of "end-use").

^^01.7 Energy Management: The modification of the time pattern of customer energy usage, with end-use service held constant.

^^01.08 Equivalent Availability: The availability of a generating facility in any selected time period, considering both scheduled and unscheduled, partial and full outages.

^^01.09 Externalities (or External Costs/Benefits): Those costs (or benefits) which result from the generation, transmission, distribution, or reduction in use through efficiency improvements of electricity which are external to the transaction between the supplier (including the supplier of efficiency improvements) and the wholesale (utility) or retail (ratepayer) customer. Any reductions in the use of fuels other than those required to satisfy electric end-use services are not included as "externalities", but shall be explicitly considered in the Total Resource Cost Test.

^^01.10 Full Scale Demand-Side Program: An energy efficiency or energy management program which is implemented by the utility for one or any combination of customer classes, and for which program design, technology, and method of implementation have been proven to be cost effective by passing the Total Resource Cost Test using actual program costs and benefits from either the implementation of a pilot program in the utility's service territory, or the implementation of a full scale program in the service territory of another electric utility as input data.

^^01.11 Least-Cost Utility Planning (LCUP): A utility resource planning process in which:

(a.) All resources reasonably available to reliably meet projected energy and demand requirements are considered by the utility on a consistent basis;
(b.) An integrated combination of demand and supply resources satisfy future demands at the least cost to all ratepayers and society, and meet constraints of safety and reliability as selected from the combination of available resources;
(c.) In addition to the primary selection criteria of least-cost, considers flexibility, risk, equity among ratepayers and classes, externalities and other factors as may be determined appropriate by the Commission.

^^01.12 Net Dependable Capacity: The maximum capacity a generating facility can sustain over a specified period of time, as modified for ambient limitations and less auxiliary loads.

^^01.13 Pilot Demand Side Program: An energy efficiency or energy management program which is implemented by the utility for one or any combination of customer classes for which program design, technology, and method of implementation has not yet been proven cost effective through either the implementation of a pilot program in the utility's service territory or the implementation of a full scale program in the service territory of another electric utility. Pilot programs are limited in scope either as to target population, duration or a combination of these factors.

^^01.14 Plan: The integrated least-cost resource plan filed by the utility pursuant to these regulations.

^^01.15 Rate Impact Test: An analysis of the extent to which unit rates for electricity are altered by the implementation of a demand side program.

^^01.16 Standard Estimates of Energy Efficiency Improvement: Standard estimates of the energy efficiency improvement from the implementation of a demand-side resource may be based upon reliable engineering or other data rather than metering. Such estimates may be utilized where it is, for example, economically impractical to monitor the actual savings of every installed demand-side measure. Where estimates are used, additional verification of energy efficiency improvement should be conducted through customer bill analysis.

^^01.17 Supply Resource: A resource or option which can provide for a supply of additional electrical energy and/or capacity to the utility beyond that currently available. A supply resource includes utility owned electric generating facilities, supply from other utilities, co-generators, or independent third parties via existing or new transmission facilities; and the life extension or upgrading of existing

facilities of the utility, whether they be generation, transmission, or distribution.

^01.18 Total Resource Cost Test : An analysis of the overall economic efficiency of the use of ratepayer resources to produce electric-driven end-uses. A program satisfies this test if the program cost per unit of electricity saved is less than the cost per unit of the supply resource avoided.

^^02 FILING REQUIREMENTS AND PROCEDURE

^^02.1 Beginning on or before _____, and every two *(or three)* years thereafter, each utility shall file a fifteen-year (15) *(or twenty- year (20))* least-cost utility plan with the Commission and an application for approval of that plan. Copies of the plan shall be provided to: *(specify at minimum the commission staff, the advocate's office, the state energy office)* , and other interested parties as may intervene in the proceeding. The application for review and approval of the plan shall clearly identify:

(a.) The name of the applicant and address of the principal place of business of the applicant;

(b.) The name, title, and address of the person authorized to receive notices and communications with respect to the application;

(c.) The location or locations that the public may inspect a copy of the application;

(d.) Requests by the utility that any information utilized in the plan which the utility deems proprietary be filed pursuant to a protective agreement allowing limited access to and distribution of such information to the parties to the LCUP proceeding. The Commission shall rule on such requests and issue an appropriate order.

^^02.2 Copies of the plans shall be made available free of charge to interested parties, as requested. Copies of an Executive Summary shall be made available to the public free of charge.

^^02.3 Plan Filing: Specific Requirements.

(a.) Executive Summary. Each utility shall prepare an Executive Summary, separately bound and suitable for distribution to the public, which shall be a non-technical description of the plan. This document shall summarize the contents of the Technical Volume(s). The summary shall include:

1. A brief introduction describing the utility, its existing facilities, and the purpose of the plan;
2. The forecast of low, high, and base growth of peak demand and energy for the next fifteen (15) years *(or twenty (20) years)* with and without utility demand-side programs, and an explanation of the economic and demographic assumptions associated with each;
3. A summary of the plan to reduce demand, listing each program and its effectiveness in terms of costs and benefits:

4. A summary of the plan to increase supply, showing each planned addition to the system for the next fifteen (15) years *(or twenty (20) years)* with its anticipated capacity, costs, and in service date;

5. A summary of the activities, acquisitions and costs included in the utility's Two *(or Three)* Year Action Plan;

6. Such other information as the Commission may determine appropriate.

(b.) Technical Volume(s). Each utility shall prepare Technical Volume(s) which shall include the information required by Sections ^^03 through ^^06, below;

(c.) Two *(or Three)* Year Action Plan. Each plan shall include a Two *(or Three)* Year Action Plan which describes the proposed resource acquisition actions which the utility must take prior to the next plan filing, and contains the information required in Section ^^10, below;

(d). Technical Appendix. A utility's plan must include a technical appendix. The appendix must contain the following:

1. Sufficient detail to enable the technically proficient reader to understand how the plan and its forecasts were prepared and to verify the adequacy and accuracy of the assumptions, and the data and the methods used in developing the plan;

2. Citations to the sources of all significant information used in the plan;

3. Documentation, inputs, and summary outputs for all models and formulas used, consistent with any proprietary requirements imposed upon the utility by outside suppliers of the models

(e.) Standard Documents. As part of its plan filing each utility shall include:

1. Its annual report to stockholders for the most recent two years;
2. FERC Form 1 for the most recent two years;
3. SEC Forms 8K and 10K for the most recent two years;

^^02.4 Hearing and Review of Least-Cost Resource Plans.

(a.) Proceedings; Timing. The Commission shall commence a hearing within three months of receipt of a utility's complete integrated least-cost resource plan;

(b.) Standard for Approval. Based upon the evidence of record presented at the hearing on the plan, the Commission shall render a decision either approving the plan, approving it subject to stated conditions, approving it in part and rejecting it in part; or rejecting it. A utility's integrated least-cost resource plan shall be approved if found to be in the public interest and to substantially comply with these regulation.

^^03 Energy and Demand Forecasting Requirements

^^03.1 Time Frame of Analysis.

(a.) Historic Data. Energy and demand forecasts shall utilize and report historic data from the ten years preceding the filing year when

such historic data are available. If actual data are not available, estimates shall be used;

(b). Forecast period. All energy and demand forecasts shall be performed for the fifteen-year (15) *(or twenty (20) year)* period beginning with the filing year.

^^03.2 Contents of Energy and Demand Forecasts.

(a). Characteristics. All of the forecasts specified below shall be weather normalized. All methodologies and processes to normalize for weather shall be fully described and justified. Non-weather normalized sales and peak demand forecasts shall also be provided, where practicable.

(b.) The load forecast shall include and report the following items for each of the historic and forecast years it covers:

1. The total annual jurisdictional sales for electricity, for the utility system and for each of the utility's aggregate customer classes;
2. The peak demands for the entire utility system and the jurisdictional portion of the system in the State of _____ for each of the aggregate customer classes, for both summer and winter;
3. Annual load factor;
4. Annual load duration curve, defined as the duration in hours of each level of kilowatt-demand over the year;
5. System load profiles, defined as kilowatt-loads and graphed as a function of the time of day, for a representative weekday in the peak winter and summer months, and for actual winter and summer peak days for the entire utility system and the jurisdictional portion of the system in the State of _____;

(b). Analysis and Documentation of Peak Demand and Energy Forecasts. The historic data and forecast of peak demand and energy usage shall include, and shall separately identify and describe the impact on peak demand and energy usage of the following load requirements and resources:

1. Utility demand-side programs which were implemented before preparing the plan under consideration;
2. Existing government-sponsored or mandated demand-side programs;
3. Substitution of alternative fuels for electricity;
4. Actual and expected interruptible demand, including number of customers and firm capacity contracted for interruption from each customer;
5. Self-generation and cogeneration by existing and future customers, including the number of customers with such capacity, their total capacity rating and, where applicable, the capacity and energy they are contracted to provide;
6. Transmission and distribution losses;

(d.) Evaluation of Previous Forecasts. Each utility plan shall contain an evaluation of previous forecasts for the purpose of improving the current forecast. The evaluation must assess the accuracy of

previous forecasts, attempt to explain the deviation between forecasted and actual energy and demand, and propose revisions to subsequent methodologies and assumptions in order to correct for potential deviations, as appropriate.

^^03.3 Forecasting Methodology.

(a.) Forecasting Methodology and Determinants. Utility forecasts shall be based on disaggregated end-use methodologies to the extent practicable and economically feasible. Forecasts based on any other methodology shall be fully explained and justified. Each forecast of energy and demand shall identify and describe the significant determinants assumed in forecasting future peak demand and energy usage. The following determinants of future peak demand and energy usage shall be accounted for in each forecast where appropriate:

1. Demographics, including population, number of households, household type (e.g., single versus multi-family), employment, and income;
2. Economic conditions, including gross product of the service area;
3. Price of electricity and price elasticity for demand for electricity;
4. The substitution of electricity for and with competing fuels in end-uses, including the rates of penetration and saturation of the market of those end-uses;
5. The future price of competing end-use fuels;
6. Behavioral factors which affect energy use by customers;
7. Energy policies of the District and federal government affecting energy use, both existing and reasonably anticipated;
8. Any other factors deemed relevant.

