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Philippines
Power Sector Study
Structural Framework for the Power Sector

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PHILIPPINES

POWER SECTOR STUDY

STRUCTURAL FRAMEWORK FOR THE POWER SECTOR

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Rural Electrification Revitalization Project (No. 9810-PH, December 23, 1991)
Power Transmission and Rehabilitation Project (No. 10996-PH, June 3, 1993)
Leyte-Cebu Geothermal Project (No. 11449-PH, January 6, 1994)
Leyte-Luzon Geothermal Project (No. 12568-PH, May 9, 1994)

CURRENCY EQUIVALENTS
(as of May 31, 1994)

Currency Unit	=	Philippine Peso (₱)
US$1.00	=	₱ 28.0
₱ 1,000	=	US$35.71
₱ 1	=	100 Centavos (Ctvs.)

WEIGHTS AND MEASURES

GW	=	Gigawatt (1 million kilowatts)
GWh	=	Gigawatt-hours (1 million kilowatt-hours)
kWh	=	Kilowatt-hours (1,000 watt-hours)
Kw	=	Kilowatt (1,000 watts)
MW	=	Megawatt (1,000 kilowatts)
HCDC	=	High capacity direct current
HVDC	=	High voltage direct current
kV	=	Kilovolt (1,000 volts)
km	=	Kilometer (0.6214 miles)
MW	=	Megawatt
MWh	=	Megawatt-hours (1,000 kilowatt-hours)

ABBREVIATIONS AND ACRONYMS

ADB	=	Asian Development Bank
BOI	=	Board of Investments
BOO	=	Build-Operate-Own Program
BOT	=	Build-Operate-Transfer Program
BTO	=	Build-Transfer-Operate
COA	=	Commission on Audits
DOE	=	Department of Energy
DOF	=	Department of Finance
DSM	=	Demand Side Management
EO	=	Executive Order
ERB	=	Energy Regulatory Board
IOD	=	Investor Owned Distributors
IPP	=	Independent Power Producer
MERALCO	=	Manila Electric Company
NEA	=	National Electrification Administration
NEDA	=	National Economic Development Authority
NPC	=	National Power Corporation
OECF	=	Overseas Economic Development Fund (Japan)
PD	=	Presidential Directive
PDP	=	Power Development Plan (NPC)
PNOC	=	Philippine National Oil Company
PPA	=	Power Purchase Agreement
ROL	=	Rehabilitate Operate Lease
ROT	=	Rehabilitate Operate and Transfer
SCADA	=	System Control and Data Acquisition
USAID	=	United States Agency for International Development

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EXECUTIVE SUMMARY

A. Introduction

1. **The Status of Private Power Development.** Since the Bank's 1988 Energy Sector Study, the Philippines has experienced a major crisis of electricity supply. At the lowest point of the crisis in 1992-1993, brownouts averaging seven hours per day were common in many regions across the Philippines. Facing serious economic losses, the Government sought to supplement the capacity of the National Power Corporation (NPC), the Philippines' monopoly supplier of electricity, with private power development. When the first Independent Power Producer (IPP) delivered a timely addition to generation capacity, the Government came to view a public/private partnership in the power sector as a viable strategy to help curtail temporary capacity shortages. As the shortage crisis deepened, the Government accelerated privatization of the power sector by taking a number of bold steps. It (i) rewrote exclusionary laws, (ii) drafted new policies in support of IPPs, (iii) streamlined clearance processes, (iv) restructured the Government energy sector policy departments and regulatory agencies and, (v) in general, acted to remove the constraints to broader participation of IPPs in Build-Operate-Transfer (BOT) and similar arrangements. By mid-1994, within an improved enabling environment, the private sector had some 30 generation projects under development, accounting for approximately 3000 MW of new capacity. While NPC remains the monopoly supplier for both generation and transmission to all electric distributors, the growing involvement of IPPs will result in a marked transformation of the power generation subsector from nearly 100% public in 1991, to nearly 80% private by 1998. With some 15 investor-owned utilities (IODs) and about 120 member-owned cooperatives (coops) owning and operating the entire distribution system, private interests will have come to predominate the Philippine power sector.

2. **Objective of the Study.** The devolution of power development to the private sector is a rapidly evolving trend, with important implications for the realignment of public and private sector roles, responsibilities and interests. Because of the urgent need to resolve the supply crisis, the Government has concentrated on creating a favorable climate for private sector-led growth. However, to assure consumers that their power needs will be met, the Government must have the capacity to make sound energy policy and coordinate sector development in the national interest. To this end, the main objective of this Study is to assist the Government to identify an appropriate structural framework to meet long-term energy goals, and to make recommendations on the actions required to guide the transformation to the post-privatization period.

B. Current Sector Structure

3. **Private Sector Effectiveness**. The recent Philippine private power development experience is marked by a successful supply response to urgent capacity shortages. Installation of 1300 MW by end-1993, completion of about 15 plants by end-1994 and agreements reached for an additional 5000 MW strongly support the policy shift from public to a public/private sector collaboration for the development and rehabilitation of generation capacity. Even with their relatively high costs, the early IPPs were justified in economic terms within a context of extreme supply shortages. More recent IPPs have lower prices and costs closer to international levels, due, among other factors to improved competition. The effectiveness of privatized generation is fully analyzed in this Report.

4. **Private Power Financing for Generation**. Detailed information on the sources and structure of private financing for power generation is limited. Evidence suggests, nonetheless, that mobilization of load capital for IPPs is on the rise. Moreover, the pattern of debt appears to have shifted from a heavy reliance on official financing in early projects to a growing participation of commercial banks and bond issues in more recent generation investments. Domestic resources have also begun to be mobilized, a phenomenon that warrants support and encouragement.

5. **Private Sector Performance in Distribution**. Responsibility for distribution in the Philippines lies entirely with some 135 investor-owned private utilities (IODs) or member-owned cooperatives (coops), all of whom have exclusive rights to provide medium and low voltage service within their franchise areas and are subject to price regulation. Only the Manila Electric Company (MERALCO) is of substantial size, with established international commercial credit. The remainder are modest operations serving small towns, villages and rural areas, with a record of operational performance ranging from acceptable to poor. MERALCO is a sound company, capable of self-financing a significant portion of its ongoing network rehabilitation and attracting IPP interest. At the same time, its regular tariffs are distorted by cross-subsidy requirements. The other 14 IODs have demonstrated mixed financial performance, notwithstanding large wholesale-retail markups on NPC-sourced power. They do not own or control their sub-transmission networks, since they lack adequate maintenance capacity. The 120 coops, on average smaller than the IODs, have even less opportunity to become commercially viable, given their size, modest engineering and maintenance capacity and concentration of low-income, low consumption customers. Notwithstanding these constraints, some coops outperform nearby or comparable IODs.

6. **Public Sector Effectiveness**. As the capacity shortage became a crisis, the Government initiated some restructuring of the various energy agencies, while seeking broader private sector participation. This Study found that the organizational framework of the Department of Energy (DOE), the Energy Regulatory Board (ERB) and the National Electrification Administration (NEA), is sound. Institutional weaknesses, which have been identified, can be remedied through capacity building, training, and a realignment of staffing levels with responsibilities. At the same time, however, these institutions do not have the authority or means to adjust their staffing and budgetary resources to address these constraints. Moreover, although the regulatory framework and law are well established, power sector reform will continue to pressure ERB's regulatory capabilities, requiring increased staffing in some instances and improved skills of existing staff. Important challenges for the regulators include: (I) the rapid increase of IPP involvement; (ii) legally mandated shifts in organizational responsibilities among the agencies; and (iii) freer interaction in the future between suppliers and consolidated distributors. As the role of private developers increases,

so, too, will the importance of regulation. These challenges can only be met successfully if the Government is committed to addressing the existing capacity constraints.

7. **Policy Formulation and Planning Capacity**. An enabling environment for private sector participation requires (i) clear Government policies and rules for independent power generation, (ii) independently priced transmission, and (iii) stronger distribution companies. This Study found that DOE's capacity for policy formulation and rulemaking has not kept pace with the requirements of sector transformation. Moreover, the growing number of decisionmakers within the power sector needing access to adequate and reliable information on supply and demand indicates that weaknesses in the public sector's capacity for planning needs to be remedied. Over the longer term, however, Government agencies' capabilities for data gathering and analysis must be upgraded to provide a reliable stream of information on the status of power projects, thereby reducing uncertainty in planning future supply. Since contracts have already been signed that ensure the provision of enough capacity by 1999, even to meet the highest demand scenarios, the Government does not need to compromise either on the approach it takes to planning, or on the fastidiousness with which it implements the accreditation process.

8. **Government Power Sector Objectives**. The Government's major power sector goal is to meet all future capacity requirements in collaboration with private developers and private capital. With that goal in hand, NPC and the distribution companies must be restructured and Government agencies strengthened to capture the benefits expected to ensue from privatization. In fact, the realization of these benefits depends in large part on the development of competitive markets for electricity at both the supply and distribution ends of the industry. This study recommends appropriate and achievable changes in the structure and operation of power-related institutions, and it recommends some legal and regulatory adjustments to this end. The interim and final structural changes outlined in this study are believed to be feasible in the Philippines context, where transformation of the power sector is well underway and the Government is prepared to make additional adjustments, within the constraints of current realities.

9. **Major Restructuring Issues**. Following the Energy Sector Action Plan (ESAP), studies have been conducted to find the best course by which the Government and the power sector can achieve their goals. At this point, three issues dominate: (i) the restructuring and privatization of NPC or some of its parts; (ii) promoting and realizing the benefits of competition as manifested by lower retail prices and the sharing of risks between suppliers and distributors, without the intervention of the Government as an intermediary; and (iii) formulating appropriate future roles of NPC and the Government in a transformed power sector. Privatization of generation has grown rapidly, but effective competition and risk sharing have been inhibited by captive relationships, franchise restrictions, and monopolies. NPC is still the dominant supplier in the sector, purchasing for resale more than 80% of planned IPP-produced electricity and assuming most of the market risk as well. NPC would prefer to pass the market risk to the distributors, but most are so weak and fragmented that few IPPs are as yet inclined to deal with them directly. Except for some direct connections to NPC's higher voltage, customers must purchase power from the local distributor. NPC holds a monopoly on the transmission system, and by literal default, responsibility for subtransmission systems outside MERALCO's service area.

10. **Further Restructuring**. NPC has effectively assumed the major role as purchaser and reseller of electricity; this role has been instrumental to the Government-private sector collaboration in addressing the recent shortage crisis. Nevertheless, NPC continues to be subject to demands for greater accountability; this pressure is manifest through a myriad of legislation that calls for the reorganization or dismemberment of NPC. This study found that a major restructuring of the

NPC was inevitable. This study also examined the structure and performance of the distribution subsector, and found it needed extensive restructuring in order to enable the market risk to revert to the distribution utilities (where it belongs).

C. Realities and Constraints

11. Successful power sector restructuring must take account of constraints that derive from current realities. The structural framework that works best will necessarily be rooted in feasible adjustments to the status quo; if adjustments are not feasible, then those constraints must be accommodated. These constraints include:

(a) ***Pressure to Privatize NPC.*** Pressure to reorganize NPC is considerable. DOE has already stretched the ESAP schedule for privatizing NPC. The momentum within the Government, the general public, and the Philippine Congress is to split NPC along regional lines. Riding this wave, the Government must steer regionalization proposals so that actions proposed are comprehensive and appropriate; and so that institutional capabilities are developed for functions that may be retained within the Government's ambit.

(b) ***NPC's Corporate Problems.*** NPC is still recovering from a decade of institutional shocks, and faces challenges to its technical, financial, and public credibility: (i) it must rebuild its technical cadre, key elements of which were lost to better-paying competitors; (ii) it must maintain credit only recently rebuilt following years of uneven financial performance; (iii) it must maintain a strong cash position and realize its local currency requirements from revenues; and (iv) it must rebuild the public confidence that was lost during the depth of the power crisis.

(c) ***Condition of Existing NPC Generating Plants.*** NPC's thermal generation facilities are old and overworked. As a result, they fall into disrepair more often than they should be for continued dependable production. Because of drought and siltation, NPC's hydro plants operate at reduced capacities. The condition of these plants will likely depress the price they could command in a privatization.

(d) ***Bundled Transmission and Underdeveloped Dispatch.*** As a sponsor of captive IPPs, generation developer, and wholesaler of electricity, NPC cannot serve as sponsor of the IPPs, developer of its own generation capacity, and wholesaler of electricity, and also act as (i) an impartial planner and operator of the transmission system and (ii) formulator of rules of dispatch. In the future, when supply is ample, multiple suppliers will need unbiased access to the transmission system. Therefore, a dispatch entity that is competent to establish fair and transparent rules needs to be developed.

(e) ***Deteriorating Distribution Systems.*** Almost all distributors have let their networks suffer from underinvestment and neglect of maintenance. The reasons for this vary widely, but the end result is the same -- substantial investment is needed to renew deteriorating assets, over and above requirements for meeting the needs of a growing market.

(f) ***Island Geography***. Geography imposes constraints and costs on the network. The nine largest islands, containing 95% of the population, are served by seven separate grids, most of them too small to optimize. Within each island, the topography and settlement patterns make electrification expensive.

(g) ***Pricing and Tariffs***. The Government's pricing policies have been at variance with NPC's supply constraints. As a result, electricity is already very expensive for unsubsidized consumers. The structure of tariffs needs revision to include demand charges. Distorting subsidies need to be eliminated or made fully transparent. Appropriate regimes for wheeling and standby charges need to be developed.

(h) ***Regulation and Rulemaking***. As the role of the IPPs increases, so too will the importance of regulation. Yet, ERB has serious capacity constraints, and the Government must support its development and assure adequate funding for its operations.

D. Proposed Structure for the Power Sector

12. **Collaboration Between the Public and Private Sectors**. This Study examined several electricity supply and demand scenarios. Including long-deferred replacement of near-failing plants, all scenarios projected capital requirements for generation during 1994-2000 at US$10 billion or more; for the same period, investments in transmission should exceed US$3 billion. Neither the Government nor the private sector, acting alone, can mobilize such amounts. Therefore, the Government and the private sector must continue collaborating constructively for the foreseeable future. For its part, the public sector must focus on two extremely different roles:

(a) ***Maintaining an Orderly Industry***. The Government needs to focus on maintaining an enabling environment, within which the private sector can compete without undue constraints. Some laws that enable independent production are currently in place. However, few limitations were placed on (i) the primary fuels or on the technology that an IPP can deploy; (ii) an IPP's ability to sell to the grid or directly to one or more distribution utilities; (iii) guaranteed off-takes through take-or-pay provisions in PPAs; or (iv) the plant factors to be realized by some of the new facilities. NPC is still formulating its policies regarding stand-by capacity and wheeling. Very little consideration was given to the requirements for economic dispatch.

(b) ***Providing Electricity Supplies***. NPC, either in its present or some unbundled form, must continue operating plants and purchasing generation and stand-by capacity over and above what is provided by the IPPs. Thus, it will continue to be the supplier of last resort and to bear the burden of market risk. The IPPs have thus far shown limited interest in investing in facilities designed to serve lesser markets, and the smaller distribution utilities lack the financial strength or the market attractiveness to make separate purchase arrangements with the IPPs.

13. **Restructuring of NPC.** Recognizing these constraints, this Study developed a restructuring proposal for the power sector, starting with unbundling of NPC. This Study recommends that certain corporate functions remain national in scope:

(a) ***Power System Planning.*** The Government should retain the responsibility for general coordination of its own and the IPPs' planned additions to the power system. Responsibility for power system planning should be moved from NPC to DOE, but only after the Government furnishes DOE with adequate staff resources to absorb this function.

(b) ***Hydroelectric Development.*** The harnessing of hydro resources involves several departments of the national Government. Therefore, investments concerning the exploitation of these resources need to be formulated at the national level, and should remain within the ambit of NPC's national headquarters.

(c) ***Backbone Transmission Systems and Dispatch.*** The backbone transmission system, consisting of facilities for 138kV and above, could still be regionalized. However, responsibility for the system should be retained at the national level, so that the priority for interconnection will not be subordinated to regional concerns. The need to ensure suppliers unrestrained access to the transmission system provides a compelling rationale for creating a transmission company that is distinctly separate from any state enterprise involved in power generation. For the same reason, this proposed new company should also own and operate all facilities for dispatch. The dispatch function must be executed fairly and efficiently. The participation of the Government, NPC, the IPPs and distributors in the formulation of a dispatch entity and dispatch policy can be an outstanding opportunity to reach long-term consensus on those principles and enable a competitive environment for private sector participation.

Other major functions, including generation, engineering, procurement, and maintenance are not national in scope, and can be organized on a regional basis (para 15).

14. **Charter and Structure of the Transmission Company.** Capitalization requirements for the new backbone transmission company need to be determined by the Government, with independent advice. At the outset, the new company would operate transmission facilities, complete projects belonging to NPC, and absorb outstanding associated liabilities. The Government should provide the new company with enough initial working capital so that it can be organized as a commercially operated utility. The company's networks should be available non-discriminatorily to all suppliers, and the rules of dispatch should be transparent. The company's investment program should be approved annually by ERB; and its tariff should be based on cost and subject to ERB regulation. While the company should follow commercial operating principles and its charter should allow for some future private ownership, scrupulous impartiality should be nurtured by not offering shares for sale to the public (and risking that one or two suppliers acquire significant ownership) until a healthy competition among suppliers has been achieved.

15. **Regional Subsidiaries.** NPC's generation facilities should be spun-off to proposed wholly-owned subsidiary regional companies, functioning as holding companies for existing plants and developers of new state-sponsored thermal generation facilities. This study recommends three such subsidiaries--one each to serve Luzon, the Visayas, and Mindinao. Capitalization plans for these companies remain to be developed; still, creditors will require the subsidiaries to absorb all liabilities related to assets they acquire from NPC. Their charters should enable them to (i) follow commercial operating practices; and, once soundly operated, (ii) sell some of their shares to private

interests. Pursuant to ESAP's commitment for NPC to privatize rehabilitation and operation of existing facilities, the regional companies should have the same authority to enter into a broad array of such arrangements with qualified IPPs. However, if the regional companies succeed in implementing commercial operating practices for their own plants, they should not be precluded from competing with the IPPs to supply distributors in their areas.

16. NPC will continue to have a vital headquarters operation in the future. In the near term, it should establish a sound basis for spinning off the transmission company and regional subsidiaries, then help them acquire investment capital and operating credit. Until the regional subsidiaries have developed favorable records for operating and financial performance, the parent could be expected to act as their guarantor. Once the subsidiaries can obtain financing on their own merits, the parent will act more like a holding company; it will (i) assist the subsidiaries with cash management, (ii) collect interest and dividends from the subsidiaries; and (iii) meet its remaining liabilities.

17. **Distribution Consolidation**. Because real competition among suppliers depends on the development of more large commercially-viable buyers, the recommended eventual structure depends on consolidation of the distribution utilities. Such a consolidation can lead to needed efficiency reforms. It should be formulated to accommodate the combination of coops and IODs; the general thrust should be shrink the number of small utilities from more than 130 entities to about 15 or even fewer continuous units. Consolidated utilities would reside within natural geographic boundaries defined by NPC's main supply points. While MERALCO would continue to be a dominant distribution company, a dozen or more amalgamated 300+ MW utilities can become a competitive market of commercially credible consumers for the IPPs.

18. Until the distribution subsector is consolidated, NPC subsidiaries will be unable to shed some important technical functions, as well as the market risk, which should really be borne by the distribution utilities. Even so, the regionalized parastatal subsidiaries will need to continue buying electricity for resale to the unconsolidated distributors; and the backbone transmission company will need to continue to operate and maintain the subtransmission networks. The process of consolidation could an opportunity to implement transition arrangements that are far more orderly than the current ones, and to develop true competition among IPPs vying to supply electricity to strengthened distribution companies that emerge from consolidation.

19. **Subtransmission**. While the subtransmission systems properly belong with the distributors, virtually all but MERALCO are too weak and fragmented to manage these networks properly. Therefore, the 69kV networks outside of MERALCO's service area should remain with the national transmission company; however these networks should be offered as incentives to distribution utilities to consolidate.

20. **Commerce among Producers, Buyers, and Sellers**. The proposed structure anticipates and supports competitive market-based contracts among all commercially qualified and credible participants. Impartial and fairly priced dispatch and transmission services would permit buyers to find the most appropriate match of wholesale level supplies, capacity, service, and price. Even as NPC subsidiaries continue to play a role as purchasers and resellers of electricity during transitional arrangements, these reforms are expected to move the power sector toward the Government's goals of ample, appropriate, and competitively priced supplies.

21. **Government Agencies and Functions**. The proposed framework will continue to involve regulation and monitoring by the Government's energy agencies (eg.DOE, ERB, and NEA).

The study analyzed their current structure and operation, and recommended roles and improvements are offered later in this summary. A major feature of the proposed sector structure is increased reliance on effective competition as a regulator. Except for some minor shifting of functions to strengthen alignment of roles within these agencies, the majority of the structural reform has already been anticipated and authorized by legislation. Significant staff development and organizational strengthening will be required, and they are needed now; these matters are discussed in the recommendations for the interim arrangements.

22. **Need for Transitional Arrangements**. The recommended framework cannot be implemented before NPC and the distribution utilities are restructured. NPC has already realigned its organization into profit centers, and it has already taken substantial steps toward (i) giving autonomy to transmission operations, (ii) separating the costs of generation from transmission, and (iii) decentralizing the structure of its generation activities. Such arrangements, rooted in decisions of the NPC Board as opposed to legislation, might not accord the necessary independence to the transmission company, but the operational aspects of reorganization could begin. On that basis, NPC and ERB could develop the parameters for wheeling charges and dispatch criteria.

23. On the other hand, the viability of the recommended structural framework depends on the reform of the distribution subsector. In their current fragmented state, distributors other than MERALCO have insufficient levels of demand to attract the attention of the IPPs or to absorb the market risk of PPAs. Many of the others have been chronically late at paying their bills and have been regarded as marginal credit risks. With few exceptions, they have no alternative but to draw their supplies from NPC since few IPPs would consider taking the commercial risk of serving them unless, they are subjected to a substantive subsector-wide reform process. The recommended structural framework cannot work unless the distribution subsector has been consolidated. Until then, the regionalized parastatal generating companies need to retain the ability to buy electricity for resale to the unconsolidated distributors; and the backbone transmission company will need to operate and maintain the subtransmission networks.

24. **Congruence of the Study Proposals with Other Initiatives**. On June 10, 1994, NPC's management presented internal reorganization proposals of its own to the National Power Board; these were directed at encouraging and decentralizing management of the various parts and functions of NPC. Proposed subsidiaries include: (i) an NPC Holdings Company, to handle treasury, planning, and centralized dispatch; (ii) a transmission subsidiary to serve Luzon and the Visayas and administer Power Purchase Agreements (PPAs) within these service areas; (iii) an integrated Mindanao Power Corporation, to provide transmission and generation services within that large southern island; (iv) separate subsidiaries for hydropower, geothermal, and barge based (and small island) supplies; and (v) an engineering and maintenance subsidiary to take responsibility for NPC's operational activities.

25. NPC's own draft proposals are generally consistent with those recommended in this Study, and point to similar structures. For example, the few generating plants in the Visayas unaccounted for in NPC's proposals could be bundled with (their) proposed Barge subsidiary to form a company similar to the Visayas Power Corporation recommended by this Study. The principle endorsed by the National Power Board-- operation of NPC's parts as profit centers-- comports with this Study's expressed concern for commercial operation as a prerequisite for continued success in gaining necessary domestic and international financing.

26. The Government's Energy Sector Action Plan (ESAP) committed the Government to policies of privatizing NPC and devolving future power sector development to private interests.

Several studies commissioned under the Plan examined possible approaches to unbundling NPC. These studies concurred that the unbundled parts of NPC can be managed more effectively than the current Corporation; in contrast, they all but left unanswered questions about how rapidly NPC can be privatized. A receptive market is needed if the Corporation would sell its shares successfully; and the Corporation cannot expect to divest itself of plant and equipment unless those assets are in good condition. Therefore, this Study concluded that the issues of power sector structure and NPC ownership are quite distinct; any recommendations to change ownership needs to be feasible, and recommendations regarding structure should not depend on changes to the pattern of ownership.

E. Planning, Regulation, Competition, and the Role of Government

27. **Financial Implications**. Private investments in generation must be integrated with NPC's own generation and transmission investments and with the distribution utilities' investments in network expansion and rehabilitation. At the same time, NPC must maintain its profitability in order to raise official and commercial capital, and structure tariffs to yield revenues adequate to cover the costs of ever more expensive generation from all sources. By efficiently (i) rehabilitating its own power plants, and (ii) improving the technical capacity of the transmission system, NPC can contain the extent of cost increases that must be recovered.

28. Only modest efficiency improvements in the distribution subsector are possible without consolidation. To date, distributors have seen few incentives to grow larger and integrate their service areas, even though larger consolidated companies could better attract effective managers, reduce overhead, and enhance distributors' financial prospects. In particular, bigger, stronger buyers capable of dealing directly with IPPs would also hasten the evolution of the power sector by shouldering the market risk for themselves, thereby enabling the Government to press the IPPs to assume the commercial risk associated with their investments. However, the Government must develop strong incentives for consolidation to occur.

29. **Competition and Risk Assumption in the Proposed Structure**. To assure ample and efficient long-term supply, the Government needs to (i) create a level playing field for all participants in the sector; (ii) foster competition at both the supply and distribution ends of the industry; and (iii) reduce the layering of institutions between suppliers and consumers. The recommended structure has at its core a separate transmission company that would wheel power between and among NPC's regionalized generation subsidiaries, the IPPs, the large volume higher voltage consumers, and the consolidated distribution companies. The distributors and large volume higher voltage consumers, in turn, would have direct contractual relationships with suppliers, so that they would absorb the market risk. Monopoly and captive relationships among originators, producers, distributors, and large consumers of power would give way to market exchanges among them, subject chiefly to technical and competitive economic considerations.

30. By moving NPC or its subsidiaries away from reselling energy, consumers and weaker participants in the power sector will be less protected from supply and price risks. These risks can be minimized and managed by a stronger DOE through its exercise of enhanced planning and accrediting functions. DOE will need to maintain a current and detailed inventory of all planned and ongoing IPP activity; and its accreditation process will need to be tightened to ensure that each new development is rationally financed and fits into a general system plan.

31. **Directly Connected Customers and Wheeling.** Some 91 consumers now receive electricity at 69kV directly from NPC. Under the proposed new structure, consumers with monthly loads over 5 MW and financial credibility will be able purchase supplies directly from IPPs, NPC subsidiaries, or their local distributors, paying suppliers for energy, NPC for wheeling related to transmission, and local distributors for wheeling related to subtransmission (where appropriate).

32. **The Role of Regulation.** Because the recommended structure anticipates and supports direct contact between suppliers and distributors, it also has the important advantage of relying less on Government regulation than several alternative frameworks that were considered. In effect, competitive market forces would protect the consumer as well as the regulatory process might. ERB would continue regulating the distributors' tariffs since they would effectively continue to have protected monopolies; moreover, since this model would continue to feature long-term supply contracts, the distributors would benefit from ERB conducting a prior review of provisions of those agreements related to distributors' ability to pass-on properly incurred energy and power costs. To strengthen its capacity, ERB would still need to undergo a substantial institution building effort; in addition, ERB needs to recruit more qualified staff and charge a regulatory fee to defray its expenses.

33. **Load Dispatch.** Implementing a fair and transparent load dispatch system appears to be one of the most important residual future roles in the power sector for the Government. Load dispatch should be linked to operation of the transmission system; that linkage appears to have advantages in the Philippines, where no precedent exists for collaborative pooling among competing suppliers. As substantial additions to capacity come on line, the dispatcher will determine the order with which plants are brought on line so as to minimize consumers' costs. However, provisions will be needed to honor NPC-executed PPAs that guarantee a high off-take for some relatively high cost electricity.

34. Technically, dispatch is an adjunct to transmission; and the dispatch function should be performed by an independent dispatch entity located at and as a part of the proposed new transmission company. The forerunner of this dispatch entity should be a preliminary technical Coordination Committee, composed of representatives of parties to existing power generation contracts, with ERB and DOE as advisors. Its purpose will be to formulate rules and priorities for dispatch, and to design a framework for the evaluation of financial risks of existing contracts. With the eventual creation of a power pool, this Committee will evolve into a permanent Committee with similar dispatch rulemaking authority.

35. **Recommended Roles of the Government Power Sector Agencies.** The framework for the eventual structure and arrangements during the transitional period rests on rationalized roles of the Government agencies participating in the sector:

(a) DOE should serve mainly as the policy maker for the sector. DOE should provide clear vision on strategic issues and clear rules forming the framework within which the regulator can adjudicate. DOE should become more fully capable and then responsible for developing the strategic plan for sector development. Because DOE is in a position to span the entire range of the power sector without conflict of interest, it should take responsibility for accrediting IPP proposals and for maintaining a comprehensive, up-to-date inventory of all power developments nationwide.

(b) NPC, through its subsidiaries, should limit its role to being an owner and sometime operator of generating facilities. It should retain lead responsibility for developing

hydropower projects, and should be one of many suppliers of thermal electricity, all competing on equal commercial footing. In the near term until DOE develops the needed capabilities, NPC should continue as the agency responsible for power sector planning. Also in the intermediate term, until distribution subsector reform has taken root, NPC will need to continue as the wholesaler of electricity.

(c) The new national transmission company should serve strictly as an owner, developer, and operator of high voltage networks, providing all suppliers with nondiscriminatory access to the system for a fee. To ensure adequate and timely service, it should submit its investment program annually to ERB for approval. To ensure that its charges are fair, its cost-based rates should be subject to regulation.

(d) NEA's should shed some peripheral activities and focus on its current primary role, that of an interested lender for subtransmission and distribution systems. To facilitate distribution utility consolidations, NEA should be encouraged to lend to the IODs with at least the same priority it has traditionally accorded coops. NEA's role in the program to reform the distribution subsector can be pivotal, as it could provide guidelines, and the distributors themselves could be invited to formulate the consolidation framework. However, NEA lacks some of the institutional capacity needed to spearhead the proposed consolidation of the distribution utilities, and it should therefore by strengthened. In addition, NEA's ability to deal with issues of credit and financial engineering will need reinforcement.

(e) ERB should remain a quasi-judicial agency for regulating mainly the tariffs of all companies that qualify as electric utilities. However, the approach to regulation should rely most heavily on market forces and thereby limit the interventions of the regulator. ERB's span of jurisdiction should be altered to include the power to award franchises, thereby bringing franchising and certification activities under the same organization (para 38).

(f) A dispatch entity needs to be created, as described above (para 30). The rules for dispatch should initially be made by a technical committee consisting of representatives of parties to existing power sales contracts, with advice from DOE and ERB.

These roles will enable the various Government agencies to create the proper environment for encouraging the continued momentum of the private sector for developing power sector facilities. Where market forces are not yet strong enough to drive sector development, these roles will permit the Government to fill those voids.

36. **Policies for Consolidation of Distribution Utilities.** Legislation to restructure the power sector should include policies on consolidation of distribution utilities. At the outset, the distributors should be invited to formulate their own consolidation programs; however if they fail to do so within a reasonable time-frame, NEA should issue detailed guidelines for accomplishing this objective. The Government could offer incentives to distribution utilities that do consolidate, and impose price and tax disincentives on those that prefer the *status quo*. The leading incentive is the 69kV subtransmission system, by which distributors with solid financial and commercial potential can earn wheeling and possibly supply charges for serving their areas' medium and higher voltage consumers. NEA should encourage the consolidation of distributors by making the availability of credit much more stringent for those refusing to combine.

37. **Enhanced Regulatory Capacity**. Structural changes in the sector have already placed new pressures on the country's regulatory capabilities. While DOE, ERB, and NEA are generally performing well, the size and technical complexity of the increased work load necessitates a major increase in staffing as well as additional training for new and existing regulatory staff. These agencies need to become quickly capable of dealing with: (i) the rapid increase in IPP involvement in the sector; (ii) legally mandated shifts in organizational responsibilities among the agencies; and (iii) the anticipated direct interaction between suppliers and consolidated distributors.

38. NEA has performed creditably as the regulator of the coops through 1992. However, with the passage of the Department of Energy Law, that function was transferred to ERB. In order to enable this recent allocation of regulatory responsibility to function effectively, additional legislation will be needed to transfer responsibility for awarding electric utility franchises from NEA to ERB. This would consolidate the authority to award franchises and to certify distributors within one agency--ERB. The effective transfer of franchising responsibility will relieve NEA of inherent conflicts between its roles as lender and quasi-regulator, while consolidating ERB's legal and technical authority.

39. **Recommended Types of Regulation**. This Study recommends continuation of rate-of-return regulation. ERB was developed according to the U.S. regulatory model, and its staff has developed expertise with regard to U.S.-based systems. At a time when ERB is struggling to expand its capacity to service 135 distribution utilities and NPC on a timely basis, it cannot also change its approach to regulation. At the same time, the IODs and NPC are all legally required to limit their financial performance to less than the maximum level stipulated by their charters. As a result, they are subject to a modified version of price cap regulation.

F. Recommendations to Enable the Environment for Competition

40. The most important objective of the enabling environment is uniform market arrangements for all participants. To develop this rapidly, the Government needs to address specific issues related to pricing, dispatch and regulation, in addition to the restructuring proposals discussed above.

41. **Tariff Reform**. Higher voltage power tariffs should by structured to reflect costs. This Study revalidated previous Bank recommendations to: (i) unbundle fixed and variable costs within tariffs, and (ii) introduce time-of-day differentials, at least for high and medium voltage consumers. Tariffs should unbundle the cost-based components of energy and capacity in order to end inter-regional distortions and stimulate demand side management. At the retail level, residential subsidies should be eliminated over a five-year period, enabling distributors to lower their rates to larger higher voltage consumers or risk losing them to less expensive wheeled supplies. Tariffs must explicitly include costs of stand-by capacity; otherwise self-generation will remain an attractive and implicitly subsidized alternative, and will continue to remain a random component in forecasts of power supply and demand. Moreover, at the wholesale level, pricing of power in the different regions should reflect the true costs of generation and transmission. Current inter-regional cross-subsidies have served as a substantial disincentive to IPPs interested in locating plants in the Visayas or Mindanao.

42. **Wheeling Charges**. The development of independent transmission is necessary for competition. Separation of transmission costs and development of wheeling charges as part of the tariff for energy can be developed and later applied to the bulk transfer of electricity between buyers and sellers in the power sector. In order to encourage IPPs to site their plants at favorable locations without losing the flexibility to identify the best possible selling arrangements, an acceptable framework for wheeling charges over the transmission and subtransmission systems is needed.

43. **Taxation**. Taxation of fuels for power generations needs to be rationalized. To enable all suppliers of electricity to pay the same amount for fuels while shouldering the fuel supply risks for themselves, this study recommends that fuel tax exemptions should be extended to the IPPs; since the IPPs have been avoiding this tax by engaging in energy-conversion contracts with NPC the Government would not be foregoing any existing tax revenues. Equal treatment of all suppliers could similarly be achieved by eliminating the fuel-tax exemption entirely; however, this would require a politically difficult 10-15% increase in retail electricity prices without concomitant improvements in service.

G. Conclusion

44. The measures employed to resolve the power crisis of 1992-93 are the leading edge of a major transformation of the Philippine power sector. The Government should now guide this ongoing transformation so that private development becomes self-sustaining, and the private sector participates in the spate of sector development prospects, not just those few that are particularly favorable financially. The Government can do this by (i) simplifying the structure and roles of public agencies participating in the sector; (ii) taking necessary steps to support development of market transactions in wheeled electricity over transparently operated transmission and subtransmission systems; and (iii) encouraging balanced market power between private companies in the generation and distribution subsectors. The principal objective of these agencies and the opening of the transmission system should be to encourage a business climate in which the private sector can flourish.

45. This study has developed a structural model based entirely on Philippine circumstances, with due consideration for the history of the power sector and the constraints which caused the recent and rapid transformation of the supply side of the sector. It does borrow from several of the other models where appropriate. But, the parameters have been designed to address Philippine issues, and efforts were made to test the feasibility of the recommended framework against Philippine problems. Therefore, the recommended structural framework is considered to be a uniquely Philippine model.

1. Realities and Constraints

A. Introduction

1.1 Since the Bank's Energy Sector Study in 1988, the Philippines has experienced a major crisis of electricity supply. At the depths of the crisis in 1992-1993, brown-outs averaging seven hours per day were common in many regions of the country. Ironically, the crisis followed the Government's substantial steps to strengthen the National Power Corporation (NPC) operationally and financially. Moreover, because existing capacity was considered sufficient to meet increases in demand projected through about 1991, NPC did have sufficient lead time to implement least- cost additions to its generating capacity.

1.2 During the period 1988-1992, (i) NPC was subjected to new regulations standardizing all Government agencies, (ii) the tariff adjustment process became politicized, so that the Company's operating and financial capacity became constrained, and (iii) the Company did not make effective use of available lead time to implement investments in needed new capacity. During that same period, persistent drought conditions resulting from the *El Nino* phenomenon limited the country's hydroelectric output (especially in Mindanao), and thereby exacerbated the growing capacity constraints. These constraints grew tighter as environmental clearances for several fully financed NPC initiatives to add coal-fired capacity to the Luzon grid were delayed because of protests from affected local populations.

1.3 In 1990, when NPC assessed the impact of delays in its program to provide new capacity and began facing the certainty of supply shortages in Luzon for 1991 and beyond, the Company determined to supplement its own efforts with private development of generating facilities. The first such initiative, a 200 MW peaking plant at Navotas developed by Hopewell Holdings under a Build-Operate-Transfer (BOT) arrangement, was synchronized with the Luzon grid in less than two years.

1.4 In many respects, that project was beneficial for all parties. Most importantly, that project showed that the Government could collaborate with private interests to make timely additions to generation capacity. The project proved to the Government that its own resource and absorptive capacity constraints need not unduly limit the development of the power sector; and it opened up prospects for the private power developers that the Philippines might be a hospitable country for pursuing business opportunities. This project was the forerunner, then, of a broader program to devolve to the private sector broad responsibility for power sector development.

1.5 On a project specific basis, the Navotas project produced ambivalent results. By purchasing a used plant in good condition, Hopewell could implement the project quickly at low cost; and it passed some of the savings on to NPC. However, NPC is assuming the fuel supply risk for the life of the project, and the Government agreed to guarantee NPC's commercial obligations under the Power Purchase Agreement (PPA). Also, the PPA included (i) a guaranteed off-take through a take-or-pay provision, and (ii) substantive incentives to exceed that off-take and thereby run the facility as a base load or intermediate plant. These features, which limited the commercial risk being borne by Hopewell, were appropriate to a circumstance where a developer was venturing a substantial long term investment in a country that had theretofore had no experience with Independent Power Producers (IPP).

1.6 As the capacity shortages became a crisis, the Government pressed for additional private sector developed projects, following the Navotas model. Within a year, the Government had committed to another dozen BOT or Build-Transfer-Operate (BTO) schemes. A number of these initiatives came under a special program, implemented in July 1992 during the first weeks of the Ramos Administration, to install 1000 MW on a "fast-track". Most of the "fast track" plants are gas turbines, which are characterized by the low capital cost, short construction period, and high operational costs typical of peaking facilities; however, for these additions to capacity to meet suppressed demand, they are run at plant factors more appropriate for base load facilities.

1.7 As of mid-1994, the Philippines was well on its way toward a broad and self-sustaining collaboration between private and public interests to supply the nation's electricity needs. Therefore, this appears to be a propitious time to assess the country's early experience with this collaborative process. This study will attempt to draw from the lessons of the past, recommendations for how to adjust the structural framework and the enabling environment so that development of the power sector in the future will be orderly and cost effective.

B. Current Sector Structure

Framework for Government Control

1.8 Until 1986, all primary energy sector institutions fell within the ambit of the Ministry of Energy. PNOC served the retail market for coal and oil-based products in addition to its primary activity as developer and converter of primary energy resources. In turn, NPC was the monopoly supplier of electricity at the wholesale level; some 15 investor owned utilities (IODs)(including the Manila Electric Company [MERALCO]) and about 120 member owned rural electric cooperatives provided service to consumers at the retail level. The Ministry of Energy was neither directly nor indirectly involved with the distribution utilities. The Energy Regulatory Board (ERB), an agency of the Office of the President, ensured adherence of the investor-owned utilities with Government policies through its authority to regulate their rates. NEA, then an agency of the Ministry of Human Settlements, enforced Government policy on the coops by setting their rates and serving as their conduit for concessionary borrowings.

1.9 In 1986, the Government disbanded the Ministry of Energy; its research functions were assigned to the newly created Office of Energy Affairs (OEA), while PNOC and NPC both were assigned to the Office of the President. To improve coordination between the various Government energy agencies, the Government created the Energy Coordinating Council (ECC) in 1989; the Executive Secretary chaired the Council; OEA served as its Secretariat; and PNOC, NPC and NEA were its permanent members. This arrangement was flawed in that ECC had no legal authority to make or enforce decisions. To remedy this, the Government created the Department of Energy (DOE) in 1992, and PNOC, NPC and NEA were all brought under its control. The Secretary of Energy became the ex-officio Chairman of PNOC and NPC; he was also legally empowered to serve as the Chairman of NEA unless the President appointed someone else (this did happen). OEA was folded into DOE, and most of OEA's staff were transferred into the Department's key positions. Under the new arrangement, ERB continues to report to the Office of the President, and its regulatory scope has been extended to cover NPC and the coops in addition to the investor-owned utilities.

The Generation Subsector

1.10 The private development of electric facilities is not a new phenomenon in the Philippines. Until 1973, virtually all power facilities were developed by private interests; in effect most load centers in Luzon as well as the larger cities in the Visayas and Mindanao were served by vertically integrated investor owned businesses that supplied limited areas. The only significant Government interest in the power sector was NPC, which had responsibility for developing the country's hydroelectric facilities. This was justified on the grounds that (i) decisions with regard to the development of particular hydro sites required inputs from and had an impact on a number of other sectors of the economy; and (ii) the construction of hydro facilities involved capital investments so large that only the Government was thought to have the needed resource mobilization capacity. Shortly after the imposition of Martial Law, the Government enunciated through Presidential Directive [P.D.] 40) a new policy which concentrated all generation and transmission facilities nation-wide in one state owned monopoly, namely NPC. As a byproduct of that policy, the Government could implement social pricing policies that kept electricity prices low for residential and other small consumers that are expensive to supply. As recently as 1979, private interests were being pressured to sell their generating plants to NPC.

1.11 This former policy was partially reversed in 1987, when the Government promulgated Executive Order (E.O.) 215 that ended NPC's monopoly on generation facilities. This measure was designed to accommodate the Philippine National Oil Company (PNOC), which could not sell the geothermal steam it was developing to NPC because the Government's required royalty on this resource raised the cost of geothermal steam powered electricity well above that of coal and oil fired alternatives. The possibility that E.O. 215 would reopen the door for privately developed generation was discounted on the basis that (i) the extent of long term capital required was greater than domestic private interests were likely to mobilize, and (ii) laws restricting foreign ownership of utilities would likely deter foreign investors from entering this business. However, as the power crisis deepened and private development came to be viewed as the only viable approach for quickly addressing the shortages, the Government committed itself to developing a full fledged plan for privatizing the power sector. In that context, it developed the legal framework to enable foreign interests to own and operate generating facilities. At this point, most of the IPPs currently constructing power facilities or promoting new ones, are foreign.

1.12 Despite the growing involvement of private developers in generation, NPC is still the monopoly supplier to all electric distributors. This Government monopoly is expected to continue for the foreseeable future. Until 1991, NPC interpreted E.O. 215 as narrowly enabling the independent production of electricity, but not direct supplies to distributors by IPPs. As a result, the vast majority of IPPs have arranged their PPAs with NPC; and NPC supplies that throughput to their clients as traders rather than producers of electricity. However, as the shortage crisis deepened, the Government could not run the political risk of appearing to restrict supplies; therefore, it allowed the accreditation of several IPP proposals to supply MERALCO directly. In short order, MERALCO and about five of the more prosperous distributors were actively pursuing such arrangements. However, as of November 1993, just three modestly sized projects were confirmed, fully financed and being implemented: the Subic Bay Metropolitan Authority (SBMA) and two Export Processing Zones in Central Luzon, all due for completion by 1995-96. In the longer term, NPC's predominance in the generation subsector will be tested after MERALCO begins purchasing significant amounts of its supplies directly from IPPs.

Transmission and Distribution

1.13 Currently, NPC has a monopoly on all transmission services nationwide. NPC owns most high voltage transmission lines and intermediate voltage subtransmission facilities; while MERALCO owns some higher voltage (69kV and 138kV) lines, it uses them only to draw electricity from NPC's delivery points on the fringes of its service area into its urban core. So far, the private sector has not made a serious offer to develop transmission facilities; and none is expected until the Government develops the details of policies concerning (i) wheeling charges, and (ii) the disposition of the higher voltage consumers currently being served by NPC. Until these policies are defined, potential offerors cannot assess their prospective returns. NPC has expressed an interest in divesting itself of the subtransmission networks; however, few of the distribution utilities have the institutional and financial capabilities to manage these facilities properly.

1.14 While the Government through NPC has dominated the generation subsector until recently, responsibility for developing the distribution subsector has been allocated entirely to some 135 investor or member owned private utilities who have exclusive rights to provide medium and low voltage service within their franchise areas and who are all subject to price regulation. Only MERALCO is of substantial size and with established international commercial credit. Some five other IODs and three member owned cooperatives are medium sized utilities with service areas that include a large urban core. The remainder are modest operations that serve small towns, villages and rural areas. NEA is the Government agency that acts as an interested lender providing subsidized loans and specialized technical assistance to the member owned cooperatives. At the time of the Energy Sector Study, the distribution utilities had serious operating and financial deficiencies. Since then, many distributors have realized major improvement, thanks in part to interventions by the Bank; however, their operational performance still has considerable scope for further improvement. Many of these utilities have expressed an interest in broadening their activities; and NPC has been seeking to devolve increasing responsibility for sector development to them.

C. Objective of the Study

1.15 These trends toward increased private development of the power sector, taken together, indicate that a major transformation in the structure of the power sector is already taking place. While the Government is addressing many of the constraints to private sector led growth in this sector, little attention has been paid to ensuring that the structural framework resulting from this transformation will serve the national interest. Only recently have Philippine authorities begun debating the objectives for that long term structural framework and how to guide the ongoing transformation. Therefore, the principal objective of this study is assist the Government by deriving the structural framework for the power sector in the post-privatization period.

1.16 To manage the new private participants, the restructured power sector will require a well coordinated set of Government institutions with a solid professional capacity to (i) formulate policy, and (ii) lead and coordinate the IPPs. This will surely involve an enhanced role for DOE. The framework for the Government institutions as developed by the Department of Energy Act of 1992 appears sound. However, this study found that needed regulations, project approvals, policy decisions, and planning guidance were delayed during official review or were not being executed at all. These problems were associated with overlaps between (i) DOE's policy-making functions and ERB's regulatory responsibilities; (ii) DOE's responsibility for energy planning and NPC's responsibility for electricity system planning; (iii) DOE's role as administrator of the IPP program, NPC's authority to accredit IPP proposals, and the National Economic Development Authority's (NEDA)

responsibility to clear IPP projects. The organizations in question coordinate poorly and so have either worked at cross purposes or alternatively left important functions unfulfilled. Moreover, while DOE inherited from OEA a strong cadre of research oriented staff, it should strengthen its capacity for institutional coordination and policy development. In the face of these institutional weaknesses, dominant IPPs have been free to self-interestedly define most of the sector's new business practices. The challenge for the Government is to regain control over those business practices, and thereby foster competition.

1.17 The private sector was invited to help relieve temporary capacity shortages in the Philippine power sector, but its role will perforce increase still further since the power sector's needs have by far outstripped the capacity of the Government. The magnitude of requirements and the need for orderly processes as the Government redefines its role, suggest that the public and private sectors will need to collaborate constructively for some time to come.

1.18 For the Philippine consumer, competition and its fruits are essential ingredients of sector reform. Electricity is already expensive for unsubsidized consumers, so new investment must be cost effective. The consumer cannot bear continued brown-outs, and cannot afford to pay for too much capacity either. Projects need to be started and completed on time, and all assets need to be operated efficiently. The private sector can produce these results. To participate in force, the private sector requires a business climate within which it can flourish. The ensuing chapters of this report will focus, *inter alia,* on resolving issues at the interface of the public and private sectors, and on corresponding improvements to the business climate.

1.19 All too often, opening up the supply side of electricity to IPPs has been equated with introducing competition; and efficiency, cost effectiveness, and additional financing are expected to follow directly from having more than one supplier. The Philippine experience shows that the development of competition depends as much on reform at the demand side as at the supply side of the business. Now that the sector has been opened to multiple suppliers, the most important pending reform is at the distribution end. Unless the distribution utilities have comparable strength with the IPPs, monopoly will merely be supplanted by monopsony.

1.20 The success of any power sector restructuring depends on how well it takes account of the issues that derive from current realities. The most important of these issues relate to planning and investments, and they will be elaborated in Chapter 2. Another broad set of issues relate to finance and tariffs; they will be elaborated in Chapter 3. A more general set of structural issues arise from the sector's existing realities, and these will be elaborated in this chapter's following paragraphs. The spate of existing issues and constraints will preclude some alternative structures and impose limitations on many others. While the remainder of this report will analyze the leading requirements of sector structure, the structural framework that works best will necessarily be rooted in making feasible adjustments to the status quo.

D. Current Realities and Derivative Issues

Privatization Policy

1.21 During 1992, as the shortage crisis was deepening, the Government urgently developed a broad based Energy Sector Action Plan (ESAP). In December 1992, DOE adopted ESAP as the road map for the future development of the sector. ESAP committed the Government to privatize NPC, and it allowed a year for study and development of proposals. DOE is now stretching the

schedule to enable more careful consideration of the objectives for privatizing NPC, and the best approach for realizing those objectives. However, the momentum within the Government and among the general public to restructure NPC is very strong, and some decisions are bound to be made within the next few months, whether or not preparations are adequate.

1.22 Several bills have been introduced in the Philippine Congress to split NPC along regional lines, reflecting this momentum and responding to pressure from the business community within the regions. None of them addresses satisfactorily the complications from proposed regionalization; but all generally anticipate that (i) the regional companies would sell bonds and shares to the public in the medium term, and (ii) private interests would be engaged to operate and maintain the NPC plants that they stand to inherit. Because of this pressure, regionalization of NPC in some form appears inevitable in the medium term. The challenge for the Government is to formulate the details of regionalization so that (i) the actions proposed are comprehensive and appropriate; and (ii) institutional capabilities are developed for functions that may be retained within the Government's ambit.

NPC's Corporate Problems

1.23 In parallel with the power crisis, NPC faced some serious corporate problems:

(a) During the mid-1980s, a large number of promising NPC technical staff left to take highly paid jobs in the Middle East. Subsequently, many other NPC technical staff left on account of salary standardization with the rest of the Government. Even if the President were to use his authority under the Emergency Powers Act raise NPC salaries, NPC would have a difficult job rebuilding its technical cadre.

(b) Since 1988, NPC's annual financial performance has been uneven. As a result, NPC has had difficulty maintaining its credit. NPC did post good results in 1992, and hopes for similarly good results in 1993; thus, it did regain some of its financial standing, as evinced by the successful closing in November 1993 of a public offering of five year Eurodollar Bonds (backed by the guarantee of the Republic).

(c) The uncertainty of tariff revenues is especially relevant in the context of NPC's local currency requirements. The Philippine financial markets do not offer a debt instrument with a term of more than three years. Funding of such short term has limited usefulness to a capital intensive utility; therefore, NPC must realize all of its local currency requirements from tariff revenues. Thus, the cash flow constraints resulting from the politicization of its tariff induced NPC to develop undue foreign exchange exposure and a bias for imported goods and equipment.

(d) NPC must now rebuild the public confidence that was lost during the depth of the power crisis. This is especially important in view of the upward pressure likely to be exerted on a tariff that is already among the highest in East Asia (para. 1.34).

Condition of Existing Generating Plants

1.24 The average age of NPC's thermal plants is 23 years. Over the years, those thermal plants have not been taken out of service for regular maintenance; moreover, they have been pushed for long periods at very high load factors. Thus, they have suffered serious deterioration and are in

poor condition even for their advanced age. Virtually all are operating at well below their rated capacity.

1.25 NPC's hydro plants are also operating at reduced capacity, although the plants themselves are in reasonable condition. The plants at Pantabagan and Ambuklao in northern Luzon did suffer some damage during the 1990 earthquake; but, their supply constraints result largely from drought, siltation of their reservoirs, and priorities accorded to agricultural and potable water. In Mindanao, which is powered by a virtually all hydro system, the twelve hour a day shortages of 1992 came about because the drawdown of Lake Lanao to precarious levels was followed by a lengthy drought. The challenge for NPC is to keep the hydrology of these plants from becoming irreparably damaged.

1.26 The weak operational condition of existing generating facilities raises two important issues: (i) the age and suspect reliability of these plants mean that new plants will be needed not only to meet the capacity deficit but also retire a large number of them; and (ii) the concern about their condition will likely reduce their salability in a privatization or depress the price these plants could command to politically unfeasible levels. The aggregate investment requirements between now and the year 2000 for new generation, whether from NPC's own resources or through IPP arrangements, are estimated at US$10 billion; about one third of that amount would cover the retirement of deteriorated (para. 1.24) or economically obsolete plants. As expected, several potential buyers or lessors of these thermal plants have indicated that any offers would depend on a thorough inspection of these plants' boilers, generating islands, and turbines. The market price these plants will command is directly related to expectations of the cost of returning them to good operating condition.

Transmission and Dispatch

1.27 The current structure (para. 1.13), where NPC owns the transmission system and is itself responsible for dispatch, led to orderly sequencing of plants as long as NPC also owned all generating facilities. This structure could also function uncontentiously under recent conditions, when available supply from multiple generators has been insufficient to satisfy demand. However, this structure will need adaptation to take account of the many outstanding PPAs that cover: (i) sales to NPC with take-or-pay provisions for significant amounts of electricity at price levels higher than might otherwise be available, and (ii) direct sales to distribution utilities also with take-or-pay provisions for consequential amounts of electricity. In the future, all generators will need assured unbiased access to the system, subject to wheeling charges that fairly cover the full costs of transmission. Similarly, the rules of dispatch will need to take account of existing contractual arrangements, and the body setting those rules should be perceived as free of bias.

Deteriorating Distribution Systems

1.28 During 1981-91, almost all distribution utilities experienced serious cash flow constraints and responded by curtailing investment and maintenance. Now, almost all need to strengthen and modernize their existing systems while expanding in order to meet load growth, but their prospects for doing so vary:

(a) MERALCO's previous ownership group acquired the Company using a self-liquidating transaction. As a result, the Company was pressed to curtail investments, maintenance and human resource development in order to sustain the level of its dividends. Following the 1986 change in control, the Company became concerned about the state of its network; however, its access to investment capital was limited by (i) its own poor

credit, and (ii) unfavorable perceptions about the Philippines in international financial markets. By 1989, the Government enabled MERALCO to have temporary access to official loans. In January 1993, the Company floated a successful primary issue of common stock through a successful world wide public offering. Now, the Company can access commercial credit, although not in the amounts sought or for the term desired.

(b) During 1969-83, electrification of the entire country was a major Government objective. NEA solicited substantial concessionary loans and onlent the proceeds to the coops with minimal spreads. While ample funding was available for investment, tariff revenues were insufficient for many of the coops to cover maintenance costs on existing systems; consequently, core systems in need of refurbishing were left untended. During 1983-91, as the bilaterals curtailed funding for investments in this sector, the coops neglected maintenance even of newly developed systems. Most coops are facing major refurbishing programs; these programs form the core of the Bank financed Rural Electrification Revitalization Project (RERP)(Loan 3439-Ph).

(c) The IODs are generally family enterprises that serve some twelve cities other than Metro Manila. The quality of their assets and management vary widely. Some of them (Cagayan Electric Power and Light Company, Cotabato Light and Power, and Angeles Electric Company) have done a good job of maintaining their networks. The condition of the others' networks varies from undistinguished to very poor. Most of these companies have had difficulty securing credit, and their access to official funding has been constrained by the lack of an appropriate financial intermediary. While NEA has the qualifications, it is not considered legally eligible to lend to these utilities.

1.29 The subtransmission networks were originally owned and operated by the distribution utilities; however, since the distributors allowed these lines to fall into disrepair, NPC absorbed them into its network by 1981. NPC currently regards these networks as the orphans of the transmission system, and has indicated its willingness to return them to the distributors. Nationwide, these networks are generally in need of substantial refurbishing; however, few distributors currently have the institutional or financial capability to maintain them.

1.30 Aside from MERALCO, the distribution utilities are generally small and financially weak companies. Individually, they have virtually no business leverage; yet their interests are too fragmented to enable their routinely combining for mutual benefit. This will become evident as more generation is provided by IPPs. Since these utilities have very little strength to negotiate directly with suppliers, they will be left to follow the terms established for them by NPC or MERALCO. Meanwhile, NPC and MERALCO, the only available strong, smart buyers for IPP supplies, are not in competition with one another. Since the Government is legally authorized to guarantee NPC's commercial obligations, IPPs wanting to offset commercial risk prefer BOT arrangements with NPC as their purchaser. Conversely, since MERALCO buys for resale to end-consumers, it can afford to pay more than NPC; therefore IPPs willing to assume more risk for a higher price prefer BOO arrangements with MERALCO as their client. This weakness at the distribution end of the sector would seem to inhibit true competition more than any condition existing at the generation end.

1.31 The condition of distribution networks nationwide is indicative of the chronic underfunding throughout the sector, regardless of whether the utility is privately owned or a Government company. The reasons for underfunding differ widely -- some utilities were unable to raise investment finance; others had difficulty implementing investments once the funding had been raised;

and still others placed a higher priority on distributions from profits than on system renewals. Unmet needs are the same, however--substantial investments to renew deteriorating assets, over and above those required to serve a growing market.

Impact of Island Geography

1.32 The Philippines is comprised of over 7,000 islands. The largest is Luzon, about 104,000 sq. km in size and bearing a population of about 38 million. Mindanao comes next (94,000 sq. km. and 14 million people). The only other island with appreciable population density is Cebu. From an electric system perspective, Luzon is comparable to a country of modest size. The network is substantial and can be optimized; however, the terrain is rugged and must be ringed rather than crossed. Mindanao is comparable to a much smaller country; each new generating plant represents a lumpy increment of supply. There too, the rugged terrain has resulted in ribbons of development along the perimeter. Because most other islands are small, efficiencies of scale are difficult to realize, and electricity supplies are generally expensive. The islands that are electrified generally have mountainous central spines, so the bulk of development is along the shore.

1.33 The island geography imposes constraints and costs on the network. The nine largest islands, containing 95% of the population, are served by seven separate grids (five in the Visayas alone). While Luzon and the eastern Visayas should be interconnected by 1998, the further interconnection of the western Visayas and Mindanao is not yet economically justifiable. Within each island, the topography and settlement patterns make electrification expensive, and the smaller and poorer islands are also the ones with the most expensive supplies and the costliest networks. NPC has been committed since 1988 to substantially escalating subsidization of supplies to about a dozen small islands that consume less than 1% of its production.

Pricing Policies and Tariffs

1.34 For many years, the Government's pricing policies have been at cross purposes with NPC's supply constraints:

(a) The overall level of retail tariffs in the Philippines is by far the highest in Southeast Asia, and is second to Japan among all Asian countries; consumers in some of the smaller, poorer islands pay nearly three times the rates charged in Washington, D.C., despite substantial subsidies in the cost of supply. Because retail rates are high, residential or small business consumers (especially in semi-urban and rural areas) have reduced their consumption to low and inelastic levels. The ability of the vast majority of consumers to continue affording real tariff increases has already been stretched. These consumers' aggregate consumption is so small that, while substantial tariff increases will surely involve hardship for them, their additional payments will only modestly increase total revenue.

(b) Since the late 1960s, NPC's tariffs to distribution utilities and industrial consumers alike have included only nominal demand charges. This has resulted in a nation-wide proliferation of low cost, energy inefficient industrial machines and major appliances. Even in the face of the recent power crisis, consumers have had little incentive to shoulder the cost of retrofitting equipment for enhanced efficiency.

(c) The combination of Government policies to (i) cross-subsidize consumption in the Visayas and Mindanao with higher rates in Luzon, and (ii) subsidize significantly a

lifeline block of consumption, leaves MERALCO and most other distribution utilities in Luzon with very little flexibility in setting prices for industrial consumers. Thus, the distribution utilities have been effectively precluded from competing with NPC to serve the higher voltage consumers currently being supplied by NPC.

(d) Consumers relying on auto-generation have maintained free-of-charge stand-by connections with NPC or their local distributor. To beat the shortages, some 1,600 MW of gensets were imported into the Philippines during 1993. Their owners are expected to keep using them for the foreseeable future while also maintaining stand-by connections. Utilities bear the cost of capacity to supply all connected customers, but do not collect revenue from the portion of their capacity which duplicates what the auto-generators are using to supply themselves. This must result in higher electricity charges to all other consumers. Clearly, the question of stand-by charges cannot be raised while the shortage situation persists; however, this issue will need to be raised when the immediate crisis has passed.

Regulatory Framework

1.35 The electric sector in the Philippines was patterned on the US model. As a result, the distributors' rates to end users have been regulated. As of 1986, ERB had the responsibility for regulating the rates of the IODs, while NEA was charged with regulating the rates of the member owned coops. NPC was not subject to external regulation; its prices were set by its Board of Directors, after informal consultations with the Office of the President. In December 1992, the Energy Sector Act accorded ERB the responsibility for regulating all distribution utilities and NPC. However, the IPPs are not subject to regulation; and no provision has been made for ERB to conduct a prior review of the take-or-pay contracts between the IPPs and the various utilities whose end user price is regulated.

