CHAPTER 9

APPRAISAL OF TRANSMISSION FACILITIES
AND
ITS IMPACT TO THE LONG-RANGE PLANNING

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9.1 Assets Appraisal for 69 kV Transmission Facilities

(1) Method of appraisal

The assets appraisal of the 69 kV transmission facilities and the purchasing price based on this appraisal exert an enormous impact on future profits.

In the first place, it is advisable to consider various methods of assets appraisal. This section concerns calculation and appraisal of the value of transmission facilities.

- Revaluation price: existing facility price plus(ratio of inflation plus repair and maintenance cost)
- Sound value: based on the present construction cost of existing facility minus (rehabilitation plus repair and maintenance cost)
- Market value: market maker is demand side and supply.

The NPC applies two types of assets appraisal: the revaluation price and sound value.

The revaluation price is arrived at through revaluation of assets centered around inflation of fixed assets. At the NPC, revaluation is carried out through consignment to outside consultants once every four years. In 1996, it was consigned to a U.S. consulting firm, and the issue of privatization has sharpened interest in the method. In addition, an internal revaluation is made every year. The rate of inflation for fixed assets in the power sector came to 4 percent in 1994 and only 0.11 percent in 1996 owing to the strengthening of the peso with the appreciation that year. Revaluation and sound value price will hike, because peso get down 20% against US dollar in October 1997. It is said that 80% of electric power materials are imported from foreign countries Other points taken into account in revaluation are interest rates and foreign exchange rates. It is difficult for an outside party to judge whether or not the NPC revaluation price is appropriate.

Negotiation of a 69 kV transmission facility that should be start from sound value. The appraisal is to draw comparisons with sound value, price of new acquisition, and replacement cost new, which is obtained by figuring in rehabilitation and repair costs with sound value.

Sound value is the present cost of construction of new facilities excluding (minus) the cost of rehabilitation, maintenance, and repair. To estimate sound value, it is necessary to make a field study of the actual facilities to evaluate them. This appraisal is based on the current construction cost with subtraction of the rehabilitation cost. In other words, the remainder after subtraction of maintenance cost and rehabilitation cost from the current construction cost is the sound value.

The facility cost includes the following costs.

- Purchasing price, freightage, installation cost, test cost
- Design and supervision cost
- Imported materials cost, insurance, customs duties
- Interest during the construction term
- 10% of Value Added Tax

Market value is generally applied in transactions for ordinary market commodities, real estate, etc.

(2) Case of appraisal of the 33-km Palo-Dorelco-Tacloban route

A study was made of 69 kV transmission facilities over five kilometers of the 33-kilometer Palo-Dorelco-Tacloban route. For example, a selection was made of the wooden poles now in use for evaluation in terms of the four classes. The Class A poles have a remaining value of 75 - 100 percent, and were evaluated based on the current purchasing price (including installation cost) of 682,000 pesos. Class B poles have a remaining value of 50 - 76 percent. Similar evaluations were made for transmission lines, insulators, and guy wires.

The table below presents the sound value based on addition of the values for poles, lines, insulators, and guy wires. The sound value amounted to 2.741 million pesos for the five-kilometer section surveyed. The value for the entire 33 kilometers on this route was consequently estimated at 18.1 million pesos, 6.6 times as much. This is 14.0 percent lower than the corresponding figure of 21.0 million pesos as of the end of 1996 shown by the NPC. In other words, the finding of the sample survey by the study team is about 2.9 million pesos lower than the sound value as calculated by the NPC. This is because of the weight of rehabilitation costs. In the evaluation of sound value by the NPC, there would in effect be a need for more rehabilitation and repair costs, and the assessed value(NPC sound value) is therefore thought to be low. The rehabilitation and repair costs for the five-kilometer stretch are estimated at 3,497 million pesos. Addition of these costs to the current sound value (based on the study) yields the replacement cost new. This is lower than the cost of entirely new facilities. In the case of adoption of the replacement cost new, the requisite rehabilitation cost rate would amount to 56.1 percent. On this basis, the assessment for the whole 33 kilometers of this route would come to 41.1 million pesos, which is about the same as the figure of 39.4 million pesos in the NPC revaluation.

For the purchasing side, even purchase at sound value would entail a tremendous expenditure in rehabilitation costs. The buyer would end up purchasing at sound value and making rehabilitation expenditures as additional investment. To put the facilities in good condition will require funding in amounts close to the revaluation price offered by the NPC. The ECs would probably not be able to accept the revaluation price. The buyer should negotiate 10 –20 percent discount of sound value price for the purchase of the facility.

The NPC may be expected to take a tough line on the revaluation price in the interest of recovering its facility investment. There is also a possibility that it will take the line of equating the assets appraisal based on revenue with the sales price.

Field survey of 69 kV transmission facilities (10km) and study of the NPC appraisal

(Unit: pesos, %)

	5-km section surveyed	Total length (6.6 times)	Sound Value	NPC sound value	Comparison with the NPC sound value
1.Palo-Dorelco-Tacloban (33km)				(As of the end of 1996)	
Poles, insulators, guy wire anchors	1,364,900	9,008,340			
Power cable	1,226,000	8,091,600			
Other wires	150,800	995,280			
Total	2,741,000	18,095,000	18,095,000	21,033,000	0.86
2.Wright-Calbayog (68km)		Total (13.6times)		(As of the end of 1996)	
Poles, insulators, guy wire anchors	2,433,300	33,092,880			
Power cable	1,722,000	23,419,200			
Other wires	214,000	2,910,400			
Total	4,369,000	59,422,000	59,422,000	30,144,000	1.99

Rehabilitation cost

(Unit:Pesos,%)

	Rehabilitation cost (5km section surveyed)	Total rehabilitation cost
1. Palo-Dorelco-Tacloban	3,496,700	23,778,000
2. Wright-Calbayog	4,517,100	61,433,000

Comparison of sound value, replacement cost new, NPC sound value, and revaluation price

(Unit: pesos)

	Sound Value(A)	NPC Sound Value(B)	Rehabilitation cost(C)	Replacement cost new(D) A+C	NPC revaluation cost(E)
1. Palo-Dorelco-Tacloban	18,095,000	21,033,000	23,078,000	41,173,000	39,428,000
2. Wright-Calbayog	59,422,000	30,144,000	61,433,000	120,855,000	74,541,000

(3) Wright-Calbayog case

The sound value of the Wright-Calbayog route was estimated at 59.4 million pesos, or 97.1 percent higher than the NPC estimate of 30.11 million pesos. The major reasons for this is that, of the 55 pole installations, 11 use two poles in an H-shaped configuration, and 12 have not only this H configuration but also an additional pole for support. These two- and three-pole structures made the sound value derived from actual survey much higher than the NPC figure. The survey suggested that the cost calculation rested on addition based on standard costs, without consideration of the individual facilities.

Constructed in 1989, the Wright-Calbayog route is fairly new, but it has suffered from poor maintenance and the effects of typhoons. The rehabilitation and repair cost is estimated at 82.2 million pesos. Sound value estimated 59.4 million pesos. This is 98 percent higher than the figure of 30.1 million pesos given by the NPC. Even if the 68-kilometer Wright-Calbayog route were purchased at the sound value, subsequent rehabilitation would call for an additional investment of 61.4 million pesos. This is as same as the figure of 74.5 million pesos proposed by the NPC as the revaluation price.

(4) Points related to the price negotiations

The NPC appraisals are essentially appropriate as far as sound value is concerned. The following observations can be made in this connection.

1) The field surveys in the two cases revealed that the NPC appraisal of sound value was basically appropriate. The gap between our appraisal and that of the NPC was about 14 percent for Leyte. The Wright-Calbayog route should negotiate 15 –20 percent discount of sound value price for the purchase of the facility.

2) The gap was about 97 percent for Samar, but the widening was apparently caused by the simplified calculation method employed by the NPC.

3) The NPC made simple calculations for totals based on standard formulas, and there was some roughness.

4) The NPC is considering negotiation for the market price as the sales price for the 69 kV transmission facilities. It apparently is not looking to make a profit on the transaction.

5) The NPC has outside parties evaluate its assets once every four years. This year (1997) is one for such evaluation (in other years, the NPC makes its own evaluation). The NPC therefore is in possession of in-depth evaluation data as well as calculation techniques. It will have a very strong hand in negotiations with the ECs.

6) The ECs should promptly conduct their own research and investigation of the transfer in order to accumulate know-how of use in the negotiations.

7) The NPC intends transfer and sale of the 69 kV transmission facility assets within the next two years. It has become more positive-minded about the sale as compared to six months previously. The key factor here is the influence of privatization in accordance with the Omnibus Bill. Ordinary private enterprises have been included within the scope of prospective buyers. In addition, power-related companies are establishing firms that specialize in services for transmission facilities, and these are also prospective buyers.

8) Difficulty in finding other buyers would work to the advantage of the ECs.

9) In the Samar case, the NPC recognizes that transfer would be impossible without extensive rehabilitation over the years 1997 - 1999 due to the poor maintenance situation. Improvements on both islands, and mainly Samar, are to be the subject of additional investments of 13.6 million pesos in 1997 and 39.5 million pesos in 1998, 53.1 million pesos in total (the two years for which budget figures are available). This will also drive up the purchasing price. If the ECs take over the existing facilities as is and carry out the improvement themselves, the cost of the work could be reduced by the gap in the aspect of personnel costs at the least. However, it would be unrealistic to transfer the facilities until after performance of improvement by the NPC.

10) The negotiation should be based on the sound value price.

(5) NPC weaknesses

The NPC believes that the need for transmission facility repair is greater on Samar than on Leyte. In fact, the 69 kV transmission facilities on Samar are in a state of advanced deterioration for their age due to poor maintenance. The following factors at work in the 1980s can be cited behind this situation: 1) lagging investment in the social capital on Samar due to its opposition to the contemporary administration, 2) inability to perform repairs due to the high level of NPA activity, and 3) extensive typhoon damage due to location on the Pacific. This point should be brought up in price negotiations with the NPC. Evaluation of real estate is not included.

9.2 Investigation of 69 kV T/L Business Transfer Cost and its Impact to Long-range Planning

(1) Study of 69 kV T/L business transfer cost and operating income and expenditures

First, a calculation will be made of the transfer price in the event of transfer of the 69 kV T/L transmission business to the ECs as well as the annual O&M cost and the O&M cost over the next ten years(the business start 2001year). Then, a calculation will be made of investment for facility rehabilitation over the next ten years. The new T/L transmission Cooperative have to finance for purchase of T/L assets. There are three types of finance scheme, one is borrowing from bank, the two is leasing method and the three is installation method. If the price applied in transfer from the NPC is high, the cost of operation of newly established transmission services will also be high. A study will be reveal a impact of T/L transmission business cost to ECs. Next, there will be a calculation of business income and expenditures of the 11 ECs combined into a single new EC, and of the same over the next ten years. This will be followed by a calculation of the 69 kV T/L transmission business cost at the new EC as the receiver of the transfer from the NPC and independent operator of the business. The findings will provide the basis for a final study of business income and expenditures at the new EC. The 69 kV T/L transmission business cost will be calculated as the transmission operating cost of the new EC, and an analysis will be made of the degree of impact exerted on earnings by the cost burden associated with this cost. Lastly, a study will be made of the business scheme of the new EC. The analytical procedure may be summarized as follows.