(b.) Each energy and demand forecast shall include detailed descriptions of the source of all determinants upon which it relies and shall document and fully justify the procedure by which the determinants were incorporated into the peak demand and energy usage forecasts. The determinants used in forecasting energy and demand must be consistent with and integrated into the different components of the forecast;

(c.) Data Requirements. Energy and demand forecasts shall be based on the best available data. Where reliable data are not available, estimates should be used and fully justified. To the extent economically feasible, each utility shall develop a data base of electricity consumption patterns by customer class and by end-use. Each utility shall conduct periodic customer surveys to obtain current data on end-use appliance penetration and saturation rates and end-use electricity consumption patterns. A proposed schedule for such surveys shall be submitted with each energy and demand forecast. Each forecast shall include a detailed description of data used in making the forecast, an identification of the sources of such data, and an explanation of techniques employed for gathering, organizing adjusting, or interpreting the data;

(d.) Econometric Forecasting Methods. Where statistical or econometric methods are used in developing forecast inputs or in the forecasting process, analyses of the reasonableness of such methods and models shall be presented, including statistical documentation and justification of each equation, variable selection, estimated coefficients, theoretical or empirical basis for functional form, and method of estimation;

(e.) Forecasting Model. Each energy and demand forecast shall include a complete description of the model or models used, including justification of model design and explanation of variables used.

^^^03.4 Sensitivity Analyses and Contingency Planning.

(a.) Sensitivity to Major Assumptions. Each energy and demand forecast shall include an analysis of the sensitivity of results to the major assumptions and estimates used in preparing the forecast. The major assumptions to be tested should include end-use efficiencies and saturation rates, electricity prices, prices of competing fuels, demographic projections, economic projections, and any other major determinant of energy use or demand. Sensitivity analyses shall assess the uncertainty ranges and the consequences of uncertainty for each of the major assumptions and combination of assumptions.

(b.) Contingency Planning. Each utility plan must contain a series of demand forecasts which represents a reasonable range of electricity sales and demand which its system may be required to serve. The range must include three levels of expected growth based on alternative assumptions of demand determinants, as follows:

1. A base case scenario, which incorporates all assumptions which the utility determines to be most likely. This case shall be used to project revenue requirements, avoided costs, ceiling prices, and resource blocks;

2. A high growth scenario, to be as a basis for developing a full array of resource options for consideration;

3. A low growth scenario, to be used as a basis for assessing the

^^04 UTILITY RESOURCE IDENTIFICATION AND INFORMATION

^^04.1 Existing Resources.

(a.) Data Requirements. The utility shall discuss and describe to the extent practicable all existing resources, including demand-side options, purchases from resource developers, purchases from other utilities, pooling or coordination agreements that reduce resource requirements, and owned or partially-owned generating facilities. This description shall include the same information required for potential future options, as described in subsections ^^04.2 through ^^04.5 below. The utility shall report actual historic information (including the most recent ten (10) years), as well as forecast future information through the life of the resource. Any forecast changes must be fully documented and justified. The information assembled

must be used by the utility in evaluating existing resources and assessing future resource options;

(b.) Assessment of Future Options. Each utility shall assess the role of existing resources in meeting future demand requirements. All existing resources shall be separately reassessed and considered in a manner consistent with potential future resources. Each resource shall be considered for the potential of continued use, upgrading, repowering, life extension, temporary mothballing, retirement, or other option. For those resources for which any action other that continued use appears to be cost-effective, the utility shall assess and document the cost and benefit associated with any such action, and justify why such action will or will not be taken. Each utility shall report any planned retirements, changes in ratings, or any other expected changes in the amount or availability of existing resources.

^^04.2 Potential Utility Demand-Side Resource Options.

(a). Assessing Technical Options. Demand-side technical options refer to any hardware, equipment, or practice that may be installed or instituted for energy efficiency or energy management purposes. Each utility shall assess the full range of technical options available for future demand-side resources, to be used in developing demand-side programs and an integrated least-cost resource plan. The assessment of technical options shall consider and, where appropriate, be based upon the inventory of end-use devices and consumption patterns developed for energy and demand forecasting as described in Section^^03. above. Each utility shall assess the full technical potential of future demand-side resources as a guide for developing comprehensive demand-side programs. For purposes of these regulations, full technical potential is defined as the amount of capacity and energy that could be obtained from the direct installation and use of the most efficient equipment and technology, without regard for economic limitations or market barriers;

(b.) The utility shall perform an initial screening of all demand-side technical options utilizing the Total Resource Cost Test.

1. An option passes the Total Resource Cost Test if the net present value of the program's benefits exceeds the net present value of the program's costs. The net present value must be calculated using the discount rate employed by the utility during the same time period for analysis of the economics of acquisition of electric supply-side resources.

2. In calculating program benefits under this test the utility shall include its avoided costs as are defined in subsection ^^01.3, above. In the case of fuel substitution programs, benefits shall also include the reduction in the costs of production, transmission, and distribution of natural gas, valued at the margin due to reductions in gas usage. Program costs include all the utility's costs of implementing the program and the participant's direct costs of participation. Participant's costs are incremental costs and include only those costs which would not have been incurred

but for participation in the program. In the event a program also provides other benefits, such as improved amenities or other fuel savings, a reasonable allocation of program costs will be made.

3. Utility estimates of these costs and benefits should, to the extent practicable, be differentiated according to seasonal, daily, and hourly cost variations. The time period for evaluation of a program's cost-effectiveness should be the same period used by the utility for evaluating electric supply resources;

(c.) Those options which fail the Total Resource Cost Test or pose unacceptable risk to system reliability shall be eliminated from pilot or full program consideration. If the utility eliminates any demand-side options, each such option shall be identified, and the reason for rejection shall be fully explained and justified:

^^04.3 Potential Purchases from and Sales to Other Utilities.

(a.) The utility shall identify and fully describe all power import and export options, both firm and non-firm, which are likely to be available to it for all or part of the fifteen-year (15) *(or twenty (20) year)* planning period. Each major new commitment for purchase, sale, or exchange of power must be documented and justified as a cost beneficial resource for inclusion in the utility's integrated least-cost plan in a manner consistent with the screening of other supply-side options as set forth in subsection ^^04.4 (b), below ;

(b.) The description of each potential or existing purchase, sale, or exchange of power from or to another utility shall include, but not be limited to, the following:

1. The nature of the purchase or sale, (e.g., firm capacity, summer only);
2. The amount of power to be purchased, sold, or exchanged;
3. The contract price;
4. Requirements to improve its generating and/or transmission system and associated costs. Such description of facilities and costs shall be made in a manner consistent with the description of new generating facilities as set forth in subsection ^^04.4(c), below;
5. Timing and duration;
6. Constraints on the utility system caused by wheeling arrangements, whether on the utility's system or on an interconnected system, or by other contract terms or separate interconnect agreements.

(c.) The utility shall demonstrate that its plan has taken full advantage of the economic opportunities for cooperative planning and coordination of pooling of power and purchasing power in order to:

1. Obtain economy energy from systems having lower costs;
2. Improve reliability;
3. Reduce reserve margins;
4. Obtain emergency power;
5. Alleviate constraints on the system caused by wheeling arrangements;

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6. To the extent that any coordination or pooling agreements exist between the utility and associated utility systems or power pools, or any coordinating organization, or are under consideration, the utility shall describe those agreements and provide the following:

i. The name of the parties to each agreement, identifying the role of each party;

ii. The Federal Energy Regulatory Commission or Commission docket or file number, if any, associated with the agreement;

iii. The commencement and termination date of each agreement;

iv. A summary of significant provisions of each agreement, and the effect of the agreement on the utility's system peak demand requirements.

(d.) The utility shall fully describe and justify its reserve margin requirement for the planning period.

^^04.4 Potential New Utility Generating Facilities.

(a.) The utility shall identify and fully describe all new utility supply-side options for meeting future demand. To the extent practicable and economically feasible, the options considered should include all technologies and designs which are expected to be available within the fifteen-year (15) *(or twenty (20) year)* planning period, either on a commercial scale or on a demonstration scale;

(b.) The utility shall perform an initial screening of all future supply-side resource options to eliminate those which, upon preliminary evaluation, are either not cost-effective in relationship to other available supply-side resources, or pose unacceptable risks to system reliability. If the utility eliminates any supply-side options, then each such option shall be identified, and the reason for rejection shall be fully explained and justified. The screening criteria used by the utility to exclude supply-side resources as planning options shall be fully described and justified.

(c.) A description, as appropriate, of each supply resource (both existing and proposed) to be considered for the integrated least-cost plan shall be provided and shall include the following information (estimated where necessary), site-specific where known, and on an annual basis:

1. Technology and design, including major pollution control equipment;

2. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;

3. Lead time, separately identifying the estimated time required for, engineering, permitting and licensing, design, construction and pre-commercial operation date testing;

4. In-service date, and project schedule;

5. Installed capacity and net dependable capability;

6. Estimated costs, in accordance with the breakdown specified in the Uniform System of Accounts, separately identifying the following:

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i. The total base cost in current dollars, and annual flows of expenditures in current dollars. "Base cost" shall be defined as total capital costs of construction, net of prospective inflation, finance costs (allowance for funds used during construction), and operation and maintenance. Base costs are the sum of the utility's estimated quarterly planning and construction expenditures;

ii. The annual flows of total incremental and sunk facility costs, including inflation and finance costs, disaggregated by allowance for funds used during construction and direct costs;

iii. Annual depreciation on capital investment;

iv. Annual return and taxes on capital investment;

v. The operation and maintenance (O&M) costs over the life of the facility described as:

a. Costs which are variable, in current dollars per kilowatt-hour, with expenses for fuel and other items indicated separately;

b. Costs which are fixed, in current dollars per kilowatt-hour;

vi. Waste disposal;

vii. Decommissioning;

viii. Insurance;

ix. Property taxes;

xi. Dedicated transmission and distribution facilities costs;

xii. Other appropriate expenses.