1.36 ERB's record in regulating the IODs has been spotty. Until about 1990, ERB was generally slow in rendering decisions, and it tended to avoid adjudicating fundamental issues. In 1991, the term of the ERB Commissioners was fixed at five years, and an unusually effective slate of Commissioners was appointed. ERB then began adjudicating substantive issues in its decisions regarding MERALCO and, subsequently, NPC; also its regulatory inquiry with regard to those two major utilities has been thorough and its decisions were rendered relatively quickly. However, because of human resource and budgetary constraints, it continued having difficulty with applying the regulatory process in a timely manner to the other IODs.

1.37 Until 1990, NEA interpreted its mandate as both setting coop tariffs and then regulating the result. The rate formula NEA was applying was too stringent and its processes too cumbersome, thereby limiting its effectiveness as a regulator. In late 1990, NEA redefined its role; it would articulate a tariff policy to the coops, and let them set their own rates. Then, it streamlined its regulatory processes, placing the onus on each coop to provide evidence that it had consulted with key groups within the community regarding the proposed adjustments. NEA continued to hold rate hearings locally, but only after the views of all parties had been formulated. In this way, NEA regulated tariff adjustments for more than 100 coops over a period of less than fifteen months. During that span, virtually every coop increased its rates by about 30 - 50%; and, yet, the coops faced only minor political opposition to these increases.

1.38 Shortly after the first round of adjustments under this new system, regulating the coops was shifted from NEA to ERB. Both organizations acknowledged that ERB was understaffed and had

insufficient budgetary resources to absorb its new regulatory responsibilities, so they jointly petitioned the Department of Budget and Management (DBM) to enable the transfer of NEA's regulatory staff and budget in their entirety to ERB; this was not considered feasible under existing law. During 1993, ERB asked NEA to continue doing the detailed work related to the regulatory process on a consultancy basis; at best, this arrangement can serve temporarily. So, now ERB has the responsibility for regulating 135 utilities with resources that were barely adequate for fifteen of them.

1.39 As the role of private development of power facilities increases, so too will the importance of regulation. The private developers are depending on regulation to ensure that the system provides no unfair advantages. The consumers are depending on regulation to protect their interests with regard to cost and quality of service. Yet, ERB has some serious capacity constraints, and its ability to fulfill its projected role will depend on the Government making available some significant opportunities for institution building.

E. Conclusions

1.40 From current realities, the foregoing paragraphs lay out constraints the structural framework will need to accommodate and issues the power sector will need to address. Additional constraints will arise from the shift in balance between the private and public sectors as a result of the spate of privately developed investments in generation that are expected during the next ten years. These will be analyzed and discussed in Chapter 2. Still other constraints will emerge from the financial impacts of adding new participants who are expected to add efficiency and reliability to the sector, but who will also expect an appropriate return as a commensurate reward. These constraints and issues are the subject of Chapter 3. Chapter 4 will consider the effectiveness of on-going private development in power. It will consider the lessons from the current crop of IPPs as well as the need to improve the effectiveness of the distribution utilities. Together, these chapters cover constraints that must be factored into any recommended structural framework for the sector.

1.41 Chapter 5 considers (i) the parameters for unbundling NPC, and (ii) the proposed structural framework for the sector. The objectives of reorganizing NPC are to enable the proper incentives for functions that should be kept national in scope, while enhancing the manageability and efficiency of functions that can be decentralized. Because of the breadth of constraints emanating from current realities, structural models that have been tried in other countries are unlikely to work in the Philippine context. The structural framework being recommended was designed specially for the Philippines and includes features from the full range of privatization models being implemented elsewhere. The benefits of recommending a structural framework for the post privatization period will be limited unless combined with an analysis of the adjustments needed to make it work. Some of that analysis will be provided in earlier chapters, in relation to very specific issues. Chapter 6 will address improvements to the enabling environment for private development of power in the Philippines, especially the legal framework, electricity pricing, and the disposition of NPC's directly connected industrial consumers through wheeling. Chapter 7 will consider the role of regulation during the privatization period and after the first wave has been completed. In that context, it will examine ERB's approach to regulation, its key processes and its institutional capabilities.

2. Power Demand and Supply

A. Introduction

2.1 NPC expects Philippine power generation capacity to increase 250% between 1990 and the year 2000, from 23 TWh to 59 Twh. This chapter assesses the expected demand for this increased power in the Philippines during the period, including long-range planning and technical options for the turn of the century. (Sector investments and financing to meet that demand are discussed in Chapter 3.) Finally, because power must be transmitted and distributed effectively, the chapter also presents analyses of the technical and investment requirements of these subsectors.

B. Power Demand and Supply to 1998

Energy and Demand Growth Estimates

2.2 The key determinant for estimating future sector investment requirements is the demand forecast. In the Philippines this needs to take into account: (a) overall economic growth; (b) differential regional development; (c) demand side management measures; (d) industrial growth; (e) distribution utilities' sales and technical efficiency forecasts; (f) income and price elasticities, and (g) the self-generation capacity resulting from gensets imported during recent power outages. The dominant factor in load growth will likely continue to be overall growth of the economy. There is always uncertainty in medium and long-range growth forecasts, and so both high and low growth scenarios and annual updates are needed to optimize the investment program. For the medium term, NPC must also develop a realistic "base load" scenario which is in line with the contracts for power supply it is currently signing with the distribution utilities.

2.3 The methodology for NPC's Power Development Plan (PDP) includes analysis of grid-specific industrial and commercial activities, demand trends, price and income elasticities, and regional and total GDP growth forecasts. Demand estimates from the distribution utilities and NPC's regional managers also play a part. However, many of these analyses have been mooted by the supply shortages which interrupted discernable trends, stimulated off-the-grid self-generation by consumers, and left analysts uncertain of how power demand would grow now that supplies have been restored. Assuming that power demand is restored to a predictable fraction of total economic activity, the main and by far most important variable in the demand projections is GDP growth, which must follow the targets set by NEDA. Constrained to use the GDP target as the basis for its own forecasts, NPC pegs its estimate of the demand elasticity for electricity at between 1.25 and 1.5 times targeted GDP growth.

2.4 NEDA GDP annual growth targets to the end of the decade average about 8%[1/], much larger than recent 2% annual historical performance of the Philippine economy during the previous decade, but smaller than sustained growth rates for the regions served by the Mindinao and Visayas grids during the 1981-1991 decade. In NPC's 1994 PDP, this level of economic growth translates into electricity demand growth forecasts of about 12% p.a. between 1994-2000. The Bank's GDP growth forecast is lower, about 5.5% per annum, with electricity sales increasing at about 9.5% p.a.

1/ NEDA's forecast for GDP growth rate for the 1994 is now 3%-4% (reduced from 6.7%) and is 7.7%, 8.2%, 8.8% and 10% for 1995-98.

(and 8.7% in Luzon). Taking the Bank's lower estimate as a baseline and NPC's 1994 forecast as a high scenario, the two total power demand estimates diverge by 10% by 1998 and 17% in the year 2000. Nevertheless, both growth projections are reasonable, being in line with those experienced by other Asian countries, particularly those with low per capita electricity consumption (Philippine consumption was 408 kWh/person during 1993).

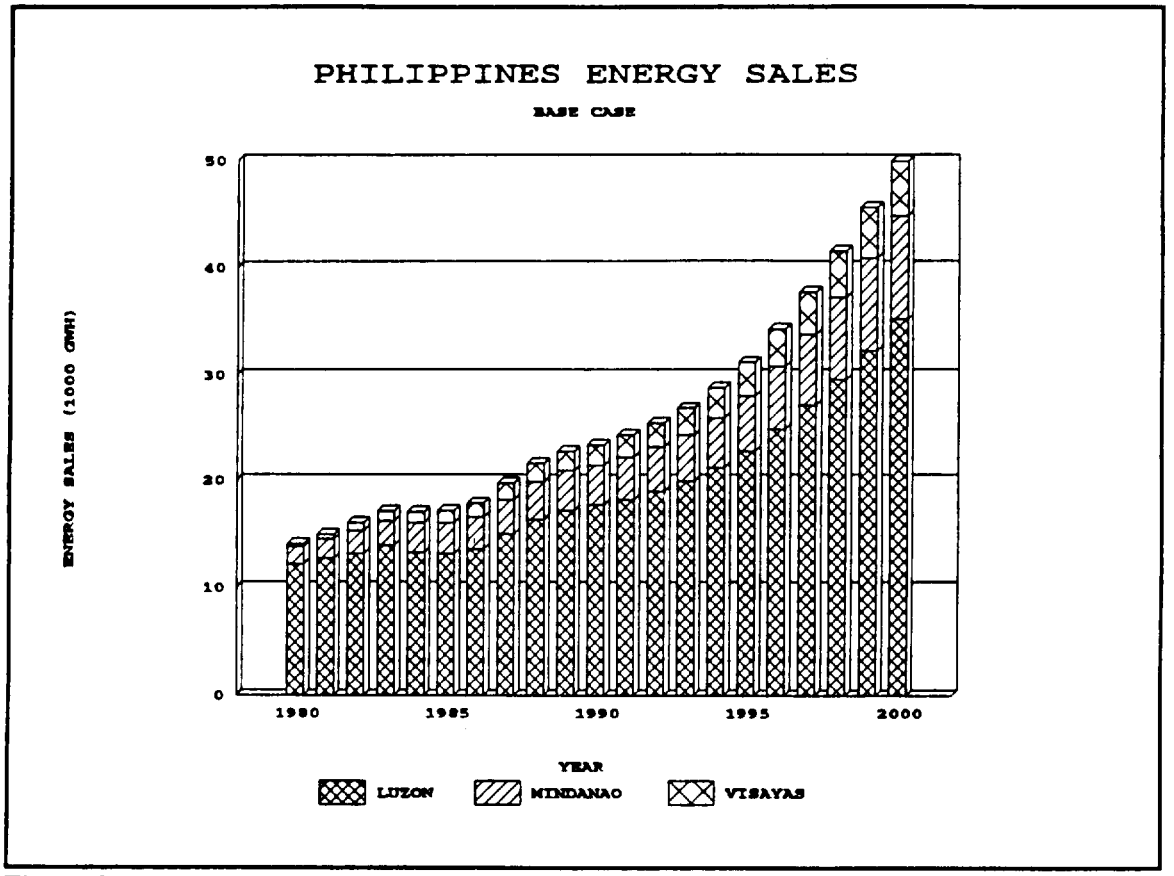

Figure 2.1

2.5 The base demand scenario is presented in Table 2.1, and assumes a GDP elasticity ratio of 1.3 for Luzon (as used by NPC) and slightly higher elasticities for Visayas and Mindanao. Under this forecast, energy sales for Luzon in 1998 will be 29.5 Twh, about 40% higher than the 21.1 TWh sales in 1994 (Table 2.1). Overall, total power sales are expected to increase 44%, from 28.7 TWh to 41.4 TWh. (Annex 1 details the forecasting assumptions and analyses for each of the three main grids.)

MERALCO's Forecast

2.6 MERALCO supplies 2.1 million consumers, accounting for about 70% of demand in Luzon and about 60% of demand in the country as a whole. MERALCO's own forecast, based on trend analysis of the domestic, commercial and industrial consumers is the basis for its US$800 million program for distribution investments during 1994-98. MERALCO assumes industrial sales will grow rapidly and increase its share of the total from 36% at present to 50% by 2010, with a smaller growth and a corresponding reduction of the share of commercial and domestic consumers. MERALCO incorporates in its forecast expected loss reductions, from 14% in 1993 to 10% by

1998. These changes, along with DSM, are expected to increase MERALCO's load factor from 65% to 72%. Overall, MERALCO's sales forecast (Table 2.2), supported by appropriate investment, is one third lower than NPC's demand forecast (and slightly lower than the Bank's).

Table 2.1 - Baseline Power Demand Forecast

Year	LUZON			VISAYAS			MINDANAO			TOTAL		
	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW
1990	17.64	19.10	3023	1.87	2.05	494	3.73	3.96	621	22.9	24.7	3974
1992	18.88	20.37	3250	2.25	2.49	622	4.24	4.46	725	23.8	25.6	4186
1994	21.13	22.84	3693	2.88	3.20	705	4.70	4.97	811	28.7	30.8	4937
1996	24.73	26.73	4286	3.52	3.91	851	6.00	6.38	1038	33.9	36.3	5830
1998	29.50	31.89	5128	4.26	4.63	1010	7.66	8.15	1329	40.4	43.2	6858
2000	35.20	38.05	6102	5.15	5.60	1201	9.52	10.13	1648	48.1	51.53	8262

Increases in Generation Capacity: IPPs, Independents, and Gensets

2.7 Most of the initial growth in NPC's generation capacity since the onset of the crisis has come from IPP installation and operation of solid, quickly-constructed plants with relatively low fuel-conversion efficiency. These plants will revert to peak demand once adequate base load capacity is available in 1995. An estimate of the reliable capacity for Luzon incorporates just such assumptions into an operating model in which the output of existing and expected plants is available according to contracts, engineering specifications, maintenance and repair schedules, age-derating, and reasonable assumptions of seasonal and annual effects on hydro generation. To forecast power supply well, it is necessary to predict accurately the completion of new plants and transmission lines. This is difficult for the IPPs, which even after contract award are subject to vagaries of equity and loan financing.[2/] Capacity increments can also be delayed when projects suffer delays due to environmental or community acceptance problems (as happened with the Masinloc and Calaca II coal plants). Table 2.3 shows estimates of Luzon's dependable power capacity, including all contracts signed with NPC.

2.8 Another source of supply--and of supply uncertainty--are the several prospective contracts between IPPs and distribution utilities and industrial users. Official intelligence about the progress of these deals remains incomplete, notwithstanding their potential impact on total supply and demand.

2.9 There are also numerous self-generation projects at factories, industrial estates, and even large commercial enterprises. Some 1600 MW of genset capacity is known to have been imported for back-up generation during the crisis. Here the uncertainty is over how much, how often,

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2/ It is precisely from such financing difficulties that several signed and accredited BOT contracts have recently been cancelled when performance contracts could not be signed.

Table 2.2 - MERALCO's Energy Sales Growth Forecast
(annual growth rates)

Period	Residenial	Commercial	Industrial	Total
	%	%	%	%
1987-1991	4.90	7.70	11.30	7.90
1992-1995	4.30	3.10	5.00	4.10
1996-2000	8.50	8.80	11.70	9.80

and under what circumstances (fuel cost changes, power outages, demand charges, peak-period pricing, etc.) this already installed but off-the-books self-generation capacity will be utilized after grid supplies are fully restored. For forecasting purposes, gensets are assumed to operate at a 10% duty cycle during the remainder of the decade.

2.10 These supply uncertainties pose a serious problem for the Philippines. There would be substantial general economic losses from a repetition of supply shortages if the expected capacity does not materialize. On the other hand, duplication of capacity would be costly for the sector and will have diverted needed capital from other investments. As self-generation capacity is already in place, its use must be tolerated, but it should be studied and monitored in order to improve local grid-demand forecasts. To minimize the backlog of uncertain projects and the supply risk the public assumes while they are pending, DOE accreditation should include definite and clear expiration dates, after which projects would be subject to reaccreditation (para. 6.27).

Power Generation, Peak Demand, and Reserve Capacity

2.11 Total energy losses within the NPC system are about 7%, split about equally between transmission and in-plant use. There are greater opportunities for loss reduction within the distribution subsector, and MERALCO and the coops are making additional efforts and investments to take advantage of them.

2.12 Capacity expansion is not only needed to meet recently unmet and new demand, but also to (i) replace obsolete and worn-out capacity; (ii) restore technologically inappropriate peaking cycle plants pressed into base-loading mode during the crisis to economic peaking operation; (iii) replace base-loaded plants fired with expensive oil with coal-fired substitutes; and (iv) replenish reserve capacity.

2.13 For the Philippines, a substantial reserve would be a prudent hedge against several risks: (i) a temporary preponderance of old, unreliable, and probably short-lived thermal plants; (ii) oil-intensive new capacity, vulnerable to sharp increases in oil prices even at lower load factors; (iii) uncertain results of the rehabilitation of some large plants, which may continue to be undependable; (iv) vulnerability of hydro plants to recurrence of severe droughts such as those of 1991-92; (v) power transmission limitations between grids and even within them; and (vi) project delays due to NPC's slow procurement, contractor failure, and regulatory obstructions.

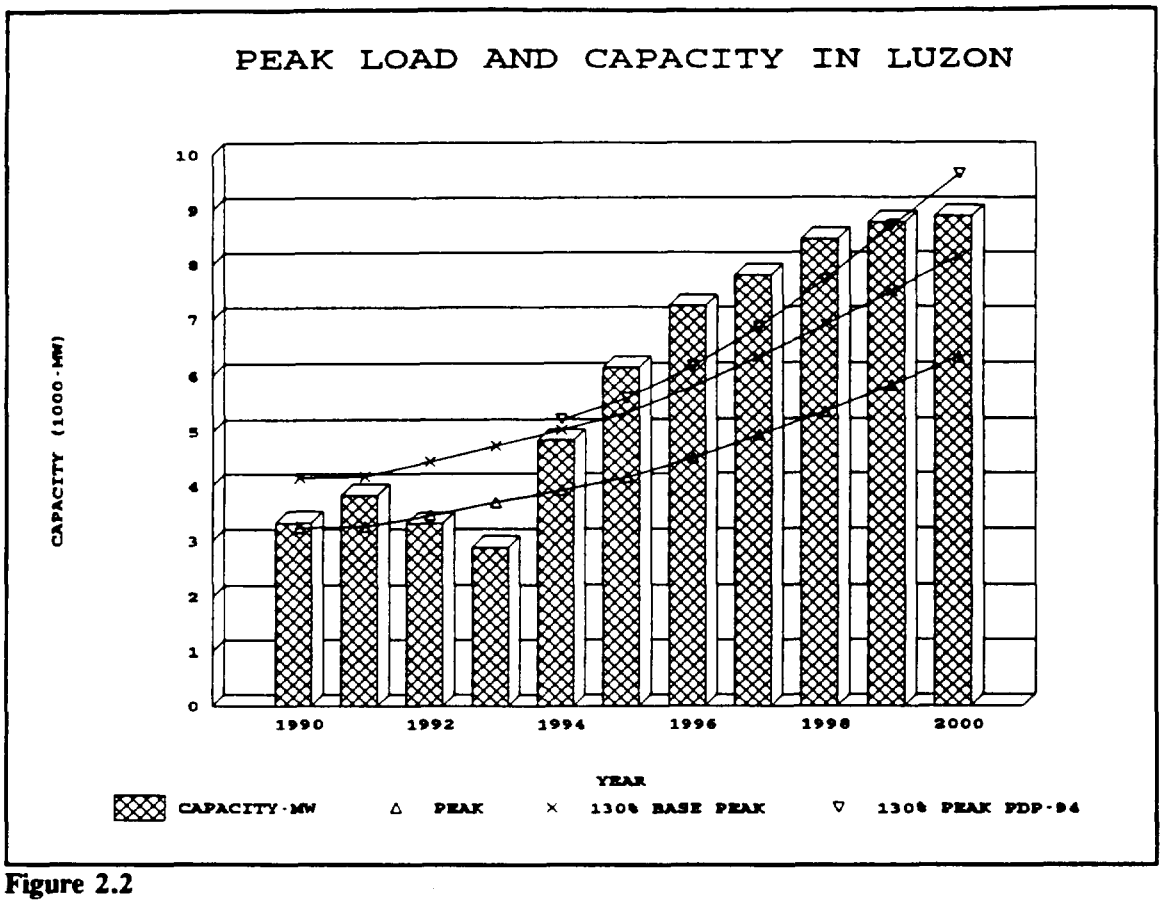

Figure 2.2

2.14 Based on NPC's investment programs for projects already committed or under implementation, and a risk approach to the likelihood that individual IPPs with the distribution utilities will be brought to fruition, the dependable capacity for the Luzon grid is expected to grow as shown in Table 2.3. This table includes: (i) plants being built by IPPs under PPAs with NPC; (ii) a modest amount of capacity that NPC is committed to develop with unilateral or bilateral financing; and (iii) and plants developed by IPPs under direct contracts with MERALCO. Details for each of the existing and planned plants entering into operation are given in Annex 1. Some old plants are also assumed to be retired by 1998 (Manila 200 MW and Sucat 350 MW) but each case will require a cost/benefit analysis before closing the plant. The analysis of supply and demand (Figure 2.2) indicates that power outages would end during 1994, and NPC would have ample reserve capacity by 1997-98.

2.15 Under the base case, total reserve capacity by 1998 would be about 2,700 MW (about half of baseline forecast peak demand, Figure 2.2). Total reserve would be adequate even if high demand growth materializes, assuming that capacity additions are not unexpectedly delayed. To reduce the risks from such timing failures, the Government should adopt the following measures: (i) it should update the PDP annually; (a) it should not sign additional take-or-pay contracts; (i) it should exercise special scrutiny before extending or renewing accreditation of contracts which are not effective by the expiration of initial accreditation periods (para. 6.28); and (ii) NPC should consider postponing by 1-2 years projects with contracts which are not yet effective.

C. From Prescriptive to Strategic Planning

2.16 Given the power sector's large investments and its influence over other sectors, a sound power investment strategy and comprehensive power plan are needed for the country's economic success. However, this is a complex task, particularly challenging because of fully joint participation of the public and private sectors. Power planning with sophisticated computer programs (e.g WASP) has previously been used to formulate least-cost expansion plans; but now it may be inadequate for the Philippines because: (i) the approach is essentially deterministic, and may not capture risks and uncertainty, such as abrupt changes in energy prices or disruptions in economic growth; (ii) most models only minimize financial costs, but offer less help in choosing among solutions when multiple objectives are to be optimized (eg. environmental quality, financial viability, and macroeconomic impact); and (iii) as private participation in the power sector increases, many decisions which formerly fell in the realm of planning are now better left to a competitive market.

Table 2.3 - Sources of Dependable Power Capacity in Luzon

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Oil	1523	1555	1465	809	1204	1495	1466	1437	1408	1013	744
Diesel and CC	0	0	0	157	911	1164	1161	1157	1137	806	757
Hydro	1119	1035	648	518	813	838	853	903	953	1298	1296
Geothermal	559	561	571	547	775	860	852	867	1139	1386	1375
Coal	116	245	245	250	246	381	1167	1376	1662	2792	3971
Gas	0	420	401	520	673	670	667	663	660	657	654
TOTAL THROUGH NPC*	3317	3816	3329	2800	4621	5408	6165	6404	6959	7952	8797
SUPPLIES CONTRACTED BY MERALCO	0	0	0	0	141	303	746	1077	1140	1142	1140
TOTAL CAPACITY (MW)	3317	3816	3329	2800	4762	5711	6911	7480	8098	9094	9936

* This includes primarily supplies being developed by IPPs under PPAs with NPC, which NPC will resell to distributors; and modest amounts of genera tion that NPC is already committed to develop.

2.17 The emergent mix of public and private power generation requires a gradual move from fully prescriptive to indicative planning; and a strategic approach incorporating risk and multiple objectives. Until sales and prices are fully determined by the market, power planning will continue to be needed to ensure optimal development of the sector, and to protect consumers from risks stemming from market imperfections. The main concern is an unbalanced expansion, including capacity shortages or surpluses, or an inappropriate fuel mix. Planning should therefore include:

(a) Reduced emphasis on the assessment of specific projects, and greater focus on the soundness of the overall expansion and the flexibility and robustness of the plan, (i.e. its ability to perform well under various scenarios.)

(b) Incorporation of risk and uncertainty associated with different technologies (eg. fuel, foreign expenditures and capital costs) and different institutional arrangements.

(c) Incorporation of multiple objectives (eg. environment, use of local energy resources, self-reliance, multipurpose use of water resources, etc.).

2.18 Particularly important would be that the overall planning takes national rather than individual company concerns into consideration, for example for fuel choices. Responsibility for overall planning should be transferred from NPC to DOE. NPC's expertise cannot be gainsaid, however, and collaboration will be needed until DOE develops its own expertise (para. 2.45). This would require training and the introduction of the Trade-off/Risk planning, as used by USA power utilities to address risk and multi-objective issues.

2.19 DOE should also improve its monitoring of new and pending contractually obligated power generation and capacity. The authorization given to the utilities to generate their own power or contract it with IPPs is now bringing additional uncertainty to NPC's forecast (para 2.8). Therefore, DOE, which is responsible for accrediting these contracts, should now assume responsibility for planning, which can be enhanced by requiring (i) the utilities to sign long-term supply contracts; and (ii) NPC to comply and compensate its consumers for demand shortages or excessive capacity. The mixture of public and private supply substantially complicates power dispatch and requires a cooperative relationship between NPC, the distribution companies and the IPPs.

Accreditation

2.20 Executive Order 215 mandates that DOE accredit independent power agreements so that PPAs are "consistent with the development plans formulated by the National Power Corporation;" and thereby ensure consistent sector development and reduce risks to consumers and the economy. Regulations set several economic *desiderata* for accreditation: (i) Greater efficiency or lower cost generation than from existing plants, (ie. an avoided cost approach); (ii) use of indigenous and/or renewable resources; and (iii) access to lower costs of capital or cheaper plant investment.

2.21 These criteria are sound, but they were largely ignored during the power crisis. Moreover, the methodologies to implement these criteria have not been defined; nor have the tradeoffs between the Government's and NPC's assumption of market risk, and the IPPs' protection by take-or-pay contracts. DOE's accreditation should require (i) better analysis of an adequate demand-supply balance, (ii) clear criteria for the application of the avoided cost, and (iii) a fuel mix strategy. Each new accredited development should also fit into a general system plan, specify appropriate technology, and include a solid financing plan. Finally, the accreditation should set a realistic but final expiration date within which the final IPP contract should be signed, and include substantial performance guarantees.

D. Power Sector Investment

2.22 The investments and capacities required until 1999 are now well defined, and should result in adequate peak capacity and reserves even under a high demand scenario. Philippine Government-controlled investments in power generation and transmission are comparable to those of Indonesia, an archipelago with similar characteristics (Table 2.4). However, private sector investments in distribution in the Philippines are clearly low at just 13% of the total sector investment and may become a major constraint for power development. By contrast,

Table 2.4 Power Sector Investment (US$/kW Demand) in Philippines and Indonesia (1994-98)

Investment	Philippines	Indonesia
Generation	1877	1774
Transmission	581	417
Distribution	381	1003
Total Sector	2840	3194

Indonesia plans to invest nearly one third of its total on distribution, targeting expanded rural electrification and reduction of distribution losses to below 12%, about half the level in the Philippines.

2.23 Philippine long-term sector power sector investment (including all generation, transmission, and distribution requirements) is estimated at US$25-38 billion for 1994-2004, depending on the demand forecast (12,000-17,000 MW by 2004).[3/] Specific strategic recommendations for additional investments will be the subject of a Master Plan Study to be prepared with support from ADB and incorporated in annual PDPs. The Government's overall policies for managing risks and benefits of available fuel options will define important parameters of sound investment plans for the sectors by: (a) optimizing the use of indigenous resources (geothermal, gas and coal), and reducing dependence on fuel imports; (b) improving thermal generation through rehabilitation; (c) creating a better strategy for hydro development; (d) linking and effectively managing a national grid; and (e) maintaining network soundness and lowering distribution losses. These goals are consistent with the Government's targeted fuel mix for power production shown in Table 2.5.

Generation Investment

2.24 Following NPC's Board decision to offer to the private sector all new power generation except multipurpose hydro, 80% of additional capacity approved for 1993-98 will be built under BOT/BTO contracts. New and recent private sector generation must be integrated with existing and rehabilitated NPC capacity to ensure: (a) a suitable mix of fuels for base, intermediate and peak load; (b) spinning reserve and backup reserve capacity to cover forced outages and scheduled maintenance situations; (c) adequate reserves in case of unusual droughts; and (d) ample transmission capacity over NPC's lines. Appropriate technology for these purposes will include: hydro with pump storage, gas turbines and diesel for peak capacity; oil fired and combined cycle plants for intermediary cycle; and geothermal and coal plants for base load. Spinning reserve capacity will be provided by normally operating coal plants at 95% of their capacity. Although specific plants are not normally designated for reserve duty, as less costly production comes on line, recently installed crisis-stemming but fuel-intensive plants may revert to reserve usage.

Thermal Plants

2.25 Thermal generation will include: (a) coal fired power plants, which constitute the least-cost solution for power generation in the Philippines; (b) rehabilitation of NPC's existing power plants; (c) geothermal energy; (d) combined cycle plants; and (e) peak plants (diesel and gas turbines, which in the Philippines use a mixture of 30% bunker and 70% fuel oil.) These investment opportunities are discussed in the following paragraphs.

2.26 **Existing Plants** NPC's existing thermal plant totals 2,225 MW, comprising four stations in Luzon (1,775 MW), six in Visayas (205 MW), and five in Mindanao (237 MW) (including three Power Barges). Luzon thermal plants[4/] average 23 years of age and require rehabilitation. Their performance has deteriorated over the last 5 years (Table 2.6), and thermal efficiencies of some have

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3/ Estimates of the ten year investment requirements for the Philippines power sector can be can be obtained (a) for generation and transmission from NPC's 1993 detailed Power Development Plan (PDP 1993) covering requirements to 2005 and (b) for distribution by extrapolating MERALCO's five year plan *prorata* with load growth, aggregated together with a similar pattern of reinforcement and expansion in proportion to their respective demands for the 15 IODs, and the 118 coops.

4/ Malaya 1&2, Manila 1&2, Sucat 1-4, and Bataan 1&2.

fallen from a design value of 33% to about 25%. Other plants show availability of about 70% compared to an industry average of about 85%. About US$300 million has been invested in rehabilitation since 1986, and five more units with a total capacity of 1,400 MW are being considered for rehabilitation. Rehabilitation of Sucat 1 & 2 was not successful. Work on Sucat 2 and 4 will be completed in 1994. Old thermal plants can be commercially viable for 15 years following rehabilitating, but they will increasingly be dispatched to meet peak demand, as more efficient and cheaply-operated plants replace them for base load operation after 1997. These plants are a valuable resource and should not be retired without detailed justification. NPC is considering Rehabilitate Operate Lease (ROL) or management contracts with private sector operators for Malaya and Calaca, on the ROL model used for Ambuklao and Binga hydro and Naga coal.

Table 2.5 Fuel Mix Targets 1994-2004

	94	98	2004
Hydro	16%	11%	25%
Geothermal	25%	35%	25%
Coal	8%	31%	25%
Oil	51%	23%	25%
Total	100%	100%	100%

2.27 **Nuclear Plant** The future of the nuclear plant is uncertain, due to opposition to nuclear development, concerns about the safety of the installation, and the progressive obsolescence of the non-nuclear components. The Government should therefore make best feasible use of the existing site and equipment by completing a study on optimal conversion of the plant or redevelopment of the site.

2.28 **Gas** Gas is the preferred fuel choice for thermal power generation. In is an inexpensive fuel, requires relatively inexpensive, operationally flexible and quickly installed plants, and generates fewer environmental problems than other fuel alternatives. Therefore, the Government should accelerate exploration of the Palawan field, and give priority to constructing the needed US$1.5 billion pipeline from the field to Bataan. This pipeline could be largely justified by the benefits to power projects,(eg. the cost savings from retrofitting gas turbines from fueling with imported high-sulphur Bunker-C to combined cycle operation.) Considerable benefits of gas field development to industrial and commercial customers are possible as well. Nonetheless, this approach needs time to develop, and is not likely to yield new gas-fired generation before 1998-2000.

2.29 **Coal** Coal is the cheapest fuel for power plants in the Philippines, and the prospects are for stable prices and ample world-wide supply. However, problems with Calaca I have engendered widespread opposition to that and other coal-fired plants, and there have been delays in gaining environmental approvals. Properly operated, low-sulphur fired plants would not interact with torrential downpours to create acid-rain. In the medium term, flue-gas scrubbers can be used to address local environmental impacts of the coal with higher sulfur content. Most larger plants being implemented by IPPs to supply NPC and MERALCO are expected to be fueled by coal.

Geothermal Development

2.30 In comparison with other countries with equivalent geothermal resources, the Philippines has been quick to develop geothermal generation capacity to about 800 MW today. With completion of the 640 MW Leyte projects in 1998, the country will make greater use of geothermal

Table 2.6 - Performance of NPC Thermal Plants

Station	Age Years	Capacity MW	Rating MW	Effy %	Avail %	Rehabilitation Year	US$m
Malaya 1	18	300	218	29	67	1987	36
Malaya 2	14	350	229	32	87	1986	12
Sucat 1	25	150	139	33	91	1989	91
Sucat 2	23	200	158	29	83		
Sucat 3	22	300	140	25	89	1993	95
Sucat 4	21	300	233	30	70	1990	92
Manila 1	28	100	95	32	95		
Manila 2	27	100	95	31	90		
BPPT 1	21	75	68	32	89		
BPPT 2	9	150	88	29	35	1994	30
Batangas	9	300	244	32	77		
Calaca				32	77		
Totals		**2325**	**1707**				**356**

Note: excludes 3 recent Mindanao power barges

energy than any other in the world.[5/]

2.31 Earlier geothermal developments were carried out by PNOC and NPC; the former responsible for steam exploration, and the latter for power generation. The recent Bank-financed Leyte projects represent a promising new model for the near term, with PNOC bearing the same responsibilities for generation and delivery of power to NPC's bulk power transmission substation as do BOT operators of conventional thermal plants. This approach provides PNOC with an opportunity to minimize costs of production, and maximize the potential of the resource. To these ends, IPPs with three separate BOT contracts will generate the power for PNOC, while the latter will retain control over the steam collection and the electric power subtransmission system. PNOC retains greater control over its investment in production drilling, wellhead, steam field and power plant maintenance, and its operations in arranging backup capability in the event of forced outages.

2.32 Tapping other geothermal resources will prove more difficult. Estimated at more than 2,000 MW, they are remote from load centers and are risky, being subject to unexpected steam-field failures. Private exploration of geothermal resources has been inhibited by excessive royalties and taxes, which reduce financial returns to around 10% in the event of success. This return is too low to warrant private investment in exploration and development in the event of success, let alone offset the risk of failure. A temporary exception on royalties has been given to PNOC (as a Government corporation), but such exceptions must be made more permanent or royalties themselves permanently lowered on an economic basis if geothermal development, notwithstanding environmental advantages,

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5/ Additional potential exists in: (i) Mindanao (Mt Apo (240 MW), Mt Pointer (100MW); (ii) Visayas (Leyte 750 MW, Leyte B 400 MW, Negros existing 112+80 MW, Mambukal (100 MW); and (iii) Luzon (Bacman (150 MW), Tiwi (330 MW), Bacban new 330 MW), Batun Buhai (100MW), Pinatubo (100 MW), and Macban (20 MW).

is to become and remain financially attractive to the private sector and PNOC, respectively. The Government is promoting as a Presidential priority a geothermal bill to eliminate royalties for the first 15 years of the Leyte project, and this can be a model for future royalty treatment.

Hydro Power Development

2.33 Philippines hydro resources are estimated at about 10,000 MW. Hydro development advantages include (i) the use of local resources (and lower import requirements), (ii) renewability, (iii) potential for multipurpose development (irrigation, water supply), and (iv) efficient dispatch in standby and spinning reserve settings. But the cycle of deforestation-erosion-reservoir siltation on the one hand, and unpredictable and extended droughts on the other, has resulted in substantially reduced hydro output. And even now that there is breathing room for fuller consideration of slower-to-develop hydro generation, examples elsewhere in the world are discouraging. Environmental and resettlement issues have substantially slowed down or paralyzed hydro development in many countries, and the project-cycle required for large dams may be as long as ten years.

2.34 Large hydro projects are likely to remain in the hands of the Government, where they have until recently languished in the feasibility stage. (A single project completed 8 years ago has been the only hydro project constructed in the last 12 years.) Some of the problems impeding development are specific to the Philippines; others are common to hydro projects everywhere. They include (i) water supply related project risks; (ii) the need for long-term (5+ year) construction loans; (iii) the long period required to amortize the investment; (iv) high local content of construction expenditures (and limited capacity for export financing); (v) difficulties in securing and expropriating land; (vi) the need to optimize total water resources; (vii) paramilitary threats in remote areas where most hydros are located (now substantially improved); (viii) absence of large capacity transmission lines (particularly for northern Luzon); (ix) cost-allocation disputes over the marginal and average cost to each hydro project of installing lines to serve multiple hydros; (x) bias of power planning tools such as the WASP program against hydro projects (because the analysis is ended after ten years, and the only benefit assumed for the remaining forty years is the unamortized cost at that time); (xi) political and environmental opposition to hydro development; (xii) requirements for consultation and approval from multiple agencies, consistent with hydro's multi-sector impacts; and (xiii) a previous lack of financing to complete the costly project designs and needed comprehensive environmental assessment which would meet these numerous obstacles.

2.35 NPC has identified 11 schemes for development of detailed designs, with an aggregate capacity of about 2,500 MW, six in Northern Luzon and five in Mindanao (Table 2.8). In addition to large hydro plants, there are some 37 "small" 20-50 MW hydro projects (mainly run-of-river), totalling 900 MW, for which feasibility studies have been completed. These projects (Table 2.8) may be offered as BOT projects to the private sector by the end of 1994. The average cost of the 80 schemes is about US$1400/kW, and if their cost can be amortized over 25 years their energy costs are quite reasonable, ranging between ₱0.85-1.85/kWh. But running transmission lines to their remote locations may make their total costs much higher. To encourage proposal development, NPC has specified a system of peak and off-peak pricing in the bidding specifications, which reduces the hydrology risk and compensates for storage characteristics. NPC has assumed responsibility for these projects, but the Government has indicated that financing the larger projects is apt to present problems. Nevertheless, some of them could be of interest to distribution utilities or larger industries if transmission facilities and wheeling arrangements could be provided. Hydros too large for existing distributors would be feasible for the consolidated distribution companies recommended elsewhere in this report (para. 5.16).

Table 2.7 Hydro Potential (MW) in the Philippines

Status	Luzon	Visayas	Mindanao	Total
Existing	1226	2	986	2214
Pre-feasibility	5083	339	1327	6749
Feasibility	2510	279	1314	4103
Definite Design	1281	20	0	1301
Total	10100	640	3627	11437

Table 2.8 Hydro Projects in Advanced Design/Feasibility Stages

Project	Installed Capacity MW	Annual Energy GWh	Construction Cost(1988) US$m	Installed Cost US$/kW	Energy Production ₱/KWh
Luzon Location					
Kalayan #3,4	300	665	270	900	0.92
San Roque (North)	390	1214	550	1410	0.98
Agbulu (North)	220	712	343	1560	1.09
Binongan (North)	175	718	485	2711	1.53
Matuno (Center)	180	528	364	2022	1.56
Casecnan (Center)	270	1397	1080	4000	1.75
Mindanao Location					
Agus III	225	1085	381	1690	0.81
Tagaloan II	62	374	139	2241	0.84
Pulangi III	90	282	162	1800	0.96
Bulanog Baton	222	876	379	1707	0.98
Pulangi V	350	1310	775	2214	1.34
Total	**2484**	**9161**	**4928**		

Transmission and Distribution Investment

2.36 NPC's 230/138/69kV transmission systems can be considered as two principal elements: (i) the bulk power or "backbone" system interconnecting the major generating stations with the substations serving the major load centers; and (ii) the radial sub-transmission lines feeding out from bulk supply substations to the rural load centers. In Luzon, the backbone system operates at 230 kV. In Visayas and Mindanao, the backbone systems operates at 138kV. Although the present backbone system is quite extensive, its power transfer capacity is limited by the relatively low voltages and the lack of interconnections between adjacent transmission lines, dictated by the rugged mountainous terrain. Transmission limitations keep thermal generating plants from being cited at remote locations which otherwise enjoy advantages of port access for fuel supplies, ample cooling water, and more easily met environmental constraints. Transmission limitations also precludes development of the substantial hydro resource already in place, particularly in Northern Luzon.

Table 2.9 - Capacities and Current Service Near Promising Small Hydros

Location	Utilities No	Utilities Sales (GWh)	Utilities LF	Hydro Sites No	Hydro Sites Generation (MW)	Hydro Sites Generation (GWh)	% sales	Cost ($/kW)
Palawan	1	2.9	40%	2	64	227	-	1000
Mindoro	2	2.9	40%	5	87	257	-	1236
Negros	5	441	55%	2	61	285	65%	1352
Cagayan De Oro	11	2118	52%	5	72	290	15%	1371
Northern Luzon	13	885	55%	15	498	1663	-	1385
General Santos	10	920	59%	6	113	364	48%	1539
Panay	7	340	54%	2	19	63	26%	2370
Total	**49**	**4709**		**37**	**914**	**3149**		

2.37 By 1998 interconnections at 500 kV within Luzon, 380 kV HCDC (800 MW HVDC) between Leyte and Luzon, and 230/138kV (200 MW) within Visayas, will reduce transmission losses and facilitate efficient intra-regional exchange of energy between generating plants and load centers. In addition, a 400 MW link between Leyte and Mindanao has been planned for the year 2000. More will still be needed, including reinforcement of existing networks and the provision of system stabilization and compensation facilities to ensure proper operation during peak and low-load conditions.[6/]

2.38 Sector planning should emphasize transmission, since the development of a fully integrated backbone system is critical to efficient long-term development of generation. Because transmission costs at US$300/kW are a fraction of generation costs at US$1000-1500 US$/kW), early investment in transmission would give substantial flexibility, offer better choices for siting of new plants, and foster increased participation by the private sector. An independent transmission organization, recovering costs by transparent wheeling arrangements, would substantially improve the priority given to transmission systems and improve its planning and operation. The transmission company should not have vested interests in generation facilities or supply individual consumers, and should concentrate its efforts on implementing transmission, communications and control facilities.

2.39 Subtransmission systems operate at 138kV and 69kV in Luzon, and at 69kV in Visayas and Mindanao. Here, too, considerable reinforcement would improve the overall efficiency of the power supply system by providing more points of supply to distributors. However, NPC has no financial incentive to extend its existing subtransmission lines to shifting true electrical load centers within franchise areas; and distributors have limited financial capacity to optimize their distribution networks and reduce losses by the same measures.

6/ Generally this includes capacitive and reactive compensation facilities installed at major substations. It may also require stabilizers retrofitted in existing generating stations to ensure generators respond to sudden changes in system demand. The need for this type of equipment will increase after the 500 kV system is operational.

Load Dispatch

2.40. The importance of adequate capitalization of dispatch facilities cannot be overstated. Proposals elsewhere in this report (para 5.40) highlight the importance of dispatch, not only for the economic scheduling and utilization of NPC's and IPPs' generation capacity and technical system stability, but also for the development of a transparent market for wheeled bulk power. The load dispatch System Control and Data Acquisition (SCADA) facilities can and should be upgraded in order to provide the proper coordination, load dispatch, and information required by buyers and sellers[7/] Needed SCADA hardware requirements are estimated at US$30-60 million. A similar amount would be needed for associated communications systems, and the development of trunk fiber optics, microwave or satellite communication facilities to provide instantaneous information from all parts of the bulk transmission system.

Subtransmission

2.41 The higher voltage subtransmission systems are operated and maintained both by MERALCO (at 138kV), and NPC (at 69kV and 138kV). The former overlays Meralco's medium voltage (mostly 34 kV) networks. Extension of the 138kV system will allow MERALCO to minimize distribution investments without jeopardizing efficiency. During the next decade MERALCO will probably need additional reinforcement using a 230 kV subtransmission overlay. If so, purchase of existing lines from NPC once the 500 kV system is in operation would be economical. In contrast to the improving conditions in metropolitan Luzon, NPC's subtransmission systems in rural areas are wood construction, single circuit transmission lines, traversing difficult terrain to the franchise areas of the numerous small electricity cooperatives. These system are generally unreliable, disrupted by weather and deteriorating wood poles. They are costly for NPC to maintain, requiring remotely stationed staff on standby duty. In the past, many of the 69kV systems were owned by the small distributors, but NPC acquired them in 1981 when it restored them from disrepair. In the long run they should gradually be returned to the distribution companies. However, the distribution companies must first consolidate (para 5.34), and then develop the capability to manage these facilities.

Electricity Distribution

2.42 MERALCO and the coops are rehabilitating and strengthening existing networks as part of Bank-financed investment programs. In addition, MERALCO is planning a foreign bond issuance to finance strengthening of its sub-transmission system. Its US$800 million investment during 1992-1996 includes subtransmission (44%), distribution system upgrading (17%), SCADA facilities (9%), and customer services (30%). The IODs are also upgrading their networks, but more slowly due to limited capital and credit access.

2.43 Coop investments coordinated by NEA are targeting loss-reduction and reliability improvement. But a lack of trained staff and procurement delays are impeding progress. Also, there is political pressure to significantly increase the 50% coverage of barangays (2.6 million consumers), and extend the networks to new service areas at the expense of upgrading existing networks. NEA estimates the capital expenditure for 100% coverage of all 13,092 barangays (4 million new consumers) at about US$1.1 billion, involving the construction of some 126,000 km of distribution lines. This would also require considerable investments by NPC in subtransmission systems.

7/ SCADA facilities are available for Luzon and Mindanao, and now being commissioned in the Visayas. The location of a proposed new national grid facility would be located near Manila.

E. Conclusions and Recommendations

2.44 With growing participation of the private sector in power generation and the establishment of a complete market price system, traditional prescriptive planning should give way to indicative and strategic planning. For now, prescriptive planning is necessary, because the demand risk under take-or-pay contracts is taken by the Government and consumers. A strategic approach should establish sector policies that guarantee a flexible and robust expansion by incorporating elements of risk and multiple objectives (eg. macroeconomic concerns, fuel security, foreign expenditures, pollution impact). DOE has properly required the utilities and NPC to sign long-term supply contracts which will be binding on all parties. This important step will encourage disciplined demand management and reserve planning, and provide confidence to private investors.

2.45 DOE's power planning should be supported, for now, by NPC, which has developed considerable expertise in this field. DOE will need substantial training and additional staff so it can improve planning and collect and analyze all power statistical data. The Asian Development Bank (ADB) has financed a Master Plan Study of strategic planning for the power sector; as it will provide a framework for deciding on capacity additions, it should be completed as quickly as possible.

2.46 The mixture of public and private supply, mostly under take-or-pay contracts, will substantially complicate power dispatch and require a cooperative relationship among NPC, the distribution companies, and the IPPs. An analysis of the best dispatch system for this new environment is needed and should be a priority.

2.47 The participation of many IPPs, all with different and incomparable PPAs, makes analysis and forecasting of NPC's future generation requirements and costs extremely difficult. The Government should continue to encourage private companies to build, operate, and rehabilitate power generation plants, provided their participation in the power sector is under transparent conditions and in accordance with the Master Plan. This should be applied to all contracts, including those between IPPs and the distribution utilities.

2.48 Sufficient capacity has been awarded or is under construction to meet demand in Luzon and the country through 1999, even under the Government's high demand growth scenario. There are elements of risk associated with the implementation of numerous awarded BOT contracts (several failed to obtain financing, and have been cancelled). However, once financing has been secured and the final contracts are signed with adequate performance guarantees, the record supports optimism toward timely construction and commissioning of projects.

2.49 Under the base case (ie. with GDP growth rates of 5.5% p.a.), and assuming the contracted plans are implemented in a timely manner, the total reserve capacity in Luzon by 1999 would be about 3,000 MW. The following measures should be adopted to plan the right balance of demand and capacity: (a) the PDP should be updated annually; (b) DOE should monitor the status of implementation of all BOT/BTO contracts; (c) DOE should evaluate the supply/demand balance before permitting new take-or-pay contracts; (d) all accredited projects should have a clearly established date after which open contracts would be subject to reaccreditation reflecting current standards for technical appropriateness and cost-efficiency (para. 6.27); and (e) NPC should consider postponing the completion date of projects now lacking effective contracts. The likelihood is that the system will have ample medium term reserve capacity, even with slippage in several ongoing contracts. Now

that the crisis has passed, the Government should take the opportunity to bring greater order into the process of contracting with the IPPS.

2.50 Registration and accreditation of IPPs should become a more substantive qualification (particularly regarding the equity of the proponents). The Government should discourage unsolicited development proposals until it has set the ground rules for projects. Developers should draw up and then share their own project timetables and construction targets with DOE; but then accreditation should be conditional on staying on schedule (para. 6.29). Diligent and thorough accreditation procedures should be employed to improve tracking of prospective project financing, as they are invaluable for spotting moribund projects and correctly predicting the need (or not) to initiate new projects to replace those that may linger for a year or more in the financing stage before dying.

2.51 The Government has the opportunity to plan an optimal fuel mix and power development strategy for the sector. In doing so, it should take into account not only direct costs, but externalities (environmental costs), macroeconomic considerations, and the indigenous fuel resources (hydro, geothermal, and gas) with substantial potential. A Master Plan should explore their development in the context of the private sector's greater role in power generation.

2.52 Royalties and taxes as great as those on geothermal resources are too high to permit adequate profit levels of even low-risk power generation projects with mature technologies, let alone encourage inherently higher risk geothermal developments. Unless these royalties are substantially reduced, environmentally preferable geothermal development will remain financially unattractive both for the private sector and PNOC.

2.53 If a fuel mix insulating the sector from drastic changes in oil supplies and prices is to be achieved, then the Philippines' substantial hydro power resources should receive due priority. Planning tools that more adequately take account of the features of hydro should be used. An important immediate step would be for the Government to develop the detailed designs for some 11 schemes already at the advanced feasibility level, with an aggregate capacity of about 2,500 MW.

2.54 Transmission is the highway to the level playing field for rational development and use of generation resources. Plans for strengthening the transmission system are in place and should remain on track. The Government should establish an independent transmission company to provide adequate transmission capacity (para. 5.15), and a transparent wheeling system for all users of the system (para. 6.46). Wheeling arrangements should also be introduced in all franchise areas to foster increased competition in power supply.

2.55 Continued underinvestment in distribution could cause interruptions of service. It is already causing high energy losses, and an overall drag on the power system and economy. High levels of private sector investment in power generation and public sector investment in transmission must be complemented higher investment in distribution if total sector investment is to be optimized.

3. Financial Implications

A. Introduction

3.1 The Philippines leads the developing world in the number and capacity of private power projects. Between 1992 and March 1994, the program attracted about US$5 billion in foreign investments. During the same period, NPC has signed 33 agreements for various private power schemes, and increased the total reliable capacity already available by 135% (Annex 2). Seven projects were "fast track," with a capacity of 925 MW; twelve projects with a total capacity of 1300 MW were operational by January 1994, and three more (total capacity 1500 MW) will be commissioned during 1994.[9/] Large as this growth in privately developed generation has been, maximum total power delivery at lowest costs will require that these investments be integrated with NPC's investments in transmission, and with NPC's rehabilitation and timely completion of its own power plants. Further coordination will be required with investments by the IODs and coops to extend and rehabilitate the distribution networks. The financial implications for NPC, the distribution utilities, and independent power producers are described in this chapter.

B. The National Power Corporation

3.2 In spite of an ageing physical plant and growing demand for power, NPC between 1985 and 1991 was in weak financial condition and made minimal and--it was proved--inadequate investments in generating capacity. A supply shortage was imminent. When record droughts crippled hydroelectric production, it only exacerbated a crisis brought on by delayed project approvals and the increasingly poor repair of the physical plant. Between 1985 and 1991 NPC's capital expenditures had averaged just ₱7 billion annually.

3.3 In mid-1992 the power crisis started, and the Government and NPC acted on several fronts at once, expediting necessary environmental approvals, clearing a backlog of rehabilitation contracts for its own plants, implementing necessary new power projects, and proceeding with the construction of long-pending coal plants of its own. NPC's own investments doubled by 1992 to ₱15 billion. The private sector was also invited to build generating capacity, and ten BOT/BTO contracts (1100 MW total capacity) were in operation by April 1994, with fifteen more (2500 MW total capacity) under construction in mid-1994. NPC also transferred rehabilitation, operation and management of several of its plants to the private sector, (including Ambuclao, Binga, Naga) and similar contracts are under bidding for other plants (Aplya, Calaca I, Malaya I and Malaya II). As a result, power outages ended by mid-1994, and adequate peak capacity should be available to meet peak demand by the end of 1994.

3.4 The dispatch with which these contracts were awarded and processed is a major achievement of the Government and NPC. The speed with which contracts were signed and financing secured was due to a unique set of circumstances:

9/ Details on these projects, their construction schedule, and other project initiatives are presented in Annex 2.

(a) The commercial opportunities for private development were immediately attractive: NPC was willing to include capacity charges and take-or-pay provisions, and take responsibility for fuel supplies, substantially limiting the commercial risk being borne by the developers. Capital requirements were relatively modest for the shorter-lived peaking plants constructed. Third, short construction times for these types of plants limited the exposure of developers and lenders.

(b) Few opportunities to build and operate BOT power plants existed outside of the Philippines.

(c) Official financiers with private sector windows (mainly the Import and Export Bank of Japan, ADB and IFC) had little or no exposure to the Philippines.

(d) The financial success from Hopewell's Navotas Project (para. 1.3) provided comfort to other interested investors;

(e) Recessions and low interest rates in many countries limited the yields available on low-risk investments, and made high yields available from Philippine projects attractive.

3.5 NPC is not alone in the Philippines in its pursuit of contracts for energy and capacity, but other plans have to date remained just plans, with a few small exceptions (para. 1.12). MERALCO has also signed contracts for medium term base-load, peaking, and reserve generation capacity, all scheduled for completion by the end of 1997. However, financing for several of these projects is still uncertain.

Table 3.1 NPC's Capital Expenditures for Transmission

	TOTAL	1994	1995	1996	1997	1998
			Million US$			
Luzon	1813	205.7	374.3	454.2	460.5	318.7
Visayas	265	39.1	82.5	80.4	27.3	35.8
Mindanao	114	40.1	36.4	20.7	6.9	9.4
TOTAL (M. US$)	2192	284.9	493.2	555.3	494.8	363.9
Foreign (M.US$)	1683	230	384	421	368	281
Local (M.Peso)	15577	1544	3181	4071	4028	2753
TOTAL (M.Peso)	66821	7949	14304	16856	15678	12035

Table 3.2 NPC's Capital Expenditures for Generation and Other Works

	TOTAL 1994-98	%	1994	1995	1996	1997	1998
			Million US$				
Luzon-Generation	2162	51.7%	529	526	349	483	275
Rehab.& General Works	1098	26.3%	219	219	208	219	233
Mindanao-Generation	516	12.3%	225	64	42	66	118
Engineering	264	6.3%	46	55	53	54	56
Islands-Generation	89	2.1%	20	25	15	14	15
Visayas-Generation	52	1.2%	51	1	0	0	0
TOTAL COST - M. US$	4181	100.0%	1089	890	668	837	697
Foreign Cost -M. US$	2477	59.2%	839	587	319	450	283
Local Cost -M. Pesos	52333	40.8%	6989	8780	10592	12253	13719
TOTAL COST - M. Pesos	126040	100.0%	30386	25803	20272	26515	23064

NPC's Investments In Generation and Transmission 1994-98

3.6 NPC plans US$6.4 billion (₱180 billion) in capital expenditures for the 1994-1998 period, US$2.2 billion for transmission works, (Table 3.1) and US$4.2 billion for generation and other works (Table 3.2). The largest share (41%) is for the completion of ongoing power generation projects, 33% is for transmission works, 21% is for rehabilitation of plants and spare parts, 4% for interest during construction, and 1% for further expansion of island grid services (Table 3.3). Loans are expected to finance 71% of this investment of about US$950 million per year.

3.7 For its part in BOT projects with NPC, private sector capital expenditures--entirely for generation-- would total US$3 billion between 1993-98, about US$600 million per year. Loans are expected to finance about 75% of this investment, about US$450 million per year, much of which is already in place.

3.8 The remainder of capital investment in the power sector for this period will be for MERALCO's generation projects; and distribution related investments of MERALCO and other distribution utilities. These are estimated at US$200 million per year during the period, of which an estimated US$160 million per year would be borrowed.

NPC's Future Finances

3.9 NPC's projected financial performance is summarized in Table 3.4. Following the Bank's forecast of economic growth, the average annual growth rate in power demand would average about 9% between 1994-98. With the additional capacity contracted for, service is expected to be reliable and NPC would have relatively large reserve capacity.

3.10 NPC has been and is exempt from income taxation on power sales, though there have been proposals that its tax status be the same PNOC-IPC, other IPPs, and private power distribution utilities. The Supreme Court, in a May 1993 ruling, reconfirmed NPC's exemption from fuel oil taxes and allowed it to seek a refund of fuel tax payments of about ₱13 billion. The Government will make this refund over the period 1994-96, providing needed cash relief to NPC.

3.11 Future NPC's operating expenses per kWh will increase rapidly, particularly because of power purchases from BOT contracts. Those payments, excluding fuel costs, are expected to in-

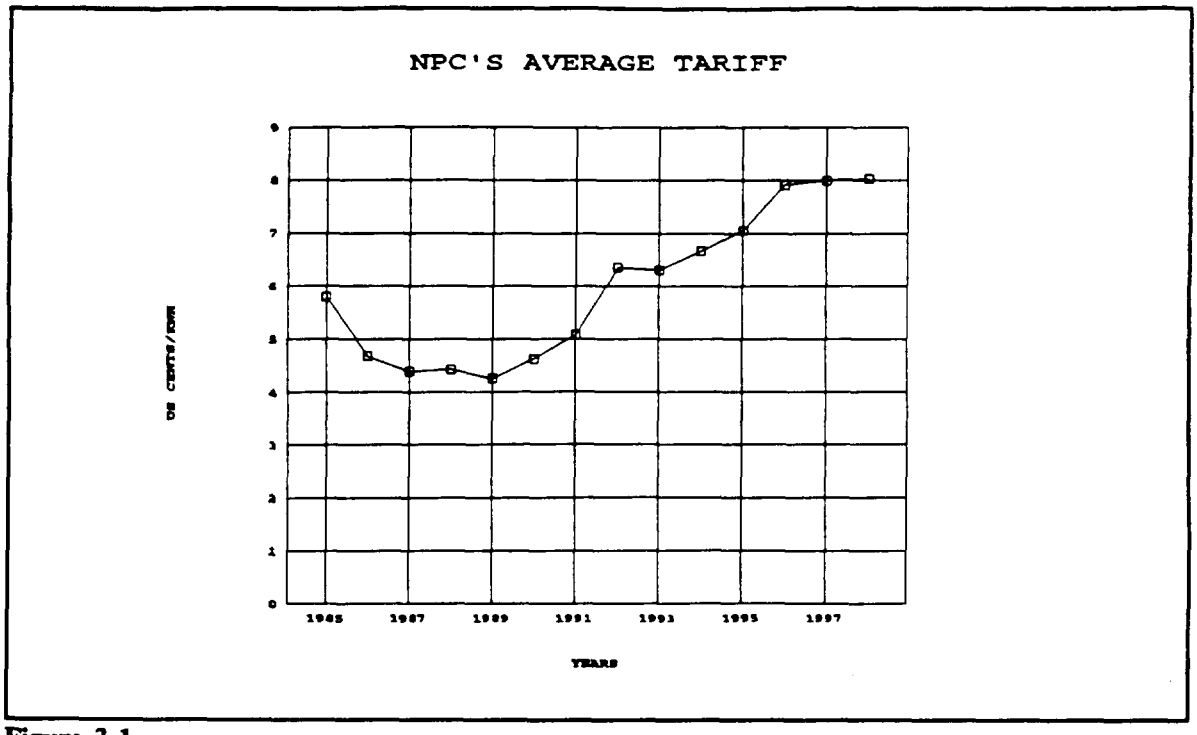

Figure 3.1

fold between 1993-98, from US$120 million to US$1.1 billion, even after amortizing BOT expenses over the plant's useful life rather than the contracted periods (This, however, does not diminish NPC's cash requirements). The BOTs would then account for about 40% of NPC's total operational expenditures (including depreciation). (Figure 3.1) The impact of BOTs and NPC-owned new assets entering into operation would be particularly high in 1996, when, under the present investment program, the depreciation and the rate of return base would increase by about 40%. This may require smoothing the required tariff increases over two years.

3.12 To fulfil existing and new covenants with international lenders, NPC must maintain a minimum after-tax rate of return on its average net revalued fixed assets in operation of 8%. To meet these covenants while also taking into account the accelerated capital recovery charges (para. 3.16) and the impact of devaluation on BOT/BTO contracts (which are mainly paid in US dollars), it is expected that tariff would have to be increased a total of about 10% in real terms by 1998. This would increase NPC rates from US$0.065/kWh to US$0.08/kWh (Figure 3.1). Automatic fuel price cost adjustments are expected to gradually increase NPC's rates in proportion to the cost of fuels and purchased energy, which represent about 82% of NPC's cash operating expenditures. However, clear and decisive actions will be needed by the Government to maintain NPC's financial viability and ensure compliance with financial covenants to ensure that existing loans are disbursed and new loans are secured.

3.13 The fact that tariffs will increase during a period of rapid supply growth, especially from presumably more efficient and cost effective private sector sources is counter to general expectations of the impact of privatization. However, the Philippine experience makes clear that developing countries seeking to devolve responsibility to the private sector need to bear initially higher costs for several reasons. To begin with, the Philippines had to offer high returns merely to attract developers foregoing healthy but lesser returns in the comparative safety of their home countries.