Analysis of the cost of transfer of the 69 kV T/L transmission business from the NPC

① Investigation of operating and reinvestment costs for the same business

② Focus on the study of T/L transmission business cost

A) Case study that T/L transmission facilities financed by a bank or financial institution

B) Case study of leasing method

C) Case study of installment method

D) Case study that T/L transmission facilities is able to purchase 20 percent discount price of Sound value price

③ Addition of the business cost to the new EC, and final study of the business income and expenditures of the new EC

④ Investigation of the business scheme of the new EC

(2) High cost burden of transfer of 69 kV T/L

There are two types of cost related to the transfer. The first is the revaluation price. Naturally, the NPC regards this revaluation price (i.e., the value upon the execution of rehabilitation) as the sales price. The second is the sound value. The ECs will enter the price negotiations taking the sound value as the standard.

Inclusive of the investment of 53 million pesos for repairs over the years 1997 - 1998, the revaluation price comes to 901 million pesos. The sound value is 449 million pesos. In any case, the transfer of the 69 kV T/Ls will be very high and impose a heavy burden on the 11 ECs. In 1996, the combined used capital of the 11 ECs came to 1,392 million pesos. Relative to this figure, the aforementioned revaluation price is equivalent to 64.7 percent, and the sound value, to 32.2 percent. The corresponding levels relative to the combined 652 million pesos in fixed assets of the 11 ECs are 138.2 percent, and 68.9 percent, respectively.

Considering the cost burden with reference to the 1996 EC cash flow of 42.4 million pesos, the revaluation price would amount to 21.3 years worth of cash flow on the same level. The corresponding figures for the sound value are 10.6 years, respectively. Because the ECs could not bear such a burden, electricity rates would have to be hiked. It can also be noted that the 11 ECs have combined borrowings of 845 million pesos, and that payment of the revaluation price would require additional borrowings equivalent to about 100percent of this amount. Even if obtained at a low interest rate of 12 percent, the yearly interest payment on such borrowings would come to 110 million pesos in the case of application of the revaluation price. Such an interest payment would be about twice as large as the yearly cash flow. Even if the sound value were applied, the interest burden would be about as high as the yearly cash flow. These data underscore the magnitude of the cost associated with the transfer. The transmission of transmission is based on a Sound value price.

Cost burden of 69 kV T/L transfer

(Unit: millions of pesos, %)

69 kV T/L transfer	Revaluation price (A)	Sound Valve(B)
901	848 + 53 1997-1998 901 investment	396 53 Sound value (B) 449 ×depreciation(50%)
Total capital of 11 ECs 1,392 Total fixed assets of 11 ECs 652	64.7% 138.2%	32.3% 68.9%
Cash flow Post-tax profit 6.3 Depreciation 36.1 42.4	21.3 Years	10.6 Years
Total borrowings 845 Interest burden (12%)	106.6% - 108	53.1% - 53.9

9.3 Facility Transfer and Operating Cost

A) T/L transmission facilities financed by the NEA or a financial institution

In this case, the guideline for the cost of transfer of the 69 kV T/L business would be the sound value (the lowest purchasing price). The sound value of the facilities is estimated at 449 million pesos in terms of the 2001 transfer price. If this price were paid entirely with funds borrowed at an annual interest rate of 12 percent, the annual interest payment would be extremely high, in the area of 53.9 million pesos. The annual depreciation cost (assuming straight-line depreciation at an annual rate of 3.3 percent) would amount to 15.0 million pesos in the initial year and the same (15.0 million pesos) in 2010.

It was assumed that the business would be operated by a staff of 70, and that personnel costs would rise at an annual rate of 3 percent from the base level of 8,000 pesos monthly per employee in 1996. As is clear from the table below, the total annual personnel costs in 2001 subsequent to the transfer were estimated at 7.8 million pesos. Administrative costs were estimated to be 0.8 times as high as personnel costs. Investment for facility rehabilitation and other types of replacement and updating was also figured as cost. The annual depreciation cost was included as well. When the sound value price is applied, business operating cost comes to 102.7 million pesos (including a profit of 4 percent) in 2001, the initial year. This cost would be assumed by the new cooperative created by consolidating the 11 ECs. In Comparison to the NPC delivery charge, the T/L operation cost per kWh would increase to 0.11 pesos in 2001, but decline to 0.08 pesos in 2010. The conditions applied in this case were as follows.

① The 69 kV T/L facility transfer cost will be based on the sound value, i.e., 449 million pesos..

② Depreciation will be carried out over a period of 30 years and by the straight-line method, with the annual cost coming to 14.97 million pesos.

③ The interest rate on borrowings will be 12 percent, for a payment of 53.9 million pesos in 2001. The share of the total cost occupied by interest payment will be 55 percent in 2001 and 46 percent in 2010.

④ Long-term borrowings will be repaid at the rate of 5 million pesos annually.

⑤ The T/L cooperative will have a staff of 70 and pay them an average wage of 8,000 pesos per month (1996 basis), with hikes of 3 percent annually.

⑥ Administrative costs will be 0.8 times as high as personnel costs.

⑦ Annual maintenance cost will be 12 million pesos (based on actual NPC costs over the last six years).

⑧ Figures for capital investment are estimates of rehabilitation investment based on the field study of T/L facilities.

⑨ The total operating cost equals the sum of depreciation cost, interest payments, personnel costs, administrative costs, maintenance cost, and depreciation cost on additional investment.

⑩ The profit rate will be 4 percent.

⑪ Total revenue equals the sum of total cost and profit.

69KV TL facility Cooperative (A) : Case1-Borrowing

Purchase at sound value

(Unit: thousand pesos)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1. Revenue	102,723	104,926	107,129	109,464	111,274	113,196	115,234	117,396	119,687	122,112
2. Costs										
1) Maintenance	15,315	16,081	16,885	17,729	18,616	19,547	20,524	21,550	22,628	23,759
2)Personnel cost(70 employees) -8,000 pesos per month per employee in 1996 -Increase at a rate of 3 percent annually	7,790	8,024	8,265	8,513	8,768	9,031	9,302	9,581	9,869	10,165
3) Administrative costs (personnel costsx0.8%)	6,232	6,419	6,612	6,810	7,014	7,225	7,442	7,665	7,895	8,132
69KV facility fixed assets balance (year-end)	434,033	419,067	404,100	389,133	374,167	359,200	344,233	329,267	314,300	299,333
4) Depreciation cost (3.3%)	14967	14,967	14,967	14,967	14,967	14,967	14,967	14,967	14,967	14,967
Capital investment	17,664	42,319	44,435	46,657	29,804	31,294	32,859	34,502	36,227	38,038
5) Depreciation (Capital investment *0.033)	589	1,999	3,481	5,036	6,029	7,072	8,168	9,318	10,525	11,793
6) Interest payments on borrowings (12%) (balance of 449 million pesos)	53,880	53,400	52,800	52,200	51,600	51,000	50,400	49,800	49,200	48,600
3. Total costs (1)+2)+3)+4)+5)+6))	98,772	100,890	103,009	105,254	106,994	108,842	110,802	112,880	115,083	117,415
4. Profit (revenue - total cost = total cost*0.04)	3,951	4,036	4,120	4,210	4,280	4,354	4,432	4,515	4,603	4,697
5. Sold energy (MWh)	403,564	439,360	480,518	521,884	566,035	614,626	663,216	715,648	772,225	833,275
6. Average power rate (P/kWh)	0.25	0.24	0.22	0.21	0.20	0.18	0.17	0.16	0.15	0.15
7. NPC Delivery Charge (P/kWh)*1	0.14	0.15	0.16	0.17	0.18	0.18	0.19	0.20	0.21	0.22
8. Net cost	0.11	0.09	0.06	0.04	0.02	-0.00	-0.02	-0.04	-0.06	-0.08

*1: The inflation rate in the Philippines was 10.1 percent over the years 1987 - 1995 and is anticipated by the government to decrease to 5 percent in 1997 and to be in the range of 6.5 - 7.5 percent in 1998. As such, the study team is predicting that the NPC delivery charge will increase by 5 percent over the coming years, seeing that its rates increased by an average of 4.9 percent annually over the period 1991 - 1996.

B) Leasing case

This case assumes that the T/L facility operating cooperative will conclude a 20-year leasing contract with a leasing company. Because of the short term and the management fee, leasing would be more costly than borrowing over the long term. Over the short term, however, the operating cost for the first five years would be lower because the interest cost would be based on the 20-year average cost. In 2001, the leasing company's interest burden would amount to 28.3 million pesos. This would be lower than in the case of borrowing by the T/L cooperative (i.e., Case 1). More specifically, in the case of borrowing by the T/L cooperative, the interest burden would hit 53.9 million pesos in 2001, the initial year. Over the first ten years, operating costs would be lower under the leasing method. For the first five years, for example, the operating cost per kWh in leasing would be 0.03 - 0.04 pesos cheaper than in Case 1. For the T/L cooperative, a low operating cost in the initial period would facilitate subscription by the ECs. In addition, as a financial specialist, the leasing company would have expertise in fund management and depreciation, and this would be linked to cost reduction in such areas.

It was also assumed that the leasing company would borrow at an interest rate of 12 percent. Naturally, funds would be raised from the NEA. The NEA would have to carry out the leasing business and support the T/L cooperative; it would be impossible for a private leasing business firm to get financing at such low interest rates. The conditions applied in this case are as follows.

① The T/L cooperative and the leasing company (or leasing division instituted by the NEA) will conclude a 20-year leasing contract.

② The T/L facilities will be owned by the leasing company, and depreciation will be carried out by the straight-line method over 20 years. The annual depreciation cost will be 22.5 million pesos (in this case, the depreciation term would be ten years shorter than in that of borrowing by the T/L cooperative).

③ The leasing company will receive financing from the NEA at an interest rate of 12 percent with payment over 20 years. The annual burden of payment would therefore amount to 28.3 million pesos. Naturally, the NEA could also operate the leasing enterprise.

④ The leasing company will bill the T/L cooperative at an amount equivalent to 10 percent of the annual interest cost, as a business operation fee. The business operating cost of it amounts to 2.8 million pesos annually.

⑤ The T/L cooperative will pay 61.9 percent of its total revenue as a leasing fee (in 2001). This leasing fee will include depreciation cost, interest cost, and the operating cost of the leasing company.

⑥ The T/L cooperative will itself make investment for rehabilitation and maintenance every year.

⑦ Leasing would bring a lower operating cost for the first ten years, but a higher one over the longer term.

