Staff Consultant's Report

Philippines: Power Sector Profile and Roadmap

Prepared by Geoffrey Brown, Jose Victor Emmanuel A. de Dios, and Helena S. Valderrama

Asian Development Bank

CURRENCY EQUIVALENTS

(as of 14 December 2005)

Currency Unit	–	Philippine peso (P)
P1.00	=	$0.0187
$1.00	=	P53.57

ABBREVIATIONS

ADB	–	Asian Development Bank
AO	–	administrative order
BOT	–	build-operate-transfer
CCGT	–	combined cycle gas turbine
CNG	–	compressed natural gas
COA	–	Commission on Audit
DOE	–	Department of Energy
DOF	–	Department of Finance
DU	–	distribution utility
EC	–	electric cooperative
EPIMB	–	Electric Power Industry Management Bureau
EPIRA	–	Electric Power Industry Reform Act
ER	–	expanded rural electrification
ERB	–	Energy Regulatory Board
ERC	–	Energy Regulatory Commission
FGP	–	First Gas Power Corporation
GDP	–	gross domestic product
GRAM	–	generation rate adjustment mechanism
HFO	–	heavy fuel oil
ICERA	–	incremental currency exchange rate adjustment
IMC	–	investment management contract
IMO	–	independent market operator
IOU	–	investor owned utility
IPP	–	independent power producer
LGU	–	local government unit
LNG	–	liquefied natural gas
MERALCO	–	Manila Electric Company
MMS	–	market management system
NEA	–	National Electrification Administration
NPC	–	National Power Corporation
NPP	–	new private provider
PBR	–	performance based rate
PEP	–	Philippine energy plan
PDM	–	price determination methodology
PNOC-EDC	–	Philippine National Oil Company Energy Development Corporation
PPA	–	power purchase agreement
PSALM	–	Power Sector Assets and Liabilities Management Corporation
PSDP	–	power sector development program
PSRP	–	power sector restructuring program
QTP	–	qualified third party

REFC	–	Rural Electrification Financing Corporation
RORB	–	return on rate base
SPUG	–	Small Power Utilities Group
TA	–	technical assistance
TDP	–	Transmission Development Plan
TRANSCO	–	National Transmission Corporation
TSC	–	transition supply contract
TWG	–	technical working group
WACC	–	weighted average cost of capital
WESM	–	wholesale electricity spot market

WEIGHTS AND MEASURES

Bbl (barrel)	–	unit of volume equal to 35 gallons or approximately 159 liter
BCF (billion cubic feet)	–	unit of volume
cct-km	–	circuit kilometer
GWh (gigawatt-hour)	–	unit of energy equal to1 million kilowatt hours
KWh (kilowatt-hour)	–	unit of energy
MMMT (million metric tons)	–	unit of weight equal to one billion kilograms
MVA (megavolt-ampere)	–	unit of apparent power
MW (megawatt)	–	unit of power, equal to 1 million watt
TCF (trillion cubic feet)	–	unit of volume

NOTE

In this Report, "$" refers to US dollars.

CONTENTS

I. BACKGROUND

A. Introduction

1. As the lead financing institution in the energy sector with a focus on the power sector, the Asian Development Bank (ADB) closely monitors the developments in and regularly reviews the situation of the sector. The objective of this report is to identify and analyze the key issues facing the sector today following the passage of the Electric Power Industry Reform Act of 2001 (EPIRA) and assist ADB in developing a plan to provide further assistance that will support the Philippine Government (Government) in its efforts to address the challenges currently being faced by the power industry.

B. Overview of Energy Sector

2. **Energy Self-sufficiency.** Being highly dependent on imported energy, the Philippines has to contend with regular price fluctuations in international energy markets and the difficulty in ensuring supply security for certain imported fuels such as coal. As such, the exploration for and development of indigenous energy resources to enhance self-sufficiency has been a continuing thrust of the Government since the oil crisis of the 1970s. The development of the Malampaya gas field in offshore Northwest Palawan and successful commissioning of natural gas fired power stations in 2002 have significantly increased the country's energy self-sufficiency ratio to more than 50.9% in 2002 from 45.5% in 2001. The Philippine energy plan (PEP) of 2004-2013 aims to further increase this self sufficiency ratio to 58% by 2013.[1] Increased emphasis has recently been given to the use of renewable energy resources such as solar, wind, and hydro which are expected to be increasingly used for electricity generation particularly in off-grid areas. The recent sharp increases in world oil prices have given renewed emphasis to energy self sufficiency efforts and the Government has launched new and intensified efforts to conserve energy, develop indigenous resources, and increase energy efficiency in all sectors of the economy.

3. **Oil.** The first significant petroleum deposit in the Philippines was discovered in 1976. Commercial production from this field, Nido, commenced in 1979. Philippine oil production is modest in relation to the country's needs. The country consumed 323,500 barrel (bbl/d) on average in 2004 of which 12,400 bbl/day, or 3.8%, was produced from three fields in the country. While oil consumption in the power sector is currently stable due to the substitution of oil fired power generation with natural gas, this is expected to provide only a short term respite and oil consumption is forecast to increase by 2.6% per annum through 2013.[2] Recent sharp increases in world oil prices have had a significant effect, particularly on transport energy costs and the cost of electricity generation. The domestic price of unleaded gasoline has increased 16.1%, while diesel has increased by 30% from December 2004 to September 2005 alone. As long as world oil prices continue to escalate, the Philippines will feel its effects particularly in the cost of supplying electricity to consumers fed by distribution networks that are not connected to a transmission grid as such generation is almost completely reliant on imported fuel oil.

4. **Natural Gas.** The discovery and ensuing development of the Malampaya gas field in offshore northwest Palawan gave birth to the Philippine natural gas industry. With reserve estimates ranging from 2.26 to 4.58 trillion cubic feet (TCF),[3] the Malampaya gas field is currently supplying gas to three power plants with an overall combined capacity of 2,760

[1] Source: Philippine energy plan (PEP) 2004-2013
[2] Source: PEP 2004–2013, though the PEP 2005 Update forecasts a 4.16% growth rate for the 2005-2014 planning period.
[3] Values vary depending on the source of such estimates.

megawatts (MW) of power in Batangas, South Luzon, and will be able to provide fuel for another 300 MW–1,000 MW of capacity for another 20 years.[4] The exploration of other fields is ongoing and the Philippine petroleum resource assessment project estimates the total gas resources, including undiscovered resources, at 28.5 TCF. There are currently, pending in both houses of Congress, Natural Gas Bills[5] that propose to establish a structure and regulatory framework for a natural gas industry in the Philippines. Demand for gas for power generation and other uses is planned to be met by indigenous gas from additional exploration activities or by imported gas, either as liquefied natural gas (LNG) in the medium term and/or through the planned Trans-ASEAN gas pipeline[6] in the long term.

5. **Coal.** Coal production has increased from 1.12 million metric tons (MMMT) in 2001 to 2.0 MMMT in 2003 due to increasing production by the Semirara Mining Corporation in Antique and an increased number of small scale mines. This represents about 23%[7] of current consumption in that year with local coal being blended with higher grade imported coal from Indonesia, China, Vietnam, and Australia for use in coal fired power generation. As of 31 December 2003, in-situ coal reserves amounted to 420 MMMT and estimates of potential coal reserves are as high as 2.3 billion metric tons.[8] The Department of Energy (DOE) is promoting the development of mine-mouth power plants to use low rank coal for which there is no alternative market and has identified potential sites in Cagayan and Isabela in Northern Luzon that can support such power plants. Other areas in the country are also under study.

6. **Geothermal Energy.** Geothermal power was first produced in the Philippines in 1979 with the development of the Tiwi and Mak-Ban fields in Southern Luzon by the Philippine Geothermal, Inc., a wholly-owned subsidiary of Union Oil Company of California. Other geothermal fields in Luzon, Mindanao, Leyte, and Southern Negros have subsequently been developed by the Philippine National Oil Company Energy Development Corporation (PNOC-EDC). The Philippines is now the world's second largest producer of geothermal power, with an installed generation capacity of over 1,930 MW, of which almost 1,200 MW[9] is owned and operated by the National Power Corporation (NPC).[10] The balance of the geothermal generation plants is owned by private sector developers under built-operate-transfer (BOT) contracts. Total generation from geothermal plants was 9,822 GWh in 2003 or about 18.6% of gross generation in that year. Potential geothermal resources are estimated at 4,790 MW.[11] By 2007 PNOC-EDC's new 40 MW Northern Negros power station and an additional 20 MW at Palinpinon in Southern Negros could come online. The Government is accelerating the development of geothermal power and in 11 March 2004 launched the first Philippine geothermal contracting round. Under this program, a total of ten geothermal fields are being offered for development by private sector investors through a competitive bidding process. A second round, which included petroleum prospects, was launched in September 2005 and offered 11 more sites.

---

4 There seems to be a general acceptance at a level of 500 MW though estimates vary.

5 Senate Bill No. 8 and House Bill No. 1533.

6 A memorandum of understanding was signed by the energy ministers of the Association of Southeast Asian Nations (ASEAN) on 5 July 2002 to develop the Trans-ASEAN Gas Pipeline Project, which includes seven gas interconnections among ASEAN countries covering a total length of about 4,500 kilometers. The total cost is estimated to be $7 billion and completion is expected by 2020.

7 Coal consumption in 2003 was 8.5 MMMT.

8 Source: DOE website, 15 December 2004, although the PEP 2005 update estimates total in-situ coal reserves at 343.4 MMMT.

9 NPC Annual Report, 2004.

10 NPC purchases steam from the field operators, such as Philippine Geothermal, Inc. or PNOC-EDC, to drive their plants.

11 Source: PEP 2004–2013 and DOE website.

7. **Hydropower.** The PEP 2004–2013 is targeting 2,950 MW of hydropower generation in the next ten years although overall hydropower resources are estimated at over 10,000 MW. Current installed capacity is over 2,900 MW, which includes the 345 MW San Roque hydropower BOT project commissioned in 2003. The development of further projects of this scale is unlikely in the medium term due to the scale of people relocation required and community opposition. While no new large hydropower schemes are identified in the Philippine Power Development Plan, the development of a limited number of mini and micro-hydro projects is continuing.

8. **Other Renewable Energy.** Apart from geothermal and hydropower resources, the country stands to benefit from other renewable energy sources such as biomass, solar, and wind that are currently being promoted and developed. For example, NPC currently has a power purchase contract for 8 MW of capacity with a cogeneration plant running on bagasse from a sugar mill in Bukidnon, Mindanao. Other similar biomass projects are in the pipeline for development in the country.

9. For wind-powered generation, the possibilities for the Philippines are abundant as the country sits on the fringes of the Asia-Pacific monsoonal belt, giving rise to tremendous wind potential. A total of 65 MW of wind generation is being developed in Ilocos Norte in Northern Luzon apart from the 25 MW already installed on 18 June 2005. Wind generators will not be required to bid into the wholesale electricity spot market (WESM) and will be allowed to generate whenever wind is available.

10. Finally, solar energy is becoming a popular electricity source of choice in off-grid villages given the prohibitive cost of extending power lines and the difficulty of transporting generator fuel to such remote villages. In 2003, for example, 594 photovoltaic battery-charging stations and 319 hybrid systems were installed in the country. This is not to say, however, that the installation of such systems does not come without challenges.

11. **Energy Efficiency and Demand-Side Management.** The Government has been promoting energy efficiency and conservation programs with the following objectives: (i) to enhance consumer understanding of energy use to lower consumer energy expenditure without constraining productivity; (ii) to reduce power capacity/transmission expansion requirements; and (iii) to reduce greenhouse gas emissions. According to DOE statistics, energy savings of 6.4 million barrels of fuel oil equivalent were registered in 2003 due to different energy efficiency and conservation programs which included intensified energy labeling of electrical appliances, as well as system loss reduction initiatives particularly from private and public companies.[12] As with other energy efficiency measures, the continued rise of fuel prices has given renewed impetus to demand side management, including the approval of time-of-use wholesale power rates by the Energy Regulatory Commission (ERC). In response to sharply escalating world oil process, the President signed Administrative Order (AO) 126 on 13 August 2005 directing the enhanced implementation of the Government's energy conservation program by directing all government agencies to limit the use of petroleum products and mandating such agencies to reduce fuel consumption for transport by 10%. The said AO cites AO 103 (s. 2004) and AO 110 (s. 2004) which likewise require government entities to reduce electricity consumption by 10%. The DOE is also pushing the following initiatives: (i) encourage the use of alternative fuels (i.e., compressed natural gas, coco methyl esther and ethanol) to reduce oil consumption; (ii) require industrial, commercial and transport entities to collect or cause the collection of waste oil for recycling; (iii) monitor the use of airconditioners and the use appropriate thermostat settings; (iv) stagger the working hours in industrial and commercial establishments or offices or fix the

[12] 2005 PEP update.

number of working days per week; and (v) limit and fix the operating hours of business and entertainment establishments.

12. **Electricity Generation Mix.** The country's installed electricity generation capacity stood at over 15,000 MW as at December 2003, up from a 2002 level of 14,700 MW and due to the commissioning of the 345 MW San Roque hydropower plant in May 2003. The commissioning of the three natural gas plants in Batangas has reduced the country's reliance on coal as a fuel source for electricity generation. Nevertheless, coal-fired plants still remained the biggest source of power generation with a 27% share in the mix; followed by natural gas at 25%; geothermal at 19%; hydropower at 15%; and oil at 14% in 2003.

C. Power Generation and Transmission

1. National Power Corporation

13. NPC has, since 1936,[13] been the state-owned utility responsible for the generation and transmission of electricity. Its primary role has been to sell electricity generated from its own plants and purchased from its contracted independent power producers (IPPs),[14] to distribution utilities (DUs), which are responsible for distribution and supply to end users. According to its 2004 Annual Report, NPC also has 155 non-utility customers, 114 of which are industries and 41 classified as "miscellaneous load". It currently owns and operates over 4,500[15] MW of grid connected generation, while NPC plants operated by IPPs have a rated capacity of over 2,400 MW. NPC contracted IPPs contribute another 5,300 MW to the total capacity controlled by NPC (a list of power generation plants owned and operated by NPC is given in Appendix 1).

14. In addition, NPC through its Small Power Utilities Group (SPUG) has been responsible for the generation of electricity to supply customers connected to island and other networks isolated from the three main grids. NPC's total small island grid installed capacity is 196.5 MW, inclusive of 35 MW of IPP-owned power plants. SPUG's generation is sold to electric cooperatives (ECs) that are responsible for distribution and retail sale. SPUG sales totaled 425 GWh in 2003 and 459 GWh in 2004.[16]

15. NPC's financial situation has deteriorated due to unfavorable currency fluctuations and contracted take or pay IPP obligations, particularly in Luzon, and inadequate tariff adjustments. In 2003, NPC posted a net loss of P117 billion ($2.1 billion), of which P78 billion ($1.4 billion) was due to a change in accounting policy. However for the first time in its history, NPC incurred an operating loss amounting to P5.3 billion ($100 million). Its total cash deficit for 2003 was P86.1 billion ($1.6 billion) of which P13.7 billion ($251 million) was from operations. This was funded by new debt (P68 billion), a P2 billion government cash injection and a P16.5 billion withdrawal from cash reserve accounts. At the end of 2003 NPC's long term debt consisted of P461 billion ($8.4 billion) in outstanding loans and P716 billion ($13.1 billion) in IPP capacity fees.

16. For FY 2004, NPC's accounts report an operating profit of P22 billion, a significant turnaround from the P5.3 billion loss in 2003. This improvement was due primarily to the (i)

[13] NPC was originally created as a public corporation by virtue of CA 120 in 1936.
[14] Executive Order No. 215 (1987) provided for private sector participation in power generation and allowed NPC to negotiate power purchase agreements with independent power producers.
[15] Based on the 2004 NPC Annual Report. This capacity includes the 600 MW coal fired Masinloc plant. PSALM anounced the sale of this plant in December 2004 but at the time of the writing of this report the sale had not been closed.
[16] Source: NPC Annual Reports for 2003 and 2004.

accrual of the deferred accounting adjustment for generation rate adjustment mechanism (GRAM) and incremental currency exchange rate adjustment (ICERA) totaling P25 billion;[17] (ii) increased power charges totaling P10 billion due to the rate increase approved by the ERC in September 2004; (iii) revenues of P1.4 billion from the universal charge for missionary electrification; (iv) 6.4% increase in electricity sales; and (v) accrual of penalty charges to Manila Electric Company (MERALCO) of P13 billion.

17. The fact that much of the additional revenue relied on for the turnaround in performance resulted from non cash sources is reflected in the fact that balance sheet receivables from power customers even increased from P45 billion in 2003 to P118 billion in 2004. The reduction in non-operating expenses was due to a one-off impact including a reduction in foreign exchange losses after the accrual of all outstanding foreign exchange loan losses in the 2003 income statement and a P11 billion reduction in restructuring costs. In spite of this apparent financial improvement, however, debt levels are still increasing. In 2004, NPC raised more than P96 billion in bonds and borrowings of which only P28 billion was used for the payment of matured debt.

Table 1: NPC Financial Performance 1998–2004
(P billion)

	1998	1999	2000	2001	2002	2003	2004
Net Operating Revenues	86.6	89.7	100.1	115.7	116.4	119.2	167.3
Operating Expenses	79.7	81.2	94.7	108.9	115.9	124.5	145.1
Operating Income	6.9	8.5	5.4	6.8	0.5	(5.3)	22.1
Interest Expense	11.0	13.0	15.1	15.1	17.9	24.9	30.2
Other Income (Expense)	0.5	(1.5)	(3.3)	(2.1)	(16.3)	(86.8)[c]	(21.8)
Net Income (Loss)	(3.6)	(6.0)	(13.0)	(10.4)	(33.7)	(117.0)	(29.9)
Net Utility Plant in Service[a]	287.1	277.6	273.5	270.1	268.9	268.2	262.8
Long Term Debt[b]	214.0	Note [e]	292.0	290.1	376.3	461.1	348.6
IPP Capacity Fees[d]	230.5	Note [e]	485.8	505.0	595.1	716.0	680.7
Total Assets	**646.1**	**862.4**	**989.8**	**1,006.0**	**1,153.0**	**990.0**	**1,056**

NPC=National Power Corporation, IPP=independent power producer, P=Philippine peso.
[a] Depreciated replacement cost.
[b] Includes bond and loan principal net of current portion.
[c] Includes a one-off charge of P78 billion due to a change in the accounting treatment of foreign exchange and IPP losses. The loss reduces to P39 million when measured on a comparable basis to 2002.
[d] Net of current portion.
[e] Total long-term debt and capacity fees were P445.0 billion but the breakdown between long-term debt and IPP capacity fees is unknown.
Source: National Power Corporation.

2. Independent Power Producers

18. Following a shortage of electricity in the late 1980s, and the 1986 decision to mothball the Bataan nuclear power plant, the Government embarked on an aggressive campaign to encourage private sector participation in power generation. Consequently, over 40 power purchase agreements (PPAs) were signed between NPC and distribution utilities (DUs) on the one hand, and IPPs on the other. These contracts generally had onerous take or pay

[17] NPC accrued receivables of over P53 billion for its GRAM and ICERA recovery. Of this amount, P28 billion was related to the period October 2002–December 2003 and should have been accrued in 2002 and 2003.

provisions[18] and required NPC to carry fuel price and foreign exchange risk. While the program was very successful in addressing the generation shortage (to the extent that there is currently a significant generation surplus on the Luzon grid), it has been a significant cause of the deterioration of NPC's financial position, largely because of lower than forecasted electricity demand and a substantial deterioration of the peso against foreign currencies. NPC currently has in place PPAs for over 8,100 MW of IPP capacity.[19] A list of generating plants subjected to IPP contracts with NPC is provided in Appendix 2.

19. DUs may also contract directly with IPPs. Most notably, MERALCO has signed PPAs with three IPPs including (i) First Gas Power Corporation (FGP) (Santa Rita, 1,060 MW, gas fired; San Lorenzo, 500 MW, gas fired); (ii) Quezon Power (511 MW coal fired); and (iii) Duracom (133 MW oil fired). Other IPPs such as Panay Power with its 72 MW oil fired plant in Panay contract directly with distributors. IPPs contracting directly with distributors have been able to wheel their power through the transmission grid since open access for transmission lines was permitted in 1995, thereby making it possible for IPPs to enter into bilateral contracts with distributors, even though they are not embedded in, or directly connected to the distributor's network. A list of private power plants with a capacity of over 10 MW that are not contracted to NPC is given in Appendix 3.

3. National Transmission Corporation

20. The National Transmission Corporation (TRANSCO) was created pursuant to Section 8 of EPIRA to assume the electrical transmission function of the NPC and manage the transmission grids serving Luzon, Visayas, and Mindanao. It is intended that TRANSCO be a wholly-owned subsidiary of Power Sector Assets and Liabilities Management Corporation (PSALM). Prior to the transfer of assets from NPC to TRANSCO, the latter's financial performance is still formally reported as part of NPC's consolidated accounts. Nevertheless, TRANSCO has operated independently from NPC, with its own board of directors, since March 2003. It publishes its own annual reports that include a separate financial statement of TRANSCO operations. A summary of the transmission assets managed by TRANSCO is provided in Table 2 below.

Table 2: Transmission Assets
(as of June 2004)

	Luzon	Visayas	Mindanao	Philippines
Transmission Lines (cct-km)				
500 kV	1,234	-	-	1,234
350 kV	390	564	-	954
230 kV	5,011	375	-	5,386
138 kV	-	1,670	3,211	4,881
115 kV & below	3,859	2,349	2,447	8,655
Total	10,494	4,958	5,658	21,110
Substation Capacity (MVA)	20,041	2,356	1,697	24,094

Cct-km=circuit kilometer; MVA=megavolt ampere
Source: National Transmission Corporation.