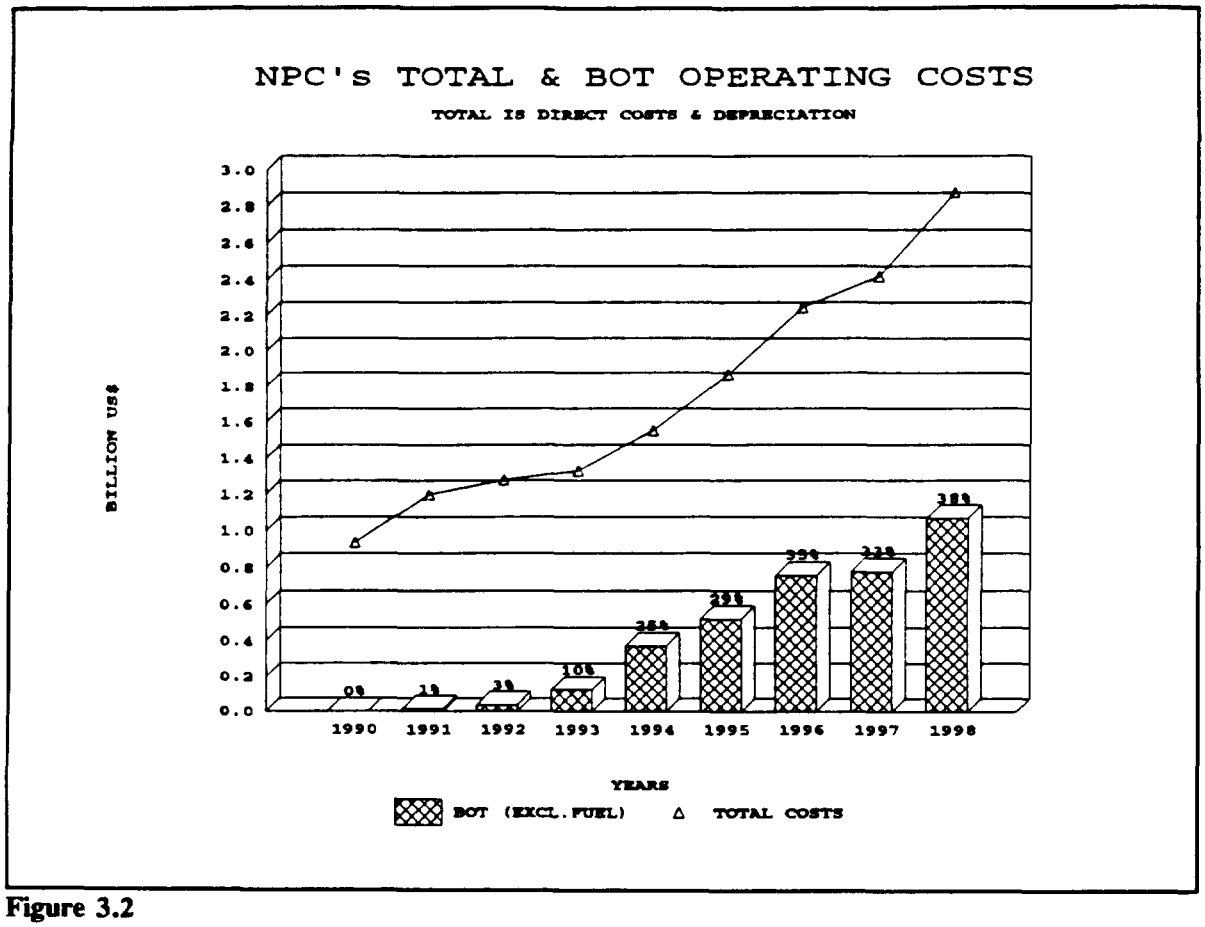

Figure 3.2

Then, higher returns continued to be needed as the country sought large amounts of fresh independently produced generation even before it had clearly established its hospitality to private sector development of power. With the number of bidding IPPs now exceeding the number of business opportunities for new projects, competition among the developers has taken root, and the returns they are seeking on their investment has begun to shrink (para. 4.7).

NPC's Financing Plan

3.14 By achieving an 8% rate of return, NPC's operating cash flow during 1994-98 would be about 74% of its capital expenditures, and its net internal cash generation (after debt service, working capital needs and the payment of taxes and dividends) would finance about 25% of its investment requirements. (Figure 3.3). The remaining 75% will be financed by loans and equity contributions. Because of high domestic interest rates, short maturities, and Government financing requirements, local borrowing is expected to be used only for working capital needs. Therefore, other than internal cash generation, most financing is expected to come from foreign loans, particularly supplier credits and official development assistance. On-going loans will provide ₱41 billion (21%) of capital expenditures between 1994-98, and loans in the final stages of negotiation will provide another ₱36 billion (18%). However, particularly for 1996 onwards, NPC would have to secure additional loans for ₱64 billion (32%) to finance the foreign component of the proposed investment. This will require NPC to maintain a strong financial position and to identify and complete the financing for its planned projects very soon. Financial markets are reacting favorably to NPC; its bond

Table 3.3 - Financial Plan 1994-1998 (Million Pesos)

	TOTAL 94-98	% OF TOTAL	1994	1995	1996	1997	1998
OPERATING CASH FLOW	148673	74.3%	22942	24703	29497	32586	38945
LESS:							
Amortization	62715	31.4%	12554	12970	13226	12796	11169
Operational Interest	38794	19.4%	6197	7544	7701	8413	8940
TOTAL DEBT SERVICE	101509	50.8%	18751	20515	20927	21208	20109
Incr.Working Capital Excl.Cash (+)	5644	2.8%	747	683	1390	840	1984
Incr. Other Assets/Liabilities (**	396	0.2%	464	61	61	-46	-144
Increase in Oil Taxes (Refunds)	-8928	-4.5%	-4400	-3400	-1128	0	0
Tax and Dividends Paid	449	0.2%	76	80	94	99	100
Other Cash Expenses	0	0.0%	0	0	0	0	0
NET INTERNAL CASH GENERATION	49603	24.8%	7305	6764	8153	10485	16897
CAPITAL EXPENDITURES							
Generation (Excluding BOTs)	81911	41.0%	22449	17146	11885	17410	13021
Transmission	66821	33.4%	7949	14304	16856	15678	12035
Island Grid (Rural)	2678	1.3%	562	720	462	429	504
Other (Rehab. Engin. & Other)	41452	20.7%	7375	7937	7924	8676	9539
Interest Capitalized	7155	3.6%	1557	1571	1860	1393	773
TOTAL CAPITAL EXPENDITURES	200015	100.0%	39893	41679	38987	43585	35872
NET TO BE FINANCED:	150412	75.2%	32588	34915	30834	33100	18975
FINANCED BY:							
Equity Contributions	11245	5.6%	5334	1412	1453	1498	1548
Grants	1833	0.9%	407	935	300	190	0
Ongoing Loans	41106	20.6%	24255	14635	2216	0	0
Loan Restructuring	0	0.0%	0	0	0	0	0
Loans under Negotiation	36178	18.1%	3902	8158	12828	8295	2995
Foreign Loans to be Obtained	64160	32.1%	0	8866	11657	22518	21119
Local Loans & Proposed Bonds	0	0.0%	0	0	0	0	0
TOTAL BORROWING	141443	70.7%	28157	31658	26701	30813	24114
TOTAL FINANCED	154522	77.3%	33898	34006	28455	32501	25662

issue of US$200 million in 1993 was fully on favorable terms. In the event that the additional loans do not materialize, NPC will need to postpone those projects for which foreign financing has not been secured. The remaining financing would be provided by Government equity contributions (5.6%, about ₱1.5 billion a year), which would partially compensate for the higher cost of providing electricity to small islands and rural areas. Foreign grants would finance another 0.9% of the investment.

3.15 NPC's finances will be satisfactory if it can achieve an 8% rate of return (Table 3.4), with a debt service coverage ratio averaging 1.4, and an operating ratio of about 80%. NPC's

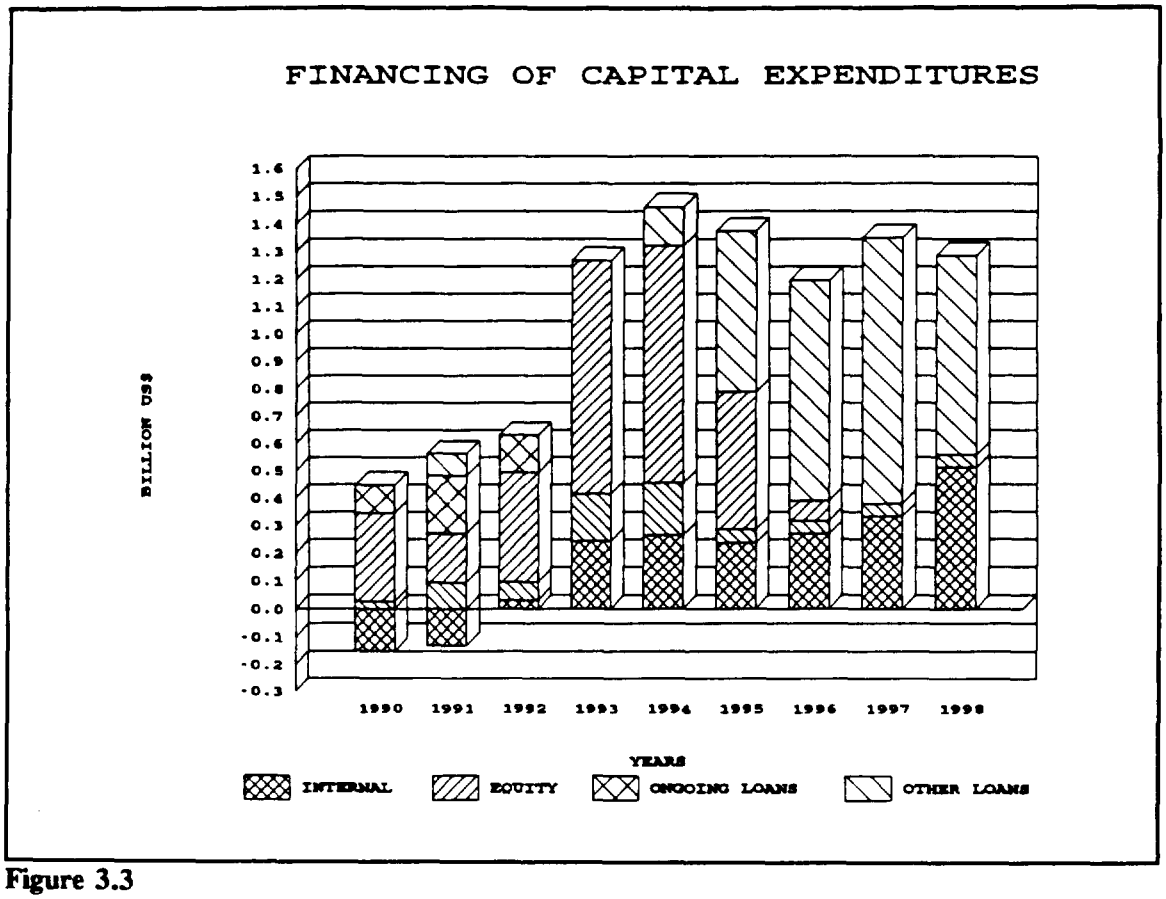

Figure 3.3

debt/equity ratio will be reduced gradually from 57% in 1993 to 39% in 1998. However, NPC will be subject to exacting financial demands. This results from: (a) the doubling of its debt service between 1992 and 1995.[9/] (b) the quadrupling of its capital expenditures between 1992 and 1994, with investments averaging US$1.3 billion per year between 1994-98; and (c) increased operating expenses due to reduced use of hydro plants for power generation and high power purchase costs associated with its BOT program.

Impact of the BOT's Cost Recovery Conditions

3.16 NPC's increased reliance on BOT/BTOs for supplies is expected to require higher tariffs unless substantial efficiency gains can compensate for two major impacts: (a) much shorter term repayments by the commercial loans used to finance these projects; and (b) the higher rates of return required by the private sector, particularly considering the risks for projects in less development countries (para. 3.13). Consequently, private costs of generation passed through to NPC could put upward pressure on tariffs. For example, Table 3.5 shows estimated production costs (US$/kWh) of electricity from a 500 MW coal plant at different recovery periods and discount rates. While the Government's imputed cost of production could be as little as US.052/kWh (repayment for 14 years

9/ This is partially due to the revaluation of the yen and large payments for new BTO contracts (which are generally amortized over just 5-7 years). Moreover, although most of NPC's foreign debts have been rescheduled as a part of the Paris Club agreements for the Philippines, NPC has been required to repay them to the Government based on the original repayment schedule.

Table 3.4 - Financial Highlights of NPC (Billion Pesos)

	1990	1991	1992	1993	1994	1995	1996	1997
Total Operating Revenues	25.779	32.342	37.432	42.368	54.039	65.095	81.143	92.510
Total Operating Expenses	20.924	30.929	30.307	33.972	41.316	52.000	65.982	74.414
Net Income	0.992	-3.722	4.118	3.006	7.235	5.915	8.936	9.454
Cash Available From Operations	-3.668	-3.586	0.781	6.554	7.305	6.764	8.153	10.485
Total Investment	11.181	9.691	14.788	31.660	39.893	41.679	38.987	43.585
Borrowing	10.245	12.910	13.407	23.198	28.157	31.658	26.701	30.813
Rate Base	68.409	79.260	99.596	111.870	136.702	164.339	189.965	219.002
Total Assets	167.612	178.530	207.968	244.905	283.883	323.587	361.273	406.021
Total Long-Term Debt (Net)	69.108	72.247	-4.785	96.184	120.822	137.149	145.872	149.678
Total Equity	40.063	44.994	145.213	73.009	99.067	120.820	148.869	189.993
Electricity Sold - TWh	23	23	23	25	29	32	34	36
Average Tariff - P/Kwh	1.12	1.40	1.59	1.71	1.86	2.05	2.40	2.53
Rate of Return-Revalued Assets 1]	7.1%	1.8%	7.2%	7.5%	9.4%	8.0%	8.0%	8.3%
Self-Financing Ratio 2]	-40.0%	-30.2%	4.2%	22.8%	19.4%	16.8%	19.7%	26.6%
Debt Service Coverage 3]	0.61	0.67	1.07	1.50	1.39	1.33	1.39	1.49
Debt /(Debt plus Equity) 4]	63%	62%	-3%	57%	55%	53%	49%	44%
Working Ratio 5]	61%	78%	62%	60%	60%	64%	67%	66%
Current Ratio 6]	70%	70%	61%	59%	70%	70%	69%	74%
Accounts Receivable (days)	52	44	39	43	38	38	38	38
Ongoing & Proposed BOTs/NPC's Capex	0.0%	0.0%	32.8%	66.7%	69.3%	49.3%	0.0%	0.0%

1] Operating income less taxes on net average historical fixed assets in operation.
2] Cash available for investment divided by 3-year average capital expenditures
3] Operating cash flow divided by debt service (amortization plus operational interest)
4] Long-term debt divided by long-term debt plus total equity.
5] Operating expenditures excluding depreciation divided by operating revenues.

at 8% discount, and assuming that NPC could manage the construction without inordinate delays) the cost of private development of the same plant, even assuming a higher efficiency, could be as high as US$0.080/kWh merely because (i) the loan is repaid just six years after the construction of the plant and (ii) the discount rate required is 14%. Recent trends in the cost of BOTs for projects with substantial economies of scale (eg. 1000 MW Sual, estimated at ₱1.40/kWh)) indicate that under good competitive conditions lower prices can be achieved. However, these costs are still higher than NPC's operating cost of ₱1.18/kWh (in 1993, including depreciation) and ₱1.38/kWh including interest charges. Moreover, the generating cost is only part of the total cost, and sales prices should include the cost of the transmission system and its maintenance, transmission losses, the provision for peak capacity, the cost of reserve capacity required for this and other plants to be maintained or replaced during outages, the cost of billing and collecting, etc. Overall, it is estimated that if all generation plants were contracted under BOT financing arrangements, NPC tariffs would increase about 20%.

3.17 NPC's capital investment program must be flexible, as generation capacity grows rapidly and changes in less than a decade from a public monopoly entirely to a joint relationship with multiple private sector partners. At present, prospects for foreign sources of investment capital are good. However, these could be quickly damaged if NPC does not maintain adequate financial performance. As cumulative risk exposure grows, and an increasing share of new generation that needs financing is for reserve capacity, foreign and international lenders will be less willing to finance

projects without seeing first that the power sector is operating with greater efficiency and the commitment of greater domestic investment. In the future, constructive collaboration with the Philippine capital markets will be needed to meet financing goals.

Table 3.5 - Impact of BOTs' Cost Recovery Conditions on Imputed Production Costs for a 500 MW Coal Plant

Discount	---------- Recovery (Years) ----------			
Rate	6	10	12	14
8.0%	7.20	5.82	5.48	5.25
10.0%	7.45	6.09	5.77	5.55
12.0%	7.71	6.38	6.07	5.86
14.0%	7.98	6.68	6.39	6.19

3.18 NPC also expects and relies on continued exemption from certain business costs, and assumes that further tariff increases to utilities can be absorbed or passed further along without suppressing power demand or encouraging self-generation. While relief from the recent power crisis is welcome, sustaining the necessary cash flow may be difficult within the current institutional framework. NPC's plan depends on regular tariff increases, continued exemption from income and fuel taxes, and the expectation that fuel cost and currency exchange charges can be automatically passed on to its consumers without political repercussions, suppression of demand, or tertiary customers' resorting to private generation. The scheduled 10% real increase in NPC tariffs may be judged a small cost to prevent further power shortages and achieve a much higher reliability (The average age of dependable generating capacity will be reduced from fifteen years to seven between 1993 and 1998). In current peso prices, however, NPC's wholesale tariff would be 50% higher by 1998 than present levels. Moreover, the tariff increases to retail consumers would be still greater because of increases in the distribution utilities' spreads.

C. Distribution Company Finances

3.19 As previously indicated, some 135 investor and member owned private utilities provide electricity distribution services nationwide. Their institutional and financial capabilities vary widely. While MERALCO is a special case because of its disproportionate size and corporate strength, the issues faced by the smaller IODs are homogeneous, and so too are the issues being faced by the member owned coops.

MERALCO

3.20 Since the change in ownership in 1986, the Company's operational and financial performance has improved steadily and substantially. System losses have dropped from 22% to about 14%; while this level is still too high, it represents a substantial reduction in the cost of inefficiency

Table 3.6 - Financing Structures of Selected Private Power Projects
(US$ millions)

	Hopewell Navotas (1991)	Hopewell Pagbilao (1992)	Northern Mindanao (1993)	Enron Batangas (1993)	Enron Subic (1994)	Total
A. DEBT						
- IFC	10.0	60.0	12.5	-		82.5
- Other multilateral/bilateral	10.0	75.0	-			85.0
- EXIM banks	-	551.9	23.0			574.9
- Commercial banks	10.0	60.0	34.5			104.5
- Debt securities	-	-	-		105.0	105.0
- Other					2.0	2.0
Total Debt	30.0	746.9	70.0		107.0	846.9
B. EQUITY						
- Sponsors	8.8	205.0	31.5		24.8	270.1
- IFC	1.1	10.0	4.5			15.6
- Other multilateral/bilateral	1.1	20.0				21.1
- Other					10.1	10.1
Total Equity	11.0	235.0	36.0		34.9	316.9
C. TOTAL FINANCING	41.0	981.9	106.0			1269.8

that is being borne by the consumers. At the same time, collections and system reliability have improved to levels appropriate to well run utilities. As a result,(i) the same Company that in 1986 showed modest accrual surpluses based on accounting conventions was realizing genuine profitability, as exemplified by the consistent realization of annual rates of return on revalued assets averaging about 8% (its charter allows a maximum of 12%); (ii) the Company's deep cash flow deficits disappeared, so that it now realizes substantial cash surpluses; and (iii) where MERALCO had been curtailing severely investments, maintenance and training, it now follows good operating practices and self finances 45% or more of a consequential investment program.

3.21 Currently, the Company's spread over its cost of power purchases is about 46%. While this represents a substantial reduction relative to earlier levels, it is still higher than comparable circumstances throughout Asia. MERALCO does face a combination of obligations not normal to the other distribution utilities in the area. As a private company, it is liable for income taxes assessed at 35% of profits and franchise taxes assessed at 3% of gross sales. While other utilities can pass the cost of many connections on to the consumer and reflect the finance raised therefrom as "Consumer Contributions", MERALCO must finance those costs (which constitute between 30 - 35% of its com-

prehensive 1990-98 investment program) either from debt or tariff revenues. Few other of the area's distribution utilities need to meet the dividend expectations of a large bloc of public shareholders. And while other distributors around the region have had access to loan finance at concessionary rates, MERALCO has been paying an average of 11% on its foreign exchange and about 20% on its local borrowings. In some ways, internal cash generation is less costly to MERALCO's consumers and shareholders than alternative debt financing.

3.22 Because of these factors, the only option available to MERALCO for reducing its spread is to reduce system losses still further. During 1992-93, the Bank retained a consultant to help MERALCO optimize its 1995-98 investment program relative to criteria including system loss reduction and system reliability improvement. The Bank and the Company thereby ascertained that, because of multiple voltage drops along very lengthy feeders, the floor under technical line losses is about 8.5% and under aggregate system losses is about 10%, through the end of the decade. While further reduction was possible, these could be achieved through the implementation of investments that would need to be justified based more on load growth than on loss reduction. A second approach to reducing the spread might be to target lower levels of profitability. However, for the foreseeable future, the Company's investment needs will continue to drive its profitability; and, since 50% of the Company's investment needs will be in local currency and it has limited sources of local currency finance other than internal cash generation, the opportunity to lower profitability responsibly is quite limited. Therefore, the floor under MERALCO's spread is in the range of 40 - 42%.

Investor Owned Distributors

3.23 The financial performance of the 14 IODs outside Manila has varied widely; in general, the three companies showing strong operating performance have also been the good financial performers. These include the Cagayan Electric Power and Light Company, Cotabato Light and Power Company, and Angeles Electric Corporation. The financial performance of the remainder ranges from undistinguished to very poor. The charters of the various IODs allow them rates of return of up to 12% on revalued assets; in practice, few can realize such healthy performance, in part because the process of securing regulatory approval of tariff adjustments has worked excessively slowly.

3.24 As with their financial performance, the condition of these Companies' networks varies widely. The stronger among them have spent reasonable amounts on network maintenance, and have used some of their earnings to invest in network extensions needed to meet demand growth. In contrast, the weaker of these utilities have clearly urgent needs for network rehabilitation. While their spreads are high, they show little visible evidence of regular maintenance or capital investment. In part, the low level of investment reflects these companies' cash flow constraints. Many of them have had difficulty securing credit. As a result, their only assured source of investment finance is whatever they can generate from operations; and the cash thus generated is often less than needed because the time needed for tariff adjustments to take effect is so long.

3.25 The distribution spreads of these utilities has varied from about 40% to about 125%; here too, the companies providing the most efficient and reliable service are the ones with the lowest spreads. Aside from losses and inefficiency, the most significant component of the spread is corporate overhead. While some of that overhead is for necessary activities such as billing and accounting, these charges are spread across both a small customer base and a low level of overall consumption. In the same vein, executive salaries and dividends are often high in relation to the scope of these companies' businesses.

Member Owned Cooperatives

3.26 If anything, the financial performance of the 120 member owned cooperatives is more precarious than the IODs'. This financial weakness stems from the tariff policy, which NEA had applied through 1990, whereby the coops were allowed merely to recover their historical costs. Under that policy, an honestly managed coop could do little more than break even; and, it had little cushion to withstand emergencies such as earthquake or typhoon damage. In contrast, coops with high historical levels of overhead could continue to support their profligacy, provided they did not retain their cash flows within the coop. Thus, the coops were effectively prevented from self financing any consequential amount of investment; moreover, as a coop only had the latitude to cut maintenance and training when its cash flow was squeezed, the policy of limiting tariffs to cost-coverage only left many otherwise well-managed coops with rapidly decaying networks.

3.27 In late 1990, NEA led a change in the Government's approach to coop tariffs. At that time, NEA decided that it could not set restrictive rates for coops, and then hold the coops accountable for the condition of their networks or the quality of their service. Under the redefined approach to coop tariffs, NEA would promulgate guidelines for the coops to follow in setting their own tariffs. Those guidelines included a provision, under which the coops could raise enough surplus from internal cash generation to self finance up to 20% of their average annual investment programs. NEA would then hold hearings on the acceptability of each coop's new rates after receiving assurances that the coop had discussed the proposed tariff thoroughly with its consumer-members. Between October 1990 and December 1991, more than 100 coops raised their rates by 30 - 50%. In the aftermath, many coops' financial performance improved markedly; at the same time, their system losses declined to an average of 22%, and outages due to system faults also declined sharply. Many coops applied their improved cash flows to strengthened maintenance and investments in urgently needed network renewal.

3.28 While the 1991 cycle of tariff increases did improve the coops' financial performance, it also increased their spreads to some of the highest levels in the world. A few well managed coops have spreads of less than 40%, but most spreads average 75 - 150% (Annex 8 para. 14). In general, the smallest coops and those serving the poorest localities have the highest spreads. As with the IODs, they simply have a low critical mass of consumers and consumption over which to spread their corporate expenses. Secondarily, many coops with high spreads also have high levels of system losses and/or low levels of reliability of service. While system loss reduction could reduce the spreads by about 10 - 15% on a case by case basis, the reduction of overheads by eliminating the duplication of common corporate functions among coops could reduce the spreads by 25% across the board within a given region.

3.29 Consolidation may have little bearing on the service and tariffs for the 25 small island coops. Those coops serve an extremely small number of very poor members, many of whom have already reduced their consumption well into the range of inelasticity in response to tariffs which in some cases are more than double those in Washington, D.C. NPC already subsidizes the cost of supplying those coops. Moreover, many of those coops are geographically restricted from realizing efficiencies of scale through merger or consolidation. Their systems were probably not economically justifiable when the original investments were made. However, now that those islands are electrified, the political cost of letting those systems deteriorate is not acceptable, while the cost of subsidizing them is relatively minor. The Government should establish an annual budgetary allocation for providing direct subsidies to those coops, and thereby reduce their reliance on cross-subsidies raised by NPC and NEA's acquiescence to inappropriate business practices.

D. Independent Power Producers

The Cost of Private Projects

3.30 Comprehensive data are unavailable on the total investment costs associated with private power projects being undertaken in the Philippines. As shown in Annex 2, Table 1, projects for which there is information cost about US$1040/kW. (These include three IFC projects: Hopewell Navotas, Hopewell Pagbilao and Northern Mindanao.) The BOT, BTO and BOO projects involve substantial new investment, whereas the rehabilitation projects require relatively modest investment sums. Power generation costs from private projects are analyzed in Chapter 4.

Financing Structures of Private Projects

3.31 Information on the financing structures of Philippine private power projects is very limited. Some projects, such as Hopewell's gas turbine barges, have been financed internally, with no direct approach to the market for debt finance. Other, smaller projects have been (or are proposed to be) financed with a combination of sponsor equity and debt from local banks. For larger projects, debt and equity have been mobilized from multiple sources, foreign and local. Of the larger projects, financing plans have been completed for the three IFC-financed projects, Enron Subic Bay, and Enron Batangas (assisted by ADB). These five projects, accounting for 1200 MW, are indicative of the larger scale funds-mobilization initiatives that have been adopted. Each has been undertaken on a limited recourse basis, in which debt finance is mobilized from the market on the basis of the project's revenue stream, and security is held on the project's assets. Some of the larger proposed projects (including MUDC and Luzon Power) are also being planned on a limited recourse finance basis.

3.32 A summary of the financing structures of these five projects is presented in Table 3.6. The debt to equity ratios range from 68:32 for Northern Mindanao to 75:25 for the Enron Subic Bay project and 76:24 for the Hopewell Pagbilao project. These ratios were weighted more in favor of debt than other IFC's power projects (67:33 for 20 projects up to December 1993). The pattern of debt financing has a heavy reliance on multilateral/bilateral and Exim bank financing, although for smaller projects there is participation of commercial banks and bond issues. All of the debt portions of these projects have been issued on an at-risk basis and no debt has been supported by loan repayment guarantees, although the payment to all BOT contractors with NPC is fully guaranteed by the Government.

3.33 The 700 MW Pagbilao project is the largest power plant under construction. Its financing, arranged by IFC, was the first where limited-recourse co-financing without government guarantees was obtained for a large project in developing countries (from Japan and US Eximbanks). The US Eximbank will not take completion risk, but will provide cover for political risk (expropriation, foreign exchange transfer or violence). To cover the construction period, Citibank will syndicate out bridge financing, which will be taken out by an Eximbank loan after project completion. Details of the US$981 million financing are presented in Annex 2. It includes three foreign banks that for the first time are participating in a JEXIM scheme. Of the IFC contribution to the loan package, some US$40 million has been syndicated with commercial banks under "B" loan arrangements.

3.34 The entry of private investors to the power sector has also resulted in some funds being mobilized from domestic sources. For example, for the 215 MW Bauang La Union diesel power plant (estimated project cost US$285 million) the US$85 million equity came from these sources:

MERALCO 40%; First Philippine Holding 20%; JG Summit 20%; and PCI Bank 20%. The remaining costs would be financed by export credit agencies and domestic banks.

Financing Options Under Privatization

3.35 The Philippines now has substantial experience with a wide range of entry arrangements for private investors and managers in the power sector. The range of participation options within the Philippines probably encompasses the varieties across all other developing countries. In addition, the pace of entry into the private power field indicates that the overall environment for financing investment is improving. A program of privatization for the power sector will need to build on the financing experience to date, in addition to dealing with the issues that a change in ownership entails.

3.36 One of the lessons to emerge from financing of privatization in other countries is that financing of the divestiture usually involves a different set of issues compared to the financing of post-divestiture investment. In the Philippines, the financing of the divestiture program would need to focus on the issue of equity mobilization. While Filipino investors have shown interest in participating in BOT and BOO contracts, because there is no limit on the return on equity on these projects, there has been limited interest in investing in the power utilities proper, where the rate of return is regulated by ERB and a maximum annual rate of return of 10% is allowed. Debt mobilization at the divestiture stage should not be difficult, provided the assets have been priced adequately and lenders are satisfied with the earnings potential of the new management. However, the issue of the high tariffs needed would be a large concern for any purchaser. Larger scale debt issues are becoming easier for the Philippines as concerns over country risk ease. Secondary market prices of Philippine debt have climbed progressively since 1990, with a rapid increase from 57% of face value in Q4 1992 to 81% of face value in Q4 1993 (the same as Mexico and considerably higher than Argentina). Eurobond issues are continuing, with JG Summit Holding's 10-year US$260 million convertible offering being a recent example. NPC successfully floated US$200 million in seven-year maturity Eurobonds in 1993.

E. Summary of Recommendations

3.37 In order to maximize total power delivery, private sector investments in generation must be integrated with NPC's generation and transmission investments and with distribution investments by the private distribution utilities. The capacity of the IPPs to obtain financing during the first part of this decade is attributable to their ability to operate on a sound financial and commercial basis. NPC's best course to securing necessary financing, as befits a leading participant in the power sector, is to maintain its profitability. NPC must increase its tariffs to pass on the costs of ever more expensive generation from all sources. But, by efficiently rehabilitating its own power plants, and effectively delivering power from its own lower-cost plants over a sound transmission system, it can control some of the necessary cost increases. By effectively ending the power outages with its own and purchased power, NPC can reduce the level of public distrust, increase tariffs with less opposition, and maintain profitability. NPC should take all steps necessary to manage itself efficiently so that it can attract the capital it needs to carry out its investment program.

3.38 MERALCO, distributor of over sixty percent of all Philippine electric power, should continue its program of rehabilitation, which it is able to self-finance in large measure. MERALCO's cost savings through immediate reduction in line losses are likely to be limited; while the Company

can reduce system losses below 10%, the investments that would bring about this result would need to be justified by increases in demand and not loss reduction alone. Along with the coops, MERALCO has been subject to a time-bound schedule of loss caps over a five year period.

3.39 The other fourteen IODs have had mixed financial performance, in spite of continued large distribution spreads on energy purchased from NPC. In order to take advantage of the restoration of full power from the grid, they should continue their investment programs and utilize DSM measures to reduce peak demand and losses. This study found that the greatest opportunities for improved service and profitability would come from consolidation of service areas of the IODs and the coops (para. 5.34).

3.40 The 120 coops are on average smaller than the IODs, and in general have less opportunity to become commercially viable for the same reasons: limited size, inadequate maintenance, and low-income low-consumption customers stretched thin by high tariffs. The coops should continue to (i) make investments in line loss reduction and (ii) efforts to reduce their managerial overhead expenses. In the future, the coops' best chances to lower the cost of purchased power and reduce management expenses is to consolidate with IODs as part of further sector reform (para. 5.34).

4. Effectiveness of the Private Sector

A. Introduction

4.1 The issuance of Executive Order 215 in 1987 laid the foundation for private sector participation in power generation in the Philippines. Rules and regulations, and Congress endorsement, were given in 1989. Since then, the Philippines has successfully attracted private offers for power generation. NPC has and continues implementing various types of schemes for IPPs, including BOT, BTO, ROL, ROM and OL arrangements for a total capacity exceeding 3500 MW. Most of initial IPPs were contracted under limited competitive conditions, but bidding is now required whenever NPC enters into IPP arrangements. Distribution companies, particularly MERALCO, have independently negotiated and signed PPAs, which have been generally accredited by DOE. Altogether, the Philippines has signed more PPAs with IPPs (totalling about 40 projects by both NPC and the private utilities) than all other developing countries combined. As a result, almost 90% of all power generating capacity additions since 1993 will have come from the private sector. Considering that (with a single exception) all distribution utilities are also private, the private sector now has the overwhelming responsibility for power supply and operation, with NPC investments focused mainly on the transmission system. This chapter reviews the cost effectiveness of the IPPs for power generation[10/] and the effectiveness of the distribution utilities.

4.2 Most private deals for power generation have involved contracts between private investors and NPC, using build-operate-transfer (BOT) or build-transfer-operate (BTO) arrangements. A number of build-operate-lease projects have also been initiated (Annex 2). All of these arrangements have been based on reasonably standardized PPAs or energy conversion agreements where NPC supplies the fuel, and then purchases the power output. NPC also takes the risks of *force majeure* events, as well as the risk associated with payment in foreign currency. A few projects, such as industrial estates and export processing zones, involve cogeneration and the sale of residual electricity to NPC ; others include IPPs' contracts directly with distributors, particularly MERALCO. Some of these projects are large, though the large ones have yet to secure financing, and their emergence raises questions regarding NPC's prior rights as supplier to the distributor or estate.

B. Effectiveness of the IPPs

4.3 This study analyzed cost effectiveness of the IPPs in financial and economic terms. The financial assessment focuses on levelized energy prices, while the economic analysis estimates total generation costs and other indicators of economic viability. Prices and costs are estimated for all 13

10/ Data sources include: (i) NPC's reports on its own ongoing power contracts as March 1994; (ii) DOE Summary Monitoring Sheets on accredited projects; (iii) reports in Project Finance International, Privatization International, Power in Asia and Infrastructure Finance journals through February 1994; and (iv) IFC's own direct project experience.

recently commissioned or nearly operational IPPs for which detailed data were available. These include gas turbines, diesel, coal-fired and combined cycle power plants[11/].

4.4 Cost effectiveness was assessed in terms of levelized prices, unit economic costs of generation, net present value, and benefit-cost ratio. Base case estimates were obtained based on the operating conditions and fuel prices guaranteed by each IPP. However, this may not represent future operational conditions for gas turbines and diesel generation plants, which were contracted at very high plant factors (70% to 92%), even though it is unlikely that given their high fuel cost they will be dispatched at such high factors[12/] after 1995, when base and medium load capacity would be available. Sensitivity analysis encompasses: (i) more realistic plant factors, based on the technical and economic characteristics of each plant and NPC's power operation optimization models, and (ii) the economic life of each plant, if different than the contracted period.

4.5 The economic viability of the IPPs was evaluated by comparing the costs under contractual conditions and fuel assumptions, with the economic cost that would be avoided by implementing the project. The avoided cost was considered variable, because during the power shortage period (1991-93) the main cost avoided was the economic cost of the power shortages, i.e. the cost to consumers of the absence of adequate service. During normal times (1994 onwards) the avoided cost is the cost of the best alternative solution.[13/] The gross economic cost of outages was assumed to be US$0.50/kWh, a figure NPC uses in its planning process. This is lower than the estimated outage costs in other developing countries, but it is consistent with the conditions predominant in NPC's power system, i.e. after a long period of unreliable service, consumers tend to be better prepared for outages, thus reducing its impact. In fact, a large number of consumers purchased 1600 MW of gensets as back-up units during the power crisis; therefore, the actual outage cost has been reduced gradually by self-generation to about US$0.17/kWh. Accordingly, the average avoided costs assumed for 1991-93 and 1994 onward were US$0.43 and US$0.28/kWh, respectively.

4.6 From 1994 onward, avoided costs are estimated as the cost of alternative generation of NPC projects implemented under a turn-key modality for construction and operation. Two plants were chosen as a reference for base load and peak generation: a 500 MW coal fired plant and a 100 MW distillate-fueled gas turbine, respectively.[14/]

11/ The financial analysis assesses the levelized price (in US$/kWh) that NPC or MERALCO will pay for each project, while the economic analysis assess their economic viability in terms of cost per kWh and net worth indicators. To clearly distinguish these two analyses, a common practice has been followed: the term "price" is used for financial values, while "cost" is used for economic values. Price and cost estimates are based on contractual fees, guaranteed capacity and energy, technical performance and contract period. Typical planning parameters such as fuel prices, price escalation and economic life of power plants were built into each model. Economic costs were obtained netting out taxes and expressing fuel costs in border prices. Baseline prices and costs do not take into account any bonuses or penalties on construction and operation. These factors were addressed through sensitivity analyses and a review of the risk allocation in the contractual arrangements.

12/ In almost all cases NPC has dispatch privileges, whereby the purchaser has the right to use a lower output.

13/ This assumes that NPC would have been unable to complete similar projects during the shortage period due to financial or institutional constraints.

14/ Costs and technical performance parameters were chosen on the basis of recent international experience. NPC's past performance was not considered relevant as a reference for comparison of future operations since the alternative turnkey projects would also include actual plant operation. Fuel cost assumptions, discount and escalation rates were consistent with the rest of this analysis. Estimated avoided costs for base load and peak load for the Philippines conditions were $.05/kWh and $.105/kWh, respectively. Although these assumptions may appear optimistic compared to NPC's recent performance, they are consistent with recent trends. In fact, the low costs associated with recent bids for turnkey projects, together with ade-

4.7 Estimated prices and costs for IPPs are summarized in Table 4.1, referring in all cases to contractual operation conditions, i.e. base load operation. As expected, they vary widely across technologies employed and by commissioning period. The average price of all IPPs analyzed of US$0.0652/kWh (₱1.83/kWh) is quite high compared to the US$0.0637/kWh current average bulk energy tariff of NPC, which includes generation, transmission, subsidies for rural and small-island consumers, peak capacity, and the provision of reserve capacity. This indicates that commissioning of these plants has and will continue to put strong upward pressure on tariffs. The average economic cost of the IPPs is US$0.0562/kWh, 11% higher than the estimated base load avoided cost. These high averages are largely attributed to very high prices and costs of the early IPPs (mostly gas turbines, which exceeded US9¢/kWh, even at the high load factors assumed). The prices and costs of post-crisis plants are, on average, 12% lower than for the initial projects. This decline is likely to result from three factors: (i) ample procurement time and better procurement procedures by NPC since the end of the crisis; (ii) similar benefits to bidders in specifying and costing equipment and technologies; and (iii) more companies interested in the successful contracting for these plants and therefore better competition.

Table 4.1 - Philippines - Prices and Costs of IPPs for Base Load Generation (in US¢/kWh)

	Financial Prices		Economic Costs	
	Average	**Sensitivity Range**	**Average**	**Sensitivity Range**
By Technology				
Diesel	5.64	5.24-7.66	5.34	4.95-7.23
Gas Turbines	9.01	8.93-13.05	6.15	6.10-9.85
Steam-coal	6.19	5.69-7.35	5.03	4.61-5.85
Combined cycle	5.96	5.56-6.27	5.35	4.65-6.05
By Commissioning Period				
1991-early 1994	6.87	5.24-13.05	5.91	5.22-9.85
1994 onward	6.04	5.39-7.35	5.21	4.61-5.93
TOTAL	**6.52**		**5.62**	

quate performance guarantees, indicate that avoided costs could be even lower.

4.8 The analysis of costs and prices of the IPPs provides these additional findings:

(a) Lower prices and costs of recent IPPs suggest that early higher-cost plants were less desirable economically. This is true under normal power supply conditions. However, the avoided economic cost indicates that in spite of their higher costs, the "fast track" projects provided a more valuable economic contribution, because the reduction in power outages avoided large costs to the economy and avoided costs during 1993-94 at a rate 4 to 6 times higher than tariffs. Recent projects do have lower costs, but they also have lower economic benefits when compared to long term generation costs of similar plants.

(b) Private sector projects have not always met the economic qualification criteria established by Executive Order 215. First, none of these projects use indigenous or renewable resources instead of imported fossil fuels. Second, capital recovery fees charged do not reflect a "cheaper plant investment" and some are much higher than current market equipment costs. Finally, IPPs' prices are neither cheaper nor more fuel-efficient than NPC's plants, which is understandable given the time pressure to solve the power crisis.

(c) The sensitivity analysis shows much higher costs and prices for gas turbines. This sensitivity is based on more usual operation of plants with similar technical and economic characteristics, and, more important, on NPC's simulated dispatch of each plant at much lower plant factors. Since their direct operational costs are very high, and payments are 90% or more based on capacity, their future operation should result in very low utilization factors once true base load plants are commissioned.

(d) The price of gas turbines is clearly higher than those of any other technology (37% higher than the average), but their economic costs are only 8% higher than the average (if the high load factors could be sustained). Financial prices for gas turbines are much higher, because they are fuel intensive and distillate oil seems to be overpriced at US$32/Bbl when border prices are estimated at US$24/Bbl. Fuel pricing may therefore be distorting investment and fuel choices.

(e) These early projects show limited evidence of economies of scale. Costs and prices of the projects that were analyzed seem more dependent on technology and fuel, plant factor, fuel and year of commissioning, rather than installed capacity. Stronger evidence for scale economies will appear when details of the arrangements for developing the 1000 MW coal fired plant at Sual are finalized.

(f) Cost differences for different technologies are consistent with international experience. Disregarding likely differences in environmental costs, coal-fired generation is the least-cost source of power, while distillate-fuelled gas turbines are the highest.

(g) No innovative technologies have been used. All projects provide conventional technology and, in some cases, the choice of technology is sub-optimal (old plants) for the proposed type of operation.

(h) The wide price range indicates market power from the seller's side[15/]. However, with increasing competence among the buyers, market powers and prices have declined.

Risks

4.9 Actual prices and costs -- *vis-a-vis* the values estimated above -- are a function of the project risks and how those are allocated among the parties involved. Risk allocation is defined in the PPAs, loan agreements and the relationship between the public utility and the state (as defined by the regulatory process). We review below the risk allocation of the standard contracts used by NPC.

4.10 Ideally, risks should be borne by the party that has greater level of control over the factors giving rise to the specific risk; in the case of uncontrollable factors, the risk should be borne by the party that would incur the lower cost if the risk were to materialize. These principles are used to assess the adequacy of risk allocations.

4.11 Most of the early PPAs were the result of solicited and unsolicited proposals that were followed by negotiated arrangements. NPC's contracts are supported by a sovereign guarantee behind NPC's performance on its commercial obligations, which relieves IPPs from country and market risks. The sovereign guarantee is the key reason why IPPs have chosen BOT schemes instead of BOO arrangements with NPC, MERALCO, or other distributors. Since assets acquired according to BOT arrangements will be transferred and belong to the Government, the Government can portray this as a financing arrangement for which it has the legal authority to serve as guarantor.

4.12 The allocation of risks to buyers and sellers is part of the purchase agreements, which have been standardized by NPC (but are different for each fuel technology). These complex contracts are generally similar to those used in the USA in structure and risk-allocating rationale (Table 4.2). NPC's PPAs establish a two-part fee structure (fixed and variable fees) with an adjustment mechanism for technical performance (but excluding *force majeure* conditions). Operating, cost-overrun, and other construction risks are borne by IPPs and guaranteed by construction and operation performance bonds. NPC supplies the fuel (and bears the price and supply risks), hence IPP's responsibilities are usually limited to energy conversion. NPC bears all other risks (eg. market, environmental approvals, transmission systems, and foreign exchange).

4.13 Overall, the risk allocation between the IPPs and NPC is reasonable. However, improvements can be sought in three areas: (i) the responsibilities and risks for fuel supply could be taken by the IPPs, since the utility is ultimately acting as an intermediary assuming availability and quality risks that are largely beyond its control. Although NPC enters into standard contracts for fuel supplies, that contract would not leave NPC whole with respect to its BOT payments if the fuel supplier failed to deliver the full extent of supplies required; (ii) the location of the plant is decided by NPC, taking site-specific risks. However, there are few favorable locations for large thermal plants; (iii) private investors are being asked to build power plants whose fuel and size have been determined by the utility, thereby taking risks associated with project selection and foregone technology opportunities. Instead, PPAs should cover capacity and energy, regardless of the fuel, technology, and location; such arrangements would foster innovative technologies and make the developer

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15/ In a perfect competitive market, market price setting mechanisms determine that the only differences in price for the same commodity – in this case power – should be the cost of transport, which reflect the location of production with respect to consumption centers.

Table 4.2 - Present Risk Allocation in the Philippines

Type of Risk	Bearer
Project Risks:	
Construction	Cost risk borne by IPP through fixed capacity fees.
	Delays borne by IPP through performance bond. Both construction risks limited to force majeure.
Operation	Overall performance risk borne by IPP through performance bond, limited to force majeure.
	Availability borne by IPP through penalties on fees.
	Thermal efficiency borne by IPP through fixed conversion efficiency.
	Fuel price risk rests with consumers, through fuel adjustment clause for tariffs.
	Fuel supply risks, including fuel quality and availability, are borne by utility.
Financial	Exchange rate risk borne by utility and state (through sovereign guarantee).
	Interest rate borne by IPP.
Market Risk	Purchase risks rest either on consumers or the state (sovereign guarantee), depending on what the regulatory process dictates.

responsible for community acceptance and environmental clearances. However, the fuel supply risks will remain an issue as long as NPC is exempt from the excise tax on fuels and the IPPs are not. Under the circumstance, the IPPs should be accorded equal treatment and therefor the same exemption. The Government would not lose any potential revenue, since the IPPs are now receiving tax-exempt fuel from NPC; and NPC could be relieved of the fuel supply risk.

4.14 Sourcing supplies from many IPPs, not all of them contracted with NPC, leaves orderly and efficient dispatch a major and technically difficult problem. Risks to the system include (i) the potential conflict between energy-take provisions and financial incentives of the IPPs; (ii) conflicts due to taxes or payment recovery periods between financial and economic (minimum cost) energy dispatch; (iii) high mortality of IPP projects, making planning uncertain and increasing the risks of capacity imbalances; (iv) an apparent *laissez faire* approach to fuel choices, that may lead to an inadequate fuel mix, since IPPs bear neither the fuel price or supply risks, and fuel price increases are passed directly to consumers; and (v) a potential lack of balance between generation and transmission investments.

C. Effectiveness of the Distribution Utilities

4.15 With one minor exception (Bohol), all distribution utilities in the Philippines, comprising 16 IODs, and 116 rural electricity cooperatives (coops) are considered private companies. MERALCO is a reasonably strong company; few of the others are without serious problems. Electricity distribution and distributors' shares of the market are shown in Table 4.3, and details are provided in Annex 4.

Table 4.3 - Market Share of Electricity Suppliers in the Philippines

Retail Supplier (1992)	Number	Sales (GWh)	Share	Demand (MW)
MERALCO	1	14868	59%	2740
NPC (Direct Connections)	86	3621	14%	550
Investor Owned Distributor	15	2574	11%	480
Coops	116	4012	16%	850
Total		**25075**	**100%**	**4620**

4.16 MERALCO distributes more than half of all Philippine electricity. With control restored to private shareholders after a period of government control and underinvestment, MERALCO is again credible and strongly managed. As a dominant buyer, the company has a strong negotiating position in its dealings with the Government, NPC and private power generators.

4.17 The coops are small (averaging 5-20 MW), supplied at a single point from NPC's grid, and often financially weaker than the urban IODs. Some 20 small island coops get power from NPC-operated Government subsidized local diesel generators. Most IODs are larger, in the 20-80 MW range, with urban service areas. In areas where the IODs and coops are served by NPC's integrated power system, consolidation of distribution would optimize supply and increase efficiency (in terms of load factor, reduced overhead, lower average prices and better financial performance; see Annex 4). Grouped distribution utilities would be capable of exercising the planning and control over the common subtransmission (69kV) system that are in many cases beyond individual IOD and coop abilities.

4.18 The coops supply about 30% more customers than MERALCO (2.68 million compared to 2.1 million customers), but they account for only 15% of the total energy sales. NEA, in its role as interested lender for rural electrification, subjects the coops to monitoring and analysis. In 1992, 30% of coops were rated as problem utilities.[16/] Root causes of poor performance are overstaffing, poor (underpaid) management, and low investments resulting from monopolistic behavior. While improvements are being implemented and some coops are well managed organizations providing good service, the distribution charges and the selling margins for many are very high (Annex 4), without evidence of commensurate improvement in facilities and service or opportunities for much greater commercial success.

16/ Grade "D", based on amortization payments, system losses, collection efficiency, payments to NPC, and non-power costs.

4.19 Ninety percent of the coops and IODs have peak demands under 20 MW. However, several coops outperform the IODs with respect to losses, consumer/staff ratios, and reliability. Consumer tariffs range widely, from MERALCO's average price ₱2.5-5/kWh in 1992 to about US10-20¢/kWh for some of the weaker coops. Such retail prices reflect high costs of operations, losses and administration, passed on in the form of a margin over NPC's bulk rate. Besides the disadvantages inherent in small companies, high margins for companies of all sizes can also be attributed to: (i) the revenue loss resulting from NPC's directly supplying some 90 large industrial or commercial consumers at 69kV; (ii) high losses, averaging 14% for MERALCO and 22% for the coops, due to underinvestments, disrepair and pilferage; and (iii) the high cost of providing coverage to low-density rural households.

4.20 All utilities, except MERALCO (where negotiations are still in progress) have signed power purchase contracts with NPC, based on peak capacity and energy charges, with a minimum off-take. A further improvement of quality could be fostered by guarantees for quality of supply along with appropriate penalties. Since demand charges reduce load factors through demand side management (DSM) and other measures, their application to each region and category of consumers would provide the utilities with some stability in electricity pricing.

4.21 Currently, the distributors neither pay for wheeling of electricity through networks belonging to others nor charge for wheeling through their own networks. Moreover, they all expect NPC to provide reserve capacity, but there is no provision for stand-by-charges. Given the transformation already in process, a framework for wheeling and stand-by charges is needed urgently (para 6.25). NEA, with current franchising authority under PD 269, can require wheeling under Section 43(b), and should promptly do so under proper legal process. With the expansion of NEA lending (para 4.25), and transfer of franchise authority to ERB, orders from ERB to implement wheeling can independently advance the goals of NEA to strengthen distribution. (Annex 8, A8.2)

4.22 The existence of so many small and inefficient distributors effectively precludes a market for sale of power from new private power generators. Under present conditions the only viable markets for IPPs are NPC and MERALCO, with NPC acting as a de-facto wholesaling agent for all other power distribution companies. If, however, the coops would consolidate among themselves and with adjacent IODs, the resulting stronger utilities would provide increased competition for sales. An optimum arrangement nationwide would amalgamate the coops and IODs within natural geographic boundaries into stock-coops, forming about one dozen strong and efficient companies capable of holding their own in purchasing arrangements with NPC (or its successors) and the IPPs. The structural aspects of such a consolidation program are discussed further in Chapter 5 (para. 5.34).

4.23 Restructuring to improve the efficiency of distribution and create effective competition in the buyers market would be difficult. One approach is to legislate changes to expand the franchise areas across regional boundaries, as was done during the 1940s by the British Government, when it consolidated private and public electricity enterprises into twelve publicly owned Electricity Supply Authorities. This would not be easy in the Philippines, given the vested interests and the attitude of regional governments to central government intervention. The New Zealand model could provide an alternative approach. Under the 1992 Energy Companies Act and 1993 Electricity Act, earlier legislation establishing electricity franchise and financing arrangements was essentially rescinded, enabling some 50 consumer-owned electricity supply companies to seek new investors for mergers and acquisitions in energy-related fields. In the Philippines however, with so many small coops serving poor rural areas and their low prospects for a return on investment, such a strategy could result in

amalgamation between IODs and mostly stronger coops, leaving the weaker companies to fail. Since those weaker coops currently provide subsidized supplies to their consumers, a move to make the subsidies open and transparent would further clarify commercial prospects

4.24 There could indeed be incentives to foster amalgamation, probably driven by the existing IODs, in those few instances where the consolidated company could obtain a significant percentage (shown in the footnote) of industrial load taken from NPC directly-supplied customers. Instances would include only six of the 135 utilities[17/], however, they accounted in 1992 for 1600 MW, or about half as much as the existing MERALCO franchise. Mergers could also be encouraged by NEA restricting financing and guarantees to companies that: (i) are being consolidated; (ii) financing the takeover of NPC's subtransmission networks by consolidated distributors; and (iii) financing the rehabilitation of distribution systems, based on an agreed productivity improvement plan, as was adopted for MERALCO.

4.25 NEA's lending powers are under the law by which it was founded somewhat broader than those it currently chooses to exercise. By authority of PD 269 Section 4(f), NEA can lend to any electric utility, public or private, rural or urban, municipal or cooperative. Whatever the cause of past policy preferences, NEA should end its historic bias towards cooperatives and should serve as lender for all utilities in the sector.

D. Directly Connected Consumers

4.26 NPC has 91 directly connected medium and higher voltage customers, largely commercial and industrial users which are serviced as exceptions to the regular geographically based distribution franchise system. About half of these (43) can be considered large, with a load of greater than 3MW. Sixty-one comparable large customers of MERALCO, pay tariffs about forty percent higher than NPC's directly connected customers for comparable (mostly 69kV) service, much it drawn from the same transmission lines. This forty percent difference in tariffs is attributable to the cross-subsidies MERALCO (and other distributors) must find in order to lower rates for the lifeline block of residential consumption and all consumption in the Visayas and Mindanao.

4.27 With the rapid increase in privatization of power generation, direct sales between producers and large consumers and other bulk sales can be encouraged by relaxing franchise restrictions and developing and applying a rationalized tariff structure. The reformed tariff structure should include modifications in rates that reflect (i) the lower costs of directly supplying power at higher voltages; (ii) wheeling charges for energy transmitted directly among IPPs, distributors, and direct consumers; and (iii) elimination of the cross-subsidies within franchise areas from (large) industrial to (small) residential consumers, and between regions from Luzon to Mindanao and the Visayas. In order to moderate the initial impact on the IODs' revenue, (a) the tariff changes should be introduced over a five year period; (b) direct connections between end users and IPPs (or out-of-service-area distributors) should be limited to those with a load greater than 5MW; and (c) NPC (or its subsidiaries) should relinquish directly connected customers to the franchised IODs.

17/ Cayangan De Oro (25%), General Santos (62%), Samar Leyte (67%), Cebu (13%), Greater Angeles (36%), and Northern Luzon (49%).

E. Conclusions and Recommendations

4.28 Private sector participation in power generation offers two main benefits: (i) mobilization of additional financial resources, and (ii) efficiency gains through greater competition and adequate incentives. The Philippines private experience is one of successful supply response to urgent capacity needs. The installation of 1300 MW by the end of 1993; the completion of some 15 plants by end of 1994; and the signing of agreements for more than 5,000 MW; all indicate that the policy of passing responsibility for developing the power sector to private interests was well conceived and effectively implemented. The early projects, even with their relatively high costs, were justified in economic terms due to the power outages, and the most recently contracted private projects have had lower prices and costs, closer to international levels.

4.29 The Government and NPC assumed an important part of the risks involved in the participation of private power developers. A decisive factor in attracting private investment has been the Government's sovereign guarantee behind NPC's performance of its commercial obligations. Important risks such as fuel price and supply, market risks, and overall country risks were borne by the Government; while IPPs limited the risk they bore to those directly associated with the project itself as limited by *force majeure*. This somewhat uneven allocation of risks was justified by the power crisis; however, in the near future, a more competitive process should result in more favorable contractual conditions and risk sharing.

4.30 Although information on the financing structures of private power projects is limited, there is evidence that additional financial resources are being increasingly mobilized. The pattern of debt financing in these projects appears to have changed from a heavy reliance on official financing in the early projects, to incipient participation of commercial banks and bond issue. Domestic resources have also started to be mobilized.

4.31 Entry conditions for private generators have not been ideal. Now that private generation by a large number of IPPs is a critical feature of the Philippine power system, a suitable regulatory framework and orderly dispatch are needed to ensure equity among suppliers and for the consumer.

4.32 Cost-based pricing needs further implementation at the wholesale and retail levels to reduce peak demand. A framework for wheeling and standby charges is needed urgently.

4.33 Although the distribution utilities are private, they are, by any standard of performance, hardly effective. Compared to other Asian consumers, Philippine consumers face high costs, poor reliability, unsatisfactory service, and limited recourse. Most weaknesses are long-standing and inherent in the fragmented, non-competitive, underinvesting structure of the distribution subsector. MERALCO is already planning to step up investment and cut electricity losses. A major step toward improved efficiency for the distribution companies should be to consolidate them into larger companies with larger service areas. This would likely improve management, reduce overhead, increase financial capacity, and reduce energy losses. It would result in stronger buyers for power, eventually bringing down the costs of supply. Legislation may be required to expand the franchise areas across regional boundaries. Mergers could be encouraged by NEA restricting financing and guarantees to coops that are either (i) being consolidated; or (ii) financing the takeover of NPC's subtransmission networks by consolidated distributors, and financing the rehabilitation of distribution systems, with agreed productivity improvement plans.

4.34 NPC maintains direct connections from the grid with ninety-one larger industrial customers at average tariffs significantly lower than those paid by comparable customers for comparable service from distributors. NPC's lower tariffs reflect the lower costs of higher voltage supply to larger customers; the distributors higher tariffs reflect the advantage distributors must take of these customers' greater ability to pay in order to cross-subsidize (i) residential customers within their service areas and (ii) all consumers in Mindanao and the Visayas. NPC should give up these customers; and franchises and tariffs should be rationalized so that all customers with a load over 5MW are able to purchase power at prices based on costs, including separately identified transmission, capacity, stand-by, and wheeling charges. Large consumers should be able to purchase at cost-based prices from local distributors, or wheeled from IPPs or other IODs.

5. Structural Framework

A. Current Framework

5.1 Through the end of 1989, the structure of the power sector was very simple. Presidential Directive (PD) 40 assured NPC of a monopoly on (i) all generation in excess of 5 MW, and (ii) all transmission lines throughout the country. In 1981, in response to some coops' financial problems, NPC took over the 69kV network, so that even these relatively low voltages came under its exclusive control in those franchise areas. As a result, the distribution utilities had to rely on NPC for virtually all of their supplies; and NPC's tariff covered the full cost of wholesale electricity supplies. Because NPC controlled the 69kV network, it was authorized to serve directly certain higher voltage customers who qualified according to criteria set by the Board of Investments (BOI). About 90 industrial consumers were able to receive service from NPC at the wholesale rate, while the rest took their supplies from their local distributors at substantially higher retail rates.

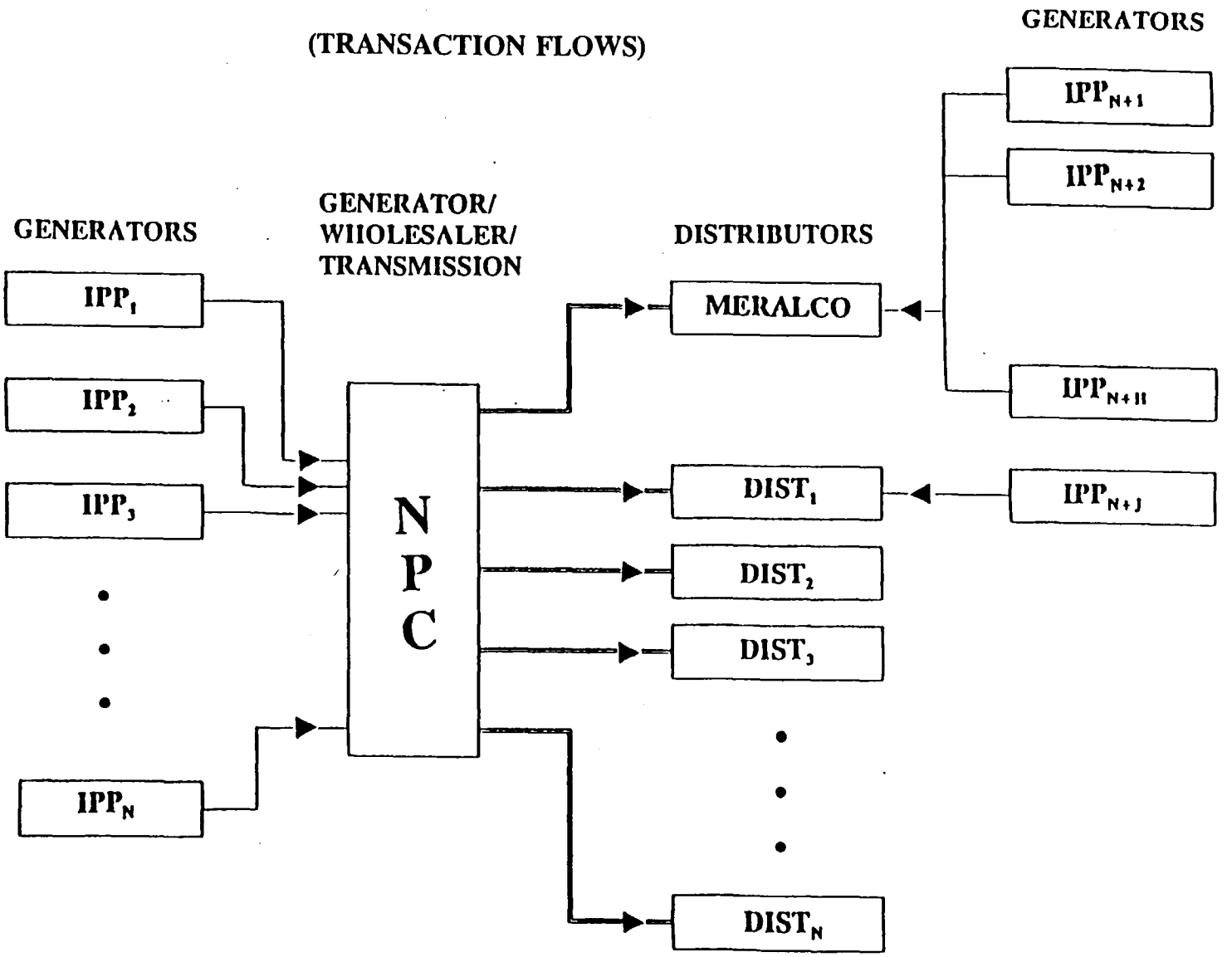
5.2 Some exceptions to this framework were recorded in instances where Government policy did not take account of proper engineering considerations. For example, the Government wished to foster local empowerment through programs to provide generation in rural areas with small scale mini-hydro and dendro-thermal generating sets. NPC thought the program was poorly conceived and sidestepped becoming involved; so NEA became the program's promoter and provided favorable financing to coops willing to invest in these facilities. The few mini-hydro sets developed produced very expensive energy while the dendro-thermal program was a total failure; still, these programs were the excuse by which a number of coops (including many isolated ones that served small islands) supplied themselves with their own generating facilities. Similarly, NPC sought to reduce its own costs by supplying MERALCO mostly at points on the periphery of its service area. Because of that area's size, NPC could not realistically restrict MERALCO's system to voltages of less than 69kV; as a result, MERALCO has continued to own extensive transmission networks energized at 138kV and 69kV. However, these exceptions were ignored from a policy perspective.