69 kV TL facility Coop (B) : Case 2 - Leasing case

Purchase at sound value

(Unit: thousand pesos)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
69kV facility fixed assets balance (year-end)	426,550	404,100	381,650	359,200	336,750	314,300	291,850	269,400	246,950	224,500
1. Depreciation cost (20years, 5%)	22,450	22,450	22,450	22,450	22,450	22,450	22,450	22,450	22,450	22,450
2. Interest payments on borrowings (12%) (449million pesos)	53,880	51,186	48,492	45,798	43,104	40,410	37,716	35,022	32,328	29,634
2.b Average interset cost	28,287	28,287	28,287	28,287	28,287	28,287	28,287	28,287	28,287	28,287
2.c Leasing corp. management fee (Average interest cost *0.1)	2,829	2,829	2,829	2,829	2,829	2,829	2,829	2,829	2,829	2,829
2.d Leasing corp. charge	53,566	53,566	53,566	53,566	53,566	53,566	53,566	53,566	53,566	53,566
3. Personnel cost(70 employees) -8,000 pesos per month per employee in 1996 -Increase at a rate of 3 percent annually	7,790	8,024	8,265	8,513	8,768	9,031	9,302	9,581	9,869	10,165
4. Administrative costs (personnel costs ×0.8)	6,232	6,419	6,612	6,810	7,014	7,225	7,442	7,665	7,895	8,132
5. Maintenance	15,315	16,081	16,885	17,729	18,616	19,547	20,524	21,550	22,628	23,759
6. Capital investment	17,664	42,319	44,435	46,657	29,804	31,294	32,859	34,502	36,227	38,038
7. Depreciation ((6)*0.033)	589	1,999	3,481	5,036	6,029	7,072	8,168	9,318	10,525	11,793
8. Total costs (2d+3+4+5+7)	83,492	86,089	88,808	91,653	93,993	96,441	99,001	101,679	104,482	107,414
9. Profit((8)*0.04)	3,340	3,444	3,552	3,666	3,760	3,858	3,960	4,067	4,179	4,297
10. Revenue	86,831	89,533	92,360	95,319	97,753	100,299	102,961	105,747	108,662	111,711
5. Sold energy (MWh)	403,564	439,360	480,518	521,884	566,035	614,626	663,216	715,648	772,225	833,275
6. Average power rate (P/kWh)	0.22	0.20	0.19	0.18	0.17	0.16	0.16	0.15	0.14	0.13
7. NPC Delivery Charge (P/kWh)	0.14	0.15	0.16	0.17	0.18	0.18	0.19	0.20	0.21	0.22
8. Net cost	0.07	0.05	0.03	0.02	-0.00	-0.02	-0.04	-0.06	-0.07	-0.09

C) Transfer in 20-year installments

In this case, the T/L facilities would be transferred not all at once, but in installments over a period of 20 years. First, the T/L cooperative would conclude a sales contract with the NPC, stipulating transfer in installments over this period. The T/L cooperative would pay the depreciation cost only for that portion of the facilities already transferred. Consequently, the initial burden of depreciation cost would be light.

The interest burden would be particularly small for the first five years because it would be necessary to raise additional funds only for the additional transfer of facilities each year. If it is to utilize all of the T/L facilities, the T/L cooperative could possibly have to pay a fee for use of facilities not yet transferred, but this contingency was excluded from consideration here. The T/L cooperative would be responsible for all investment for facility maintenance and rehabilitation. Because it would assume this burden, the T/L cooperative could be regarded as, in effect, shouldering part of the facility leasing cost. An additional drawback would be the procedural complexity and cost associated with transfer of facilities each year.

For the T/L cooperative, the average cost per kWh would be much lower due to the alleviation of the interest and depreciation burden. Over the second half of the term, the cost burden would swell as the extent of transfer increases, but the expanded sales should keep the average cost per kWh on the same level or only slightly higher. Furthermore, when allowance is made for the discounted NPC delivery charge, the net cost at the start would be negative. For this reason, there would be absolutely no burden on the ECs. The conditions applied in this case are as follows.

① The T/L facilities will be transferred from the NPC not all at once but in installments over a period of 20 years.

② The T/L cooperative will not have to pay a fee for use of facilities not yet transferred.

③ The T/L cooperative will be responsible for all investment for maintenance and rehabilitation of all T/L facilities, right from the start.

④ Transfer of another installment every year will complicate matters and drive up procedural costs.

69KV TL facility Cooperative (C) : Case 3 - Installment - 20 years

Purchase at sound value

(Unit: thousand pesos)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1. Revenue	34,703	40,985	47,392	53,931	59,945	66,071	72,313	78,678	85,174	91,803
2. Costs										
1) Maintenance	15,315	16,081	16,885	17,729	18,616	19,547	20,524	21,550	22,628	23,759
2)Personnel cost(70 employees) ·8,000 pesos per month per employee in 1996 ·Increase at a rate of 3 percent annually	7,790	8,024	8,265	8,513	8,768	9,031	9,302	9,581	9,869	10,165
3) Administrative costs (personnel costs×0.8%)	6,232	6,419	6,612	6,810	7,014	7,225	7,442	7,665	7,895	8,132
69KV facility fixed assets balance (year-end)	22,450	44,900	67,350	89,800	112,250	134,700	157,150	179,600	202,050	224,500
4) Depreciation cost (3.3%)	748	1,497	2,245	2,993	3,742	4,490	5,238	5,987	6,735	7,483
Capital investment	17,664	42,319	44,435	46,657	29,804	31,294	32,859	34,502	36,227	38,038
5) Depreciation (Capital investment *0.033)	589	1,999	3,481	5,036	6,029	7,072	8,168	9,318	10,525	11,793
6) Interest payments on borrowings (12%) (balance of 449 million pesos)	2,694	5,388	8,082	10,776	13,470	16,164	18,858	21,552	24,246	26,940
3. Total costs (1)+2)+3)+4)+5)+6))	33,368	39,408	45,569	51,857	57,639	63,529	69,532	75,652	81,898	88,272
4. Profit (revenue - total cost = total cost*0.04)	1,335	1,576	1,823	2,074	2,306	2,541	2,781	3,026	3,276	3,531
5. Sold energy (MWh)	403,564	439,360	480,518	521,884	566,035	614,626	663,216	715,648	772,225	833,275
6. Average power rate (P/kWh)	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
7. NPC Delivery Charge (P/kWh)	0.14	0.15	0.16	0.17	0.18	0.18	0.19	0.20	0.21	0.22
8. Net cost	-0.06	-0.06	-0.06	-0.06	-0.07	-0.08	-0.08	-0.09	-0.10	-0.11

D) 20-percent discount on the sound value

This case is based on that of borrowing (Case 1). The question is the cost-reducing effect in the event of transfer of the T/L facilities at a price that is 20 percent less than the sound value. It is estimated that the discount would yield a cost reduction of about 14 percent, or 0.03 pesos per kWh (2001), on the average. In terms of the net cost, this would result in arrival of the break-even point (even balance) one year early. In light of the need for borrowing in large sums and the accompanying increase in the interest burden, the reducing effect would basically be limited to operating cost. The method would probably not be viable unless there were a highly efficient scheme for raising funds.

The calculation result is shown in Appendix 9.3.

9.4 Premises in Use of the Long-Term Management Planning Model

- Forecast the business of all ECs over the next ten years -

NRI's long-term management planning model was used to forecast the business of all ECs over the next ten years. This forecast applied the procedure and conditions noted below as regards items such as income and expenditure, financial statements, and borrowings. The following section also sets forth the application standards and reasons for particularly important items, i.e., profit, financial items, and account titles.

(1) Forecast of sales revenue

Sales revenue was viewed as consisting of rate revenue, reinvestment funds (equivalent to 5 percent of rate revenue), and "other" revenue. The forecast was made for the ten-year period 1997 - 2006. In addition, breakdowns are presented for rate revenue categories (residential, commercial, etc.). For power sales, values are presented in both monetary terms and kilowatt-hours. As viewed from the ECs standpoint, the subject is gross (crude) sales revenue, i.e., the sum of sales revenue and reinvestment.

The handling of reinvestment funds, which come to 5 percent of the rate revenue, in accounting is as follows.

Ordinary accounting

	Debits	Credits
Accounts due	****	
Cash	****	
Sales revenue		****

Accounting method for reinvestment funds

	Debits	Owned capital (pure assets)
Sales	****	
Reinvestment funds		****

The reinvestment funds amount to 5 percent of the rate revenue and are transferred directly as funding for net assets. In accounting, they are consequently posted on the earning side as special profit, and act to increase other net assets. In NRI's long-term management planning model, which is based on gross sales revenue, reinvestment funds equivalent to 5 percent of revenue are included in current profit. This standard was applied because reinvestment funds are used for capital investment. Subtraction of the reinvestment funds from gross sales revenue yields the net sales revenue.

(2) Breakdown of prime cost

For the prime cost (i.e., the cost of purchased power), the following categories were applied.

- Power purchase cost
- Distribution operation cost
- Distribution maintenance cost

In other words, these two distribution costs (operation and maintenance) were added to the power cost per se. But 50 percent of two distribution costs were deducted as the personnel expenses.

(3) Sales administration costs and other costs

The breakdown of sales administration costs and other costs is as follows.

- Consumer accounts
- Administrative and general costs
- Depreciation costs
- Interest on long- and short-term debt

Annual rates of increase were set in accordance with the rates of sales increase. Annual rate of wage increase was set 3 percent. And number of employees were set 3 percent until 2003 year, after that it set 5 percent. 50 percent of consumer account was also deducted as the personnel expenses. Personnel expenses were adjusted by the administration and general cost finally. It's adjusted figures that was 80 percent in 1996 fiscal year.

(4) Depreciation costs and term

It was assumed that depreciation would be carried out by the fixed-amount method and over a period of 30 years for buildings and distribution facilities. As a result, the yearly depreciation rate was put at 3.3 percent.

(5) Non-operating revenue and costs

The following procedure was adopted for non-operating revenue and cost. The yearly rate of increase in non-operating revenue was set at 3 percent based on the 1996 figure. The ratio of non-operating cost to non-operating revenue was based on the actual figure of 52.9 percent recorded in 1996 (the average for the two years 1995 and 1996 being 32.2 percent).

(6) Capital investment plans

Capital investment can be estimated by estimating the marginal capital investment ratio (capital coefficient) from the ratio of capital investment to increased revenues over the last five years among the seven major companies. However, we estimated investment plans based on the RE plans. Naturally, the GDP growth rate was also taken into account.

Privatization is anticipated to intensify competition in the power sector. The rate of increase in sales was put at about 12.2 percent, on the assumption that some industrial customers could be lost to other suppliers. Consequently, the rate of increase in capital investment was also set on a low level.

(7) Entry standards for financial statements

In utilization of NRI's long-term management planning model, a partial unification was made of account titles for the P/L and financial statements of ECs. Cash and deposits were viewed as the sum of cash, deposits, and loan funds (general funds, loan funds, house wiring funds, and temporary cash investment). Allowances for uncollectable accounts were subtracted from accounts receivable, and other credits were added to the same.

For inventory, the study employed the sum total for parts, distribution supplies, meters and other supplies, distribution lines, house wiring, fuel stock, and other inventory items.

The category of investment and others was viewed as consisting of sinking fund-loan amortization, sinking fund-reinvestment, other property and investment, and other current and accrued assets.

Equity and margin were distinguished as follows. Fees for membership in cooperatives were regarded as capital. Accumulated margins were added to other equities and margins and posted as other reserves.

As for long-term debt, long-term borrowings from the NEA (funding for power facility construction) and deferred interest on the same were regarded as long-term borrowings. Accounts payable consisted of accounts payable for purchase of power and fuel. Consumer deposits and payments due that are greatly in arrears were regarded as other fixed debt.

(8) Financial standards in long-term management planning

Determination of long-term management plans over the next ten years requires a forecast of the proper scale of requisite cash and deposits, inventory, accounts receivable arising from transactions, and debt associated with purchasing. The standards applied are set with consideration of the past trend and the business characteristics of the ECs. Here, annual revenue was used as the standard. For example, the combined cash and deposits of the 11 ECs came to 9.4 percent of their combined annual turnover (i.e., 1.12 months worth of the monthly turnover). As such, the corresponding ratio of cash and deposits over the next ten years was set at 8.5 ~9.0 percent. The major items are as follows.

- Cash and deposits came to 9.4 percent of the annual turnover in 1996, and the corresponding forecast rate was set at 8.5 percent until 2004 and at 9.0 percent over the years.
- Accounts receivable came to 14.2 percent of the annual turnover in 1996, and the corresponding forecast rate was 12.0 percent until 2003 and set at 13.0 and 14.0 percent over the years.
- Inventory came to 10.8 percent of the annual turnover in 1996, and the corresponding forecast rate was 9.0 percent until 2003 and set at 10.0 percent over the years.
- Accounts payable came to 5.8 percent of the monthly turnover in 1996, and the corresponding forecast rate was 7.0 percent until 2003 and set at 6.0 percent over the years.
- Interest rates for both long- and short-term loans were set at 12 percent.
- The rate of repayment of long-term borrowings was set at 8.7 percent of the outstanding balance in the previous year.
- Interest on cash and deposits was set at zero.
- The annual rate of increase in other fixed debt was set at 3.0 percent.