[18] The standard contract required NPC to pay for the expected electricity output if the plant operated at around 80% of plant capacity, provided the plant was available for generation, irrespective of whether or not the electricity was actually required.

[19] Including NPC owned plants under long term operating contracts, plants operated by IPPs and IPP plants still to be commissioned.

21. It is difficult to compare the reliability of the TRANSCO network with other networks due to (i) the use of different reliability indicators; (ii) differences in the way similar indicators are defined and measured; and (iii) the need to make allowance for different network arrangements and different external environmental conditions. The reliability indicators reported by TRANSCO such as system average interruption duration index and system average interruption frequency index are more commonly used for distribution networks, and other indicators such as system minutes of energy not supplied and circuit availability, which are commonly used to measure transmission system reliability are not reported by TRANSCO. However, one indicator that is relevant to both transmission and distribution networks is trips per 100 circuit kilometers (cct-km) of line. According to information on TRANCO's website, the average annual trips per 100 cct-km over the period 1999–2003 ranged from 8.05 in Visayas to 10.82 in Mindanao. If this figure is to be compared to the 1.24 faults per 100 cct-km experienced by Transpower New Zealand for the period 2003–2004, one may attempt to explain this difference by the fact that a significant proportion of the TRANSCO grid is operated at 69 kV and that low voltage lines can be expected to fault more frequently than the higher voltage lines. This explanation, however, fails if one were to consider the fact that while the average number of faults per 100 km reported by the 28 New Zealand distribution line businesses in 2003–2004 at 10.9 was only marginally higher than the figure reported by TRANSCO, the same was accounted for by a vast majority of distribution network trips occuring on 11 kV lines. While it is not suggested that TRANSCO should be able to match the reliability performance of the Transpower New Zealand network, which operates in a more developed economy, the figures show a very wide gap and indicate there is ample scope for improvement and upgrading in TRANSCO's performance and systems.

22. TRANSCO is also responsible for dispatching generation capacity to ensure that all connected loads are supplied. The TRANSCO website provides a daily update of the firm generation capacity available on each of its three grids and this can be compared with the rated installed capacity to give an indication of generation availability. Among the reasons for generation unavailability are (i) inability to produce rated output because of poor plant condition; (ii) plant is out of service following an unplanned outage; (iii) plant is out of service for planned preventive maintenance; and (iv) the unavailability of the water needed to operate hydropower generating plants at full rated capacity. While historical data are not available, Table 3 provides a summary of generation availability as of 11 October 2005. This shows generator availability ranging from 79% in Luzon to 63% in Visayas. An availability margin of about 25% is considered appropriate in a well managed system if continuous supply to all customers is to be assured. However, Table 3 would indicate that a higher margin is needed in the Philippines, particularly in Visayas where much of the diesel generation plants are very old and in Mindanao where hydropower capacity could be limited by a shortage of water during dry periods.

Table 3: Generation Availability as of 11 October 2005

	Luzon	Visayas	Mindanao
Available Capacity (MW)	8,565	990	1,307
Installed Capacity (MW)	10,809	1,582	1,809
Proportion of Capacity Available (%)	79%	63%	72%

Source: National Transmission Corporation website.

D. Distribution and Supply

23. The distribution of power is a regulated activity wherein the right to distribute electricity is granted by a franchise covering a particular geographical area. DUs have the exclusive right to sell electricity to end users connected to their respective distribution networks subject to the entry of qualified third party (QTP) providers in unviable areas of a franchise area. There are

currently 136 DUs in the country, of which 13 are investor owned utilities (IOUs), four are local government units (LGUs) owned, and 119 are customer owned ECs. A list of investor owned DUs is provided in Appendix 4, and data on all ECs are provided in Appendix 5.[20]

24. By far, the largest electricity distributor in the Philippines is MERALCO, which holds the distribution franchise[21] for Metro Manila and urban and rural areas surrounding the capital. About a quarter of the total population of the Philippines lives within the consolidated MERALCO franchise area. MERALCO supplies electricity to over four million customers in 25 cities and 86 municipalities.[22] Its electricity sales in 2004 were 24,700 GWh, or about 56% of nationwide sales in that year.[23] MERALCO is a public company listed on the Philippine Stock Exchange.

25. The ECs are generally small with only 11% having more than 100,000 connected customers, and only 28% having electricity sales greater than 100 GWh in 2004. Being customer owned and controlled by locally elected boards, they have proven to be susceptible to local political volatility,[24] resulting in poor management in many of them. Based on National Electrification Administration (NEA) data, 23 of the 119 ECs are in arrears for debt payment as of December 2004 and 37 ECs have overdue accounts with NPC as of September 2005. The ECs operate under the general oversight of the NEA, which provides technical and managerial support and loan financing for grid augmentation projects.[25] Under the EPIRA, NEA is also mandated to prepare ECs to operate in a deregulated electricity market and strengthen their technical and financial viability.

E. Regulation

26. From 1993 to 2001, the regulation of NPC and DUs had been undertaken by the Energy Regulatory Board (ERB). Upon the passage of the EPIRA, industry regulation became the responsibility of the ERC. The tariffs of NPC and IOUs have been set using a return on rate base (RORB) methodology, which allows a 12% return derived on the rate base and fair and reasonable costs, based on an analysis of a historic test year. EC tariffs were set differently and were based on a cash needs approach, where tariffs were set to recover only the cash costs, including power purchases, operating and debt servicing, of a historic test year. All tariffs were reset in 1994. Since then, adjustments to tariff levels to reflect government wage determinations, as well as fuel and foreign exchange cost adjustments, have been allowed.[26] However, in spite of the large increase in industry debt levels, the ERB was generally cautious to sanction further tariff increases. In order to avoid the risk of ERB mandated tariff reductions, many utilities refrained from petitioning for tariff increases, preferring to rely on revenue increases as a result of load growth to create the headroom necessary to cover cost increases that are not subject to automatic adjustment and also to fund additional capital expenditure.

[20] Data on most investor owned utilities are not readily available at the end of 2005.
[21] On 28 June 2003, RA 9209 took effect granting MERALCO a consolidated 25-year franchise over its current service area.
[22] Based on MERALCO website.
[23] Excluding gross generation, systems losses and own use power, 2004 sales were at 44,075 GWh.
[24] The electricity cooperatives are also a force in national politics. The Association of Philippine Electric Cooperatives (APEC) is registered as a political party and currently has three party list representatives in the national Congress.
[25] Grid extension projects have traditionally been funded by grant aid, provided from either the government budget or by external donors.
[26] Until 2002 these adjustments were automatic. However in 2002, regulated entities have had to secure approval from the ERC before applying generation and foreign exchange rate adjustments. Furthermore, no automatic rate adjustments are applied to compensate for government approved wage increases. In October 2004, the ERC reinstated the automatic GRAM and ICERA adjustments.

F. The Electric Power Industry Reform Act

27. In June 2001, Congress approved the EPIRA which mandated a radical restructuring of the power sector and privatization of NPC. The EPIRA was designed to improve the efficiency of the industry and reduce the sector's alarming public debt levels by increasing competition and private sector investment. Its more significant provisions include the (i) creation of PSALM to take ownership of and manage the orderly privatization of NPC's generation and transmission assets (except those used for off-grid missionary electrification); (ii) creation of WESM to provide competition in the wholesale electricity market; (iii) abolition of the ERB and creation of a more robust and more independent ERC with the power to set tariffs in the non-competitive transmission and distribution subsectors and with wide-ranging powers to regulate the behavior of participants in all sectors of the industry; and (iv) development, subject to certain conditions precedent, of competition in the retail supply of electricity, starting with large electricity users and eventually extending to the supply of electricity to the household level. After more than four years of EPIRA, the sector continues to struggle with the implementation of these changes. EPIRA's implementing rules and regulations were approved by the Joint Congressional Power Commission on 27 February 2002. The progress made to date in the power sector reform mandated by EPIRA is described in Chapter II and some of the more significant issues and risks that the sector faces are discussed in Chapter III of this report. There have been a number of bills introduced in the Legislature that would amend EPIRA.

II. POWER SECTOR RESTRUCTURING

A. Department of Energy

28. The DOE is the agency responsible for the formulation of government policy for the country's energy sector in general, and the electric power industry in particular. As part of its streamlining efforts to address the critical issues facing the power sector, it established an Electric Power Industry Management Bureau (EPIMB) to be responsible for matters relating to the power industry. In particular, one of EPIMB's functions is the preparation of an annual power development plan, although given the extent of the sector's deregulation envisaged under EPIRA, the influence of the power development plan in the ongoing development of the power sector may be limited. Other projects in which it is directly involved include (i) the establishment of WESM in collaboration with other industry participants and, in particular, the appointment of an independent market operator to manage the market; (ii) promotion of rural electrification and coordination of the Government's expanded rural electrification (ER) program that aims to provide electricity to all barangays in the country; (iii) administration of policies promoting the use of electricity generated from renewable sources; and (iv) administration of the host community fund.

29. An important responsibility of DOE is the coordination of the ER program. This program aims to electrify all barangays in the country by 2008. In order to meet this target, it is estimated that 2,910 barangays (of a total of 41,945) will need to be electrified over the period 2005–2008. The program is focused on developing approaches that encourage greater private sector involvement in the effort. One particularly successful approach is to encourage private sector generators to fund barangay electrification projects by advancing their future mandated contributions to the electrification fund. Under this program, Mirant Philippines Corp. has already sponsored the electrification of 1,000 barangays. When 100% barangay electrification is achieved, the focus will switch to household electrification with the present target being a 90% household electrification level by 2017. In order to ensure that the Government's barangay electrification target is met, it is anticipated that from 2005, existing funding sources for off-grid

barangay electrification will be augmented by subsidies from the missionary electrification component of the universal charge.[27]

30. The host community fund was established under DOE's Energy Regulation 1–94 and is designed to recognize and provide recompense for the contribution made by local communities that host power generation facilities and/or energy resource development projects. The fund is sourced from a surcharge of P0.01 per kWh of electricity sales. Fifty percent of the fund is used to electrify unelectrified communities; 25% for community development and livelihood projects; and 25% for reforestation, watershed management, health and environment enhancement projects.

B. Power Sector Assets and Liabilities Management Corporation

31. PSALM has been established as a government corporation to implement EPIRA's restructuring and privatization mandate and to this end has been (i) mobilizing resources to cover NPC's stranded debts and stranded costs; (ii) reviewing and renegotiating IPP contracts to obtain more favorable terms; (iii) developing and implementing a privatization plan for the sale of NPC's generation assets and other properties, and the transfer of NPC's transmission operations to a private sector concessionaire; (iv) developing a plan for the assumption of the NEA's long term loan liabilities following the condonation of EC loans in accordance with Section 60 of EPIRA; and (v) negotiating transition supply contracts (TSCs) with DUs for the sale of electricity in accordance with Section 67 of EPIRA, among others.

32. Following EPIRA's mandate, PSALM had, by the end of 2004, substantially renegotiated 20 of the 35 IPP contracts resulting in savings of up to $2.94 billion in nominal terms and $1.028 billion in discounted present value terms. Following PSALM's negotiation model, MERALCO has likewise renegotiated its power supply contracts with FGP and Quezon Power Philippines Ltd., which has resulted in some savings as well over the contract life of these IPPs.

33. On the other hand, the award of the NPC transmission system to a private sector concessionaire was expected to generate concession revenues of up to $2 billion. However, this estimate of the concession proceeds was predicated on the assumption that NPC would assign its transmission system operating franchise to the concessionaire. This was not provided for in EPIRA and enabling legislation to allow assignment of the franchise is still awaiting the approval of Congress. There is a real risk that approval may not be forthcoming. In the meantime, PSALM is preparing a concession contract that will provide for a concession without the franchise.[28] In 2003, it called for expressions of interest on two occasions, but in both cases, the procurement process failed because only one international transmission company expressed interest.[29] A third round of bidding is expected in early 2006.

---

[27] Section 34 of EPIRA allows the ERC to impose a universal charge on all end use electricity consumers. This charge is to be used for a number of specified purposes, including missionary electrification.

[28] The effect of this is that the franchise holder will operate the network and interact with customers, while the concessionaire will manage the assets. Constitutional requirements prevent the franchise holder delegating or contracting out network operation to another party such as the concessionaire.

[29] An invitation to register interest, pre-qualify and bid was published on 27 January 2003. On 17 March, the closing date for the receipt of expression of interest (EOI), 14 firms from Asia, Europe, and North America had submitted EOIs. However, the bidding was declared as failed on 14 July 2003 because only one of the 14 initially interested companies (Singapore Power) submitted prequalification documents and took the initial step to undertake due diligence. A new bidding process was launched on 7 August when PSALM invited interested parties to resubmit the EOIs. The second biding was again declared as a failure on 22 August 2003, as only Singapore Power sent in a new EOI by the deadline. After the two failed biddings, the PSALM Board authorized interested parties to submit offers under approved negotiation rules and guidelines and PSALM entered into negotiations with a number of interested parties. However, this process also failed as PSALM was unable to perform adequate evaluation due diligence as the offers were complex and variant.

34. Following the approval by President Macapagal-Arroyo of its privatization plan, PSALM commenced the privatization of NPC's assets with the successful bidding of the 3.5 MW Talomo mini-hydroelectric power plant in Mintal, Davao City. By the end of 2004, the sale of five small mini-hydro power plants with a combined total capacity of 8.5 MW had been successfully completed, representing about 0.2% of NPC's total eligible generation assets for privatization and generating a total sale price of $5.2 million. Further, in December 2004, PSALM announced the sale of the 600 MW Masinloc coal fired power plant to YNN Pacific Corporation, a Filipino-Australian consortium, for $561.7 million but as of November 2005 this transaction had still to be completed.

35. Section 60 of EPIRA requires that all outstanding financial obligations of ECs to NEA and other government agencies be condoned and assumed by PSALM in accordance with a program approved by the President and that the distribution rate of each EC be reduced by an amount commensurate to the resulting savings. NEA's outstanding loan portfolio, including loan arrears, was P16.776 million ($307 million) as of 31 December 2002.[30] In 2003 and 2004, PSALM assumed almost P18 billion of EC liabilities to NEA and had made payment of P2.3 billion towards this as of March 2005. By 30 October 2004, the ERC had issued provisional authorities for 115 ECs to reduce their distribution rate by between P0.06 and P1.35 per kWh.

36. PSALM's major revenue sources include (i) revenue from the sale of NPC's generation facilities; (ii) revenue from the transmission grid concessionaire; (iii) assumption of debt by the Government;[31] and (iv) the stranded debt and stranded contract cost portion of the universal charge levied on all electricity end users in accordance with Section 34(a) of EPIRA.[32] On the basis of estimated privatization proceeds of $5 billion and a government debt absorption of P200 billion ($3.6 billion) the privatization plan analysis indicates that PSALM would have sufficient revenues to fund all its debt liabilities except the stranded portion of NPC's eligible contracts, which will be covered through the stranded contract cost component of the universal charge.[33]

C. Wholesale Electricity Spot Market

37. The DOE has commenced establishment of WESM in accordance with Section 30 of EPIRA. Under WESM, a day will be divided into 24 one-hour trading periods and generators will bid competitively for a position on the dispatch schedule for each trading period. In any trading period, generators will be dispatched in the order of their bid prices, with the market clearing

[30] NEA's annual report for 31 December 2002 records long term loan receivables as P14.852 million. However, the P16.776 million also includes P1.924 million shown as the matured portion of loans receivable from ECs. This latter amount is recorded in the balance sheet as a current asset.

[31] Section 32 of EPIRA provides for the Government to assume directly up to P200 billion ($3.9 billion) of NPC's financial obligations. The Government had considered increasing the debt assumption to 500 billion pesos, but eventually only the 200 billion pesos required by EPIRA was assumed.

[32] Other revenue sources include proceeds from the sale of subtransmission assets to distribution utilities and generation revenue from the Agus and Pulangui hydropower stations in Mindanao, which will not be sold. These revenues are unlikely to materially affect PSALM's financial position.

[33] Stranded IPP contract costs may be recovered through the universal charge only if the IPP contract was approved by the ERB prior to 31 December 2000. This means that many large IPP contracts, including those using Malampaya gas, are ineligible for stranded cost recovery through the universal charge.

price being set by the highest bidder to be dispatched.[34] This model is economically efficient because competition for dispatch should ensure that at times of low electricity demand, higher priced generators are not dispatched, and the price paid by customers purchasing electricity from the market is reduced. As demand increases, prices should rise to the extent that it becomes economic for investors to build new generation to enter the market. Since there are no constraints on the entry of new generation, economic theory would suggest that only efficient new generation will be constructed since an inefficient new entrant would risk being displaced by a more efficient new generator, and therefore, not being dispatched. A more detailed description of the operation of WESM is given in Appendix 6.

38. It is intended that all generation, except small plants embedded in distribution systems, will be dispatched through the market on the basis of bid price.[35] However, a financial hedge market will operate in parallel with the physical WESM. Financial hedges are bilateral contracts between electricity generators and purchasers for a fixed price and quantity of electricity in a given trading period, and require the contracting parties to pay one another the difference between the market clearing price and the hedged contract price for the quantity of electricity contracted.[36] Hedge contracts play an important role in the operation of the market, giving price certainty to purchasers and providing generators with a secure and predictable revenue stream. In a mature market, hedge contract prices will be similar to the expected market clearing price. However, consistent with Section 45(c) of EPIRA, no DU is able to hedge more than 90% of its electricity requirements for the first five years of market operation.

39. Preparations for implementation of WESM are in progress. The WESM rules have been issued and the governance structures that will oversee the operation of the market have been put in place. In particular, the technical working group provided for in Clause 10.4.19 of the WESM rules, and the Philippine Electricity Market Board provided for in Clause 1.4.1 of the WESM rules has already been established. The market management system (MMS)[37] was delivered in December 2004 and site acceptance tests are underway. It is planned that market operations on the Luzon grid will commence in the first quarter of 2006.

40. There are issues to be resolved before market operations can commence in Luzon. While the ERC issued an order on 14 March 2004 allowing the detailed design of the MMS to proceed, it required a further filing before finalization of the price determination methodology (PDM). Furthermore, the ERC order noted inconsistencies between the proposed PDM and the WESM rules and stated that the WESM rules would need to be amended. Delays in the privatization of NPC owned generation assets and the poor credit rating of many grid-connected

---

[34] This is strictly true only for an unconstrained loss-free transmission grid. In practice, the need to minimize losses, ensure that the thermal capacities of transmission grid elements are not exceeded, and that adequate network security is maintained means that the location of generation on the grid is an important consideration. As a result, a more complicated dispatch model will be used and there will be different clearing prices for each grid node. While this may result in some low priced generation not being dispatched and being displaced by more expensive bidders, it does not alter the fundamental economic concepts on which the market design is based.

[35] Some generation, such as wind power, cannot bid into the market since output will vary continuously with prime mover availability. Such generators are necessarily "price takers" and in any trading period will be paid the market clearing price for the node to which they are connected.

[36] Hedge contracts are also known as "contracts for differences" because, if the market clearing price is above the hedge price, the generator will pay the difference to the purchaser while the reverse will occur in a situation where the hedge price is greater than the market price. In this way, the physical operation of the system or the market clearing price is not distorted by the bilateral contracts, but the net amount paid to the generator by the purchaser is equal to the bilateral contract price.

[37] The market management system is the computer software and hardware that will be used to manage market bidding and determine the optimal generation dispatch schedule, calculate final market prices, and manage financial settlements between purchasers and generators. It is being financed under ADB Loan 1984-PHI approved by the Board on 19 December 2002.

DUs could also impede the effectiveness of market operations. After completing the requirements contained in the March 2004 ERC directive, the DOE, through PEMC, resubmitted its proposed PDM in August 2005 and is awaiting ERC's final ruling.

D. Small Power Utilities Group

41. SPUG is a separate division of NPC which supplies electricity to ECs and LGUs operating distribution networks that are not connected to any of the three main grids. Its power plants range in size up to 14 MW and the large power barges use bunker C heavy fuel oil (HFO) while the smaller plants are generally fueled by light fuel oil.[38] SPUG also owns and operates off-grid transmission systems in Palawan and Mindoro.[39] In accordance with Section 47 of EPIRA, SPUG's assets are exempt from the privatization process. Nevertheless, the DOE and NPC initiated a program aimed at luring private sector players into the business of missionary electrification. Through a DOE Circular which became effective on 12 February 2004,[40] NPC-SPUG areas are to be grouped into waves based on the suitability of the areas for supply by new private providers (NPPs). The first wave groupings consisting of 14 areas were selected on the basis of their respective peak demand levels. A total of six areas have, through different options, commenced their respective processes for the entry of NPPs. Section 70 of EPIRA requires that missionary electrification be funded from sales of electricity in missionary areas and from the missionary electrification component of the universal charge. In accordance with this provision, NPPs taking over from SPUG in privatized supply areas will also be eligible for subsidy funding from the universal charge.