5.3 In 1987, the promulgation of Executive Order (EO) 215 officially ended NPC's monopoly on generation; however, since NPC was charged with establishing criteria for and accreditation of IPPs, EO 215 was not expected to lead to a significant restructuring of the power sector. Even Hopewell's implementation of the Navotas project was viewed in some Government circles as an exceptional, interesting experiment, and not as a precursor of things to come. This perspective changed dramatically as the power crisis began and then deepened.

5.4 In the three years since the onset of the crisis, the structural framework has evolved, with a clear role for IPPs. (Chart 1) NPC is still the dominant participant in the sector, and the purchaser of more than 80% of planned IPP-produced electricity (perhaps more, if some of the developments intended to supply MERALCO should not materialize). NPC is still the sole supplier for virtually all of the distribution utilities, although MERALCO plans to acquire significant supplies from several IPPs with which it has signed PPAs. A few other IODs have flirted with IPPs, generally conceived as small ventures to be situated within their service areas and geared to the modest capacity requirements of the utilities in question. Because of the weakness of the vast majority of distributors and NPC's dominance as a supplier, only modest pressure has been applied to demonopolize the transmission system, with only MERALCO and the IPPs aiming to supply MERALCO raising

CHART 1: CURRENT STRUCTURE

(TRANSACTION FLOWS)



questions about wheeling charges.

5.5 While the small distributors and/or the larger industrial consumers could combine and thereby develop credibility as customers for the IPPs, no discernable efforts have been made in that direction. Instead, most of them are inward looking, interested more in protecting their small share of the market than in increasing their influence and financial strength through innovation. The few that have shown a broader vision have generally been geographically remote from one another, thereby precluding them from leading the way to a broad-based consolidation program. NEA has made tentative efforts at developing regional combinations of coops to develop stronger management teams, but these loose confederations have an untested capacity to collaborate on joint power purchases from an IPP, let alone address the complex issues of network optimization that would maximize the economic feasibility of such purchases.

B. Privatization of NPC

5.6 As the power crisis deepened, the Government came under increasing pressure to reconsider NPC's role as the monopoly supplier. Some of these pressures came from the business community, which suffered significant revenue losses because of uncertain supplies and therefore pressed to bring perceived private sector efficiencies into the sector. Congress applied additional pressure, as legislators had to respond to their constituents' pleas to end the disruptions caused by decreasingly reliable, increasingly costly electricity. NPC's capacity to respond to these pressures was limited by financial and other constraints. In effect, it could not finance the full scope of investments required to meet existing and future demand on the strength of its own credit, and the Government could not provide the full extent of financial support required. Also, environmental problems constrained NPC's ability to implement investments, even after financing had already been secured. As a result, in mid-1992, the Government's ESAP provided for NPC to be privatized. By late 1993, some half dozen bills has been filed in Congress, each proposing to mandate a different approach for privatizing NPC; the most common approach was to split NPC into three regional companies, each of which would follow commercial operating practices and prepared for earliest feasible privatization.

5.7 The Government recognized that privatizing NPC would have a profound effect on the structure of the sector, and undertook four studies to examine the various privatization options. The first, financed by USAID and conducted by Price Waterhouse (PW), proposed some options and provided a superficial discussion of their benefits. These include:

Option 1: direct piecemeal sale of all of NPC's generation and transmission assets to investors;

Option 2: progressive sale of all generation assets to consolidated distribution companies, forming vertically integrated region-wide utilities, but leaving NPC responsible for national functions of backbone transmission and dispatch;

Option 3: transfer of NPC's transmission assets to distribution companies; mainly MERALCO;

Option 4: sale of NPC's transmission grids as integrated systems; and

Option 5: private management contracts for different NPC facilities.

5.8 The PW study discussed the presumed benefits of these various options, based in part on PW's experience in other countries, and in other part on a desk assessment of the Philippine power sector. On that basis, PW favored option 2; however, the report did not discuss *how* this approach could be adapted to the Philippines, especially how the fragmented distribution utilities could be induced to combine. Because this vertically integrated framework was considered (and rejected) by this study, a separate analysis of this option is presented in this chapter (para. 5.44). With regard to the other options, the PW study did recommend that (i) NPC's best plants be sold as a first priority; (ii) Rehabilitation-Operation and Transfer (ROT) arrangements be used for plants that cannot be sold but still do attract private sector interest; and (iii) management contracts be used in connection with the operation and maintenance of existing plants that do not otherwise draw private sector involvement. The PW study also supported the use of BOT, BOO and BTO arrangements for the construction of all new generation, as well as allowing MERALCO to meet some of its power needs through autogeneration or independent arrangements with other IPPs. Some of these options are already being adopted, while others have been incorporated into the framework being recommended by this study.

5.9 The second study, conducted for NPC by Ridgehouse and Lahmeyer (RL) in conjunction with local Mindanao business interests, considered the feasibility of transferring all of NPC's facilities and activities in that area to a separate Mindanao Power Corporation (MPC). Presumably, if this approach proved feasible, it could serve as the model for the creation of separate Visayas and Luzon Power Corporations (VPC and LPC). The RL proposal involved initially creating MPC as a subsidiary of NPC; the Government would then sell its equity in the Company to private investors within five years. The proposal covered reasonably well (i) the mechanisms for capitalizing MPC; (ii) the framework for absorbing NPC's assets; and some salient operational and/or commercial issues (e.g., tariffs). However, it was sketchy on the important issues of assuming the existing liabilities and otherwise compensating NPC for the assets and business that MPC would acquire. Thus, it did not adequately recognize the importance or the complexity of securing the approval of NPC's creditors for the proposed restructuring. Needless to say, this study came to the preordained conclusion that this approach was feasible; it has since been used to develop the support of local business and political interests for restructuring NPC along regional lines. The study also found that in order for the Mindanao company to be financially viable it would have to increase its rates very substantially; because of cross-subsidies from the Luzon Grid, Mindanao's rates are currently more than 30% below levels needed for an independent MPC to be creditworthy.

5.10 The third study was conducted for NPC by the Electricity Supply Board of Ireland (ESB), under a Bank-executed Japanese Grant. That study assessed different approaches to managing NPC, based on the assumption that NPC's scope of business would remain unchanged. It found the existing span of executive control to be far too broad, and that management should be decentralized with separate business units formed for different geographic areas.

5.11 The fourth study, conducted by RCG/Hagler, Bailly (RCG/HB) for USAID, was conducted in parallel with this sector study. The approaches followed by the two coincident studies were dramatically different. This sector study took a top-down approach, predicated on best practices, whereas RCG/HB tried to find the most comprehensive and cost effective way of implementing the Government's policy of devolving maximum feasible responsibility for power sector development to private interests. Despite differences in approach, the two studies were highly complementary. This confirms the earlier view (para. 1.20) that very few available structural alternatives could satisfactorily accommodate existing realities and constraints.

5.12 As of early 1994, some restructuring of NPC appeared inevitable. The ESAP has committed the Government to the privatization of NPC. The spate of pending legislation aiming to restructure NPC suggests that Congress might take the initiative if the more deliberate approach being considered by DOE and NPC does not come to timely closure. The momentum behind these various initiatives, together with the impact of the growth of IPP sponsored generation, ensures that the character of NPC will change significantly during the next two years.

5.13 Most of the pending initiatives aim to decentralize NPC; the more prominent proposals would split the Company along regional lines. However, while the ESB report validates the premise underlying the recommendations to decentralize NPC, the various proposals are generally unclear as to what activities should be regionalized, and how that restructuring should be accomplished. This study focused on identifying which of NPC's activities should, by their very nature (i) remain national in scope; and (ii) be devolved to the distribution companies. The remaining activities could then be spun off to regional companies.

5.14 The issues of structure and ownership were treated separately. In effect, the structural framework being recommended by this study would work well, even if NPC or its successors would never be privatized. In turn, the Government should still aim to privatize its power sector holdings, even if it does not adopt the proposed framework. The proposed regional companies would initially be organized as subsidiaries of NPC; but their charters and *modi operandi* should accommodate broader ownership later.

Unbundling of NPC

5.15 The activities that should properly remain national in scope include:

(a) **Power System Planning**. Given the multiplicity of IPPs, the Government should retain the responsibility for general coordination of planned additions to the power system. These plans should take account of strategic concerns such as fuel mix, conservation and environmental priorities as well as system specific issues such as the amount and timing of new capacity additions and transmission investments. Moreover, given the importance of social acceptability to the environmental clearance process, the Government should include in the planning process the development of an inventory of environmentally benign sites. Decisions with regard to fuel mix are strategic in nature, and should reside with DOE. Ultimately, the responsibility for power system planning should also be moved to DOE; however, since NPC currently is the repository of the Government's expertise in that area, it should continue conducting system planning for the short-to-intermediate term, until the Government furnishes DOE with adequate staff resources to absorb this function. Thereafter, NPC should conduct system planning as it applies to the development of its own facilities.

(b) **Hydroelectric Development**. The harnessing of hydro resources affects much more than the nation's electricity system. Many of these resources would provide drinking water or irrigation facilities to a broad range of localities. Some schemes may involve significant environmental impacts or social issues (such as resettlement or tribal disruptions). Because these diverse issues would concern several departments of the national Government, decisions concerning the exploitation of these schemes need to be formulated at the national level. This activity could also remain within the ambit of NPC's national headquarters.

(c) **Backbone Transmission Systems and Dispatch.** Currently, the backbone transmission system, consisting of facilities for 138kV and above, could be regionalized. However, the Bank financed Leyte-Cebu and Leyte-Luzon Projects will interconnect Luzon with much of the Visayas, and the interconnection of Mindanao through Camiguin may become economically attractive later in the decade. Unless responsibility for the backbone transmission system is retained at the national level, the priority for interconnection would likely be subordinated to regional concerns. The backbone transmission system should be managed by a national company; however, the requirement all generators will have unrestrained access to the transmission system provides a compelling rationale for creating a transmission company that is distinctly separate from any state enterprise owning or operating generation facilities. For the same reason, this proposed new company should also own and operate all facilities for dispatch.

The appropriate level and structure of capitalization for the new backbone transmission company should be determined by the Government, with independent advice. At the outset, the new company would operate transmission facilities and complete projects currently belonging to NPC. NPC's creditors will require that the new company absorb the range of liabilities associated with the facilities it would acquire. The Government should provide enough initial working capital for the network to be operated properly until it attains financial self-sufficiency. It would be organized as a commercial utility. Access to the company's networks should be non-discriminatorily available to all suppliers. The company's investment program should be reviewed and approved annually by ERB; its tariff should be based on cost and subject to ERB regulation. The company's shares should not be offered for sale to the public until a healthy competition among suppliers has been achieved; otherwise shares might be acquired by interests friendly to particular suppliers, who could then restrict competition.

The overall management structure proposed for NPC is depicted in Chart 2.

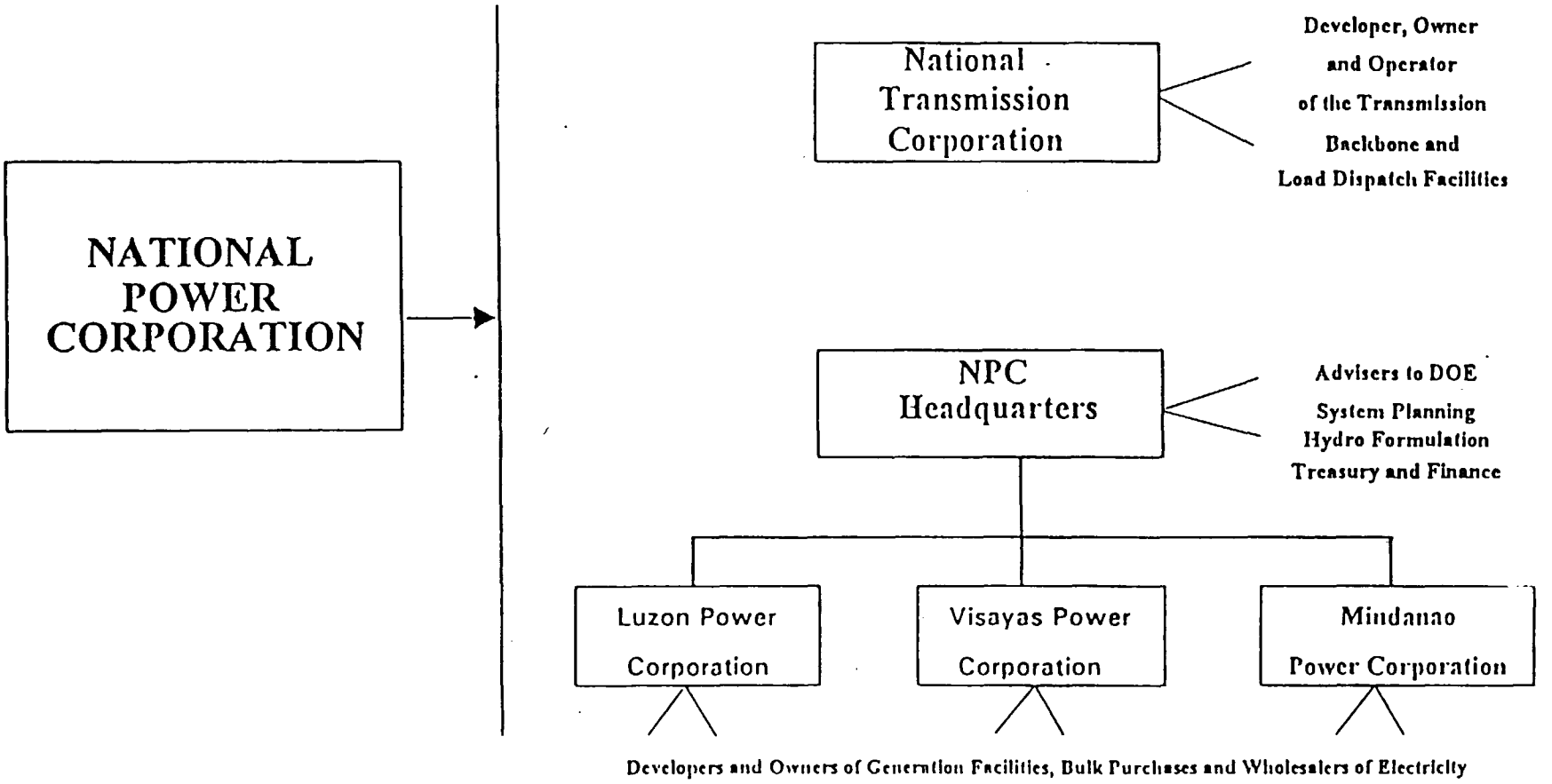
Subtransmission Networks

5.16 The 69kV subtransmission systems currently belong to NPC; however, NPC's management views these networks as a distraction. Technically, the key component of the subtransmission system is the set of delivery points to the distribution system; to be cost effective, they should be optimized according to the requirements of load growth. Thus, these networks should reside with the distribution utilities; however, the 130 or so distribution utilities other than MERALCO are generally fragmented and weak, and lack the capacity to operate these systems or manage their expansion. The proper development and operation of the subtransmission are among several compelling reasons for the Government to follow a policy of consolidating the distribution utilities. Until a consolidation program is implemented, (i) MERALCO should acquire the 69kV networks within its service area, and (ii) the new backbone transmission company should retain the remaining subtransmission networks. The transfer of these assets to the private sector should be based on a proper valuation and payment mechanism.

NPC's Generating Facilities

5.17 NPC's generation facilities should be spun off to the proposed regional companies, which would function as holding companies for existing plants and developers of new state sponsored thermal generation facilities. Initially, these companies would be established as wholly-owned subsidiaries. However, their charters should enable them to (i) follow commercial operating practices;

CHART 2: RESTRUCTURING OF NPC



and (ii) sell some of their shares to private interests once they have established solid financial records. Presumably, the shares of well managed and financially sound subsidiaries could attract substantial interest from professional investors; however, the prospects for privatization of poor performers will drop very sharply and very quickly. The details of how these companies should be capitalized remain to be developed; still, the creditors will require all three companies to absorb all liabilities related to the facilities they acquire from NPC.

5.18 Because these regional companies would be smaller and have a more concentrated focus than NPC, they would have greater capacity to oversee activities related to generation. The Government's policy, as summarized in the ESAP, is to privatize the rehabilitation and operation of existing facilities; in that context, the regional companies should have the authority to enter into a broad array of such arrangements with qualified private developers. However, if the regional companies succeed in implementing commercial operating practices, they should not be precluded from competing with the IPPs to supply the distributors in their areas.

5.19 The foregoing approach to reorganizing NPC provides the optimal balance between (i) the needs associated with privatizing the Government's stake in the power sector, and (ii) the requirement of present and prospective private generators and distributors that the power sector be orderly and well managed. This approach can also satisfy the business and political interests seeking to participate in the restructuring of the sector. The following sections of this chapter develop the most workable structural framework for the power sector that accommodates current constraints as well as the foregoing approach to reorganizing NPC.

NPC's Headquarters Operation

5.20 Even if NPC is unbundled as recommended in the preceding paragraphs, it will continue to have a vital headquarters operation for many years to come. In the immediate future, its primary activities will be establishing a sound basis for spinning off the transmission company and the regional subsidiaries. After these companies are established, NPC will need to help them acquire investment capital and operating credit; in fact, until the regional subsidiaries have developed favorable records for operating and financial performance, the parent may well be expected to act as their guarantor. Once the subsidiaries can obtain financing on their own merits, the parent will act more like a holding company; it will (i) assist the subsidiaries with cash management, (ii) collect interest and dividends from the subsidiaries; and (iii) meet its remaining liabilities. Under the circumstances, NPC will continue to have scope to perform staff services at its headquarters office. In particular, for the foreseeable future, it should continue its a) system planning activities; b) setting standards for the IPPs; and c) developing hydro projects in their formative stages.

Reorganization Proposals Pending before NPC's Board

5.21 On June 10, 1994, NPC's management presented a spate of reorganization proposals to the National Power Board. These proposals were formulated by the Company based in part on earlier feedback from this study and also from the work of RCG/Hagler, Bailly. The proposals include formation of:

(a) An NPC Holdings Company, to handle the treasury and planning functions as well as centralized dispatch.

(b) A transmission subsidiary to serve Luzon and the Visayas. This company would have responsibility *inter alia* for fuel management, local dispatch and administration of the existing PPAs within its service area.

(c) An integrated Mindanao Power Corporation to provide transmission and generation services within that large southern island. NPC would prefer to divest itself completely of these activities, which in the aggregate have produced heavy financial losses despite significant cross subsidization from the Luzon Grid; however, the feasibility of divestiture on reasonable terms has not been analyzed comprehensively. If a reasonable price is not obtained from commercial interests, NPC may need to retain the transmission facilities and attempt to divest itself of the potentially more profitable generation activities. Until divestiture, this company would remain an NPC subsidiary.

(d) A Hydropower subsidiary that would be charged with the development of this indigenous resource.

(e) A Geothermal subsidiary that would also be charged with developing another important indigenous resource.

(f) A Metro Manila Thermal subsidiary, to own and operate the plants located within easy reach of the capital region.

(g) An Integrated Barge subsidiary, which would have as its primary interest supplying small island grids. NPC would prefer to divest itself of these activities, which have accounted disproportionate financial losses; however, it has little realistic likelihood of finding a buyer willing to offer acceptable terms. As a result, it may need to retain this subsidiary, and arrange an acceptable transparent subsidy from the Government.

(h) An Engineering and Maintenance subsidiary, which would take responsibility for NPC's operational activities.

These proposals take account of all of NPC's major assets except for a few generating plants in the Visayas. Those plants, which are producing financial losses, could probably be bundled with the Barge subsidiary to form a company similar to the Visayas Power Corporation recommended by this study. The National Power Board has still not decided on any of these proposals. However, it has decided to reorganize NPC so that the activities enumerated above would be run as profit centers.

5.22 These proposals bear considerable similarity to those recommended in this study. As NPC develops the details, the similarities are likely to intensify. Again, this confirms that only a few of the options for reorganizing NPC would take adequate account of existing realities and constraints.

C. Eventual Structural Framework

5.23 The three principal objectives for the Philippine power sector are to (i) provide adequate cost effective supplies of electricity; (ii) secure as much non-Governmental financing as possible for the needed investments; and (iii) transfer as much of the market risk as possible from NPC to the distributors. To meet the first two objectives, the Government will need to maximize the role of the private sector in all areas of the power sector, as it has endeavored to do already in the genera-

tion subsector. This report contains many recommendations that would improve the business climate for private developers, and thereby address their concerns about country risk. To meet the former objective, the Government needs to a) create a level playing field for all participants in the sector; b) foster competition at both the supply and distribution ends of the industry; and c) reduce the layering of institutions between the generators and the consumers. The structure hereby being recommended is portrayed in Chart 3. Briefly, a separate transmission system would wheel power between and among NPC's regionalized generation subsidiaries, the IPPs, and the consolidated distribution companies. The distributors and large volume higher voltage consumers, in turn, would have direct contractual relationships with suppliers, so that they would absorb the market risk. Monopoly and captive relationships among originators, producers, distributors, and large consumers of power would give way to market exchanges among them, subject chiefly to technical and economic considerations.

Transmission System

5.24 For technical reasons, this study has recommended spinning off NPC's transmission activities as a separate company. The new transmission company, which would own and operate only the high voltage nationwide network, would be designed purely to provide a service for a fee; it would not be authorized to buy electricity for resale. The company would follow proper engineering and economic practices in formulating and implementing new investments as well as operating and maintaining its networks; it would follow commercial principles in pricing its wheeling services, billing and collecting from its clients and financing its investments.

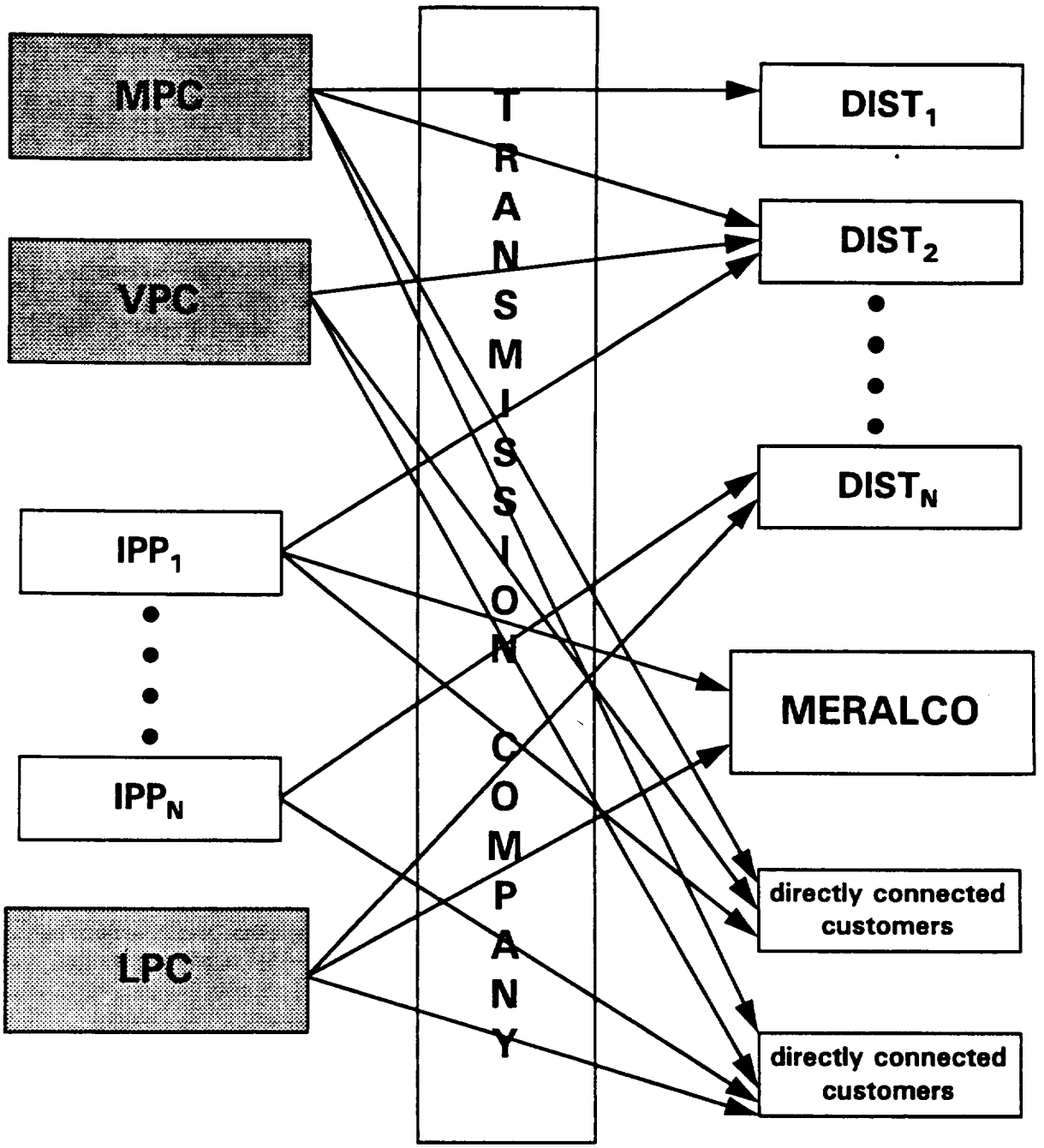
5.25 This study concluded that detaching the transmission grid from any particular generation or distribution interest is not only good engineering practice, but would be essential for creating a level playing field among suppliers. This separation ensures that no one supplier receives favored treatment, either through the provision of facilities or the imposition of wheeling charges, and facilitates the development of a load dispatch function that follows proper economic principles. NPC's current proposal to spin off an integrated Mindanao Power Corporation would result in the transmission system for that island belonging to a generating company, thereby limiting the incentives for IPPs in that area. Hopefully, NPC will reconsider this proposal before the National Power Board acts on the pending recommendations.

5.26 In general, load dispatch should be linked to operation of the transmission system; that linkage appears to have advantages in the Philippines, where competitors have a tradition of pursuing their own interests, and no precedent exists for collaborative pooling among competing suppliers. In fact, implementing a fair and transparent load dispatch system appears to be one of the most important residual future roles in the power sector for the Government. The Government concurs that development of dispatch could be an important part of a Grid Code governing NPC interconnection procedures and transmission access policies.

5.27 While ownership and operation of the national transmission backbone would initially be vested in a Government company, the study does not contemplate that this would remain a parastatal activity in perpetuity. If the transmission company functions successfully, shares could in time be sold to private interests. However, this should not be considered until healthy competition among suppliers has been achieved. Otherwise, one or two suppliers could seek to limit competition by buying a significant stake in the transmission company. While the new transmission company would operate, maintain and develop existing lines networks for the foreseeable future, it should explore formats for integrating into the system high voltage lines that might be developed by the private sec-

CHART 3: EVENTUAL STRUCTURE

(TRANSACTION FLOWS)



tor. As yet, no credible private sector offer to develop transmission has yet been received[18], and none is likely until DOE, NPC and ERB establish commercially viable wheeling charges.

5.28 This study did consider the possibility of privatizing the transmission network right away, in the context of restructuring NPC. In effect, the Government could call for bids for NPC's high voltage network, and implement a transparent process of evaluation that would consider guarantees regarding the future development of the system in addition to the financial offer for existing assets. This approach had several important weaknesses: (i) the condition of the existing network is somewhat suspect, so the likely price it would command might be less than a Government could accept on political grounds; (ii) the parameters for wheeling charges have not yet been developed, and the Government might be subjected to heavy political pressures if it attempted to establish those parameters in the context of adjudicating among offers for the system; (iii) private companies would have considerably more difficulty obtaining rights of way than Government companies; (iv) the guarantees offered with regard to future development of the network would be difficult to evaluate, given the substantial increments of supply expected within the next few years; and (v) the downside risk to the Government of selling the system to a potentially irresponsible bidder would be severe, given the public's exasperation with the recent shortages and NPC's image problems. The more deliberate approach that was chosen might not yield immediate efficiency gains, but it is consistent with the study's broader recommendation of having the Government concentrate its recruitment of private investors into clearly lucrative generation projects.

Generation and Supply

5.29 The main objective for the generation subsector is to have as many cost effective producers as possible competing to supply the distribution utilities and major higher voltage consumers directly. Almost as important is the objective of shifting the market risk from the supplier to the distributor. The current practice of producers selling to a parastatal wholesaler, who in turn supplies the distributors, adds a layer of cost between the producer and the end-consumer. Moreover, the addition of an intermediary can encourage inefficiency by reducing the accountability of the producer; under the current framework, wherein the long-term take-or-pay provisions of PPAs entered into by NPC are subject to prior regulatory approvals but not ongoing reviews, the IPPs have no apparent accountability.

5.30 Still, the elimination of the parastatal intermediary will create a systemic void that will need to be filled. Currently, NPC assures the technical integrity of the private proposals it solicits. Moreover, its system planning does take account of the IPPs with whom it has PPAs outstanding. While existing procedures do not adequately take account of direct IPP arrangements with distributors, MERALCO has a well established capacity to protect itself and its consumers, and direct supplies to other distributors are still insignificant. Once IPPs' direct supplies become pervasive, DOE will need to maintain an up-to-date detailed inventory of all planned and ongoing IPP activity; and its accreditation process will need to be tightened to ensure that each new development (i) fits into a general system plan; and (ii) depends on the implementation of a rational financing plan.

18/ NPC has already received three private proposals for developing transmission lines. However, two of these were proposals by foreign contractors aimed at obtaining exclusive turn-key contracts to construct NPC's future transmission lines; these really did not shift the responsibility for developing the system away from the Government. The third was a foreign proposal for an exclusive mandate to run the country's entire transmission subsector and set all wheeling charges, free of any Filipino or other foreign participation. This latter proposal could not be accepted for reasons of national security.

5.31 In the short term, the regional subsidiaries should honor the PPAs for supplies to their service areas that were signed by NPC; however, in the long run, these companies should cease purchasing electricity for resale. As long as they play the role of intermediary and supplier of last resort, the distribution utilities will not feel pressure to address their structural inefficiencies. Moreover, this role inhibits NPC or its successors from moving the market risk back to the distributors. The Government should allow for an adequate transition period; however, since the success of reforms already under way at the supply end of the industry depends on reforms yet to begin in the distribution subsector, the Government should avoid signalling that it will continue supporting distributors who do not follow its policies.

5.32 The development of hydropower needs to be considered separately from thermal generation. The Government needs to develop a fuel mix policy that would insulate the power sector from sudden dramatic changes in world supplies of coal and oil. This policy would lead to the development of targeted levels of hydropower generation, in proportion to the country's overall generation requirements. Moreover, hydro projects provide water for agricultural and other economic purposes, over and above the electricity they produce. The private sector can play an important role in the construction and operation of hydro facilities; however, one single Government agency needs to take responsibility for the coordination of initial activities with the other Government agencies that have vital interests in the development of particular river basins. This coordination also needs to take account of laws requiring the Government to involve local communities in the formulation of infrastructure projects that affect them.

5.33 NPC's existing hydro development department needs strengthening, so that it may undertake broad autonomous responsibility for planning, prioritizing, engineering and implementing hydro projects supported by the Government. This department should focus on the development of river basins, and have the organizational capacity to deal with local, provincial, and regional issues arising from hydro-power system development and related economic activity. This unit would be responsible for river basin planning activities, including feasibility studies. It should have responsibility for liaising with the River Basin Development Committees representing potential stakeholders in water resources and associated community development. In that context, it should be responsible for interacting with affected populations regarding possible environmental or resettlement issues. This unit should also have the capacity to implement financially difficult hydropower projects along traditional public sector lines; or, if a project is found to have good financial prospects, it should be equipped to offer them for development either by private interests or NPC's regional generation subsidiaries.

The Distribution Subsector

5.34 The success of this structural framework depends on reform at the distribution end of the business. Simply put, the development of real competition at the supply end depends on the development of more large commercially viable buyers. This study has proposed that reform in this subsector be based on the consolidation of distribution utilities (regardless of whether they were coops or IODs), within natural geographic boundaries defined by NPC's main supply points. While MERALCO would continue to be the dominant distribution company, this recommendation would result in the creation of more than a dozen new utilities with a demand of about 300 MW each. These should be commercially credible consumers whose business would prove attractive to the IPPs.

5.35 The leading incentive that can be offered to stimulate distribution subsector reform is the 69kV subtransmission system. Acquiring these networks would allow distributors with solid financial and commercial potential to supplement their earnings by (i) supplying higher voltage con-

sumers within their service areas with less than 5 MW of demand directly; and, (ii) earning wheeling charges related to the supply of their areas' larger higher voltage consumers. The cost of operating and maintaining these networks would be offset by the lower rate they would pay as a result of receiving their supplies at a higher voltage. Much as they would provide clear benefits to the distributors, NPC has already expressed a keen interest in divesting itself of these networks.

5.36 As interested as NPC may be to devolve the 69kV system to the distributors, little would be gained if the recipients remain small and fragmented. While the Government could consider using the 69kV system as an inducement to consolidation, the difficulty of realizing the hoped-for combinations should not be underestimated. The IODs are generally family businesses that provide good cash dividends and political power to local leaders. The coops have served as a fount of patronage for important regional politicians; and the coops' Board elections have served as stepping stones to higher office for political aspirants. However, existing laws prevent the Government from arbitrarily forcing consolidations or abrogating franchises.

5.37 Distribution reform is the key to putting the sector back on its feet; and the public, which has been sensitized by the recent crisis to the need for reform, is likely to support bold moves by the Government in that direction. The policy of consolidation should be included in legislation to restructure the power sector (the bills to reorganize NPC should be amended accordingly). At the outset, the distributors could be invited to formulate their own consolidation programs; but if they fail to do so within a reasonable time-frame, DOE should be prepared to issue its own detailed guidelines for accomplishing this objective. The Government could follow up with incentives to the distribution utilities that do consolidate, and price and tax disincentives on those that prefer the status quo.

5.38 The study considered the alternative of recommending that the consolidations be so comprehensive as to cover the entirety of each region. While this alternative would yield fewer distribution utilities, they have the potential to be much stronger than the dozen or so companies that would result from merely following natural boundaries. This alternative was not rejected; however, the study did acknowledge that great difficulties would be faced in collapsing 130 distribution utilities into twelve, and surmised that accomplishing an even deeper set of combinations would be still more difficult.

Role of Regulation

5.39 Because the recommended structure anticipates and supports direct contact between suppliers and distributors, it also has the important advantage that it relies less on Government regulation than the alternatives that were considered. In effect, competitive market forces would protect the consumer as well as the regulatory process might. ERB would continue regulating the distributors' tariffs; moreover, since this model would continue to feature long-term supply contracts, the distributors would benefit from ERB conducting a prior review of provisions of those agreements related to distributors' ability to pass on properly incurred energy and power costs. To strengthen its capacity, ERB would still need to undergo a substantial institution building effort; in addition, ERB needs to recruit more qualified staff and charge a regulatory fee to defray its expenses.

The Role of Dispatch

5.40 Under recent circumstances, where supplies are barely enough to meet demand, dispatch decisions are relatively uncomplicated. The system had scope for all available generation to operate at very high load factors, and the thrust of dispatch decisions has been scheduling. As sub-

stantial additions to capacity come on line, the role of dispatch will include minimizing the cost of production that will be passed through to the consumer. In effect, dispatch decisions will be an important determinant of the load factor and, correspondingly, the revenues for each generating facility in the system. The guiding principle of dispatch is that plants are brought on line in some merit order, usually in inverse relation to cost. However, to attract private developers, NPC has executed PPAs that guarantee a high off-take for some relatively high cost electricity. The need to honor these provisions must be a major input in establishing the merit order. The IPPs and the Government have a real interest in ensuring that dispatch decisions are fair and transparent, and that the dispatch function is performed efficiently.

5.41 Technically, dispatch is an adjunct to transmission; and the dispatch function should be performed by an independent dispatch entity located at and as a part of the proposed new transmission company. The forerunner of this dispatch entity would be a preliminary technical Coordination Committee, composed of representatives of parties to existing power generation contracts, and including ERB and DOE as advisors (para. 6.37). Its purpose will be to formulate rules and priorities for dispatch, and to design a framework for the evaluation of financial risks of existing contracts. With creation of a power pool, this Committee will evolve into a permanent Committee with similar dispatch rulemaking authority. Since neither the transmission company nor the dispatch entity would have generating facilities of its own nor act as traders of electricity, they could perform the dispatch function under the rules of the dispatch entity without bias, and thereby ensure the level playing field that is essential to drawing private developers into this sector. Moreover, as the parameters of merit order are constantly varying to reflect changes in the patterns of demand and the cost structure of supply, technical specialists who recompute those parameters need to be located near the dispatch center, where the required data will be collected for the Coordination Committee. Adjustments needed to take account of the take-or-pay provisions of PPAs will be calculated under rules of the Coordination Committee and adjudicated by the ERB, a body with a specific mandate to act in the interest of the consumer. In summary, a dispatch entity is envisioned, staffed by its own technical committee, and sited at the transmission company, where it develops and updates dispatch rules and parameters which are in turn applied by transmission company operators. Finally, (i) ERB would have to provide *ex post* endorsement of adjustments that result in deviations from pure merit order; and (ii) the generators and distributors would have recourse to ERB in cases where the parameters of dispatch decisions might be unduly weighted against their interests.

5.42 The dispatch entity would also need to include a market clearing mechanism to ensure that billings accurately reflect actual patterns of generation. In some instances, the dispatch entity would send bills to users on the suppliers' behalf; these bills would first be endorsed by the suppliers, and payments would be remitted directly to them, so that the dispatch entity would not find itself bearing any market risk.

5.43 In the long run, dispatch decisions could limit one or more generators from supplying their contractually guaranteed levels of off-take. Those dispatch decisions would not relieve the purchasers of their obligations under valid PPAs. Moreover, the issues concerning extra costs incurred in connection with those guarantees would be adjudicated by ERB. In short, the dispatch and regulatory processes should be flexible enough to allow extra costs that were essential to a supply contract, but should not automatically allow the consumer to be lumbered with unnecessary additional costs.

The Vertically Integrated Model

5.44 One important alternative structure that was considered and rejected was creating a single vertically integrated company to provide generation, transmission and distribution services in

each, Luzon, Mindanao and the Visayas. These regional monoliths would be created by divesting NPC's assets to companies formed by combining all the distribution utilities within the specified geographic area. The main advantage is that this approach would indeed lead to the immediate privatization of the entire industry. However, this study found many disadvantages:

(a) Despite their private ownership, the distribution utilities have not distinguished themselves as efficient or effective companies.

(b) In contrast to the current IPPs, which consist mainly of foreign direct investors, the existing distribution utilities have difficulties in providing even small amounts of equity for new investments. The integrated regional companies provides only a minor role for foreign direct investors, and a heavy reliance on local companies that have a history of underfunding investments.

(c) Even if the vertically integrated companies were inclined toward satisfactory levels of investment, they would likely have difficulty raising the necessary resources. Under the recommended framework, this study found that the public sector would need to supplement the financing raised by the private sector. However, the private companies that would be created under this alternative would not legally qualify for official borrowing or Government guarantees.

(d) While this arrangement would reduce layering as far as possible, it would also eliminate any pretense of competition and would substantially complicate the regulator's protection of the consumers.

(e) The difficulties of effecting the combinations would be even greater than merely attempting a consolidation program to create larger distribution utilities, mainly because the stakes would be much higher. In the alternative this study is recommending, vested interests would simply be reluctant to cede the status quo; in this alternative, that problem would be exacerbated by other interests jockeying for position in the new arrangement.

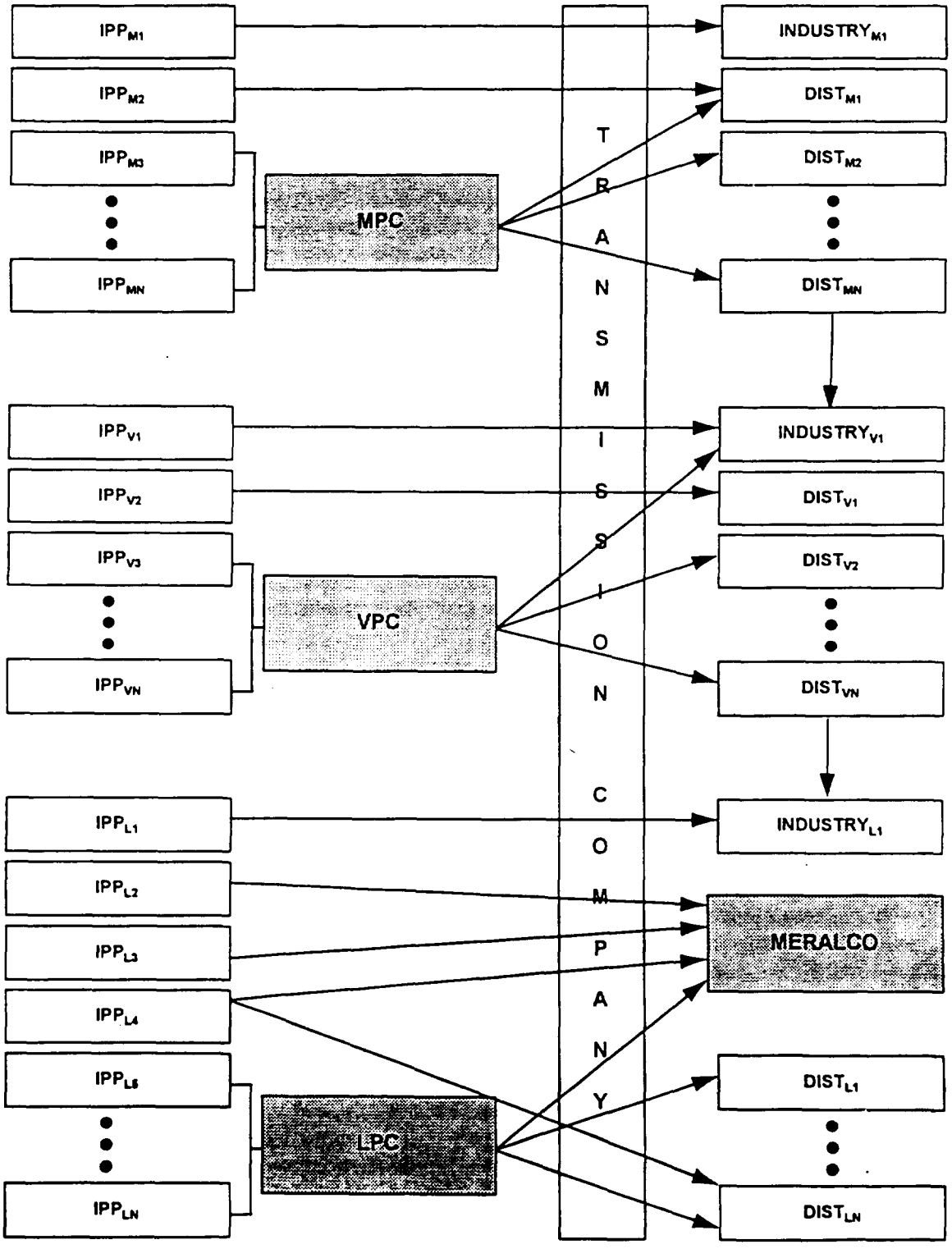
(f) The absence of a national company would assure that issues of national interest, such as the interconnection between regions and the formulation of hydro projects, would be given short shrift.

D. Transitional Arrangements

5.45 The recommended framework cannot be implemented before NPC and the distribution utilities are restructured. While a number of bills to regionalize NPC have been introduced in the two houses of the Philippine Congress, the passage of legislation is not a prerequisite to the desired restructuring. Indeed, the purpose of legislation would be to establish the regional subsidiaries as parastatals with independent charters, each having the right to increase its capitalization and borrow by decision of its own Board. However, NPC has already realigned its organization into profit centers (para. 5.21), and it has already taken substantial steps toward (i) giving autonomy to transmission operations, (ii) separating the costs of generation from transmission, and (iii) decentralizing the structure of its generation activities. Such arrangements, rooted in a National Power Board decision as opposed to legislation, might not accord the necessary independence to the transmission company,

CHART 4: TRANSITIONAL STRUCTURE

(TRANSACTION FLOWS)



but the operational aspects of reorganization could begin. On that basis, NPC and ERB could develop the parameters for wheeling charges and dispatch criteria.

5.46 Even if a new law is not required to reorganize NPC, DOE has indicated that some legislation is likely. The Government recognizes that the pending bills are a manifestation of the widespread view that NPC is difficult to manage, and the public's desire to shift control over these facilities closer to the regions. The Government plans to file a bill of its own that will take account of these regional aspirations in late 1994. Regional leaders have indicated that the transmission systems need not be included among the assets to be decentralized. In short, the recommended structural framework does not need to include special transitional arrangements to cover the period until the restructuring of NPC is given a sound legal basis. Nor does the framework depend on actually privatizing NPC.

5.47 On the other hand, the viability of the recommended structural framework depends on the reform of the distribution subsector. In their current fragmented state, distributors other than MERALCO have insufficient levels of demand to attract the attention of the IPPs or to absorb the market risk of PPAs. Less than ten of the 130 distributors show a peak demand exceeding 30 MW; most of them have peak demand of about 10 MW. Moreover, many have been chronically late at paying their bills and have been regarded as marginal credit risks. With few exceptions, they have no alternative but to draw their supplies from NPC since few IPPs would consider taking the commercial risk of serving them unless, as a group, they are subjected to a substantive subsector-wide reform process.

5.48 Over and above their commercial weakness, most distributors lack the technical and financial capability to manage the subtransmission systems. To induce the distributors to consolidate, the Government might consider the transitional arrangement of devolving the subtransmission system to the new backbone transmission company, which would operate and maintain those networks and hold the assets in trust for the distributors, pending implementation of a regional consolidation process. Since the distributors are all privately owned and the Philippine system is rooted in due process, the consolidation process cannot be forced. NEA could provide guidelines, and the distributors themselves could be invited to formulate the consolidation framework. The subtransmission assets for each regional amalgamation would be released to the reorganized distribution utility upon completion of the consolidation program for its area.

5.49 NEA would need to play a pivotal role in the program to reform the distribution subsector. However, it currently lacks some of the institutional capacity needed to spearhead effectively the proposed consolidation of the distribution utilities. Although its transformation to the role of interested lender is well advanced, (i) NEA's ability to deal with issues of credit and financial engineering needs reinforcement, and (ii) the Administration is still engaged in a number of peripheral functions that are of questionable relevance to its role as a lender. Moreover, to facilitate interaction with the IODs, NEA needs to exercise the broader powers it already has but has chosen not to use, to extend distribution and subtransmission loans to those companies (para 4.25).

5.50 The recommended structural framework cannot work unless the distribution subsector has been consolidated. Until then, the regionalized parastatal generating companies need to retain the ability to buy electricity for resale to the unconsolidated distributors; and the backbone transmission company will need to operate and maintain the subtransmission networks. These transitional arrangements are depicted in Chart 4. Due to difficulties in accomplishing the consolidation of the distributors (para. 5.36 and 5.48), the likely time-frame for these transitional arrangements cannot reasonably be estimated. However, implementation of the transition arrangements would lead to a structure

that is far more orderly than the current one, and would set the stage for real competition as a by-product of distribution subsector reform.

E. Conclusions

5.51 The measures employed to resolve the power crisis of 1992-93 are the leading edge of a major transformation of the Philippine power sector. Increasingly, the private sector has taken the initiative; and now the Government must develop a structural framework for the further development of the sector. The challenge now facing the Government is to guide the ongoing transformation so that (i) private development of power facilities will become self-sustaining, and (ii) the private sector would willingly address the spate of sector issues, not just a select few with particularly favorable financial prospects.

5.52 The Government must now develop a structural framework, within which the private sector can flourish. The cornerstone to this framework is to simplify the roles of the Government agencies participating in the sector, so that they can contribute where most needed to orderly development in the future. This study envisions the following roles for the Government's participants:

(a) DOE should serve mainly as the policy maker for the sector. In that context, DOE should provide clear vision on strategic issues and clear rules forming the framework within which the regulator can adjudicate. Once it has strengthened its planning capability, DOE should be responsible for developing the strategic plan for sector development. Because DOE is in a position to span the entire range of the power sector without conflict of interest, it should take responsibility for accrediting all IPP proposals, assuring their consistency with DOE policy and plans. To the same end, DOE should also assume responsibility for maintaining a comprehensive, up-to-date inventory of all power developments nationwide.

(b) NPC, through its subsidiaries, ultimately, should limit its role to being an owner and sometime operator of generating facilities. It should be given the lead responsibility for developing hydropower projects, and should be one of a number of suppliers of thermal electricity, all of whom would compete on equal commercial footing. While this report recommends unbundling NPC's generation facilities, the objective is to enhance the company's capacity to manage these operations, and enable privatization of the more successful ones. In the near term, but only until DOE develops the needed capabilities, NPC should continue as the agency responsible for power sector planning. Also in the intermediate term, until distribution subsector reform has taken root and some more credible distribution companies have emerged, NPC will need to continue as the wholesaler of electricity, buying from IPPs for the purpose of resale to the distributors.

(c) The recommended new national transmission company should serve strictly as an owner, developer, and operator of high voltage networks, providing all suppliers with non-discriminatory access to the system for a fee. To ensure that its service is adequate and timely, its investment program should be submitted annually to ERB for approval; to ensure that its charges are fair, its cost based rates should be subject to regulation.

(d) NEA's scope should be reduced and its focus sharpened so that it serves only as an interested lender for subtransmission and distribution networks. Because of its capacity to apply conditionality in relation to its loans, it would become the principal agent for implementing the Government's policy to consolidate the distribution utilities; in that context, NEA should exercise its legally broader power to lend to the IODs as well as the rural electric coops. Since many of the distribution utilities are weak and lack market power, NEA should continue to assist them with system planning, investment formulation, and centralized procurement. In the longer term, NEA objective should be to return these functions to stronger, larger distribution utilities.

(e) ERB should remain a quasi-judicial agency for regulating mainly the tariffs of all companies that qualify as electric utilities. However, the approach to regulation should rely most heavily on market forces and thereby limit the interventions of the regulator. ERB's span of jurisdiction should be altered only to the extent that the power to award franchises should be brought under its control, thereby bringing the franchising and certification activities under the same organization (para. 6.8).

(f) A dispatch entity needs to be created. The facilities it would operate should be housed with the new transmission company. The rules for dispatch should initially be made by a technical committee consisting of representatives of parties to existing power sales contracts, with advice from DOE and ERB.

In these capacities, the various Government agencies can create the proper enabling environment for effective private sector performance; or where the private sector will not participate, the public sector can guarantee that necessary services are offered.

5.53 The recent Philippine power sector transformation has drawn heavily on the U.S. experience, within which the predominant responsibility for sector developments has been vested with private interests. In recent years, Argentina, Chile, the U.K., and New Zealand (among others) have also implemented broad-based privatization of their power sectors. Many useful lessons can be learned from those experiences, but the Government should avoid the temptation to copy one of those models, ignoring unique constraints of the Philippines.

5.54 This study has attempted to develop a structural model based entirely on Philippine circumstances. It does borrow from several of the other models where appropriate. But, the parameters have been designed to address Philippine issues, and efforts were made to test the feasibility of the recommended framework against Philippine problems. Therefore, the recommended structural framework is considered to be a uniquely Philippine model.

6. Requirements for an Enabling Environment

A. Introduction

6.1 An enabling environment for private sector participation requires clear Government policies and rules for independent power generation, independently priced transmission, and stronger distribution companies. DOE, as the Government body responsible for energy policy, will take the lead in information gathering, planning, and coordinating sector development. First, the Government must determine the structure of the sector, how much competition it wishes among private participants (producers and consumers), and the functions it wishes to remain within the public sector.

6.2 The Government's principal objectives are to (i) attract private capital; (ii) reduce costs and increase efficiency by opening generation and distribution to market forces; (iii) reduce dependency on scarce budget funds and borrowings; (iv) and reduce still further its own involvement in the sector as a player. Once the structure has been determined, the existing legal and regulatory framework must effectively encourage the rapid development of new institutions independently of Government policy. It can do so by ensuring that regulation is clear and transparent, providing fair procedures in setting prices, allowing new producers entry into the market and access to the transmission system, enabling optimal system operations, and enforcing fair and neutral operating and reliability standards.

6.3 The Bank has reviewed these aspects to help identify the most suitable structure for increasing efficiency, encouraging competition, and enabling greater private sector participation. The Bank has concluded that the Government has not yet clarified its objectives for the power sector, its ownership role, or how to structure and regulate competition among private power producers. Until it does so, the enabling environment for the power sector will be less than optimal; and efficient, low cost electricity supply will be an elusive goal. Now that power shortages have been met, the Government should set a heading for the longer term and set a clear timetable and strategy for restructuring the sector through to at least the year 2000. The previous Chapter recommended a structural framework which can meet the demands of future growth while accommodating current constraints. The present chapter discusses issues of policy, legal and regulatory framework, pricing, dispatch, and accreditation; and makes recommendations required to enable a suitable environment for efficient and orderly private sector participation.

B. Policy Aspects

6.4 While DOE's role under ESAP is officially clear, the combination of a small and inexperienced staffing and extended statutory involvement of its Secretary in other energy organizations confuses DOE's real authority. DOE has sole responsibility for policy formulation (but not regulation) for the sector, and also supervises through accreditation the IPPs' sale of power to utilities other than NPC. DOE's Secretary is also empowered to serve as Chair of NPC, PNOC, and

NEA,[19] the other leading quasi-Governmental energy agencies, but during the power crisis, the President's strong and direct leadership has put all of DOE in his shadow.

6.5 The formation of DOE is a progressive step, but the Government is still too involved in the sector through yet other agencies and programs, examples of which are:

Department of Management and Budget approval of NPC budgets and Cabinet approval of NPC salaries.

NEDA approval of capital expenditures and foreign loans and the Government Auditor's approval NPC expenditures.

Commission on Audit's (COA) disapproval of commercial practices among government-owned entities in the sector.

Government direction of NPC and the rural coops to underwrite subsidized electricity consumption, by (i) capping bills on relatively large monthly household "lifeline" consumption and (ii) extending Government-subsidized supply to about 60 islands.

6.6 If the Government wishes to increase the efficiency of the public power sector and encourage more private sector involvement especially in financing, it must give greater autonomy to boards and management of NPC, which must be allowed to operate on a fully commercial basis. Financial statements should be prepared in accordance with international accounting standards, and the audit should focus more on business processes than on the pre-approval and verification of transactions.

C. Legal and Regulatory Issues

6.7 The Philippines have a history of public service regulation which can be traced back to legislation from 1903, creating municipal franchises. The Philippines therefore have a history of modern regulatory structures which is as long or longer than that of most other countries using similar systems. A similar general description of systems and functions fits all such systems, but as should be expected for any system with ninety years of history, the Philippine system and the articulation of laws is particular to the country. Therefore, the Philippine system of regulation is itself a potential "model" for comparative purposes, and not merely an example of some other form of system.

Present and Future Duties of Regulators

6.8 Current Philippine regulatory structures are based on legislation passed in 1936, as subsequently amended. ERB was reorganized in its present form in 1987 by Executive Order EO 172. ERB is a quasi-judicial/quasi-legislative body with price regulatory powers; its duties and procedures resemble those of similarly functioning bodies in other jurisdictions. At present its only non-price powers concern certain matters of safety and quality of service. In 1973 legislative power over

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19/ The current Secretary is indeed Chairman of NPC and PNOC; however, the President has nominated another official to serve as Chairman of NEA.

electric utility franchises was delegated to the NEA; this included franchising powers for all private (i.e. non-governmental utilities other than cooperatives) and cooperative entities. Power to issue certificates of public convenience (CPC) or certificates of public convenience and necessity (CPCN) are divided between the NEA which certifies the coops, and ERB which certifies other private utilities. DOE's regulatory functions are restricted to certificate matters in the petroleum industry. The most recent major change in regulatory structure occurred in December 1992, when the Philippine Congress created DOE, granting that Department responsibility for energy policy and centralizing price regulatory functions that had formerly been given to NPC or NEA within ERB (Republic Act RA 7638, the DOE Act).

6.9 The resulting split between the authority to award franchises, the power to issue operating certificates, and the authority to regulate prices, divides responsibility that would better be consolidated. This study recommends that ERB assume NEA's franchising powers and the ability to place conditions on all utility certificates or franchises, as necessary to effect the distributor consolidations or to effect a competitive environment in the electric sector. ERB should then exercise this power in order to effect cost-effective consolidations of small distributors organized around the 69kV sub-transmission lines and to create a more competitive electric sector generally. (Statutory language to effect these changes in proposed in Annex 8). ERB would also be the price regulator for the dispatch entity to be created as discussed in the section on dispatch. Thus, ERB will become a more complete regulatory institution, with the full range of price-regulatory powers necessary to effect and protect a competitive market for electricity. It would become a modernized and more effective version of what is already required by Philippine law, not an institution with substantially expanded powers.

Summary Comparison of Agency Duties

6.10 Planning functions are presently performed by DOE and NPC, subject to review by NEDA. In November 1993, officials of ERB and DOE came together to discuss and develop common understandings of their respective powers under the DOE Act of 1992. Based on those understandings, DOE can be described as "the Government's cabinet agency which forms policy" and the ERB as "a special court with investigative powers", exercising those powers subject to DOE policies when DOE has properly issued rules for such purposes.

Summary of Statutory Authorities

6.11 The basic powers and duties of DOE are oriented toward policy formation to meet the broad purposes required by law. More specifically, DOE is a policy-making body acting largely through administrative processes, but generally lacking direct jurisdiction. ERB is predominantly a quasi-judicial body with direct jurisdiction and enforcement powers. The specific current authorities and duties of ERB and DOE are summarized in Annex 5, giving specific legislative citations.

Legal Transparency of Regulation

6.12 Because the Bank's policy on electric sector lending requires a determination of the transparency of such process, we give a detailed transparency review in Annex 7 and summarize

here.[20] The Administrative Code of 1987 sets specific standards of transparency for government and regulatory agencies, including requirements for adequate and public notice and opportunities for submission of views by all interested parties in rule making. In addition, ERB and NEA have rules that exceed Code standards. While there is the appearance of jurisdictional overlap in the authorities of ERB and DOE, and such overlap might imply conflict, the precedence of DOE in setting policy establishes a sequence to follow by which authority to determine the correct result in a case. This study presumes that ERB has and in the long run will continue to apply transparent processes.

Rule Making as a Regulatory Tool

6.13 Since many entities are being regulated, ERB may enhance its efficiency by the use of generic rules and other forms of rule-makings, application of which can simplify decision making for particular cases. DOE will most likely continue to have policy responsibility for matters such as market entry, dispatch and planning policy, fuel mix, etc. Presumably, such specific policies will be influenced by statutory standards, which determine openness to competition, etc. Where DOE has properly issued a policy rule on a particular subject, ERB can then apply that policy if lawful; where DOE has issued no policy on a matter properly before ERB, then ERB can apply normal common law rules of precedent, etc. to determine the correct result to adjudicate the case fairly. NPC would be simply another company to whom such policies are applied. To influence the actions of NPC or its proposed subsidiary companies, DOE could issue formal rule, following procedures set out in the Code. Also, DOE (and NEA) can use the "cross-reference" doctrine to file proposed rules at ERB, for ERB to consider subject to its normal notice and hearing process. ERB in turn would apply properly promulgated DOE rules, but since ERB is also required to enforce the laws of the Republic, it would thus be required to assure that the DOE policies properly reflect their statutory purposes.

6.14 To assure that NEA, DOE, and ERB continue to maintain orderly and transparent interrelationships in instances that are not within the clear ambit of one of them DOE should issue a rule clarifying how the Administrative Code Book VII Chapter 2 Section 9 (1) will be used. This section is vague as to actual processes which must be followed. DOE could not rely on the more detailed rules of Code Book VII Chapter 3 because they are too complex for administrative rule makings; and in any event, Chapter 3 defines procedures for contested cases, while contested electric utility cases are clearly within the ambit of ERB.