7. The rates of escalation of cost, including:

i. Capital costs;

ii. O&M costs which are variable and related to fuel;

iii. O&M costs which are variable and unrelated to fuel;

iv. O&M costs which are fixed

8. The total annual average cost per kilowatt-hour at projected loads in current dollars for each year of the plan for each existing and proposed facility;

9. Equivalent availability factors, including both scheduled and forced outage rates;

10. Capacity factors;

11. Duty cycle, i.e., baseload, intermediate, or peaking;

12. Heat rates (efficiency), for various levels of operation;

13. Unit lifetime, both book and engineering;

14. Complete list of applicable state, local and federal licenses necessary for the facilities;

15. Potential socio-economic impacts such as employment, personal income levels, and the competitiveness and health of the marketplace economy of the state;

16. Any other information necessary to perform the resource assessment described in Section ^^06.

(d.) Assumptions should be fully justified and, where appropriate, explicitly compared to the historic values of similar existing resources

of the company, as described in subsection ^^04.1, or of other companies.

^^04.5 Financial Information.

(a.) The financial assumptions and models used in the plan shall be fully described. Those assumptions which shall be stated and justified include at a minimum:

1. The general rate of inflation;
2. The AFUDC rates used in the plan;
3. The cost of capital rates used in the plan;
4. The discount rates used in the calculations to determine present worth;
5. The tax rates used in the plan.

(b.) The plan shall include at a minimum the following financial information, together with supporting documentation and justification:

1. Present worth of revenue requirements for each alternative plan considered for evaluation and risk analysis;
2. Nominal revenue requirements by year;
3. Average system rates per kilowatt-hour by year;
4. Total ratebase by year;

^^05 UTILITY DEMAND-SIDE PROGRAM OPTIONS

^^05.1 Development of Demand-Side Program Designs.

(a.) Each utility shall develop a comprehensive set of demand-side management program designs. The program designs shall be matched to those technical demand-side resource options identified in subsection ^^04.2(a) which pass the Total Resource Cost Test discussed in subsections ^^04.2 (b), above;

(b.) Programs should be designed as either full scale or pilot programs. A full scale program is appropriate only when the demand-side technology has been proven cost effective in a full scale program in another utility service territory, or when a pilot program of the demand-side technology has been proven cost effective by the utility in the State of _____;

(c.) For full scale programs, alternative program designs shall be described to realize the optimum market penetration for each technical demand-side resource option. Optimum market penetration is that level of market penetration which produces the greatest ratepayer benefit for the least unit cost. To the extent practicable and economically feasible, market penetration estimates shall be made for each program design based on varying levels and types of incentives to determine the appropriate incentive required to achieve optimum market penetration;

(d.) Programs shall be designed to minimize cream skimming and free riders, wherever feasible. Cream skimming is that instance in which some, but not all, cost-effective demand-side measures are installed or otherwise implemented at a customer's facility, and it then becomes uneconomical or impractical to return at a later time to that facility to obtain the next incremental demand-side resource. Free

riders are those customers who would have implemented a demand-side measure regardless of the utility demand-side program;
(e.) At least one program design shall be developed to realize the optimum market penetration for each technical demand-side resource option passing the Total Resource Cost Test;
(f.) In developing full program designs, each utility shall consider the applicability of different types of utility actions to achieve optimum market penetration for each cost effective demand-side option. Types of utility action considered shall include at least the following:

1. Financial incentives for demand-side measure adoption, including:
   i. Rebates to customers or demand-side measure vendors;
   ii. Customer bill credits and shared savings;
   iii. Loans at no interest or below-market interest;
   iv. Payments to customers or third parties based on estimated or measured energy and/or demand savings;
   v. Any combination of the above or other incentives as appropriate.
2. Direct installation of demand-side measures in customer premises at varying levels of cost to the customer, including no cost to the customer;
3. Information and education, including:
   i. Educational literature and advertising;
   ii. On-site energy audits or surveys in customer premises;
   iii. Design team or other technical assistance to architects, contractors, builders, and developers;
   iv. Other information as appropriate.
4. Building and equipment efficiency requirements as tariff conditions for the determination of hook-up fees for initiation of utility service to new or existing facilities.

^^05.2 Program Costs

(a.) For each program design developed, detailed estimates of program costs shall be developed by end-use or program as appropriate. In developing these estimates, the following components of cost shall be separately identified:

1. Expected demand-side measure expenditures by program participants, if any;
2. Expected demand-side measure expenditures by the utility, if any;
3. Utility administrative expenses for the program that add to the total cost of the demand-side measure(s).

(b.) For demand-side programs that entail utility expenditures for all or part of the direct cost of demand-side technologies, each utility shall include a program cost estimate based on the assumption that appropriate direct expenditures are recovered in a manner consistent with the provisions of Section ^^09 of these regulations;
(c.) The costs of utility educational and informational activities that are focused on demand-side programs, but that do not directly cause

demand-side measure implementation must be separately described and justified.

^^05.3 Projected Effects of Program Designs. The effects on energy consumption and peak demand of each program design developed pursuant to this section shall be estimated by end-use or program, as appropriate.

(a.) The estimates shall be based on the technology performance data developed pursuant to subsection ^^04.2(a) and the market penetration estimates developed pursuant to subsection ^^05.1 (c);

(b.) The estimates shall include the annual change in energy consumption and peak demand pursuant to the program for:

1. Each year of the program's assumed operation; and
2. Each year after the program's assumed cessation in which the demand-side measures caused to be implemented by the program are expected to remain in place.

(c.) For program designs whose demand-side measures impact gas and/or oil and electricity use, the effects of the program on the rate of use of energy other than electricity shall also be estimated. At a minimum, where applicable, program effects on maximum annual (hourly or daily) demand, maximum seasonal demand, and average demand during any time-varying energy costing periods used by the utility (on-peak, off-peak, shoulder) shall be estimated.

^^05.4 External Program Costs and Effects. The costs and effects of each program design, other than those identified pursuant to subsections ^^05.2 and ^^05.3 above, shall be identified, described, and, where feasible, quantified. This description shall address at a minimum the expected net effects of the program on:

(a.) The equity of the costs to and benefits of utility sponsored demand-side programs among individual households, businesses, and agencies, and among classes of customers. One measure to determine this factor is the use of the rate impact test. Failure of the rate impact test is not a basis for excluding a measure or program from further consideration, but it may be used to develop a relative ranking of programs for implementation;

(b.) Air quality, water quality, and other measures of environmental protection;

(c.) Public health and safety;

(d.) Employment and personal income levels in the state;

(e). The competitiveness and health of the marketplace economy in the State of _____

(f.) The degree to which the program has the potential to reach optimum market penetration of the appropriate technical demand-side resource option(s).

^^05.5 Risk Assessment. To the extent practicable and economically feasible, the risks and uncertainties surrounding each program

design, and associated data and estimates shall be assessed. Items to be considered for assessment include but are not limited to:
(a.) Uncertainties in the assumed market penetration rates;
(b.) Uncertainties in the implementation schedule;
(c.) Uncertainties in the estimates of demand-side technology effects;
(d.) Uncertainties in the estimates of utility administrative expenses;
(e.) The risks of unanticipated changes in customer energy usage patterns;
(f.) The risks that the implementation of the program will result in legal action against the utility or its agents.

^^05.6 Program Evaluation.
(a.) Each utility shall develop a plan to evaluate the impact on energy use of demand-side programs. The plan shall identify the anticipated method for evaluating the effects of each program design developed pursuant to subsection ^^05.1 above. The plan shall identify procedures to be employed with regard to the following aspects of the evaluation of each program:

1. Establishment of protocols to collect basic data describing program activity, including utility actions to optimize market penetration of programs;
2. Comparison of demand patterns of similar participant and nonparticipant groups, and/or use of customer bill analysis, engineering estimates, meter data or other methods to identify the impact before and after program participation on customer's usage and demand patterns.

(b.) The utility shall use program evaluation data gathered from previous demand-side programs implemented in the past two years to assist in the development of program design options required in the preceding subsections ^^05.1 through ^^05.5.

^^06 DEVELOPMENT OF LEAST-COST PLAN

^^06.1 Assessment of Individual Resources. All potential resources which were identified and described as required in Section ^^04, and which were not excluded by the utility's screening process, shall be considered for inclusion in the utility's integrated least-cost resource plan. Each potential resource shall be assessed based on at least the following criteria:
(a.) Revenue requirements, including all direct and internal costs associated with the resource;
(b.) Impact on the utility system and its customers, including non-price criteria such as operating performance of the resource, and ability to meet energy service needs of customers;
(c.) The qualitative and, to the extent practicable, quantitative impact on the environment and society, including all appropriate external costs associated with the resource;
(d.) Where limited data are available to assess fully any of the above criteria, the utility shall use its best estimate of the data. The utility

shall identify and fully describe and justify any methodologies used to evaluate or rank potential resources using the criteria listed above.