9.5 Business Plans for the New EC (aggregate of the 11 ECs in area VIII)

(1) Low growth rate of revenue and power cost hike

A forecast was made of the business of the new EC (aggregate total for the 11 ECs in Area VIII) over the ten-year period 1997 - 2006. Tariff revenue was forecast to increase at an annual rate averaging 13.1 percent, for a nominal 3.4-fold increase over the period in question. This is because power sales prices would be driven up by the rise in the price of purchased power. However, electricity sales are anticipated to increase by a factor of 3.12 over the period and reach 614,626 MWhs, for an annualized growth rate of only 12 percent. Along with the privatization of state utilities, the power industry cannot look forward to growth rates in excess of 20 percent, and the ECs would not be immune to this influence. The main constituents of prime cost are purchased power, distribution operation, and distribution maintenance. For the forecast, the (average) prime cost rate over the period in question was set at 74.0 percent. Although there is some margin for rationalization of distribution O&M costs, it would be extremely difficult to cut the rate of power purchasing cost, which accounts for most of the prime cost, relative to revenues.

Cost breakdown

(Unit:million pesos, %)

	1996	1997	1998	19999	2000	2001	2002	2003	2004	2005	2006
Revenue	799.8	879.8	1231.8	1293.3	1422.7	1564.9	1721.4	1893.6	2082.9	2291.2	2520.4
Power purchasing costs	553.8	620.4	867.9	911.3	1002.4	1102.6	1212.9	1334.2	1467.6	1614.4	1775.8
Operation and maintenance costs(excluding personnel costs, which account for 50%)	28.0	30.8	43.1	45.3	49.8	54.8	60.2	66.3	72.9	80.2	88.2
Prime cost total	581.79	651.2	911.01	956.57	1052.2	1157.4	1273.1	1400.5	1540.5	1694.6	1864.0
Prime cost rate	72.7	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0

Personnel costs were expected to rise by 3 percent a year. The number of employees was forecast to increase by 2 percent over the years 1997 - 2002 and by 3 percent over the years 2003 - 2006 (the latter increase owing to an increase in revenue). Because the total personnel cost is spread among the other cost items, it was assumed that personnel costs would amount to 50 percent as much as the respective costs of distribution operation, distribution maintenance (these two being prime cost constituents), and customer management in the residential segment. Any personnel cost difference (shortage) was deducted from general administration costs. For example, in 1996, personnel costs came to about 86 percent of the general administrative costs. It was estimated that general administrative costs and residential customer management costs would grow at a rate that was 1 percentage point lower than the rate of revenue growth, since these costs can be cut by rationalization of management. Actual data for 1996 show that level of administrative costs as percentage of net revenue, at 4.4 percent, was the highest after that of

Input Data

ECs VIII Sound Value
— Case Borrowing —

Revenue

		0 Year
Division	Unit	1996
Power Revenue	1000 P	799,839
Investment Fund	1000 P	36,046
Other Revenue	1000 P	26,934

		1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Division	Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Power Revenue	%	10.00	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Investment Fund	%	22.04	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Other Revenue	%	10.00	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00

Cost

		0 Year
Division	Unit	1996
Power Cost	%	72.7
Investment Fund	%	0
Other Cost	%	90

		1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Division	Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Power Cost	%	74.0	74.0	74.0	74.0	80.6	80.1	79.7	79.3	78.9	78.5
Investment Fund	%	0	0	0	0	0	0	0	0	0	0
Other Cost	%	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0

P/L Plan

		0 Year			1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Item	Unit	1996	Item	Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Number of Employees	Person	1,259	Number of Employees	Person	1,284	1,310	1,336	1,363	1,390	1,418	1,461	1,504	1,549	1,596
Wages per Employee	1000 P	108.0	Rate of Wage Increase	%	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Depreciation	1000 P	36,078												
	1000 P	0	Operation Cost Increase Rate 1	%	0	0	0	0	0	0	0	0	0	0
Consumers Account	1000 P	21,270	Operation Cost Increase Rate 2	%	9.0	39.0	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
A&G Cost	1000 P	14,103	Operation Cost Increase Rate 3	%	9.0	39.0	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Tax	1000 P	0	Tax Ratio	%	0	0	0	0	0	0	0	0	0	0
Other Cost	1000 P	0	Other Cost Increase Rate	%	0	0	0	0	0	0	0	0	0	0
Interest Received	1000 P	0												
			Dividends, ETC.	1000 P	0	0	0	0	0	0	0	0	0	0
Non-Operating Income	1000 P	11,395	Non-Operating Other Income	1000 P	11,700	12,100	12,500	12,900	13,300	13,700	14,100	14,500	15,000	15,400
Interest Paid	1000 P	36,671												
			Other Interest	1000 P	0	0	0	0	0	0	0	0	0	0
Non-Operating Cost	1000 P	6,033	Non-Operating Other Cost	1000 P	6,189	6,401	6,613	6,824	7,036	7,247	7,459	7,671	7,935	8,147
Current Profit	1000 P	18,363												
Special Profit	1000 P	0	Special Profit	1000 P	0	0	0	0	0	0	0	0	0	0
Special Loss	1000 P	0	Special Loss	1000 P	0	0	0	0	0	0	0	0	0	0
Corporate Tax	1000 P	0	Corporate Tax	%	0	0	0	0	0	0	0	0	0	0
Dividends	1000 P	0	Dividends per Share	P	0	0	0	0	0	0	0	0	0	0
Executive Bonuses	1000 P	0	Executive Bonuses	1000 P	0	0	0	0	0	0	0	0	0	0
Other External Expend.	1000 P	0	Other External Expenditures	1000 P	0	0	0	0	0	0	0	0	0	0

B/S input data

Item	Unit	0 Year 1996	Item	Unit	1 Year 1997	2 Year 1998	3 Year 1999	4 Year 2000	5 Year 2001	6 Year 2002	7 Year 2003	8 Year 2004	9 Year 2005	10 Year 2006
Cash and Deposit	1000 P	80,797	Ratio of Cash & Deposit to Rev.	%	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	9.0	9.0
Accounts Receivable	1000 P	122,350	Ratio of Receivable to Revenue	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	13.0	14.0	14.0
Inventories	1000 P	87,279	Ratio of Inventories to Revenue	%	9.0	9.0	9.0	9.0	9.0	9.0	9.0	10.0	10.0	10.0
Other Liquid Asset	1000 P	0	Ratio of Other Liquid Assets to Rev.	%	0	0	0	0	0	0	0	0	0	0
Ratio of Cash & Deposit	%	9.4												
Cash & Deposit Interest Rate	%	0	Cash and Deposit Interest Rate	%	0	0	0	0	0	0	0	0	0	0
Depreciation Assets(Acqu.)	1000 P	916,868	Depreciation Assets(New)	1000 P	70,000	92,500	80,000	57,300	65,100	61,300	61,900	58,900	72,900	68,400
Accumulated Depreciation	1000 P	265,258	Depreciation Ratio	%	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Land	1000 P	0	Land(New)	1000 P	0	0	0	0	0	0	0	0	0	0
Investment and Other	1000 P	225,810	Investment and Other(New)	1000 P	0	0	0	0	0	0	0	0	0	0
Defferd Assets	1000 P	224,541	Defferd Assets	1000 P	217,894	211,270	204,932	198,784	192,820	198,600	204,560	210,700	217,020	223,530
Accounts Payable	1000 P	50,199	Ratio of Accounts Payable to Rev.	%	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.0	6.0	6.0
Other Liquid Debt	1000 P	93,451	Ratio of Other Liquid Debt to Rev.	%	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Bill Discounted	1000 P	0	Bill Discounted	1000 P										
			Discount Rate	%										
Short-term Borrowings	1000 P	92,080												
Short-term Borrowings Interest	%	12.0	Short-term Borrowings Interest	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Reserve for Tax	1000 P	0												
Long-term Debt	1000 P	844,986	Long-term Borrowings(Returned)	1000 P	67,599	62,191	57,216	52,638	48,428	44,553	40,988	37,709	34,692	32,158
			Long-term Borrowings(New)	1000 P	0	0	0	0	0	0	0	0	0	
Long-term Debt Interest	%	12.0	Long-term Debt Interest	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Corporate Bonds	1000 P	0	Corporate Bonds(New)	1000 P										
			Corporate Bonds(Redemption)	1000 P										
Corporate Bonds Interest	%	0	Corporate Bonds Interest	%										
Other Fixed Debt	1000 P	138,998	Other Fixed Debt	1000 P	143,000	147,000	151,000	155,000	160,000	164,000	169,000	174,000	185,000	190,000
Reserves	1000 P	6,036	Reserves	1000 P										
Capital	1000 P	1,364	New Shares	1000 P										
Number of Shares Issued	1000 S.	272.8	New Issued Par Value	1000 S.										
Par Value	P	5	Par Value	P	0	0	0	0	0	0	0	0	0	0
Reserve for Capital	1000 P	0	New Issued Public Offering	1000 S.			0							
Reserve for Profit	1000 P	0	Share Price(Public Offering)	P										
Other Reserve	1000 P	165,273	Share Split	1000 S.										

Revenue (1)

ECs VIII Long-Range Management Planning (1997-2006 Year)
—Case Borrowing —
- Sound Value -

Item	0 Year	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Revenue	862,819	953,441	1,334,817	1,401,558	1,541,714	1,695,885	1,865,474	2,052,021	2,257,223	2,482,946	2,731,240
Power Revenue	799,839	879,823	1,231,752	1,293,340	1,422,674	1,564,941	1,721,435	1,893,579	2,082,936	2,291,230	2,520,353
Investment Fund	36,046	43,991	61,587	64,666	71,133	78,246	86,071	94,678	104,145	114,560	126,016
Other Revenue	26,934	29,627	41,478	43,552	47,908	52,698	57,968	63,765	70,141	77,156	84,871
Revenue(%)											
Power Revenue	92.7	92.3	92.3	92.3	92.3	92.3	92.3	92.3	92.3	92.3	92.3
Investment Fund	4.2	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Other Revenue	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Power Cost	605,724	677,734	948,827	996,268	1,095,895	1,308,771	1,431,041	1,566,571	1,714,896	1,877,221	2,054,861
Power Cost Rate	70.2	71.1	71.1	71.1	71.1	77.2	76.7	76.3	76.0	75.6	75.2
Power Cost	581,483	651,069	911,497	957,071	1,052,778	1,261,342	1,378,870	1,509,182	1,651,769	1,807,781	1,978,477
Investment Fund	0	0	0	0	0	0	0	0	0	0	0
Other Cost	24,241	26,665	37,331	39,197	43,117	47,428	52,171	57,388	63,127	69,440	76,384
Gross Profit	257,095	275,707	385,990	405,290	445,819	387,114	434,433	485,451	542,327	605,725	676,379
Gross Profit Rate	29.8	28.9	28.9	28.9	28.9	22.8	23.3	23.7	24.0	24.4	24.8
Power Revenue	218,356	228,754	320,256	336,268	369,895	303,599	342,566	384,396	431,168	483,450	541,876
Investment Fund	36,046	43,991	61,587	64,666	71,133	78,246	86,071	94,678	104,145	114,560	126,016
Other Revenue	2,693	2,963	4,148	4,355	4,791	5,270	5,797	6,376	7,014	7,716	8,487

Revenue (2)