Immediate Rule Makings

6.15 Currently, ERB has an opportunity to show how it might apply rule making capability to resolve issues related to coop pricing. ERB could convoke a hearing on whether the NEA Tariff

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20/ Decisional and dispute resolution process has certain unique features in the Philippines. The Administrative Code of 1987 sets at least minimum standards for transparency for all agencies with regulatory or rule making powers. In Book VII, Chapter 2 Section 9(2) the Code requires that "if not otherwise required by law, an agency shall, as far as practicable, publish or circulate notices of proposed rules and afford interested parties the opportunity to submit their views prior to the adoption of any rule". This section therefore applies to all of DOE, ERB and NEA when any of them act in any rule making capacity. The Code also applies to government corporations when they act in governmental capacity, and therefore applies to NPC. Code Book VII, Chapter 3 then lays out more detail about the processes of administrative agencies in contested cases. Both ERB and NEA have prescribed rules for their electric energy hearings processes, which meet or exceed Code standards and therefore those rules govern directly their processes without further reference to the Code. DOE, however, is governed more directly by the Code. Although the authority of each agency is defined by the law and interpreted by the Department of Justice, in some areas there is an apparent overlap of authority, and certainly an overlap in subject matter affected by that authority. But differences in procedure and definitions of purpose of the two such agencies can be developed such that no actual conflicts result.

Manual should be adopted as the formal ERB pricing rule for coop rates. In so doing, ERB would issue notice of the requested opinion, and then use its normal hearing processes to assess the various questions involved. The hearing could yield the result that much of the manual contains reasonable rules, but that some aspects need to be changed. ERB would then issue an order adopting NEA's proposed rule as modified. Subsequently, each cooperative could submit rates applications with some expectation that the application conforms to the rates manual. ERB could then provide summary confirmation of compliance with the Tariff Manual, thereby simplifying this process considerably. Any cooperative could follow any other pricing principles, but that proposal would be subject to ERB's full rates proceeding.

IPP Regulation

6.16 The IPPs structure their commercial behavior carefully, and thereby avoid regulation by DOE and ERB, except for DOE's screening of their pre-bid qualifications. (Annex 8, A8.2, Section C proposes to make this a more permanent part of the regulatory structure.[21/]) Restrictions that might be applied to their structure and commercial behavior relate to (i) the consistency with power plans, (ii) their ownership, and (iii) their capacity to serve the public as a contractor or agent of NPC.[22/] This study recommends that IPPs, directly connected NPC customers drawing over 5MW, and other similar industrial type facilities be exempted from the requirements of a franchise in order to transact with each other or other electric utilities (Annex 8.2). Accomplishing this objective merely involves invoking and expanding sections of existing law (PD 269 Section 43(b)), which NEA has so far not used. This will somewhat simplify the creation of a more fully competitive market. However the constitutional constraint on ownership will not be affected by this change, and this will remain a strong factor inhibiting full market development.

Summary of Price Regulation

6.17 The most rapidly growing segment of the generation subsector, the IPPs, are unregulated except through the bidding process. Current structural practices can be embodied into law (Annex 8, A8.2). However, transmission and distribution utilities are subject to regulation, as is all electricity offered for resale. Technical price regulation for these utilities is largely determined by statute in the form of price-capped rate of return regulation. Each IOD has a Congressional charter which stipulates a maximum rate of return; the member owned cooperatives are subject to NEA's pricing policies, which currently prescribe a targeted level of internal cash generation. ERB permits a price

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21/ Under the proposed statutory structure, a company whose sole business is generation would not be "public service entity," subject to regulation. We do not discuss whether such companies are "public utilities" for equity purposes under the Philippine Constitution.

22/ Details of DOE's current authority over IPPs are somewhat complex. Philippine laws affecting rights of private power producers are Presidential Directive 40 (PD 40), Executive Order 215 (EO 215), and The Build Operate Transfer Law (RA 6957, the BOT Law). Under PD 40 and EO 215 private power generators may "sell their production to the grids", meaning to the NPC grids, "consistent with the development plans formulated by the National Power Corporation". EO 215 supersedes PD 40 where the two may conflict. NPC published EO 215 rules on June 5, 1989. Subsequently, the BOT Law was passed. The BOT Law governs infrastructure projects which carry out public responsibilities by private parties. An electric generation BOT is subject to utility ownership restrictions of the Philippine Constitution, which impose at least 60 percent local ownership. In contrast, an entity acting only under EO 215 would simply be a private power project, not a public utility, hence would not be subject to constitutional restrictions on ownership (so long as it also does not hold out offers of sales to "the public", as further discussed in Chapter 7). Rules implementing the BOT Law have also been published. Therefore, the Philippines has two sets laws for private sector generation, governing (i) cogeneration and related private power facilities (under EO 215) and (ii) BOT facilities (under the BOT Law). The proposed dispatch entity will need to take account of these subtleties to avoid inadvertently imposing IPP price regulation in the course of redesign of the sector.

within that cap, after review of all costs of each utility. Many of the detailed cost accounting, rate base determination, and rate design processes used in that review are similar to those used by regulators in other common law jurisdictions. Cost-cap regulation and related methods in the form of price-flexibility regulation could usefully be added to this repertoire for distribution utilities competing with IPPs to serve larger industrial and commercial customers (para 7.6).

Regulatory Fund

6.18 Judicial independence of ERB is vital. ERB performs an important role as price regulator, and this study proposes that it might also acquire important and difficult new duties over franchises. Also, the 1992 DOE Act, as here interpreted, places the ERB effectively in the role of a special court for energy matters, particularly where enforcement of DOE policies is involved. This is a unique collection of vital duties, all of which require strict judicial independence if the ERB is to continue to be respected as a fair judge. Therefore, this study also proposes that a special dedicated regulatory Fund be created, funded by users fees earmarked for this purpose, which would then be appropriated by Congress only to cover ERB's requirements. This is the same mechanism used in most other countries and jurisdictions with utility regulators. (This is discussed in greater depth at para 7.13.) The Fund should be accomplished by statue (Annex 8, A8.2, Section 2).

D. Pricing

6.19 An hospitable environment for private participants in the power sector should attract private investment and induce efficiency through competitive and innovation-inducing mechanisms. Cost-based energy pricing policy and practice are essential to attain these objectives. Where the public sector assumes a predominant role in the supply of power, correct pricing signals consumers to induce economically efficient consumption patterns. In that case, the optimization of supply decisions is usually addressed through sophisticated, though not necessarily successful, centralized system planning. However, this process usually relies on the planning capability of the same government which permits or encourages price distortions in order to promote other policies. Experience has proven that this approach fails to achieve an optimal allocation of resources for two main reasons. (i) The planning process seldom succeeds in proposing even approximately optimal investment programs because system planning faces the impossible challenge of forecasting accurately a wide range of variables, such as demand growth, capital costs, fuel prices, construction and operation performance, etc. (ii) The conflicts between a least-cost economic program and distorted prices -- stemming from the tax regime and controlled/subsidized prices -- create financial incentives on public utilities that tend to prevent the enforcement of a least-cost plan. Therefore, even when investments are made by a single decision maker (ie. the government), cost-based prices are required to assure that those decisions are economical.

6.20 The need for adequate cost-based prices is more evident when the sector is open to private participation. In that case, investment and consumption decisions are made by a large number of parties, and the effectiveness of planning is substantially reduced, particularly in guiding short term decisions. Further, cost-based pricing is justified not only on the grounds of introducing efficiency incentives, but also as a condition for achieving a fair competitive environment and hence attracting more private producers. Energy prices should therefore be consistent with cost levels and structure; and the tax regime should be fair to all parties and oriented towards the correction of price levels and structure for market failure, instead of introducing further distortions.

6.21 The Philippine Government is aware of the potential impact of distorted energy prices, and has improved power tariff levels and structure with (i) the adoption of tariff adjustment mechanisms for fuel prices, purchase power prices and exchange rates; and (ii) the formulation of a new tariff structure for bulk energy based on fixed (demand) and variable (energy) charges. However, many price distortions and related problems remain, including: (a) cross-subsidies among regions and consumer groups; (b) no distinction between peak and off-peak tariffs; (c) a lack of guidelines for PPAs to ensure an adequate fee structure thus creating the risk of potential disincentives for an efficient operation of the system; and (d) dissimilar tax regimes for the public and private sectors. [23]The Government must correct these distortions if an efficient and open power market is to be achieved. Although the move towards an open market will tend to correct distortions such as price levels at the bulk energy level, structure and retail price anomalies will always require policy and regulatory measures.

Cross Subsidies

6.22 Current tariff structure maintains two types of cross subsidies: (i) among regions whereby Luzon consumers subsidize those in the Visayas and Mindanao; and (ii) among consumer groups within a region whereby industrial and, to a lesser extent, commercial consumers are subsidizing residential consumers. These subsidies respond to the government's social objective of protecting lower income groups. While these objectives address legitimate social concerns, they could be dealt in more efficient ways -- such as direct subsidies -- instead of using tariffs as an instrument for income redistribution with the consequences explained below. The effect of cross subsidies can be illustrated as follows:

- NPC sells bulk energy at higher prices in Luzon than in the Visayas and Mindanao, without respect to actual generation costs. NPC plants in Luzon must add this implicit subsidy surcharge to prices while IPPs located in Luzon do not. This dichotomy is especially pronounced where IPPs sell directly to distributors. Thus the IPPs have an incentive to locate in Luzon, and this impacts adversely on power supplies elsewhere.

- The existing cross-subsidy among consumer groups constitutes a hurdle to better power service for large consumers. Ideally, large consumers should be granted the option of purchasing capacity and energy from NPC's proposed regional subsidiaries or any other producer/distributor, inducing a highly competitive market likely to benefit all participants. However, the prevalence of cross-subsidies will not allow the implementation of such a system without major financial disruptions. MERALCO currently serves more than half the country's large consumers, charging them an average regulated tariff US$.09/kWh, thereby enabling the Company to subsidize residential consumers. On the other hand, NPC negotiates directly with its large consumers and charges an average tariff US$.069/kWh. As long as distribution companies bear cross-subsidy obligations, competition engenders cost-shifting, and a fair competitive system can not be implemented.

Tariff Structures

23/ The analysis of tariffs in this study is somewhat cursory because the Bank has already held extensive dialogues with Philippine counterparts through (i) The Energy Sector Study (Report No. 7269-PH; Nov 9, 1989); (ii) the Rural Electrification Sector Study (Report No. 9810-PH; Dec 23, 1991); and (iii) preparation of the Energy Sector Projects: the Power Transmission and Rehabilitation Project (Loan 3626-PH; June 1993); the Leyte-Cebu Project (Report 11449-PH; Jan 6, 1994); and the Leyte-Luzon Project (Report 12568 PH; Oct 8, 1993).

6.23 The ERB is reviewing new proposals for the wholesale tariff structure that would replace the existing single energy charge with separate charges for energy and demand, reflecting the actual cost components of service. Retail consumers paying on the new basis would have some incentive to reduce peak demand and manage better their total demand. However, this limited disaggregation of tariffs still does not capture time-of-day cost variations nor the cost of stand-by capacity; and this deficiency could have an important adverse impact if (i) IPPs are to play an important role in future capacity additions, and (ii) self-generation continues to be a popular option among many consumers.

6.24 Without peak-capacity charges on consumers, the private sector would continue investing exclusively in base-load plant with the risk of reaching a peak capacity shortage, while NPC would be left with the financial burden of providing peak capacity sold at low prices. On the other hand, the lack of stand-by fees would also affect NPC adversely. Without such a fee, consumers will be misled towards uneconomic self-generation choices, since these consumers would not be paying the real cost of stand-by capacity, provided by NPC's proposed regional subsidiaries. This study therefore finds that tariff distinctions between peak and off-peak energy and a schedule of stand-by fees should be the next and logical step in improving the tariff structure.

6.25 Given that the proposed unbundling of NPC and the sector restructuring calls for the transmission system to be disaggregated into a separate company (and possibly the further disaggregation of portions of the subtransmission system to consolidated distributors), some system of charges that would enable the recovery of transmission costs needs to be included in the overall tariff framework. The development of an acceptable framework for wheeling charges is thus needed urgently. This would need to be formulated by NPC and submitted as quickly as possible to ERB.

Power Purchase Agreements

6.26 PPAs are being negotiated by NPC and MERALCO without uniform guidelines for operating conditions and fees structures. Although most projects have adequate fees, there are two features which could impede efficient energy dispatch: (i) minimum energy off-take provisions that may give priority to plants with higher variable costs; and (ii) single energy fees, combining the coverage of fixed and variable costs, and overpaying the latter. Guidelines should establish a common set of practices for all new PPAs, by which (a) fees would relate more closely to actual fixed and variable costs, and (b) take-or-pay provisions are minimized.

E. Accreditation Issues

6.27 Initially the Government had given NPC the right to accredit IPP proposals, and NPC has expended considerable effort in evaluating the technical parameters and financial merits of the offers it received. However, NPC has experienced considerable difficulty in serving as accreditor of proposals being made by IPPs directly to the distribution utilities, especially MERALCO; this difficulty arose from NPC's own perception of a conflict between its role as supplier to those utilities and as licensor of competing suppliers. It, therefore, ceded to DOE the role of accrediting IPP proposals for supplies to other utilities.

6.28 Unfortunately, DOE has lacked the capacity to perform this function with the same diligence as NPC had exercised in evaluating its own proposals from IPPs. In fact, the information DOE has collected is mainly census data on most of these plants; and while this partial census has

included technological data, very little information has been sought regarding the financial capabilities of the IPPs themselves or the financing plans for their projects.

6.29 The entire accreditation process should be united under DOE. Given its current capacity constraints, DOE can reasonably ask NPC to evaluate the proposals it receives from IPPs, and use that NPC evaluation as the basis for accrediting those projects. This arrangement should be temporary, however, and DOE should develop the capacity to conduct its own evaluations. DOE should also require that distribution utilities to formulate a comprehensive accreditation document. The contents of that document could at this time be based on NPC's evaluation reports, but should include comprehensive technical, economic and financial data as well as the proposed terms for selling the project's output to the utility. Each project proponent would pay an accreditation fee that would cover DOE's cost of independently validating any materials provided in connection with the accreditation process. This would result in a meaningful accreditation.

6.30 Because the process of contracting with IPPs binds the purchaser through the PPA in the event that the seller obtains financing, and there are substantial risks that the seller might not be able to bring the proposed financing package to closure, the Government is in effect accepting uncertainty and imbalance in its power system planning process in exchange for private assumption of responsibility for a heavy burden of investment. In that context, the Government should take any reasonable steps to reduce the level of uncertainty. In particular, two important issues can be addressed through the accreditation process:

(a) Bidding. NPC's example so far has been that IPP proposals that were solicited through a transparent competitive bidding process encompassed both lower prices and greater likelihood of coming to closure. As a result, NPC has stopped entering into negotiated agreements with IPPs, and has adopted a policy that all future IPP arrangements will be solicited through competitive bidding. Under the Philippine legal framework, the Government could not proscribe two private parties from entering into transactions with one another except under very restrictive circumstances. It cannot, therefore, routinely require that the distributors foreswear negotiated arrangements with IPPs. However, the Government could apply tighter terms to the accreditation of negotiated arrangements than to proposals acquired through a transparent bidding process. The accreditation would need to ensure that a negotiated project is consistent with the Government's power system plans, that the technology is appropriate, and that pricing is reasonable with respect to cost.

(b) Validity Period of the Accreditation. Some IPP proposals are still active, although the proponents have still not secured financing after several years of searching. In some such instances the purchasers have already made alternative arrangements, so that the conclusion of financing packages would risk adding unnecessary capacity. To address this uncertainty and the concomitant risk, the accreditation should carry a fixed validity period. Because the IPP will be incurring expenditures and the timing of this financing can differ greatly from project to project, the validity period should be based on the IPP's own estimate of the timing required. That validity period could be extended; however, the purchaser should be required to certify, as a condition of that extension, that (i) the project is still needed and appropriate; (ii) the purchase price is still advantageous to the consumer; and (iii) the seller has reasonable prospects of closing on the needed finance within the time-frame of the extension.

F. Dispatch Issues

6.31 Most problems discussed in this report have both a physical and institutional intersection in one problem: dispatch of the power system energy resources. Dispatch, in the first instance, is a technical choice of which plants to use from among those available at a given moment. On purely technical grounds, dispatch involves choices of fuel efficiency and availability, output capabilities of plants, available loadings or outage conditions of transmission lines, etc. But dispatch is not only technical. Plant availability can be affected by many other factors, including economic efficiency objectives (least-cost dispatch, i.e. to minimize variable costs); policy considerations (such as fuel imports, the operation of multipurpose hydro systems); and contract conditions of availability (power supply contracts might require or inhibit uses of plants at particular times or at particular load factors).

6.32 At the same time, needed technical or regulatory rules, which may govern power system operations, are missing and need to be formulated. These include rules for technical coordination of independent power systems; power pools or similar power trading arrangements; and coordination agreements for long term transmission and power system planning. Yet, while the technical aspects of these rules remain undeveloped, the increased participation of IPPs tends to constrain dispatch. In general, the IPPs seek to minimize market risks and pass fuel costs risks to consumers. Two emergent problems associated with the entry of IPPs are: (i) the existence of energy off-take provisions that may force the dispatch of plants even when their variable costs are higher than others not dispatched, (i.e. a distortion in dispatch economic priorities), and (ii) single energy fees combining fixed and variable costs and overpaying the latter.

6.33 At least three dispatch models bear further examination for the Philippines context. These are analyzed in the framework of principles that should govern the development of a dispatch structure. The three models are:

I. Competition structured as a power pool with central dispatch against hourly supply and demand offers.

II. Unstructured free market; (A market mechanism matching buyers and sellers is maintained, and coexists with independent contracts between buyers and sellers using the transmission system to wheel power.)

III. Pure merit order economic dispatch. (All power is dispatched as a commodity on economic merit order, with due consideration for system balance and stability.)

6.34 When NPC monopolized power generation the dispatch method used in the Philippines was close to model I, with NPC theoretically able to apply a least-cost dispatch criteria to its own plants. As production from multiple IPPs increases and surplus capacity becomes available, the dispatch model will resemble Model II. The dispatcher first applies PPA contract provisions and commitments; only when such contracted resources are exceeded is a form of economic dispatch applied.

6.35 In principle, the dispatch of all three models should coincide in a sufficiently large and diverse system. In reality, market size, past history, and other factors can cause each to have very different actual results in any application. Thus, these three basic models of dispatch regulation should be studied in more detail before a final recommendation of the best method for the Philippines can be made. This analytical effort, to be undertaken by NPC's study on "Contracting and

Economic Dispatching of Private Power", should focus on the need to solve the conflict between existing bilateral dispatch agreements (the PPA's energy off-take provisions, inadequate fee structures) and least-cost objectives; and recommend a better model for the future.

6.36 For the long run, this study expects that a Model I type structure (power pool relationship governed by a coordination council, with a central computer based "brokerage" system) will be created. If necessary, one pool should exist for each region. But, if possible, the entire country should be encompassed by a single pool, because the greater the diversity of dispatchable resources and potential buyers, the greater will be the opportunity for gains from trades. Many possible Type I models may exist, and design of the proper one for the Philippines should be made carefully.

6.37 Below is a summary of the features that are likely to be required in a Model I dispatch structure for the Philippines:

- The physical dispatch facility should be located on the backbone NPC transmission system;
- The rules of the dispatch entity should be regulated by ERB, just as are other practices of the transmission utility (Annex 8).
- The dispatch entity should normally be a not-for-profit corporation or a private association of users chartered to operate on a cost-only basis;[24/]
- Technical dispatch rules and rules governing daily and short term operations should be established by a Coordination Committee, consisting of experts nominated by all affected parties;
- Transactional accounting and billing system should be fully automated, and operated by rules also to be established by the Coordination Committee;
- The dispatch entity should be funded by all users in proportion to energy each transacts (and/or size of the user entity);
- The dispatch entity should be subject to ERB regulation, in which ERB would:
    - Propose and approve the dispatch rules as those affect conditions of trading among suppliers, rules for matching offers for purchase and sale, and related matters;
    - Assure that no economic rents are created by the dispatch rules or extracted by the dispatch entity;
    - Oversee the various activities of the technical Coordination Committee to assure compliance with the above two principles and resolve disputes;
    - Approve the budget of the Dispatch entity;

24/ Normally, the Dispatcher neither buys, sells, nor owns power. In the Philippines, the Dispatcher will need to be authorized to buy and sell power at cost, this to enable some IPPs to sell power at cost at cost directly to large 69kV non-utility consumers.

- Approve the rate charged by the Dispatch entity to the users, and assure that this is set only to recover the costs of the Dispatch entity.

6.38 Pending creation of this or a similar system, the present policy-modified Model II type structure will operate within the backbone transmission company. Several adaptations are recommended for immediate implementation. Plants should be dispatched in order of their technical efficiency (heat rates and ramp rates) and in order of economic efficiency. To accomplish this, mutually acceptable rules should be devised for allocating the rents created by imposing technical efficiency priorities for dispatch. These rules will assure that the allocation of financial risks of existing contracts is fully covered, and that the technical stability of the system and sound operation of all plants is preserved. This study suggests that a "preliminary technical Coordination Committee" be started immediately from among all affected participants with present contracts (IPPs, utilities, NPC, with DOE and ERB acting as advisors or observers). This committee would identify and solve the common implementation problems for the transitional phase, with ERB serving as the independent adjudicator. The preliminary Coordination Committee should assure that, until a true market develops or is created at the level of dispatch operations, the essential standard for all dispatch will be pure economy dispatch methods (Model III), with deviations only as justified by substantial reasons of policy. Those, too, would be adjudicated by ERB.

G. Summary of Recommendations

6.39 Now that the generation subsector has been radically altered by the participation of IPPs, the Government should encourage the rapid development of institutional arrangements for an effective enabling environment for the sale, transmission, and distribution of power. It can do so by (i) ensuring that regulation is clear and transparent, (ii) providing fair procedures in setting prices, (iii) allowing new producers entry into the market and access to the transmission system, (iv) enabling optimal system operations, and (v) enforcing fair and neutral operating and reliability standards.

6.40 The Government can readily grant the Board and management of NPC and its regional subsidiaries greater autonomy; and thereby permit them to increasingly operate on a commercial basis. In so doing, the Government should change (i) the accounting consequences for NPC of the Government's social policies mandating inter-regional subsidies and tariff differentials; (ii) the large volume of mandated subsidized blocks of consumption, and; (iii) supply subsidies to small islands and remote parts of the country. This study recommends that NPC not be required to bear the costs of these direct and indirect subsidies on its own books because doing so would result in distortions in prices and supply.

6.41 This study recommends that certain splits of authority between NEA and ERB be repaired, particularly as regards franchises and operating certificates. Specifically, NEA's franchise authority for electric utilities should be transferred to ERB.

6.42 Regulation in the absence of clearly articulated policy cannot be transparent. This study found that DOE's capacity for policy formulation and rulemaking needs to be improved and that this can be accomplished through institutional strengthening. Institutional development will permit ERB better-defined opportunities to establish clear regulations and interpretation of rules, as required by the needs of the sector. This study also recommends certain rulemakings on the Administrative Code Book, to establish priority order of DOE and ERB activities related to regulation.

6.43 ERB performs an important role as price regulator, one which has expanded and become more complex with the privatization of generation capacity and movement toward unbundling of tariffs. In addition, this study recommends that ERB is should assume direct responsibility over franchises and certification. Recognizing that these regulatory activities must be adequately funded, this study recommends that a special independent regulatory Fund be created, funded by users fees earmarked for this purpose.

6.44 Pricing of power remains problematic at all levels. At the generation level, PPAs should ensure an adequate fee structure, distinguishing between fixed (demand) and variable (energy) costs. This study recommends that greater attention be given to cost-based pricing (para. 6.18). The unbundling of fixed and variable costs within tariffs and disaggregation of rates can lead to greater efficiencies. These options should be pursued.

6.45 Taxation of fuels for power generations should be rationalized. NPC is currently exempt, so the IPPs have generally entered into fuel processing agreements wit NPC. In order to pass the fuel supply risk back to the IPPs, the exemption should be extended to them as well.

6.46 In order to encourage the cost-effective and flexible siting of IPP-sponsored power plants, DOE should develop an acceptable framework for wheeling charges over the transmission and subtransmission lines. This is also critical to the viability of the proposed new backbone transmission company.

6.47 At the wholesale level, pricing of power in the different regions should be permitted to reflect generation and transmission costs, instead of bearing the burden of subsidies and penalties for regional development. This change is needed to remove the disincentive that IPPs have to locating plants outside of Luzon.

6.48 At the retail level, the Government should support tariffs that differentiate between peak demand and energy charges. This is an important aspect of DSM; but more needs to be done. Specifically, tariffs that reflect the cost to NPC or its successors of stand-by capacity need to be developed and introduced. Without stand-by fees, self-generation will remain an attractive, implicitly subsidized, alternative to purchase from the grid, and will continue to remain a random component of forecasted power supply and demand.

6.49 The extended periods during which IPPs have searched for financing has introduced considerable uncertainty and risk for the purchasers. As part of accreditation reform, DOE should improve its ability to investigate the creditworthiness of IPPs. DOE should develop and implement improved accreditation processes for new PPAs and charge fees collected from bidders and prospective bidders to improve data collection about financing applications and improve analysis of them.

6.50 As numerous IPPs' power plants come on line, they will compete with established power generation capacity from NPC's (or its successors') plants. A fair, efficient, and effective dispatch system is needed to regulate the load, and assure all parties that their ability to sell power to the grids and to large consumers reflects their commercial ability. This study recommends that as part of the unbundling of NPC and the establishment of a backbone transmission company, dispatch models be investigated immediately.

6.51 This study further recommends that the dispatch entity created, whatever dispatch model is followed, quickly establish its technical readiness to develop rules and procedures for dispatch. These rules should fairly reflect the structure of existing PPAs, and be based on well placed

confidence in the technical and regulatory readiness of the dispatcher to serve the interests of the public as well as the power generators. This study recommends that a preliminary technical committee be developed, with representatives of the power sector, public and private. This Committee should develop and propose procedures for dispatch, to be carried out by the transmission company.

7. Regulatory Issues

A. Introduction

7.1 The regulatory structure of the Philippines has evolved over ninety years from turn-of-the-century North American state antecedents; the most recent reform of that structure occurred in December 1992 in connection with the Department of Energy (DOE) Act (para 6.8). Additional changes are still needed for the system to be capable of meeting the challenges of the next twenty years. DOE must increase its effectiveness as the policy-making body for the sector, as envisioned by present law. ERB should be the body which drives distribution sector reform by consolidating under it the authorities to award franchises, issue certificates, and regulate service, quality, and prices. NEA needs to become more focused on its duties as an interested lender for much of the distribution sector, rather than as a regulator.

7.2 NEA had carried out its statutory and regulatory functions effectively through December 1992 when the DOE Bill was enacted and reallocated certain regulatory functions from NEA to ERB. The discussion below seeks to create the conditions for effective compliance with the letter and intent of the new law.

B. Summary of Regulatory Issues

Institutional Conflicts of Interest

7.3 Regulators should have no direct part in the operation, administration nor planning of the business operations they affect. This suggests two changes in the present regulatory structure. The Chairman of the NPC is also the Secretary of Energy and hence the person ultimately responsible for policy at DOE; this apparent conflict will need to be allayed in the context of the reorganization and concomitant corporatization of NPC. Also at present, the NEA is an interested lender primarily for the coops, and it has the scope to lend to the IODs; however, NEA also serves as a regulator with authority over franchises for both the coops and the IODs.

7.4 Under the 1992 reorganization, ERB was given authority over price and service quality of public service entities, but NEA retained authority under PD259 Section 43(b) to decide certain cost allocation issues and other terms and conditions of service among such entities. Essentially all of these conflicts of interest and similar problems cited should be resolved by the transfer of franchise powers to ERB. This change is critically important from a regulatory perspective. At present, ERB is responsible for regulating service quality and price, but its capacity to make tough decisions is hampered because it lacks the ability to place conditions on franchises and certificates. This issue will need to be addressed by legislation (See Annex 8). If ERB were given authority over both franchises and certificates it could become the primary driver of distribution subsector reform.

IPP Regulation

7.5 IPPs do not presently face price regulation in the Philippines; at most, the IPPs must meet pre-bid certification requirements when acting as cogenerators under EO 215, or as independent power producers under the BOT Law or as exceptions to PD 40. However, with the proposed devel-

opment of a market for wheeled electricity between the IPPs and multiple purchasers, the IPPs may be at risk to being declared "utilities" and thus subject to price regulation and foreign ownership restrictions. The Philippine Constitution constrains ownership in public utilities to at least 60 percent domestic shareholdings. IPPs with less than this threshold of local ownership can operate now because Philippine law (as interpreted by DOJ Opinion No. 95 of 1988) classifies entities as "utilities" only when they hold out service to "the public"; whereas, to date, the IPPs have only held out service to the NPC (or with dispensation) to MERALCO. To avoid this issue in the future, this study proposes that the dispatch entity will be a legal intermediary, constituted as part of the transmission utility. It will be subject, because of it own price-responsive rules of operation, to ERB regulation under present law. Nonetheless, all aspects of dispatch rules can be embodied in statue (Annex 8, A8.2, Section 3 (C)).

Form of Price Regulation, Including Price-Caps and Benchmarks

7.6 Electric energy price regulation is the responsibility of the ERB. Present price regulation is a form of cost-of-service regulation in which rate of return is capped by legislative policy through the utilities' Congressional charters. These charters limit MERALCO and other investor-owned utilities to a maximum rate of return of 12 percent, and NPC to a maximum of 10 percent. NEA has a target policy of 20 percent internal cash generation for the coops. Present ERB regulation uses elements of traditional cost-of-service (rate-of-return), energy, and incentive rates. Therefore, present ERB regulatory methods are usually the same set of techniques that best suit Philippine conditions, current and foreseeable. This study specifically endorses continued ERB use of the above "American Style" methods. Current practices can be adapted to price-cap and other methods as needed, and indeed already have been (para. 6.18).

7.7 This study specifically considered more extensive use of "price-cap" regulation as a necessary part of a restructuring proposal and considered this approach to have at best limited application in the Philippines. Most new and some existing generation is currently unregulated, except by process; and energy may be priced eventually by market devices upon implementation of a proper dispatch procedure. Price-cap regulation would therefore create less market oriented pricing devices than already exist. Regulating the IPPs in order to create price-cap regulation would thus reduce the competitiveness, with uncertain benefits.

7.8 Transmission is not a good candidate for price-cap regulation either, because there is only one transmission entity, (either NPC or the proposed national backbone transmission company), which would retain its natural monopoly even after transmission is unbundled from other services and prices. Under these circumstances, the effect of price cap regulation would simply be to permit revenue reallocation by the transmission company from its more elastic customers to its less elastic ones. While there are pricing problems in transmission, marginal cost based two-part rates for transmission will create less distortion than price-cap regulation.

7.9 Only the distribution subsector may develop in such way that price-cap regulation could be useful. Electricity wheeled over the lines of the local distribution company to large consumers would be in direct competition with the distributor's own sales of power and energy. In this situation, the rates of the distributor to the wheeling customers may be set by price-cap regulation methods. This would permit the distributor, the locally dominant seller holding the franchise for the area, to meet competition using flexible prices, while also assuring competitive entry for power and energy services. However, in setting price-caps, discounting from the cap should be at the risk of the distribution company, and not simply a device to reassign revenue recovery to other less elastic customers (residential and smaller commercial and industrial customers) without access to other,

competitive supply sources. In the Philippines, this form of price-cap acts as a form of incentive rate making. The statutory limit forms an effective benchmark against which each company must continually compte.[26/]

7.10 In many past cases, the Bank and various Philippine bodies have agreed to use marginal cost type rate design methods. This agreed pricing structure has not been implemented, especially at the distribution level. More rational pricing is discussed in Chapter 6 (para. 6.18).

Role of Competition

7.11 The previous paragraphs enunciate this study's conclusions that price regulation best serves the public interest, including the interests of consumers, producers and distributors, by assuring that competition can work as effectively as possible, wherever competition is possible. As a matter of general principle, both DOE and ERB should use their powers to create conditions of entry wherever technology makes possible competitive entry for any previously regulated service. Where competition can set the price for any service or commodity, regulation should permit it to do so. Therefore, even where regulators are required by law to set prices, they should assure that price structures reflect the same kinds and levels of price differences as would occur in competitive markets. Reaching this objective in the Philippines is complex because there is no national law, such as an antitrust law, reflecting a statutory commitment to competition policy. Therefore this study also proposes regulatory methods (Annex 8) which in part create a competition standard under which ERB could regulate entry. DOE can already use policy powers to issue appropriate rules on the structure of the industry. ERB can already exercise rate-making powers in a manner that requires proof of conditions of competition as part of its normal rate making processes; ERB could permit market-determined prices so long as these meet other statutory standards.

Use of Generic Rules

7.12 ERB should also establish, by generic rule, a reasonable time limit by which it will complete each case review and issue a final order. ERB should use generic rules to create automatic adjustment clauses for proper applications, such as for fuel costs for coops. Rulemaking will be also very important in the exercise of DOE policy functions. However, Philippine Administrative Code language as applied to DOE rules is potentially vague. The weaknesses of the Code language will become more important as use of rulemaking increases. Therefore, DOE should issue a rule which defines in more detail the form of rule process that DOE will use. This rule should at least state the time-frame by which DOE will issue policies, and the timing and medium for receipt of public comment (para. 6.12).

C. Independent Regulatory Fund

7.13 The judicial independence of ERB is especially important. Most countries and jurisdictions have found that the best way to achieve this both in appearance and in fact is through use of dedicated sources of revenue, from which the ERB budget would be appropriated by Congress. This Fund could be created in the Philippines by simple modifications to existing laws because part of the mechanism is already in place. ERB presently recovers a statutory fee of 50 centavos per 100 pesos

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26/ It may be better than a purely regulatory determined incentive, since the regulator can not easily give relief to the company which fails to meet the incentive condition.

of issued capital, plus other minor fees and penalties, which together yield about ₱24 million annually. The annual budget of the ERB is currently about ₱45 million pesos divided roughly equally between staff salaries and other costs (see also institutional development discussion below). But, there is currently no connection between these two figures. Fees go to general revenues. The budget of the ERB is appropriated by the Congress, from general revenues. To create a Fund, it is only necessary to form this link: these fees and other similar fees including a small per kWh users fee charged on all energy transacted, should be set aside in a separate Fund from which expenses of the ERB would be appropriated by Congress. A legislatively created, annually appropriated, wholly dedicated ERB Fund would thus be easily created.

7.14 In other jurisdictions, such a Fund is derived from users fees, typically applied to all energy sold or wheeled by all utilities, and subject to the jurisdiction of the commission. Fees would be based on the total cost of regulation per annual kWh. Also, specific regulatory costs for the review of a particular case might be charged to the utility, particularly for filings initiated by the utility at its own option. Other fees might be charged for filing specific applications by jurisdictional utilities; those fees would be related to the general administrative cost of the agency for processing the specific application.[27/]

7.15 All fees collected according to by any of the above charges would be paid into the Fund (which might however be collected by the regulator in behalf of the Fund). The cash inflows into the Fund would be considered state revenue, and therefore would need to be appropriated by the Congress. Thus, the annual budget of the regulator would be appropriated in very much the same way as the budget of any other agency, with certain differences: (i) no expenses incurred with regard to utility regulation would be paid from general revenues or taxes; (ii) appropriations from the Fund would be only for the budget requirements of the regulatory body, not for other uses or general revenue purposes; and (iii) since the Fund is accumulated from dedicated users fees, amounts collected in one year and not expended by ERB would be retained in the Fund for appropriation to ERB in future years. A proposed statutory definition for this Fund is given in Annex 8.

D. Regulatory Institution Development

Department of Energy Policy Development

7.16 DOE needs to strengthen its own capabilities. As a first stage, the office of the Undersecretary for Policy needs to be expanded. That office needs at least five staff (plus clerical support) with qualifications to think strategically about energy development issues and about institutional capability. This staff needs to be recruited at the earliest opportunity. As soon as possible thereafter, DOE needs to consider how to create rule making and oversight capabilities within the policy office.

7.17 Much DOE policy will be promulgated through rulemakings. DOE staff will need to analyze technical issues in depth, to conceive and decide among alternative approaches, then to state preferred approaches as proposed rules; publish these rules as drafts for public comment; and subsequently consider the public comment and incorporate such into a final revised rule. Given the range of topics on which DOE is required by law to "assist" (Annex 6, Table 3), this active policy devel-

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27/ However, filing fees are typically not assessed to intervenors nor to those filing complaints against utilities.

opment staff will need to be much larger than the five core persons supporting the Undersecretary directly.

7.18 The policy office also requires some means of oversight. The oversight function would not be prosecutorial, but rather an adjunct to creating and implementing policy. Since ERB, not DOE, has enforcement powers, DOE oversight capability must be developed with this separation of authority in mind. DOE oversight staff should be able to (i) review and understand filings made before ERB, (ii) participate (as an intervenor or oppositor) in cases at ERB when necessary to state DOE's views; and (iii) initiate cases before ERB (such as by formal complaint or petition) to cause enforcement of DOE policy on entities over which ERB has proper jurisdiction. When appearing in ERB proceedings, DOE could recommend (a) concrete actions by utilities or (b) specific forms of Orders which ERB could issue, usually with forward-looking application. DOE could participate in filings (such as rate cases) initiated by other parties, or could itself initiate proceedings by formal application. DOE could also use ERB processes to effect some or even all DOE rulemakings by proposing the desired DOE rule in the form of a complaint to be heard by ERB. In matters of price policy where ERB not DOE has original jurisdiction, application for a proceeding at ERB may be the only way DOE could effect policy.

ERB Institutional Development

7.19 ERB's duties and powers recently expanded to include price regulation of NPC and some 120 small distribution cooperatives, all without staff growth or appreciable staff development. ERB will require significant additions to staff to meet these new responsibilities and also to review DOE's policy rulemakings and make its own rules implementing DOE policies, particularly those related to franchising generally and distribution system reform in particular. ERB has requested institutional development, training assistance, and immediate consulting support to address duties added to ERB's responsibilities under earlier changes in Law without commensurate increases in staff numbers or training. This assistance is seen as intermediate steps while ERB builds direct staff capabilities. USAID has also made specific recommendations for training and staffing. Annex 5 provides details of the requested assistance and also contains an analysis of ERB staffing and its functional relations to the additional responsibilities attendant to the reforms proposed in this study. Singly and cumulatively, ERB development needs should be addressed as a priority item. In particular, ERB will need to recruit an adequate number of suitably qualified staff and then assure the proper training for them.

E. Summary of Recommendations

7.20 The regulatory structure of the Philippines power sector needs to be rationalized, so that it can be effective in dealing with changes that have already taken place in the sector. Three types of changes must be addressed and effectively dealt with through changes in regulation: (i) a rapid increase in IPP involvement in the sector, placing new and greater demands on regulators; (ii) legally mandated organizational shifts of responsibilities among the agencies; and (iii) future structural changes in the power sector, required to enable the sector to complete its current course of reform. DOE, ERB, and NEA need further restaffing and reorganization so that regulation entrusted to the Department and agencies can be effectively and expeditiously conducted by adequate and appropriately trained staff, and without conflicts of interest.

7.21 Legislation should be introduced to relieve NEA of its role in franchising of coops and the IODs, and to give ERB consolidated authority over both franchises and certificates. Together with this transfer of authority, must come adequate staffing and further training for ERB to fulfill its increased regulatory function. The proposed new legislation should enable NEA to transfer its rates staff to ERB. ERB has requested, and this study recommends, that the Board immediately institute thorough programs of institutional staff development and increased technical support. These actions should have the effect of relieving NEA of current conflicts in its role as both lender and quasi-regulator, while consolidating ERB's legal and technical authority.

7.22 This study examined the role of price-cap regulation and found it to have limited usefulness in the Philippine context. This study found that a better approach would be to facilitate market price regulation, by encouraging the structural reform of the transmission system (para. 5.24), establishing an unimpeachable system of fair dispatch for the many various suppliers, and regulating unbundled transmission charges on energy freely wheeled through the transmission system.

7.23 This study recommends that ERB can best maintain its effectiveness and independence through adequate and reliable funding. A sound means of achieving these ends would be the establishment of an independent regulatory Fund, with dedicated sources of revenue: fees and charges for services in proportion to the reliance by energy producers and wheelers on ERB's regulatory services. The Fund should be established by statute and should be to meet ERB's recurrent expenditures for power regulation.

7.24 This study has confirmed that DOE is authorized to play a major role in the formulation of power sector policy and rulemaking, but that it lacks adequate staffing to carry out its duties effectively. This situation will become more serious as the sector emerges from the recent crisis, and strategic planning for efficient development becomes more important. Therefore, DOE's capacity for policy development should be enlarged and the Department should be furnished with staff appropriate this role.

PHILIPPINES

SUPPLY AND DEMAND ASSUMPTIONS

Power Outages

1. The power crisis of 1991-93 seriously threatened the economic recovery of the Philippines, and resulted in economic losses of about US$1 billion per year during that period. Power shortages caused substantial outages — four to eight hours per day in Luzon and up to 10 hours in Mindanao, where power sales declined by one-third. These outages hampered industrial and commercial and contributed to rising unemployment. Root causes were the near the lack of additional or replacement power capacity between 1986-92, stemming from lengthy delays in securing the environmental approvals and social consensus for new power plants, slow procurement procedures by the National Power Corporation (NPC), and the mothballing of the country's sole nuclear power plant. Effective power capacity was further reduced by inadequate maintenance and rehabilitation of several thermal plants, damage to two important dams, and a record drought that reduced hydro generation to 20% of normal levels.

2. In response to the power crisis, the Government moved to rapidly increase generation capacity by approving a "fast track" power supply program, based on new capacity financed and operated by the private sector under build-operate-transfer (BOT) contracts. This program has been very successful in addressing the power crisis, as about 15 new plants will be operating by the end of 1994. However, many of these plants are gas turbines or diesel units, which entails a trade-off of their initial low cost and fast installation for their comparatively expensive operating costs. There is still considerable investor interest in building additional power plants. A key question addressed in this analysis concerns the capacity that would be prudent for NPC to contract in the near future.

Demand Side Management

3. In a further response to the power crisis, the Government has initiated several programs to reduce power demand, including: (a) introducing demand charges; (b) encouraging commercial and industrial consumers to use energy-efficient lamps; (c) replacing inefficient street lights; (d) requiring energy audits of large industries; (e) setting efficiency standards for various electric appliances; and (f) conducting conservation campaigns, particularly for lighting and air conditioning. Most of these actions are in the early stages of implementation, and their effect is unproven. They do comprise a part of a cost-effective DSM policy and set of programs which the Asia Alternative Energy Unit is asisting DOE in developing, including training and other technical assistance. Over the long term, cost-effective DSM measures could complement conventional supply alternatives.

NPC's Power Development Program

4. NPC annually updates its demand forecast model based on statistical analyses of population, industrial and commercial growth, surveys of major utilities and industries, and the Government's estimate of GDP growth. The demand analysis is included in NPC's Power Development Program (PDP), which determines the least-cost generation expansion program using the WASP model to define an optimal sequence of plant additions. The PDP details the generation and transmission systems the regions, transmission grids and independent island systems. In the past,

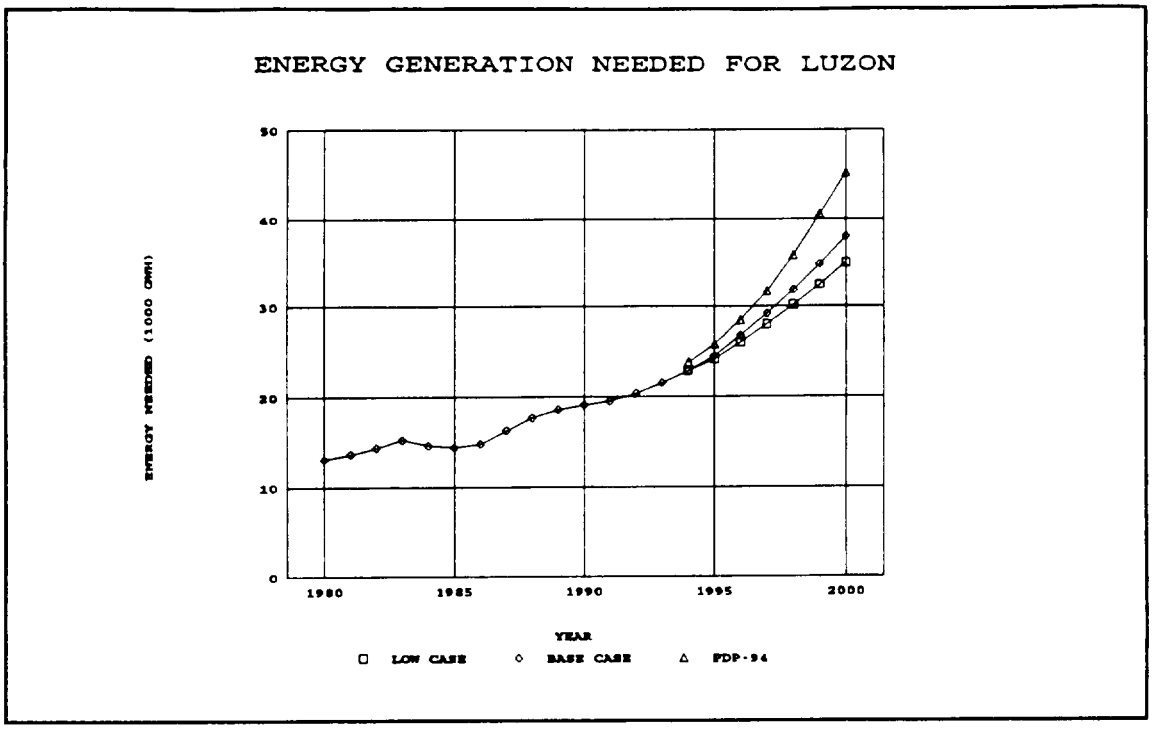

Figure 1

the implementation of the PDP was delayed by NPC's lengthy procurement process and the delays associated with securing environmental and public approval for new plants (even after financing was in place).

Table 1 - Power Demand Summary

Year	LUZON			VISAYAS			MINDANAO			TOTAL		
	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW	Sales 1000 GWh	Generation 1000 GWh	Peak Demand MW
1990	17.64	19.10	3023	1.87	2.05	494	3.73	3.96	621	22.9	24.7	3974
1992	18.88	20.37	3250	2.25	2.49	622	4.24	4.46	725	23.8	25.6	4186
1994	21.13	22.84	3693	2.88	3.20	705	4.70	4.97	811	28.7	30.8	4937
1996	24.73	26.73	4286	3.52	3.91	851	6.00	6.38	1038	33.9	36.3	5830
1998	29.50	31.89	5128	4.26	4.63	1010	7.66	8.15	1329	40.4	43.2	6858
2000	35.20	38.05	6102	5.15	5.60	1201	9.52	10.13	1648	48.1	51.53	8262

5. The Bank's forecast GDP growth rate for the Philippines is 3% for 1994, 5% for 1995 and 5.5% thereafter, much lower than the National Economic and Development Authority's (NEDA) targets of GDP growth rate for the years 1994 of 4%, 7.7%, 8.2%, 8.8% and 10% for 1995-98[1/]. The Bank forecasts GDP growth of 30% in the period 1994-98, just over half the 55% increase assumed by NEDA. All of these growth rates, however, are much higher than the average 2% p.a. achieved during the last

1/ NEDA is now reviewing and it is likely to reduce the GNP targets.

ten years. Regardless, NPC is required to use NEDA's targets for its forecast of electricity sales in the preparation of the PDP.

6. The PDP for 1993 projects higher power growth rates for Visayas and Mindanao, increasing their proportion of NPC's total sales from 25% to 30% by the year 2000, and reducing sales to Luzon correspondingly. However, this pattern is inconsistent with the experience of the last 15 years, in which Luzon's share of total sales has remained stable at 75%. There were no compelling reasons to support drastic changes in growth assumptions as proposed by the 1993 PDP, and the 1994 PDP is more moderate in its forecasts. Moreover, the high demand elasticity observed in the past in Visayas and Mindanao was due to the promotion of high energy-intensive industries (PASAR, National Steel, etc.), when power was abundant and inexpensive. This is no longer the case.

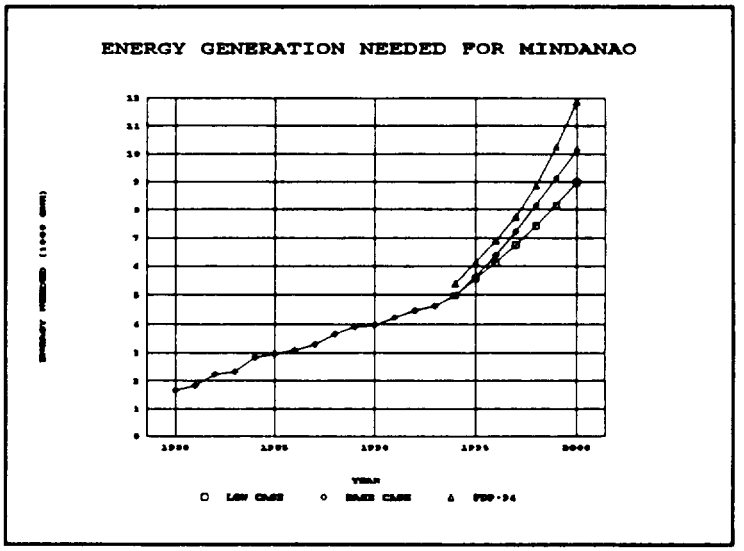

Figure 2

Sales Forecast

7. The forecast demand scenario by the Bank (Table 1) assumes a GDP elasticity ratio[2/] of 1.3 for Luzon (as used by NPC) and ad hoc forecasts for Visayas and Mindanao based on existing demand trends in those regions. The key assumptions are presented in Tables 3 and 4. Under this scenario, energy sales for Luzon in 1998 will be 29.5 TWh, 40% higher than the 21.1 TWh for 1994. (Figure 1 and Table 4). For Visayas, energy sales are expected to increase 47% between 1994-98, from 2.88 TWh to 4.25 TWh (Figure 2 and Table 6).

8. For Mindanao, energy sales are expected to increase 62% between 1994-98, from 4.70 TWh to 7.66 TWh, reflecting the elimination of large outages (Figure 3, Table 7). During the same period, total power sales in the Philippines are forecast to increase 44%, from 28.7 TWh to 41.4 TWh (Figure 4 and Table 7).

9. The differences in sales forecasts for each region are shown in Figures 1-3. The lower demand used in this report results from the following factors: (a) lower GDP growth rates; (b) price elasticity due to required tariff increases of about 10% during the period 1994-98, as required for NPC to achieve the 8% rate of return agreed with most financiers; (c) energy conservation efforts; (d) self-generation by industrial and commercial consumers; (e) the implementation in the second part of 1994 of demand charges and the resulting incentives for industries to use their own generation sets during peak hours; and (f) the planned reduction in losses of the power utilities (implementing the ERB's directives). In addition, the unplanned contracting by the private utilities could duplicate the available capacity and reduce the utilization of the plants contracted by NPC.

2/Ratio between the power demand and the GDP growth rates.

10. The above factors create considerable uncertainty in power demand. For instance, substantial overcapacity, particularly under take-or-pay conditions, would require considerable tariff increases that would be unpopular with the public. On the other hand, power shortages and outages like the ones experienced in 1992-93 would result in huge losses for the economy, many times the cost of the respective investments. Therefore, it is critical that DOE and NPC closely monitor (i) power demand, and particularly NPC's sales; (ii) IPP contracting by the distribution utilities; and (iii) DSM success.

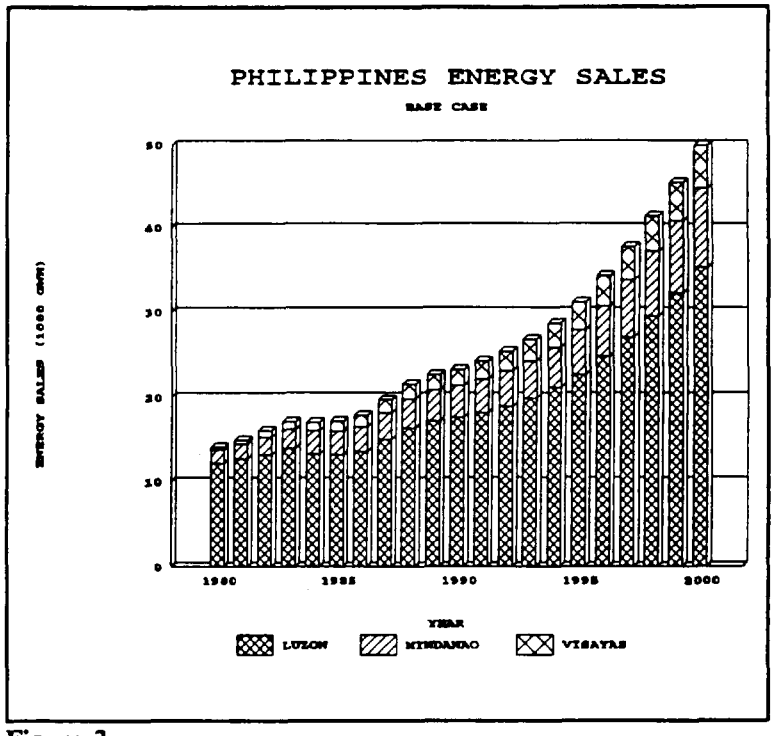

Figure 3

Power Generation and Peak Demand

11. Total energy losses within the NPC system average about 7%, of which transmission losses are just 3% to 3.5%, and 3.5%-4% stems from the in-plant use, which is commensurate with the substantial requirements for auxiliary power for thermal generation. At present, MERALCO and the coops are attempting to reduce distribution losses, and some of their actions are succeeding. However, additional efforts and investments are needed to reduce technical losses at the distribution level even further.

12. Using Bank forecasts, power generation would increase from 30.8 TWh in 1994 to 43.2 TWh in 1998 (Table 9). Peak demand would increase by 2,200 MW between 1994 and 1998 (1,450 MW in Luzon) and 3,600 MW between 1994 and 2000 (2,410 MW in Luzon). In its PDP for 1994 (March 1994), NPC revised downward its forecast power sales, but they are still higher than the Bank's estimates, resulting in demand increases of 9% p.a. between 1994 and 1998 (an addition of 3,300 MW to xits peak demand) and 10.2% p.a. between 1994 and 2000 (5,570 MW). The corresponding values for Luzon are 8.6% p.a. between 1994 and 1998 (an addition of 2,435 MW to peak capacity) and 9.6% p.a. between 1994 and 2000 (4,000 MW). In this report, these values comprise a high estimate of power demand, depending as they do on presumed high GDP growth rates. The difference in total peak capacity would be about 12% in 1998 and 20% in 2000.

13. New plants and the restoration of capacity through rehabilitation of existing ones are expected to end outages by mid 1994. Based on NPC's investment programs for projects already committed or under implementation, the dependable capacity for the Luzon grid is expected to grow as shown Table 2 and Figure 6. The generation capacity shown is the estimated reliable capacity, based on the performance of each plant, and its expected derating or rehabilitation over time. Details on each of the existing and planned plants in the Luzon grid are shown in Table 10. (On average, the reliable capacity is about 25% lower than the name plate capacity.) Although NPC plans to retire two large thermal plants by 1998 (Manila 200 MW and Sucat 350 MW), and this has been assumed in the forecast,

costs and benefits of doing so must be analyzed further. Replacing these plants is likely to be expensive (given the new stricter emissions standards) and difficult (given the problems in securing sites for power plants).

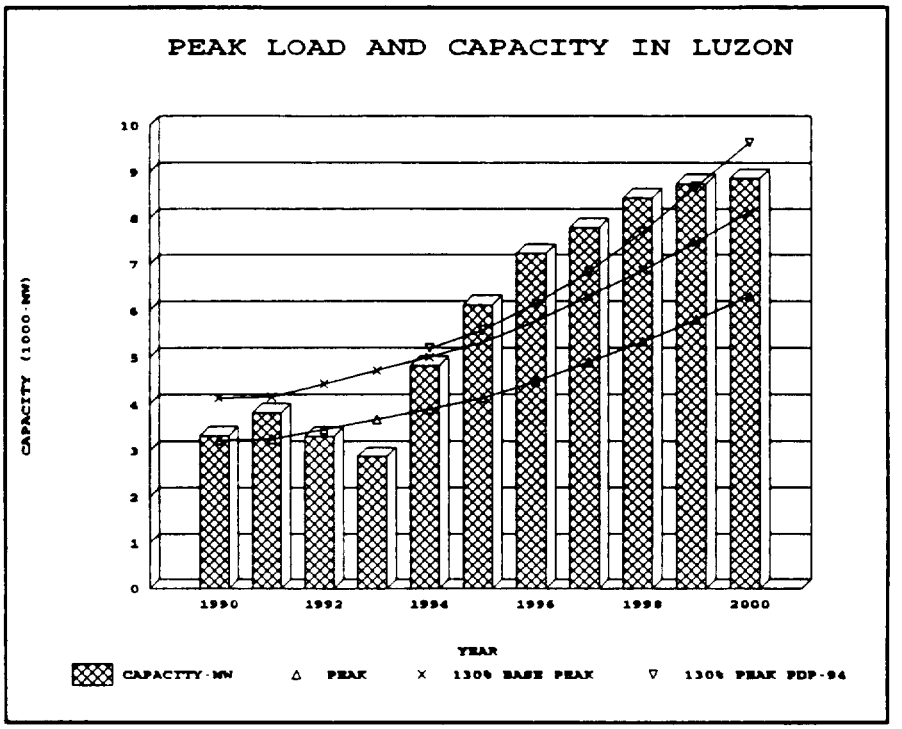

Figure 4

14. While NPC has expanded its own capacity, some private utilities and large industries have simultaneously signed contracts with IPPs. However, it is very difficult to assess the likelihood all projects will reach fruition. Further delays of two to three years are also possible, even after obtained financing, due to environmental or community acceptance problems (as happened with the Masinloc and Calaca II coal plants).

Private Sector Participation

15. NPC has delegated responsibility for thermal power generation to the private power, mainly through BOT and BTO contracts, but also through several contracts for the rehabilitation, operation and management of existing power plants. There are 33 of these contracts (see Annex 2), for a total capacity of 5,360 MW (4,600 MW in Luzon, 460 MW in Visayas and 300 MW in Mindanao). By 1999, these contracts will represent about 80% of NPC's incremental capacity and about 58% of its total.

IPP Contracts

16. Total IPP capacity awarded or accredited for Luzon alone (excluding NPC's BOTs or power plants under construction) is about 3,500 MW, which would double the reliable power generation capacity on Luzon if it were all to materialize. (In addition, about 1,600 MW of generation sets have been imported by individual companies with BOI approval). Recently, problems with insufficient equity or financing have prevented several awarded and accredited BOT contracts from becoming effective. In most cases, these awards have to be canceled and replaced by other companies. For contracts which are not effective, a probabilistic approach has been followed to estimate the expected capacity. (Large contracts awarded by MERALCO, not yet effective two or more years after signing, constitute a large part of the total uncertainty of future supply.) The capacity from IPPs is estimated at about 1,000 MW by 1998, but this could substantially change if IPPs for some large plants (Magelan 600 MW, Luzon Power 400 MW Cavite Energy 330 MW, etc.) are not able to obtain close on financing. Several BOT projects being considered by NPC are also uncertain and have been assigned low probabilities for completion.

Energy Demand and Capacity

17. An adequate reserve capacity for NPC would exceed 30% of its peak load, given the unreliability of its old plants and inability of the backbone transmission system to wheel electricity among the regional grids. Required reserves would depend, among other things, on the rain cycles, the fraction and usefulness of plants nearing retirement age, changes in power demand and the likelihood of construction delays. All of these are only unreliably predictable. However, the system should, in other ways, become more reliable. Due to the substantial increases in capacity in recent years, the average age of NPC power plants decline from more than 18 years currently to about seven years by 1999. Moreover, a substantial number of these plants would be operated and maintained by diverse private operators, which fact is expected to facilitate the provision and effective use of spare parts, reducing non-productive maintenance periods. Overall expected capacity changes will be dramatic. During the 1993 power crisis, NPC had a net capacity deficit in Luzon of about 800 MW. By end-1994, the addition of new plants and the rehabilitation of older plants will result in a normal power supply, adequate reserves, and adequate energy generating capacity. (Gas turbines and diesel plants, due to their high operational costs, are normally used at load factors below 15%. However, they can be used at higher load factors, as they have been during 1993, thereby increasing the total energy generating capacity.)

Reserve Capacity

18. Under the base case demand forecast, there is a high probability that installed capacity will exceed peak demand by more than a third. The risk of overcapacity would result from NPC's timely completion of projects by 1998 (including Calaca II, Leyte-Luzon, Masinloc, Pagbilao and Sual); and fully commissioned IPP contracts with distribution companies, which output NPC does not consider in calculating its own supply requirements. NPC itself expect to add almost 4000 MW in Luzon (see NPC's PDP in Annex 3). The total reserve capacity is forecast at about 2700 MW (about 56% of the peak demand, Figure 7), even with the retirement of the Manila 1-2 plants. Capacity in excess of the peak demand plus a nominal 30% is shown in Figure 7.