^^06.2 Development of a Least-Cost Resource Plan

(a.) Each utility shall develop a least-cost resource plan to meet the needs identified by each demand forecast scenario described in subsection ^^03.5, based on the least-cost combination of the potential demand and supply resources assessed. The utility shall perform an analysis which integrates resources found to be cost beneficial with considerations of:

1. Financial planning;
2. Regulatory constraints;
3. All source bidding;
4. Efficiency incentives.

(b.) The development of such a plan shall be primarily based on utility system assessment of multiple combinations of potential resources, and a determination of which combination of resources minimizes the present worth of total revenue requirements (PWRR) over the planning period. The purpose of this assessment is to determine the minimum costs of providing energy services provided by electricity to the utility's customers, including benefits associated with reductions in the use of competing energy resources;

(c.) The utility shall conduct an analysis of the sensitivity of all major assumptions and estimates used in its plan. Those analyses shall at a minimum include:

1. Risk and Uncertainty. The utility shall consider the risks and uncertainties associated with its resource plans. Any plan which poses unacceptable risks or uncertainties shall be rejected by the utility or modified to reduce such risks or uncertainties. A detailed explanation for any such rejection shall be provided by the utility. Items of risk and uncertainty to be considered include:
   i. Forecast of load;
   ii. In service dates;
   iii. Unit availability;
   iv. Fuel prices;
   v. Schedule and impact of demand-side programs;
   vi. Inflation in plant construction costs and costs of capital;
   vii. Availability and costs of purchase power.
2. Equity of Rate Impacts Between Classes. The utility shall determine whether, after considering risk and uncertainty, its least-cost resource plan will result in inequitable rate impacts between customer classes, or between significant components of any customer class. Such impacts shall be considered by the utility in the ranking and order of implementation of demand-side programs, but should not be used as a screening tool;
3. End Effects. The utility shall extrapolate its resource planning period five (5) years beyond the base fifteen (15) year (or twenty (20) year) period to determine the sensitivity of its least-cost resource plan to such an extension of the planning period.

^^06.3 Each least-cost resource plan shall be fully explained and documented. The utility shall specify the basis for selecting the plan, and shall describe how the plan meets the criteria described in subsections ^06.1 and ^06.2, above. The utility's analysis must address the relationship among the factors used in making the utility's decision including the relationship between avoidance of risk and the minimization of cost.

^^07 TWO *(OR THREE)* YEAR ACTION PLAN, WORKING GROUPS, PLAN AMENDMENT, AND SEVERABILITY

^^07.1 Two *(or three)* year action plan based on integrated analysis.

(a.) Each Plan of a utility must include a detailed action plan based on its integrated analysis. In the action plan, the utility shall specify all tasks which are necessary to implement its plan in the succeeding two (2) year *(or three year)* period, prior to the filing of its next plan. The action plan must contain;

1. A schedule for the acquisition of data, including planned activities to update and refine the quality of data used in forecasting, and a budget for such acquisition;
2. A section in which the models and techniques used to develop the forecast are compared with currently recognized procedures. Any proposed changes in the methodology must be fully justified, including an analysis of the costs and benefits;
3. A section describing any plans to acquire new or additional models for forecasting, or resource or integration analysis and evaluation;
5. A section describing demand-side programs and activities during the action plan period, including:
   - i. A description of continued planning efforts to develop new demand-side programs;
   - ii. A listing of each demand-side program which will be implemented in the action period, and justification for implementation of each through a cost benefit analysis;
   - iii. Designation of whether those programs will be a full or pilot program, and a justification for such designation;
   - iv. Estimated savings of energy and demand from the implementation of each program;
   - v. Detailed time tables for implementation and resource acquisition;
   - vi. Description of the method for evaluation of each program, and verification of energy and demand savings;
   - vii. Detailed budgets for costs to be incurred for each program during the action period.
6. A section describing the acquisition or construction of supply-side resources during the action period, including:
   - i. A listing of each supply-side facility to be constructed or to commence construction in the action period;

ii. A listing of each new firm power purchase to be made during the action period, and the timing and cost of that purchase;
iii. A time table for acquiring a permit to construct and a construction schedule for each facility;
iv. A detailed construction budget for each facility to be constructed or under construction during the action period, and, in the case of facilities already under construction, a comparison of the last submitted budget in the previous plan filing with actual expenditures to date.

7. A tabulation of all costs associated with the development of the plan;

8. A tabulation of costs for which the utility will seek recovery under the provisions of Sections ^^08 and ^^09, above, in the action period, and the method and timing of that recovery;

(b.) All budgets for demand and supply resource acquisition activities in the action period must be in a format which facilitates the comparison of budgeted with actual expenditures. Expenses must be presented in a format which is consistent with the categories and periods to be presented in subsequent filings for cost recovery as described in Sections ^^08 and ^^09, above;

(c.) The action plan must contain schedules suitable for comparing planned and actual activities. Points of decision committing major expenditures must be shown;

(d.) The Commission's Order on the plan shall separately address the utility's action plan. The Commission will approve the utility's action plan as filed, approve it subject to stated conditions, approve it in part and reject it in part, or reject it, as filed pursuant to these regulations, only upon a finding, after hearing, conducted in accord with _____, that the action plan is in the public interest, and substantially complies with these regulations;

(e.) Approval of an action plan constitutes only approval of the programs contained in the plan. The prudence of the expenditures to be recovered will be reviewed by the Commission in a separate proceeding in accordance with _____, above, or in a general rate proceeding, as may be appropriate;

(f.) Every six (6) months after the approval of a two (2) year *(or three year)* action plan the utility shall submit to the Commission and other parties to the proceeding a progress report of the actions taken and expenditures incurred to implement the action plan. This report shall compare the expenditures budgeted and incurred, the actions proposed and taken, and explain any significant deviations from the utility's approved action plan. Any party of record may request the Commission hold a hearing on the report.

^^07.2 Working Groups.

(a.) A least-cost working group shall be formed for each utility which is composed of representatives from: *(specify at minimum the effected utilities, commission staff, advocate's office).*

(b.) Each entity represented, as listed above, shall have one vote. Votes shall be non-binding, and shall be advisory only;
(c.) All meetings of the working group shall be open to other intervenors to the plan proceeding, interested parties, and the general public;
(d.) The utility shall chair the working group and schedule meeting as necessary;
(e.) Working Group meetings shall be scheduled on a periodic basis between plan filings for the purpose of:

1. Learning of utility progress in developing plans and plan amendments;
2. Determining whether key assumptions are reasonable and are being applied in a consistent manner;
3. Determining whether models and modeling techniques are reasonable and consistent;
4. Determining whether key results are reasonable;
5. Determining whether progress on the activities described in the utility's most recently approved two (2) year action plan are consistent with the plan;
6. Offering recommendations and suggestions as appropriate.

(f.) The utility shall prepare a summary of the agendas and the conclusions reached by the working group, if any, at each meeting. The summaries shall be filed with the utility's plan.

^^07.3 Amendment of the plan. The utility may apply for permission to amend its plan before it submits its next plan if:
(a.) It anticipates submitting an application for a permit to construct a generating or transmission facility, or purchase interest in generating or transmission capacity pursuant to the provisions of _____ of the Commission's regulations, which was not previously approved as part of a two (2) year action plan;
(b.) It anticipates the need to make a binding commitment for the acquisition or construction of a supply or demand resource which was not previously approved as part of a two (2) year action plan;
(c.) The basic data used in the formulation of its last approved plan requires significant modification which affects the choice of a resource which was approved as part of a two (2) year action plan;
(d.) The conditions under which an amendment is sought must be specifically set forth in the application for amendment.

^^07.4 Severability. If any provision of this Chapter is held invalid, the Commission intends that such invalidity not effect the remaining provisions to the extent that they can be given effect.

^^08.0 COST RECOVERY

^^08.1 Recovery of cost of developing plan
(a.) All costs incurred by a utility in developing its plan must be accounted for in its books & records separated from amounts attributable to any of its other activities. All accounts, including

subaccounts, must be maintained in such a manner as will allow these costs to be identified readily. These costs must be segregated into the same categories as specified in the budget for the plan of action.

(b.) The commission will consider all prudent & reasonable costs incurred by a utility in developing its plan to include all costs of trial programs.

(c.) A balancing account treatment may be used to recover the cost of developing the resource plan.

(d.) Prior approval of the amount to be charged or credited must be obtained from the commission.

^^08.2 Recovery of costs to implement programs for conservation and load management.

(a.) All prudent and reasonable costs incurred by a utility in implementing full programs for conservation and load management which have been approved by the commission as part of the utility's plan of action are eligible for recovery through general rates pursuant to the established procedures for adjusting general rates.

(b.) At the commission's hearing to consider the utility's plan, the utility shall demonstrate the projected amount and duration of the savings in energy and demand of all proposed full programs. The commission will treat appropriate preapproved costs associated with those programs for conservation and load management as operating expenses or as ratebase.

(c.) All full programs previously ordered or approved by the commission for implementation before the filing of the utility's next plan will be treated as operating expense or as ratebase.

(d.) All costs of implementing the programs for conservation and load management must be accounted for in the utility's books and records separately from accounts attributable to any other activities. All accounts must be maintained in such a manner as will allow these costs to be identified in readily. Costs attributable to specific programs must be readily identified. These costs must be segregated into the same categories as specified in the budget for the plan of action.

ANNEX IV: TECHNICAL, ECONOMIC, AND MARKET EVALUATION OF DSM MEASURES

This annex provides background assumptions used in the evaluation of the DSM measures discussed in Section IV. Much of the information, such as the level of mark-ups for program administration is based only on rough judgements. At best, assumptions presented in this annex are estimates of costs and performance which will no doubt change based on the experience with earlier phases of the project. Economic analysis is done using the TRC test, i.e. in economic terms, so that import tariffs, lost revenues, and other transfer payments are not considered. One way this analysis could be improved at the present time would be to gather additional information on the market composition of the sectors considered here, and examine the growth of these markets. This would help determine delivery mechanisms, and would give better estimates of the amount of equipment to be added for various end-uses.