42. SPUG's provisionally approved unbundled base generation rate is currently P3.7064 per kWh in Luzon, P5.6404 per kWh in Visayas, and P4.8024 per kWh in Mindanao.[41] The ERC's December 2002 order setting these rates specifically states that they are lower than the rates actually charged by SPUG in October 2002[42] (based on the base rate set in 1993 and subsequent fuel cost and foreign exchange adjustments), and that they are significantly lower than the ERC's own calculation of the rates required to fully fund SPUG's operating costs.[43] In fact, in Visayas and Mindanao they were not sufficient to even cover SPUG's fuel cost.[44] In order to meet the gap between SPUG's revenues from electricity sales and its cash requirements for operating costs and capital expenditures, SPUG petitioned ERC for approval of a P0.0831 per kWh missionary electrification component of the universal charge. It was provisionally granted an availment of P0.0168 per kWh in December 2002, and in ERC's final decision issued in June 2003, the missionary electrification component of the universal charge was increased to P0.0373 per kWh. The provisional amount provided for operating expenses only, whereas the final decision included provision for capital expenditure, calculated on the basis that SPUG's capital expenditure would be fully funded from the universal charge. ERC has still to approve an updated missionary electrification component of the universal charge for 2004 or 2005 but has allowed PSALM to continue to collect the charge and subsidize SPUG at

[38] The exception is Balongbong in Catanduanes province, which is a 1.8 MW hydropower station.
[39] Ongoing projects are in Masbate, Marinduque, and Catanduanes.
[40] DOE Circular No. 2004-01-001.
[41] These rates include the transmission component to cover the cost of the transmission grids in Palawan and Mindoro but do not include fuel cost and foreign exchange adjustments.
[42] SPUG claims that the ERC included fuel cost adjustment (FCA) for the current month and not the FCA for earlier increases being charged by SPUG on a staggered basis.
[43] In its order setting a provisional rate, ERC's calculated rate required to fully fund SPUG's operating costs was P5.8212 per kWh in Luzon, P8.4054 in Visayas and P7.5201 per kWh in Mindanao.
[44] According to SPUG, its 2002 fuel costs per kWh sold were P2.15 in Luzon; P6.57 in Visayas; and P6.38 in Mindanao. The difference in fuel costs between Luzon and the other areas is due primarily to the high proportion of heavy fuel oil (HFO) generation in Luzon and also the high fuel transport costs to supply small plant in other areas.

the 2003 rate. Hence, SPUG's revenue from both electricity sales and subsidies is insufficient to cover its costs and its operations are still subsidized by NPC. To minimize this funding shortfall, SPUG has reduced its capital expenditure to a level that is not sufficient to permit its existing service levels to be sustained over time.

E. Electricity Distribution

43. While EPIRA did not materially alter the franchise arrangements[45] or structure of the distribution sector, it introduced a number of changes that will impact the way these utilities operate. The more significant changes include the (i) structural and functional unbundling of distribution business activities and rates which means, among others, that generation, transmission, distribution and supply costs will be shown separately on customer bills and generation and transmission costs will be treated as a pass-through; (ii) introduction of open access and retail competition on distribution wires[46]; (iii) provision of restrictions on the sourcing of demand requirements from associated firms (not more than 50%) and from bilateral contracts (DUs must purchase at least 10% of their requirements from WESM for the first five years after its establishment);[47] (iii) condonation of the loans of ECs and the assumption of these loans by PSALM in exchange for a reduction in the rates of the ECs by an amount commensurate to the resulting savings; and (iv) removal of cross subsidiaries within a grid, between grids and/or classes of customers within three years from the establishment of a universal charge by ERC.

44. Moreover, Section 8 of EPIRA provides that NPC's subtransmission assets should be segregated from transmission assets and operated by TRANSCO until they are sold to qualified DUs. To facilitate this, the EPIRA further requires that TRANSCO grant concessional financing to ECs for the purchase of subtransmission assets.

F. Electric Cooperatives

45. ECs are customer-owned nonprofit organizations without a capital structure. The financial and operational position of the 119 ECs vary for each cooperative. In 2004, 62 ECs generated insufficient revenues to cover their operating and debt service costs while 26 were unable to cover even their operating costs. In addition, 50 ECs reported total power losses greater than 14%.[48] Of these, 12 reported losses higher than 20%. Twenty-three ECs are in arrears to NEA on loan repayments as of 31 December 2004 and 37 had overdue accounts with NPC for purchased power as of September 2005. The NEA balance sheet shows P2.6 billion in outstanding EC loans as of 31 December 2004, down from P3.7 billion as of 31 December 2003 and from P15.4 billion as of 31 December 2002. The movement is primarily due to the assumption, in accordance with EPIRA, by the PSALM of the ECs' loan obligations to NEA as of June 2001. In 2003 and 2004, PSALM assumed almost P18 billion of EC loans and made payments of around P2 billion during this period. NEA uses a categorization system to measure the performance of ECs. The system

[45] Prior to the passage of EPIRA, the power to award distribution franchises was vested in the National Electrification Commission operating under NEA. Under Section 27 of the EPIRA, this power is now vested in Congress provided that existing franchises must continue for their full term and that the power to renew and cancel the franchises of ECs will remain with NEA for a period of five years after the effectivity of EPIRA.

[46] At present, distribution utilities have an exclusive right to supply electricity to customers connected to their network. Under open access and retail competition, electricity supply will become competitive and distribution utilities must let competing electricity suppliers transport electricity over their network.

[47] It is likely that many of the smaller distribution utilities will not be able to meet the prudential requirements to allow them to trade in the market. However, Section 30 of EPIRA provides that NEA may, "in exchange for adequate security and a guarantee fee" act as a guarantor for purchases of electricity in WESM by any electric cooperative or small distribution utility.

[48] In accordance with RA No. 7832, 1994 (the Anti-Pilferage Act) ECs are subject to a loss cap of 14%. The cost of losses above the cap is ignored when setting the rate and cannot therefore be recovered from customers.

ranks ECs on a scale from A+ to E based on (i) loan repayment history; (ii) system loss levels; (iii) revenue collection efficiency; (iv) level of power purchase payment arrears; and (v) level of non-power operating costs. The rankings as of 31 December 2004 are shown in Table 4 below.

Table 4: EC Rankings as of 31 December 2004

Ranking	No of ECs
A+	60
A	13
B	16
C	5
D	5
E	20

Source: National Electrification Administration.

46. NEA is under severe financial stress. In 2003, it realized a net operating loss of P518 million, up from P122 million in 2002. Its 2003 balance sheet reported a deficit of P7 billion as well as current assets of only P2.7 billion (including P1.3 billion of matured loan receivables from ECs) compared with current liabilities of P13.1 billion. The balance sheet also showed some P5.5 billion in long term loans from the government. Some of these loan advances had been made to ensure that NEA does not default on repayment of its foreign debt, which balance amounted to P3.1 billion as of 31 December 2003. Loan condonation will mean that PSALM, rather than the ECs will be responsible for making most outstanding loan principal and interest payments and therefore, should not significantly impact NEA's financial position. In early 2004, NEA was reorganized and staffing levels rationalized to address the financial problems and more effectively carry out its revised mandate under EPIRA. The reduction in personnel expenses and the restructuring of a number of EC loans resulted in a 2004 net operating income of P200 million, a marked improvement over the previous year's performance.

G. Manila Electric Company

47. MERALCO is the largest DU in the Philippines. As the recipient of an ADB loan,[49] its performance is of particular interest. During the mid-1990s, over the period immediately following the approval of ADB's loan, MERALCO's financial performance proved to be satisfactory. However, as shown in Table 5, in recent years, MERALCO's financial position has deteriorated to the extent that it has failed to meet ADB's required 8% RORB since 1997. In fact, in 2002, it also failed to meet its covenanted self financing ratio of 20%. MERALCO posted a before tax loss of P29.6 billion in 2002, before slightly recovering in 2003.[50] A major reason for this deteriorating financial performance has been the fact that there were no increases in MERALCO's distribution rate between 1994 and 2003.

[49] ADB.1992. *Report and Recommendation of the President to the Board of Directors on a Proposed Loan to theManila Electric Company in the Republic of the Philippines for the MERALCO Distribution Program*. Manila.

[50] This includes the extraordinary loss realized because of the SC refund decision.

Table 5: MERALCO's Financial Performance 1998–2004
(P billion)

	1998	1999	2000	2001	2002	2003	2004
Revenues[a]	81.50	84.40	103.70	129.40	117.80	132.00	147.60
Operating Expenses[b]	76.80	80.20	99.70	125.80	116.20	126.40	137.50
Operating Income	4.70	4.20	4.00	3.60	1.60	5.60	0.40[c]
Net Income (loss)	5.00	3.30	2.50	1.50	(28.20)[d]	1.30	(2.60)
Net Utility Plant in Service	68.70	73.60	71.90	77.20	79.30	85.50	87.30
Non-current Liabilities	26.80	27.80	41.50	43.20	46.70	70.00	87.00
Total Assets	**97.40**	**102.30**	**125.00**	**134.70**	**145.60**	**144.90**	**154.70**

[a] Parent Company figures; restated figures are used when applicable.
[b] Excluding income tax.
[c] Net of a provision of P9.8 billion loss in the event of an adverse decision of MERALCO's rate case currently before the Supreme Court.
[d] Includes P23.8 extraordinary loss (net of tax benefit) due to the November 2002 Supreme Court refund decision
Source: Manila Electric Company.

48. In January 1994, ERB granted MERALCO a provisional rate increase of P0.184 per kWh, subject to a review of the test year accounts by the Commission on Audit (COA).[51] The COA reported in February 1997 that in its view, the accounts were defective in that (i) the rate base should be calculated by averaging the asset base at the end of each month of the test year rather than by simply averaging the asset base at the beginning and end of the test period; and (ii) income tax was not an allowable operating expense in calculating the RORB. Subsequently, in February 1998, the ERB issued a final decision on the 1993 rate petition that reduced the allowed rate increase by P0.167 per kWh and further required MERALCO to refund the difference between the provisional and final rate increases on all electricity sold since the provisional rate increase was applied. MERALCO did not act on the ruling and appealed the ERB decision to the courts. MERALCO's position was upheld by the Court of Appeals, but the Supreme Court overturned this ruling and upheld the ERB decision. Subsequently, ERC approved a phased refund implementation process, beginning with MERALCO's smallest residential customers. By the end of 2003, MERALCO had refunded approximately 80% of its active customers, representing an amount in excess of P5 billion.

49. MERALCO has also been in dispute with NPC over IPP power purchases. In 1994, MERALCO signed a 10-year PPA with NPC, to purchase a minimum annual electricity quantity of 20,000 GWh. It subsequently signed PPAs directly with three IPPs including FGP, which eventually constructed 1,500 MW of combined cycle gas turbine generation, operating on gas from the Malampaya gas field. Since the commissioning of these gas fired plants in 2002, MERALCO has been contracted to purchase a minimum annual quantity of 34,000 GWh, approximately 8,000 GWh more than its annual requirement, inclusive of network losses and electricity for its own use. MERALCO's response to this contracted over-capacity was to request dispatch of FGP to the full extent of its contracted capacity and to only pay NPC for excess power requirements over and above that purchased from its own IPPs. However, FGP has not

[51] In the Philippines, the regulator sets the rate based on a review of costs in a historic test year. This contrasts with the situation in many jurisdictions where forecast costs are used as the basis for rate setting.

been able to dispatch its plant to its minimum contracted capacity due to transmission constraints.[52] NPC claimed against MERALCO for not paying for contracted power purchases, while MERALCO counter-claimed against NPC for losses incurred because it did not make sufficient transmission capacity available to enable it to use its minimum contacted capacity with FGP. After mediation, this dispute was settled in July 2003. The terms of settlement are that MERALCO will compensate NPC P27.5 billion for energy contracted but not consumed, while NPC will compensate MERALCO P7.5 billion for its failure to provide sufficient transmission capacity to allow FGP to run at minimum contracted levels.[53] The settlement is subject to ERC allowing for the recovery of the P20 billion net settlement amount through a levy on MERALCO customers over a staggered 5-year period. As part of the settlement, NPC has agreed to make sufficient transmission capacity available to enable the dispatch of FGP at contracted levels.[54] NPC and MERALCO have jointly filed the settlement to ERC for approval.

H. Energy Regulatory Commission

50. The ERC was created by EPIRA as the industry's independent regulator, succeeding the ERB). New functions and responsibilities have been introduced by the law including (i) developing and enforcing technical standards for transmission and distribution; (ii) enforcing the WESM rules; (iii) licensing of generators and suppliers of electricity;[55] (iii) setting of rates for non-contestable sectors of the industry;[56] (iv) determining and approving the level of the universal charge; (v) preventing abuse of market power and anti-competitive or discriminatory behavior by industry participants; and (vi) resolving disputes between industry participants or between industry participants and customers.

51. Following the passage of EPIRA, all utilities have been required to file a petition for the approval of unbundled rates while ECs have also been required to file a petition for rate reductions due to the condonation of NEA loans. In the unbundled rate, generation, transmission and universal charges are separately itemized on a customer bill and any changes in the unbundled components of generation, transmission, and universal charges are treated as a pass through, although ERC approval is required before these changes can be reflected in customer bills. Loan condonation applications from ECs are being treated separately. Loan condonation applies only to the distribution component of the unbundled rate and the petitions were filed in accordance with Section 60 of EPIRA which requires that there be a reduction of the rates of ECs commensurate with the savings due to loan condonation. The processing of loan condonation and rate unbundling petitions is now substantially complete.

52. Rate unbundling applications have been examined by the ERC using 2000 as the historic test year. While rate unbundling is technically revenue neutral, the process used has effectively involved a review of the existing costs, and distribution rates have therefore been

[52] These constraints have arisen because NPC has used its transmission capacity in a way that minimizes its own costs. Transmission capacity not required is then made available to FGP.

[53] NPC will need to rearrange its own generation dispatch schedules to make the necessary capacity available. The extent to which this will increase its generation costs is not known.

[54] The outcome of the petition to ERC that would allow the net P20 billion cost of the NPC settlement is still awaited. Assuming 6% per annum load growth, a rate increase of about P0.14 per kWh is necessary to achieve the required recovery over five years. MERALCO's rate petitions are usually strongly opposed and history would suggest that an outcome favourable to the company cannot be assured.

[55] The purpose of a license is to ensure adherence to standards rather than to limit the number of participants. Consistent with this philosophy, licenses in the generation sector are called "Certificates of Compliance" in EPIRA.

[56] Rates for generation and supply are currently regulated. Generation rates will cease to be regulated after the commencement of WESM, and upon the implementation of retail competition, the retail supply rate to contestable customers will no longer be regulated.

revised as a result.[57] ERC first replaced the previous automatic cost adjustment formulae with a GRAM and ICERA; but has now introduced the automatic adjustment of generation rates and system loss rates (AGRA) to replace GRAM. Under GRAM and ICERA, adjustments needed to be pre-approved by ERC before they can be included in customer bills, but under AGRA the process has been changed to allow adjustments to be applied by the regulated entities, subject to retrospective approval by ERC.

53. With technical assistance (TA) from ADB,[58] the ERC promulgated on 29 May 2003, the performance based rate (PBR) making methodology for the transmission sector. The PBR regime departs from the traditional RORB methodology, which has been used in the Philippines for the past 80 years. The methodology provides that a revenue cap for each year of a five year regulatory period will be set before the beginning of the period[59] and that, under normal circumstances, these caps will not be changed.[60] The revenue caps will be based on a series of building blocks that include (i) operating and maintenance expenditure; (ii) depreciation; (iii) a return on invested capital including system assets valued using the depreciated optimized replacement cost method; (iv) a return on capital expenditure undertaken during the regulatory period; and (v) income and other taxes. The contribution of each building block to the revenue requirement in a particular year is based on a forecast of the business' expenditure requirements over the regulatory period. The scheme includes an efficiency incentive whereby the operator is rewarded or penalized depending on the difference between its achieved level of network performance and preset performance targets, and an efficiency carryover mechanism whereby the benefits achieved by reducing costs below forecast levels can be retained by the regulated entity for a five year period. A description of the PBR rate setting mechanism to be used by ERC is given in Appendix 7.

54. On 5 January 2005 the ERC issued guidelines for a new methodology for setting wheeling rates for private DUs. This is a performance based rate setting methodology that is similar in most respects to the PBR rate setting methodology to be used for the transmission sector. The key difference is that for the distribution sector, the methodology will be used to determine a maximum average price[61] rather than a maximum allowed revenue as determined for the transmission business. Hence, under this rate setting mechanism, the total revenue received by DUs can rise and fall with the volume of electricity delivered, whereas the maximum allowed revenue determined for TRANSCO is independent of electricity volumes. A less significant difference is that the regulatory period for DUs is only four years.

55. These new PBR rate setting guidelines for both transmission and distribution are based on current Australian and UK regulatory practices and are designed to make the transmission concession attractive to the private sector. They reward the operator for reducing costs, provided network reliability does not deteriorate, while at the same time providing protection from the impact of uncontrollable events that could significantly impact business performance. In the short-term, transmission wheeling charges are likely to increase under the new regulatory environment but over time, rates should decrease as efficiency gains are eventually fed back to customers[62].

---

[57] Some utilities have experienced rate reductions as a result of their unbundling applications.

[58] ADB. 2001. *Technical Assistance to the Philippines for* a *Competition Policy for the Electricity Sector*. Manila.

[59] It is envisaged that a regulatory period will normally last for five years.

[60] There are provisions for a review of the revenue caps in situations that are outside the control of the regulated entity and that would have a significant impact on the profitability of the regulated entity.

[61] The average price is determined by dividing the total amount billed for regulated services in a regulatory year by total energy delivered in that year.

[62] The design of the system is such that efficiency gains will not result in rate reductions until commencement of the third regulatory period in 2011.

III. CRITICAL ISSUES AND RISKS

A. National Power Corporation's Financial Crisis in Macroeconomic Context

56. In the Philippines, electricity accounts for about 9% of the industry sector and 2.8% of the gross domestic product (GDP) as the industry sector accounts for 32% of GDP. Growth in electricity consumption slowed to 3.2% in 2004, down from 10.6% in 2003. However, NPC has incurred a heavy debt burden, large debt service obligations, and continuing financial losses since 1998. The failure to effectively address these problems has had a negative impact on the economy and created a large financial burden on the National Government. The ongoing financial problems of NPC are attributable to operating inefficiencies, under-capitalization, inadequate tariff adjustments, depreciation of the peso, the high cost of foreign borrowings and debt servicing, rising global fuel prices, and unresolved conflicts with DUs.

57. The Government's response to the power crisis of the 1990s resulted in NPC incurring huge liabilities. NPC's long term debt as of end-2003, excluding amounts owed to the Government and its agencies, amounted to P454.2 billion. This represented 27% of estimated Government contingent liabilities as of 31 December 2003. This ratio has placed the National Government in a precarious debt situation causing concern to investors over the power sector's and the country's ability to manage the debt situation. Furthermore, as of December 2004, NPC's outstanding long term lease obligations to IPP contractors stood at P681 billion. The extent that these obligations are "stranded"[63] cannot be accurately assessed and will depend on the rate of growth in electricity demand over the next few years.

58. NPC's financial situation is precarious. As shown in Table 1 there was a significant deterioration in its financial position from 2002 to 2003, albeit with some improvement in 2004. During the period 2002–2003, NPC's total IPP lease obligations increased by 42% due to the commissioning of the Ilijan natural gas plant and the San Roque hydropower plant, both of which were committed for construction during the late 1990s. This was exacerbated by the failure to increase generation rates in 2002 to cover the corporation's IPP liabilities from existing facilities and the Ilijan and San Roque plants. At the same time, NPC's total long-term debt increased. By the end of 2003 NPC's total assets were less than its accumulated liabilities, implying that the corporation was technically bankrupt. As a result, NPC has been forced to increase borrowings to meet these additional operating costs. In 2004 and 2005, NPC borrowed a total of almost $2.2 billion from, among others, the international bond markets.

59. To address NPC's financial difficulties, there is an urgent need to (i) minimize or altogether halt increases in its long-term debt; (ii) pare down such debt as much as possible; and (iii) generate sufficient operating surplus after debt service by, among others, increasing generation tariffs to satisfactory levels. While the 2004 accounts indicate that some progress has been made, closer scrutiny indicates that much of the improvement is due to non-cash accrual adjustments of which some, such as the MERALCO penalty accruals, may not be realized. [64]

---

[63] In this context "stranded" lease obligations refer to capacity payments to IPP contractors that NPC is contractually obliged to pay but where it is unable to use the capacity due to a lack of electricity demand.

[64] MERALCO and NPC settlement agreement regarding the former's liabilities vis-à-vis its 10 year supply contract is premised partly on NPC being able to write-off a P40 billion receivable from MERALCO. The problem here is that it would take an act of Congress to effect such write-off on the books of NPC. Therefore, it is quite possible that even ERC's intervention may not solve the TSC problem, at least to MERALCO's satisfaction that all of its liabilities to NPC will be extinguished.

60. It is noteworthy that while EPIRA was promulgated in 2001, the first significant step to address NPC's financial crisis was not taken until September 2004, when ERC granted provisional authority to increase NPC's generation rates by an average of 40%. There can be little doubt that this delay has caused NPC's financial position to deteriorate more significantly than it would have, had more timely action been taken. And even then, the September 2004 rate increase was insufficient to bring to NPC a healthy and sustainable operating surplus. The analysis underpinning the ERC decision shows a RORB provision of P13.5 billion, well short of NPC's 2004 interest cost of P30.2 billion. Moreover, the ERC has required savings made from restructuring and downsizing to be passed through to customers, rather than retained to address the financial problems of the company.

B. Generation Capacity

61. The tables in Appendix 8 compare the electricity demand forecasted for each of the three main grids in the country with existing connected generation and committed new projects for three different scenarios. The DOE scenario is based on the growth rate assumed by DOE in its 2005 PEP update while the historical growth scenario assumes that the average growth rates observed over the period 1994–2004 in each of the three grids will be maintained. The low growth scenario postulates a reduction in growth due to a tightening of the economy as the government manages the high debt levels and higher electricity prices as industry restructuring gathers momentum. This analysis shows a 2004 capacity margin[65] varying from 90% in Luzon to 43% in Mindanao. If reliable supply is to be assured, there must always be a capacity margin between connected generation and maximum, or peak demand in order to allow for the (i) inability to operate plants at rated capacities due to wear and tear; (ii) need to provide for plant maintenance outages and unplanned plant failures;[66] (iii) need to provide for transmission constraints; and (iv) possibility of not being able to operate hydropower plants in dry years because of a shortage of water. A minimum capacity margin of about 30% would be prudent for the Philippines but this may need to increase where existing plants are very old (this is the case in Visayas), or where there is a significant amount of hydro capacity subject to water shortages in a dry year. For example, for Mindanao, where hydropower capacity accounts for about 60% of total installed capacity, the ideal reserve margin should be 50%.