Item	0 Year	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Operation Costs	207,423	207,975	235,655	250,628	268,512	287,845	308,469	332,779	358,707	387,282	418,066
(Operation Costs Rate)	24.04	21.81	17.65	17.88	17.42	16.97	16.54	16.22	15.89	15.6	15.31
Wages	135,972	145,606	155,982	167,031	178,927	191,595	205,228	222,024	239,986	259,525	280,769
	0	0	0	0	0	0	0	0	0	0	0
Consumers Account	21,270	23,184	32,226	33,515	36,532	39,819	43,403	47,309	51,567	56,208	61,267
A & G Cost	14,103	15,372	21,367	22,222	24,222	26,402	28,778	31,368	34,192	37,269	40,623
Depreciation	36,078	23,813	26,080	27,859	28,831	30,028	31,060	32,077	32,962	34,280	35,406
(Business Tax)	0	0	0	0	0	0	0	0	0	0	0
(Others)	0	0	0	0	0	0	0	0	0	0	0
Opearting Profit	49,672	67,732	150,335	154,662	177,307	99,270	125,964	152,672	183,620	218,443	258,313
(Operating Profit Rate)	5.76	7.1	11.26	11.03	11.5	5.85	6.75	7.44	8.13	8.8	9.46
Non-Operating Income	11,395	11,700	12,100	12,500	12,900	13,300	13,700	14,100	14,500	15,000	15,400
Interest Received	0	0	0	0	0	0	0	0	0	0	0
Non-Operating Other income	11,395	11,700	12,100	12,500	12,900	13,300	13,700	14,100	14,500	15,000	15,400
Non-Operating Costs	42,704	121,727	129,125	134,458	134,459	137,486	145,224	151,166	158,415	165,700	166,229
Interest Expense	36,671	115,538	122,724	127,845	127,635	130,450	137,977	143,707	150,744	157,765	158,082
Short-Term Debt Interest	0	18,196	33,169	45,455	51,836	60,715	73,821	84,683	96,442	107,806	112,135
Long-Term Debt Interest	0	97,342	89,555	82,391	75,799	69,735	64,156	59,024	54,302	49,958	45,947
Corporate Bound Interest	0	0	0	0	0	0	0	0	0	0	0
Non-Operating Other Costs	6,033	6,189	6,401	6,613	6,824	7,036	7,247	7,459	7,671	7,935	8,147
Current Profit	18,363	-42,295	33,310	32,703	55,747	-24,916	-5,560	15,605	39,705	67,743	107,484
(Current Profit Rate)	2.13	-4.44	2.5	2.33	3.62	-1.47	-0.3	0.76	1.76	2.73	3.94
Special Profit	0	0	0	0	0	0	0	0	0	0	0
Special Loss	0	0	0	0	0	0	0	0	0	0	0
Pretax Profit	18,363	-42,295	33,310	32,703	55,747	-24,916	-5,560	15,605	39,705	67,743	107,484
(Pretax Profit Rate)	2.13	-4.44	2.5	2.33	3.62	-1.47	-0.30	0.76	1.76	2.73	3.94
Reserve for Corporate Tax	0	0	0	0	0	0	0	0	0	0	0
Net Profit	18,363	-42,295	33,310	32,703	55,747	-24,916	-5,560	15,605	39,705	67,743	107,484
(Net Profit Rate)	2.13	-4.44	2.5	2.33	3.62	-1.47	-0.3	0.76	1.76	2.73	3.94
Dividends	0	0	0	0	0	0	0	0	0	0	0
Executive Bonuses	0	0	0	0	0	0	0	0	0	0	0

B/S Plan

Item	0 Year	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Liquid Assets	290,426	281,265	393,771	413,460	454,806	500,286	550,315	605,346	711,025	819,372	901,309
Cash and Deposit	80,797	81,042	113,459	119,132	131,046	144,150	158,565	174,422	191,864	223,465	245,812
Accounts Receivable	122,350	114,413	160,178	168,187	185,006	203,506	223,857	246,243	293,439	347,612	382,374
Inventories	87,279	85,810	120,134	126,140	138,754	152,630	167,893	184,682	225,722	248,295	273,124
Other Liquid Assets	0	0	0	0	0	0	0	0	0	0	0
Fixed Assets	877,420	923,607	990,027	1,042,168	1,070,637	1,105,710	1,135,950	1,165,773	1,191,710	1,230,330	1,263,323
Depreciation Assets(Book)	651,610	697,797	764,217	816,358	844,827	879,900	910,140	939,963	965,900	1,004,520	1,037,513
Depreciation Assets(Acquisition)	916,868	986,868	1,079,368	1,159,368	1,216,668	1,281,768	1,343,068	1,404,968	1,463,868	1,536,768	1,605,168
Accumulated Depreciation	265,258	289,071	315,151	343,010	371,841	401,868	432,928	465,005	497,968	532,248	567,655
Land	0	0	0	0	0	0	0	0	0	0	0
Investment and Others	225,810	225,810	225,810	225,810	225,810	225,810	225,810	225,810	225,810	225,810	225,810
Defferd Assets	224,541	217,894	211,270	204,932	198,784	192,820	198,600	204,560	210,700	217,020	223,530
Total Assets	1,392,387	1,422,766	1,595,068	1,660,560	1,724,227	1,798,816	1,884,865	1,975,679	2,113,436	2,266,722	2,388,163
Liquid Debt	235,730	378,037	575,220	661,224	717,781	860,715	992,877	1,104,073	1,234,834	1,344,069	1,385,184
Accounts Payable	50,199	66,741	93,437	98,109	107,920	118,712	130,583	143,641	135,433	148,977	163,874
Short-Term Borrowings	92,080	211,185	341,627	415,951	447,982	563,935	666,420	744,969	862,392	934,383	934,529
Reserve for Taxes	0	0	0	0	0	0	0	0	0	0	0
Other Liquid Debt	93,451	100,111	140,156	147,164	161,880	178,068	195,875	215,462	237,008	260,709	286,780
Fixed Debt	990,020	920,387	862,196	808,980	760,342	716,914	676,361	640,373	607,664	583,972	556,814
Long-Term Borrowings	844,986	777,387	715,196	657,980	605,342	556,914	512,361	471,373	433,664	398,972	366,814
Corporate Bonds	0	0	0	0	0	0	0	0	0	0	0
Reserves	6,036	0	0	0	0	0	0	0	0	0	0
Other Fixed Debt	138,998	143,000	147,000	151,000	155,000	160,000	164,000	169,000	174,000	185,000	190,000
Net Worth	166,637	124,342	157,652	190,356	246,103	221,187	215,627	231,232	270,937	338,680	446,164
Capital	1,364	1,364	1,364	1,364	1,364	1,364	1,364	1,364	1,364	1,364	1,364
Capital Reserve	0	0	0	0	0	0	0	0	0	0	0
Reserve for Profit	0	0	0	0	0	0	0	0	0	0	0
Other Reserves	165,273	122,978	156,288	188,992	244,739	219,823	214,263	229,868	269,573	337,316	444,800
Total Debt/Net Worth	1,392,387	1,422,766	1,595,068	1,660,559	1,724,226	1,798,816	1,884,865	1,975,678	2,113,435	2,266,721	2,388,162

69.2 percent for the power purchasing cost. Unlike the power purchasing cost, the administrative costs can be reduced by efforts on the part of management. Without campaigns to rationalize the administrative division, the ECs are liable to fall into deficit operation.

Due to the increase in the cost of purchased power, the prime sales cost rate, which was 72.7 percent in 1996, was forecast to increase to 74.0 percent, up 1.3 points, in 1997 and succeeding years. As such, the gross profit rate over the years 1997 - 2006 was forecast at 28.9 percent, 0.9 points lower than in the standard year. Due to the rise in the prime cost rate and the slowing of the rate of sales increase, the business result is anticipated to be in the red for the year in 1997. The net profit is forecast to go into the black 3.6 percent in 2000, with the rate hitting 5.01 percent in 2002 and over 10 percent in 2005 and the following years. Besides the rise in the prime cost rate, the causes of the negative net profit include the difference of accounting standards for interest paid on borrowings; in 1996 and previous years, interest due was deferred, and the interest burden appearing on financial statements was therefore light. In long-term plans, the standard is gross sales. Consequently, the net profit includes a reinvestment fund equivalent to 5 percent of sales. The effective sales profit rate excluding this 5 percent reinvestment fund would come to 6.8 percent in 2006.

The estimates of capital investment were based on data in plans for rural electrification. In other words, it was assumed that the capital investment made by the ECs each year in Area VIII until 2006 would be in accordance with this long-term plan. It is forecast that capital investment will peak at 92.5 million pesos in 1998 and recede to 68.4 million pesos in 2006. The ratio of capital investment to revenue is anticipated to decline from 6.9 percent in 1998 to 2.5 percent in 2006. The major assumptions were therefore a decline in capital investment, lightening of the burden of interest payments due to improved profit, and improvement of the financial picture.

Investment (Unit: million, %)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gross Revenue (A)	953.4	1334.8	1401.6	1541.7	1695.9	1865.5	2052.0	2257.2	2482.9	2731.2
Investment (B)	70.0	92.5	80.0	57.3	65.1	61.3	61.9	58.9	72.9	68.4
(B)/(A) (%)	7.3	6.9	5.7	3.7	3.8	3.3	3.0	2.6	2.9	2.5

(2) Continuation of net deficit for two years in the event of transfer at Sound value price

What impact would transfer of the 69 kV transmission facilities from the NPC at the Sound value price of 449 million pesos have on profits and finances? In the initial year (2001), the annual burden would reach 102.7 million pesos. This burden would consist of interest payments, personnel costs, facility operating costs, and investment for facility maintenance. The prime cost rate would rise by 6.6 points to 80.1 percent. As a result, financial statements would show a net deficit for two years. In 2001, the net loss would reach 25 million pesos, and the sales profit rate would be a negative 1.5 percent. The business would go into the black in 2003.

For the ECs which are not in a financially sound position, purchase of 69 kV transmission facilities would entail an additional burden of borrowings amounting to 449 million pesos if made at the sound value. This would be accompanied by a heavy burden of interest payments amounting to about 53.9 million pesos per year (at an interest rate of 12 percent). In other words, at any of the prices in question, takeover of the 69 kV transmission facilities from the NPC, the impact on profit and finances would clearly be considerably large and persist over the long term. In any case, genuine improvement of profits would not begin until around 2004.

(3) Leyeco V: high earning power and maintenance of profit independently even after takeover of the transmission business

Leyeco V has strong earning power, partly due to its good business conditions. A study was made as to whether it would be possible for Leyeco V to receive a transfer of only its own 69 kV transmission facilities. The same conditions as noted above were applied for the business plan for the next ten years. The study used a prime cost rate of 77.9 percent and a rate of 21.6 percent for capital investment, seeing that Leyeco V accounts for this percentage of all EC revenue in Area VIII and that investment burdens are revenue-based. According to this analysis, it would be possible for Leyeco V to realize profits in each year of the ten-year medium-term business plan. The main reasons are its good financial health, low burden of interest payments, and low operation costs. It was estimated that Leyeco V would post a net profit of 44 million pesos, for a sales profit rate of 13.4 percent, in 2000. Even with deduction of the support from the reinvestment fund, it would be able to post a profit rate of 8.4 percent.

In 2001, the prime cost rate is forecast to rise from the previous 74.0 percent to 78.2 percent due to the transfer and autonomous operation of the transmission facilities. Without this burden, revenue is estimated to reach 365 million pesos, and profit, 51.4million pesos. The operation cost for the transmission facilities at Leyeco V ranges between 11 and 14 million pesos in terms of the sound value. Even with the takeover, this level of cost could be absorbed in 2001 by the on-term profit, which was forecast at 37.1million pesos. Over the longer term, there are prospects for improvement of the outage situation, loss rate, and profitability due to autonomous operation of the transmission facilities.