Market penetration estimates are disaggregated into two parts: (i) the cumulative penetration (as measured at the end of the period) expressed in relation to the equipment stock or number of eligible customers which existed at the beginning of the period; and (ii) the penetration (as measured at the end of the period) in relation to new equipment or customers added during that period.

Industrial Programs

I.1: Improved Motors

Background:

Based on experience in other countries, it is assumed that motors account for 74% of industrial electricity consumption on the Java-Bali system[1]. Given the predominance of industrial demand, motor improvements may yield a significant reduction in system load.

Industrial motor consumption represents about 26% of system peak. Since motor utilization is relatively even throughout the day, motor improvements could provide a substantial amount of strategic conservation. However, the high technical and economic potential of motor programs is tempered by disappointing market penetration in many programs. For example, participation in such programs in the United States generally has not exceeded 5% of eligible customers.

[1] Motors represent 78.3% of industrial electricity consumption in the U.S., 73.7% in India, 70.7% in the Sao Paulo, Brazil utility, and 75% in Thailand. For some countries the percentage is much higher, reflecting the absence of primary industries that rely on electrolytic processes and intensive process heating; in Costa Rica, for example, motors account for 95% of industrial demand.

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Industrial motor programs in the United States concentrate on upgrading the efficiency of new motor purchases and replacing, rather than repairing, old motors which have burnt out. Generally, these programs offer rebates which offset the incremental cost of a more efficient motor over a standard motor. Most of these programs are promoted through direct mail brochures and personal contacts with trade allies and eligible customers, particularly large industrial customers.

Proposed Measures:

Motor improvements may entail exchanging a motor for a more efficient or correctly sized model. Two measures are considered:

(a) **High efficiency motors.** High efficiency motors are made with higher quality materials, improved bearings and fans, and superior windings. These motors typically cost 20 to 40% more than conventional motors. Energy savings of such motors vary from 2 to 8%, with the larger savings in the smaller horsepower ranges. It is assumed that high efficiency motors could be used in the half of motor applications in which multispeed motors and variable speed drives are not appropriate.

(b) **Multi-speed motors and variable speed drives.** Motor efficiency is generally highest when motors operate within 50% of their rated loads. For many applications, though, the load placed on the motor varies over time. Motors driving pumps, fans and cooling systems typically encounter significant load variations.

Multi-speed motors contain two or more sets of windings, allowing the motor to operate at two or more speeds. These motors typically cost 30 to 80% more than conventional motors and reduce energy consumption by 8 to 10%. Variable speed drives, on the other hand, adjust the speed of the motor by varying the frequency of the power supplied to the motor. Energy savings with variable speed drives can range from 20 to 50%, while costs may be twice as much. It is assumed that each type of motor would be appropriate in 25% of all industrial motor applications.

Motor downsizing can also reduce energy consumption. However, the increase in efficiency from operation of a properly sized motor is often only a marginal improvement over the efficiency loss resulting from use of a smaller motor. Furthermore, motor downsizing would likely be most effective if it is done as part of the two measures described above. Therefore, a separate motor downsizing program is not considered here.

It is assumed that industrial motor programs would be administered as information and rebate programs and not as direct installation programs. Nonetheless, aggressive, alternative program delivery mechanisms, such as the CESP Fleximotor program in Brazil, are possible

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but require pilot programs to determine the feasibility and effectiveness of these programs in Indonesia.

Improvements in motor lubrication, drive trains, and motor or system operations and maintenance (O&M) can also reduce industrial consumption. These measures are considered under the Energy Management Audit program since they do not involve capital equipment replacement but entail lower cost changes in plant operations.

Maximum Technical Impact:

Technical impact of these measures is based on the following assumptions:

Measure	Portion of consumption for which measure is technically possible	Reduction in consumption per installation
High efficiency motors	50%	5%
Multi-speed motors	25%	9%
Variable speed drives	25%	25%

The weighted average technical maximum savings for the implementation of all three measures is 11%.

Economic Potential:

An economic assessment of these measures over a range of motor sizes and load factors suggests that all technically appropriate installations would be economically justified. The analysis shows that even if a conventional motor has just been installed, replacing the motor

with an improved motor would be justified on the basis of the expected energy savings. This analysis is summarized in the following figure.

Assuming that these measures would reduce overall industrial motor consumption by 11%, and that they could be implemented immediately wherever technically and economically appropriate, they would reduce average daily peak demand by 105 MW and reduce annual consumption by 855 GWh.

Market Penetration:

Eligible customers are often reluctant to participate because of production disruptions which result from replacing motors. Experience with several industrial motor programs in the United States indicates that participation rates (the number of participants divided by the number of eligible customers) are generally less than 3% for programs typically lasting between 6 and 24 months. Some highly focussed programs which target small groups of large consumers have fared better. For instance, a motor rebate program administered by Niagara Mohawk in New York reached 8 out of 24 eligible customers over the seven month life of the program in 1986.

In some countries, more aggressive programs than information-and-rebate are underway. A major utility in Sao Paulo, Brazil, is developing a program, called "Fleximotor", which will track motors used among all customers to determine optimal replacements. This program has not yet been implemented, but may well achieve penetration rates higher than previously recorded in other countries. A 50% program administration markup (except for the largest motors) has been included in the cost of the measure reflecting a similarly aggressive motor program for Indonesia. Despite the additional costs of such a program, motor changes remain a cost-effective measure.

If a more aggressive program is adopted, market penetration will be limited by the ability of PLN or its contractors to implement it. It is assumed to follow the pattern given below:

Portion of Motor Consumption Modified by the Program during:	Consumption from Existing Motor Stock	Consumption from New Stock Additions
the first two years of the program	0.1%	1.0%
the second two years of the program	0.5%	2.5%
the third two years of the program	1.2%	15.0%

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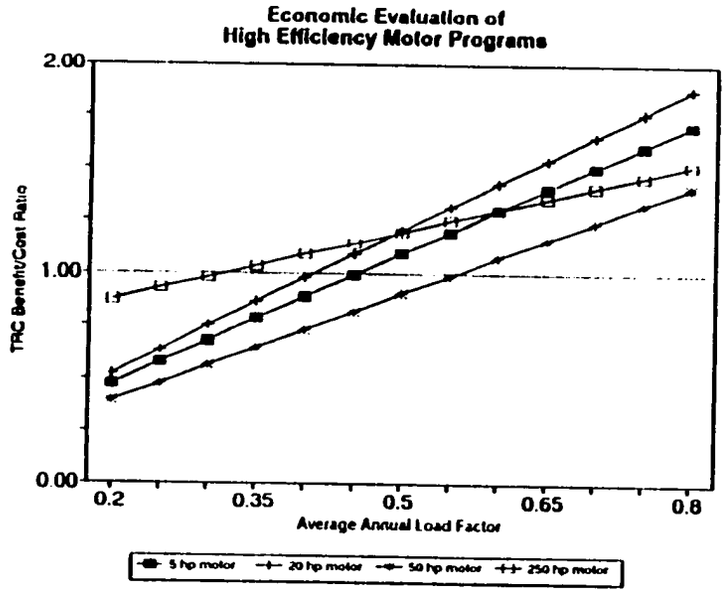
Economic Assessment of Industrial Motor Programs

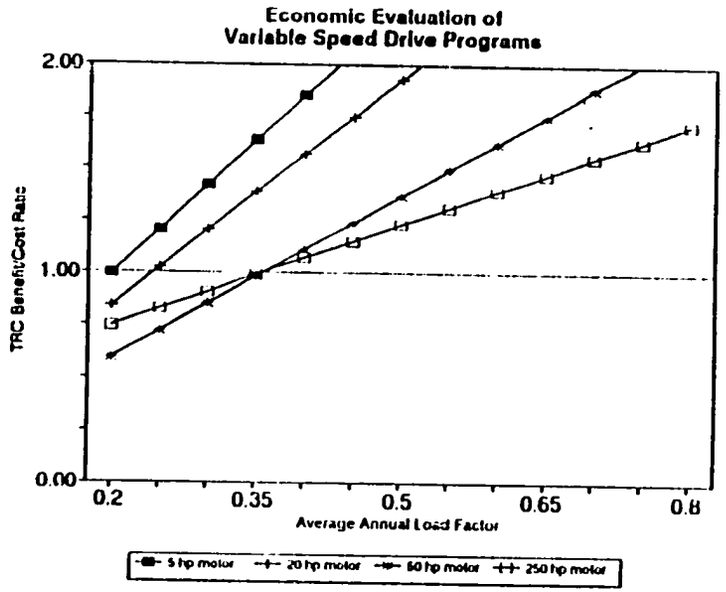
Assumptions

Discount Rate (%)	10%
Marginal Cost of Energy ($/kWh)	0.048
Cost of Generation Capacity ($/kW)	267
System T&D Losses (%)	15.3%

	High Efficiency Motors				Variable Speed Drives			
Units	per motor	per motor	per motor	per motor	per motor	per motor	per motor	per motor
Cost of Measure ($)	400	1000	2300	12000	600	1700	4000	20000
Installation/Admin Markup (%)	50%	50%	50%	20%	50%	50%	50%	20%
Life of Measure (years or hours)	20	20	20	20	20	20	20	20
Cost of Standard Equipment ($)	300	850	1900	8000	300	850	1900	8000
Life of Standard Equipment (y)	20	20	20	20	20	20	20	20
Standard Motor Power (hp)	5	20	50	250	5	20	50	250
Energy Savings (%)	8.0%	5.5%	3.8%	2.0%	25.0%	15.0%	10.0%	5.0%
Coincidence Factor	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Results





A 20% installation/admin markup assumes information and rebates for program delivery. Credit is given for the avoided cost of new conventional motors.
A 50% installation/admin markup assumes direct installation. No credit is given for the conventional motor which is displaced.