62. The analysis in Appendix 8 raises questions about DOE's forecasts. The assumed growth rate for Luzon is about 2.7% higher than the average growth in generation observed over the last ten years while the DOE's forecast growth rate for Visayas is about 1.3% lower. The assumed growth rate for Mindanao, however, is consistent with past trends. It is difficult to speculate on the reason for these differences but inaccurate growth forecasts can have a significant impact in electricity planning. For example, the analysis in Appendix 8 indicates that if we are to go by the DOE forecasted growth rate, new generation capacity should be in place in Luzon by 2009, assuming that a 30% capacity margin is required; whereas if a continuation of historical growth rates is assumed, the new capacity will only be needed in 2011. If an even lower growth rate eventuates, then new capacity will not be required until beyond the 2012 planning horizon. There presently seem to be no indicators that electricity consumption will increase above historical growth levels in the medium term. Indeed, indications are that the growth in electricity consumption is likely to soften given the anticipated tightening of the economy to manage the current debt crisis and the fact that electricity prices will inevitably rise as the impact of the industry reforms becomes more evident.

[65] In this context, capacity margin is defined as the difference between installed capacity and maximum demand, measured as a percentage of maximum demand.

[66] It is a standard practice to operate a grid with some generators operating only partly loaded in order to be able to pick up load to maintain supply in the event of an unplanned generation outage. Such generation is known as "spinning reserve".

63. The analysis presented in Table A8-2 confirms that the capacity situation in the Visayas is acute with additional generation capacity being required in 2008 under the historical growth scenario and in 2010 under a low growth scenario. Given the archipelagic profile and the consequent dependence on limited capacity submarine cables, the supply–demand situation in Visayas is even more critical than shown by the above analysis especially for Panay which is the most outlying grid in the region. Indeed, generation shortages were already being experienced in Cebu in 2003 due to (i) higher than forecasted system demand; (ii) a high number of unplanned plant outages including the unavailability of a 50 MW geothermal plant in Negros; and most critically (iii) delays in upgrading the Leyte-Cebu transmission interconnection.[67] Geographically situated in the country's belly, the Visayas grid is a long and narrow string of island grids, stretching from Leyte from one end, to Panay at the other, with the islands in between connected by limited capacity submarine cables. While there is a surplus of generation available in Leyte given the rich geothermal resources available there, constraints on transmission capacity limit the export of this power to Cebu, Negros, and Panay to the extent that even after allowing for the capacity of the submarine cable, the availability of generation in Cebu and Panay is already marginal. This is illustrated in Table 6, which shows that (i) even in 2011, the generation capacity in Leyte will significantly exceed local requirements; (ii) in 2003, Cebu, Negros, and Panay were all reliant on imports from Leyte to provide an adequate capacity margin; and (iii) by 2005, there will be a deficit in Panay even after allowing for maximum imports from Negros.[68] NPC plans to relocate a diesel power station from the Luzon grid to Panay to alleviate the situation. Panay will require an anchor base plant north of the island to assure supply reliability. Further, that even if the total capacity of the submarine interconnection to Panay is available, voltage instability along the transmission system will not permit all of the available power to be used in Panay. Once the Panay deficit is addressed, the situation in Negros will be less critical partly because of the expected commissioning of the Northern Negros geothermal plant by 2007.

Table 6: Supply and Demand on Visayas Grid

	Generation (MW)				Forecast Load (MW)			
	2003	**2005**	**2008**	**2011**	**2003**	**2005**	**2008**	**2011**
Leyte-Bohol-Samar	814	782	782	782	228	275	352	442
Cebu	398	384	384	285	426	477	613	781
Negros	193	233	233	233	163	198	242	290
Panay	183	82	82	82	189	221	262	313

Notes: Leyte-Cebu interconnection capacity is 200 MW increasing to 400 MW in 2005.
Cebu-Negros and Negros-Panay interconnections are both 100 MW.
Source: Consultant analysis based on load forecast in 2003 Transmission Development Plan.

64. The DOE forecast for Mindanao is generally consistent with historical growth rates. It can be seen from Table A8-3 that the commissioning of the Mindanao Coal plant in 2006 will only alleviate the electricity supply situation in Mindanao for about two years, and that even more generation capacity is likely to be required in 2008. The required commissioning date for such additional capacity could be delayed until 2010 under the low growth scenario. In a dry year, the capacity margins in Mindanao will actually be lower than that shown in Table A8-2 as insufficient water will be available to run hydro generation at full capacity. The medium term generation situation in Mindanao has been exacerbated by the government's earlier decision not to proceed with the Leyte-Mindanao high voltage direct current interconnection. This

[67] Leyte-Cebu interconnection upgrading and Leyte-Mactan interconnection projects were commissioned in October 2005.

[68] The reduction in generation in Panay between 2002 and 2005 is due to a need to retire very old diesel generation facilities.

decision needs to be reviewed on the basis of detailed surveys to identify a suitable submarine cable route so the lead-time required for implementation would be relatively short once financing is confirmed. However, it appears that implementation of such a major interconnection would require government intervention and is unlikely to proceed under the relatively "hands-off" approach to transmission planning mandated by EPIRA.

65. Given the long lead-time required for the construction and commissioning of power stations, there is a need to draw up plans for, and encourage developers to invest in the construction of new generation capacity for connection to all three grids. New capacity is urgently required in the Visayas and Mindanao grids, but is unlikely to be needed until 2010–2011 in Luzon. Nevertheless, the plant capacities required in Luzon are much larger and therefore need longer lead times. For Luzon, natural gas is a preferred fuel source given its clean burning quality and availability within the country, and it is estimated that the Malampaya gas field infrastructure has sufficient capacity to support another 500 MW power station. The existing Malampaya gas price is considered relatively expensive especially if compared to LNG sold in the region; but given the marginal investments required by the field developers to support an increased off-take level, it should be possible to negotiate a reduced price for any incremental off-take above existing contracted levels. However, a new gas fired power station cannot be built in Batangas at the shore terminal of the Malampaya gas pipeline, as there is insufficient transmission capacity to transport the electricity to Manila. The decommissioned 850 MW Sucat power station in Metro Manila is a suitable site for a new gas fired power station and could be supplied by the proposed Batangas-Manila gas pipeline (Batman I), which may be constructed by the PNOC-EC.[69] A second possibility is for a new power station to be constructed in Bataan and supplied by imported LNG. Re-gassified LNG could then be also delivered to Sucat, in Metro Manila though a new gas pipeline laid under Manila Bay. This alternative proposal has been under active study by private sector investors.

66. While the Government's successive power development plans list indicative generation projects, there is currently a lack of interest from the private sector in investing in these developments.[70] NPC is prohibited by Section 47 of the EPIRA from building new generation plants or purchasing power under new bilateral contracts. Under the restructured industry arrangements, it is hoped that the onset of retail competition and open access, with WESM-determined prices, would signal generation investment opportunities and that all new generation would be from private sector financed merchant plants. It is to be noted that with open access, greenfield project developers can sign up bilateral contracts with end-users, either commercial and industrial customers or with aggregator. However, delays in the implementation of retail competition and open access, including the implementation of WESM, are creating a vacuum within the industry resulting in investor uncertainty over the success of ongoing industry reform. In fact, many IPPs and potential investors have been expressing concern over the delayed privatization efforts of the Government and cannot help but gauge the success of the sector's restructuring on the basis of this delay. Other factors that might be limiting investor interest even in existing assets include (i) higher investment risk in the new competitive but uncertain environment;[71] (ii) a perceived lower risk in purchasing existing NPC plants which are supposed to be sold with TSCs providing a guaranteed short-term revenue stream; (iii) difficulty in the current uncertain environment of securing the guaranteed revenue stream through long-term power supply agreements necessary to make a new generation project bankable; (iv) regulatory uncertainty, and the fact that existing regulated generation rates are well below even the costs

[69] It is estimated that there is a potential 25 MW equivalent gas demand along the proposed Batman 1 route.

[70] The private sector proposal for a new power station in Bataan for a power station using LNG is a notable exception.

[71] In the IPP contracts signed in the 90s, the power purchaser generally took foreign exchange, fuel price and capacity risk.

faced by an efficient new entrant; and (v) concerns about the credit rating of many existing DUs. In the short term, until the industry reform is completed, the government may have to rely on oil-fired generation, including plant transfers from Luzon, to meet demand growth in the Visayas and Mindanao grids.

C. Transmission Constraints

67. According to PSALM's privatization plan, and subject to the enactment by Congress of enabling legislation, the franchise to operate the transmission network will be assigned to a private sector concessionaire. Under its concession contract, the transmission concessionaire will be required to (i) meet agreed performance targets for the operation of the network;[72] (ii) complete all projects under construction at the time the concession is awarded; (iii) prepare the transmission development plan (TDP) on behalf of TRANSCO[73] and in consultation with other industry participants; and (iv) complete any ERC approved projects included in the TDP. The transmission rate charged by the franchisee will be regulated by the ERC under the new PBR rate setting guidelines. To date there have been two failed biddings for the TRANSCO concession with only one interested bidder participating each time. However, there has been increased interest since the May 2004 presidential elections and PSALM shall conduct a third bidding round soon. The lack of interest from the private sector in taking up the TRANSCO concession is a concern, given that revenue from the concession contract was expected to make a substantial contribution to the alleviation of PSALM's debt problems. If no concession is let, the Government will need to continue borrowing to fund expansion of the transmission grid, even though transmission rates should rise as a result of the PBR rate setting methodology. The failure of Congress to pass the legislation required before any new concessionaire could be awarded, the transmission franchise may be creating uncertainty among prospective concessionaires in regard to TRANSCO's ability to fulfill its obligations in respect of any concession contract that might be signed.

68. There is increasing evidence that capital investment in the transmission system is poorly targeted. The 2005 Sector Assistance Program Evaluation Study[74] noted that the current average loading of the 500 kV transmission lines was only 30.8% and that, if the current TDP was implemented on schedule, this would fall to 22% in 2013. On the other hand, some 230 kV lines are currently overloaded, with one line said to be carrying twice its rated load. It is usually possible to manage transmission line loading by the judicious scheduling of generation, and best practice transmission planning accepts that transmission constraints are not, of themselves, bad and should only be alleviated when the cost to the market for higher cost generation is greater than the cost of installing a transmission system augmentation. On this premise, it would seem that the delays in upgrading the Leyte-Cebu interconnection came at a significant cost to the industry since it required the use of diesel-fed generators in Cebu as the limited interconnection capacity prevented the import of underutilized geothermal capacity from Leyte. The apparent transmission constraint to the south of Manila is also cited as an economic impediment since it prevented IPPs located south of the capital, including the plants using Malampaya gas, from simultaneously delivering their power to Metro Manila. However, when the transmission system delivering power into Manila from the south is operating at full capacity any additional load required in Metro Manila can be imported from the north. Hence, economically, the constraint is only a problem if the economic cost of reinforcing the

[72] The regulatory arrangements include provision for a performance incentive scheme where the concessionaire is financially rewarded for superior performance and penalized for poor performance.

[73] TRANSCO is responsible for preparing the transmission development plan under Section 9(f) of the EPIRA.

[74] ADB.2005. *Sector Assistance Program Evaluation of Asian Development Bank Assistance to Philippines Power Sector.* Manila.

transmission system to alleviate the constraint is greater than any incremental economic cost of having to import additional power into Manila from the north.[75]

69. This would suggest that transmission planning is as much an economic exercise as it is a technical exercise and that it requires the cost of transmission augmentations to be compared with the incremental cost of scheduling (or constructing) alternative generation capacity to meet the demand if such augmentation does not proceed. This requires the economic modeling of the complete power system and the simulation of market behavior. A major weakness of the EPIRA reforms is that transmission planning is left largely to the TRANSCO concessionaire, who derives no benefit from any reduction in generation costs, and therefore has no incentive to take such a holistic approach to the transmission planning issue.

70. Experience in other jurisdictions also suggests that transmission planning is too critical to be left to a transmission system operator which, as noted above, may have little incentive to proceed with economically efficient augmentations. In New Zealand, where there has been no major transmission line construction in over 20 years, the government recently established an Electricity Commission which will have the power to require the grid operator to proceed with augmentation projects on the shared network and also require the cost to be shared by all users. As a result, there is likely to be a major investment in transmission grid development over the next few years, with many lines to be upgraded from 220 kV to 400 kV. In Australia, there is an inter-regional planning committee with the power to require the construction or augmentation of regulated grid interconnections, where all users again recover the cost. In fact, in the state of Victoria, Australia where the grid is privatized, there is a central planner that can contract for new grid augmentations.

71. In the Philippines, the archipelagic nature of the country makes grid planning all the more important because of the high cost of interconnections requiring submarine cables. ERC should undertake economic screening for alternatives to transmission asset expansion. Chapter 6 of the Grid Code describes in detail the engineering processes and tools to be used by grid planners but does not necessarily provide the higher-level purpose or objectives of grid planning. There needs to be a clarification of planning objectives, together with a formalized process by which transmission development proposals are scrutinized and approved. The culmination of the decision process is likely to require formal approval by the ERC, which would allow the grid operator to recover the cost of the augmentation from all grid users.

D. Wholesale Electricity Spot Market

72. The spot market described in the WESM rules is envisioned to be one of the most sophisticated electricity markets in the world. In any event, after WESM becomes operative, most DUs are likely to continue to cover the bulk of their electricity purchases through bilateral hedge contracts as this will give a measure of price certainty and limit their exposure to spot market volatility. Section 45(c) of EPIRA requires all DUs, including ECs, to source at least 10% of their electricity requirements through the spot market for the first 5 years of market operation.[76] Whereas in the past, most ECs have purchased electricity from NPC under sales agreements approved by the regulator and with fixed prices, they will now be faced with electricity price volatility for at least 10% of their requirements. ECs will also be required to meet the prudential requirements of the market, as set out in the WESM rules. However, many ECs currently do not have the financial or technical capacity to trade in the market, as evidenced by

[75] In the wholesale market, the economic cost of the constraint would be transparent since any constraint would cause a different market clearing price in the north and south of Manila.

[76] Many ECs do not have a grid connection and buy their electricity from SPUG. These utilities will not be affected by this requirement.

the significant number of ECs in arrears with NPC for power purchases. Section 30 of the EPIRA anticipates the prudential requirements problem and provides that NEA may act as a guarantor for ECs, subject to adequate security and a guarantee fee. However, NEA's own financial situation is problematic to the extent that it is doubtful whether it can sustain the financial strength needed to provide guarantees to satisfy market prudential requirements. In any case, NEA should be proactively assisting the ECs under its care to prepare for the start of market operation.

73. A spot market provides a mechanism whereby generators compete on the basis of a bid price for the right to operate. The model is predicated on the assumption that there is no collusion between competing generators and that no one generator dominates. While it is not necessary that each generator competing in a market has a different owner, it is important that that there are a number of different owners in the market and that no one owner is dominant. For this reason, Section 45(a) of EPIRA requires that no company or related group can own, operate or control more than 30% of the installed generating capacity of a grid or more than 25% of the national installed generating capacity. In spite of this requirement, Section 47(f) of EPIRA excludes privatization of the Agus and Pulangui complexes in Mindanao for a minimum period of ten years. Hence, only the Talomo (3.5 MW hydro); Agusan (1.6 MW hydro); and Iligan[77] (68.4 MW bunker C fueled diesel) are to be privatized in the short term. Furthermore, while the Mindanao coal fired power plant expected to be commissioned in 2006 will be privately owned, this is subject to a 25-year IPP agreement with NPC. Hence, the Mindanao plants to be privatized represent about 5% of the present installed generating capacity in Mindanao[78] producing less than 30%[79] of the total electricity generated in 2004. Therefore, it is unlikely that an effective market can be established in Mindanao in the short term. WESM operation on the Visayas grid may also be problematic because of the limited capacity of the submarine cables between the different islands. While there might be an appropriate spread of generator ownership across the whole grid, if a single generator is dominant on an individual island, it would be possible for that generator to use its dominance to force up the wholesale price of electricity on that island.

74. The California electricity crisis of 2000–2001 demonstrated how the behavior of electricity markets could be unpredictable under stress. A discussion of the events that led to the California crisis and a comparison of the California market with the proposed Philippine design are provided in Appendix 9. The analysis indicates that while some of the weaknesses that gave rise to the California crisis do not exist in the Philippine model, other weaknesses are not effectively addressed. It suggests that the WESM start-up could be problematic in cases there exist generation shortages and the excessive market power of some generators. A prudent approach would be to start the market in Luzon initially before subsequently moving to Visayas and Mindanao. Given the delay in privatization and in setting up the WESM, a major concern is that during such a period of delay, EPIRA does not provide a satisfactory mechanism to allow for the construction of new generation during the transition period and prior to the operation of a wholesale spot market.

---

[77] Iligan was currently privately owned, but under its BOT contract, ownership reverted to NPC by December 2003. It is operated as a peaking plant and in 2000, total generation was only 16 GWh, compare with 12 GWh each from Tolomo and Agusan.

[78] Based on DOE data, total installed capacity in Mindanao as of end-2004 was 1,665.3 MW.

[79] For 2004, total generation from diesel was 1,915,500 megawatt-hour (MWh), about 27% of total generation in Mindanao of 7,087,140 MWh.

E. Distribution

75. As already indicated, electricity distribution is undertaken by IOUs and ECs. The IOUs have a corporate capital structure that provides the resources necessary to access capital markets. Their rates, although regulated by the ERC, are structured to provide for reasonable operating and maintenance costs, depreciation and a return on invested capital. The difficulties currently being faced by MERALCO have already been discussed in this report. Leaving such problems aside, IOUs generally appear to be competently managed.

76. ECs, on the other hand, operate on a different business model. While they are cooperatively owned, the owners have no equity in the business, preventing ECs from accessing commercial capital markets. Consequently, they have historically been completely reliant on NEA lending to finance capital investment. As TRANSCO has ceased developing sub-transmission links, ECs now have to access non-NEA funds to develop these lines. However, many ECs have very limited knowledge how to meet the lending requirement of banks. The regulated rate of ECs is calculated differently from IOUs and makes no provision for depreciation or for a RORB. It provides only for operating and maintenance expenditure and actual debt service requirements, together with a 5% reinvestment surplus,[80] that must be placed in a separate account. Funds from this reinvestment account must be used for capital investment in the network in accordance with an approved plan and their use must be justified to the ERC. Given the lack of a capital structure, some of the traditional financial indicators to measure borrower performance have no meaning. In fact, even with competent management, ECs will only be viable in situations where there is electricity sales growth since the only revenue available to cover operating cost increases is the distribution margin on electricity sales over and above those in the test year on which the tariff calculations were based. Between the period 1994 and 2001, total electricity generation increased by 54%, an annual growth rate of 6.5% providing sufficient head room to enable competently managed ECs to cover operating cost increases not reimbursed through automatic rate adjustments.

77. The developments transpiring since EPIRA's effectivity are further likely to reduce the ECs' operating margins. Firstly, the ERC has discontinued the former practice of allowing automatic adjustments to cover the cost of government mandated wage increases. Secondly, loan condonation has been accompanied by a commensurate rate reduction, which in turn has reduced the distribution margin on sales growth that ECs rely on to cover operating cost increases. Thirdly, it is understood that historically, the ERB did not closely monitor the use of the 5% reinvestment allowance, which could be diverted to cover increased operating expenses. Such diversion will not be possible given the controls ERC is now placing on the use of these funds. As a result of these additional constraints, the levels of default in payments to NPC for power purchases are likely to increase.[81]

78. In accordance with the Anti-electricity and Electricity Transmission Lines/Materials Pilferage Act of 1994 (RA 7832), loss caps of 9.5% for IOUs and 14% for ECs are applied when setting DU rates. This means that the cost of losses over and above the cap cannot be taken into account when setting the customer rate, and therefore must be absorbed by the utility. This is a significant burden for many utilities.

---

[80] The 5% reinvestment surplus is based on the gross revenue requirement in the test year, including power purchase and transmission service costs. Typically, distribution costs are 20% of total operating costs. On this basis, the reinvestment allowance would typically equate to around 25% of the EC's non-power purchase operating costs or about 1% of the rate base of a well managed utility.

[81] In the past, many ECs have defaulted on loan repayments to NEA, in order to generate additional cash to fund operations. This will not be possible after NEA loans have been condoned.

79. Losses are classified as administrative, technical, and non-technical. Administrative losses consist of the electricity purchased by a DU and used for its own purposes rather than for sale to customers, and is the only form of electricity loss that can be measured directly. Technical losses are those that are inherent in the physical delivery of electricity and result from the flow of electricity through the network and, for a given network capacity, will increase as power flows increase.[82] Non-technical losses are caused by metering inaccuracies and tampering, and electricity pilferage. Total network losses can be readily measured by comparing electricity sales with purchases. However, the development of an efficient loss reduction strategy is problematic. This requires that non-administrative losses be split into technical and non-technical, neither of which can be measured directly. The normal practice is to estimate the level of technical losses through detailed and sophisticated network analysis and to assume that non-administrative losses over and above the technical loss estimate are non-technical. Unfortunately, the analysis of technical losses is complex given that losses vary non-linearly with load and are dependent both on network design and the spatial distribution of load across the network. A TA grant (through Public Private Infrastructure Advisory Facility) to ERC has been implemented to study the methodology and guidelines for setting adequate caps for system losses.