Table 2 - Dependable Power Capacity in Luzon

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Oil	1523	1555	1465	809	1204	1495	1466	1437	1408	1013	744
Diesel and CC	0	0	0	157	911	1164	1161	1157	1137	806	757
Hydro	1119	1035	648	518	813	838	853	903	953	1298	1296
Geothermal	559	561	571	547	775	860	852	867	1139	1386	1375
Coal	116	245	245	250	246	381	1167	1376	1662	2792	3971
Gas	0	420	401	520	673	670	667	663	660	657	654
TOTAL THROUGH NPC	3317	3816	3329	2800	4621	5408	6165	6404	6959	7952	8797
Total Indep. Suppliers	0	0	0	0	141	303	746	1077	1140	1142	1140
TOTAL CAPACITY (MW)	3317	3816	3329	2800	4762	5711	6911	7480	8098	9094	9936

19. With construction periods of two to four years for thermal plants, the investment decisions currently under consideration pertain to power plants that would not be operational until 1999. From the above analysis, it is clear that sufficient capacity has already been awarded or purchased for Luzon, but there is still some uncertainty concerning implementation. Consequently,

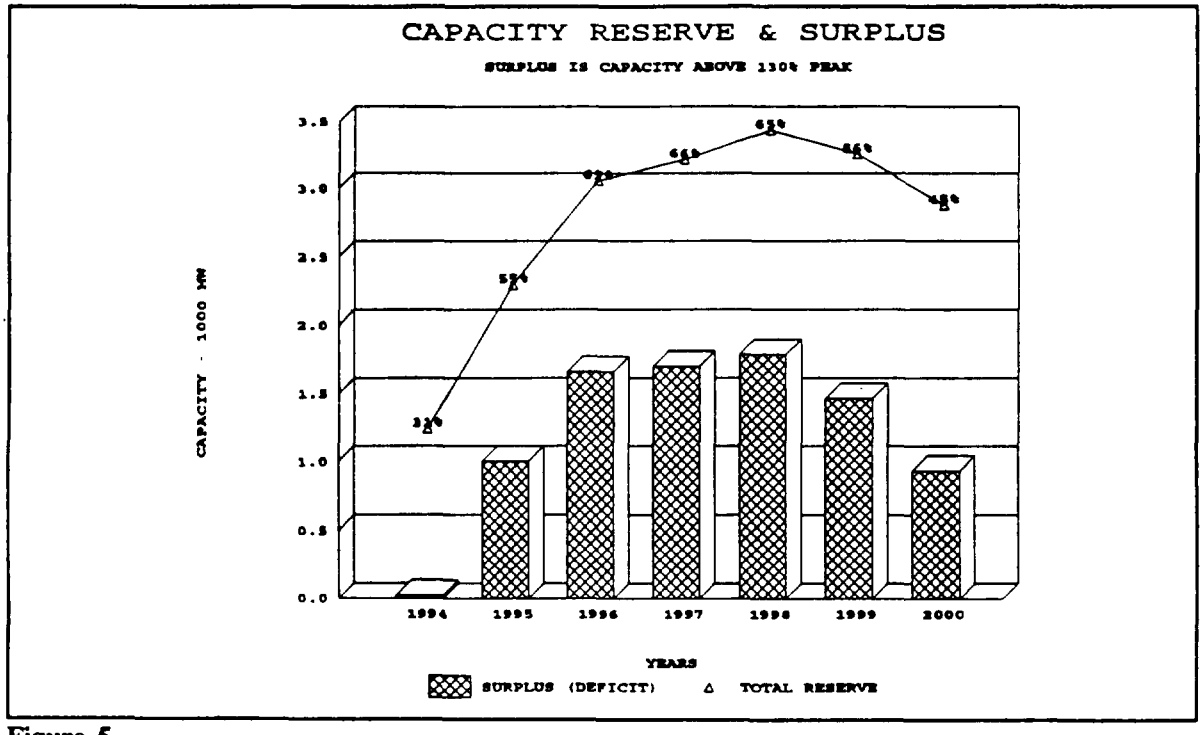

Figure 5

those decisions concerning plants to be operational after 1999 (or additional take-or-pay contracts) can be postponed until early 1995, when a revised Master Plan and PDP will be completed by consultants contracted under an ADB grant. Although less critical, it is also important to monitor proposed power plant expansions in Visayas and Mindanao by NPC and private investors, to avoid the risk of overcapacity under take-or-pay contracts.

Philippines

NPC's Power Demand

Table 3 - Gross Domestic Product and Power Demand

YEAR	GDP 1985 Prices (Billion Pesos)	% Increase	POWER SALES 1000 GWh	OF WHICH LUZON SALES 1000 GWh	POWER RATE CONSTANT PRICE	POPULATION Million Persons Mid-Year	POPULATION GROWTH	KWh Per Person (For Total Population)	Energy Intensity GWH per Million P. GDP (1985 Prices)	--- % INCREASE p.a. --- Power Sales	Power Rates 1985 Prices	KWh per Person
1979	579.50		12.55	11.21	1.04	47.04		267	21.7			
1980	609.77	5.22%	14.03	12.16	1.37	48.10	2.3%	292	23.0	11.8%	30.9%	9.38%
1981	630.64	3.42%	14.92	12.69	1.47	49.54	3.0%	301	23.7	6.3%	7.6%	3.22%
1982	653.47	3.62%	16.00	13.13	1.38	51.28	3.5%	312	24.5	7.3%	-6.4%	3.60%
1983	665.72	1.87%	17.09	13.91	1.69	52.06	1.5%	328	25.7	6.8%	22.5%	5.22%
1984	616.96	-7.32%	17.01	13.25	1.70	53.35	2.5%	319	27.6	-0.5%	0.6%	-2.90%
1985	571.88	-7.31%	17.14	13.14	1.70	54.67	2.5%	314	30.0	0.8%	0.5%	-1.64%
1986	591.42	3.42%	17.65	13.46	1.49	56.00	2.4%	315	29.8	2.9%	-12.5%	0.49%
1987	619.71	4.78%	19.34	14.72	1.36	57.36	2.4%	337	31.2	9.6%	-8.8%	7.01%
1988	658.46	6.25%	21.18	16.08	1.29	58.72	2.4%	361	32.2	9.5%	-4.8%	6.98%
1989	698.38	6.06%	22.24	16.80	1.17	60.10	2.3%	370	31.9	5.0%	-9.3%	2.62%
1990	717.26	2.70%	22.92	17.37	1.25	61.48	2.3%	373	31.9	3.0%	6.6%	0.70%
1991	712.26	-0.70%	23.60	18.12	1.40	62.87	2.3%	375	33.1	3.0%	11.6%	0.70%
1992	712.33	0.01%	23.84	18.63	1.47	64.26	2.2%	371	33.5	1.0%	5.6%	-1.18%
1993	726.58	2.00%	25.06	18.63		65.65	2.2%	382	34.5	5.1%		2.90%
1994	755.64	4.00%	28.71	20.87		67.04	2.1%	428	38.0	14.6%		12.21%
1995	793.42	5.00%	31.03	22.24		68.42	2.1%	453	39.1	8.1%		5.89%
1996	837.06	5.50%	33.87	24.14		69.80	2.0%	485	40.5	9.2%		7.00%
1997	887.29	6.00%	36.98	26.19		71.17	2.0%	520	41.7	9.2%		7.07%
1998	940.52	6.00%	40.37	28.43		72.54	1.9%	557	42.9	9.2%		7.13%
1999	1001.66	6.50%	44.08	30.85		73.89	1.9%	597	44.0	9.2%		7.19%
2000	1066.76	6.50%	48.14	33.48		75.22	1.8%	640	45.1	9.2%		7.26%
2001	1136.10	6.50%	52.36	36.33		76.54	1.8%	684	46.1	8.8%		6.89%
1980-85	-1.3%		4.1%			2.6%		1.4%	5.4%			
1985-90	4.6%		6.0%			2.4%		3.5%	1.3%			
1980-1990	1.6%		5.0%			2.5%		2.5%	3.3%			

Philippines

Table 4 - Main Assumptions for Power Demand

	Actual					Assumptions				
Period:	1990/85	1992/87	1991/90	1992/91	1993/92	1994/93	1995/94	2000/95	2005/00	2010/05
LUZON:	% Growth Rates									
Low Case						9.00%	5.10%	7.02%	7.02%	7.02%
Base Case	5.74%	4.82%	4.34%	2.80%	0.00%	12.00%	6.60%	8.52%	8.52%	8.52%
High Case						15.90%	9.66%	12.16%	9.24%	10.02%
Year	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Power Losses %	7.8%	7.4%	7.4%	6.7%	6.7%	6.5%	6.5%	6.5%	6.5%	6.5%
Load Factor %	70.8%	72.0%	70.9%	71.0%	80.0%	72.0%	71.5%	71.5%	71.5%	71.5%

	Actual					Assumptions				
Period:	1990/85	1992/87	1991/90	1992/91	1993/92	1994/93	1995/94	2000/95	2005/00	2010/05
VISAYAS	% Growth Rates									
Low Case						11.50%	10.50%	8.90%	8.25%	7.60%
Base Case	9.16%	8.46%	11.99%	9.83%	12.61%	13.00%	12.00%	10.40%	9.75%	9.10%
High Case						24.11%	12.03%	14.18%	10.65%	10.60%
Year	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Power Losses %	11.6%	11.4%	10.7%	10.3%	10.0%	10.0%	10.0%	8.0%	7.0%	7.0%
Load Factor %	64.5%	61.6%	68.5%	59.3%	65.6%	67.4%	68.0%	69.0%	69.0%	69.0%

	Actual					Assumptions				
Period:	1990/85	1992/87	1991/90	1992/91	1993/92	1994/93	1995/94	2000/95	2005/00	2010/05
MINDANAO	% Growth Rates									
Low Case						26.91%	11.00%	10.00%	8.10%	8.10%
Base Case	5.66%	-1.03%	-7.78%	-13.67%	31.66%	27.91%	12.00%	11.00%	9.10%	9.10%
High Case						37.66%	12.01%	15.00%	15.59%	10.10%
Year	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Power Losses %	4.8%	5.0%	5.1%	4.3%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Load Factor %	71.5%	72.2%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%

Philippines

Table 5 - Luzon Power Demand (Base Case)

Year	TOTAL NPC's SALES				Of Which MERALCO (After 1988)			Total Energy Losses	Total Energy Gene-	Load Factor	Total Peak Demand	Peak Demand with 30.0%
LUZON	GWh	% On NPC's Total	Annual Increase p.a.	Avg. 3-year Incr. p.a.	GWh	Annual Increase p.a.	% on Luzon Sales	%	ration GWh	%	MW	Reserve
1976	2211	74.5%			6931			6.4%	2361	16.2%	1659	2157
1977	2085	69.4%	-5.7%		7631	10.1%		10.2%	2323	15.5%	1709	2222
1978	3519	74.1%	68.8%		8181	7.2%		5.7%	3731	23.9%	1780	2314
1979	11210	89.3%	218.6%		8914	9.0%	79.5%	10.3%	12504	74.1%	1926	2504
1980	12164	86.7%	8.5%		9096	2.0%	74.8%	7.3%	13115	72.0%	2074	2696
1981	12690	85.1%	4.3%		9394	3.3%	74.0%	7.1%	13666	70.1%	2225	2893
1982	13126	82.0%	3.4%	5.4%	9747	3.8%	74.3%	8.8%	14398	69.5%	2364	3073
1983	13908	81.4%	6.0%	4.6%	10493	7.7%	75.4%	9.1%	15294	70.5%	2478	3221
1984	13245	77.9%	-4.8%	1.4%	9759	-7.0%	73.7%	9.6%	14655	70.3%	2374	3086
1985	13136	76.6%	-0.8%	0.0%	9827	0.7%	74.8%	9.1%	14449	71.4%	2311	3004
1986	13461	76.3%	2.5%	-1.1%	10260	4.4%	76.2%	8.8%	14756	69.2%	2435	3166
1987	14720	76.1%	9.4%	3.6%	11367	10.8%	77.2%	8.2%	16030	70.6%	2592	3370
1988	16078	75.9%	9.2%	7.0%	12445	9.5%	77.4%	7.8%	17439	71.4%	2780	3614
1989	16795	75.5%	4.5%	7.7%	13024	4.6%	77.5%	7.8%	18222	70.8%	2938	3819
1990	17368	75.8%	3.4%	5.7%	13722	5.4%	79.0%	7.4%	18755	72.0%	2973	3865
1991	18122	76.8%	4.3%	4.1%	14004	2.1%	77.3%	7.4%	19561	70.5%	3166	4116
1992	18630	78.2%	2.8%	3.5%	14478	3.4%	77.7%	6.7%	19976	71.0%	3203	4164
1993	18630	74.4%	0.0%	2.4%	14350	-0.9%	77.0%	6.7%	19968	78.0%	2922	3799
1994	20866	72.7%	12.0%	4.8%	15498	8.0%	74.3%	6.5%	22316	72.0%	3538	4600
1995	22243	71.7%	6.6%	6.1%	16428	6.0%	73.9%	6.5%	23789	71.5%	3798	4938
1996	24138	71.3%	8.5%	9.0%	17739	8.0%	73.5%	6.5%	25816	71.5%	4110	5344
1997	26194	70.8%	8.5%	7.9%	19204	8.3%	73.3%	6.5%	28015	71.5%	4473	5815
1998	28426	70.4%	8.5%	8.5%	20956	9.1%	73.7%	6.5%	30402	71.5%	4854	6310
1999	30848	70.0%	8.5%	8.5%	22952	9.5%	74.4%	6.5%	32993	71.5%	5268	6848
2000	33476	69.5%	8.5%	8.5%	25122	9.5%	75.0%	6.5%	35803	71.5%	5701	7411
2001	36328	69.4%	8.5%	8.5%	27480	9.4%	75.6%	6.5%	38854	71.5%	6203	8064
2002	39424	69.2%	8.5%	8.5%	30038	9.3%	76.2%	6.5%	42164	71.5%	6732	8751
2003	42783	69.1%	8.5%	8.5%	32810	9.2%	76.7%	6.5%	45757	71.5%	7305	9497
2004	46428	68.9%	8.5%	8.5%	35814	9.2%	77.1%	6.5%	49655	71.5%	7906	10278
2005	50383	68.7%	8.5%	8.5%	39062	9.1%	77.5%	6.5%	53886	71.5%	8603	11184
2006	54676	68.6%	8.5%	8.5%				6.5%	58477	71.5%	9336	12137
2007	59334	68.5%	8.5%	8.5%				6.5%	63459	71.5%	10132	13171
2008	64390	68.4%	8.5%	8.5%				6.5%	68866	71.5%	10965	14254
2009	69876	68.3%	8.5%	8.5%				6.5%	74733	71.5%	11932	15511
2010	75829	68.2%	8.5%	8.5%				6.5%	81100	71.5%	12948	16833
1980	12164	86.7%			9096		74.8%	7.3%	13115	72.0%	2074	2696
1985	13136	76.6%	1.55%		9827	1.56%	74.8%	9.1%	14449	71.4%	2311	3004
1990	17368	75.8%	5.74%		13722	6.90%	79.0%	7.4%	18755	72.0%	2973	3865
1995	22243	71.7%	5.07%		16428	3.67%	73.9%	6.5%	23789	71.5%	3798	4938
2000	33476	69.5%	8.52%		25122	8.87%	75.0%	6.5%	35803	71.5%	5701	7411
2005	50383	68.7%	8.52%		39062	9.23%	77.5%	6.5%	53886	71.5%	8603	11184
2010	75829	68.2%	8.52%					6.5%	81100	71.5%	12948	16833

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Table 6 - Visayas Power Demand (Base Case)

Year	TOTAL SALES GWh	Annual Increase p.a.	Avg. 3-year Incr. p.a	% On NPC's Total	Total Energy Losses %	Total Energy Gene-ration GWh	Load Factor %	Peak Demand MW
VISAYAS								
1976	10			0.3%	9.1%	11	62.6%	2
1977	51	410.0%		1.7%	7.3%	55	20.3%	31
1978	214	319.6%		4.5%	7.0%	230	62.5%	42
1979	224	4.7%		1.8%	7.8%	243	53.3%	52
1980	292	30.4%		2.1%	9.0%	321	54.5%	67
1981	456	56.2%		3.1%	9.3%	503	46.3%	124
1982	700	53.5%	46.2%	4.4%	9.9%	777	54.8%	162
1983	933	33.3%	47.3%	5.5%	11.7%	1057	52.7%	229
1984	1020	9.3%	30.8%	6.0%	13.3%	1177	55.4%	242
1985	1173	15.0%	18.8%	6.8%	12.7%	1343	59.9%	256
1986	1261	7.5%	10.6%	7.1%	14.0%	1467	59.0%	284
1987	1490	18.2%	13.5%	7.7%	12.0%	1693	63.0%	307
1988	1644	10.3%	11.9%	7.8%	12.4%	1876	64.1%	333
1989	1768	7.5%	11.9%	7.9%	11.6%	1999	64.5%	354
1990	1818	2.8%	6.9%	7.9%	11.4%	2051	61.6%	380
1991	2036	12.0%	7.4%	8.6%	10.7%	2280	68.5%	380
1992	2236	9.8%	8.1%	9.4%	10.3%	2492	59.3%	478
1993	2518	12.6%	11.5%	10.0%	10.0%	2798	65.6%	487
1994	2845	13.0%	11.8%	9.9%	10.0%	3161	67.4%	535
1995	3187	12.0%	12.5%	10.3%	10.0%	3541	68.0%	594
1996	3518	10.4%	11.8%	10.4%	9.6%	3890	68.2%	649
1997	3884	10.4%	10.9%	10.5%	9.1%	4275	68.4%	714
1998	4288	10.4%	10.4%	10.6%	8.7%	4699	68.6%	782
1999	4734	10.4%	10.4%	10.7%	8.4%	5166	68.8%	857
2000	5226	10.4%	10.4%	10.9%	8.0%	5681	69.0%	937
2001	5736	9.7%	10.2%	11.0%	7.8%	6220	69.0%	1029
2002	6295	9.7%	10.0%	11.1%	7.6%	6812	69.0%	1127
2003	6909	9.7%	9.7%	11.2%	7.4%	7460	69.0%	1234
2004	7583	9.8%	9.7%	11.3%	7.2%	8170	69.0%	1348
2005	8322	9.8%	9.7%	11.4%	7.0%	8948	69.0%	1480
2006	9079	9.1%	9.5%	11.4%	7.0%	9763	69.0%	1615
2007	9905	9.1%	9.3%	11.4%	7.0%	10651	69.0%	1762
2008	10807	9.1%	9.1%	11.5%	7.0%	11620	69.0%	1917
2009	11790	9.1%	9.1%	11.5%	7.0%	12678	69.0%	2097
2010	12863	9.1%	9.1%	11.6%	7.0%	13831	69.0%	2288
1980	292			2.1%	9.0%	321	54.5%	67
1985	1173	32.1%		6.8%	12.7%	1343	59.9%	256
1990	1818	9.2%		7.9%	11.4%	2051	61.6%	380
1995	3187	11.9%		10.3%	10.0%	3541	68.0%	594
2000	5226	10.4%		10.9%	8.0%	5681	69.0%	937
2005	8322	9.8%		11.4%	7.0%	8948	69.0%	1480
2010	12863	9.1%		11.6%	7.0%	13831	69.0%	2288

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Table 7 - Mindanao Power Demand (Base Case)

Year	TOTAL SALES GWh	Annual Increase p.a.	Avg. 3-year Incr. p.a	% On NPC's Total	Total Energy Losses % GWh	Total Energy Gene-ration GWh	Load Factor %	Peak Demand MW	Peak Demand with 30.0% Reserve
MINDANAO									
1976	745			25.1%	3.0%	768	69.4%	126	164
1977	868			28.9%	3.7%	901	66.4%	155	202
1978	1017	17.2%		21.4%	2.7%	1045	68.6%	174	226
1979	1113	9.4%	14.3%	8.9%	2.9%	1146	67.1%	195	254
1980	1577	41.7%	22.0%	11.2%	4.4%	1650	68.8%	273	355
1981	1772	12.4%	20.3%	11.9%	2.6%	1819	66.8%	311	404
1982	2174	22.7%	25.0%	13.6%	2.9%	2238	66.0%	387	503
1983	2248	3.4%	12.5%	13.2%	3.6%	2331	64.9%	410	533
1984	2741	21.9%	15.6%	16.1%	3.3%	2834	74.5%	433	563
1985	2831	3.3%	9.2%	16.5%	4.5%	2965	72.0%	470	611
1986	2923	3.2%	9.1%	16.6%	3.8%	3040	71.7%	484	629
1987	3127	7.0%	4.5%	16.2%	4.4%	3272	70.1%	533	693
1988	3458	10.6%	6.9%	16.3%	4.7%	3629	72.4%	571	742
1989	3681	6.4%	8.0%	16.5%	4.8%	3866	71.5%	617	802
1990	3729	1.3%	6.0%	16.3%	5.0%	3926	72.2%	621	807
1991	3439	-7.8%	-0.2%	14.6%	5.1%	3625	70.0%	591	769
1992	2969	-13.7%	-6.9%	12.5%	4.3%	3101	70.0%	504	656
1993	3909	31.7%	1.6%	15.6%	5.5%	4137	70.0%	675	877
1994	5000	27.9%	13.3%	17.4%	5.5%	5291	70.0%	863	1122
1995	5600	12.0%	23.6%	18.0%	5.5%	5926	70.0%	966	1256
1996	6216	11.0%	16.7%	18.4%	5.5%	6578	70.0%	1070	1391
1997	6900	11.0%	11.3%	18.7%	5.5%	7301	70.0%	1191	1548
1998	7659	11.0%	11.0%	19.0%	5.5%	8104	70.0%	1322	1718
1999	8501	11.0%	11.0%	19.3%	5.5%	8996	70.0%	1467	1907
2000	9436	11.0%	11.0%	19.6%	5.5%	9986	70.0%	1624	2111
2001	10295	9.1%	10.4%	19.7%	5.5%	10894	70.0%	1777	2310
2002	11232	9.1%	9.7%	19.7%	5.5%	11886	70.0%	1938	2520
2003	12254	9.1%	9.1%	19.8%	5.5%	12967	70.0%	2115	2749
2004	13369	9.1%	9.1%	19.8%	5.5%	14147	70.0%	2301	2991
2005	14586	9.1%	9.1%	19.9%	5.5%	15435	70.0%	2517	3272
2006	15913	9.1%	9.1%	20.0%	5.5%	16839	70.0%	2746	3570
2007	17361	9.1%	9.1%	20.0%	5.5%	18371	70.0%	2996	3895
2008	18941	9.1%	9.1%	20.1%	5.5%	20043	70.0%	3260	4238
2009	20665	9.1%	9.1%	20.2%	5.5%	21867	70.0%	3566	4636
2010	22545	9.1%	9.1%	20.3%	5.5%	23857	70.0%	3891	5058
1980	1577			11.2%	4.4%	1650	68.8%	273	355
1985	2831	12.4%		16.5%	4.5%	2965	72.0%	470	611
1990	3729	5.7%		16.3%	5.0%	3926	72.2%	621	807
1995	5600	8.5%		18.0%	5.5%	5926	70.0%	966	1256
2000	9436	11.0%		19.6%	5.5%	9986	70.0%	1624	2111
2005	14586	9.1%		19.9%	5.5%	15435	70.0%	2517	3272
2010	22545	9.1%		20.3%	5.5%	23857	70.0%	3891	5058

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Table 8 - Total Power Demand (Base Case)

YEAR	ELECTRICITY SALES GWh Luzon	Visayas	Mindanao	TOTAL	Annual Increase p.a.	Avg. 3-year Incr. p.a.	Total Energy Losses %	Total Energy Gene-ration GWh	Load Factor %	Peak Demand MW	Total Kwh per person
1976	2,211	10	745	2,966			5.5%	3140	20.0%	1787	
1977	2,085	51	868	3,004	1.3%		8.4%	3279	19.8%	1895	
1978	3,519	214	1,017	4,750	58.1%		5.1%	5006	28.6%	1996	
1979	11,210	224	1,113	12,547	164.1%		9.7%	13893	73.0%	2173	295
1980	12,164	292	1,577	14,033	11.8%		7.0%	15086	71.1%	2414	314
1981	12,690	456	1,772	14,918	6.3%		6.7%	15988	68.6%	2660	323
1982	13,126	700	2,174	16,000	7.3%	8.4%	8.1%	17413	68.2%	2913	340
1983	13,908	933	2,248	17,089	6.8%	6.8%	8.5%	18682	68.4%	3117	359
1984	13,245	1,020	2,741	17,006	-0.5%	4.5%	8.9%	18666	69.7%	3049	350
1985	13,136	1,173	2,831	17,140	0.8%	2.3%	8.6%	18757	70.5%	3037	343
1986	13,461	1,261	2,923	17,645	2.9%	1.1%	8.4%	19263	68.7%	3203	344
1987	14,720	1,490	3,127	19,337	9.6%	4.4%	7.9%	20995	69.8%	3432	366
1988	16,078	1,644	3,458	21,180	9.5%	7.3%	7.7%	22944	70.9%	3684	391
1989	16,795	1,768	3,681	22,244	5.0%	8.0%	7.7%	24087	70.3%	3909	401
1990	17,368	1,818	3,729	22,915	3.0%	5.8%	7.3%	24732	71.0%	3974	402
1991	18,122	2,036	3,439	23,597	3.0%	3.7%	7.3%	25466	70.3%	4137	405
1992	18,630	2,236	2,969	23,835	1.0%	2.3%	6.8%	25569	69.5%	4186	398
1993	18,630	2,518	3,909	25,057	5.1%	3.0%	6.9%	26902	75.2%	4084	410
1994	20,866	2,845	5,000	28,711	14.6%	6.8%	6.7%	30769	71.2%	4937	459
1995	22,243	3,187	5,600	31,030	8.1%	9.2%	6.7%	33256	70.8%	5359	486
1996	24,138	3,518	6,216	33,872	9.2%	10.6%	6.6%	36284	70.9%	5830	520
1997	26,194	3,884	6,900	36,978	9.2%	8.8%	6.6%	39592	70.9%	6377	556
1998	28,426	4,288	7,659	40,373	9.2%	9.2%	6.6%	43206	70.9%	6958	596
1999	30,848	4,734	8,501	44,083	9.2%	9.2%	6.5%	47155	70.9%	7592	638
2000	33,476	5,226	9,436	48,139	9.2%	9.2%	6.5%	51470	70.9%	8262	684
2001	36,328	5,736	10,295	52,359	8.8%	9.1%	6.4%	55969	70.9%	9009	731
2002	39,424	6,295	11,232	56,951	8.8%	8.9%	6.4%	60862	70.9%	9797	
2003	42,783	6,909	12,254	61,945	8.8%	8.8%	6.4%	66184	70.9%	10654	
2004	46,428	7,583	13,369	67,379	8.8%	8.8%	6.4%	71972	70.9%	11555	
2005	50,383	8,322	14,586	73,291	8.8%	8.8%	6.4%	78269	70.9%	12601	
2006	54,676	9,079	15,913	79,668	8.7%	8.7%	6.4%	85079	70.9%	13698	
2007	59,334	9,905	17,361	86,601	8.7%	8.7%	6.4%	92481	70.9%	14890	
2008	64,390	10,807	18,941	94,137	8.7%	8.7%	6.4%	100529	70.9%	16142	
2009	69,876	11,790	20,665	102,330	8.7%	8.7%	6.4%	109278	70.9%	17595	
2010	75,829	12,863	22,545	111,237	8.7%	8.7%	6.4%	118789	70.9%	19127	
1980	12164	292	1577	14033			7.0%	15086	71.1%	2414	314
1985	13136	1173	2831	17140	4.1%		8.6%	18757	70.5%	3037	343
1990	17368	1818	3729	22915	6.0%		7.3%	24732	71.0%	3974	402
1995	22243	3187	5600	31030	6.3%		6.7%	33256	70.8%	5359	486
2000	33476	5226	9436	48139	9.2%		6.5%	51470	70.9%	8262	684
2005	50383	8322	14586	73291	8.8%		6.4%	78269	70.9%	12601	
2010	75829	12863	22545	111237	8.7%		6.4%	118789	70.9%	19127	

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Table 9 - Low, Base and Maximum Forecast Generation (GWh)

	LUZON			VISAYAS			MINDANAO			TOTAL		
	Low	Actual/ Base	High	Low	Actual/ Base	High	Low	Actual/ Base	High	Low	Actual/ Base	High
1976		2361			11			768			3140	
1977		2323			55			901			3279	
1978		3731			230			1045			5006	
1979		12504			243			1146			13893	
1980		13115			321			1650			15086	
1981		13666			503			1819			15988	
1982		14398			777			2238			17413	
1983		15294			1057			2331			18682	
1984		14655			1177			2834			18666	
1985		14449			1343			2965			18757	
1986		14756			1467			3040			19263	
1987		16030			1693			3272			20995	
1988		17439			1876			3629			22944	
1989		18222			1999			3866			24087	
1990		18755			2051			3926			24732	
1991		19561			2280			3625			25466	
1992		19976			2492			3101			25569	
1993	19768	19968	21301	2770	2798	2941	3930	4137	5177	26468	26902	29419
1994	21547	22316	24688	3088	3161	3650	4987	5291	7126	29623	30769	35464
1995	22646	23789	27073	3413	3541	4089	5536	5926	7982	31595	33256	39144
1996	24236	25816	30364	3716	3890	4669	6089	6578	9179	34042	36284	44212
1997	25937	28015	34056	4047	4275	5331	6698	7301	10556	36683	39592	49943
1998	27758	30402	38196	4407	4699	6087	7368	8104	12139	39533	43206	56422
1999	29707	32993	42839	4800	5166	6950	8105	8996	13960	42611	47155	63750
2000	31792	35803	48047	5227	5681	7936	8915	9986	16055	45934	51470	72037
2001	34024	38854	52485	5658	6220	8781	9638	10894	18558	49319	55969	79824
2002	36412	42164	57333	6125	6812	9716	10418	11886	21452	52955	60862	88501
2003	38969	45757	62628	6630	7460	10751	11262	12967	24797	56861	66184	98177
2004	41704	49655	68413	7177	8170	11897	12174	14147	28664	61055	71972	108973
2005	44632	53886	74731	7769	8948	13164	13160	15435	33134	65561	78269	121029
2006	47765	58477	82219	8359	9763	14559	14226	16839	36481	70351	85079	133259
2007	51118	63459	90458	8995	10651	16103	15379	18371	40165	75492	92481	146726
2008	54707	68866	99522	9678	11620	17809	16624	20043	44222	81009	100529	161553
2009	58547	74733	109494	10414	12678	19697	17971	21867	48688	86932	109278	177879
2010	62657	81100	120465	11205	13831	21785	19427	23857	53606	93289	118789	195856
1980		13115			321			1650			15086	
1985		14449			1343			2965			18757	
1990		18755			2051			3926			24732	
1995	22646	23789	27073	3413	3541	4089	5536	5926	7982	31595	33256	39144
2000	31792	35803	48047	5227	5681	7936	8915	9986	16055	45934	51470	72037
2005	44632	53886	74731	7769	8948	13164	13160	15435	33134	65561	78269	121029
2010	62657	81100	120465	11205	13831	21785	19427	23857	53606	93289	118789	195856

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Table 10 - NPC's Power Plants and Reliable Capacity in 1998-99

	PROBAB.	COMMEN. YEAR	NOMINAL CAPACITY	DEPENDABLE CAPACITY - MW 1994	1995	1996	1997	1998	1999	2000
Botocan/Caliraya,Buhi,Cawa	100%	1948.0	51.0	34	34	34	34	34	34	34
Ambuklao-ROL (12/94)	100%	1957.0	75.0	0	60	60	60	60	60	60
Binga ROL (8/93)	100%	1960.0	100.0	80	80	80	80	80	80	80
Manila 1	100%	1965.1	100.0	79	78	77	76	75	0	0
Manila 2	100%	1966.1	100.0	88	86	84	82	80	0	0
Angat	100%	1968.0	200.0	136	136	136	136	136	136	136
Sucat 1	100%	1968.1	150.0	122	119	116	113	110	0	0
Sucat 2	100%	1970.1	200.0	0	170	168	166	164	162	160
Sucat 3	100%	1971.1	200.0	170	166	162	158	154	150	146
Pantabagan	100%	1972.0	100.0	20	20	20	20	20	20	20
Bataan 1	100%	1972.1	75.0	59	58	58	57	57	57	56
Sucat 4	100%	1972.1	300.0	255	252	249	246	243	240	237
Malaya 1	100%	1975.1	300.0	186	180	174	168	162	156	150
Bataan 2	100%	1977.1	150.0	0	138	137	137	136	135	134
Tiwi	100%	1979.1	330.0	300	297	293	290	287	284	280
Malaya 2	100%	1979.1	350.0	245	238	231	224	217	210	203
Mak-Ban	100%	1980.1	330.0	307	304	300	297	294	290	287
Masiway	100%	1981.0	12.0	4	4	4	4	4	4	4
Kalayaan 1-2	100%	1982.0	300.0	270	270	270	270	270	270	270
Magat	100%	1984.0	360.0	205	205	205	205	205	205	205
Calaca I	100%	1984.0	300.0	246	241	237	232	228	223	218
Angat Auxiliary	100%	1986.0	28.0	7	7	7	7	7	7	7
Bataan-BTPP GT 1-4	100%	1989.1	120.0	100	99	99	98	98	97	96
Malaya-GT 1-3	100%	1989.1	90.0	80	80	79	79	78	78	77
Hopewell BOT-1	100%	1990.1	70.0	60	60	60	59	59	58	58
Hopewell BOT-3	100%	1991.1	70.0	60	60	59	59	59	58	58
Navotas GT-3 Barges BOT	100%	1991.1	90.0	63	63	62	62	61	61	60
Hopewell BOT-2	100%	1991.1	70.0	60	60	59	59	59	58	58
Benguet Mini-Hydro Electri	100%	1992.6	22.0	22	22	22	22	22	22	22
Sucat Land Base GT	100%	1993.0	30.0	30	30	30	29	29	29	29
Subic Zambales ROL	100%	1993.0	28.0	28	28	28	28	28	28	0
Polar/Fels Diesel-OL ?	0%	1993.0	90.0	0	0	0	0	0	0	0
Navotas-Hopewell BOT	100%	1993.0	100.0	100	100	99	99	98	98	97
Bakman-Ormat BOT	100%	1993.0	15.7	16	16	16	16	15	15	15
Hopewell ROM-GT	100%	1993.1	120.0	120	120	120	120	120	120	120
Limay (Bataan) A CC-BTO	100%	1993.1	300.0	234	300	299	297	296	294	293
Clark Base-Electrobus ROM	100%	1993.1	50.0	45	45	44	44	43	43	42
Pinamucan Enron I- BOT	100%	1993.1	105.0	105	104	103	102	101	100	99
Bacon Manito I	100%	1993.1	110.0	110	109	108	107	106	105	103
Calaca Far East Barges-BOT	100%	1993.1	90.0	14	90	90	90	90	63	0
Limay (Bataan) B CC-BTO	100%	1993.1	300.0	233	300	299	297	296	294	293
Bacon Manito II	100%	1994.0	40.0	32	40	40	40	39	39	39
Subic Enron II BOT	100%	1994.0	108.0	91	103	102	100	99	98	97
Navotas-Van der Horst-OL	100%	1994.0	120.0	84	120	120	120	120	36	0
Makban Ormat - BOT	100%	1994.0	15.7	9	16	16	15	15	15	15
North Harbor-Far East-OL	100%	1994.0	90.0	63	90	90	90	89	0	0
Malaya-Protech-OL	100%	1994.0	50.0	35	50	50	50	50	0	0
Malaya Skid Mounted-Protec	100%	1994.0	50.0	25	50	50	49	49	25	0
Eng'sg Island-Sabah-OL	100%	1994.0	100.0	70	100	100	100	100	0	0
Bauang-La Union-FPPC-BOT	100%	1994.1	215.0	22	215	215	214	213	212	211
Maibarara	0%	1995.0	13.0	0	0	0	0	0	0	0
Makban (D/E)	100%	1995.1	80.0	0	48	48	47	47	46	46
Pagbilao I Hopewell BOT	100%	1995.1	350.0	0	140	350	350	348	347	345
Pagbilao II Hopewell BOT	100%	1995.1	350.0	0	18	350	350	348	347	345
Calaca II	100%	1996.0	300.0	0	0	300	294	288	282	276
Masinloc 1	100%	1997.1	300.0	0	0	0	150	300	294	288
Tongonan (Leyte-Luzon) BOO	100%	1997.1	440.0	0	0	0	88	440	440	438
Masinloc 2	100%	1998.0	300.0	0	0	0	90	300	297	294
Sual-Coal	100%	1999.0	1000.0	0	0	0	0	0	1000	1000

PHILIPPINES

POWER SECTOR STUDY

Status of Private Sector Power Plants

Projects Commissioned by NPC

1. NPC has signed 33 agreements with the private sector for power generation. Of these, twelve were completed by end 1993. The first was the 210 MW Hopewell Navotas gas turbine project commissioned in January 1991. This was followed by the 22 MW Benguet Province Mini-Hydro plant in June 1992, and the remaining projects commenced operations during 1993. A total of 25 projects for 2,485 MW are scheduled to be in operation by end-1994. The names, fuel, contractor and targeted schedules are included in Table 2. The two largest of these projects are two coal plants, Sual plant (Hopewell, 1,000 MW) and Pagbilao (Hopewell, 700 MW).

2. The 33 agreements with the private sector for power generation include:

(a) 13 BOT (build-operate-transfer) projects amounting to 2900 MW;

(b) 5 BTO (build-transfer-operate) projects amounting to 826 MW of capacity (610 MW of which is in three projects in blocks A and B of the Limay, Bataan combined cycle power plant and 200 MW in the Mindanao power barge project).

(c) 3 ROL (rehabilitate-operate-lease) projects amounting to 203 MW of capacity (175 MW of which is hydro).

(d) 2 ROM (rehabilitate-operate-maintain) projects amounting to 320 MW of capacity (a 50 MW diesel plant at Clark air base and a 270 MW gas turbine barge with Hopewell).

(e) 5 BOO (build-own-operate) projects amounting to 303 MW (made up of two export processing zone projects, two barge-mounted generators and a mini-hydro).

(f) 2 OL (operating lease) projects amounting to 115 MW and an 'energy conversion' project of 55 MW.

Status of DOE Accredited Projects

3. DOE must accredit projects between IPPS and private purchasers, including distribution utilities. MERALCO has signed five power purchase agreements for a total capacity of 1380 MW. These are: (a) Cavite Energy Corp., a 330 MW combined cycle plant scheduled for July 1996; (b) Duracom Mobile Power Corp. 350 MW, (c) Luzon Associates for a 400 MW (US$466 million, US$679 million including transmission costs) combined cycle power plant to be commissioned in 1996. and (d) Magellan Utilities Development Corporation has signed a contract for a 326 MW coal plant (US$280 million) and proposes a second unit of 326 MW costing US$205 million. Other DOE accredited projects include two by the Angeles Electric Corporation for the supply of 42 MW of capacity, one signed by the Mactan Export Processing Zone for a 50 MW diesel power plant and one by the Cavite Export Processing Zone for a 48 MW cogeneration plant.

Other Project Initiatives

4. Other proposals regarding private power initiatives include: (a) Litton Mills 52 MW BOO diesel plant to MERALCO ($43 million); (b) Two 100 MW Westinghouse units offered in the settlement of the Bataan nuclear court are being bid on a BOT/BOO basis by General Public Utilities Corp (US)/MERALCO Industrial Engineering Services Corp; (c) Edison Global Electric 54 MW diesel plant at Talisay, Negros Island for the Central Negros Cooperative; (d) PNOC Exploration will put up a gas-fired plant in Echaque, north of Manila (financed by a Canadian grant of P55.4 million and a counterpart fund of P21.6 million from PNOC); (e) Block C (310 MW) of the Limay Bataan combined cycle plant by ABB/Kawasaki/Marubeni ($350 million); (f) the S. Roque 390 MW multipurpose hydroelectric plant, a US$2 billion BOOT project by a joint venture of Ontario Hydro International of Canada, MCA Power Corp of Manila and MBf Asia Capital Corp of Malaysia).

The Cost of Private Projects

5. There is limited information available in the cost of BOT and BOO projects. DOE should, as a part of its sectorial planning require all approved projects to fill information on the costs and financing of these projects, either public or private financing. This would increase the transparency of the awarding systems. For the following projects, for which information is available, the total cost per kWh is about US$1,040/kW, but they include different fuel sources and a few ROL, as shown in Table 1, below:

Details of Project Financing

6. The first BOT contract with Hopewell for the Navotas plant provided the basis for all future contracts with the private sector and the terms for subsequent contracts have been substantially the same. A particular feature of these contracts, not used in other countries is that the fuel is provided and pay by NPC (at established efficiency rates sets in each contract). The assumption of this risk by NPC may partially explain why so many contracts have been signed and are in operation, many times larger than in any other country.

7. Financing of these contracts has taking different approaches. The Pagbilao 700 MW Pagbilao project is the largest under construction. Its financing, arranged by IFC, was the first time that limited-recourse co-financing without government guarantees had been provided for a large project in the developing world by Japan Eximbank and US Eximbank. The US Eximbank will not take completion risk, but it will provide cover for political risk (expropriation, foreign exchange transfer or violence). To cover the construction period, Citibank will syndicate out bridge financing, which will be taken out by an Eximbank loan after project completion. The $185 million US Eximbank portion was arranged by Citicorp and completed in late March. Of the $367 million Japan Eximbank portion, 40% was commercially syndicated by Bank of Tokyo and DKB as a two-tranche loan over 13 years. Tranche A, amounting to $88 million, carries MITI insurance covering political risk. Tranche B is fully covered for both commercial and political risk. This was the first time that MITI has agreed to comprehensive insurance in the Philippines without a government guarantee. In addition to Bank of Tokyo and DKB (lending $29.5 million each), the lending banks are Fuji ($26 million), Credit Suisse Tokyo ($24 million), Dresdner Tokyo ($19 million), Sumitomo ($10 million) and UBS ($9 million). It was the first time that the three foreign banks had participated in a Jexim scheme. Of the IFC contribution to the loan package, some $40 million has been syndicated with commercial banks under "B" loan arrangements.

Table 1 - Cost of Private Projects

Project Name	Contractor	Type	Capacity MW	Fuel	Year Operat.	Est.Cost US$ Mn	Cost US$/kW
Navotas GT 1-3	Hopewell Holding-HK	BOT	210	Diesel	1991	41	195
Subic, Zambales Diesel I	Enron Power Co.-USA	ROL	108	Bunker	1993	135	1250
Navotas GT 4	Hopewell Energy Int.-HK	BOT	100	Diesel	1993	40	400
Limay-Bataan CC GT "A"	ABB/Marubeni/Kawasaki	BTO	300	Diesel	1993	330	1100
Makban Binary Geothermal	Ormat Inc.-USA	BTO	15.73	Geoth.	1993	17	1049
Pinamucan, Batangas Diesel	Enron Power Co.-USA	BOT	105	Bunker	1993	120	1143
Calaca Batangas Barges	Far East Levingston	BOO	90	Bunker	1993	78	867
Limay, Bataan CC "B"	ABB/Marubeni/Kawasaki	BTO	300	Mix	1993	350	1167
Bataan EPZA Diesel	Edison Global (HK)	BOO	58	Bunker	1994	31	534
Cavite EPZA Diesel	Magellan Utilities	BOO	63	Bunker	1994	22	349
Bacman Geothermal	Ormat Inc.-USA	BTO	15.73	Geoth.	1994	17	1049
Malaya Skid-Mounted Diesel	Pro-Tech	OL	50	Bunker	1994	14	280
Eng'g. Island Barge	Sabah Shipyard Sdn BHD	BOO	100	Naphtha	1994	30	300
Bauang, La Union Diesel	First Private Power-PHIL	BOT	215	Bunker	1994	285	1326
Pagbilao, Quezon Coal I	Hopewell Energy Int.-HK	BOT	350	Coal	1995	491	1401
Pagbilao, Quezon Coal II	Hopewell Energy Int.-HK	BOT	350	Coal	1996	491	1401
Tongonan Leyte-Luzon	PNOC-EDC/Private	BOO/BOT	440	Geoth.	1997	486	1104
Sual Pangasinan Coal	Hopewell Holding (HK)	BOT	1000	Coal	1999	1100	1100
Toledo Cebu Coal	Atlas Consolidated-PHIL	ECA	55	Coal	1993	60	1091
Iligan Diesel I/II	Alson/Tomen-PHIL/Japan	BOT	98	Bunker	1993	60	612
TOTAL			4023			4196	1043

8. The entry of private investors to the power sector has also mobilized some funds from domestic sources, for the 215 MW (US$285 million) Bauang La Union diesel power plant. The $85 million equity (30% of project was provided by MERALCO 40%, First Philippine Holding 20%; JG Summit 20%; and PCI Bank 20%. The remaining costs would be financed by export credit agencies and domestic banks.

9. In January 1994, Subic Power successfully offered $105 million in 15-year senior secured notes to finance the Subic Bay power project. Backed by the assets of the Enron Corporation, the issue represented a breakthrough in terms of precompletion project financing, and were priced at 385bp over the 15-year portion of the Treasury curve. The placement of these securities indicated a continuation of the renewed access to international capital markets that Philippine projects have had since the early part of 1993.

10. The Edison Global Electric Ltd (Hong Kong) 58 MW (US$31 million) diesel station for the Bataan Export Processing Zone (15 MW) and the remaining 40 MW would be sold to NPC at ₱1.38 (¢5.1) per kwh. NPC sells power to MERALCO and other utilities in Luzon for ₱1.87 (¢6.9) per kwh.

11. In February 1994, lead banks Credit Suisse and BNP were syndicating $167 million from European banks to finance California Energy's Upper Mahiao geothermal power plant. The three-year construction loan will roll over at completion to a 10-year US Exim term loan.

Other Private Projects.

12. In addition to the projects contracted with NPC (Table 2), there are other contracts between distribution utilities and independent power producers, which have been awarded for a total capacity of about 3,700 MW, of which about 1000 MW are expected to be completed and become operational including: Magellan 600 MW, Luzon Power-300 MW, Edison Global-192 MW, Cavite Energy 330 MW, Northern Luzon RECs-300 MW, MUDC Power Barges-50 MW, ARCAM Bagasse-20 MW, Texaco/Caltex-165 MW, Cabanatua 11 MW, Angeles 30 MW, EDZA-Quezon-120 MW, Panelco diesel 19 MW, NAIA 30 MW. This also includes about 1,600 MW of generator-sets imported through the Board of Investments, but expected to be mainly used for backup (emergency) and to reduce demand charges.

Table 2 - NPC's Contracts for Power Generation with the Private Sector

		Contractor	Type	Capacity	Cum. Capac.	Fuel	Year	Status
							Operat.	
1	Navotas GT 1-3	Hopewell Holding-HK	BOT	210.0	210.0	Diesel	1991.01	Operation
2	Benguet Province Hydro	Hydro Electric Dev. Corp.	BOO	22.0	232.0	Hydro	1992.06	Operation
3	Subic-Zambales Diesel I	Enron Power Co.-USA	ROL	28.0	260.0	Bunker	1993.01	Operation
4	Gas Turbine Barges 1]	Hopewell Tileman-HK	ROM	270.0	530.0	Mix	1993.01	Operation
5	Subic, Zambales Diesel I	Enron Power Co.-USA	ROL	108.0	638.0	Bunker	1993.03	Operation
6	Navotas GT 4	Hopewell Energy Int.-HK	BOT	100.0	738.0	Diesel	1993.03	Operation
7	Limay-Bataan CC GT "A"	ABB/Marubeni/Kawasaki	BTO	210.0	948.0	Diesel	1993.04	Operation
8	Makban Binary Geothermal	Ormat Inc.-USA	BTO	15.7	963.7	Geoth.	1993.04	Operation
9	Clark Base Diesel	Electrobus-PHIL	ROM	50.0	1013.7	Diesel	1993.06	Operation
10	Pinamucan, Batangas Diesel	Enron Power Co.-USA	BOT	105.0	1118.7	Bunker	1993.07	Operation
11	Binga Hydro	Chiang Jiang Inc.-China	ROL	100.0	1218.7	Hydro	1993.08	Operation
12	Calaca Batangas Barges	Far East Levingston	BOO	90.0	1308.7	Bunker	1993.09	Operation
13	Limay, Bataan CC "B"	ABB/Marubeni/Kawasaki	BTO	210.0	1518.7	Mix	1993.11	Operation
14	Bataan EPZA Diesel	Edison Global (HK)	BOO	58.0	1576.7	Bunker	1994.04	Construction
15	North Harbor Diesel Barge	Far East Levington (Sing)	BOO	90.0	1666.7	Bunker	1994.04	Construction
16	Cavite EPZA Diesel	Magellan Utilities	BOO	63.0	1729.7	Bunker	1994.04	Construction
17	Bacman Geothermal	Ormat Inc.-USA	BTO	15.7	1745.5	Geoth.	1994.04	Construction
18	Malaya Skid-Mounted Diesel	Pro-Tech	OL	50.0	1795.5	Bunker	1994.04	Construction
19	Eng'g. Island Barge	Sabah Shipyard Sdn BHD	BOO	100.0	1895.5	Naphtha	1994.04	Construction
20	Navotas Diesel Barge	Van der Horst	BOO	120.0	2015.5	Bunker	1994.04	Construction
21	Limay, Bataan CC Cycle "A"	ABB/Marubeni/Kawasaki	BTO	90.0	2105.5	Mix	1994.08	Construction
22	Limay, Bataan CC Cycle "B"	ABB/Marubeni/Kawasaki	BTO	90.0	2195.5	Mix	1994.09	Construction
23	Bauang, La Union Diesel	First Private Power-PHIL	BOT	215.0	2410.5	Bunker	1994.10	Construction
24	Ambuklao Hydro Rehab.	Miescor-PHIL	ROL	75.0	2485.5	Hydro	1994.12	Construction
25	Pagbilao, Quezon Coal I	Hopewell Energy Int.-HK	BOT	350.0	2835.5	Coal	1995.06	Construction
26	Pagbilao, Quezon Coal II	Hopewell Energy Int.-HK	BOT	350.0	3185.5	Coal	1996.01	Construction
27	Tongonan Leyte-Luzon	PNOC-EDC/Private	BOO/BOT	440.0	3625.5	Geoth.	1997.06	Construction
28	Sual Pangasinan Coal	Hopewell Holding (HK)	BOT	1000.0	4625.5	Coal	1999.01	Awarded
	TOTAL LUZON	As of March 1994		4625.5				

	Project Name	Contractor	Type	Capacity MW	Cum.Cap. MW	Fuel	Year Operat.	Status
1	Toledo Cebu Coal	Atlas Consolidated-PHIL	ECA	55.0	55.0	Coal	1993.20	Operation
2	Naga Thermal Plant	Salcom (PHIL)	ROM	203.0	406.0	Coal/Diesel	1994.04	Construction
3	Tongonan, Leyte Geothermal	PNOC-EDC/Private	BOO/BOT	200.0	400.0	Geoth.	1996.12	Construction
	TOTAL VISAYAS			458.0				
1	Iligan Diesel I/II	Alson/Tomen-PHIL/Japan	BOT	98.0	98.0	Bunker	1993.12	Operation
2	Mindanao Power Barge I/II	Mitsui/BWES-Japan-Denm	BTO	200.0	298.0	Bunker	1994.04	Construction
	TOTAL MINDANAO			298.0				

BOO: Build, Own, Operate	BOT: Build, Operate, Transfer	BTO: Build, Transfer, Operate	OL: Operate & Lease
ROL: Rehabilitate Oper. Lease	ROM: Rehabil. Operate, Maintain	ROO: Rehab. Own, Operate	

PHILIPPINES

POWER SECTOR STUDY

NPC's Power Development Program 1/

Year	Project Name	Capacity - MW				Total	Cumul.
		Oil	Coal	Geoth.	Hydro	Year	Total
	LUZON						
1991	Navotas GT 1-3 -BOT	210				210	210
1992	Power Barge GT	30				30	240
1993	Benguet Province Hydro-BOO				22	301	541
	Sucat Land Base-ROL	30					
	Subic-Zambales Diesel-ROL	28					
	Gas Turbine Barges BOT	150					
	Subic, Zambales Diesel-BOT	108					
	Navotas GT 4-BOT	100					
	Limay CC GT "A" BTO	210					
	Makban Binary Geo. BTO			16			
	Clark Base Diesel-ROM	50					
	Bacon Manito I/II	0147		150			
	Pinamucan, Batangas BOT	105					
	Binga Hydro-ROL				100		
	Maibara Geothermal			13			
	Calaca Batangas Barges-BOO	90					
	Limay, Bataan CC "B"-BTO	210					
1994	Bataan EPZA Diesel-BOO	58				1007	1547
	Bacon Manito II			40			
	North Harbor Barge-BOO	90					
	Cavite EPZA Diesel-BOO	63					
	Bacman Geothermal			16			
	Malaya Skid-Mounted-BOO	50					
	Eng'g. Island Barge-BOO	100					
	Navotas Diesel Barge-BOO	120					
	Limay, CC Cycle "A"-BTO	90					
	Limay CC Cycle "B"-BTO	90					
	Bauang, La Union-BTO	215					
	Ambuklao Hydro-ROL				75		
1995	Makban D & E			80		730	2277
	Pagbilao, Quezon I-BOT		350				
	Calaca II		300				
1996	Pagbilao, Quezon II-BOT		350			350	2627
1997	Leyte-Luzon Geo BOO/BTO			440		740	3367
	Masinloc I		300				
1998						0	3367
1999	Sual Pangasinan-BOT		1000			1000	4367

1/ As revised by NPC, March 1994.

Year	Project Name	Capacity - MW				Total Year	Cumul. Total
		Oil	Coal	Geoth.	Hydro		
	VISAYAS						
1991	ABB-GT 1 GT-Power Barge	36 30				66	66
1992	Janopol-Hydro				5	5	66
1993	Palinpinon 1 Geothermal			20		20	86
1994	Palinpinon 2 Geothermal			20		20	106
1995	Palinpinon 3-4 Geothermal			80		80	186
1996	Leyte-Cebu Geo BOO/BOT			200		200	386
1998	Mambucal			60		60	446
	MINDANAO						
1991	GT-Barges	120				120	120
1993	Agus I-II Hydro Tomen Diesel BOT NSC Diesel BOT Iligan Diesel-BOT	 40 50 98			80	268	388
1994	Mindanao Barges I-II-BTO Agus 1 Unit 1	200			 40	240	628
1996	Mindanao Geo 1-2			40		40	668
1997	Mindanao Geo 3-6			80		80	748
1998	Mindanao Geo 7-8Coal BOT			40 200		240	988

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POWER SECTOR STUDY

Status of the Distribution Utilities and Financial Benefits of their Consolidation

A. Overview

1.. This annex discusses key performance indicators of the power distribution utilities in the Philippines, focusing on the benefits of sector consolidation.[4/] The distribution utilities are private, and include three main groups: (a) MERALCO, responsible for power distribution in the Manila Metropolitan Region; (b) another 14 investor-owned utilities (14 IODs) in other main cities; and (c) 119 rural electrification cooperatives (coops, [also called RECs in the Figures]).

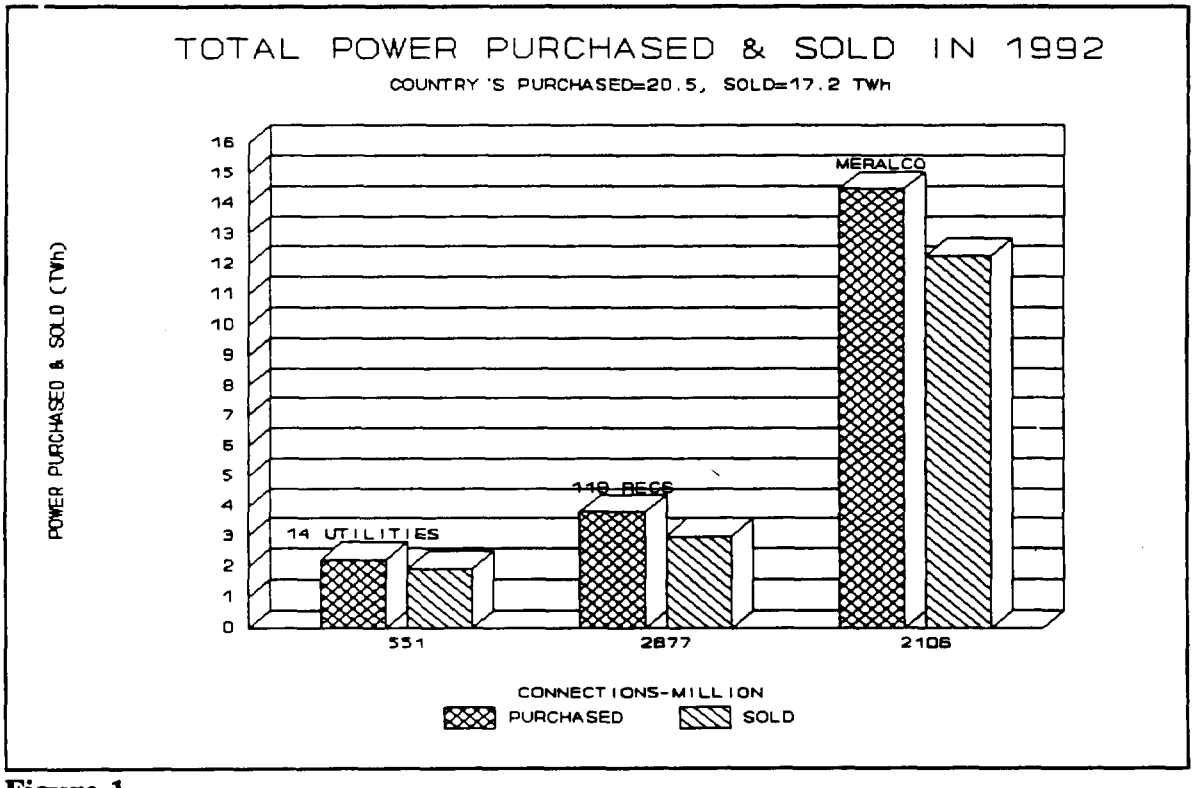

Figure 1

2.. The relative sizes of these groups vary depending on the indicator used. In terms of service, the coops have the largest customer base (2,877,000), followed by MERALCO (2,106,000) and the other 14 utilities (551,000). MERALCO is preeminant in sales, holding 60% of the total market (Figure 1).

4/ Data are from 1992, the last year for which data on all distributors was available.

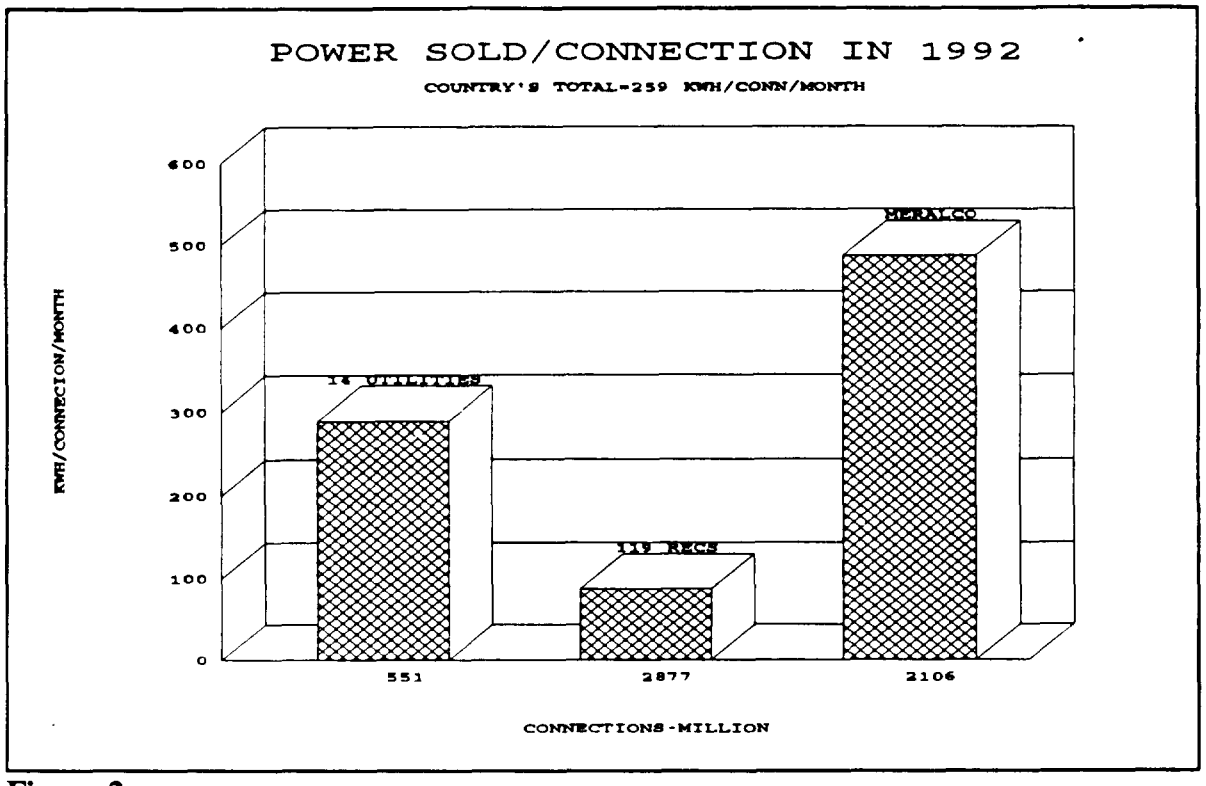

Figure 2

3. Average power usage per connection is very low (Figure 2). The 87 kWh/month average for the coops implies that the majority of consumption is subsidized from other service areas because power tariffs below 100 kWh/month are heavily subsidized in the Philippines, and there are no large customers available to subsidize the large number of small customers served by the coops. By comparison, the average sales per connection for the 14 IODs are three times higher (290 kWh/month), and MERALCO's are six times higher (486 kWh/month).

4. Since power losses are very high for all groups, a significant effort will be needed to reduce these losses, including the passage of anti-pilferage legislation and the adoption of substantial technical improvements. MERALCO's power losses (14.9 %) are at the average level of the 14 IODs. Average coop losses are much higher at 20.8%.

B. Consolidation of the Rural Electrification Cooperatives:

5. Consensus has been reached in the Philippines regarding the importance of enhancing power sector efficiency. In this regard, a main recommendation of this report is the consolidation of the 135 distribution utilities into regional units (to be known as stock coops), a move which would enable them not only to lower retail prices by distributing managerial costs over a larger number of users, but also to increase their purchasing power. At present, the only creditable future buyers of power are NPC and MERALCO. As explained below, this consolidation would not only be beneficial to some of the coops, but also to some of the IODs (para. 18).

6. At this stage, it is impossible to predict the actual composition or the size of the resulting stock coops, not only because this process would take place in the political arena, but also because it should be largely voluntary and supported by incentives which the owners may nonetheless decline. Consequently, the consolidation process is likely to take several years. It is anticipated that the consolidation would integrate adjoining coops within a certain island or physical area into larger stock coops. Therefore, as a proxy for the resulting consolidation, we have simply used the 12 existing regions as defined by NEA. This breakdown allows the evaluation of the general impact of the prospective integration, although actual results would obviously depend on the size of the final stock coops and the particular coops that would be involved.