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I.2: High Efficiency Lighting

Background:

Based on experience in other countries, it is assumed that lighting accounts for only 7% of industrial electricity consumption on the Java-Bali system[2]. Although lighting is a relatively small portion of industrial demand, experience in the United States has shown that savings can be as high as 75% of consumption for each high efficiency installation, and participation rates can exceed 50%, depending on program design.

Industrial lighting represents slightly more that 2% of system peak. Compared to residential and small commercial lighting demand, industrial lighting demand is spread more evenly throughout the day, so that industrial lighting programs provide strategic conservation rather than peak clipping.

Industrial programs in the United States fall into three general categories: information-only programs, rebate programs, and direct installation programs. Information programs include mailings and audits that highlight lighting efficiency opportunities. These programs are characterized by the lowest participation rates. Rebate programs are the most common. They are typically offered through direct mailing, sometimes require utility inspection before installation to reduce free riders, and generally involve payments to the consumer (although some make payments to lighting suppliers). Direct installation programs are usually run by the utility or approved contractors, and cover all or most of lighting equipment purchase and installation costs. Some portion of these costs may be recovered through future billing. These programs achieve the highest penetration.

Proposed Measures:

Lighting programs involve replacing lamps and/or ballasts with higher efficiency versions, as well as installing fixture reflectors and lighting controls. Only occupancy sensors are considered here, although other lighting controls such as timers are also available. The selection of measures depends on the current state of the lighting stock, in terms of the applications, technologies currently used, and age. Although a large amount of data has been collected on the residential lighting stock in Indonesia, little is known about the industrial lighting stock.

[2] Lighting represents 5.8% of industrial electricity consumption in the U.S., 9.0% in India, and 2.6% in Costa Rica.

Most industrial lighting probably consists of fluorescent or high intensity discharge (HID) lamps. It is assumed that 10% of industrial lighting (on an energy basis) is incandescent, 25% is HID, and 65% is fluorescent. Of the HID lamps, it is assumed that 60% is mercury vapor. This breakdown is consistent with estimates for other countries such as India.

The following measures are proposed:

(a) replacing incandescent bulbs with compact fluorescent lamps (CFL);

(b) replacing standard fluorescent tube lamps with energy-saving fluorescent tube lamps;

(c) replacing standard fluorescent ballasts with high-efficiency magnetic or electronic ballasts;

(d) installing optical reflectors and removing lamps that are no longer required;

(e) installing occupancy sensors; and

(f) replacing mercury vapor HID lamps with sodium vapor HID lamps.

It is assumed that measures (a) and (f) would be delivered through direct installation programs, while the other measures would rely on information and rebates for delivery. New building standards would also be an important part of ensuring that these measures are adopted.

Maximum Technical Impact:

Technical impacts of the above measures are based on the following assumptions:

Measure	Portion of consumption for which measure is technically possible	Reduction in consumption per installation
replacing incandescent lamps with CFLs	7%	75%
replacing standard fluorescent lamps with high efficiency fluorescent lamps	60%	10%
replacing standard ballasts w/high efficiency magnetic ballasts*	60%	10%
replacing standard ballasts w/high efficiency electronic ballasts*	60%	25%
installing reflectors	40%	50%
installing occupancy sensors	20%	50%
replacing mercury vapor lamps with sodium vapor lamps	10%	35%

* These two measures are mutually exclusive.

Economic Justification:

Not all of the above measures will be economically justified in every technically possible application. The following table and graphs indicate the conditions under which each measure is economically justified. With respect to compact fluorescents, replacement of low wattage bulbs is not justified under any circumstances, and higher wattage installations are justified only if the installed cost of each CFL is under $18. Neither are high efficiency electronic ballasts justified. Replacements of mercury vapor with sodium vapor lamps, on the other hand, are justified for the full range of usage considered here (500 to 8500 hours per year). On the basis of this analysis, the following assumptions are made regarding

maximum economic potential (expressed in terms of the portion of total consumption for which it would be economically justified to implement the measure).

Measure	Portion of consumption for which measure is economically justified
replacing incandescent lamps with CFLs	75%
replacing standard fluorescent lamps with high efficiency fluorescent lamps	100%
replacing standard ballasts w/high efficiency magnetic ballasts*	40%
replacing standard ballasts w/high efficiency electronic ballasts*	0%
installing reflectors	60%
installing occupancy sensors	25%
replacing mercury vapor lamps with sodium vapor lamps	100%

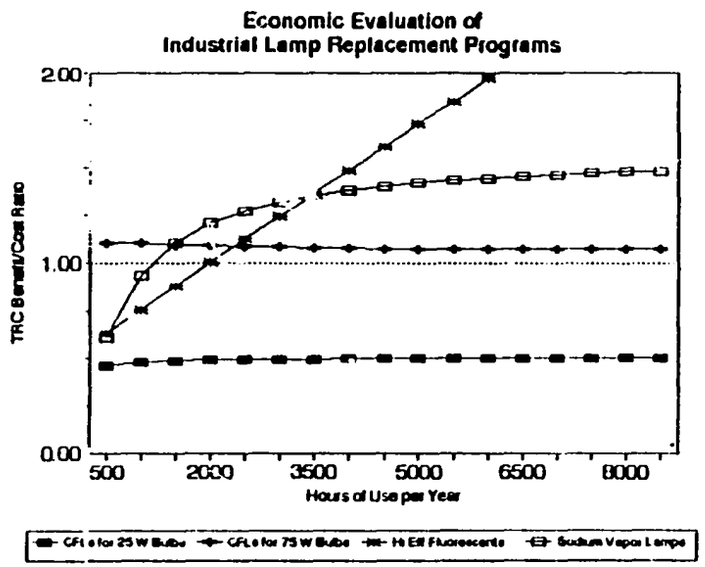
Economic Assessment of Industrial Lighting Programs

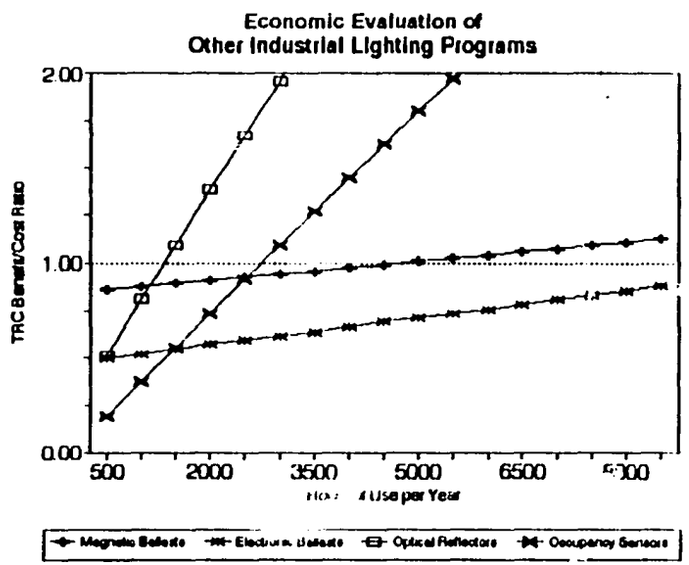
Assumptions

Discount Rate (%)	10%
Marginal Cost of Energy ($/kWh)	0.048
Cost of Generation Capacity ($/kW)	287
System T&D Losses (%)	15.3%

	Compact Fluorescents		Energy-Saving Fluorescents	High Efficiency Magnetic Ballasts	High Efficiency Electronic Ballasts	Optical Reflectors	Occupancy Sensors	Sodium Vapor HID Lamps
Units	per lamp	per lamp	per lamp	per fixture	per fixture	per 4x34W fixture	per sq. ft of building	per 250W lamp
Cost of Measure ($)	12	12	2	15	30	50	0.5	80
Installation/Admin Markup (%)	50%	50%	20%	20%	20%	20%	20%	50%
Life of Measure (years or hours)	5000	5000	2	15	20	25	15	15000
Cost of Standard Equipment ($)	1	1	1	12	12	0	0	60
Life of Standard Equipment ($)	1000	1000	2	10	10	25	15	5000
Standard Eq. Power Consumption (W)	25	75	40	14	14	136	1	250
Energy Savings (%)	75%	75%	15%	10%	25%	50%	50%	35%
Coincidence Factor	0.7	0.7	0.7	0.7	0.7	0.7	0.1	0.7

Results





Measures with a 50% installation/admin markup are distributed by direct installation. No credit is given for replacement of existing conventional equipment.

Measures with a 20% installation/admin markup are distributed using information and rebates. It is assumed these measures are installed when conventional equipment would have been installed

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On the basis of these assumptions, the maximum savings potential resulting from economically justified installations is 34%. These savings correspond to 250 GWh annually and 32 MW of peak demand.

Market Potential:

Direct installation programs offer the greatest and most rapid market penetration. Some programs in the United States have achieved participation rates of more than 35% in less than three years. Information and rebate programs have had more modest results, typically on the order of 1% to 3%, and rarely exceeding 10% for programs of similar duration. Experience in the United States suggests that the effectiveness of each of these delivery mechanisms depends upon personal marketing by utility representatives directly to individual consumers. We assume the following penetration rates for Indonesia:

Measure	Type of Delivery Mechanism	Penetration during first two years (Existing/ New)	Penetration during 2nd two years (Existing/ New)	Penetration during 3rd two years (Existing/ New)
replacing incandescent lamps with CFLs	direct installation	1%/5%	3%/20%	5%/50%
replacing standard fluorescent lamps with high efficiency fluorescent lamps	information/rebate	0.5%/10%	1%/20%	2%/40%
replacing standard ballasts w/high efficiency magnetic ballasts	information/rebate	0.5%/5%	0.7%/10%	1%/25%
installing reflectors	information/rebate	0.5%/2%	0.7%/10%	1%/25%
installing occupancy sensors	information/rebate	0%/2%	0%/10%	0%/20%
replacing mercury vapor lamps with sodium vapor lamps	direct installation	2%/10%	10%/50%	25%/75%

I.3: Time of Use (TOU) Tariffs

Background:

Time differentiated electricity pricing can be an effective tool for load shifting, and to a certain extent, for strategic conservation as well. Time of use (TOU) rates typically shift demand from on-peak to off-peak periods by offering the consumer lower electricity prices during off-peak periods. TOU rates often result in lower annual energy consumption as well. In the United States, 55% of investor owned utilities and 15% of publicly owned utilities offer voluntary TOU rates to their customers. PLN currently offers a TOU rate for larger

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industrial consumers but bases it on contracted demand rather than maximum coincident demand.