80. The reduction of non-technical losses involves ensuring meter accuracy, putting systems in place to detect electricity pilferage, and taking action against such pilferage once detected. It is largely an operational issue. Reducing technical losses, on the other hand, requires increasing the capacity of the network necessitating additional capital expenditure. If a technical loss reduction program is to be efficient, then an in-depth understanding of network capacity and power flows is necessary to ensure that loss reduction initiatives are well targeted. Technical losses are typically high in a situation that currently exists in the Philippines, where load growth is high and access to funds for capital expenditure is limited. At present, few ECs have the tools or technical capability to effectively analyze network losses. Furthermore, it is questionable whether the application of loss caps is an effective policy instrument since expenditure by utilities on losses above the loss cap would be better spent on loss reduction initiatives.

81. In September 2004 the ERC issued new guidelines that will allow it to set different loss caps for individual DUs. Separate caps will be set for administrative, technical, and non-technical losses. Administrative losses are to be measured by directly metering consumption while technical losses are required to be estimated on the basis of losses calculated from computerized load flow simulations of the network. Total losses are to be calculated as the difference between electricity purchases and billings and any losses over and above those assessed to be administrative or technical are assumed to be non-technical. Implementation of these guidelines is likely to be challenging as most of the smaller utilities lack the computational models or technical expertise required to accurately estimate technical losses.

82. There is an urgent need to improve the management and financial and technical capabilities of ECs. A review of the Presidential Decree No. 269 provision mandating that ECs be non-profit organization would be needed to strengthen financial viability of the distribution sector. Consultants engaged by both ADB and the World Bank to assess EC performance[83] have noted poor management and technical capabilities, lack of exposure to competition, and a traditional public service culture as major impediments to improving the performance of these ECs. More particularly, there is a lack of planning, system and project analysis, and project

[82] The relation between power flow and losses is non linear. For a given network capacity, doubling the power flow will increase the technical losses by a factor of four.

[83] ADB. 2002. Technical *Assistance to the Philippines for Preparing the Rural Electrification Project*. Manila

management skills. Until now, poor EC performance appears to have been hidden by the different accounting and rate setting procedures applied to ECs and IOUs.[84] However, in the post-EPIRA environment, it is expected that the accounting structures and rate setting methodologies that apply to ECs will, over time, become more commercial and more closely aligned to those used by IOUs. Hence, the inefficiencies of ECs will become more transparent and ECs with such inefficiencies will be left behind, unless the technical and financial capability of their management is improved.

83. Apart from addressing the capability issue, there is a need to ensure that ECs are provided access to capital for network development. Traditionally, financing for capital investments has been sourced from NEA but this window is no longer feasible, firstly because NEA's finances have deteriorated to a level that its credibility as a lending institution has been impaired, and secondly since Executive Order 138 issued in 1999 requires development finance to be channeled through commercial lending institutions rather than government entities. From the perspective of suitability for accessing investment finance, ECs have been broadly categorized into three groups: (i) those potentially suitable for commercial financing; (ii) those showing the potential to become commercially viable and hence considered suitable for financing by multilateral development institutions; and (iii) those that are unlikely to become commercially viable in the medium term. With assistance from the United States Agency for International Development and the National Rural Electric Cooperative Association International of the US, some of the better performing ECs have established the Rural Electrification Financing Corporation (REFC), which will provide development finance to the cooperative sector on a commercial basis. REFC now has 46 ECs as participants and is considering more ECs for REFC financing.

84. The World Bank has approved an electric cooperative system loss reduction project for the ECs that may not currently meet the criteria for REFC funding but have the potential to become commercially viable. This financing is to be channeled through the Development Bank of the Philippines. Under the project, the World Bank also provides support for the pilot implementation of investment management contracts (IMC) to turn around selected ECs with the management of their operations taken over by strategic investors over a long-term contractual period. Over the short term, IMCs are planned to be implemented at three ECs which accounted for 8% of the arrears to NPC. There is a need for continuing dialogue with the authorities regarding an action plan to strengthen the weak ECs, including scaling up the implementation of IMCs as one of the options to improve EC performance. In addition, there is a need to assess potential assistance to market participants of WESM in designing a workable prudential requirement package.

F. Missionary Electrification

85. Missionary electrification includes the (i) generation of electricity for supply to ECs operating distribution networks that are not connected to one of the three main grids and (ii) provision of electricity to unelectrified barangays where connection to the distribution network of the EC holding the local franchise is uneconomic. Currently, the supply of electricity to off-grid ECs is undertaken by SPUG whereas the electrification of unelectrified barangays is being coordinated by the DOE under its ER program. In accordance with Section 70 of EPIRA, missionary electrification is to be funded from the sale of electricity in missionary areas and also from the missionary electrification component of the universal charge. Missionary electrification

[84] Unlike investor owned utilities, the EC rate structure does not provide for depreciation or a RORB.

is also funded out of the electrification fund established under electricity regulation ER 1-94.[85] At present, DOE's missionary electrification plan covers only the development of SPUG's existing generation activities, and the ERC's approved P0.0373 per kWh missionary electrification component of the universal charge is intended to subsidize only SPUG's existing activities. Under ADB's good governance TA,[86] the TA consultant has assisted DOE in preparing a more comprehensive missionary electrification development plan that covers both SPUG's existing operations and DOE's rural electrification activities. The new plan, which covers the five year period 2005–2009, will be used to support a petition to the ERC for an increase in the missionary electrification component of the universal charge in order to increase the subsidies available to support off-grid missionary electrification.

86. As a result of NPC's financial difficulties, capital expenditure by SPUG on its missionary generation activities has fallen well below the level necessary to ensure that the provision of existing service levels can be maintained over time. There is also increasing evidence that the efficiency of SPUG's operational activities could be improved significantly. To address these problems, the DOE, with the World Bank assistance, has engaged a transaction advisor to manage the transfer of generation activities in 14 of SPUG's supply areas to NPPs. If this process succeeds, the transfer of SPUG operations to NPPs in other areas will follow. Furthermore, a management study of SPUG's remaining operations is proposed to identify ways in which the inefficiency of its operations can be reduced. These initiatives, if fully implemented, are expected to result in savings in the cost of SPUG's missionary generation activities in 2006 and beyond.

87. DOE is also working with the World Bank funded consultants to develop micro-grid contracts. Under these contracts, a private sector investor will be designated as a QTP under Section 59 of the EPIRA and will be responsible for generation, distribution and supply of power to customers supplied from a small micro-grid, unconnected to an existing EC distribution network. It is not anticipated that micro-grid operations will be sustainable without subsidy support from the missionary electrification component of the universal charge and model micro-grid contracts where subsidies will be based on contract outputs, as distinct from resource inputs, are being developed. A major issue is the basis on which the customer tariff should be set before a subsidy is applied. Traditionally, the ERC has benchmarked customer tariffs in uneconomic areas against the tariff paid by customers connected to the nearest main grid. If this approach is maintained, the subsidies required will be extremely high, and probably unsustainable. The DOE is therefore hoping that ERC will benchmark micro-grid customer tariffs against avoided costs, such as the cost of kerosene for lighting.[87] This will result in customer tariffs significantly higher than current levels. However, it may raise equity concerns because many of the customers required to pay a higher off-grid rate would qualify for a subsidized lifeline rate if they received a grid connected supply.

88. While the Government is making impressive progress towards its target of 100% barangay electrification, still much has to be done. Of the estimated 3,182 barangays still to be electrified as of 1 January 2005, the DOE has estimated that 1,735 will be grid connected and the remaining 1,447 will require an off-grid solution.[88] Renewable energy is the preferred

[85] Under ER1-94, generators and energy resource developers are required to pay P0.01 per kWh into a fund, administered by the DOE, which is used to enhance the welfare of the community hosting the facility. One half of this fund is directly applied to electrification projects.

[86] ADB. 2003. *Technical Assistance to the Republic of the Philippines in Promoting Good Governance in the Restructured Power Sector.* Manila.

[87] ERC is an independent regulator and DOE has no power to set tariff policy or to issue directives to ERC on policy matters.

[88] Current estimate of unelectrified barangays is at 2,910.

solution for off-grid electrification, but except in those relatively few areas where a hydropower resources are available, photovoltaics is the only practical renewable generation source. The level of service that can be provided from a photovoltaic supply is limited and many barangays prefer to wait until a micro-grid is provided. The DOE is still developing policies and delivery mechanisms in relation to QTP participation in off-grid electrification using diesel powered generators. Furthermore, rate policies still need to be resolved by the ERC, and the availability of subsidies from the universal charge finalized before the off-grid electrification program can proceed. The time needed to resolve such issues has resulted in DOE's 100% barangay electrification target being pushed later from 2006 to 2008.

G. Electricity Tariffs, Affordability and Subsidies

89. Among the key objectives of the power sector restructuring mandated by EPIRA are the assurance of affordability of the supply of electricity and reasonable and transparent electricity prices in a regime of free and fair competition. However, there is expectation from the public that the electricity tariffs should be reduced as a result of power sector restructuring as an immediate dividend. Unfortunately, this expectation has been reinforced by (i) the mandated P0.30 rate reduction in accordance with Section 72 of EPIRA; (ii) condonation of EC loans to NEA and the associated rate reduction; and (iii) the capping of the power purchase adjustment to P0.40 per kWh in May 2002.[89] Moreover, the recent decision of the Supreme Court requiring MERALCO to refund P30 billion to its customers, and the fact that some unbundling decisions have resulted in a rate reduction, are further reinforcing this expectation. This focus on rate reduction has created a community expectation that rate reductions will be the short-term outcome of the reform process. In fact, rates have already been reduced even before the completion of the restructuring and the implementation of cost reduction measures resulting in the continued increase of NPC debt to unsustainable levels. Delays in implementing the reform process will make the recovery even more difficult.

90. The ERC is caught between customer clamor for lower electricity prices and the need for industry participants to earn sufficient revenue to ensure that their operations are sustainable over time and also to encourage investments in new capacity. Decisions by the Supreme Court to annul rate increases granted to NPC in September 2003 and MERALCO in November 2003 have arguably made it more difficult for the ERC to carry out its mandate in a timely manner. Be that as it may, the ERC in September 2004 issued a provisional order, in response to a further rate petition, increasing NPC's average generation rate charged to grid connected customers by 40% and this order has not been overturned by the courts. The order was finalized in April 2005 with a further increase of 2%. This decision also allowed NPC to charge time-of-use rates if requested by the customer. Furthermore, TRANSCO has applied for a revenue cap under the PBR setting guidelines and this should apply from 1 January 2006. In addition, three DUs, including MERALCO, have indicated to the ERC that they intend to apply for their rates to be set in accordance with the recently issued performance based price setting guidelines for DUs. This will entail an interim adjustment on 1 July 2006 and a new average price cap to apply from 1 July 2007.

91. If the reform process is to be successful and sustainable, savings from efficiencies generated by the restructuring of the sector must be used to provide private sector investors with returns commensurate to the risks they are being asked to assume and also to stabilize industry debt levels, before such benefits are allowed to translate to lower customer prices. For this reason, prices may even need to rise in the short term before stabilizing and eventually falling to more reasonable levels. The ERC has recognized this with the adoption of the PBR rate setting

[89] The introduction of the generation rate adjustment mechanism has largely overtaken this decision.

methodology for transmission and privately owned DUs. This and the likely modification of the EC rate setting methodology to allow an increase in the level at which they can self-finance capital expenditure, and the proposal to benchmark off-grid electricity rates on avoidable costs all point to significant increases in electricity prices over the next few years. The success of the power sector reforms initiated by EPIRA will depend on the government's acceptance of these price increases and its success in managing political pressures and public expectations.

92. Section 74 of EPIRA requires the ERC to ensure that inter-grid, intra-grid cross subsidies and subsidies between different customer classes are removed within three years from the establishment of a universal charge and that in the interim subsidies be made transparent and identified separately on customer bills. Notwithstanding this feature, Section 73 provides for a subsidized lifeline rate to apply to marginalized end-users. Inter-grid and intra-grid cross subsidies were identified as separate line items in the unbundled TRANSCO rate schedule issued as part of the NPC rate unbundling decision dated June 26, 2002.[90] This decision required TRANSCO to phase out the cross subsidies over a three year period ending June 2005. Cross subsidies between separate customer classes have also been separately identified in the different DU rate unbundling decisions. However, these decisions have deferred action on the removal of these cross subsidies pending introduction of the universal charge to support cross subsidy removal as provided for in Section 34(e) of EPIRA. Cross subsidies to support the lifeline rate are also separately identified in DU rate unbundling decisions and are discussed further below.

93. DUs report increased demand from existing household customers ranging from 5–7% per year since 2002. This indicates that current tariffs are affordable and that there is a potential for tariff increases. However, most customers probably do not appreciate the decline of the rates in real terms that they have experienced the past few years. For those serviced by ECs, evidence suggests that customers are willing and able to pay provided that they receive good service. The interesting thing to note is that poor EC performance is correlated with low tariffs. Those ECs that charge appropriate levels, even if those levels are high in comparison to other ECs (and high versus the benchmark MERALCO rate), are able to collect and successfully run their businesses, provided that service quality is maintained and the EC operations are insulated from political influence. While grid connected residential end users receiving lifeline rate subsidies are typically paying P3.50 per kWh for electricity, for the unconnected population, affordability studies done in the context of the World Bank/Global Environmental Fund financed Rural Power Project suggest that levels of over P15 per kWh are affordable.

94. Hence, current subsidy programs in the Philippines could be better targeted, designed, or implemented, with the result that subsidy provision is not fully successful in achieving social protection and other economic objectives. While under the EPIRA, most cross-subsidies within the industry are to be phased out over a three-year time frame, the lifeline rate is to remain for at least ten years. The lifeline rate provides a lower electricity rate for grid connected end-use customers with a low electricity consumption. The subsidies provided by the lifeline rate schemes are extensive. For example, residential customers in the MERALCO franchise area using less than 50 kWh per month get a discount of 50% on their electricity bill and customers using from 51–100 kWh per month get a 20% discount. In order to fund these subsidies, all customers using more than 100 kWh per month pay an additional P0.0761 per kWh. This lifeline charge is over twice the missionary electrification component of the universal charge, as currently approved by the ERC. It is understood that around 40% of MERALCO's residential customers are entitled to a subsidized lifeline discount. The provision of such extensive lifeline subsidies is expected to create equity problems when the Government's policy for providing diesel powered micro-grids is fully implemented. According to its web site, MERALCO's average residential rate in 2003 was

[90] ERC Case No. 201-901.

P6.0375. Low use customers taking advantage of the 50% lifeline discount would pay P3.0188 per kWh. However a similar customer supplied from a diesel powered micro-grid in an area not connected to a main distribution grid could be expected to pay up to P18/kWh, even after provision of a missionary electrification subsidy.

H. Electricity Supply

95. A key EPIRA reform feature is the express recognition of the supply sector and its role in the industry, and the consequent unbundling of electricity supply from distribution. Suppliers of electricity to the contestable market will need a license from ERC, but the rates at which they will sell electricity to end users will not be subject to ERC regulation. During the progressive introduction of retail competition, end-users with demand below the contestability threshold shall remain part of the captive market and will continue to be supplied by DUs at rates that are regulated by the ERC. Under retail competition an electricity supplier need not be the incumbent distributor. Suppliers will pay distributors a wheeling or use of system charge and may contract directly with end users for the sale of electricity. For the first two years, retail competition will be limited to end-users with an average peak demand of at least 1 MW. The threshold will then be reduced to 750 kW after two years. Subsequently, the contestability threshold will be reviewed annually by ERC and progressively reduced until all consumers are contestable.

I. Development of Natural Gas Industry

96. Even under a low economic growth scenario and in consideration of escalating oil and coal prices, the country's natural gas requirement is estimated to increase annually from 93.7 billion cubic feet (BCF) in 2003 to 145.5 BCF by 2012. Demand in the power sector will account for the bulk of the total demand, with up to 4,200 MW of additional capacity that could utilize natural gas during the period, if needed. The demand for non-power use (clustered industries near or along the proposed gas pipeline) is also expected to grow from about 1.0 BCF in 2005 to 16.0 BCF in 2012. Moreover, with ADB's assistance,[91] the DOE is undertaking a study to develop a master plan for the use of compressed natural gas in the public transport sector, including a pilot project phase, toward full commercialization of vehicles run by natural gas. Based on the current and expected market conditions for the supply of natural gas, this master plan has established LNG imports as a feasible and economically viable option to meet gas demand in the Philippines in the medium term. Estimates of gas demand for the power sector indicate the need for imported LNG of about 23.2 BCF by 2008 to as much as 194.2 BCF by 2012. LNG may be imported from Australia, Brunei, Indonesia, Malaysia, or Qatar. An efficient infrastructure system that will enable the Philippines to meet the anticipated demand for natural gas will include the transmission, distribution, and city gas pipelines; LNG receiving terminals and associated structures; compressed natural gas refilling stations; and related facilities. The DOE has identified two major pipelines for development and construction in the next few years: (i) a 100 kilometer (km) Batangas-Manila pipeline, and (ii) a 150 km Bataan-Manila pipeline, and corresponding LNG receiving terminals. An innovative public-private sector partnership needs to be developed to realize the needed investment. Moreover, the prospect of LNG imports calls for the rationalization of competitive fiscal terms to promote further private sector investments in petroleum and gas exploration and production activities even as LNG imports come to the country.

---

[91] ADB. 1998. *Report and Recommendation of the President to the Board of Directors on Proposed Loans and a Technical Assistance to the Republic of the Philippines and a Technical Assistance Grant to the Republic of the Philippines and the Land Bank of the Philippines for the Metro Manila Air Quality Improvement Sector Development Program.* Manila.

J. Risk Management in the Electricity Sector

97. It can be concluded from this chapter that the EPIRA reforms have been carefully designed to bring the debt crisis facing the industry under control and to put in place a regime that will ensure a more efficient and cost effective electricity sector in the medium term. Achievement of this goal is contingent upon the reforms being successfully implemented in a timely manner. As indicated in Chapter II, progress in implementing these reforms has been slow. In view of the implementation experience in the last four years of EPIRA's existence, it is timely to reflect on the progress made to date and identify and analyze the key risks that may hinder the successful implementation of the reform package. As with other centerpiece legislation, however, the implementation of EPIRA has run into problems and delays that have given rise to concerns from industry stakeholders. A careful analysis of these challenges and their concomitant risks is needed to encourage the formulation of adequate strategies to allow the successful achievement of the objectives of the law. This analysis will help identify strategies that will allow these risks to be effectively managed thereby increasing the probability of the sector reform objectives being achieved.

1. Retail Competition and Open Access

98. At the heart of the many reforms mandated by EPIRA is the implementation of retail competition and open access. While the law specifically imposes a three-year deadline to implement this, there is as yet no declaration of such from the ERC as the conditions necessary for such declaration have not been fully met. The ERC, however, in a Resolution dated 21 September 2004, set a timelime for the implementation of retail competition and open access. While still enumerating the conditions imposed by the law, the ERC set commencement for retail competition and open access in Luzon on 1 July 2006. In any event, of the five prerequisties enumerated in the law, there are evident difficulties in surmounting three, namely the establishment of the WESM, privatization of at least 70% of the total capacity of NPC generating assets in Luzon and Visayas and the transfer of the management and control of at least 70% of the total energy output of power plants under contract with NPC to the IPP Administrators.

2. Wholesale Electricity Spot Market

99. Industry players still seem to be waiting for the signals to determine how the market for the efficient buying and selling of electricity will perform as the same is critical for them to ascertain whether they can generate reasonable and acceptable returns. The hardware and software needed for WESM have been installed and trial operations are in progress. The basic design of WESM is sound but as an energy only market with a limited number of separately-owned participating entities at the outset, it is likely to feature a high degree of price volatility. The mismatch between this and the capacity of most off-takers to cope with the situation increases the importance of taking steps to manage these risks. Such measures include (i) maximizing contract cover; (ii) reducing the number of pricing nodes; (iii) establishing market price caps to limit extreme price spikes;[92] (iv) establishing clear supplier of last resort arrangements in case of retailer failure; (v) establishing generator of last resort for DUs, notably ECs, that will not meet WESM prudential requirements;[93] and (vi) establishing a more aggressive training program for participants as most of the ECs are still not WESM compliant. Upon review of market performance after 1–2 years, should price volatility continue to be a

[92] While price caps can increase certainty for both generators and suppliers, it is important that they are not set so low as to deter investment.

[93] The supplier of last resort and generator of last resort functions are interrelated and some mechanisms (e.g., a default aggregator or power purchasing arrangement) could be common to both.

major issue, other options such as the introduction of capacity contracting or cost-based bidding in some circumstances may need to be considered.

100. The successful implementation of the EPIRA reform package requires the establishment of WESM to provide a mechanism for the buying and selling of electricity. However, there are increasingly worrying signs that the conditions necessary for the successful operation of a competitive electricity market are not present, particularly in the Visayas and Mindanao grids. In the absence of WESM, there is no alternative central buyer and seller of wholesale electricity provided for in EPIRA. Hence, in order to secure a revenue stream, a private sector investor in power generation would need to negotiate bilateral electricity sales contracts with retailers or distributors before a new power generation project becomes bankable and construction can commence. This problem is further exacerbated by the large number and relatively small size of many DUs, their high credit risk and the need, in the absence of WESM, for all bilateral electricity sales contracts to be pre-approved by ERC. The looming power shortages in Visayas and Mindanao are a manifestation of this problem. Since WESM may not be extended to Visayas and Mindanao in the short run, the Government needs to develop a contingency plan that would ensure that the EPIRA objectives are achieved without WESM in place.

3. Privatization of Assets

101. With respect to the privatization of NPC generation assets, it is clear that PSALM needs to accelerate this process aggressively considering that only a small portion of the assets have been privatized to date. And even for the privatized assets, which include the 600MW Masinloc power plant that was bidded out in December of 2004, financial closing for assets is still to be reached. Apart from this, there seems to have been some difficulty on Government's part to attract genuine interest and excitement from existing IPPs and first time investors to participate in these bidding exercises as can be gleaned from the failed bidding of the Calaca power plant in June 2005 and the relatively slow pace of the privatization efforts to date.