Input Data

LEYECO V Sound Value

Revenue

		0 Year				1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Division	Unit	1996		Division	Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Power Revenue	1000 P	174,224		Power Revenue	%	10.00	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Investment Fund	1000 P	7,880		Investment Fund	%	22.04	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Other Revenue	1000 P	3,884		Other Revenue	%	10.00	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00

Cost

		0 Year				1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Division	Unit	1996		Division	Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Power Cost	%	69.2		Power Cost	%	74.0	74.0	74.0	74.0	78.2	77.7	77.2	76.8	76.5	76.1
Investment Fund	%	0		Investment Fund	%	0	0	0	0	0	0	0	0	0	0
Other Cost	%	90		Other Cost	%	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0

P/L Plan

		0 Year				1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Item	Unit	1996		Item	Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Number of Employees	Person	178		Number of Employees	Person	182	185	189	193	197	200	206	213	219	226
Wages per Employee	1000 P	129.12		Rate of Wage Increase	%	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Depreciation	1000 P	4,703													
	1000 P	0		Operation Cost Increase Rate 1	%	0	0	0	0	0	0	0	0	0	0
Consumers Account	1000 P	3,977		Operation Cost Increase Rate 2	%	9.0	39.0	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
A&G Cost	1000 P	1,495		Operation Cost Increase Rate 3	%	9.0	39.0	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Tax	1000 P	0		Tax Ratio	%	0	0	0	0	0	0	0	0	0	0
Other Cost	1000 P	0		Other Cost Increase Rate	%	0	0	0	0		0	0	0	0	0
Interest Received	1000 P	0													
				Dividends, ETC.	1000 P	0	0	0	0	0	0	0	0	0	0
Non-Operating Income	1000 P	1,429		Non-Operating Other Income	1000 P	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Interest Paid	1000 P	6,335													
				Other Interest	1000 P	0	0	0	0	0	0	0	0	0	0
Non-Operating Cost	1000 P	92		Non-Operating Other Cost	1000 P	100	100	100	100	100	100	100	100	100	100
Current Profit	1000 P	23,773													
Special Profit	1000 P	0		Special Profit	1000 P	0	0	0	0	0	0	0	0	0	0
Special Loss	1000 P	0		Special Loss	1000 P	0	0	0	0	0	0	0	0	0	0
Corporate Tax	1000 P	0		Corporate Tax	%	0	0	0	0	0	0	0	0	0	0
Dividends	1000 P	0		Dividends per Share	P	0	0	0	0	0	0	0	0	0	0
Executive Bonuses	1000 P	0		Executive Bonuses	1000 P	0	0	0	0	0	0	0	0	0	0
Other External Expend.	1000 P	0		Other External Expenditures	1000 P	0	0	0	0	0	0	0	0	0	0

B/S input data

Item	Unit	0 Year 1996
Cash and Deposit	1000 P	20,390
Accounts Receivable	1000 P	35,826
Inventories	1000 P	3,358
Other Liquid Asset	1000 P	0
Ratio of Cash & Deposit	%	11
Cash & Deposit Interest Rate	%	0
Depreciation Assets(Acqu.)	1000 P	128,192
Accumulated Depreciation	1000 P	35,235
Land	1000 P	0
Investment and Other	1000 P	5,813
Defferd Assets	1000 P	34,805
Accounts Payable	1000 P	11,162
Other Liquid Debt	1000 P	15,515
Bill Discounted	1000 P	0
Short-term Borrowings	1000 P	327
Short-term Borrowings Interest	%	12.0
Reserve for Tax	1000 P	0
Long-term Debt	1000 P	94,019
Long-term Debt Interest	%	12.0
Corporate Bonds	1000 P	0
Corporate Bonds Interest	%	0
Other Fixed Debt	1000 P	19,195
Reserves	1000 P	0
Capital	1000 P	206
Number of Shares Issued	1000 S.	41.2
Par Value	P	5
Reserve for Capital	1000 P	0
Reserve for Profit	1000 P	0
Other Reserve	1000 P	52,725

Item	Unit	1 Year 1997	2 Year 1998	3 Year 1999	4 Year 2000	5 Year 2001	6 Year 2002	7 Year 2003	8 Year 2004	9 Year 2005	10 Year 2006
Ratio of Cash & Deposit to Rev.	%	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Ratio of Receivable to Revenue	%	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Ratio of Inventories to Revenue	%	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Ratio of Other Liquid Assets to Rev.	%	0	0	0	0	0	0	0	0	0	0
Cash and Deposit Interest Rate	%	0	0	0	0	0	0	0	0	0	0
Depreciation Assets(New)	1000 P	15,120	20,000	17,300	12,400	14,100	13,200	13,400	12,700	15,700	14,800
Depreciation Ratio	%	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Land(New)	1000 P	0	0	0	0	0	0	0	0	0	0
Investment and Other(New)	1000 P	0	0	0	0	0	0	0	0	0	0
Defferd Assets	1000 P	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Ratio of Accounts Payable to Rev.	%	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.0	5.0	5.0
Ratio of Other Liquid Debt to Rev.	%	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Bill Discounted	1000 P										
Discount Rate	%										
Short-term Borrowings Interest	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Long-term Borrowings(Returned)	1000 P	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Long-term Borrowings(New)	1000 P	0	0	0	0	0	0	0	0	0	
Long-term Debt Interest	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Corporate Bonds(New)	1000 P										
Corporate Bonds(Redemption)	1000 P										
Corporate Bonds Interest	%										
Other Fixed Debt	1000 P	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000
Reserves	1000 P										
New Shares	1000 P										
New Issued Par Value	1000 S.										
Par Value	P	0	0	0	0	0	0	0	0	0	0
New Issued Public Offering	1000 S.			0							
Share Price(Public Offering)	P										
Share Split	1000 S.										

Revenue (1)

LEYECO V Long-Range Management Planning (1997-2006 Year)

- Sound Value -

Item	0 Year	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Revenue	185,988	205,536	287,750	302,137	332,351	365,586	402,145	442,359	486,595	535,255	588,780
Power Revenue	174,224	191,646	268,305	281,720	309,892	340,881	374,970	412,467	453,713	499,085	548,993
Investment Fund	7,880	9,617	13,463	14,137	15,550	17,105	18,816	20,697	22,767	25,044	27,548
Other Revenue	3,884	4,272	5,981	6,280	6,908	7,599	8,359	9,195	10,115	11,126	12,239
Revenue(%)		0	0	0	0	0	0	0	0	0	0
Power Revenue	93.7	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2
Investment Fund	4.2	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Other Revenue	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Power Cost	124,059	145,663	203,929	214,125	235,538	273,409	298,875	326,700	357,555	391,813	428,799
Power Cost Rate	66.7	70.9	70.9	70.9	70.9	74.8	74.3	73.9	73.5	73.2	72.8
Power Cost	120,563	141,818	198,546	208,473	229,320	266,569	291,351	318,424	348,452	381,800	417,784
Investment Fund	0	0	0	0	0	0	0	0	0	0	0
Other Cost	3,496	3,845	5,383	5,652	6,218	6,839	7,523	8,276	9,103	10,014	11,015
Gross Profit	61,929	59,872	83,821	88,012	96,813	92,177	103,270	115,659	129,040	143,441	159,981
Gross Profit Rate	33.3	29.1	29.1	29.1	29.1	25.2	25.7	26.1	26.5	26.8	27.2
Power Revenue	53,661	49,828	69,759	73,247	80,572	74,312	83,618	94,042	105,261	117,285	131,209
Investment Fund	7,880	9,617	13,463	14,137	15,550	17,105	18,816	20,697	22,767	25,044	27,548
Other Revenue	388	427	598	628	691	760	836	920	1,011	1,113	1,224

Revenue (2)

Item	0 Year	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Operation Costs	33,158	34,206	38,735	41,417	44,492	47,819	51,150	55,240	59,775	64,527	69,778
(Operation Costs Rate)	17.83	16.64	13.46	13.71	13.39	13.08	12.72	12.49	12.28	12.06	11.85
Wages	22,983	24,675	26,336	28,250	30,291	32,464	34,607	37,427	40,634	43,867	47,533
	0	0	0	0	0	0	0	0	0	0	0
Consumers Account	3,977	4,335	6,026	6,267	6,831	7,445	8,115	8,846	9,642	10,510	11,456
A & G Cost	1,495	1,630	2,265	2,356	2,568	2,799	3,051	3,325	3,625	3,951	4,306
Depreciation	4,703	3,567	4,109	4,544	4,803	5,110	5,377	5,642	5,875	6,199	6,483
(Business Tax)	0	0	0	0	0	0	0	0	0	0	0
(Others)	0	0	0	0	0	0	0	0	0	0	0
Opearting Profit	28,771	25,666	45,086	46,595	52,321	44,359	52,120	60,419	69,265	78,915	90,204
(Operating Profit Rate)	15.47	12.49	15.67	15.42	15.74	12.13	12.96	13.66	14.23	14.74	15.32
Non-Operating Income	1,429	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Interest Received	0	0	0	0	0	0	0	0	0	0	0
Non-Operating Other income	1,429	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Non-Operating Costs	6,427	11,252	10,729	9,980	9,282	8,682	8,082	7,482	6,882	6,282	5,682
Interest Expense	6,335	11,152	10,629	9,880	9,182	8,582	7,982	7,382	6,782	6,182	5,582
Short-Term Debt Interest	0	170	247	96	0	0	0	0	0	0	0
Long-Term Debt Interest	0	10,982	10,382	9,782	9,182	8,582	7,982	7,382	6,782	6,182	5,582
Corporate Bound Interest	0	0	0	0	0	0	0	0	0	0	0
Non-Operating Other Costs	92	100	100	100	100	100	100	100	100	100	100
Current Profit	23,773	15,814	35,756	38,015	44,439	37,077	45,438	54,337	63,783	74,032	85,922
(Current Profit Rate)	12.78	7.69	12.43	12.58	13.37	10.14	11.3	12.28	13.11	13.83	14.59
Special Profit	0	0	0	0	0	0	0	0	0	0	0
Special Loss	0	0	0	0	0	0	0	0	0	0	0
Pretax Profit	23,773	15,814	35,756	38,015	44,439	37,077	45,438	54,337	63,783	74,032	85,922
(Pretax Profit Rate)	12.78	7.69	12.43	12.58	13.37	10.14	11.30	12.28	13.11	13.83	14.59
Reserve for Corporate Tax	0	0	0	0	0	0	0	0	0	0	0
Net Profit	23,773	15,814	35,756	38,015	44,439	37,077	45,438	54,337	63,783	74,032	85,922
(Net Profit Rate)	12.78	7.69	12.43	12.58	13.37	10.14	11.3	12.28	13.11	13.83	14.59
Dividends	0	0	0	0	0	0	0	0	0	0	0
Executive Bonuses	0	0	0	0	0	0	0	0	0	0	0