Proposed Measure:

The design of appropriate TOU rates can be complex. It is assumed that a rate structure is adopted that achieves results consistent with the experience in the United States and Mexico. This requires that PLN switch from contract demand rates to maximum coincident rates. These rates and time periods may be established in advance; alternatively, innovative pricing programs such as real-time or peak-activated prices may be used. These are discussed further in the companion report to this study. Although enhanced TOU rates can be offered on a voluntary basis, it may be appropriate for PLN to mandate the use of such rates for particular groups of industrial users.

Maximum Technical Impact & Economic Justification:

According to the Comision Federal de Electricidad, the TOU tariff recently introduced in Mexico has resulted in a peak load decrease of 500 MW, or just under 7% of industrial demand during the peak period (4 to 5 PM). In the United States, the Electric Power Research Institute estimates that in 1990, TOU rates resulted in a reduction in peak industrial demand of 1.37% and a reduction in annual energy consumption of 0.13%. These savings are expected to reach 3.5% and 0.34% respectively by the year 2000. The impact of a particular TOU tariff in Indonesia will depend on the potential savings to firms for adopting TOU rates, which in turn depends on such factors as the ability to reschedule operations and the cost of doing so, and the on- and off-peak tariff levels. Information on potential savings can only be collected through surveys of individual industrial establishments. It is assumed here that TOU tariffs will save 5% of industrial motor demand during the peak period and 0.5% of annual energy consumption, and that TOU tariffs would have no impacts on lighting or process demand. It is assumed that this reduction is economically justified.

Market Penetration:

Market penetration is estimated to increase from 30% during the first two years to 65% to 100% at the end of the third period. This assumes an aggressive, perhaps mandatory, application of TOU rates.

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I.4: Interruptible and Curtailable (I&C) Rates

Background:

Interruptible and curtailable (I&C) rates allow the utility to interrupt or reduce service on critical days to those consumers using the rate. Consumers on the rate benefit from rate discounts. These programs typically require consumers to offer a minimum interruptible load of 500 kW to be eligible for the tariff. A 1988 survey conducted by EPRI estimated that by 1990 approximately 75% of U.S. utilities would offer I&C rates.

Proposed Measure:

As with TOU rates discussed above, specific I&C rates will not be proposed here. Instead it is assumed that rates can be designed and implemented which yield savings similar to those achieved in other countries. I&C rates may be particularly attractive to the large number of industrial firms in Indonesia which have their own captive generation sets.

Maximum Technical Impact and Economic Justification:

EPRI estimates that in 1990, industrial I&C rates reduced industrial peak demand by 4.65% in the United States. This is expected to grow to nearly 6% in 2000 and almost 8% by 2010. It is assumed here that the maximum technical and economic impact over the course of the program is a 5% reduction in peak demand.

Market Penetration:

As with TOU rates, market penetration is estimated to increase from 30% during the first two years to 65% to 100% at the end of the third period. This assumes an aggressive, perhaps mandatory, application of I&C rates.

I.5: Energy Management Audits

Background:

Energy audits are used to identify opportunities for the consumer to implement energy-saving measures, and further serve to motivate the consumer to implement the measures. Audits typically entail either a walk-through of the facility with checklists, or a computerized review that provides reports on the costs and potential savings of various measures. Audit programs generally cover a broad range of energy systems, including process uses, lighting, HVAC, motors, etc. While audits can be used to identify opportunities for the consumer to

participate in other DSM programs, audit programs are frequently packaged with their own incentives to help consumers act upon audit recommendations.

Innovative audit programs are underway in a number of countries. In Brazil, for example, the "Maxiwatt" program of the Companhia Energetica de Sao Paulo (CESP) has established a computerized audit program. CESP conducted audits using the program for 46 of its largest customers, and will now franchise the use of the program to private firms. Although CESP does not provide financing for adoption of recommended measures, it does provide post audit service to facilitate implementation.

PT Konservasi Energi Abadi (KONEBA) is the Indonesian national energy conservation center. KONEBA has conducted numerous energy audits of industrial users on a for-profit basis, and offers innovative financing assistance for implementation of audit recommendations. Although KONEBA has had difficulties operating on a self-financing basis, it would nonetheless be a key source of industrial auditing expertise. In fact, its potential role as an ESCO could financially revitalize it.

In addition to the measures already included in the aforementioned industrial programs, energy audits are particularly effective for identifying low cost or no cost measures. Examples of such measures include the identification and repair of leaks in compressor systems, changing HVAC temperature setpoints, and improved insulation for refrigeration or heating systems. Proper operation and maintenance (O&M) for certain motor-driven systems can provide energy savings of 20 to 40% in these systems. Use of synthetic lubricants can save around 2% of energy consumption. Cogged V-belts on smaller motors and synchronous belts on larger motors can provide efficiency gains of 2 to 5%. These are only some examples of the possible measures that can be identified as part of an industrial audit program.

Proposed Measure:

An aggressive, or perhaps even mandatory, program of free audits would be carried out by KONEBA or similar groups under contract to PLN. The audits would be followed-up by further visits to help implement the identified measures and encourage implementation of further measures. This would help ensure that technical potential is achieved and that it persists. Financial assistance for implementation would also be provided. The program would first target industrial consumers in the I-3 and I-4 tariff classes, since these customers account for the majority of industrial consumption.

Maximum Technical Impact and Economic Justification:

In the United States, audit programs typically achieve savings on the order of 4% to 6% at a cost of $0.01-$0.02/kWh. In this assessment, an economically-justified reduction of 4% is

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assumed, net of the savings brought about by any other programs in which the consumer may participate.

Market Penetration:

In the United States, customer response to voluntary audit programs is generally limited. Most utilities surveyed reach approximately 1% of eligible customers each year. Only a few utilities have reached more than 10% of their eligible customers on a cumulative basis; some of those however, have reached between 60% to 90% of specific C&I segments. Each of these programs combined free audits with extensive personal marketing efforts.

Given the option of an aggressive or even mandatory audit program in Indonesia, market penetration will likely be constrained not by customer willingness to participate in audits, but by the ability of PLN to administer an audit program. KONEBA has already audited some of the largest energy consuming industrial users, but there are over 3,400 industrial customers in the I-3 and I-4 tariff categories (over 200 kVA). These consumers account for more than 88% of industrial electricity consumption. We assume here that PLN, using its own staff and contractors such as KONEBA, can conduct 200 audits in the first two years of the program, 500 in the next two years, and 600 in the last two years. The corresponding cumulative penetration profile would then be approximately 6%, 21% and 38% of existing industrial customers.

Commercial and Public Sector Programs

Based on 1989/90 sales data for PLN by tariff class, the commercial and public sectors (which include hotels, offices, retailers, and institutional buildings, but not including street lighting) accounts for slightly more than 19% of total electricity consumption. In contrast, commercial consumption accounts for about 30% of total consumption in the United States.

C.1: Improved Air Conditioning

Background:

Based in part on audits of commercial buildings conducted in Jakarta, it is estimated that heating, ventilating and air conditioning (HVAC) accounts for 55% of office and public building load, 50% of consumption in retail buildings, and 65% in hotels[3]. In Thailand, for

[3] Energy Audit Summary Report, ASEAN-USAID Project on Energy Conservation in Buildings, Project I.2, December, 1989.

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comparison, HVAC represents about 45% of office load, 60% of hotel load, and 40% of retail load[4]. In the United States, this percentage is around 41% for the entire commercial sector.

Commercial and public sector HVAC accounts for nearly 8% of system peak. Since HVAC systems are in use throughout the day, HVAC efficiency improvements provide both peak reduction and conservation.

Proposed Measure:

Work carried out by KONEBA and the ASEAN-USAID Project for Energy Conservation in Buildings has identified several measures to improve air conditioning efficiency and/or reduce consumption:

(a) proper sizing of cooling tower pump;

(b) using enthalpy control to reduce chiller loads;

(c) increasing set point temperatures;

(d) reducing air leakage and infiltration;

(e) operating fans according to loads; and

(f) using more efficient compressors, pumps, and motors.

Thermal storage is considered as a separate program possibility because of the cost and site specific nature of these installations.

Most of the HVAC programs presently offered by utilities in the United States offer rebates for air conditioners and heat pumps which exceed minimum efficiency requirements. These programs target the installation or replacement of HVAC systems. In addition, some U.S. utilities conduct programs directed towards HVAC maintenance and controls; others provide custom assistance to individual customers.

The program envisioned here would include personal marketing and rebates to trade allies (both vendors and architects) for the promotion of properiy sized and efficient equipment. In

[4] Busch, J.F., From Comfort to Kilowatts: An Integrated Assessment of Electricity Conservation in Thailand's Commercial Sector, LBL-29478, Lawrence Berkeley Laboratory, Berkeley, California, 1990.

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addition, information and audits would be offered directly to consumers, which would emphasize low cost/no cost measures such as changes in set points.