102. While there are many who procure the bidding documents and even attend pre-bid conferences, only a small number of IPPs invest the proper resources to prepare for and eventually submit bids. In fact, for the Masinloc and Calaca plants, none of the major IPPs had actually submitted any bids. Such IPPs quickly point out that without any TSCs or long-term PPAs accompanying these assets, it becomes altogether difficult, if not impossible, to secure adequate project financing to support their respective acquisitions. While EPIRA's mandate is only for PSALM to enter into TSCs with DUs for the eventual parceling out of transition capacity among the assets that are to be sold in public bidding, no such TSCs with major DUs including MERALCO have been executed. And even then, the law effectively allows for TSCs with terms of a maximum of only four years, which does not really bode well for any meaningful financing acceptable to many IPPs. If PSALM is experiencing difficulty executing TSCs with DUs, one can only imagine how much more challenging it would be for IPPs to enter into full blown PPAs with DUs that require terms of upwards of 15 years and mandate burdensome conditions. Though these concerns are not unique to the Philippines and a change in paradigm is clearly required from lenders and project developers in view of the market reforms process in many countries, the question is whether countries like the Philippines have the luxury of time to wait for this change in paradigm to occur.

103. On the other hand, DUs seem to be hesitant to enter into even the shorter term TSCs, much less the full blown PPAs, for the reason that should WESM become fully functional during the effectivity of such longer term contracts, they may find themselves having to purchase power at prices higher than those being traded in the open market, leading to substantial losses. And this is the case even as EPIRA only requires DUs to purchase a minimum of 10% of their

total demand requirements from WESM within a period of five years from its establishment. A possible way out of this stalemate is to pass on the risk of securing long-term power supply from the DUs to the end-users themselves. One possible way is to establish and encourage contractual open access as tripartite agreements between the competitive customer, the DU and the generation supply provider. Such agreements actually improves the ability of the DU to manage its contractual risk – under the unbundled rate scenario where generation cost is pass-through, the DUs need not absorb the market risk of contracting in behalf of its large customers. This arrangement can work well for majority of the DUs, especially those that do not have large take-or-pay agreements with their own IPPs.

104. In fact, we are beginning to see the emergence of suppliers and aggregators who have been trying to lock in contracts with purchasers of power (whether ECs, DUs, or even ultimate end-users) on the one hand, and generators of power (IPPs) on the other. Given the need for end-users to secure long-term supply to enable them to plan their respective businesses over a longer horizon, there appears to be a genuine desire from a number of such customers to enter into longer term contracts that properly adjust for WESM generated prices while at the same time ensuring that all proper transmission and distribution wheeling charges are paid to TRANSCO and the relevant DU. Admittedly, however, there may be greater difficulty in getting DUs to purchase larger blocks of capacity for extended periods given the reasons already cited.

4. Investments for New Capacity

105. In the face of all of this, one must raise the issue about required investments in additional capacity that would be needed for the country at various times within the next five years, depending on the particular forecast scenario that one chooses to adopt. If, at this juncture in EPIRA's implementation, Government is already facing a degree of difficulty in selling off its existing assets, it would not be amiss to say that encouraging investments in new power plants would be even more challenging in view of the time constraints faced by some of the grids. And what may exacerbate this situation is the fact that by virtue of the EPIRA, there is no longer a default producer of power that the country can look to in the face of a power crisis as the traditional generator of capacity, NPC, has effectively been prohibited from generating new capacity or even purchasing power through bilateral contracts with generation companies or other suppliers. Therefore, a possible solution may lie in the emergence of a class of suppliers who may be in a position to bridge the gap between the DUs and the retail customers on the one hand, and the generators on the other, without having to necessarily violate any of the EPIRA provisions.

106. In addition, given the need to fulfill the conditions precedent for the introduction of retail competition, there is also the need to protect the end-users that comprise the contestable market. While Section 23 of EPIRA requires DUs to supply electricity to their captive market, no similar obligation exists for supply to end-users forming the contestable market. Hence, the real possibility exists of an end-user in the contestable market being unable to find an electricity supplier particularly if the latter's existing electricity supplier suddenly ceases to trade for any reason whatsoever. To address these concerns, safeguards should be put in place to protect end-users in the contestable market. Such safeguards should include a guarantee that supply will continue to be given on existing terms and conditions by a DU to an end-user in a market even after the market initially becomes contestable. A further important safeguard is the appointment of a supplier of last resort who will provide supply to end-users in a contestable market under published terms and conditions, should the latter's existing electricity supplier suddenly cease trading. The ERC is currently considering rulings that would establish this supplier-of-last-resort in consultation with Philippine Electric Market Corporation, TRANSCO, and other stakeholders.

5. Transmission Network

107. Another major concern that needs to be addressed in relation to the ongoing reform process is the urgency of ensuring a stable and reliable transmission network. This brings into consideration the need for Government to finally firm up its plans in relation to the operations of TRANSCO. As with the privatization of NPC's generation assets, the future of TRANSCO remains somewhat in suspended animation given that after two failed biddings, no private concessionaire has been identified and selected to run the country's transmission system and improve its lines. And given the professed need to work around the legal obstacles dealing with the franchise requirements, many expect that attracting international transmission companies with the requisite experience and capacity to expend vast amounts of capital to improve and strengthen the system would be a difficult task to accomplish.

108. There seems to be less of a concern for the privatization of transmission operations due possibly to the fact that the system continues to run albeit in a less optimal manner than it should. As had already been pointed out, critical line and system constraints in south of Manila (Dasmariñas line) and in the Visayas (Leyte-Cebu interconnection) have been recently addressed and this has eased some of the pressure on the affected grids. However, given the performance of other transmission systems in the region, it seems that the country is still some way off the ideal situation.

109. Integral to the provision of a reliable and sturdy transmission system is the need to institute solid and sensible transmission planning. The EPIRA itself provides in Section 9 that TRANSCO shall undertake the preparation of the TDP which shall be submitted to the DOE for integration with its Power Development Program. Any augmentation of the transmission system should be consistent with the TDP and subject to the approval of the ERC.

110. Experience in other countries has shown that transmission planning is too important to be left solely in the hands of the transmission operator. It is envisioned that even with a private concessionaire, TRANSCO should have a strong say in the transmission planning process.

6. Distribution Utilities

111. Another major concern deals with the distribution sector and how many of the current DUs, particularly the small ECs, are unable to provide the service required of them due to their poor financial condition. Under the EPIRA reforms, a sovereign guaranteed NPC will no longer exist to perform a de-facto banking function for the sector and the industry will only function effectively if all industry participants are able to settle their contractual obligations in a timely manner. The law is replete with provisions to that aim to remedy this imbalance including the assumption by PSALM of all outstanding financial obligations of ECs to NEA and other government agencies incurred for the purpose of financing rural electrification programs, and the grant to NEA of the power, in exchange for adequate security and guarantee, to act as a guarantor for the purchase of electricity by ECs in the WESM.

112. While such measures are meant to remove many of the ECs from a mold similar to that of NPC's, the fact of the matter remains that there are still many ECs that will continue to suffer financially despite these reform provisions primarily because of poor management and overwhelming political pressure. Be that as it may, innovations continue to be introduced to ensure that the greater bulk of such ECs improve their performance and financial standing over time. One possible approach, which has been successfully implemented in many countries, is to consolidate existing distributors into a small number of financially viable entities. An alternative approach would be to guarantee the liabilities of smaller distributors trading in the reformed

environment. This approach is consistent with Section 30 of EPIRA, which provides that NEA may, in exchange for adequate security and a guarantee fee, act as guarantor for electricity purchases from WESM by any EC or small DU. Unfortunately NEA's balance sheet is such that it may not presently be in a position to provide a credible guarantee. A related concern is the probability that many ECs lack the management expertise to trade effectively in the reformed environment. If EPIRA reforms are to work as intended, it may be necessary to establish a brokerage firm to buy electricity on behalf of under-performing ECs. In any event, to prevent market operations being hampered by any failure to meet payment obligations, it is likely that any such brokerage will still need to be backed by a sovereign guarantee.

IV. CONCLUSIONS AND ROADMAP FOR FUTURE ADB ASSISTANCE

113. The Government is currently facing challenges in implementing its power sector reform and restructuring due to financial, political, and regulatory constraints. At the same time, it has to address the looming power crisis in an environment where the private sector is reluctant to invest in the power sector. There is a growing realization that, given the lead time required for the development and construction of new generation capacity, action on the installation of new transmission and generation is required now, particularly in Visayas and Mindanao, if future energy shortages are to be averted. Under Section 47 of EPIRA, NPC is prohibited from investing in new generating plants. Hence, all new plants must be constructed by private sector investors. If no new plant is constructed, there is a real risk that the country will again face massive blackouts and enter into another cycle of shortages; emergency IPP programs under onerous PPAs; higher prices; more debt; and a stalled reform program.

114. ADB and other development financing institutions have been actively assisting the Philippine power sector. To better coordinate these operations, an understanding was reached between ADB and the World Bank on the division of responsibility in the power sector. According to the understanding, ADB would take the lead in providing policy advice to the Government on power sector restructuring while continuing support to NPC prior to its privatization. The World Bank, on the other hand, would focus on providing assistance in rural electrification. The cooperation between ADB and the World Bank has been satisfactory to date. The World Bank has not lent to NPC since 1997, while ADB approved a Power Sector Restructuring Program (PSRP) in December 1998, which was complemented by a partial credit guarantee of $500 million, approved in December 2002. ADB also approved a new investment loan to establish a WESM in the Philippines in December 2002. Total ADB loans to the sector amount to almost $2.3 billion while TA in the amount of $13.8 million has been provided. A list of loan and TA projects is given in Appendix 10. In view of the looming power crisis, investor concerns have already been raised with ADB by representatives of the Combined Chambers of Commerce. The Government has also approached the ADB for further assistance to sustain the momentum of power sector restructuring.

115. New ADB assistance should take into account the lessons learned from previous interventions, particularly the PSRP financed under Loan 1662-PHI. The Philippines is among the first developing member countries to implement fundamental power sector restructuring leading to full competition. This is a complex task and involves a large number of coordinated legislative, regulatory, and policy actions spread over a period of time. With hindsight, a more appropriate modality for such operation would have been a cluster approach, where the reform actions are prioritized and sequenced more realistically. In the first phase, the program could have only concentrated on establishing a sound policy, legal and regulatory framework for introducing new competitive markets, laying the groundwork for the transfer of assets, privatization and absorption of stranded debt in following phases. Therefore, one important lesson is that power sector restructuring in developing countries is a long drawn out process,

and as such the design of policy reforms should recognize the need for a steady and even approach with a phased and realistic implementation schedule.

116. As the lead financing agency in the power sector in the Philippines, ADB will continue to review and monitor the privatization process and conduct regular policy dialogues with the Government. ADB's future operational strategy should be carefully defined and adjusted in pursuing its policy objectives. In December 2002, the Board indicated that no further assistance would be provided to the power sector unless progress is achieved in sector restructuring and privatization. It is necessary to reassess the situation and propose appropriate instruments to assist the Government in meeting the challenges ahead, and to avoid another power crisis, as experienced in early 1990s.

117. The financial difficulties of the power sector have for some years complicated the macro-economic situation. Although a package of tax reform measures that is expected to generate additional revenues for the Government is being imeplemented, it is still necessary to reduce the financial drain on the Government's fiscal position caused by NPC's operating losses and the provision of wide-ranging guarantees on debt obligations and IPP liabilities. Financial recovery of the power sector is key to fiscal consolidation. The upfront actions of the power sector development program (PSDP), such as measures allowing the recovery of NPC's just and reasonable costs and a reasonable RORB, and assumption of about P200 billion of NPC's debt will be the first few critical steps to restore the power sector's financial viability. Effective and timely implementation of the PSDP will be critical to strengthening the Government's financial management. In tandem with the power sector reforms, implementation of tax reforms will help achieve fiscal consolidation.

118. Some entities opposing the ongoing power sector restructuring cite it as the principal cause of the current financial situation, suggesting a return to the previous vertically integrated government-owned monopoly. Such a reversal would further aggravate the situation and discourage private participation in the sector. The ongoing restructuring with an early establishment of a competitive electricity market is the right approach—it is the major delays in its implementation, among other factors (e.g., low tariff), that have led to the financial problems in the power sector.

119. The restructuring has reached a critical juncture. The legal, regulatory and institutional framework for privatization and competition is largely in place. However, for these two key objectives of the restructuring to succeed, the sector's financial viability has to be restored; regulatory performance improved; and the confidence of private sector investors enhanced. ADB is considering a new PSDP designed to provide a more holistic solution with a multi-pronged approach that recognizes the complexity of the restructuring process and the links among various components. The final goal of the PSDP is a financially sustainable, efficient and secure power supply that arrests the drain on the Government's finances caused by the power sector, thus freeing up resources for the social sectors, and minimizes the risk of power shortages that would impede economic growth. The specific objective of the PSDP is to assist the Government in completing the power sector restructuring.

NATIONAL POWER CORPORATION GENERATING PLANTS

Table A1.1: National Power Corporation Owned Generating Plants—Luzon[1]

Commissioning Year	Plant	Province	Installed Capacity (MW)	Firm Capacity[2] (MW)
Hydro				
1957	Barit	Camarines Sur	2	2
1967-1986	Angat	Bulacan	245	226
1977	Pantabangan	Nueva Ecija	100	80
1981	Masiway	Nueva Ecija	12	11
1983-4	Magat	Isabela	360	360
2002	Cawayan	Sorsogon	1	1
Total Hydro			**720**	**680**
Geothermal				
1979-1982	Tiwi	Albay	330	155
1979-1996	Macban	Laguna	410	315
1993-1998	Bacman	Sorsogon	150	126
Total Geothermal			**890**	**596**
Coal				
1984	Calaca I	Batangas	300	260
1995	Calaca II	Batangas	300	270
1998	Masinloc	Zambales	600	600
Total Coal			**1,200**	**1,130**
TOTAL LUZON			**2,810**	**2,405**

[1] As of 31 December 2004.
[2] Firm capacity = maximum plant output as at 31 December 2004.
Source: Department of Energy.

Table A1.2: National Power Corporation Owned and Operated Generating Plants—Visayas[1]

Commissioning Year	Plant	Location	Installed Capacity (MW)	Firm Capacity[2] (MW)
Hydro				
1968	Loboc	Bohol	1	1
1962	Amlan	Negros Oriental	1	1
Total Hydro			**2**	**2**
Geothermal				
1983	Palinponon I	Negros Oriental	113	99
1994-1995	Palinponon II	Negros Oriental	80	80
1981-1982	Tongonan I	Leyte	113	99
Total Geothermal			**306**	**278**
Oil				
1978-1989	Bohol DPP	Bohol	22	18
1979-86	Panay DPP1	Iloilo	37	25
1981	Power Barge 101	Bohol	32	24
1981	Power Barge 102	Cebu	32	24
1985	Power Barge 103	Iloilo	32	24
1985	Power Barge 104	Cebu	32	24
2004	Leased plant	Iloilo	10	10
Total Oil			**197**	**149**
TOTAL VISAYAS			**505**	**429**

[1] As of December 2004
[2] Firm capacity = maximum plant output as at 31 December 2004.
Source: Department of Energy.

Table A1.3 National Power Corporation Owned and Operated Generating Plants—Mindanao[1]

Commissioning Year	Plant	Location	Installed Capacity (MW)	Firm Capacity[2] (MW)
Hydro				
1998	Talomo	Davao City	4	2
1957	Agusan	Bukidnon	2	2
1953-1971	Agus VI	Lanao Norte	200	165
1979	Agus II	Lanao Sur	180	120
1983	Agus VII	Lanao Norte	54	54
1885	Agus V	Lanao Norte	55	55
1985	Agus IV	Lanao Norte	158	158
1985-1986	Pulangui IV	Bukidnon	255	255
Total Hydro			**908**	**811**
TOTAL MINDANAO			**908**	**811**

[1] As of 31 December 2004
[2] Firm capacity = maximum plant output as of 31 December 2004.
Source: Department of Energy.

GENERATING PLANTS CONTRACTED TO NATIONAL POWER CORPORATION

Table A2.1: Generation Plants subject to IPP Contracts with NPC[1] – Luzon

Commissioning Year	Plant	Location	Installed Capacity (MW)	Firm Capacity[2] (MW)
Hydro				
1960	Binga	Benguet	100	100
1993	Hedcor – Ampohaw	Benguet	25	25
1993	Northern Mini-hydro	Benguet	12	6
2001	Bakun	Banguet & Ilocos Sur	70	70
2002	Casecnan	Nueva Ecija	140	140
1982	Kalayaan 1&2	Laguna	300	300
2004	Kalayaan 3&4	Laguna	350	350
2005	San Roque	Benguet	345	85
Total Hydro			**1,342**	**1,076**
Geothermal				
1994	Macban - Ormat	Laguna	16	6
Total Geothermal			**16**	**6**
Oil (Bunker C)				
1995	Malaya I	Rizal	300	300
1995	Malaya II	Rizal	350	350
1993	Pinamucan	Batangas	111	97
1994	Subic	Zambales	116	100
1994-1995	Bauang	La Union	235	210
1994-1995	Edison Global	Bataan	64	50
1995	Magellean Cogen	Cavite	63	60
Total Bunker C			**1,239**	**1,167**
Oil (Diesel)				
1990-1993	Novatas	Manila	310	180
1993-1994	Limay	Bataan	590	540
Total Diesel			**900**	**720**
Coal				
1996	Pagbilao	Quezon	764	764
1999	Sual	Pangasinan	1,294	1,146
Total Coal			**2,058**	**1,910**
Natural Gas				
2002	Ilijan	Batangas	1,200	1,200
Total Natural Gas			**1,200**	**1,200**
TOTAL LUZON			**6,755**	**6,079**

Note 1: As at 31 December 2004.
Note 2: Firm capacity = maximum plant output as at 31 December 2004.
Source: Department of Energy.

Table A2.2: Generation Plants Subject to IPP Contracts with NPC[1]—Visayas

Commissioning Year	Plant	Location	Installed Capacity (MW)	Firm Capacity[2] (MW)
Geothermal				
1996-1998	Leyte A	Leyte	611	578
Total Geothermal			**611**	**578**
Oil (Bunker C)				
1977-80	Cebu DPP1	Naga, Cebu	44	30
Total Bunker C			**30**	**30**
Oil (Diesel)				
	Cebu GT	Naga, Cebu	55	50
Total Diesel			**55**	**50**
Coal				
1994	Cebu TPP1	Naga, Cebu	53	50
1986	Cebu TPP2	Naga, Cebu	57	55
Total Coal			**110**	**105**
TOTAL VISAYAS			**806**	**763**

[1] As of 31 December 2004.
[2] Firm capacity = maximum plant output as at 31 December 2004
Source: Department of Energy.

Table A2.3: Generation Plants Subject to IPP Contracts with NPC[1]-— Mindanao

Commissioning Year	Plant	Location	Installed Capacity (MW)	Firm Capacity[2] (MW)
Geothermal				
1996	Mt Apo I[4]	Cotabato	54	54
1999	Mt Apo II[4]	Cotabato	54	54
Total Geothermal			**108**	**108**
Oil (Bunker C)				
1992	NMPC I	Lanao Norte	64	20
1993	NMPC II	Lanao Norte	45	40
1994	Barge 117	Agusan del Norte	100	100
1994	Barge 118	Davao del Norte	100	95
1997	Zamboanga Diesel	Zamboanga del Sur	107	100
1998	General Santos Diesel	South Cotabato	56	50
Total Bunker C			**472**	**405**
TOTAL MINDANAO			**580**	**513**

[1] As of 31 December 2004.
[2] Firm capacity = maximum plant output as at 31 December 2004.
Source: Department of Energy.

PRIVATE POWER PLANTS NOT CONTRACTED TO NATIONAL POWER CORPORATION

Commissioning Year	Plant	Location	Installed Capacity (MW)	Firm Capacity (MW)
Luzon				
Coal				
2000	Quezon Power	Quezon	511	511
Diesel				
1995	Duracom	Metro Manila	133	113
1995	East Asia Diesel	Metro Manial	109	109
1994	Angeles DPP	Angeles City	30	30
1996	FCVC DPP	Cababatuan City	32	32
1995	Tarlac Electric	Tarlac	19	13
	Trans Asia Power	La Union	52	52
Natural Gas				
1994	San Antonio	Isabela	3	3
2000-2001	Santa Rita	Batangas	1060	1000
2002	San Lorenzo	Batangas	500	500
Other				
1998	Manito Geothermal	Albay	2	2
	Mini-hydro	Luzon	16	16
	NIA- Baligatan	Benguet	6	6
Total Luzon			**2,473**	**2,387**
Visayas				
Coal				
1993	Sangi	Toledo City, Cebu	89	40
Diesel				
1995	Panay Power	Iloilo City	75	72
1995	PECO	Iloilo City	20	15
1993	Carmen	Toledo City, Cebu	46	35
1995	Cebu Private Power	Cebu City	70	70
1995	East Assia Utilities	Cebu City	50	46
	Mirant	La Paz, Iliolo	40	40
Hydro				
	Jonopol	Bohol	5	5
	Mini-hydro		5	5
Total Visayas			**400**	**328**
Mindanao				
Diesel				
1995	Mindanao Energy	Cagayan de Oro City	19	19
	Cotobato Light	Cotobato	10	8
1995	Davao Light	Davao City	59	42
Hydro				
	Mini-hydro		3	3
	Bubunawan		7	7
Total Mindanao			**98**	**79**

Source: Department of Energy.