B/S Plan

Item	0 Year	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
						P/L Plan					
Liquid Assets	59,574	63,716	89,202	109,867	145,936	187,993	239,600	300,008	365,997	444,331	535,423
Cash and Deposit	20,390	20,554	28,775	46,418	76,143	111,220	155,150	207,113	263,812	331,927	411,779
Accounts Receivable	35,826	39,052	54,672	57,406	63,147	69,461	76,407	84,048	92,453	101,698	111,868
Inventories	3,358	4,111	5,755	6,043	6,647	7,312	8,043	8,847	9,732	10,705	11,776
Other Liquid Assets	0	0	0	0	0	0	0	0	0	0	0
Fixed Assets	98,770	110,323	126,215	138,970	146,567	155,557	163,380	171,138	177,963	187,464	195,781
Depreciation Assets(Book)	92,957	104,510	120,402	133,157	140,754	149,744	157,567	165,325	172,150	181,651	189,968
Depreciation Assets(Acquisition)	128,192	143,312	163,312	180,612	193,012	207,112	220,312	233,712	246,412	262,112	276,912
Accumulated Depreciation	35,235	38,802	42,910	47,455	52,258	57,368	62,745	68,387	74,262	80,461	86,944
Land	0	0	0	0	0	0	0	0	0	0	0
Investment and Others	5,813	5,813	5,813	5,813	5,813	5,813	5,813	5,813	5,813	5,813	5,813
Defferd Assets	34,805	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Total Assets	193,149	208,039	249,417	282,837	326,503	377,550	436,980	505,146	577,960	665,795	765,204
Liquid Debt	27,004	31,275	41,896	42,299	46,529	51,182	56,300	61,930	63,257	69,583	76,541
Accounts Payable	11,162	12,332	17,265	18,128	19,941	21,935	24,129	26,542	24,330	26,763	29,439
Short-Term Borrowings	327	2,500	1,611	0	0	0	0	0	0	0	0
Reserve for Taxes	0	0	0	0	0	0	0	0	0	0	0
Other Liquid Debt	15,515	16,443	23,020	24,171	26,588	29,247	32,172	35,389	38,928	42,820	47,102
Fixed Debt	113,214	108,019	103,019	98,019	93,019	88,019	83,019	78,019	73,019	68,019	63,019
Long-Term Borrowings	94,019	89,019	84,019	79,019	74,019	69,019	64,019	59,019	54,019	49,019	44,019
Corporate Bonds	0	0	0	0	0	0	0	0	0	0	0
Reserves	0	0	0	0	0	0	0	0	0	0	0
Other Fixed Debt	19,195	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000
Net Worth	52,931	68,745	104,501	142,517	186,955	238,349	297,661	365,197	441,683	528,193	625,643
Capital	206	206	206	206	206	206	206	206	206	206	206
Capital Reserve	0	0	0	0	0	0	0	0	0	0	0
Reserve for Profit	0	0	0	0	0	0	0	0	0	0	0
Other Reserves	52,725	68,539	104,295	142,311	186,749	238,143	297,455	364,991	441,477	527,987	625,437
Total Debt/Net Worth	193,149	208,039	249,417	282,835	326,503	377,550	436,980	505,146	577,960	665,795	765,204

(4) Extreme difficulty of external fund procurement

The new enterprise for operation of the 69 kV transmission lines will be a cooperative. Its customers will be the distribution enterprises on Leyte and Samar. As a cooperative, the new enterprise will not be able to raise funds from external sources as easily as a joint-stock company. In the new cooperative, subscribers with 1,000 shares will have the same voting rights as those with only one share. The new cooperative will have a low rate of profit and no plans for payment of dividends. Subscription will be limited to the 11 ECs. This kind of organization will be unable to attract subscription based on equity.

Because the 11 ECs will subscribe in the new cooperative, operation costs will have to be held to the minimum. Profit will probably be curtailed to the level of 4 percent, and there will obviously be no payment of dividends. This is because the cash flow (profit plus depreciation) will be applied to repayment of finances for the facilities purchased. Furthermore, the business will have an annual turnover on the order of 100 million pesos, employ 70, and have a high rate of borrowing. These features would rule out attraction of external subscription based on equity.

The rate of borrowing from commercial banks would be extremely high and result in an excessive burden of interest payments. As such, the new cooperative would have to depend on low-interest (12 percent) financing from the NEA. This financing would take the form of a two-step loan, which is the only type of provision of official funding from sources such as the World Bank, OECF, and ADB. As for the question of whether or not the new cooperative would have enough earning power to attract external investment, the following points can be made.

1) In the first place, the new cooperative could not pay dividends; if it did, the payment would result in increased operating costs.

2) The scale of the business will be small, and the growth rate, low.

3) The profit rate will be held to a low level in order to curtail costs.

4) Because of the cooperative status, there would be negligible appeal in the eyes of subscribers as compared to a joint-stock status.

For these reasons, it would be impossible for the new cooperative to raise funds from the open market. Consequently, procurement of funds from official institutions would be the only alternative.

In BOT projects, funds are ordinarily raised from external sources (and foreign ones in particular) by sales of stock (capital subscription) for 20- 30 percent of the requirement and debt for 80 - 70 percent. Stock is purchased by banks, commercial firms, project sponsors and official institutions. These parties also are sources of financing. Emphasis is placed on the ability to maintain earning power on a high level, the prospects for dividends commensurate with investment, and the chances of retrieval of funds on the foreign exchange standard. These considerations also imply that it would be extremely difficult to attract external funding, and subscription in particular, with a cooperative organization.

(5) High probability of improvement of earning power over the long term with conversion into joint-stock companies

At each EC, 5 percent of revenue is capable of use as reinvestment funds. Such assistance is liable to make management soft. It is important for the ECs to make self-help efforts for transformation from cooperatives into joint-stock companies. Those with adequate earning power should extricate themselves from the management environment of provisions for use of 5 percent of revenue for capital investment at any time and for tax exemptions. The state-run NPC is to be privatized within the next two or three years, and this will put pressure on the ECs to carry out programs of rigorous rationalization. In addition, it is impossible for cooperative organizations to raise funds externally. While management in the form of joint-stock companies is the premise, it would not be possible to raise outside funds, particularly through stocks, bonds, and long-term loans, unless the organization maintains earnings, executes efficient management, and is attractive to external investors.

A change in the status of ECs to joint-stock companies would require a decision by a vote of a certain proportion of the members. Some of the members are apprehensive that such a change would trigger tariff rate hikes in pursuit of profit. However, management in the form of joint-stock companies would hold better prospects for bringing rates down over the long term. This is because introduction of the competitive mechanism induces reduction of costs, as evidenced by past cases of privatization of state enterprises. Organizations that are capable of introducing rational management in the form of joint-stock companies should promptly do so. Some of the ECs will not be able to subsist without flexible adaptation to these changes in the business environment. As such, there is a strong possibility that those ECs which cannot keep abreast of the intensified competition and fail to carry out efficient management will be absorbed by other enterprises.

CHAPTER 10

CONCLUSION
AND
RECOMENDATIONS

Chapter 10: CONCLUSION AND RECOMMENDATIONS

The study team investigated the possibilities of transfer of the 69 kV transmission lines and systems owned by the NPC on Leyte and Samar to the private distribution utilities.

The process culminating in the conclusion began with an identification of three basic options for the transfer: 1) transfer to a newly established transmission cooperative, 2) transfer in installments to the existing ECs, and 3) transfer to the amalgamated ECs.

Upon assessment, it was decided that the best option was transfer of all of the 69 kV transmission lines and systems to a new transmission cooperative established through joint outlays by the 11 ECs.

Finally, the team prepared a draft plan for transfer of the facilities to the new transmission cooperative and conducted a case study of the transmission operating costs.

The study concluded that the 69 kV transmission lines owned by the NPC should be transferred to a newly established transmission cooperative.

The team also formulated recommendations on various needs associated with the establishment of the new transmission cooperative. These include price negotiations with the NPC, conversion of the ECs into joint-stock companies, training and the establishment of a training center for human resource development, and further investigation for EC rationalization.

10.1 Conclusion

It is the conclusion of this study that the option of transferring the NPC 69 kV transmission lines on Leyte and Samar to a new transmission cooperative (i.e., a company established jointly by the 11 ECs on these islands for operation and management of these lines) would have possibilities of realization if the requisite conditions are met.

The succeeding section describes the results of a case study as to the preconditions for the transfer and the approach in the financial aspect.

10.1.1 Preconditions for transfer of the 69 kV transmission lines to the new transmission cooperative

The following is a summary of the major prerequisites for the transfer as regards the scope of facilities, transfer price, schedule, etc.

- The subject of the transfer will be the NPC 69 kV transmission lines on Leyte and Samar posterior to the outlet of the 138/69 kV substations, and inclusive of the ABSs mounted on these lines. This division of assets must be clearly agreed upon with the NPC.

- A new transmission cooperative will be established to accept the transfer. The new cooperative will be established mainly through subscription by the 11 ECs, but will not exclude subscription by other enterprises.
- The establishment of the new cooperative will not change the arrangement of 11 ECs, each of which will remain in existence. However, it is possible that each EC could post some of its technicians to the new cooperative at the time of establishment.
- The new transmission cooperative will be established in 2001. Upon the passage of the Omnibus bill, the NPC and ECs will engage in negotiation to determine the transfer price by the time of establishment in 2001. They will also take steps to execute all other tasks related to the transfer (e.g., determination of business policy, preparation of the organizational setup, and procurement of funds).
- While the matter will depend on the outcome of negotiation with the NPC, the study team believes that it would be appropriate to negotiate for application of the sound value as the transfer price, as related in Chapter 9.
- Although some of them are undergoing a program of rehabilitation by the NPC in 1997 and 1998, most of the 69 kV transmission lines have not been properly maintained. After it accepts them, the new transmission cooperative must fully maintain these lines. This will demand an increase in the technical levels of the technicians participating in the new cooperative.

10.1.2 Case Study of the Cost of Transmission Operation by the New Cooperative

The sound value of the 69 kV transmission lines that are the subject of the transfer is 449 million pesos. This figure amounts to 10.6 years worth of the combined 1996 cash flow of the 11 ECs (42.4 million pesos). In addition, it would require additional borrowing of an amount more than 50 percent as high as the current combined borrowings of the 11 ECs (845 million pesos).

The study team implemented a case study of the prospective 69 kV transmission operation cost of the new transmission cooperative. This study compared the subtransmission cost under the unbundled tariff scheme of the NPC (the basic case) with the transmission operating cost in several other cases, as noted below.

The study concluded that the most realistic approach would be to have the new cooperative borrow funds for purchase of the 69 kV transmission lines from the NEA or a bank (i.e., Case A). Nevertheless, the new cooperative would have a higher burden of operation cost to 2005 in this case as compared to that of the operation by the NPC.

The burden of operation cost over the initial five years could conceivably be lessened relative to Case A by leasing (Case B) or by payment in installments over a period of 20 years (Case C). In Case B, the cost would be 0.03 or 0.04 pesos per kWh lower than in Case A, and the increase in the burden of the new cooperative would be resolved in 2004. In Case C, the operation cost relative to the NPC delivery cost would be negative right from the start, and there would be absolutely no burden on the ECs. However, Case B would require entry by the NEA into leasing business, and Case C, the conclusion of a contract with the NPC for receipt of the assets in 20-year installments. In the latter case, it would probably be very difficult to negotiate such a contract.