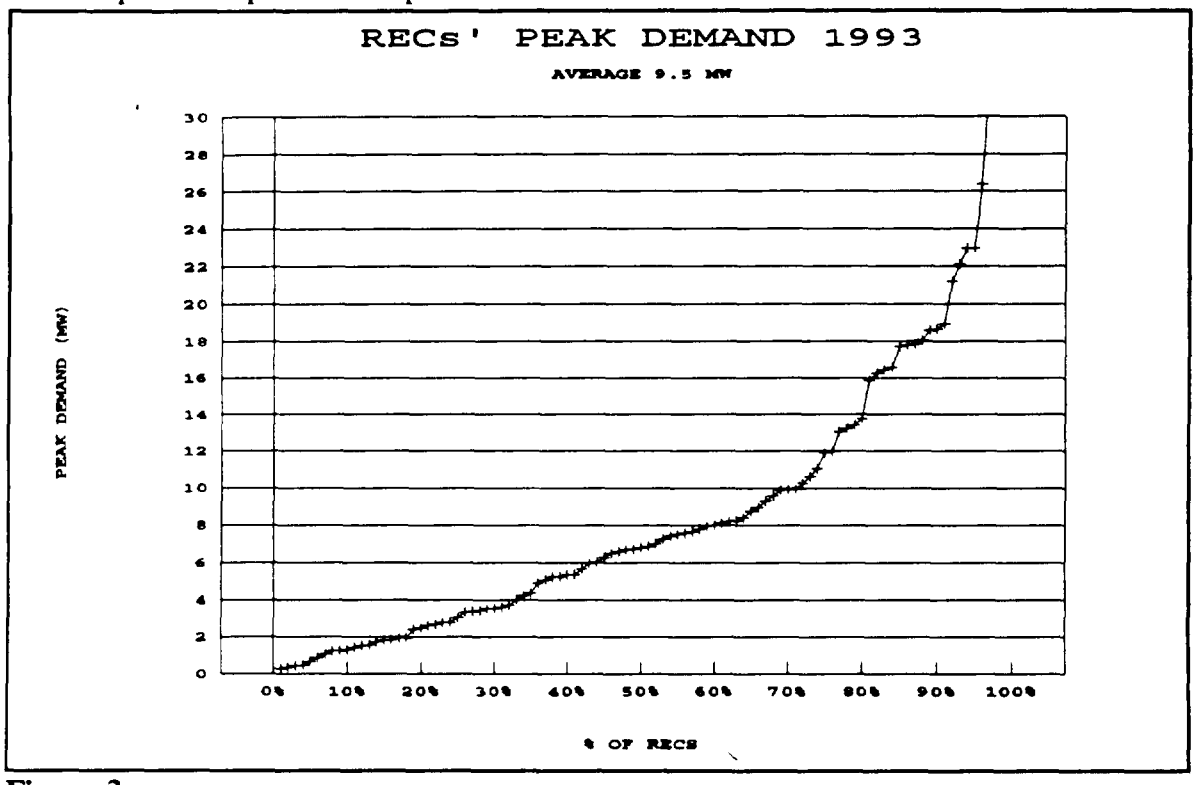

Figure 3

7. The purchasing, managerial and technical capacities of the coops are weak because they are dispersed among 119 entities and because the power demand of each coop is very low, averaging just 9 MW in 1993 (Figure 3). Many coops have a peak demand below 5 MW, while about 80% of them have a peak demand below 12 MW, and 90% below 18 MW. This greatly inhibits their ability to manage their demand or to influence the prices of their power purchases. Assuming that the coops within a region could be consolidated, average peak demand would bea 70 MW and most of the resulting stock coops would have peak capacities exceeding 40 MW (Fig 4). The strength of these stock coops could be enhanced further with the inclusion of one of the 12 IODs in a regional consolidation.

8. The benefits of consolidation in some areas may be be modest. Economies of scale would be difficult to achieve in regions which include many small islands and, although the general costs would be more widely distributed by regional stock coops, these small islands will probably continue to require subsidies. The primary savings resulting from the proposed consolidation would be the reduction of overhead (management, system analysis, accounting, engineering and planning).

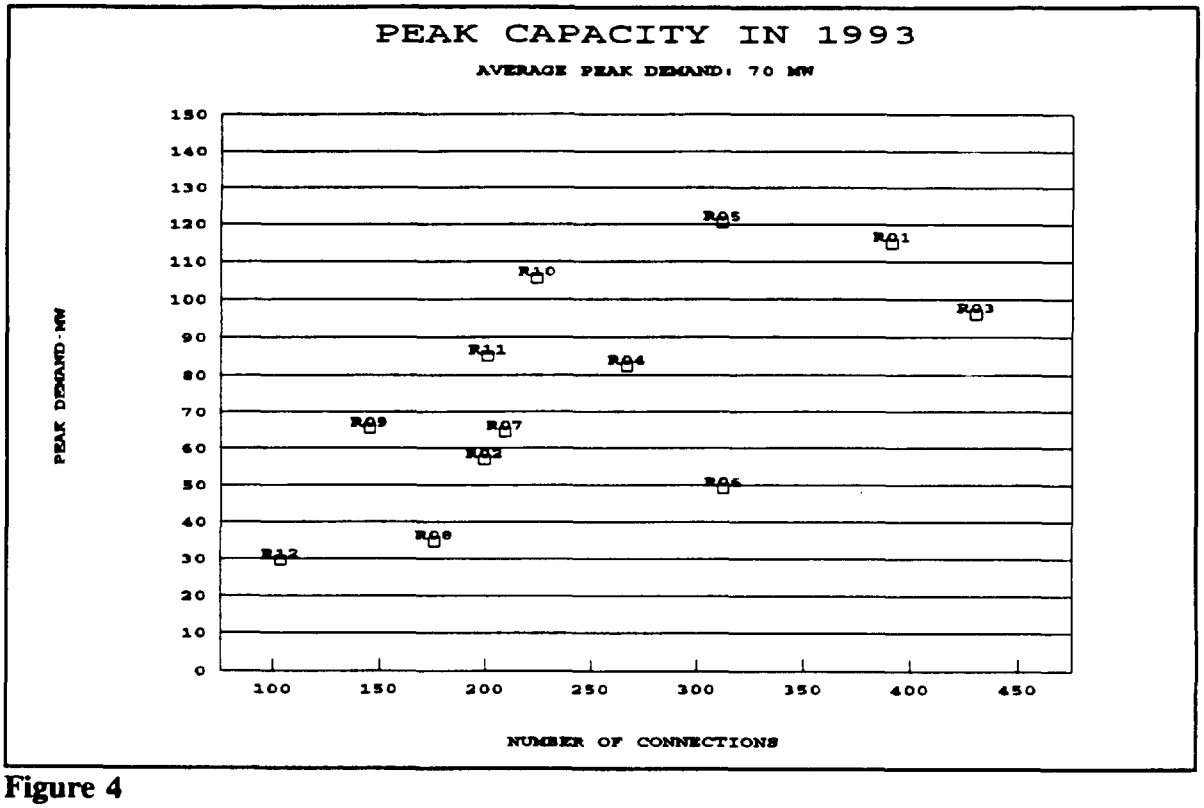

Figure 4

Moreover, ensuring capable managerial and technical staff would be easier for 12 coops rather than for 120.

9. The small size of the coops also limits the number of managerial and technical staff that they can afford. In 1992, the number of connections varied between 600 and 83,000, although 14 of the 17 largest distribution utilities are coops which serve 49,000 to 83,000 customers each. The consolidation would allow for better management, salaries, training and enhanced technical specialization, resulting in improved planning and technical efficiency. While 60% of the coops have less than 140 employees (Figure 5), the stock coops would have from 1,000 to 2,500 employees (Figure 6).

10. As shown in Figure 7, just 30% of the coops serve about 60% of the connections and account for about 70% of the total power sales. However, the total sales for half of the coops is less than 15% of the total coop sales.

11. The major financial benefits of the consolidation would be to reduce general costs and to lower the number of connections served by each employee. The latter is a key efficiency indicator and, as shown by Figure 8, the figure is still very low for many coops — all the moreso since the average (152) for all coops is skewed by the impact of the larger and more efficient coops. The difference between the best and worst performers. measured by the number of connections per employee, varies by a factor of six, indicating considerable scope for improvement. Consolidation into stock coops could provide strengthening, which could be a major factor in realizing better levels of service and extending the share of the population with power services from the current 60%, to 75% by the year 2000.

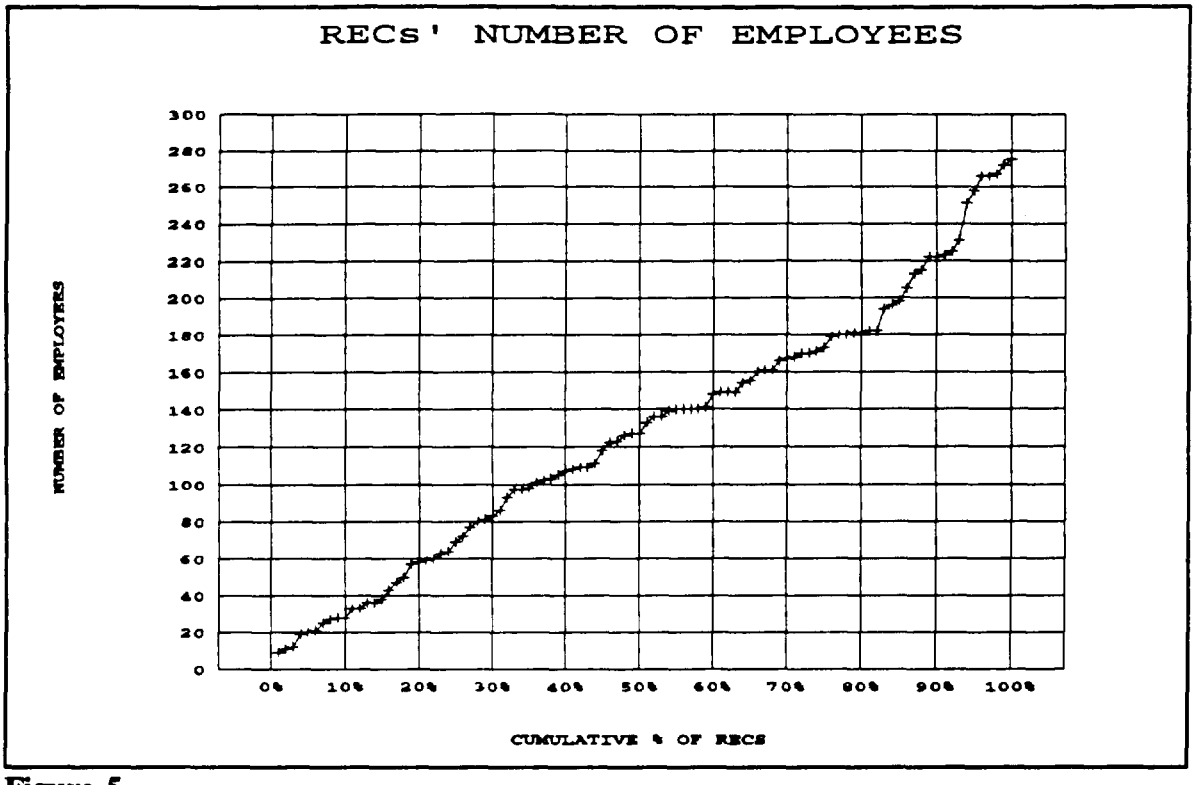

Figure 5

12. At present, retail tariffs vary widely, even between coops that are adjacent. This variation represents a major issue — and one which is difficult to justify to consumers — since the main cost, which normally represents about 60%-70% of the retail price, is the cost of power generation and transmission, and is the same within a region. Figure 9 shows the buying and selling prices for power by the different utilities, sorted by the size of the utility (in terms of number of connections). While the buying price (other than in Mindanao) was about ₱1.8/kWh in 1992, the average retail selling price of some coops reached ₱5/kWh (about ¢20/kWh), which is extremely high (about three times the price of electricity in Washington, DC.), particularly considering the low income of the population. There is also considerable variation in the margin between buying and selling prices, with this spread being smaller for the largest coops.

13. A major financial and political impact of the proposed stock coops would be to average the costs over a larger number of consumers in the same geographical area. As shown in Figure 10, the creation of stock coops could result in lower tariffs and margins (even without considering efficiency impacts). Some regions (9, 10 and 11) would even have tariffs and margins lower than MERALCO's (₱2.5/kWh).[2/]

14. The large margin between the retail power price charged by the coops and the purchasing price paid to NPC is shown in Figure 11. The selling margin, in which the retail price is

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2/ These regions are all in Minadanao, which enjoys a grid price about 30% lower than Luzon's. If wholesale prices were rationalized to eliminate cross-subsidies, the end-user rates in these regions might not be so favorable.

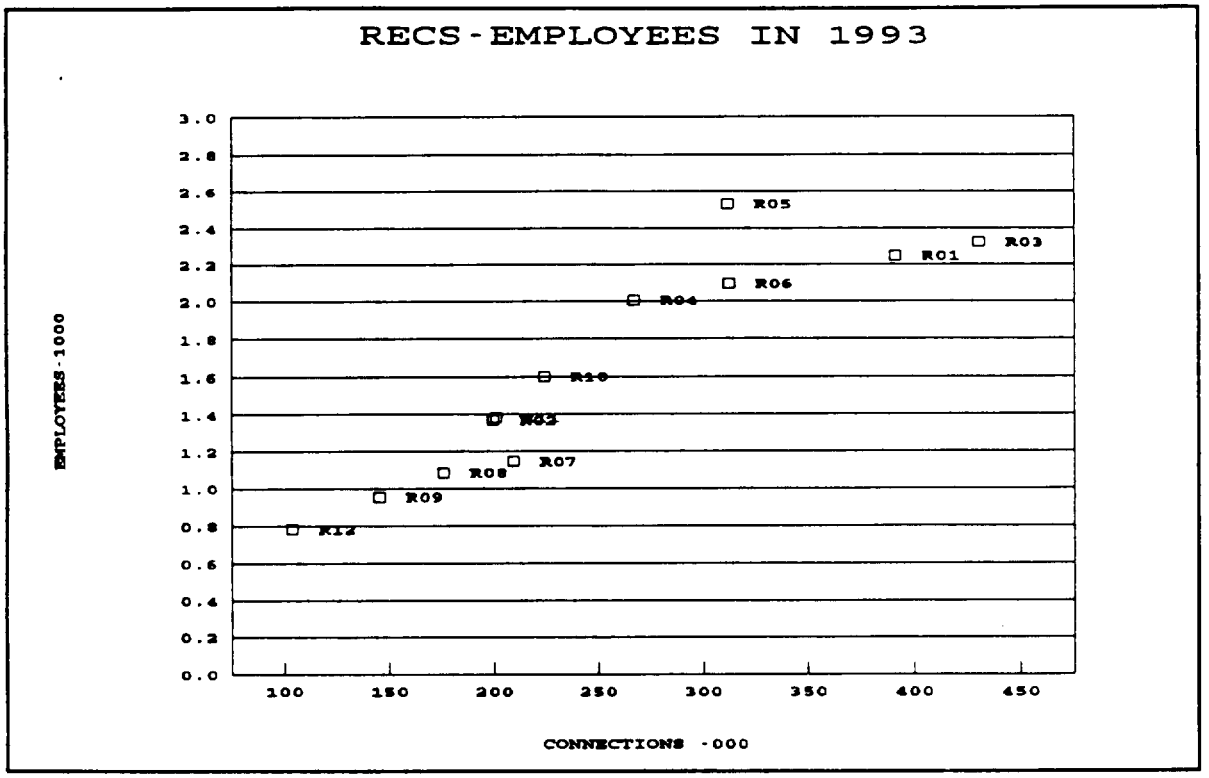

Figure 6

expressed as a percentage of the purchase price, shows wide variation (38% to 222%) about a high average level of 113% Financial consolidation would by itself substantially reduce these margins (Figure 12), both in terms of range (69% to 131%) and average (94%). Moreover, the actual performance of the coops should improve over time because of economies of scale in management, inventories, etc. Most other countries have fewer and larger distribution companies. For example, recent reforms of the electricity sector in the UK, Chile and Argentina have created structures where about a dozen utilities provide all distribution services.

15. Consolidation should also improve the load factor of the stock coops, which would facilitate the implementation of demand charges to reduce peak demand. As shown in Figure 13, the load factor averages about 40%, but is less than 45% for almost 70% of the coops, and is as low as 20% for some. Under the ongoing rationalization of tariffs and the implementation of demand charges, higher average tariffs would then result for coops with low load factors (which may also include the poorest consumers), while larger utilities and industries would have a higher load factor resulting in lower capacity and tariffs charges.[3/] The immediate impact of establishing stock coops would be to increase their overall load factors, with the aim of raisng the average load factor to 50% for all stock coops, and having a minimum of 40% (Fig 14).

16. A major objective of sector improvement is the reduction of energy losses, resulting from pilferage and technical deficiencies. In other countries, the institutional strategy of establishing large, specialized technical groups in a utility to deal with these problems has produced significant

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3/ Load factors shown here overstate normal operating conditions, since outages were significant in 1992 (particularly in Mindanao) suppressed peak demand.

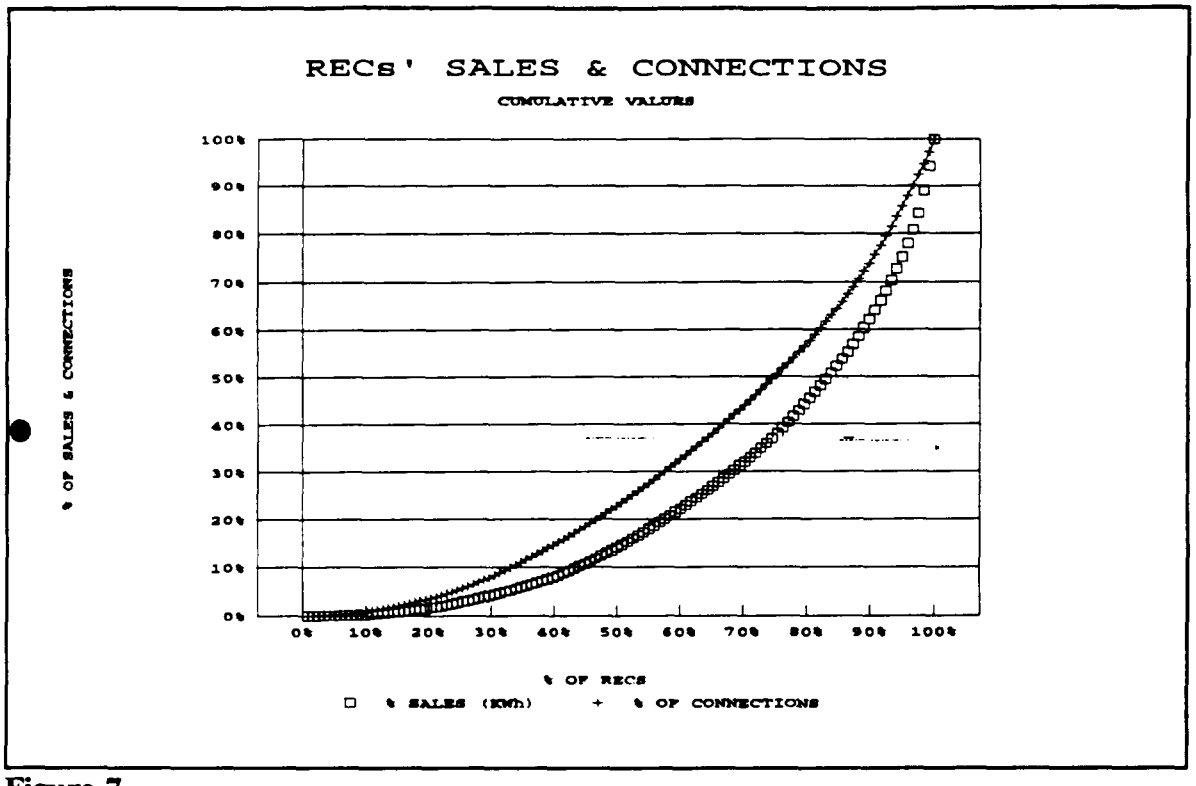

Figure 7

results. Therefore, it would be expected that losses would be lower for the largest coops; however, the data available similiar loss rates for the larger coops. In fact, some coops with as many as 30,000 customers have losses of almost 40% (Fig 16). The magnitude of these losses provide ample evidence for the need to pass the anti-pilferage legislation presently in Congress since, at present, there is in practice no sanction for power pilferage. Moreover, the lack of adequate legislation affords the utilities an excuse justifying their high loss levels. It will also be necessary to expand and rehabilitate the networks/substations to reduce technical losses, and for the ERB to continue reducing the allowable losses to be included as operational costs, until power losses are more reasonable. These measures would reduce the cost of power and thereby reduce pressure for future investments in generation.

17. A major benefit of the proposed stock coops would be to help those coops in financial distress by sharing profits within an entire region. This would break a vicious circle, whereby financial difficulties inhibit measures to expand the power system, reduce losses, hire competent staff, and sustain proper self-financing ratios. In previous years, sustaining service in many coops has required subsidies or periodic bailouts. The consolidation would, in most cases, eliminate financial losses and the need for government assistance since the coops as a group achieved a net profit of ₱263 million in 1992, even as some coops had individual losses of up to ₱20 million in that year (Figure 17). The consolidation would provide a sounder financial basis for the sector. As shown in Figure 15, most stock coops would generate net profits, although regions 9 to 12 would still experience some net income losses — but the percentage would be much lower than it would have been for the individual coops. The reduction in the total number of distribution utilities would also facilitate their financial restructuring, their tariff review by the ERB, and better monitoring of their performance.

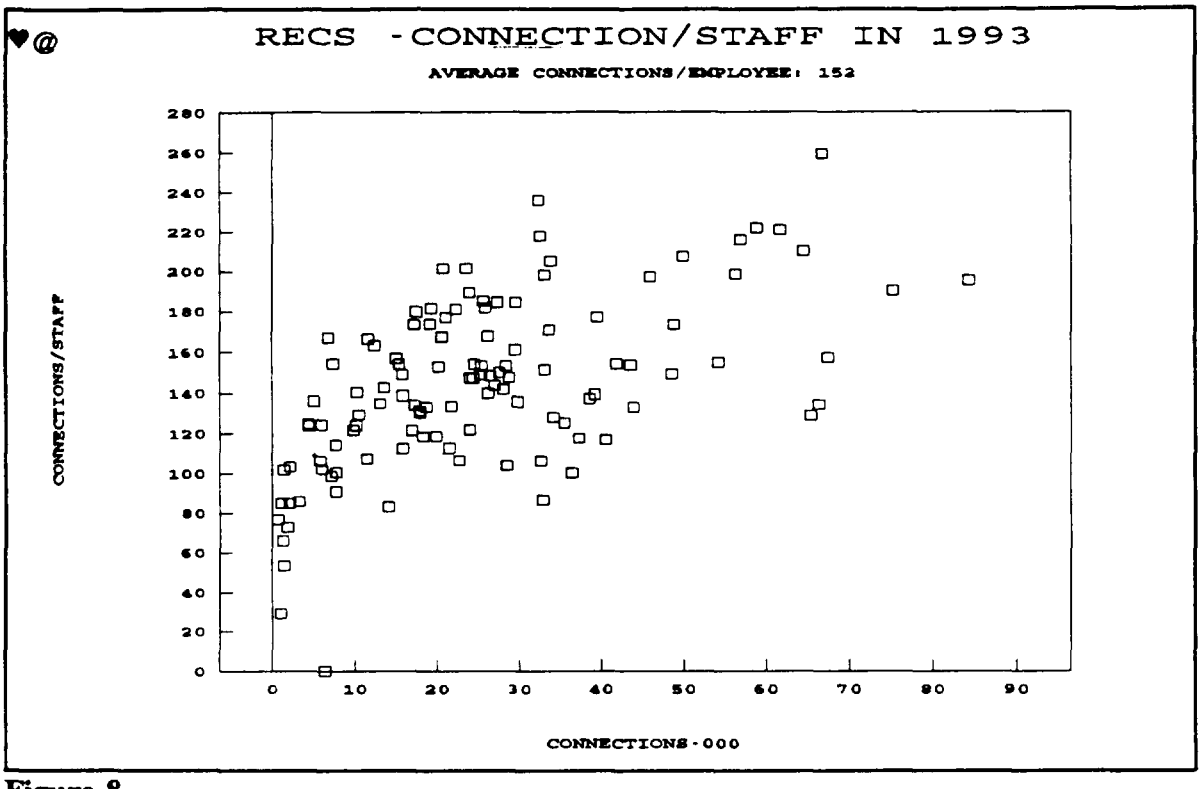

Figure 8

C. Analysis of the 15 Power Utilities

18. There are 15 investor-owned power utilities (IODs) that distribute power in their respective cities (9 in Luzon, 2 in the Visayas and 4 in Mindanao). These IODs are associated under PEPOA. Some are smaller than many coops, though the largest, MERALCO, accounts for about 60% of total energy sales in the Philippines and has 2.1 million connections, compared with just 0.16 million connections for the second largest utility (VEPCO). As shown in Figure 18, the IODs vary widely in number of consumers, and even more so in relation to their peak demand. Excluding MERALCO, the other 14 IODs require just 430 MW (about 18% of MERALCO), and have an average peak load of just 60 MW. Therefore, the benefits (para 5ff.) associated with the consolidation of the coops would also apply to the 14 IODs. Twelve of the IODs employ fewer than 300 workers; only three employ more: DALIGHT (330), VECO (582) and MERALCO (8,594). This indicates that in many cases these utilities may also have problems in keeping adequate financial, technical and managerial staff.

19. Power losses of the 15 IODs averaged 14.7% in 1992. This figure is high compared with distribution utilities in other countries (which average less than 10%), and disguises wide variations (between 6% and 35%). One in five utilities (and coops) have losses below 10%, (Davao, Cagayan and Cotabaco). In contrast, some IODs show losses as high as the worst coops (20% to 35%), including Tarlac, Manaoag, Ibaan, Cabanatuan and Ologampo. These will require prompt and substantial improvements.

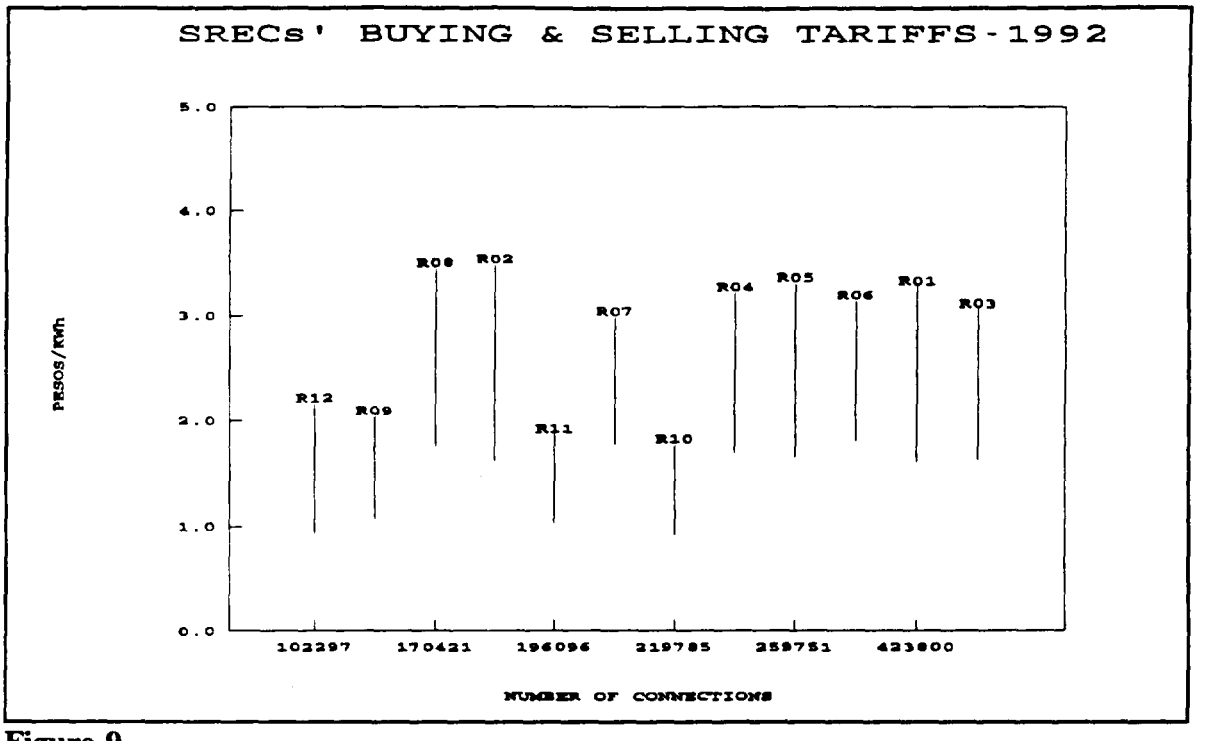

Figure 9

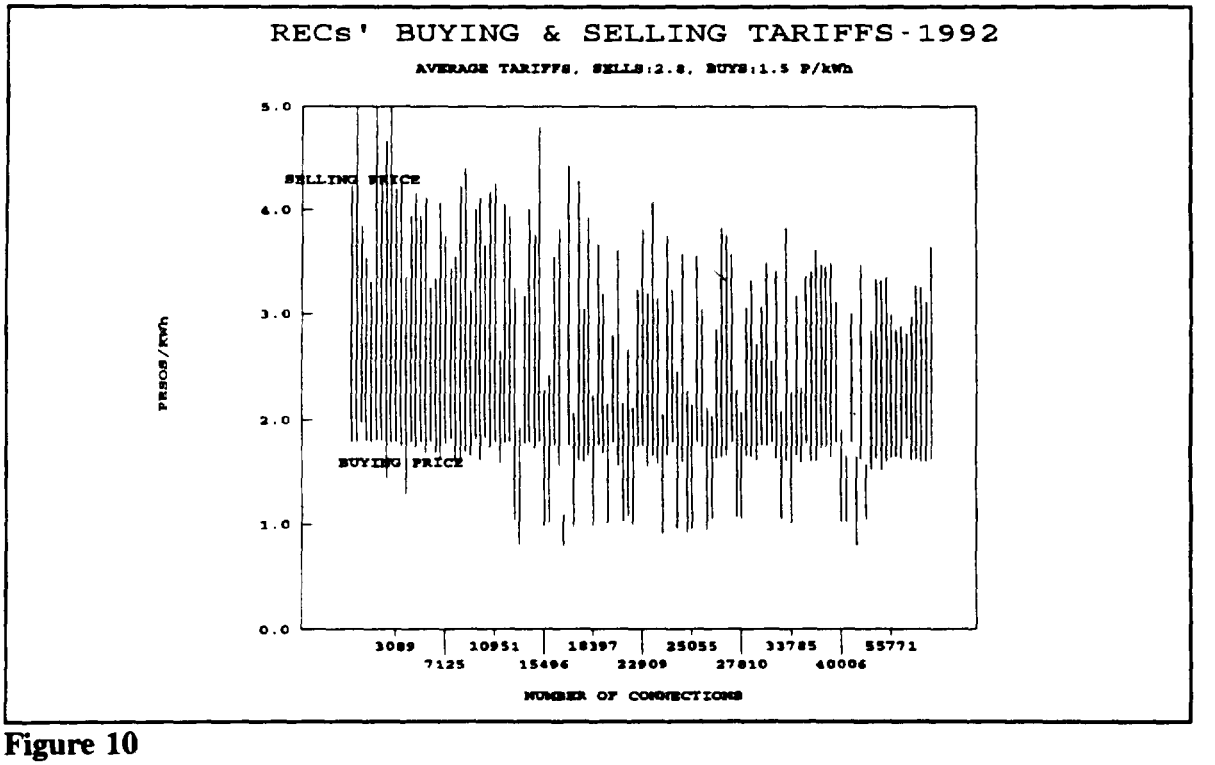

Figure 10

20. Some 40 coops and IODs achieved losses below 15% in 1992 (Fig 19). Many coops outperformed IODs (shown in capital letters) in controlling power losses. MERALCO, although

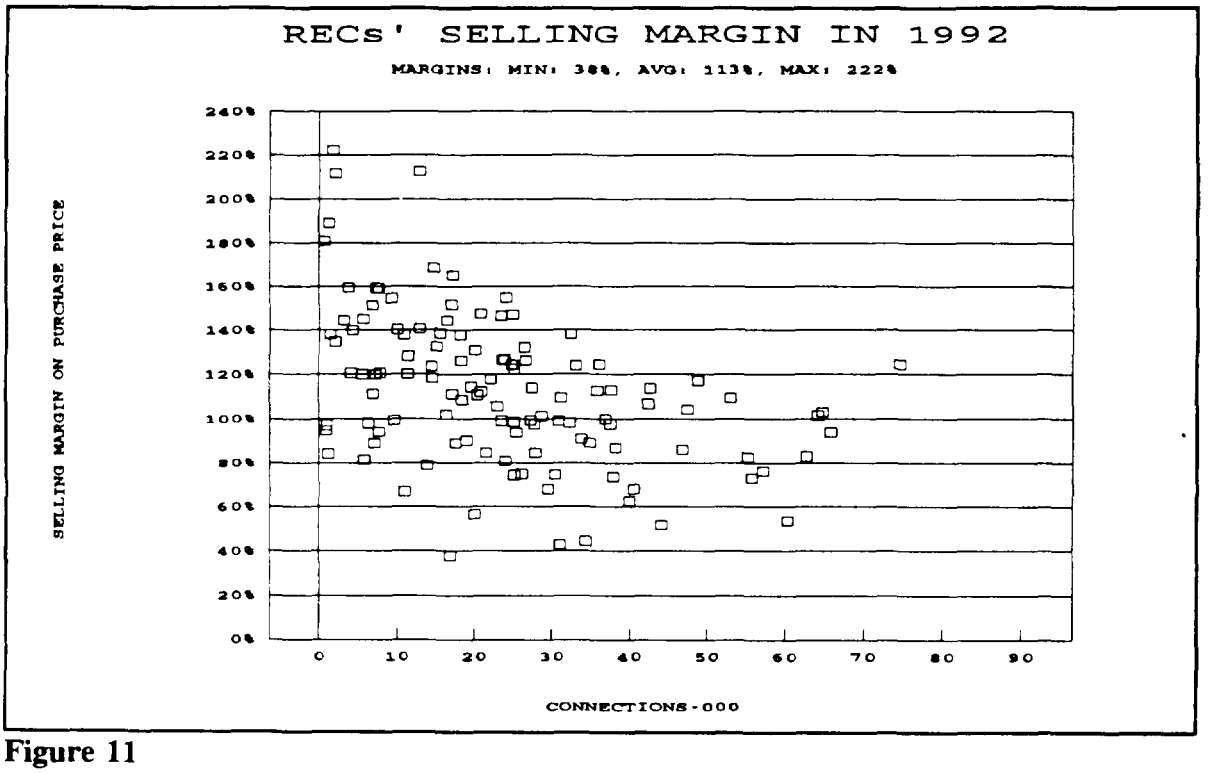

Figure 11

technically much stronger than any of the others had middling losses, accountable to long lines within its large service area.

21. An important indicator of efficiency is the number of customers per employee. The average for these utilities of 223 consumers per employee is low (Fig 20), since power generation and transmission are not included. However, on the average, the IODs serve almost 50% more consumers per employee than the coops as a group.

22. The average retail power prices charged by IODs are generally lower than the prices charged by the coops, both because of their greater economies of scale and their higher share of industrial sales. Their average tariff is ₱2.5/kWh (about the same as MERALCO's), with most tariffs in the range between ₱2.5 to ₱3/kWh, while three IODs in Mindanao charge less than ₱1.7/kWh (partially because NPC tariffs are lower in Mindanao). As shown in Figure 22, the selling margin is relatively high (and averages 62%), but it is lower than some of the coops. Although some IODs (ILPI, CEPALCO and MERALCO) have somewhat lower margins of between 50% and 60%, these are high by international standards.

23. There are wide variations in the load factor (40% to 75%) among the IODs (Figure 23), and they are generally higher than the coops'. As expected, large industrial cities show a higher load factor (above 60%), like Angeles, Davao, VEPCO, MERALCO and Cotabaco. The peak demand is very low, except for MERALCO (2,400 MW) and VECO (157 MW), and averages below 78 MW, indicating that buying power will be very limited without consolidation.

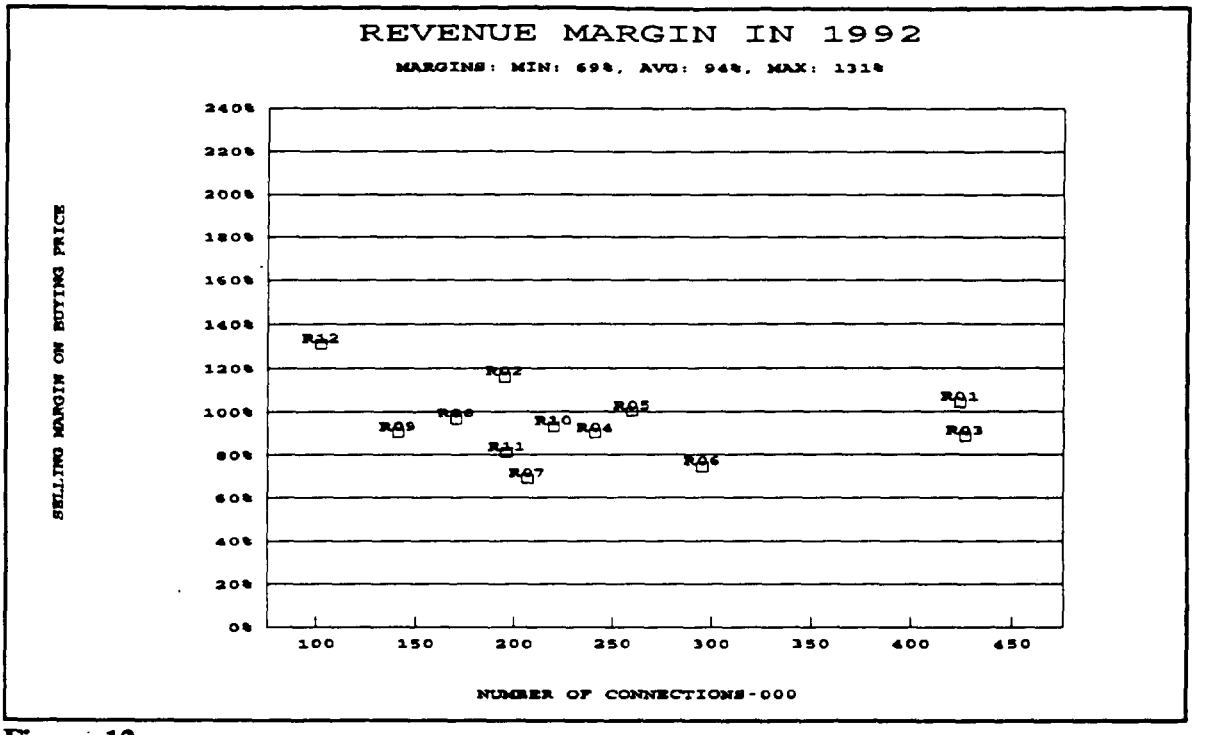

Figure 12

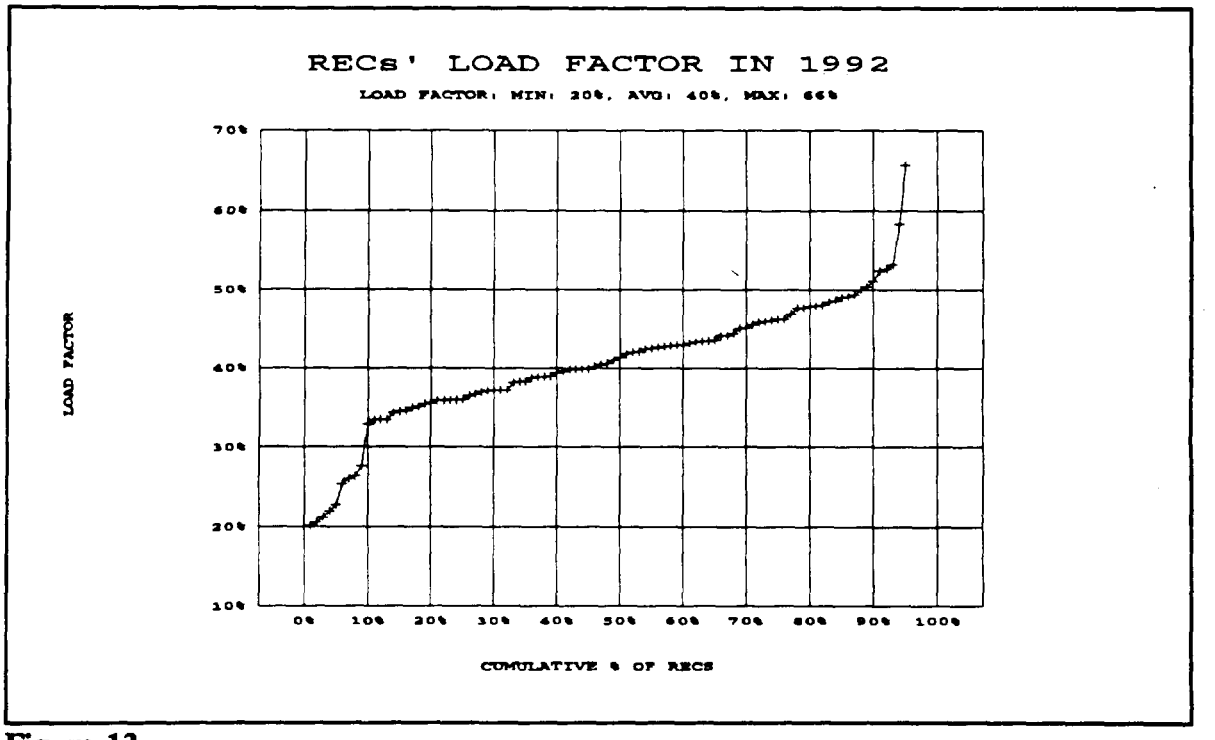

Figure 13

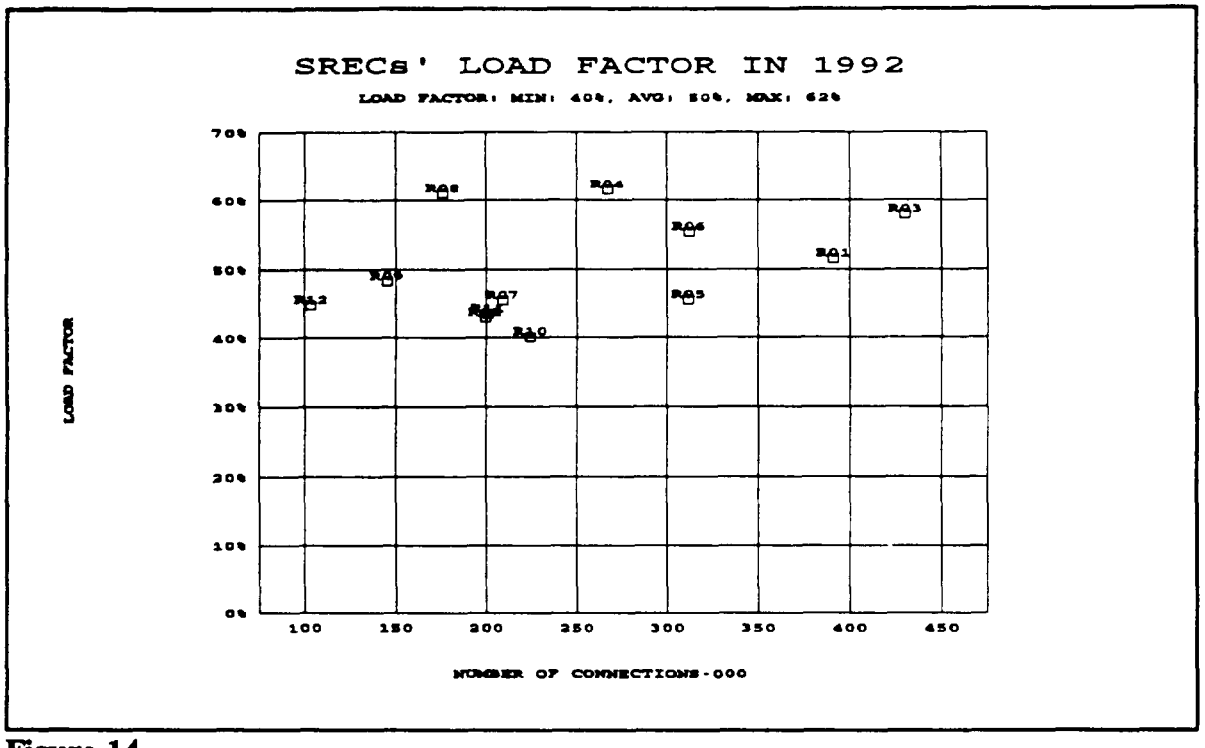

Figure 14

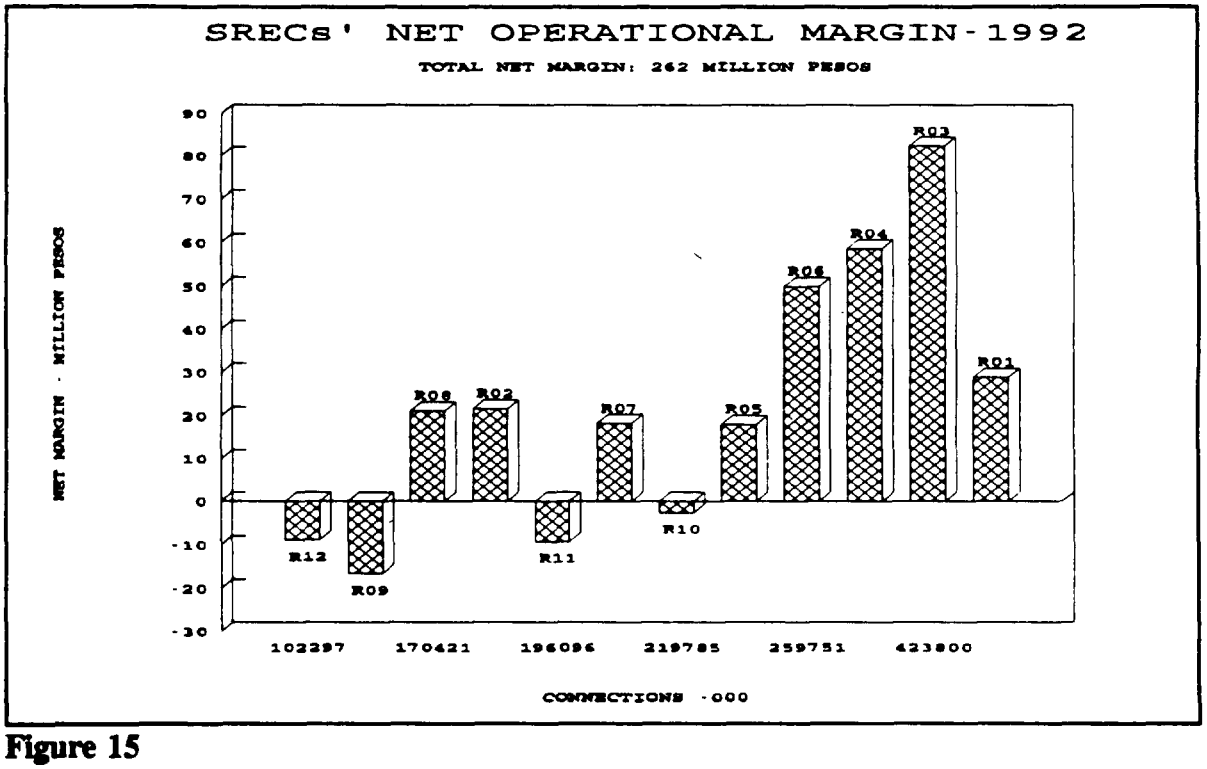

Figure 15

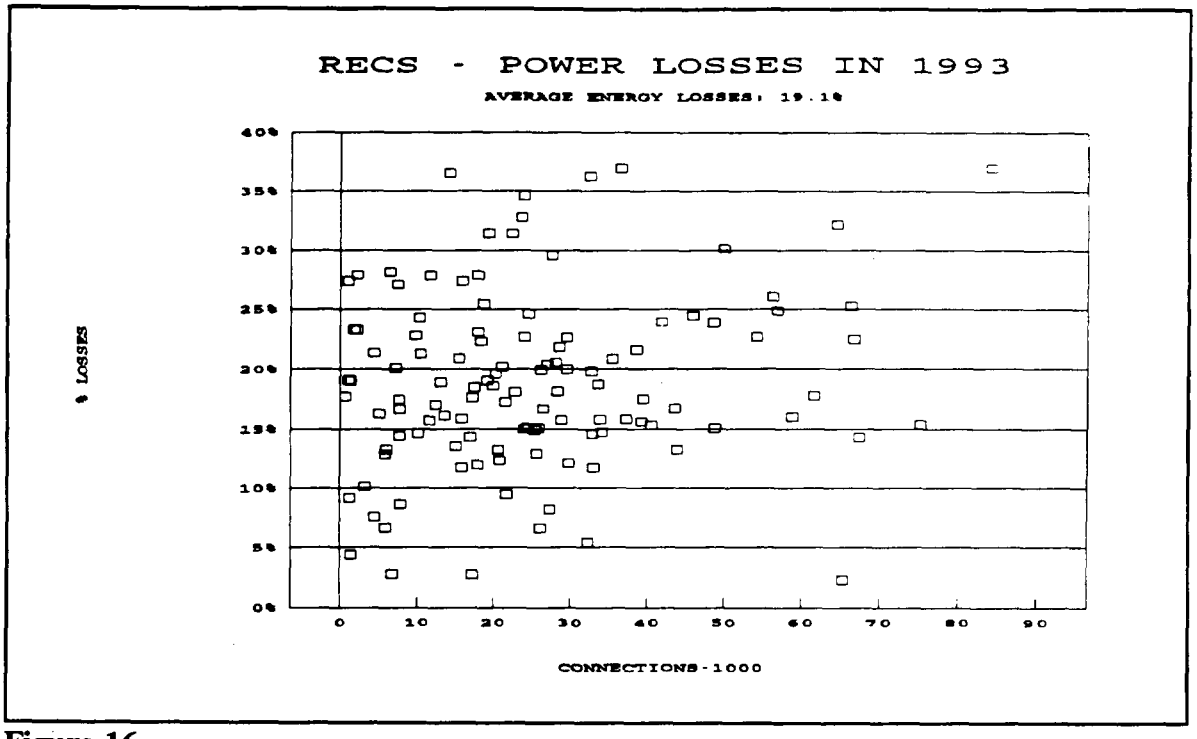

Figure 16

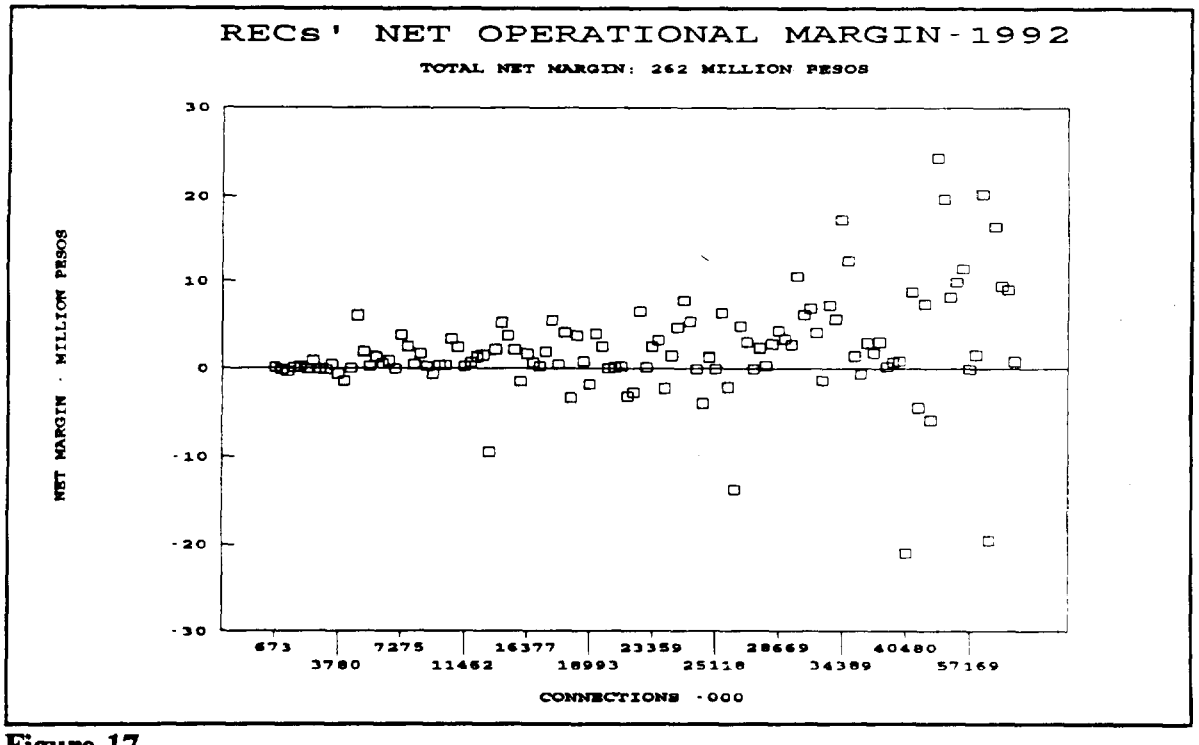

Figure 17

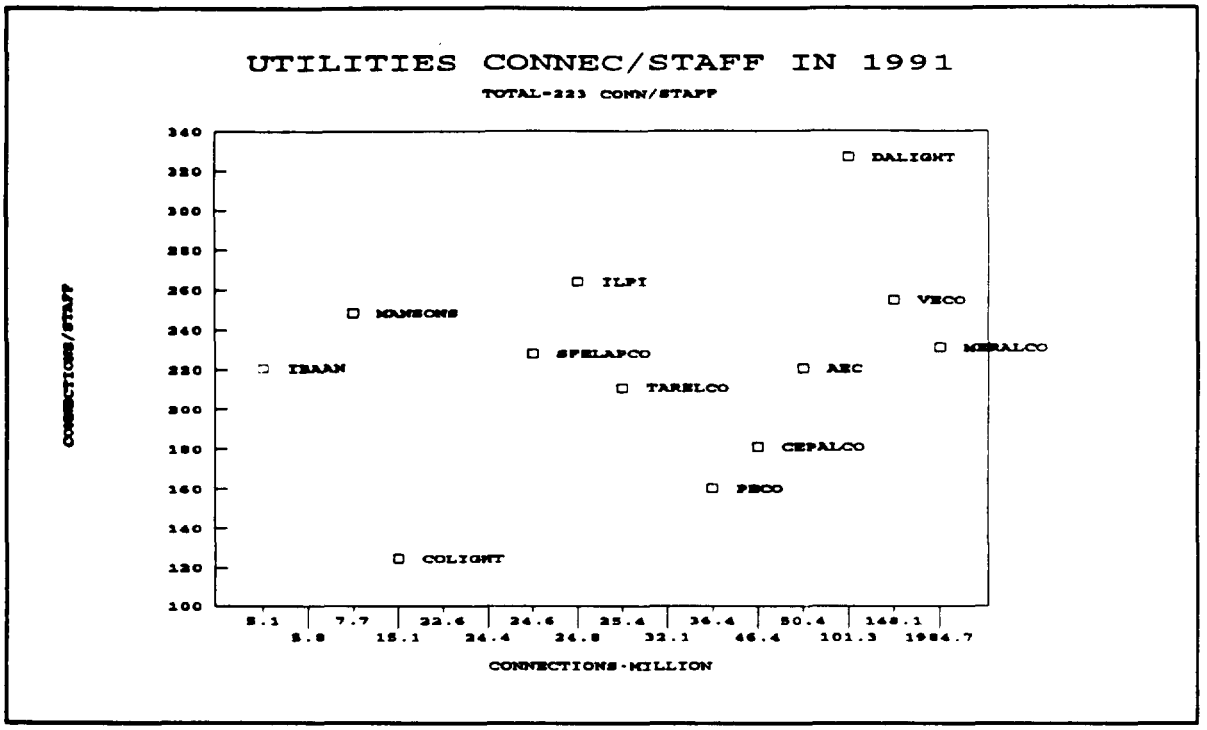

Figure 18

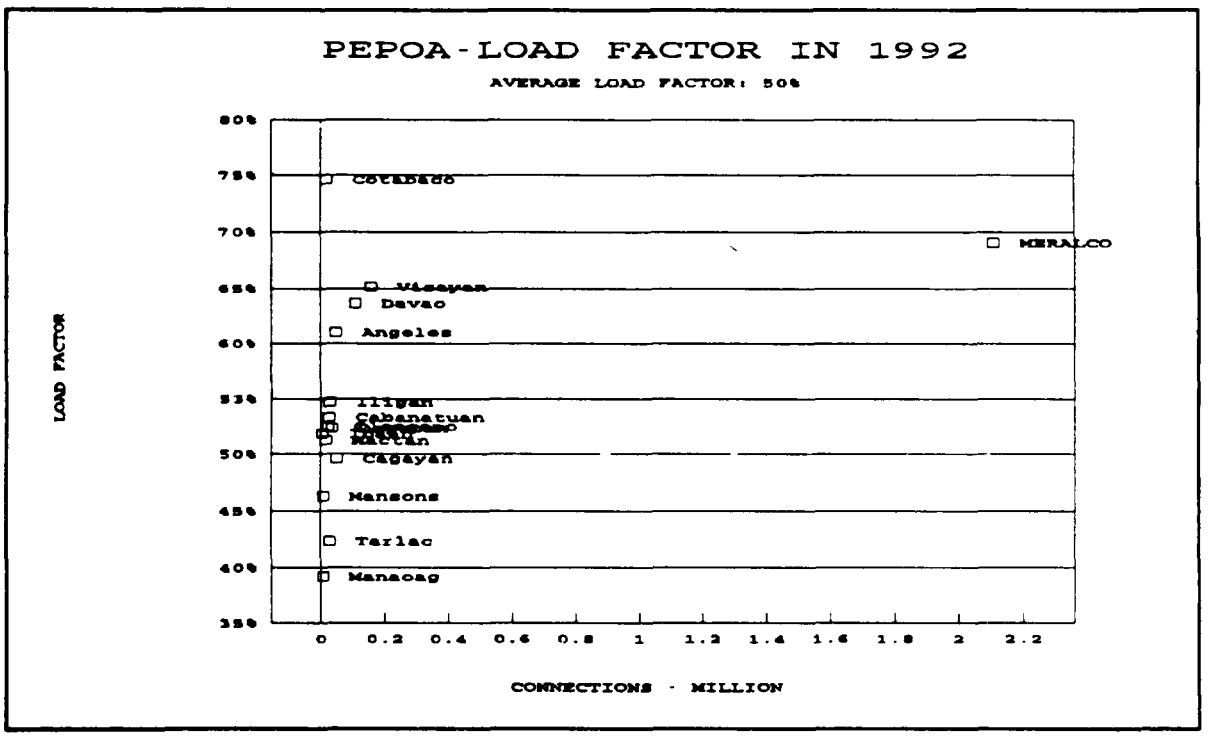

Figure 20

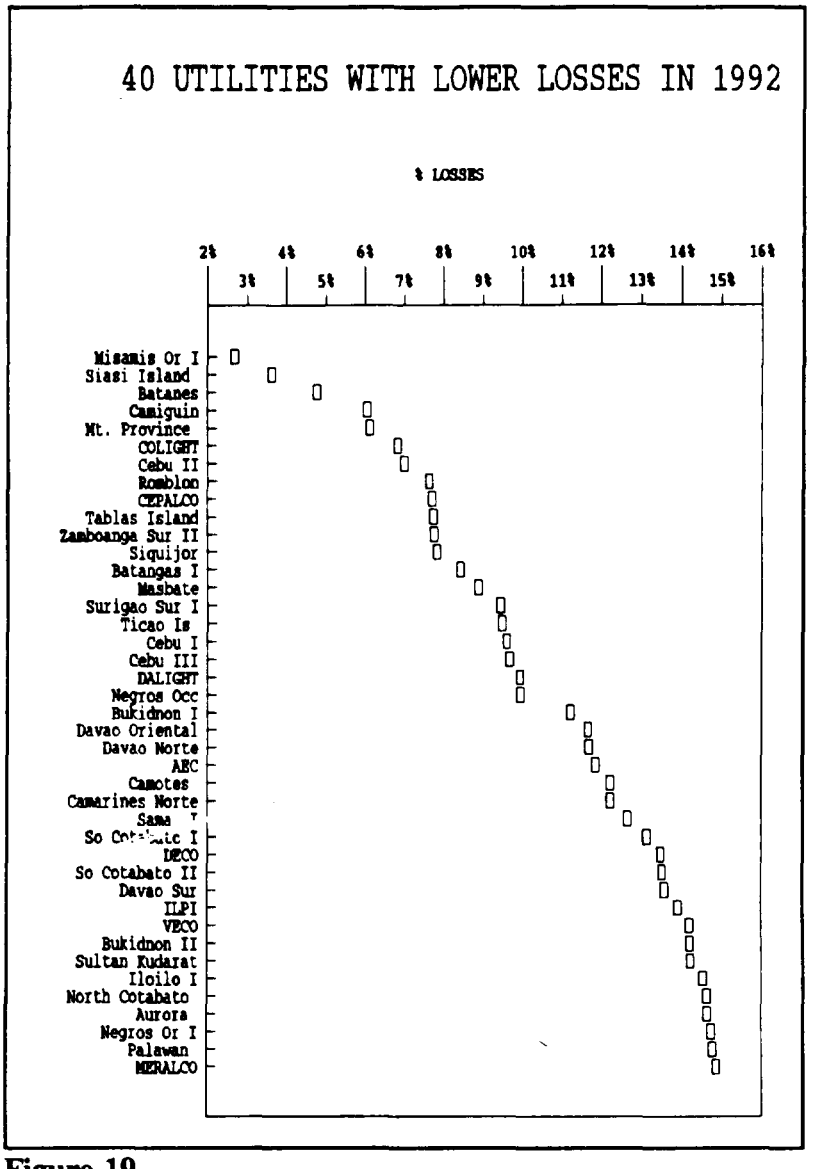
40 UTILITIES WITH LOWER LOSSES IN 1992
% LOSSES
2%
3%
4%
5%
6%
7%
8%
9%
10%
11%
12%
13%
14%
15%
16%
Misamis Or I
Siasi Island
Batanes
Camiguin
Mt. Province
COLIGHT
Cebu II
Romblon
CEPALCO
Tablas Island
Zamboanga Sur II
Siquijor
Batangas I
Masbate
Surigao Sur I
Ticao Is
Cebu I
Cebu III
DALIGHT
Negros Occ
Bukidnon I
Davao Oriental
Davao Norte
AEC
Camotes
Camarines Norte
So Cotabato I
DECO
So Cotabato II
Davao Sur
ILPI
VECO
Bukidnon II
Sultan Kudarat
Iloilo I
North Cotabato
Aurora
Negros Or I
Palawan
MERALCO