PHILIPPINE INVESTOR OWNED AND LOCAL GOVERNMENT UTILITIES

Utility	Mnemonic	Province	Type
Luzon			
Angeles Electric Corporation	AEC	Pampanga	IOU
Bauan Electric Light System	BELS	Batangas	LGU
Cabanatuan Electric Corporation	CELCOR	Nueva Ecija	IOU
Olongapo Public Utilities Department	PUD	Zambales	LGU
Dagupan Electric Corporation	DECORP	Pangasinan	IOU
Ibaan Electric and Engineering Corporation	IEEC	Batangas	IOU
La Union Electric Company Incorporated	LUECO	La Union	IOU
Manila Electric Company	MERALCO	Manila	IOU
Mansons Corporation		Pampanga	IOU
San Fernando Electric Power & Light Co Inc	SFELAPCO	Pampanga	IOU
Tarlac Electric Incorporated	TEI	Tarlac	IOU
Visayas			
Bohol Electric Company Incorporated	BLCI	Bohol	IOU
Mactan Electric Company	MECO	Cebu	IOU
Panay Electric Company	PECO	Panay	IOU
Visayan Electric Company Incorporated	VECO	Cebu	IOU
Mindanao			
Cagayan Electric Power & Light Co Inc	CEPALCO	Davao del Sur	IOU
Cotabato Light & Power Company Incorporated	COLIGHT	Cotabato	IOU
Davao Light & Power Company Incorporated		Davao del Sur	IOU
Iligan Power & Light Company Incorporated	ILPI	Lanao del Norte	IOU

IOU=investor owned utility, LGU=local government unit.
Source: Energy Regulatory Commission.

PHILIPPINE ELECTRICITY COOPERATIVE DATA FOR FY 2004

	EC	Mnemonic	NEA Grade	Gross Revenue (Php million)	Load (MW)	Sales (GWh)	Loss (%)	Av System Rate Php/kWh
1	Abra	ABRECO	A	162.8	6.9	25.1	15.5	6.48
2	Aklan	AKELCO	A+	535.9	26.4	92.0	14.1	5.83
3	Albay	ALECO	E	1,120.4	56.2	222.6	21.1	5.03
4	Agusan Norte	ANECO	A+	720.9	49.7	212.2	9.9	3.40
5	Antique	ANTECO	A+	247.7	11.9	42.5	12.6	5.83
6	Agusan Sur	ASELCO	A+	216.5	13.8	52.9	16.0	4.09
7	Aurora	AURELCO	A+	99.0	3.5	15.4	13.9	6.41
8	Bantayan	BANELCO	A+	85.2	3.2	11.3	10.7	7.55
9	Basilan	BASELCO	E	116.6	6.6	17.1	18.4	6.84
10	Batanes	BATANELCO	A+	20.3		3.5	5.4	5.86
11	Batangas I	BATELEC I	A+	933.2	42.5	177.0	14.1	5.27
12	Batangas II	BATELEC II	A	2,160.9	90.2	419.8	13.9	5.15
13	Benguent	BENECO	B	1,210.7	57.7	248.9	10.7	4.86
14	Biliran	BILECO	B	83.3	4.9	13.5	17.7	6.19
15	Busuanga	BISELCO	A	28.7	1.3	4.3	14.1	6.68
16	Bohol I	BOHECO I	A+	360.5	20.1	65.1	12.4	5.53
17	Bohol II	BOHECO II	A+	247.7	14.1	43.7	11.7	5.67
18	Bukidnon II	BUSECO	C	240.3	16.6	59.6	18.0	4.03
19	Cagayan I	CAGELCO I	A+	500.9	26.1	100.8	14.3	4.97
20	Cagayan II	CAGELCO II	A+	316.4	16.7	52.8	19.0	6.00
21	Camiguin	CAMELCO	D	53.3	3.6	10.8	17.4	4.94
22	Camarines Norte	CANORECO	C	393.5	17.7	68.0	15.9	5.79
23	Capiz	CAPELCO	A+	564.5	26.1	103.8	14.0	5.44
24	Cagayan De Sulu	CASELCO	E	2.2	0.2	0.2	25.1	9.00
25	Camarines Sur I	CASURECO I	E	201.3	10.1	34.2	18.6	5.88
26	Camarines Sur II	CASURECO II	D	845.8	37.8	156.2	18.9	5.42
27	Camarines Sur III	CASURECO III	E	312.3	15.6	50.5	21.4	6.18
28	Camarines Sur IV	CASURECO IV	A	138.0	6.7	23.5	15.2	5.86
29	Cebu I	CEBECO I	A+	387.8	21.7	80.4	9.0	4.82
30	Cebu II	CEBECO II	A+	591.0	28.9	118.4	10.7	4.99
31	Cebu III	CEBECO III	A+	296.7	18.1	76.6	7.2	3.87
32	Camotes	CELCO	A+	39.1	1.7	4.6	12.4	8.43
33	Central Negros	CENECO	A	1,956.0	93.6	398.8	15.1	4.90
34	Central Pangasinan	CENPELCO	B	926.5	45.7	169.6	19.2	5.46
35	North Cotabato	COTELCO	A+	392.8	27.4	97.3	14.3	4.04
36	Davao Norte	DANECO	B	839.6	60.4	222.9	15.9	3.77
37	Davao Sur	DASURECO	A+	523.8	31.2	141.4	10.3	3.70
38	Dinagat	DIELCO	A+	24.1	1.1	3.3	8.8	7.40
39	Davao Oriental	DORECO	A+	226.3	13.8	54.5	7.6	4.15
40	Eastern Samar	ESAMELCO	E	157.5	7.9	29.7	19.3	5.39

Source: National Electrification Administration

EC = electric cooperative, GWh = gigawatt hours, MW = megawatt, NEA = National Electrification Administration, Php = Philippine peso

PHILIPPINES ELECTRICITY COOPERATIVE DATA FOR FY2004

	EC	Mnemonic	NEA Grade	Gross Revenue (Php million)	Load (MW)	Sales (GWh)	Loss (%)	Av System Rate Php/kWh
41	First Bukidnon	FIBECO	A+	333.5	22.3	80.5	12.8	4.14
42	First Catanduanes	FICELCO	A	166.0		21.7	13.1	7.65
43	First Laguna	FLECO	E	310.6	16.9	58.6	23.0	5.30
44	Guimaras	GUIMELCO	B	86.4	4.3	13.5	16.7	6.39
45	Ifugao	IFELCO	B	52.0	2.0	8.1	19.3	6.44
46	Iloilo I	ILECO I	A+	572.0	29.6	106.6	12.4	5.36
47	Iloilo II	ILECO II	A	402.9	20.2	68.6	15.1	5.88
48	Iloilo III	ILECO III	A+	217.2	10.8	35.5	13.6	6.13
49	Ilocos Norte	INEC	A+	805.4	35.6	153.8	12.5	5.27
50	Ilocos Sur	ISECO	A+	698.3	33.5	133,4	14.0	5.24
51	Isabela I	ISELCO I	C	859.5	40.9	16.0	15.7	5.13
52	Isabela II	ISELCO II	B	455.5	21.4	81.6	18.1	5.58
53	Kalinga Apayao	KAELCO	B	88.4	3.8	13.0	16.6	6.77
54	Lanao Norte	LANECO	A+	195.1	13.1	47.6	11.9	4.09
55	Lanao Sur	LASURECO	E					
56	Leyte I	LEYECO I	D	182.4	10.8	30.5	20.7	5.99
57	Leyte II	LEYECO II	A+	625.7	31.3	127.8	14.3	4.90
58	Leyte III	LEYECO III	A+	107.2	5.1	17.9	14.1	6.00
59	Leyte IV	LEYECO IV	A+	168.5		29.7	13.4	5.67
60	Leyte V	LEYECO V	A+	482.1	23.5	95.1	14.0	5.07
61	Lubang	LUBELCO	E	11.7	0.7	1.4	20.5	8.16
62	La Union	LUELCO	A+	588.0	27.3	106.9	14.0	5.50
63	Maguindanao	MAGELCO	E	186.6	16.5	45.4	28.2	4.11
64	Marinduque	MARELCO	B	148.4	9.1	24.0	15.7	6.20
65	Masbate	MASELCO	D	179.0	8.7	32.4	17.4	5.52
66	Misamis Occidental I	MOELCI I	A+	134.5	8.7	29.9	13.0	4.49
67	Misamis Occidental II	MOELCI II	A+	320.5	25.6	86.8	14.5	3.69
68	Mountain Province	MOPRECO	B	56.7	3.2	9.2	15.6	6.15
69	Misamis Oriental I	MORESCO I	A+	300.3	18.0	77.9	6.5	3.86
70	Misamis Oriental II	MORESCO II	A+	226.1	16.8	62.8	13.9	3.60
71	Nueva Ecija I	NEECO I	E	467.0	19.3	81.6	15.9	5.72
72	Nueva Ecija II	NEECO II NTH	D	499.8	24.9	83.1	21.0	6.01
73	Nueva Ecija - NMT	NEECO II SOUTH		464.8	20.6	84.1	15.1	5.52
74	Negros Occidental	NOCECO	A+	618.0	34.6	115.7	12.7	5.34
75	Negros Oriental I	NORECO I	A+	173.2	9.6	31.1	13.7	5.57
76	Negros Oriental II	NORECO II	A+	687.0	31.6	131.9	13.9	5.21
77	Northern Samar	NORSAMELCO	E	178.3	8.5	31.2	20.1	5.71
78	Nueva Vizcaya	NUVELCD	A+	334.7	15.1	61.0	12.8	5.49
79	Occidental Mindoro	OMECO	B	213.7	11.6	35.9	16.2	5.95
80	Oriental Mindoro	ORMECO	A+	548.6	26.7	97.8	13.6	5.60

Source: National Electrification Administration

EC = electric cooperative, GWh = gigawatt hours, MW = megawatt, NEA = National Electrification Administration, Php = Philippine peso

Note 1: Area operated by NEA

PHILIPPINES ELECTRICITY COOPERATIVE DATA FOR FY2004

	EC	Mnemonic	NEA Grade	Gross Revenue (Php million)	Load (MW)	Sales (GWh)	Loss (%)	Av System Rate Php/kWh
81	Palawan	PALECO	A+	528.7	21.6	98.7	11.9	5.36
82	Pangasinan I	PANELCO I	B	298.6	14.3	52.4	17.9	5.70
83	Pangasinan III	PANELCO III	A	941.6	43.9	177.7	17.4	5.30
84	Pampanga I	PELCO I	B	552.4	26.0	102.0	20.4	5.42
85	Pampanga II	PELCO II	E	1,050.3	51.5	206.6	21.9	5.08
86	Pampanga III	PELCO III	E	780.9		166.4	20.9	4.69
87	Peninsula	PENELCO	A+	1,084.4	51.1	214.2	12.6	5.06
88	Pampanga Rural	PRESCO	A+	106.1		19.3	12.7	5.51
89	Province of Siquijor	PROSIELCO	A+	68.3	2.3	8.3	10.4	8.25
90	Quezon I	QUEZELCO I	A+	542.7	27.4	98.0	14.3	5.54
91	Quezon II	QUEZELCO II	C	86.7	3.7	15.3	19.2	5.67
92	Quirino	QUIRELCO	A	94.4	4.3	15.2	14.7	6.20
93	Romblon	ROMELCO	A+	41.1	1.9	6.7	12.9	6.09
94	San Jose City	SAJELCO	B	222.5	10.1	44.8	16.5	4.98
95	Samar I	SAMELCO I	A	167.7	7.7	31.0	13.1	5.41
96	Samar II	SAMELCO II	A+	191.7	9.2	33.5	19.3	5.72
97	Siargao	SIARELCO	A+	44.4	2.1	7.3	10.7	6.07
98	Siasi	SIASELCO	A	9.7	0.5	1.3	10.2	7.32
99	South Cotabato I	SOCOTECO I	A+	429.6	26.4	116.2	13.5	3.70
100	South Cotabato II	SOCOTECO II	A+	1,424.4	89.9	420.0	14.0	3.39
101	Southern Leyte	SOLECO	A	219.2	12.8	42.2	15.7	5.20
102	Sorsogon I	SORECO I	E	149.2	7.2	27.1	18.2	5.50
103	Sorsogon II	SORECO II	E	306.4	12.4	48.3	19.0	6.35
104	Sultan Kudarat	SUKELCO	A+	349.6	21.3	88.9	13.9	3.93
105	Sulu	SULECO	D	109.4	4.8	15.7	35.9	6.96
106	Surigao Norte	SURNECO	B	239.1	16.4	60.5	22.3	3.95
107	Surigao Sur I	SURSECO I	A+	152.9	9.3	34.7	13.5	4.40
108	Surigao Sur II	SURSECO II	A+	133.4	7.8	30.2	13.4	4.42
109	Tarlac I	TARELCO I	A+	634.3	28.2	114.6	12.7	5.53
110	Tarlac II	TARELCO II	A+	621.7	27.5	117.1	11.2	5.31
111	Tawi-Tawi	TAWELCO	E	57.9		7.9	40.9	7.36
112	Tablas	TIELCO	A+	82.9	3.8	13.8	9.8	6.01
113	Ticao Island	TISLECO	E	11.3		1.7	28.4	6.57
114	Vresco	VRESCO	A+	549.8	25.8	102.6	14.2	5.36
115	Zamboanga City	ZAMCELCO	B	1,209.4	84.9	374.1	16.2	3.23
116	Zambales I	ZAMECO I	C	287.7	13.1	52.9	15.5	5.44
117	Zambales II	ZAMECO II	E	392.0	16.9	72.2	13.5	5.43
118	Zamboanga Sur I	ZAMSURECO I	A+	416.8	24.2	105.0	13.5	3.97
119	Zamboanga Sur II	ZAMSURECO II	A+	244.8	16.6	60.3	13.9	4.06
120	Zamboanga Norte	ZANELCO	A+	341.9	24.7	96.7	14.0	3.54

Source: National Electrification Administration

EC = electric cooperative, GWh = gigawatt hours, MW = megawatt, NEA = National Electrification Administration, Php = Philippine peso

THE WHOLESALE ELECTRICITY SPOT MARKET OPERATION

1. The wholesale electricity spot market (WESM) will allow generators, distributors, and large electricity users to buy and sell electricity without the need to negotiate bilateral contracts with one another. Each day will be divided into 24 one hour trading periods. Electricity generators will bid into the market to be allowed to generate for a particular trading period. Generators will be dispatched according to the prices bid so that the total cost of electricity paid by purchasers is minimized. The dispatch schedule for a given trading period will be prepared by the market operator using a mathematical model of the network and a linear programming based optimization algorithm.

2. The Philippine market will be a gross real time market, similar to that used in Australia and New Zealand. All grid connected generation, except renewable energy generation such as wind where the ability to generate cannot be foreseen in advance, will be dispatched through the market. The market will use a system of nodal pricing, whereby a market clearing price will be established for each connection point on the network.[1] All generators will be paid the market clearing price for the node at which they connect to the grid. Electricity purchasers will pay a zonal price, which will be equal to the weighted average nodal price at all off-take nodes within a pricing zone.

3. In order to protect against market price volatility it is a standard practice for generators and purchasers to negotiate bilateral contracts where the price of electricity is fixed in advance. In the Philippines, such contracts will be structured as “contracts for differences”. These are financial hedge contracts rather than contracts for electricity supply. If the hedge contract price is above the market price, the purchaser will pay the generator the difference between the contract price and the market price. Conversely, if the hedge contract price is below the market price, the difference will be paid by the generator to the purchaser.

4. The buying and selling of electricity subjected to a hedge contract will thus involve two separate financial transactions. The first transaction will be for electricity supply through the market, where the purchaser will pay the market operator the market clearing price for the contracted electricity purchased during a trading period. This market clearing price will be paid by the market operator to the generator for the electricity sold to the market. The second transaction is a bilateral off-market financial transaction where the electricity is priced at the difference between the market price and the contracted price[2]. The net effect of the two transactions is that the purchaser will pay and the generator will receive the electricity price set by the bilateral off-market hedge contract.

5. The gross market planned for the Philippines will require all generators to bid into the market if they want to be dispatched and paid by the market for electricity generated. It differs from a balancing market, like the market in England and Wales, where generators with bilateral contracts are given preferential access to the grid. These generators are paid in full for electricity supplied directly by the purchaser, through a single transaction that does not involve the market operator. In such a situation the real time market is simply a balancing market to settle electricity sales and purchases that are not covered by bilateral contracts. The main

[1] The market clearing price at any node will be established by the bid price of the connected generator with available spare capacity that would need to be used to supply a marginal increase in demand at that node. This is a frequently used approach that takes account of network losses and grid constraints.

[2] The market rules include provision for contracts for differences to be settled through the market operator at the same time as the parties settle their electricity sales and purchases through the market. However, in respect contracts for differences, the market operator is simply providing a service to facilitate settlement and is not directly involved in the transaction.

advantage of a gross market, as planned in the Philippines, is that it allows total generation to be optimized to minimize the cost of generation to the economy as a whole. It also provides a mechanism to minimize and allocate the total cost of grid losses and network constraints.

6. In the planned Philippine market, renewable energy generators such as wind, where the ability to generate cannot be foreseen in advance, will not be required to bid for dispatch.[3] These generators will be allowed to generate if they can, and will be price takers in that they will be paid the market clearing price at the node to which they are connected. The market operator will need to schedule additional reserve capacity to be used if the generators cannot generate and it is understood that the cost of these additional reserves will be smeared across all market participants.

7 For the market to function there needs to be an assurance that purchasers will not default on payments for electricity that is purchased through the market. Purchasers will therefore be required to put up adequate security for electricity purchases before they can join the market, and the WESM rules specify the level of security required. Provision of the necessary security is likely to be a problem for some electricity cooperatives, particularly those that are financially vulnerable or are already in arrears to the National Power Corporation (NPC) for electricity purchases. Section 30 of EPIRA provides that the National Electrification Administration may act as a guarantor for electricity purchased by small electricity utilities.

8. An electricity spot market will operate most effectively where (i) there are a number of different generating companies actively competing to supply electricity into the market; (ii) electricity supply and demand is roughly in balance; and (iii) the transmission network has sufficient capacity to ensure that grid constraints to not unduly constrain the dispatch of generation in accordance with bid prices. If there is no diversity in ownership of generation there is a risk that the dominant generator will manipulate the market to increase overall prices and generate monopoly profits. If electricity demand exceeds supply then prices will rise as generators bid high to take advantage of the situation[4]. However, if supply exceeds demand, the risk is that excessive competition may prevent generators recovering their fixed costs, forcing less efficient generators out of the market and providing few incentives for new generation to enter the market. Over time, this can create supply shortages in a market where demand is increasing. If the market is highly constrained, there will be large price variations across a grid in any trading period. Furthermore, individual generators may have a high level of market power, thereby reducing competition and exacerbating price differentials.

[3] The WESM rules require that such generators will need to advise the market in advance of their expected level of generation for a given trading period in order to assist the market operator schedule expected generation and reserve requirements

[4] Electricity demand is relatively inelastic to price.

PERFORMANCE BASED RATE SETTING METHODOLOGY

1. On 29 May 2003, the Energy Regulatory Commission (ERC) approved new guidelines for the setting of transmission system wheeling rates and on 5 January 2005 the ERC issued similar guidelines for the setting of distribution rates for distribution utilities. This appendix describes in some detail the performance based rate setting methodology for the transmission grid operator's wheeling rates and then describes the key differences between the regulation of transmission rates and the regulation of the distribution wheeling rates of private distribution utilities.

A. Transmission

2. The rate charged for transmission services will be limited by a revenue cap,[1] termed the maximum allowed revenue (MAR). At the beginning of each five year regulatory period the regulator will set a MAR for each year of the regulatory period, based on a forward looking forecast of the revenue requirements for the regulatory period. While the revenue forecast is likely to indicate a "lumpy" revenue requirement from year to year, depending on capital expenditure requirements, the regulated revenue cap will be smoothed into a function of the form:

$$MAR_{t+1} = MAR_t(1+CWI-X)-K-RBR$$

where

MAR_t = revenue requirement in year t
MAR_{t+1} = revenue requirement in year t+1
CWI = change in weighted index
X = efficiency factor
K = under/over recovery adjustment
PBR = performance base rate

3. The efficiency factor, X, is set at the beginning of a five year regulatory period and reflects the regulator's assessment of the extent that TRANSCO can reduce its required revenue over time through the implementation of operating efficiencies. While it is likely to be positive, it could theoretically be negative (reflecting a real price increase over time) if the regulator considered increased capital or operating expenditure was required to meet high load growth or to improve the quality of service. The change in weighted index, CWI, takes account of the impact on both local price inflation and the exchange rate on the cost of inputs. The under/over recovery adjustment, K, corrects for previous under or over recovery of revenues compared to the allowed revenue cap.[2] The performance based rate, PBR, is determined by the ERC and provides a mechanism whereby the maximum allowed revenue can be reduced by up to 50% of the reported net income from related businesses in the previous year.[3]

4. TRANSCO will be free to set its own transmission rate structure,[4] subject to the requirement that its overall revenue from the provision of regulated services does not exceed the allowed revenue cap in any year. However, TRANSCO's actual revenue in any year will be dependent on its actual energy throughput, over which it has no control. There is therefore

[1] The revenue cap will apply to TRANSCO together with its concessionaire.
[2] An under or over recovery of revenues will occur when actual power deliveries differ from forecasted levels.
[3] Under section 30 of EPIRA, TRANSCO is permitted to engage in related unregulated businesses, provided that a portion (up to 50%) of the income from such businesses is used to reduce the transmission rate. The PBR component is used to apply such reductions.
[4] This freedom will be subject to "side constraints" that limit the amount that individual rates can be varied from one year to the next.

provision in the guidelines for the revenue cap to be adjusted to offset any revenue over-recovery or under-recovery in the previous year.[5,6]

5. The guidelines require the revenue cap to be set on the basis of a forecast revenue requirement that is prepared using a "building block" approach. The individual building blocks in the revenue forecast are specified in the guidelines and are:

(i) Operations and maintenance expenditure
(ii) Taxes other than corporate income tax
(iii) Depreciation
(iv) Return on capital[7]
(v) Estimated corporate income tax[8]

6. For the purposes of determining the regulatory asset base, TRANSCO must complete an independent asset revaluation using the optimized depreciated replacement cost method.