Basic case: the cost of transmission through 69 kV transmission lines owned by the NPC (wheeling rate for subtransmission under the system of unbundled power tariffs)

Case A) Purchase of the 69 kV transmission lines by the new cooperative with funds borrowed from the NEA or a bank

Case B) Transfer of the 69 kV transmission lines to the new cooperative based on a leasing contract

Case C) Conclusion of a contract with the NPC for transfer of the subject assets to the new cooperative in 20-year installments

Case D) Transfer of the 69 kV transmission lines to the new cooperative at a 20-percent discount on the sound value

Table 10.1-1 Future estimates of the subtransmission operation cost in each case

Unit: pesos per kWh

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Basic case: NPC wheeling rate	0.14	0.15	0.16	0.17	0.18	0.18	0.19	0.20	0.21	0.22
A) Borrowing	0.25	0.24	0.22	0.21	0.20	0.18	0.17	0.16	0.15	0.15
B) Leasing	0.22	0.20	0.19	0.18	0.17	0.16	0.16	0.15	0.14	0.13
C) 20-year installments	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
D) Borrowing (20-percent discount)	0.22	0.21	0.19	0.18	0.17	0.16	0.15	0.14	0.14	0.13

- In Case A, the cost of operation of the 69 kV transmission lines in 2001 would be higher than that of operation by the NPC (i.e., the NPC wheeling rate). Beginning in 2006, the reverse would be true, and operation cost by the new cooperative would be cheaper than operation by the NPC. In short, the facilities must be managed from a long-term perspective, and with autonomous efforts that could lead to further cost reduction. Transfer of the 69 kV transmission lines in line with this case is consequently thought to be fully possible.
- In Case B, the cost of operation based on leasing would be from 0.03 to 0.04 pesos per kWh lower than in Case A. This lower level of operation cost in the initial phase would facilitate participation by the ECs in the new transmission cooperative. In addition, further cost reduction could be expected as a result of the performance of fund management and depreciation by the leasing company as a financing specialist. However, leasing would offer a lower operation cost only for the first ten years; thereafter, it would be more expensive.
- Case C posits transfer of the 69 kV transmission lines in 20-year installments, and would necessitate the conclusion of a contract to that effect with the NPC.

  The increase in requisite funds each year would be held to the amount of increase for the portion transferred that year. The burden of interest payments would therefore be low for the first five years. The operation cost per kWh would be greatly lowered by the lighter burden of interest and depreciation costs. As a result, the net cost would be negative right from the start, and there would be absolutely no burden on the ECs.
- In Case D, the transfer at a 20-percent discount on the sound value would decrease the operation cost by only 0.03 pesos per kWh, and the balance would be evened up (in terms of the net cost) only one year earlier than in Case A.

10.2 Recommendations

10.2.1 Establishment of the New Transmission Cooperative

Toward establishment of the new transmission cooperative, the basic framework of the business must be determined by 2001, the year of commencement. The main items are as follows (details are presented in Section 8.3).

1) Attraction of participation in the new cooperative by other electric power enterprises as well as the 11 ECs (the main participants)

2) Institution of an organ of conference to determine the internal particulars of the new cooperative and serve as a window for negotiation with the NPC and other parties

3) Recruitment of personnel and construction of offices for the new cooperative

4) Negotiation with the NPC for determination of matters such as the division of assets, pricing, and scheme of system operation

5) Formulation of the business policy of the new cooperative and determination of the method of repayment of transfer funds, etc.

6) Provision of technical training to new technical employees for operation and maintenance of the 69 kV transmission lines

In the execution of business beginning in 2001, the new cooperative must prepare proper plans for rehabilitation and maintenance of the 69 kV transmission lines and establish setups for implementation of the same in order to keep them in good working order.

In purchasing supplies, the new cooperative must solicit and compare price estimates from competing sources and analyze the level of price relative to quality in order to hold down the cost of investment in facility upkeep. It also must strive to improve job efficiency by clarifying the responsibilities of each employee, in order to hold down personnel expenses and improve the balance of payments. With management of this orientation, the rise in wholesale prices to the ECs could be lessened.

10.2.2 Negotiation of the Transfer Price

In negotiation with the NPC over the price to be applied in transfer of the 69 kV transmission lines, the EC side should adopt a stance based on the facts noted below.

1) The NPC made simple calculations for totals based on standard formulas, and there was some roughness.

2) The NPC is considering negotiation for the market price as the sales price for the 69 kV transmission facilities. It apparently is not looking to make a profit on the transaction.

3) The NPC has outside parties to evaluate its assets once every four years. This year (1997) is one for such evaluation (in other years, the NPC makes its own evaluation). The NPC therefore is in possession of in-depth evaluation data as well as calculation techniques. It will have a very strong hand in negotiations with the ECs.

4) The ECs should promptly conduct their own research and investigation of the transfer in order to accumulate know-how of use in the negotiations.

5) The NPC intends transfer and sale of the 69 kV transmission facility assets within the next two years. Ordinary private enterprises have been included within the scope of

prospective buyers. In addition, power-related companies are establishing firms that specialize in services for transmission facilities, and these are also prospective buyers.

6) Difficulty in finding other buyers would work to the advantage of the ECs.

7) In the Samar case, the NPC recognizes that transfer would be impossible without extensive rehabilitation over the years 1997 - 1999 due to the poor maintenance situation. Improvements on both islands, and mainly Samar, are to be the subject of additional investments of 13.6 million pesos in 1997 and 39.5 million pesos in 1998 (the two years for which budget figures are available). This will also drive up the purchasing price.

10.2.3 Need for Conversion of the ECs from Cooperatives to Joint-stock Companies

As described in Section 10.1.2, the operation cost of the new cooperative will constitute a high wholesale rate depending on the method of repayment of capital. This high rate will impose a burden on the ECs and therefore could also affect prices to final customers. The ECs consequently must absorb this burden through management efforts. Promotion of action to this end requires the transformation of ECs into joint-stock companies.

At each EC, 5 percent of revenue is capable of use as reinvestment funds. Such assistance is liable to make management soft. It is important for the ECs to make self-help efforts for transformation from cooperatives into joint-stock companies. Those with adequate earning power should extricate themselves from the management environment of provisions for use of 5 percent of revenue for capital investment at any time and for tax exemptions. The state-run NPC is to be privatized within the next two or three years, and this will put pressure on the ECs to carry out programs of rigorous rationalization. In addition, it is impossible for cooperative organizations to raise funds externally. While management in the form of joint-stock companies is the premise, it would not be possible to raise outside funds, particularly through stocks, bonds, and long-term loans, unless the organization maintains earnings, executes efficient management, and is attractive to external investors.

10.2.4 Technology Transfer and Training for Human Resource Development

The technical levels of the present ECs' staff are insufficient to execute construction, operation and maintenance, formulation of transmission line plan and various technical system analyses. Should the transmission facilities be transferred to the ECs under these situations without improving the technical levels of the ECs' staffs, long time power supply outages and other troubles can possibly occur. Therefore, it would be essential to execute transfer of technical knowledge and knowhow sufficiently prior to transfer of the 69 kV transmission lines.

The following two methods can largely be considered for executing transfer of technical knowledge and knowhow, and it is considered preferable to execute technical training based on a combination of the below two methods:

1) To employ professional engineers, and educate and train other engineers of the ECs to be engaged in planning, construction, operation and maintenance of the 69 kV transmission lines; and

2) To let the ECs' staff visit outside organizations and receive training from the experts of the organizations, or accept the experts from outside organizations and let the experts train the ECs' staffs to accumulate the technical knowledge and knowhow.

The preliminary technical training schedule until and immediately after accepting the 69 kV transmission lines are as proposed below:

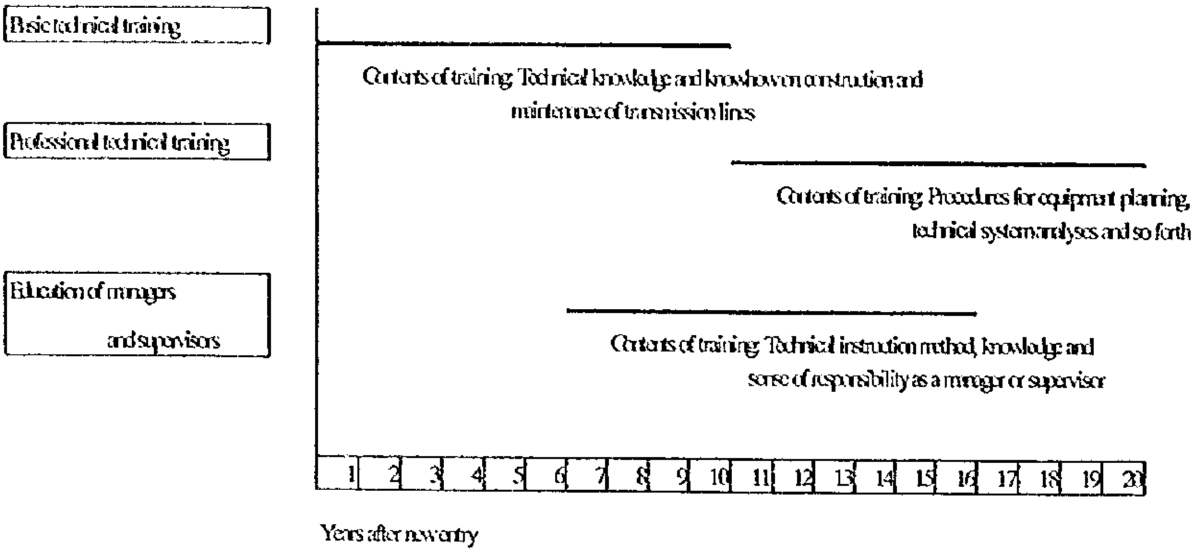
a. To let the ECs' engineers receive training by obtaining cooperation of the NPC, MERALCO, CEPALCO and other companies before acceptance of the transmission facilities in 2001;

b. To let the ECs' staff master technical knowledge and knowhow through field on-the-job training from the engineers dispatched from the NPC; and

c. At the same time, to let the senior engineers of the ECs trip to the NPC and acquire the technical knowledge and knowhow regarding the concept of equipment planning and technical system analyses.

Table 10.2-1 shows the schedule for human resource development. Training for this purpose should be divided into two stages: basic technical training and professional technical training. Programs for instruction of managers and supervisors must be conducted at the same time.

Table 10.2-1 Training schedules of engineers for operation and management of 69 kV T/Ls in the future



10.2.5 Construction of a Training Center

The realization of the plans will require an improvement in the modernization of EC technicians as regards distribution technology in order to supply electricity to end customers stably, and also require an acquirement of technical capability for the engineer of the new transmission cooperative as regards 69 kV transmission lines. One of the options to this end is training with the support of other enterprises, as noted in Section 10.2.4. It is advisable for programs of instruction and training to be implemented jointly, also for higher efficiency.

As such, it is recommended that the NEA set up a training center as part of its technical assistance for ECs and the new transmission cooperative, and also equip this center with facilities for training in distribution systems and transmission lines. Naturally, this center should offer programs not only for the 11 ECs and the new transmission cooperative on Leyte and Samar but also for those in the rest of the Philippines.

Furthermore, the programs at this center should not be confined to maintenance technology; they should aim for improvement of capabilities, including new technology and know-how, in a wide range of fields, such as facility planning, facility diagnosis, and operation.

10.2.6 Study for EC Rationalization

This study made it clear that the ECs have a financially weak disposition and insufficient modern technical levels. Unless this situation is remedied, the ECs could be unable to operate the 69 kV transmission lines as a business even if transferred.

If they are to receive the 69 kV transmission lines, the ECs therefore must reinforce the foundation of their management, improve their productivity, and otherwise strengthen their constitution. The preparation of a new program for the rationalization of EC management is indispensable to this end.

The study team consequently proposes the implementation of another study on rationalization and increase in the level of technology following this one. The results will provide footing for the preparation of a specific program and manual for the establishment of systems for control of management and finances. The contents may be outlined as follows.

1) Evaluation of the existing EC organization and review of the form of organization

2) Establishment of the management control system

3) Establishment of the financial control system

4) Increase in the level of technology and training

The team membership (in terms of fields of competence) and work load for this study are as follows.

1) Fields of competence (and number of consultants in each)

- Organization and institutional arrangements (one)
- Power enterprise management (two)
- Finances (one)
- Technology (three)

2) Work load

- Estimated at from 60 to 65 MM per year for a single region