Maximum Technical Impact and Economic Justification:

KONEBA estimates that the technical impact of the above measures results in typical energy savings of 30%. In the course of building audits, ASEAN-USAID project identified available cost-effective measures saving from 2.5% to 13.5% of total HVAC load using at least some of the above measures, depending on the building. Work by the American Council for an Energy Efficiency Economy (ACEEE) concluded that cost-effective HVAC improvements could reduce HVAC consumption by 50%. It is assumed here that the technical potential for HVAC savings is 20% of current HVAC demand, and that all technical potential is economically justified.

Market Penetration:

The most effective programs in the United States have achieved penetration rates of around 1% per year. These programs have focussed on rebates for new or replacement equipment; hence, low penetration rates are expected since eligible consumers are likely to participate only when they must add or replace a piece of HVAC equipment. Expanded programs which include audits and other customized information for consumers could be expected to reach higher market penetration. The following assumptions are used for penetration of HVAC programs in Indonesia:

Portion of HVAC Consumption Modified by the Program during:	Consumption from Existing HVAC Systems	Consumption from New HVAC Systems
the first two years of the program	0.1%	1.0%
the second two years	0.5%	3.0%
the third two years	1.2%	20.0%

C.2: High Efficiency Lighting

Background:

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In Indonesia, commercial and public lighting together account for slightly more than 6% of system peak. Lighting's share of commercial and public (C&P) sector load varies with building type. Based on audits conducted in Jakarta, is assumed that lighting accounts for 40% of consumption in retail buildings, 20% in hotels, 25% in offices, and 30% in public buildings. C&P lighting programs are particularly attractive given that experience in the United States has demonstrated savings as high as 75% per installation, and participation rates of greater than 50%, depending on program design.

Lighting programs for the commercial and public sectors fall into the same categories as in the industrial sector; the three types of programs are direct installation, rebates, and information.

Proposed Measures:

Lighting programs involve replacing lamps and/or ballasts with higher efficiency versions as well as installing fixture reflectors and lighting controls. Occupancy sensors and timers are also effective lighting conservation measures, particularly in hotels and office buildings. The potential lighting measures described under the industrial lighting program can also be considered here. The selection of measures depends on the current state of the lighting stock, in terms of the applications, technologies currently used, and age. Although a large amount of data has been collected on the residential lighting stock in Indonesia, little is known about the C&P lighting stock. Building audits, however, reveal lighting intensities ranging from an efficient 10 W/m^2 of floorspace to slightly more than 16 W/m^2. (However, based on surveys from throughout the ASEAN region, average intensities are thought to be on the order of 17 W/m^2).

Maximum Technical Impact and Economic Justification:

Most of the potential for C&P lighting programs probably lies in the use of occupancy sensors and timers, replacing incandescent lamps with compact fluorescent lamps, replacing fluorescent lamps with high efficiency fluorescent lamps, and the use of optical reflectors. The industrial lighting measure analysis indicates the conditions under which each of these measures are justified. It is assumed that these measures can cost-effectively reduce consumption-weighted average intensity from an estimated 17 W/m^2 to 10 W/m^2, a reduction of 41%.

Market Potential:

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Instead of disaggregating market penetration by measure as was done with industrial lighting programs, market penetration is expressed here as the portion of load which achieves lower lighting intensity. Penetration rates are taken as the average of penetration rates for CFL replacement and occupancy sensors in the industrial program.

Portion of Lighting Consumption Modified by the Program during:	Consumption from Existing Light Systems	Consumption from New Lighting Systems
the first two years of the program	0.5%	2.5%
the second two years	1.5%	8.0%
the third two years	4.0%	30.0%

C.3: New Construction

All assumptions regarding the design and impact of commercial and public sector new construction programs are stated in the main text.

Residential Sector Programs

Based on surveys and analyses already conducted in Indonesia[5], the composition of residential electricity demand is assumed as follows:

[5] World Bank/ESMAP, Indonesia: Urban Household Energy Strategy Study, Report No. 107A&B/90, Washington D.C., 1990; and "Electricity Conservation Through Introduction of Energy Saving Lamps", unattributed document.

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End-Use	% of Total Residential Consumption	
	Urban Consumers	Rural Consumers
Lighting	53	60
TV	9	12
Iron	7	6
Refrigerator	10	10
Other, of which:	21	12
AC/Fans	3	
Water Pumps	6	
Miscellaneous	12	

Programs proposed here concentrate on lighting and refrigeration, which together account for about two-thirds of total residential consumption.

R.1: Improved Refrigerators

Background:

Refrigerator ownership is growing rapidly in Indonesia. Refrigerators imported from Japan are generally efficient relative to international norms. Most refrigerators, however, are assembled or produced in Indonesia. These models offer considerable scope for efficiency improvement.

Proposed Measures:

Work conducted by the Lawrence Berkeley Laboratory[6] identifies three strategies for improving household appliance efficiency:

- *The Downstream Approach.* This approach provides better information to consumers regarding appliance efficiency and relative economic benefits. Many

[6] Schipper, L., Meier, A., & Meyers, S., "Household Electricity Use in ASEAN Countries: The Upstream Strategy for Greater Efficiency", paper presented at the FINESSE Workshop, Kuala Lumpur, Malaysia, October, 1991.

countries have found that the most effective means of providing this information is to test appliances and label each with a measure of the absolute cost of energy expected for the appliance as well as its rating relative to other appliances in the same category.

- *The Midstream Approach.* This approach is used in many DSM programs in the United States. This approach encourages the sale of high efficiency appliances through rebates offered to vendors and/or consumers for those appliances.

- *The Upstream Approach.* This approach entails the government or utility working directly with manufacturers and importers to ensure that appliances offered for sale meet at least minimum efficiency standards.

A combination of these three measures are proposed for Indonesia. Downstream activities could be handled by Yayasan Lemabaga Konsumen Indonesia, Indonesian consumers union, and the utility laboratory and testing facility, PLN-LMK. Midstream and Upstream activities could be undertaken by PLN in collaboration with trade organizations.

Maximum Technical Impact and Economic Justification:

According to the World Bank\ESMAP report, simply producing refrigerators with rotary compressors and improved insulation would reduce energy consumption in domestic refrigerators by at least 20% and perhaps as much as 40% if the best technology available today were used. It is assumed here that the improved refrigerators reduce consumption by 25%. The World Bank/ESMAP report suggests that these changes would be economically justified.

Market Potential:

There has been little experience with residential appliance programs in the developing countries. It is expected that because the gap in household incomes and purchasing patterns between developing and developed countries is so much greater than between commercial and industrial enterprises, experience from the United States has even less relevance here than for the evaluations of commercial and industrial programs. It is assumed below that only 0.5% of the existing refrigerator stock is replaced with more efficient models than would have otherwise been purchased as a result of the program. This is consistent with the notions that (i) assuming a 10 year refrigerator life, far less than 10% of the total refrigerator stock is turned over every year; and (ii) that most who replace refrigerators would, even in absence of the program, have purchased more efficient (but also more expensive) Japanese refrigerators. It is also assumed that as a result of a successful upstream program, 30% of first-time buyers during the first two years of the program, 70% during the next two years, and 80% during the remaining two years, purchase the improved refrigerators.

Portion of Refrigerator Consn. Modified by the Program during:	Consumption from Existing Refrigerators	Consumption from New Refrigerators
the first two years of the program	0.5%	30.0%
the second two years	8.0%	70.0%
the third two years	17.5%	80.0%

R.2: High Efficiency Lighting

Background:

Surveys conducted by PLN for rural areas and DGENE for urban areas indicate that the average household has installed five lamps, three incandescent and two fluorescent. In particular, fluorescent bulbs are under represented among those burning more than 6 hours per day. Virtually all households have at least one lamp burning more than 12 hours per day.

PLN has subsequently undertaken a pilot project with three producers of high efficiency lamps in its Cabang Kebayoran branch in Jakarta. PLN, together with Indonesian trade associations, will install more than 3,000 energy saving lamps in households in the area. PLN is financing the survey of households to identify willing participants, as well as the cost of replacement. The producers are providing the lamps at reduced prices. Participants in turn pay for the lamps through PLN's Employee Cooperative.

Proposed Measures:

Replacing standard incandescent lamps with CFL's can reduce energy consumption by 75%. A direct installation program is proposed in which PLN or contractors replace incandescent lamps with CFLs in households. The pilot program currently underway by PLN will suggest the most effective ways of conducting this replacement. Financing the use of these more costly CFLs is one of the major impediments to broad dissemination; PLN appears to be addressing this problem through the use of the PLN Employee Cooperative. It is not known if payments are made through customer billing.

Maximum Technical Impact and Economic Justification:

Based on the report "Electricity Conservation through Introduction of Energy Saving Lamps", it is assumed that the lighting load of the average house will decrease by 45% by replacing the

three incandescent lamps with CFLs. That report, as well as the World Bank/ESMAP report, indicate the cost effectiveness of replacing these standard incandescent lamps with CFLs.

Market Potential:

The potential is assumed to be constrained by PLN's ability to install the devices. Clearly, door-to-door installation of an average of three bulbs for hundreds of thousands of households could present serious logistical problems. These problems could be reduced by concentrating on those households identified as having more than three bulbs to be replaced (although utilization, and hence energy savings, may decrease in these cases). It is assumed that an installer can replace 5,000 bulbs per year. (Installers could be paid per lamp replaced). The following assumptions are also made:

	Number of Lamps Replaced	Number of Installers Required
during the first two years of the program	310,000	31
during the second two years	420,000	42
during the third two years	520,000	52

These assumptions result in the following penetration estimates:

Portion of Lighting Consumption Modified by the Program during:	Consumption from Existing Lamps	Consumption from New Lamps
the first two years of the program	1.5%	1.5%
the second two years	3.0%	3.2%
the third two years	4.5%	4.0%

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This publication was made possible through support provided by the Office of Energy and Infrastructure, Bureau for Research and Development, U.S. Agency for International Development. The opinions expressed herein are those of the author(s) and do not necessarily reflect the views of the U.S. Agency for International Development.

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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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