7. Except for certain force majeure events and tax changes that would materially impact the financial performance of the transmission grid operator, there is no provision for the MAR to be adjusted mid way through a five-year regulatory period. This provides an incentive for the operator to reduce its costs below forecasted levels, since the increased profits resulting from such cost savings can be retained until the next 5 year rate reset. These incentives are strengthened by an efficiency carry over mechanism that provides for the net efficiency gains[9] in one five year regulatory period to be "carried over" and added to the forecast revenue requirement for the subsequent period.[10] The guidelines also make provision for an incentive regime that rewards good service and penalizes poor service. The incentive regime is designed to prevent an operator making cost savings by avoiding prudent network expenditure.

8. The guidelines envisage that the first five-year regulatory period will start on 1 January 2006. This will require ERC to conduct a rate setting review through 2005. Prior to the formal review TRANSCO will need to obtain its independent asset revaluation and forecast its capital and operating expenditure and tax requirements for the five-year period 2006–2010.[11] Based on its assessment of the asset revaluation and expenditure forecasts ERC will need to determine, before the end of 2005, the MAR that will apply in each year over the regulatory period 2006–2010.

9. The guidelines include transitional provisions that will apply for FY 2004 and FY 2005. Essentially, these transitional provisions provide that (i) in FY 2004, the MAR will be P24,591 million escalated by the CWI over FY 2003; and (ii) the MAR in FY 2005 will be equal to the

---

[5] In the case of distribution utilities, the revenue cap is likely to be replaced by a price cap, which will limit the weighted average rate at which each class of customer is charged for distribution services. Hence, revenue will be able to vary with electricity sales and no annual recovery adjustment will be necessary.

[6] The revenue cap adjustment will actually be based on the revenue in the twelve months ending 30 September of the previous year allowing time for the adjustment to be approved by ERC.

[7] TRANSCO is permitted to earn a return equal to its weighted average cost of capital on its regulatory asset base and also on its working capital requirement.

[8] The inclusion of corporate income tax as an allowed revenue building block is at variance with the 2002 Supreme Court decision on MERALCO's allowed return on rate base.

[9] Net efficiency gains are the overall difference between forecast and actual expenditure over the 5-year regulatory period.

[10] The efficiency carryover to a subsequent regulatory period does not prevent the regulator taking account of achieved efficiencies in determining the revenue requirement for the next regulatory period. These savings should generally offset the negative impact of the carryover on the maximum allowed revenue that applies in the next revenue period.

[11] Capital expenditure requirements are likely to be based on the approved transmission development plan.

MAR determined for FY 2004 escalated by the CWI for FY 2004 and then adjusted for any over or under recovery in revenue in FY 2003.

10. Performance based rate setting is likely to result in a significant increase to the transmission rate in FY 2006. This increase is likely to be due to (i) automatic annual rate adjustments to allow for inflation and changes in the foreign exchange rate, (ii) a replacement cost based asset revaluation that will reflect movements in the cost of transmission system equipment between 1996 and 2004,[12] (iii) the inclusion of income tax in the allowed revenue requirement, (iv) the use of a rate of return based on weighted average cost of capital rather than a mandatory 12%, and (v) the use of forward looking cost forecasts rather than historic test year costs as a basis for determining the revenue requirement.

B. Distribution

11. For privately owned distribution utilities the performance based rate setting methodology is very similar to the methodology used to set the transmission wheeling rate. Both methodologies require the ERC to forecast, before the beginning of a regulatory period, the required revenue of each regulated business for each year of the regulatory period using the same building block approach. However, in the case of distribution utilities, the required revenue is then divided by the forecast volume of electricity delivered to derive a maximum average rate, which becomes the price control variable. Hence the revenue that a distribution utility is allowed to earn without breaching the price cap will vary with the volume of electricity distributed and the over / under recovery adjustment factor K in the price control formula (para 3 above) will not need to include an adjustment to provide for the under/over recovery of revenue due to differences in actual and forecast electricity delivery volumes.[13] The use of a revenue cap for the regulation of transmission businesses and a price cap for the regulation of distribution businesses is consistent with standard practice in jurisdictions such as Australia and reflects the fact that a higher portion of the costs of providing transmission line services are fixed.

12. For distribution businesses, the first regulatory period for which performance based rate setting will apply commences on 1 July 2007 and finishes on 30 June 2011. Hence the regulatory period for distribution businesses is four years, rather than the five years applied to transmission businesses. Over the period 1 July 2005 to 30 June 2007 transitional arrangements, which allow the average price to be adjusted by the CWI, will apply.

[12] TRANSCO's last replacement cost asset valuation was undertaken in 1996. No indexation has subsequently been applied to 1996 replacement costs.

[13] Since distributors will likely charge different distribution rates to different classes of customer, there is a provision for an ex post assessment of the average rate after the end of a regulatory year. The distributor will still need to make an adjustment in a following year to offset any over/under recovery of revenue to the extent that this is attributed to a difference beween the regulated actual rate and the forecast actual rate.

PROJECTED ELECTRICITY SUPPLY AND DEMAND

1. The following tables compare the projected electricity demand with installed generation capacity for each of the three main grids for the period 2002–2012. Demands for the period 2002–2004 are actual demands reported in the TRANSCO annual report. Three scenarios are forecast for demands beyond 2004: (i) DOE where demand from 2004 increases at the rate assumed in the 2005 Philippine energy plan, (ii) historical where the growth from 2004 is assumed to increase at about the same rate as occurred over the 10 year period 1994–2004, and (iii) low where growth is restricted due to reduced demand resulting from higher prices brought about by economic and industry restructuring.

Table A8-1: Electricity Supply-Demand Balance, Luzon

	Forecast Demand (MW)			Installed Capacity (MW)	Capacity Margin (%)		
	DOE (8.2%)	Historical (5.5%)	Low (4%)		DOE (8.2%)	Historical (5.5%)	Low (4%)
2004	6,323	6,323	6,323	12,038	90%	90%	90%
2005	6,841	6,671	6,576	12,383	81%	86%	88%
2006	7,402	7,038	6,839	12,383	67%	76%	81%
2007	8,009	7,425	7,113	12,383	55%	67%	74%
2008	8,666	7,833	7,397	12,383	43%	58%	67%
2009	9,377	8,264	7,693	11,733	25%	42%	53%
2010	10,146	8,718	8,001	11,733	16%	35%	47%
2011	10,978	9,198	8,321	11,733	7%	28%	41%
2012	11,878	9,704	8,653	11,733	-1%	21%	36%

GDP = gross domestic product, MW = megawatt.
Source: Consultant analysis using Department of Energy demand forecast.

Table A8-2: Electricity Supply-Demand Balance, Visayas

	Forecast Demand (MW)			Installed Capacity (MW)	Capacity Margin (%)		
	DOE (5.7%)	Historical (7%)	Low (6.5%)		DOE (5.7%)	Historical (7%)	Low (6.5%)
2004	955	955	955	1,711	79%	79%	79%
2005	1,009	1,022	1,017	1,601	59%	57%	57%
2006	1,067	1,093	1,083	1,601	50%	46%	48%
2007	1,128	1,170	1,154	1,601	42%	37%	39%
2008	1,192	1,252	1,229	1,601	34%	28%	30%
2009	1,260	1,339	1,308	1,601	27%	20%	22%
2010	1,332	1,433	1,393	1,601	20%	12%	15%
2011	1,408	1,534	1,484	1,502	7%	-2%	1%
2012	1,488	1,641	1,581	1,502	1%	-8%	-5%

GDP=gross domestic product, MW=megawatt.
Source: Consultant analysis using Department of Energy demand forecast.

Table A8-3: Electricity Supply-Demand Balance, Mindanao

	Forecast Demand (MW)			Installed Capacity (MW)	Capacity Margin (%)		
	DOE (5.9%)	Historical (6%)	Low (4%)		DOE (5.9%)	Historical (6%)	Low (4%)
2004	1,177	1,177	1,177	1,686	43%	43%	43%
2005	1,246	1,248	1,224	1,686	35%	35%	38%
2006	1,320	1,322	1,273	1,886	43%	43%	48%
2007	1,398	1,402	1,324	1,886	35%	35%	42%
2008	1,480	1,486	1,377	1,886	27%	27%	37%
2009	1,568	1,575	1,432	1,886	20%	20%	32%
2010	1,660	1,670	1,489	1,886	14%	13%	27%
2011	1,758	1,770	1,549	1,886	7%	7%	22%
2012	1,862	1,876	1,611	1,886	1%	1%	17%

GDP = gross domestic product, MW = megawatt.
Source: Consultant analysis using Department of Energy demand forecast.

LESSONS LEARNED FROM THE CALIFORNIA CRISIS

1. In 1996 three quarters of California's electricity demand was supplied by three large vertically integrated, privately owned utilities.[1] In spite of a surplus of generating capacity, electricity prices were approximately 50% higher than the United States national average. These high electricity prices were caused by the need to recover investment in electricity generation, particularly nuclear power plants. Furthermore, the state required utilities to purchase power from independent power producers using renewable and other technologies at prices significantly higher than the cost of traditional technologies.

2. Prior to the commencement of the Californian electricity market in April 1998, the three privately owned utilities were required to sell off their gas fired generation plants to independent power producers, but without any transitional contracts to buy back the output of the plants[2]. Furthermore, after the commencement of market operations, utilities were required to buy their electricity requirements from external producers through the market and were prevented from subsequently entering into bilateral supply contracts or contracts for differences.

3. At the time of market opening in April 1998 the price of electricity sold through the market was expected to drop substantially because of the supply surplus and the increased competition. However, retail electricity prices were fixed for the first four years of market operation (until March 2002) or until the utilities had recovered their stranded costs, at what was considered an artificially high level of $55 per MWh. This regulated retail price was similar to the prevailing price prior to the commencement of market operation and was fixed, at the request of the utilities, to provide a margin that would enable them to recover their stranded generation cost.

4. At the time of commencement of market operations California imported about 20% of its electricity requirements. A further 20% of supply was sourced from renewable energy suppliers, under long term contracts at rates higher than power sourced from traditional technologies. Approximately 25% of generating capacity was hydropower and 40% was oil or gas fired steam or turbine driven plant. Availability of hydropower generation fell in dry years, while the cost of thermal generation was subject to the volatility of oil and gas prices.

5. No significant new power generation or transmission expansion was commissioned in California between 1992 and 2000 due to (i) investor uncertainty in the early years about how the new power market would operate, and (ii) excessive delays in obtaining siting permits in the face of local opposition and the need to meet stringent environmental requirements. Over this period, load growth continued unabated both in California and neighboring states, progressively reducing the margin between supply and demand. The availability of imported electricity also diminished.

6. For the first two years of operation, the Californian electricity market performed in line with expectations. In 1999 the average market price of electricity was $32 per MWh, comfortably below the regulated retail price. However the crisis was precipitated by an extreme summer heat wave in mid 2000, when demand was significantly higher than forecast at a time when available hydropower capacity was diminished due to reduced water flow. It would seem that this instability was exacerbated by subsequent rising gas prices due, in part, to the abnormally cold winter that followed. Furthermore, independent power producers took advantage of the shortage of generation to bid prices into the market that were significantly higher than their cost

[1] The rest of the state was served by municipal utilities of varying sizes.
[2] It was believed that transitional or hedge contracts would reduce competition in the competitive generation market.

of supply. Over the next twelve months the wholesale market price rose to levels significantly higher than the regulated retail price.[3]

7. The causes of the Californian crisis are complex and remain the subject of much debate. However, it would seem that the following factors contributed significantly to the chain of events that unfolded:

(i) The failure to build new generation or transmission at a time when electricity demand was increasing;
(ii) The inability of retailers to enter into long term hedging contracts for their electricity requirements and their consequent exposure to volatile market prices;
(iii) When market prices rose, the regulated retail price left retailers with no option but to buy electricity at a price that was higher than that at which they were permitted to sell it;
(iv) The exercise of market power by some industry participants; and
(v) The inability of the legal and regulatory environment to take timely action to mitigate unforeseen market outcomes.

8. Table A9 below provides an assessment of the proposed Philippine market design in the context of the events that led to the Californian crisis.

TABLE A9: LESSONS FROM CALIFORNIA CRISIS AND THE CHARACTERISTICS OF THE PHILIPPINE MARKET

What went wrong in California	Characteristics of the Philippine Market	Remarks
Entry of New Generation Capacity: The permitting of new capacity in California took 4–5 years due to environmental requirements. As a result, very little new generation capacity was added between 1992 and 2000.	Historically, new generators in the Philippines have not faced stringent environmental permitting requirements and this is expected to continue in the foreseeable future.	Under the proposed industry reform new generation must be constructed by the private sector. At present there is little appetite for such investment primarily because (i) existing (pre-market) tariffs are being regulated to levels well below the cost of generation to new entrant, and (ii) many distribution utilities are seen as poor credit risks. If a market is to function effectively over time, new generation must be constructed to keep pace with increases in electricity demand.

[3] During the crisis the average wholesale price was $200 per MWh and at some points was as high as $1,900, substantially higher than the regulated retail price of $55.

What went wrong in California	Characteristics of the Philippine Market	Remarks
Entry of New Transmission Capacity Environmental requirements have also prevented the construction of major new transmission circuits.	Construction of new transmission is continuing with the support of ADB and other financiers. The proposed private sector concessionaire will be responsible for financing new transmission projects.	Development of the transmission network to keep pace with demand growth will be critical to efficient market operation and to the minimization of generation costs. However transmission planning in the restructured environment is weak in that, irrespective of the legal responsibilities of DOE under EPIRA, it is likely to be left to the TRANSCO concessionaire. Effective market operation and minimization of generation costs will not be primary objectives of the concessionaire.
No Hedging Opportunities: The major distribution utilities were prohibited from signing bilateral electricity supply contracts and were required to purchase all their electricity from external suppliers through the spot market. The market was therefore exposed to volatile price fluctuations.	The EPIRA allows distribution utilities to contract up to 90% of their electricity requirements on a bilateral basis. These will be structured as "contracts for differences" and will protect utilities from volatile price fluctuations.	This is consistent with accepted good business practice and addresses one of the major weaknesses in the Californian model.
Rate Freeze: The "partial deregulation" that requires buying power at the wholesale rate and selling at a regulated rate proved to be financially unviable.	Retail tariffs will be unregulated only after the introduction of open access and retail competition and then only in respect of contestable customers. However, there will be no long term rate freeze as was introduced in California.	Open access and retail competition is to be introduced progressively and will start only after commencement of WESM and privatization of at least 70% of NPC generation in Luzon and Visayas. Hence retail prices to small customers will generally be regulated over the short to medium term. Electricity regulation in the Philippines has historically been a slow and time consuming process and is unlikely to respond quickly to volatility in wholesale rates. The impact of this regulatory lag will be partially mitigated if ERC approves retail tariffs on the basis of a utility's hedged electricity price, which may be different from the average market price.

What went wrong in California	Characteristics of the Philippine Market	Remarks
Exercise of Market Power		
Many of the generators selling into the market took advantage of their market power and were able to manipulate the situation to their advantage, unnecessarily inflating the market price.	EPIRA has cross ownership restrictions designed to limit the market power of any one generation class market participant. ADB has provided a TA to assist ERC develop competition policies, and procedures to deal with the abuse of market power.	Concerns remain over the extent to which generators in both Mindanao and Visayas will have sufficient power to manipulate market prices. In Mindanao, limitations on the privatization of NPC generators mean that base and medium load generators will be predominantly owned or controlled by PSALM over the medium term. In Visayas network constraints across limited capacity submarine interconnectors may give individual generators the ability to control market price in certain parts of the grid.
Regulatory Failures:		
Reaction by the state and federal regulators to correct market problems was uncoordinated, slow and ineffective.	EPIRA gives ERC very strong powers to regulate market operation. Furthermore it has power to suspend the market in crisis situation. ADB and other agencies are providing support and training to both ERC and DOE to assist then perform their governance obligations.	A lesson from the Californian crisis is that markets, when under stress, can behave unpredictably. In such situations an effective short-term regulatory response will invariably be politically unpopular[1]. The ability of ERC to implement unpopular regulatory decisions when faced with a crisis situation, is uncertain.

Note 1: The Californian crisis may have been mitigated if the rate freeze had been lifted once it became apparent that retail electricity prices were insufficient to cover wholesale market prices.

ADB ASSISTANCE TO THE ENERGY SECTOR

Table A10.1 details lending and Table A10.2 shows technical assistance from the Asian Development Bank (ADB) to the Philippines energy sector.

TABLE A10.1: ASIAN DEVELOPMENT BANK LENDING

Loan No.	Date	Borrower	Project/Main Component	$ million
77	02/11/71	NPC	Agus VI Expansion and Associated Transmission	23.4
96	13/07/72	NPC	Agus III (Mindanao) Hydroelectric Station Engineering	21.0
196	07/11/74	NPC	Agus III (Mindanao) Hydroelectric Station Engineering	1.0
223	27/05/75	NPC	Supplementary Loan - Agus II and Agus VI	22.7
291	21/12/76	NPC	Agus IV (Mindanao) Hydroelectric Station	52.0
326	09/12/77	NPC	Agus V (Mindanao) Hydroelectric Station	29.0
421	19/11/79	PNOC	Malangas Coal Development	14.0
427	27/11/79	NPC	Pulangi IV (Mindanao) Hydroelectric Station	60.7
482	18/11/80	NPC	Negros & Mindanao Transmission	60.5
542	17/11/81	NEA	Rural Electrification	87.5
607	07/12/82	NPC	Power Systems Development	32.8
666	12/12/83	NPC	Negros-Panay Interconnection	43.8
726	20/12/84	PNOC	Philippine National Oil Company Energy Loan	85.0
728	10/12/84	NPC	Second Power System Development	33.0
823	18/12/86	NPC	Third Power System Development	92.0
914	27/10/88	NPC	Fourteenth Power (Sector)	120.0
985	14/11/89	NPC	Fifteenth Power (Sector)	160.0
991	23/11/89	Hopewell	Navotas 200 MW Gas Turbine	10.0
1042	13/10/90	NPC	Masinloc Thermal Power Station (Stage I)	200.0
1207	10/12/92	MERALCO	MERALCO Distribution	138.0
1230	18/05/93	Hopewell	Pagbilao 700 MW Coal-fired Power Station	40.0
1231	18/05/93	NPC	Pinamucan 123 MW Oil-fired Power Station	26.5
1288	14/12/93	NPC	Power Transmission on Luzon & Mindanao	164.0
1398	02/11/95	NPC	Northern Luzon Transmission & Generation	244.0
1474	30/09/96	NPC	Leyte-Mindanao Interconnection Engineering	5.3
1590	16/12/97	NPC	Power Transmission Reinforcement	191.4
1662	16/12/98	DOF	Power Sector Restructuring Program	300.0
1984	19/12/02	NPC	Electricity Market and Transmission Development	40.0
			Total	**2,297.6**

DOF = Department of Finance, MERALCO =Manila Electric Company, NEA = National Electrification Administration, NPC = National Power Corporation, PNOC = Philippine National Oil Company.
Source: Asian Development Bank.

TABLE A10.2: TECHNICAL ASSISTANCE

TA No.	Date	Title	$ '000
251	24/10/78	Malangas Coal Mine	114
430	17/11/81	Rural Electrification (Dendro Thermal Study)	150
431	17/11/81	Rural Electrification	120
447	25/02/82	Industrial Energy Audits & Energy Conservation	560
450	25/02/82	Second Coal Development	330
496	07/12/82	Cagayan River Hydropower Study	150
611	05/07/84	Electricity Tariff Study	229
651	19/12/84	Private Sector Coal Development Study	350
652	20/12/84	Refinery Sector Rationalization Study	450
733	24/12/85	Geothermal Steam Pricing Study	212
755	17/06/86	Mindanao Power System Development	350
733	15/10/86	Geothermal Steam Pricing Study (Supplementary)	63
834	18/12/86	Luzon Power System Development	260
1015	22/07/88	Development Study of the Visayas Power System	358
1050	27/10/88	Power Sector Cost Structure & Transfer Pricing Study	230
1158	17/05/89	Mineral Resources Development	75
1169	21/06/89	Power Sector Training	93
1372	11/09/90	Review of NPC's Asset Revaluation	96
1405	30/10/90	Environmental Management of Coal-based Power Generation	636
1966	20/10/93	Long-term Power System Planning Study	600
2365	20/07/95	Natural Gas Sales Negotiations	100
2435	02/11/95	Formation of Power Transmission Subsidiary	500
2623	30/07/96	Evaluation of Environmental Standards of Selected Industries	400
2653	30/09/96	Leyte-Mindanao Interconnection Engineering	575
3126	16/12/98	Electricity Pricing & Regulatory Practice in a Competitive Environment	600
3127	23/03/00	Consumer Impact Assessment	720
3422	23/03/00	Rural Electrification Institutional Strengthening	750
3516	10/10/00	Rural Electrification	600
3820	19/12/01	Competition Policy for the Electricity Sector	990
4073	19/12/02	Transition to Competitive Electricity Markets	800
4151	18/07/03	Promoting Good Governance in the Restructured Power Sector	800
4174	16/09/03	Rehabilitation of Renewable Energy Projects for Rural Electrification and Livelihood Development	800
4198	18/10/03	Institutional Strengthening for the Development of Natural Gas Industry	800
4557	28/12/04	Institutional Strengthening of ERC and Privatization of NPC	1,200
		Total	**15,061**

ERC = Energy Regulatory Commission, NPC=National Power Corporation.
Source: Asian Development Bank.