Figure 19

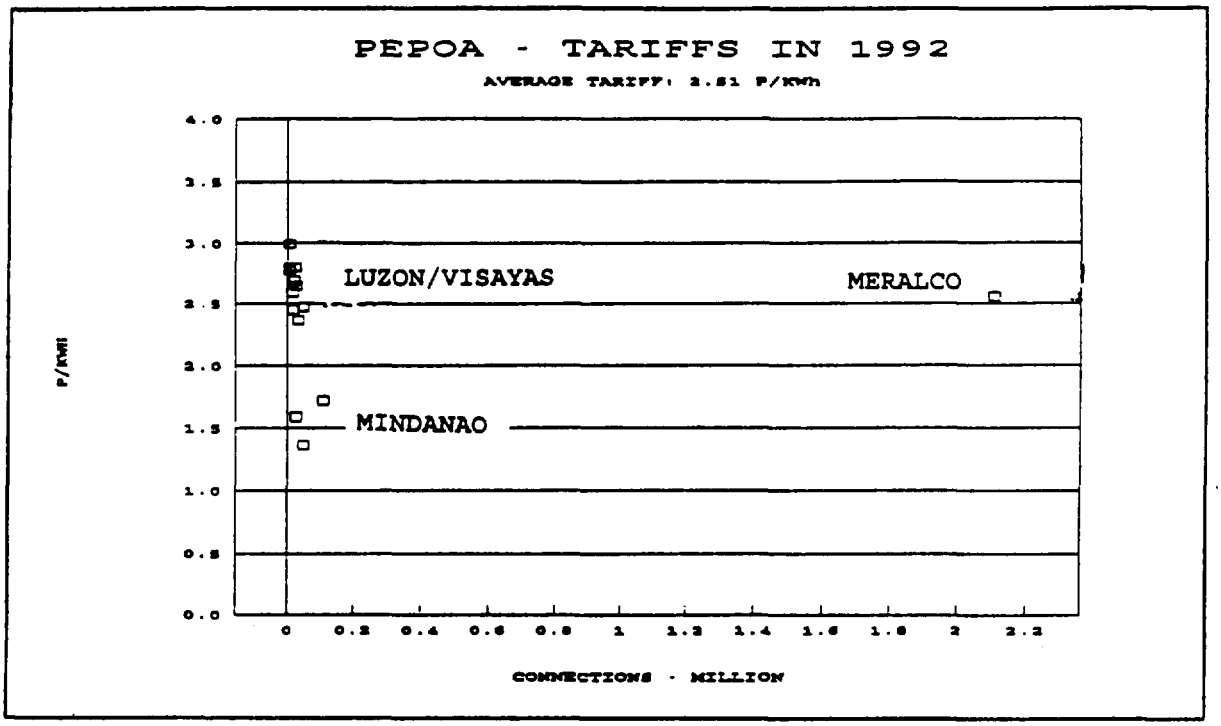

Figure 21

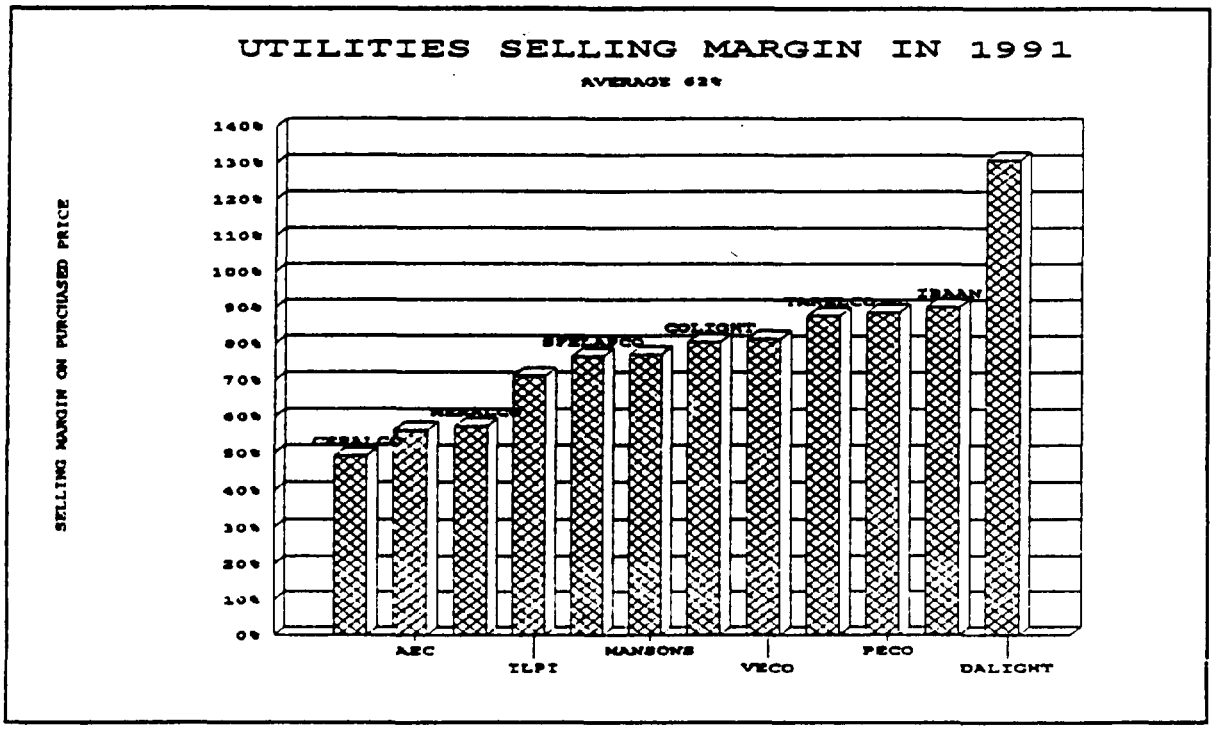

Figure 22

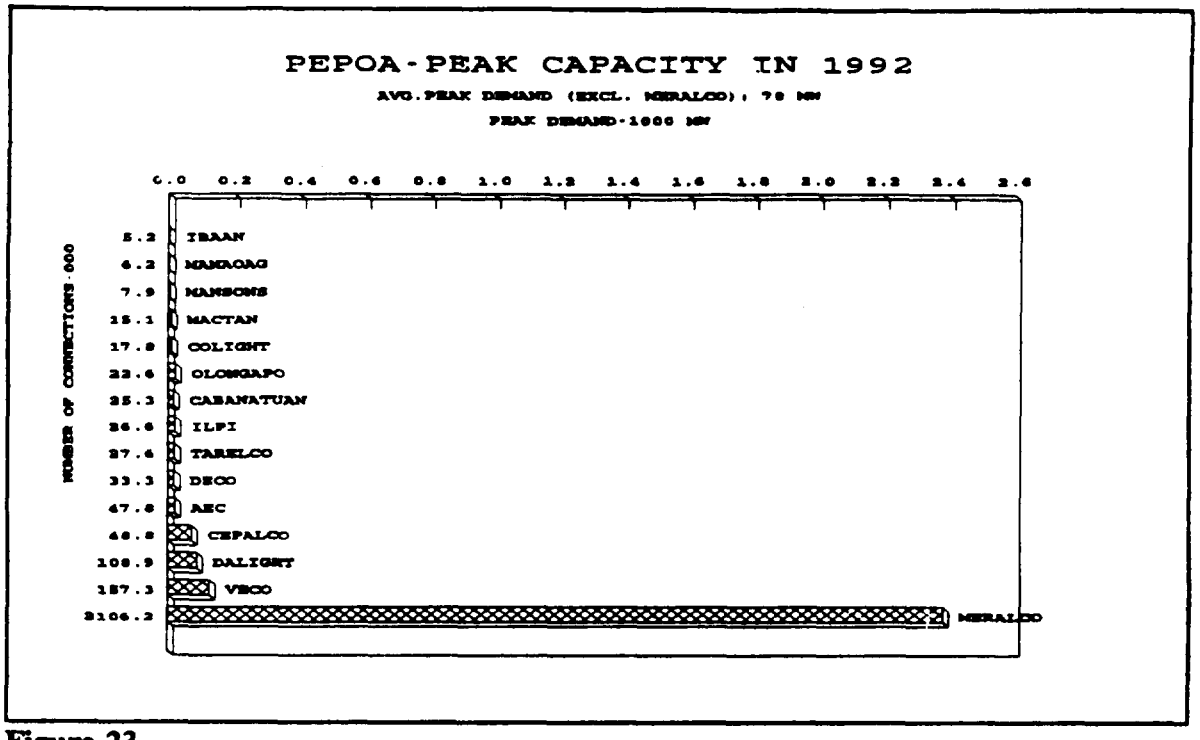
PEPOA-PEAK CAPACITY IN 1992
AVG.PEAK DEMAND (EXCL. MERALCO): 78 MW
PEAK DEMAND-1000 MW
0.0 0.2 0.4 0.6 0.8 1.0 1.2 1.4 1.6 1.8 2.0 2.2 2.4 2.6
NUMBER OF CONNECTIONS-000
5.2 IBAAN
6.2 MANAOAG
7.9 MANSONS
15.1 MACTAN
17.8 COLIGHT
22.6 OLONGAPO
25.3 CABANATUAN
26.6 ILPI
27.6 TARELCO
33.3 DECO
47.8 AEC
48.8 CEPALCO
108.9 DALIGHT
157.3 VECO
2106.2 MERALCO

Figure 23

PHILIPPINES

POWER SECTOR STUDY

ERB Institutional Development

1. This Annex is in two parts. Part A is a justification for an institutional development request for ERB, followed by a description of the content of the requested training. Part B is an analysis of staffing needs for the ERB.

A. Institutional Development Request for the Energy Regulatory Board

2. Electric power rate regulatory functions in the Philippines, including assurances of service quality, are the responsibility of the of the Energy Regulatory Board (ERB). This Study proposes to also add franchise authority. ERB is a traditional quasi-judicial regulator using very conservative methods, founded in common law traditions of administrative evidence and rate review. The ERB is an independent regulatory agency broadly respected in the Philippines, whose previous electric regulatory duties were limited to the investor owned distribution (IOD) systems. ERB rate duties have recently been expanded significantly to include regulation of prices of NPC and of the many rural cooperatives (coops). ERB duties will expand further as sector restructuring continues. As of December 1993 authorized staffing is 223, but actual staffing was about 173, and ERB's requested staff to carry out present duties assigned by the Department of Energy Act in December 1992 is 263. A further increment of at least 50 is required by this Study, for a total increase of 140.

3. The purpose of this request is to procure direct institutional support and training which will enable the ERB to conduct regulating activities necessary to effect the purposes of the 1992 Department of Energy Act in a manner which is appropriate to the Philippines. Three forms of support are requested. To provide immediate assistance, consultant-specialists in aspects of regulation and special issue studies will be made available to ERB. To provide longer term support, ERB staff training will be offered. Institution matching ("twinning") will be arranged if a suitable twin organization is available. Other support services are also noted.

4. TRAINING REQUEST. The training request covers many different technical areas. While all areas are of eventual importance to ERB, an orientation course is needed immediately. Priority should be given to the basic duties of ERB. Remaining topics are then of co-equal importance as technical subjects likely to be encountered by ERB in the course of its normal duties. Each topic is stated as a technical block of subject matter. Each technical block must be presented as a single coherent body of materials, in the form of a course-module of one to five days duration. Each module could be taught in similar form on several different occasions. Each module must be developed and presented so that each means of solving a particular regulatory problem is analyzed for how implementation of that method affects the relevant major systems. Modules will present the several major current and/or historical methods used for each significant problem area. Each method will be evaluated in a manner which induces students to understand the choices required, and to reach their own judgements on the possible applications of these methods in the Philippines. Each course should assume a fully professionally qualified student lacking only in experience in a regulatory agency. Each module shall specify the technical background assumed for the subject matter discussed, and shall provide an appendix which summarizes the relevant materials and provides citations to appropriate reference texts for necessary

background material. The provider should also cite additional topics required for coverage of that topic, and for each module, the provider shall add a section for "other current issues" which highlight recent trends, fads, ideas, problems, of the subject matter of the module.

5. The initial training module requested by ERB is an orientation course for new staff. This paragraph therefore requests a module entitled "Orientation to Energy Regulation", to be structured according to the general descriptions given above, and which shall include at least the following materials: overview of the purposes and history of regulatory institutions; the legal context of regulatory institutions; the economic functions proposed for regulators; typical procedural methods used by regulatory bodies; typical cases which come before regulators; standards of evidence used by regulators; standards of judgment and kinds of rules, orders or opinions made by regulators; history of regulation in the Philippines and how it relates to the general principles summarized; other current general topics.

6. Technical Training Modules, Basic Topics

6.1 Electric System Rate Design
- Forms of cost recovery and their relationship to revenue requirements
- Microeconomic concepts of rates and pricing
- Descriptions of possible rate forms including demand charges, customer fees, billing fees, energy ates, and other system charges
- Theories and methods of electric system rate design
- Theories and methods of electric system cost allocation methods
- Relationships of rate design methods to economic efficiency
- Relationships of rate design methods to engineering efficiency
- Theories of regulatory pricing, including but not limited to "AJ effect", first best and second best pricing, marginal cost pricing, average cost pricing
- Relationships of pricing methods to engineering concepts
- Relationships of pricing methods to power system design and operation concepts, including to dispatch and power pool operations
- Automatic adjustment clauses

6.2 Regulation of Rural Cooperatives
- Cost accounting
- Debt analysis and debt coverage analysis
- Rate base valuation and depreciation methods
- Sources and means of financing
- Forms of rural cooperatives and their special management and technical problems: distribution cooperatives, transmission cooperatives, generation agreements, generation and transmission cooperatives, and other associations of cooperatives
- Effect of transmission system rates on distribution system operations
- Special management problems of cooperatives
- Billing and other daily management issues

6.3 Regulatory Law
- Theories of legal systems: common law systems, administrative law systems
- Idea of a quasi-judicial institution
- Regulatory law in the Commonwealth (Britain, Canada, New Zealand, India, Australia): major statutes, form, structure and function of institutions
- Regulatory law in the U.S. States: structure of institutions, typical public utility Acts, principal duties, typical decisions and problems

- U.S. federal regulatory law: major statutes, major court decisions, structure of institutions, principal duties, typical decisions and problems, the role of rule makings
- Regulatory law in other major jurisdictions of Europe and Asia: major statutes, form structure and function of institutions
- Competition law in major jurisdictions: regulation of entry, price discrimination, market concentration
- Conflict of interest regulation: affiliated entities, conflicts of officers and directors
- Understanding holding companies
- Rule making processes: when and how to use them, subsequent revisions of rules
- Rate case processes
- Certificate processes
- Service territories: when to save them and when to remove them
- Regulation of market entry
- Special problems of regulatory hearings and of regulatory evidence

7. Other Technical Training Modules

7.1 Regulated Electric Power Systems
- Power system planning concepts and theories
- Power system operations and control concepts and theories
- Power system optimization theories and methods
- Power system modelling using such methods as WASP or Promote
- Dispatch institutions and issues, including control areas, economy dispatch, power pool concepts, power brokers as dispatchers, and related concepts.
- Coordination agreements and technical aspects of load flow control
- Analysis of fuel supply arrangements and contracts
- Load factor and its effect on efficiency, planning, operations and rates.

7.2 Regulatory Accounting
- Summary of theories, concepts, methods and problems of regulatory accounting
- Concepts and methods of rate base valuation and of related depreciation methods
- Concepts of cost of service
- Test periods: past, present and future
- Analysis of energy contracts
- Analysis of working capital
- Analysis and problems in regulatory tax accounting
- Fuel clauses
- Other automatic adjustment clauses

7.3 Management Analysis
- The concept of a regulatory management assessment
- Theories of corporate and cooperative management and organizational designs
- Management performance measurements
- Quality of service standards and measurements
- Evaluation of management effectiveness
- Relationships of regulatory accounting and pricing methods to management actions
- Review of problems of power system management, by major functional area: transmission, generation, distribution, metering, management information systems, accounting systems, personnel systems, and other systems
- Identifying management issues for regulatory assessment

- Effective regulatory actions which lead to improved service, efficiency or other regulatory purposes
- Planning as a management tool, including integrated planning, "least cost" planning, and demand side management
- Incentives created by private ownership and private equity and what they mean for efficient management and utility planning

7.4 Analysis of Return on Equity
- Concepts of return and of rate base
- Concepts and methods of rate base valuation
- Capital structure analysis
- Evaluation of equity markets
- Effects of rate of return analysis on efficiency and planning
- Economic concepts including but not limited to the "AJ effect"
- Understanding equity
- Ownership and control
- Affiliated entities and problems of conflict of interest, limits of jurisdiction, rules affecting conflicts, ownership, and affiliates
- Role of officers and directors as owners of equity
- Employee share ownership

7.5 Demand Side Management (DSM) Methods
- History of DSM methods
- Concepts of DSM programs and program design
- Past record of effectiveness of DSM programs (summarize/compare plans to results of actual past cases)
- Design of rates for DSM, including cost basis for rates
- Rate base concepts and methods for DSM
- Methods to compare costs of DSM to costs of supply side
- Relationship of DSM rates to marginal costs of supply
- Sources of data for DSM program DSM equipment efficiency measures
- Evaluation of utility DSM management programs and costs
- Methods of utility energy use audits
- Types of programs for commercial and industrial customers
- Types of programs for residential users

8. DIRECT INSTITUTIONAL SUPPORT. Regulation is a technical subject, and even professionally qualified personnel may take several years to acquire needed experience and practical knowledge to function fully effectively. Therefore, this portion of the request seeks to provide immediate temporary assistance to the ERB to enable it to perform its present duties, while it is also building its own internal staff capabilities. These terms of reference would therefore provide services to ERB and its staff in a manner which builds the capabilities of ERB, and which does not compromise the integrity and independence of the ERB, yet which also provides capabilities much faster than would occur through normal training and institution-building processes.

9. Several areas of support are sought in the paragraphs below, including direct technical research support, counterpart organization personnel sharing and other consultant contract support. Some duties under this contract will also be performed by a single individual or institution, cited as the "coordination consultant", and further described below.

10. Many of the issues which ERB already faces or will shortly face are similar to issues and problems which have become familiar to other similar kinds of institutions. Such issues could be examined for ERB in one-time single-issue research reports. For example, ERB is considering review of how revenue requirements might be set for rural electric cooperatives which have limited or no equity, yet require a cash flow to cover capital expenses; ERB has expressed interest in concepts such as the "Times Interest Earned Ratio" (TIER) for deciding such matters. Where such specific focused questions can be posed by ERB, specific highly focused one-time research papers could be prepared by specialists to offer ERB a concise review of the issues and previous resolutions of the indicated matter. Such papers would be designed to offer "systems view" analyses of what choices or options are implied by the question posed by ERB, and how various possible ERB actions affect outcomes. ERB could then use these research papers as part of its deliberative processes. Also, ERB may be employing generic rule makings as part of its processes, in order to simplify rate proceedings in matters where similar issues may be repeated in many cases, or where frequent filings of a similar sort occur by the same applicant (as in automatic adjustment clauses). Therefore, ERB might also seek specific generic policy advice from qualified specialists, in the form of concise single issue topic studies or reports. All such one-time specific topic research papers will be contracted through a topic specialist recruited by the coordination consultant.

11. ERB acts through written orders, much as does any other similar quasi-judicial common law regulator. Therefore, ERB's published orders might be a subject of interest for on-line subscribers to services such as WestLaw or Lexis/Nexis. Therefore, the coordination consultant will explore with both ERB and such on-line services whether and in what form ERB orders may be listed on such services.

12. A current library of basic legal and regulatory materials is essential for ERB. ERB relies upon the same common law base of prior decisions of other regulators and courts as do similar institutions in other countries. Therefore a basic set of subscriptions to from four to eight major legal sources will be obtained, including a complete series of the United States' Federal Power Commission (FPC) Reports from their inception until 1978, and Federal Energy Regulatory Commission (FERC) Reports from 1978 to present, a current subscription to the FERC Reports published by Commerce Clearing House, other principal U.S. Department of Energy regulatory series publications, publications of the National Association of Regulatory Commissioners (NARUC) research studies, and other principal sources from major regulatory jurisdictions to be identified.

13. ERB uses similar methods, processes and concepts for rate setting as do other similar bodies in other jurisdictions, and relies upon the common law body of knowledge for how to carry out such regulation. Yet ERB has essentially no research capability to access publications in other jurisdictions, except one current subscription to one, respected but limited, source publication. Therefore, a contract will be sought with an existing research library facility which has in place research support capabilities (including electronic libraries such as Lexis/Nexis and WestLaw), access to extensive printed materials, and which is experienced in providing quick turnaround times for specific topic research requests. Such facility could communicate with the Philippines directly via fax, modem or overnight mail services, and/or by use of the coordination consultant.

14. TWINNING AND DIRECT STAFF SUPPORT. Many of the duties of ERB resemble those of utility regulators in other jurisdictions, especially in the Canadian provinces and the states of the United States. Therefore, the coordination consultant will seek to arrange one or more "twinning" type arrangements between the ERB and such other regulatory bodies. The purposes of such twinning or similar arrangements will be to at least explore and where possible provide for at least following possibilities: short term (one to three month) specific exchanges of staff with operating responsibilities; participation of the ERB in receiving studies performed by the National Regulatory Research Institute

(NRRI), the research institution funded by NARUC. Specific assistance will particularly also be sought from the twin agency in DSM programs. Suitable twin candidates could be a U.S. State Commission, Oregon's for example, which has expressed interest in twinning for DSM purposes, or other U.S. State or Canadian Provincial regulatory bodies.

15. TEMPORARY STAFF CONSULTANTS. Apart from twinning arrangements, and to the degree that twinning is unable to provide suitably qualified short term staff, the coordination consultant will also recruit suitably qualified short term consultants who would work for limited periods with and on the staff of ERB, on matters of interest to ERB to meet its various duties. Such consultants would be placed for various time periods as recruiting conditions permit, such as from one to six months, or may be placed for various short intervals over a longer period of time. Specialists will be found for at least three different regulatory areas: rate design; rural cooperatives; regulatory accounting.

16. THE TERM "COORDINATION CONSULTANT" in these Terms of Reference refers to an individual who will perform the duties of coordination directly and indirectly required by the above paragraphs. The coordination consultant will also assure that services received by ERB are of professional quality, that they meet the particular terms of reference for the specific service under which requested, that services are delivered in a timely fashion and in a manner suitable to the context of Philippine and ERB regulation and processes, and otherwise are of acceptable quality. With consent of the Bank, and where otherwise professionally qualified, the coordination consultant may also provide specific particular instructional, research or advisory services which may arise under these Terms of Reference.

B. Analysis of ERB Institutional Development and Staffing Requirements

17. ERB has a long history. Its duties and powers recently expanded to include price of a large number of cooperatives, of a major energy company (the NPC), in conduct of review of policy rulemakings both directly and in implementation of DOE policies made through separate rulemakings, and if the proposals made here are carried out, also in the matters of franchising generally and distributor consolidation in particular. ERB requires significant additions to staff to meet these duties. In 1992 ERB had a total budget of about ₱34 million, and a total staff (after reorganization) of 173, before any staff additions for new duties. The approved ERB budget for 1994 is about ₱45 million for a staff of about 253. If the full recommended staff below were added, ERB would have a permanent staff of at least 300 and a budget of at least ₱55 million. It will require additional assistance to effect the distributor consolidation.

18. We have attempted to take a realistic view of ERB capablility. The Board has been styled after American state regulators, and its staff has been trained in the Philippine/American educational systems. Like the best of those institutions, it will be constrained by the resources and politics of the jurisdiction, and can lead only a little faster than legislation permits. Institutional development will help ERB do the best job in such circumstances.

19. ERB has requested and requires institutional development and training assistance. ERB seeks an immediate training course which summarizes regulation, as an orientation course for its large group of new employees. ERB also seeks in-depth training in specific regulatory subjects. The ERB 1994 budget as approved includes only the equivalent of US$29,000 for all training needs including travel. Only limited training is currently being provided through AID, and this is likely to be reduced or eliminated due to AID funding constraints. Other present Bank support deals with IPP or BOT policies, not duplicated by the attached request. ERB also seeks additional immediate consulting support as an intermediate step while it builds direct staff capabilities.

20. ERB has an immediate need for additional staff in its rates functions. Legislative transfer of NEA rates staff should help this problem. This suggestion is placed before other analysis of ERB needs. However, this transfer will not resolve rates staff requirements, since rates issues will also arise for NPC rates, for successor company rates, transmission rates, and for rates issues of the proposed dispatch entity.

21. A better overall understanding of ERB staff needs is found in the personnel totals (both professional and support) proposed by ERB for the 1993 and 1994 fiscal years. The November, 1993 staff totals were approximately: Rates -16; Engineering (includes staff required for statutory meter calibration and inspection duties) - 35; Legal - 23; Administrative - 38; Offices of Chairman and Board - 20; Other (includes the office of the executive director and any clerical and support personnel not otherwise specifically identified by function) - 41; for a total of 173. ERB's proposed 1994 budget staff totals are shown below. Here, "administration and support" includes the offices of the Chairman, of the Board members, of the Executive Director and of Financial and Administrative Support:

Function	Total Staff
Energy Pricing	75
Energy Regulation	65
Legal	33
Administration and Support	80
Total	253

22. In addition to the increment of 80 staff (principally professional) shown by these totals, ERB sought an additional 38 staff with functional title "Audit and Investigations". This group was to implement a recommendation by AID that ERB separate its present staff case review functions in a form similar to those of US regulatory bodies. In such bodies, utility rate applications are reviewed by a separate "litigation" staff, which conducts an independent review of the filing and presents evidence in opposition to the utility at a public hearings. The Commission policy staff then independently reviews the hearing and proposes an Order for the case. In the present ERB procedure, there is a public hearing at which the ERB staff typically does not present formal evidence; however, the applicant utility and any interested party present evidence. Information from a detailed review of the case is provided to Board members or ERB counsel, who question the applicant and other witnesses at the hearing, and make other discovery enquiries on topics of interest. The Commission on Audit (COA), a constitutional audit body, also presents an independent audit of the application. The Budget Office thus felt that adding separate ERB staff with the title "Audit" would duplicate the service of COA, and hence denied this increment of staff and budget.

23. Comments are in order regarding this analysis. AID's recommendation assumed that a functional separation of staff in the style typical in US regulatory institutions is necessary to legal transparency, and/or that the present ERB staff structure means there is essentially no staff to advise the Board. Both conclusions are incorrect. Present ERB processes are legally transparent (as discussed in detail in Annex 7): ERB rulings must be based on evidence, such evidence may be submitted in open hearing by any party, diverse parties including both the applicant and an independent COA audit present evidence, the evidence relied upon in any ERB Order must be reviewed in that Order, and any such Order is subject to Supreme Court review. Thus, the absence of a formal evidentiary presentation at hearing by ERB staff, while unusual to American eyes, is not a necessary indicator of lack of transparency. Secondly, once it is realized that the ERB staff does not engage in evidentiary presentations, it becomes clear that the ERB staff is actually all available to advise the Board without the

procedural difficulties that prevent trial staff in American jurisdictions from subsequently directly advising Commissions.

24. The above discussion also shows that ERB still requires staff with essentially the same capabilities as the proposed Audit and Investigations staff, as well as other additional staff. First, precisely because COA presents a formal audit review as evidence, ERB must be able to review and as necessary question COA witnesses on their recommendations. Therefore, ERB requires the requested skills even if ERB makes no evidentiary presentation as in American procedures. This will become especially apparent as ERB undertakes the rather complex reviews that will begin to occur as NPC or its constituents are privatized and as the distribution sector becomes more coherently organized into larger entities. Similarly, ERB duties in review of franchises, distributor consolidations, and dispatch rules (all new duties advised for transfer to ERB by this Study) will be technical and complex and therefore require capable staff. ERB must also be capable of reviewing and applying DOE policy in numerous areas of DOE interest; much of this work will require skills not otherwise available from other ERB functional staff.

25. Therefore, it is reasonable that ERB requires about 50 additional staff with skills in regulatory analysis, investigations, dispatch analysis, franchising and consolidations, not already requested in the 1994 budget. Added to the 1994 staffing of 253, this would place the staffing needs of ERB at a total of at least 300, an increment of at least 130 over 1993 levels. Note that we do not adjust this number for the impact of adding franchise review to ERB duties, as per Annex 8. Should restructuring result in consolidation of distribution, a possibly large but specialized staff requirement will appear, remain for the several-year period of reform, then expire. Such needs are best met by temporary consulting support services.

PHILIPPINES

POWER SECTOR STUDY

ERB and DOE Regulatory Powers

Table 1

POWERS AND DUTIES OF ERB

"TO ACHIEVE MORE COHERENT POLICY FORMULATION ... CONSOLIDATE AND ENTRUST IN ONE BODY ALL THE REGULATORY AND ADJUDICATORY FUNCTIONS COVERING THE ENERGY SECTOR" (EO 172 PREAMBLE)

REGULATE PRIVATE[1] ELECTRIC ENERGY COMPANY RATES (CA 146, EO 172)

ISSUE PRIVATE ELECTRIC ENERGY COMPANY CERTIFICATES OF PUBLIC CONVENIENCE (CA 146, PD 1206, OPINION 98)

REGULATE COOPERATIVE RATES (RA 7638, PD 269 SEC. 16(O) CHAPTER II)

REGULATE NPC RATES (RA 7638, RA 6395 SEC. 4)

APPLY NOTICE, HEARING, PROCEDURE AND RELATED POWERS IN ITS PROCESSES (CA 146, ETC)

[1] "PRIVATE" USED HERE TO MEAN ANY NON-GOVERNMENT COMPANY ORGANIZED AS OTHER THAN A COOPERATIVE.

Table 2

POWERS AND DUTIES OF DOE

(ALL REFERENCES TO REPUBLIC ACT 7638)

POLICY OF THE STATE: CONTINUOUS AND ADEQUATE SUPPLY OF ENERGY, ULTIMATELY THROUGH SELF RELIANCE, USE OF INDIGENOUS RESOURCES, EFFICIENT USE OF ENERGY
(SEC. 2 (A), MADE PURPOSE OF DOE BY SEC. 4)

POLICY OF THE STATE: INTEGRATE AND COORDINATE
(SEC. 2 (B), MADE PURPOSE OF DOE BY SEC. 4)

POWERS AND FUNCTIONS OF DOE (SEC. 5)
(A)FORMULATE POLICIES FOR EFFICIENT SUPPLY, ECONOMIC USE
(A) PROVIDE A MECHANISM TO RATIONALIZE AND INTEGRATE

(B)DEVELOP ENERGY PROGRAM ANNUALLY (INCLUDING PRIVATIZATION AND COMPETITIVE OBJECTIVES)

(C) PROGRAMS FOR ...

(D) SUPERVISE GOVERNMENT ACTIVITIES

(E) REGULATE PRIVATE SECTOR ACTIVITIES UNDER EXISTING LAW

(F) ... (J) DO VARIOUS THINGS IN FOUR YEARS

(K) FORMULATE SUCH RULES AND REGULATIONS AS MAY BE NECESSARY TO IMPLEMENT THIS ACT

(L) OTHER IMPLIED NECESSARY POWERS

Table 3

DUTIES OF DOE BUREAUS

(ALL REFERENCES TO RA 7638, SECTION 12)

VERB	CITE	BUREAU	DUTY
DEVELOP AND IMPLEMENT			
	12(B)(3)	EUMB	NEW TECHNOLOGIES
	12(B)(6)	EUMB	MIDDLE AND LONG TERM ENERGY TECHNOLOGY STRATEGIES
	12(B)(10)	EUMB	ENERGY CONSERVATION PROGRAMS
	12(B)(2)	EPMB	DATA AND INFORMATION PROGRAM
ASSIST			
	12(A)(1)	ERDB	FORMULATE AND IMPLEMENT PLANS FOR LOCAL SUPPLY OF ENERGY
	12(A)(2)	ERDB	LOCAL RESOURCE PLANS
	12(A)(5)	ERDM	FORMULATION OF POLICIES FOR SERVICE PROVIDERS
	12(B)(1)	EUMB	POLICIES FOR ENERGY SECTOR PRODUCTION, TRANSMISSION AND DISTRIBUTION
	12(B)(4)	EUMB	RURAL ENERGY DEVELOPMENT
	12(B)(5) AND SEC. 25		
		EUMB	POLICY FOR ALLOCATION IN CRITICAL LOW SUPPLY
**	12(C)(1)	EIAB	REGULATORY POLICIES FOR RESOURCE SUPPLY ACTIVITIES
**	12(C)(3)	EIAB	FINANCIAL AND FISCAL POLICIES FOR ENERGY SUPPLY COMPANIES
	12(D)(1)	EPMB	INTEGRATED SHORT, MEDIUM AND LONG TERM PLANS
CONDUCT			
	12(A)(3)	ERDB	RESEARCH ON LOCAL RESOURCES
	12(D)(6)	EPMB	STUDIES ON INTERNATIONAL ISSUES
ASSURE			
	12(D)(5)	EPMB	INCORPORATION OF ENVIRONMENTAL POLICIES

Table 3

DUTIES OF DOE BUREAUS (continued)

(ALL REFERENCES TO RA 7638, SECTION 12)

VERB	CITE	BUREAU	DUTY
PROVIDE			
	12(A)(4)	ERDB	CONSULTATIVE TRAINING AND ADVICE TO REGULATORY INSTITUTIONS
	12(B)(6)	EUMB	INFORMATION ON ENERGY TECHNOLOGY
REQUIRE			
	12(B)(9)	EUMB	COLLECTION OF WASTE OIL
REVIEW			
	12(D)(4)	EPMB	PATTERNS OF ENERGY CONSUMPTION
SUPERVISE, COORDINATE AND INTEGRATE			
	12(D)(3)	EPMB	PLANS FOR ENERGY SUPPLY DEVELOPMENT
MONITOR			
	12(B)(2)	EUMB	ENERGY SECTOR CONSUMPTION
	12(B)(7)	EUMB	ENVIRONMENTAL STANDARDS OF DENR
RECOMMEND			
	12(B)(8)	EUMB	WAYS TO RESOLVE CITING ISSUES
DRAW-UP			
	12(C)(2)	EIAB	PLANS FOR SUPPLY DISRUPTIONS

Table 4

HOW THE AGENCIES DIFFER

ERB	DOE
QUASI-JUDICIAL PROCESSES (CA 146)	CODE PROCESSES (AT MOST)
HAS POWER OF SUBPOENA (CA 146)	HAS NO SUCH POWER
ACTS BY VOTE BASED ON FORMAL EVIDENCE (CA 146)	ADMINISTRATIVE DECISIONS USING AUTHORITY OF EXECUTIVE
ACT USING ONLY FORMAL RULES PROCESSES (CA 146)	FORM OF ACTION NOT DEFINED BUT HAS POWER TO ISSUE RULES AND REGULATIONS NECESSARY TO ITS DUTIES (RA 7638)
ALL PROCEDURES DETERMINED BY CA 146 AND CODE	ELECTRIC PROCEDURES (WEAKLY) DETERMINED BY THE CODE; (PETROLEUM POWERS SET BY RA 6173, PD 1206, PD 1573)
HAS DIRECT JURISDICTION OVER PARTICULAR ENTITIES INCLUDING ENFORCEMENT (RA 146, PD 1206, EO 172)	NO SPECIFIED DIRECT JURISDICTION, MAY HAVE IMPLIED JURISDICTION OVER PERSONS (AND CORPORATIONS)
INVESTIGATE ANY PUBLIC SERVICE MATTER ON OWN MOTION (CA 146)	INVESTIGATE ONLY SPECIFIED OR IMPLIED MATTERS (RA 7638)
NO DIRECT JURISDICTION OVER IPPS (OPINION 95 OF 1988)	DIRECT JURISDICTION OVER IPPS (RA 7638, BOT LAW, EO 215)

PHILIPPINES

POWER SECTOR STUDY

Transparency of Regulatory Institutions

1. Application of the Bank's policy for power sector lending requires, among other analysis, consideration of the legal and regulatory system. This section therefore discusses transparency, while a more detailed discussion of Philippine electric regulatory laws and institutions appears in Annex 6. The interpretations of present powers given in this Annex, and in this report generally, reflect understandings reached among DOE and ERB in meetings facilitated by the Bank, and which reflect DOJ Opinion 98 of 1993. If applied consistently in that framework, and as elaborated in more detail below, the regulatory institutions of the Philippines can be considered transparent under the criteria of the Bank's policy statement on electric sector lending, "principle one". ERB and NEA will also remain transparent after the changes in authority among these agencies described in Annex 8.

2. In general, the legal and regulatory rules of the Philippines are set forth in the Constitution of the Philippines and in various legislative acts, in executive orders which have the force of law, and in court decisions which together form an internally consistent legal framework. The Philippine legal system is a common law system, and draws upon case law from other common law jurisdictions in reasoning toward decisions in cases where local law or precedent do not determine the result.

3. Energy price regulation is conducted by ERB. ERB is a non-constitutional body created by legislation, and can trace its origins to legislation dating to the early twentieth century. Executive Order 172 of 1977 created the entity currently named ERB under legislative limited term authority prior to establishment of the present Philippine Constitution. EO 172 primarily reorganized specific previously legislatively created regulatory authority, a matter in any event within the executive authority, but did not either create nor destroy any quasi-legislative or quasi-judicial powers. To do either requires an act of the Philippine Congress. ERB has its own sets of published procedural rules, published case decisions, and related case law dating from at least 1936, which form sets of predictable precedents for its action. All matters which reach the ERB therefore are potentially decidable based upon known rules of law and procedure, much as in any other common law jurisdiction.

4. The second Philippine energy regulator, the DOE, has responsibility generally for "non-price" matters including NPC planning, coordination among utilities, and energy sector policy generally. The DOE was created in December, 1992 under the Department of Energy Act (DOE Act), Republic Act 7376. The DOE is an administrative agency with powers to "formulate such rules and regulations as may be necessary to implement the objectives of this Act".

5. As such, DOE therefore falls under the Administrative Code of 1987, Book VII, Chapter 2, Section 9, Paragraphs (1) and (3):

"(1) If not otherwise required by law, an agency shall, as far as practicable, publish or circulate notices of proposed rules and afford interested parties the opportunity to submit their views prior to the adoption of any rule. ...
"(3) In the case of opposition, the rules on contested cases shall be observed."

More detailed rules for conduct of contested proceedings are then laid out in Chapter 3 of the Administrative Code, Book VII. The Chapter 3 rules are in general those of a quasi-judicial or quasi-legislative regulatory body in any common law jurisdiction, while the Chapter 2 rules for rule makings are certainly at least the minimal requirements for transparent rule makings.

6. DOE is now directly responsible for both the BOT rules, and indirectly, through NPC, for the EO 215 rules. DOE actions in issuing rules are governed by the Administrative Code of 1987. The Code also applies to the NPC since the Code includes "government corporations with respect to functions regarding private right, privilege, occupation or business..." (Code at Book VII, Chapter 1, Section 2 Paragraph (1)). In issuing the implementing rules for EO 215 in 1989, the NPC followed at least minimal requirements of this Code, publishing the rule more than fifteen days before the proposed implementation date, preceded with a series of public meetings in which public comment was received and subsequently accounted for.

7. Since ERB has its own rules which meet or exceed Code standards, the Code rules do not impose additional constraints on ERB procedure. Similarly, when NEA is acting in a quasi-judicial or quasi-legislative capacity, such as deciding on its Congressionally delegated franchise matters, it also uses transparent processes which are specified in sections 46 through 60 of PD 269. The relevant sections of this law which require transparent processes for franchise matters would be also applied to ERB under the legislation of Annex 8, and would remain in force as applied to all remaining hearings of the NEA. Therefore, both ERB and NEA would retain transparent processes following the reforms suggested here.

8. However, DOE has no non-Code administrative processes nor quasi-judicial powers (in the electric sector), therefore DOE is required to follow at least the above cited minimal Code administrative processes in rule setting. In 1989 NPC did follow the Code by holding public meetings prior to publication of the rules for EO 215. Code Book VII Chapter 2 Section 9 (1) however is rather vague about the public processes which should be followed in rule makings. It is likely that as more frequent and complex rule makings are used, that the vague language of the Code may not seem adequate. Therefore, the DOE should conduct a rule making whose purpose is precisely to set forth rules and processes for future DOE rule makings.

9. DOE does not have quasi-judicial processes for complaints which could arise in the electric industry, nor for means of enforcing its rules and policies. Therefore complaints which arise about DOE (or NEDA, or ICC, or some aspects of NPC) processes would likely be taken to the Philippine courts at present. But careful review of ERB electric industry authority shows that ERB already has transparent quasi-judicial processes, jurisdiction over the most of proper parties, and enforcement authority for proper policies of the DOE. Further, any party can make a complaint at ERB, and, therefore, certainly DOE can make complaints or other formal filings at ERB. Therefore, as a practical matter the DOE can enforce its policies by making such appropriate filings at ERB. Such enforcement would also therefore fall under transparent processes.

10. Court, ERB and NEA rules of practice, procedure, evidence and decision are published and enforced in a manner generally similar to those of other common law jurisdictions. As in other

common law jurisdictions, the remedy for failure to properly apply a rule (or to follow a contract) is appeal to the courts, or, where the rule is an order of, or in the jurisdiction of the ERB, by complaint before the ERB. The ERB enforces its own orders. Errors of the ERB can be and are corrected by the courts by normal appeals processes similar to other common law jurisdictions. In contrast, NPC has published rules for IPPs (under EO 215) and the DOE have published rules for the BOT Law, but under the emergency conditions of the recent period, these rules may not have been strictly enforced in all details. Although DOE actions, if challenged, could be appealed to the courts, it is suggested that the ERB is already structured as both the appeals and enforcement body for DOE policy, since ERB has the appropriate jurisdiction, ERB is required to follow proper DOE policy, and since ERB (and not DOE) has the appropriate quasi-judicial powers and ability to impose remedies.

11. Transparency also requires analysis of processes for changes in rules. ERB has known rules and procedures for both establishing and changing any of its published rules, namely "notice and hearing". ERB can change price policies as evidence warrants, and set prices according to policies which ERB may determine, subject to proper notice and hearing. In so far "changing rules" relates to industry structure, the Bank's framework presumes that the ability to effect such changes may be specified to some named regulatory body. To the extent such body exists in the Philippines this body is DOE. The Administrative Code of 1987 provides for notice and public comment for major actions of policy when issued as rules, which is how DOE would so act. Assuming DOE uses Code processes, then changes in sector policy would also become subject to transparent process.

PHILIPPINES

POWER SECTOR STUDY

Methods of Forming Consolidated Distribution Entities

STATUTORY ISSUES

1. This Annex discusses statutory issues essential to the reforms discussed in this report. Part A8.1 summarizes possible ways to form more effective distribution entities from the present distribution cooperatives. These entities will be larger than the present many small distributors, will own and operate 69 kV subtransmission lines presently held by NPC, and will include in their territories any commercial or industrial customers presently directly served from the 69 kV lines. These customers will then be eligible to purchase power from competing sellers, other than the distributor, by requiring that the distributor wheel power over its lines. Part A8.1 discusses possible present organizational forms; it supports the conclusion that the reorganized entities could be cooperatives but that certain changes of law are needed regarding voting rights of larger customers in electric distribution cooperatives.

2. Changes in law necessary for reorganization of distribution and other objectives of the long term sector structure are also suggested in part A8.2 below. Section 1, Reorganization of Distribution, involves the form of organization of the sector, merger and wheeling policy, and the duties of regulatory institutions. The introductory paragraph (A) states the purpose of the legislation as to create a cost effective consolidation of many small distribution entities into fewer larger ones, organized around the 69 kV sub-transmission lines. Paragraph (B) transfers to ERB the necessary franchising authority to effect these consolidations. Paragraph (C) states the criteria that will be applied by ERB in effecting consolidations. Paragraph (C)(1) defines the criteria to be applied for consolidating entities into larger regional entities. Paragraph (C)(2) discusses rates conditions; it assures that NPC rates to consolidated entities who purchase 69 kV plant are lowered to reflect the reduced NPC rate base, that rates to non-consolidated entities are not so lowered, and that non-consolidated entities must meet certain efficiency criteria. Paragraph (C)(3) summarizes wheeling matters; it assures that any former NPC direct sale customer receives an offer of wheeling and that any other large customer over a stated threshold (using here 5 MW) in any service territory is also offered wheeling service within five years. A consolidated distribution entity is also entitled to request price-cap type rates and price flexibility in unbundled services offered to customers facing competitive entry. Paragraph (C)(4) deals with amendments to voting rights of larger industrial or commercial customers of an electric distribution cooperative consolidated under this statute; the changes encourage equity contributions from larger customers, and thereby permits that some or all of the new entities remain as cooperatives. Paragraph (C)(5) deals with mechanics of transfer of franchises and certificates to the consolidated entity.

3. Part A8.2, Section 2, Dedicated Regulatory Fund, creates a dedicated regulatory fund, for support of the ERB, as discussed in the main text at Chapter 7.

4. Part A8.2, Section 3, Electric Public Service Companies, updates statutory definitions to match current practice. Paragraph (A) updates the definition of "public service entity"used in PD 269 to accommodate recent and ongoing changes in the sector. Paragraph (B) then interprets the jurisdictional definition of ERB over electric public service entities (which is presently interpreted as historically derived from CA 146) in terms of the updated definition of PD 269. Paragraph (C) assures that ERB has the power to adjudicate dispatch rules. These changes retain all existing jurisdiction of ERB (including that transferred to ERB from NEA by Section 1) over companies engaged in electricity transmission or distribution, or over any integrated company engaged in any combination of transmission, distribution and generation, while assuring that rates or franchises of present or future companies engaged only in the generation of electricity are not regulated by ERB. However, electric system dispatch rules, which therefore could imply pricing issues as affected by dispatch decisions, remain in the jurisdiction of the ERB, since these rules are essentially practices of NPC or it's successor transmission company; paragraph (C) says this explicitly.

A8. 1. Possible Forms of Consolidated Distributor Organization Under Existing Law

Larger Cooperative Merger of several existing primary cooperatives into a larger primary cooperative is possible under existing law. Such entity would receive NEA preference for loans, and favorable tax treatment. For these reasons a cooperative is a desirable form for the final entity, although not the only possible form. The new consolidated cooperative would need to meet membership and share restrictions of Philippine cooperative law: members could include corporations, voting is one vote per member, and equity is held as membership shares. No member may hold more than 20 percent of such share value of a single cooperative. Thus, consolidation to larger cooperatives is simplest when there are no (large) commercial or industrial companies taken within the 69 kV territory of the consolidated cooperative. Any larger industries taken into territory would presently be required to accept limited voting rights while making large share contributions as contributions in aid of construction for their respective subtransmission plant or substations. It is therefore likely that to encourage larger commercial and industrial enterprises to contribute equity, and indeed to accept the new distribution system at all, would require an amendment to the existing Cooperative Code. This is proposed in the legislative text below at paragraph (C)(4).

Ordinary Corporation The option of creating the consolidated distributor as an ordinary corporation exists. Such corporation would receive lower preference from NEA lending, and lose income tax exemptions enjoyed by cooperatives. An ordinary corporation could however have more effective and efficient administrative structure. This characteristic is also shared by some of the other forms stated below. Therefore, it is not necessary that the consolidated entity could only be a cooperative, as other forms could also meet the efficiency criteria of the legislation below.

Non-Stock Corporation An entity called a non-stock corporation exists in Philippine law, as one in which capital stock may be divided into shares but for which no dividends are paid. Apparently voting control of the corporation would be determined by the corporate articles or by-laws. It is possible, though not clear without further research, that such entities might be able to not pay taxes. Such entity would receive lower priority for NEA loans. The apparent purpose of such corporate forms is to effect private associations or educational purposes, not to create operating

companies, and therefore the related case law may not be fully appropriate to the operation of a business entity such as a utility.

Joint-Stock Company A non-statutory form of corporation might be formed, called a joint stock company, which could be structured as desired. It is unlikely such entity could be exempt from various taxes without special legislation. It would receive lower priority for NEA loans.

Business Trust A business trust is a non-statutory but recognized form in which trustees hold and operate the named trust property for the benefit of the donors. In this case, the donor-beneficiaries would presumably be members of the former cooperatives, plus the commercial entities in the service territory. A business trust can be organized as desired as regards control of the trustees (that is, distribution of equity and voting rights), and thereby avoid some of the difficulties inherent in the present law of cooperatives. If properly crafted, a business trust might also be exempt from taxation. Not being a cooperative, it would not receive priority for NEA loans.

A8. 2. Statutory Language

SECTION. 1 Reorganization of Distribution --

(A) *Objective of legislation is economic consolidation of electric distribution*. The objective of this section is to cause consolidation of the many smaller entities of the distribution sector into larger and more economically viable distribution entities, and to otherwise conform current law with current good business practices. To effect this aim, as soon as practical but in no event later than five years from the date of enactment of this Act, all electricity distribution companies including cooperatives, and all direct sale distribution customers of NAPOCOR, normally and predominantly taking service from 69 kV or smaller subtransmission feeders, shall have the opportunity and shall be encouraged to be reorganized into larger services territories served by consolidated distribution entities.

(B). *Franchise powers transferred to Energy Regulatory Board.*

(1) All powers granted to the National Electrification Administration (NEA) under Presidential Directive 269, Chapter IV Sections 41 through 45 inclusive are hereby transferred to the Energy Regulatory Board (ERB).

(2) Powers under Section 46 are transferred to ERB to the extent they relate to powers in Sections 41 through 45. Power to require reports under Section 43 (a) shall remain in effect as applied to both ERB and NEA.

(3) Powers and duties of NEA under PD 269 Sections 46 applied to NEA as necessary to the conduct of NEA duties not transferred to ERB by assignment of Sections 41 through 45, and sections 47 through 61, shall remain in full force and effect as applied to NEA. In the event of a dispute of authority between ERB and NEA over a matter arising under Section 46, the matter shall be deemed in the jurisdiction of ERB.

(4) ERB shall exercise its powers under sections 41 through 46 according to the definitions stated in PD 269 Chapter I. Powers, duties and responsibilities granted NEA under PD 269 Sections 47, 48, 49, 50, 53, 54, 55, 56, 57, 58, 59, and 60 shall also be granted to ERB in

the exercise of the powers stated in Sections 41 through 46; when applied to ERB, the terms "NEA" in the cited Sections shall be replaced by "ERB", and references to the "Board of Administrators" shall mean the Energy Regulatory Board.

(5) To the extent necessary and proper to effect the purposes of this Act, or to the extent necessary and proper to assure a competitive market for production, transmission and sales of electrical energy, ERB shall have the power to place conditions on issuance of franchises and certificates of cooperatives and other public service entities, or to place conditions on the continuation or renewal of existing franchises and certificates, including, as to cooperatives, requiring the exercise of powers stated in PD 269 Sections 29 through 36 inclusive.

(C). *ERB to implement the purposes of this act.* ERB, as the holder of franchise authority, shall take all steps necessary to carry out such consolidations to the fullest possible extent consistent with this Act, and providing that any such consolidation is cost-effective in a manner which does not result in an increase in total rates to consumers.

(1) *Creation of consolidated entities and transfer of assets.* The service territory of each consolidated entity shall consist of, at least, all distribution cooperatives, small distribution companies, and all direct sale distribution customers who are contiguous to each other and connected to a single 69 kV distribution feeder line, but shall preferably also include all of the customers contiguous to all of the contiguous, adjacent or intertied 69 kV subtransmission lines connected to common substations, and including up to the largest local area defined by natural boundaries. The consolidated entity shall purchase the 69 kV and smaller subtransmission facilities and appertaining rights of way, equipment, parts, and other related plant, land, equipment and service facilities, at a fair market price. Where the consolidated entity is acquiring a privately owned distribution company which was franchised and in existence and operating prior to December 31, 1992, which lies within the contiguous territory defined by the applicable 69 kV or smaller subtransmission system, the consolidated acquiring entity shall pay the fair market value of the acquired net asset value of the plant, land, other assets and good will of the company acquired. ERB shall not use its power to consolidate to break up existing economically viable entities into smaller or less viable entities or to separate and redistrict parts of economically viable entitities to other less viable entities.

(2) *Rates of consolidated and non-consolidated entities.* Rates for the consolidated entities shall be subject to the jurisdiction of the ERB. Rates of NAPOCOR, its divisions or successor companies, to the consolidated distribution entities, shall be reduced by an amount proportionate to the amount of plant and services transferred to the consolidated entity. Rates of NAPOCOR, its divisions or successor companies, to distribution companies and other customers on subtransmission feeder lines which do not consolidate, shall include the full cost of all subtransmission plant and services. Also, the ERB shall assure that rates (covering all costs except fuel costs) of non-consolidated cooperative distribution companies subject to its jurisdiction shall not exceed the average of rates (for all costs except fuel costs) for similar classes or type of service offered by consolidated entities by more than 7.5 percent, and that rates for fuel costs of non-consolidated entities shall not be greater than the average of fuel costs for similar fuel types by more than three percent.

(3) *Wheeling service.* The provision of wheeling services is appropriate to expedite the furnishing of service on an area coverage basis. Therefore, upon passage of this Act, ERB

shall hold hearings for all existing public service entities in order to determine the proper terms, conditions, rates, and implementation of such services for each. Further:

(i) Consolidated entities shall offer wheeling services to any commercial or industrial customer who was formerly a direct sale customer of NAPOCOR or its successor companies.

(ii) All distribution companies, including all cooperatives whether consolidated by this Act or not consolidated, shall offer wheeling service to any large commercial or industrial customer in their service territory whose monthly peak day demand is 5 MW or higher.

(iii) Wheeling service shall be available immediately to any former direct sale customer of NAPOCOR taken into the service territory of a consolidated entity, and shall be made available to all other qualified customers as soon as possible but in no event later than five years from the date of passage of this Act.

(iv) All new large customers and existing or former direct sale customers of NAPOCOR with a monthly peak day demand above 5 MW shall be granted the option of purchasing capacity and energy directly from NAPOCOR or any of the independent producers (wheeling through the distribution entity within whose territory they lie), or to purchase directly from the distribution entity holding the area franchise. Wheeling service shall be made available to all former, present or new NAPOCOR direct sale customers, and to all independent power producers, immediately upon passage of this Act.

(v) Any customer who is offered wheeling service may choose to accept wheeling service and to separately acquire capacity and energy, or to take their full service including capacity and energy from the distribution company.

(vi) Under its own motion or by application of any utility, ERB may grant flexible rates to any utility whose services are subject to competition, for those services determined by ERB to be subject to such competition. Such flexible rates shall be set by ERB to be no more than a maximum determined by well founded economic analysis, and no less than the variable costs incurred in providing the service. In setting flexible rates, ERB shall assure that the option to flex rates is taken at the risk of the utility, and that the method of determination of maximum rates does not result in shift of cost recovery from customers to whom competing service options are available, to customers who do not have competing services available to them.

(4) *Form of consolidated entities.* Consolidated entities may be primary cooperatives or other forms of private distribution companies. When the entities being consolidated are predominantly cooperatives, ERB shall prefer that the consolidated entity shall also be a cooperative. Consolidated cooperatives may be primary electric cooperatives as presently understood by the Cooperative Code of the Philippines RA 6938 and as normally administered under PD 269, except for the special membership exceptions allowed by this section of this Act, which special exceptions are available for creation of consolidated entities only pursuant to this Act. RA 6938 is hereby amended to create a special class of electric distribution cooperative membership, as follows:

(i) *Qualifications for Membership*: To the extent not already provided by law, commercial and industrial entities which are within the franchise area of the consolidated primary cooperative may become members of the cooperative, with voting rights, regardless of the form of legal organization of such commercial and industrial enterprises;

(ii) *Special Share Interests*: Commercial or industrial entities may acquire additional shares of the cooperative by making contributions in aid of construction of subtransmission and substation plant required to serve their load. Customers who were previously direct sale customers of NAPOCOR or its successors and which made such contributions in aid of construction shall receive equity shares in the consolidated cooperative in proportion to such contributions. Such additional share ownership will receive voting rights in the cooperative in proportion to their total percentage share of member equity of the cooperative, but no member may acquire more than 20 (twenty) percent of the voting rights in a single cooperative, regardless of their total percentage of equity share ownership;

(iii) *Customer Memberships*: Where the consolidated entity is a cooperative, the former customers of private distribution companies or municipal companies acquired by the consolidated entity shall become members of the consolidated distribution entity;

(iv) *Non-Conflict With Other Laws*: any other provision of PD 269 or RA 6939 which is or appears to be in conflict with the provisions of this Act is hereby repealed to the extent necessary to permit exercise of the purposes and provisions of this Act. The provisions of PD 269 Section 21 shall not be interpreted to prohibit nor affect the right and ability of a corporation which is also a member of a cooperative as defined in this Act, to assign, transfer, sell or otherwise alienate assets of the member in the cooperative, at such time as said member corporation may itself be sold, transferred or otherwise reorganized, provided that the successor to such rights and assets also properly is or becomes a member of the cooperative.

(5) *Franchising and certificates*:

(i) All previously existing franchises, certificates of public convenience, and certificates of public convenience and necessity, however originally granted, which were previously granted to any entity acquired into or joining the consolidated entity shall be considered as automatically transferred to the consolidated entity upon final sale and registration of the consolidated entity with the appropriate registration body. Upon proper application of the consolidated entity to ERB such regulator shall grant all necessary amended or extended additional franchises or certificates as are within their jurisdiction, and required to effect the expanded services and operations of the consolidated entity.

(ii) PD269 Sections 45 and 43(b) notwithdstanding, industrial plants, factories, mills, mines and similar or other power consuming or generating faciliites over 5MW and any former NAPOCOR customers specified by Sections (3)(i) or (3)(ii) above, are not required to obtain a franchise to provide service to other such entitites or to any transmission or distribution public service company.

SECTION 2: Dedicated Regulatory Fund

(A) *Regulatory Fund.* There is hereby established an Energy Regulatory Fund (Fund), which shall be an earmarked source of revenue available for appropriation by Congress exclusively for the annual budget of the ERB.

(1) All revenues collected from the fifty centavo per 100 peso share fees paid by regulated distribution companies to the ERB, and any other regulatory fees, taxes, duties, penalties or other revenues paid to ERB by regulated companies subject to ERB jurisdiction, or paid to such companies by others for the purpose of payment of fees dedicated to this Fund, shall be placed into the dedicated earmarked Fund.

(2) Fees applied to the Fund shall be established by ERB so that they generate sufficient revenues to pay the operating expenses of the ERB. A fee of no more than one-half of a centavo per KWH, collected by the regulated entity and paid to the Fund, may be established by ERB and charged on all KWH sold by or wheeled by any entity subject to ERB jurisdiction.

(3) ERB shall establish fees dedicated to the Fund upon notice to the public and hearing.

(4) Utility company rates may be set by ERB in sufficient precision to assure imposition and collection of this fee. Any existing statute, law, contract or utility charter provision which appears to restrict the level of precision of rate determination shall be interpreted as applying to rates other than the fees established and paid to the Fund.

(5) The annual budget of the ERB shall be appropriated by Congress to the ERB from revenues in the Fund. Properly appropriated other sources of revenue may also be applied to the budget and expenditures of ERB.

(6) Amounts in the Fund shall only be appropriated to the budget of the ERB.

(7) Amounts unexpended in the Fund at the end of any fiscal year shall be remain in the Fund and may be applied to ERB budgets or applied to reduce the annual level of the regulatory fees charged, in subsequent years.

SECTION 3: Electric Public Service Entities

(A) *Updated definition of "public services entities" in PD 269.* The definition of "public service entities" in Presidential Directive 269, Chapter I, Section 3(c) is hereby repealed and replaced with the following definition:

> (c) "Public service entities" shall mean (1) a cooperative, (2) the NPC, (3) any successor company to NPC engaged in the transmission or distribution of electricity, (4) local governments and privately-owned public service entities which are engaged in the transmission or distribution of electricity.

(B) *Updated interpretation of CA 146 and successor acts and legislation.* For purposes of determining the jurisdiction of the ERB over any electric public service company or electric

utility, the words "... electric light, heat and power, water supply and power ... and other similar public services ..." found in Commonwealth Act 146, Chapter II, Section 13(b), shall be interpreted to mean a "public service entity" as defined under Presidential Directive 269 Chapter I, Section 3(c), as amended, except that where ERB may be otherwise granted jurisdiction over an entity by a Congressional corporate charter, then ERB retains that jurisdiction.

(C) *ERB jurisdiction over dispatch rules*. Upon notice and hearing, the ERB shall have the power to decide all questions, including those raised on its own motion, regarding rules of electric system dispatch.