Chapter 8 Tech-Economic Assessment of Important Issues in Energy Sector

(1) Comparison of Electricity Generation System

Figure 8.1 shows the comparison of construction costs among the types of power generation (Diesel, GT, and CCGT) as compiled by ESMAP, by Kennedy & Donkin, and by JICA study team. Please note that the data by the JICA team was compiled with the data of Southeast Asian and other developing countries taken as references.

The ESMAP data are hard to use for comparison as they only have one point per item. The Kennedy & Donkin data are, however, seen to show almost the same trend as that of the JICA study team data.

On the basis of these construction cost figures, the power generation costs for various types of power generation are shown in Tables 8.1 through 8.4, with the utilization rate taken as the variables. Please note that these data are compiled for 1994, and the fuels for the GTs and the CCGTs are compared for both kerosene and gasoil.

From these diagrams, it is seen that GTs are appropriate for the peak demand response, and CCGTs are appropriate for the intermediate load, with diesels being appropriate for the base load. There is no practical difference between diesels and CCGTs.

From now on and for the reasons provided below, in planning the power development schemes for the next 30 years, the JICA study team will employ CCGTs for supply to the intermediate load and for the base load:

1) When CCGTs are employed, GTs will be installed on the power system in advance for peak demand. These GTs will be usable later with only the additional installation of ST. This provides a greater certainty of securing power supply sources.
2) For the above reason also, facility delivery time and construction time would be shortened when CCGTs are employed.
3) When the maintenance work is compared, CCGTs are more convenient than diesels.

Table 8.1 COMPARISON OF GENERATION COST OF GT

Item	Unit	Financial						Ecconomic					
Plant Type		GT	GT	GT	GT	GT	GT	GT	GT	GT	GT	GT	GT
Fuel		kerosene	kerosene	kerosene	Gasoil	Gasoil	Gasoil	kerosene	kerosene	kerosene	Gasoil	Gasoil	Gasoil
Unit Capacity	MW	30	50	75	30	50	75	30	50	75	30	50	75
Number of Unit		1	1	1	1	1	1	1	1	1	1	1	1
Annual Plant Factor	%	90	90	90	90	90	90	90	90	90	90	90	90
Annual Energy	GWh	237	394	591	237	394	591	237	394	591	237	394	591
Service Life	Years	20	20	20	20	20	20	20	20	20	20	20	20
Scheduled Outage Ratio	%	12	12	12	12	12	12	12	12	12	12	12	12
Forced Outage Ratio	%	4	4	4	4	4	4	4	4	4	4	4	4
Construction Cost	US$/kW	520	480	450	520	480	450	520	480	450	520	480	450
Discount Rate	%	12	12	12	12	12	12	12	12	12	12	12	12
Capital Recovery		0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142
Capital Cost	US$/kW	73.84	68.16	63.90	73.84	68.16	63.90	73.84	68.16	63.90	73.84	68.16	63.90
O/M Annual Fixed Cost	US$/kW	5.30	3.84	3.15	5.30	3.84	3.15	5.30	3.84	3.15	5.30	3.84	3.15
Fixed Cost Total	US$/kW	79.14	72.00	67.05	79.14	72.00	67.05	79.14	72.00	67.05	79.14	72.00	67.05
	US$/kWh	0.010	0.009	0.009	0.010	0.009	0.009	0.010	0.009	0.009	0.010	0.009	0.009
Fuel Caloric Rate	kcal/kg	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366
Fuel Heat Rate	kcal/kWh	2,914	2,818	2,532	2,914	2,818	2,532	2,914	2,818	2,532	2,914	2,818	2,532
Fuel Price	US$/kg	0.3211	0.3211	0.3211	0.4357	0.4357	0.4357	0.254	0.254	0.254	0.2659	0.2659	0.2659
Unit Fuel Cost	US$/kWh	0.090	0.087	0.078	0.122	0.118	0.106	0.071	0.069	0.062	0.075	0.072	0.065
Variable O/M Cost	US$/kWh	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Variable Cost Total	US$/kWh	0.092	0.089	0.080	0.124	0.120	0.108	0.073	0.071	0.064	0.076	0.074	0.066
Total Cost	US$/kWh	0.102	0.098	0.088	0.134	0.129	0.116	0.083	0.080	0.072	0.086	0.083	0.075
Operating Hours													
1000	US$/kWh	0.1711	0.1609	0.1470	0.2033	0.1921	0.1750	0.1522	0.1427	0.1306	0.1555	0.1459	0.1335
3000	US$/kWh	0.1183	0.1129	0.1023	0.1505	0.1441	0.1303	0.0994	0.0947	0.0859	0.1028	0.0979	0.0888
5000	US$/kWh	0.1077	0.1033	0.0933	0.1400	0.1345	0.1213	0.0889	0.0851	0.0769	0.0922	0.0883	0.0799
7000	US$/kWh	0.1032	0.0992	0.0895	0.1354	0.1303	0.1175	0.0844	0.0809	0.0731	0.0877	0.0842	0.0760
8000	US$/kWh	0.1018	0.0979	0.0883	0.1340	0.1291	0.1163	0.0829	0.0797	0.0719	0.0863	0.0829	0.0748
8760	US$/kWh	0.1009	0.0971	0.0876	0.1332	0.1283	0.1156	0.0821	0.0789	0.0712	0.0854	0.0821	0.0741

Table 8.2 COMPARISON OF GENERATION COST OF CCGT

Item	Unit	Financial						Ecconomic					
Plant Type		CCGT	CCGT	CCGT	CCGT	CCGT	CCGT	CCGT	CCGT	CCGT	CCGT	CCGT	CCGT
Fuel		kerosene	kerosene	kerosene	Gasoil	Gasoil	Gasoil	kerosene	kerosene	kerosene	Gasoil	Gasoil	Gasoil
Unit Capacity	MW	100	150	225	100	150	225	100	150	225	100	150	225
Number of Unit		2+1	2+1	2+1	2+1	2+1	2+1	2+1	2+1	2+1	2+1	2+1	2+1
Annual Plant Factor	%	80	80	80	80	80	80	80	80	80	80	80	80
Annual Energy	GWh	701	1,051	1,577	701	1,051	1,577	701	1,051	1,577	701	1,051	1,577
Service Life	Years	20	20	20	20	20	20	20	20	20	20	20	20
Scheduled Outage Ratio	%	15	15	15	15	15	15	15	15	15	15	15	15
Forced Outage Ratio	%	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Construction Cost	US$/kW	770	670	570	770	670	570	770	670	570	770	670	570
Discount Rate	%	12	12	12	12	12	12	12	12	12	12	12	12
Capital Recovery		0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Capital Cost	US$/kW	115.50	100.50	85.50	115.50	100.50	85.50	115.50	100.50	85.50	115.50	100.50	85.50
O/M Annual Fixed Cost	US$/kW	7.64	6.64	5.59	7.64	6.64	5.59	7.64	6.64	5.59	7.64	6.64	5.59
Fixed Cost Total	US$/kW	123.14	107.14	91.09	123.14	107.14	91.09	123.14	107.14	91.09	123.14	107.14	91.09
	US$/kWh	0.018	0.015	0.013	0.018	0.015	0.013	0.018	0.015	0.013	0.018	0.015	0.013
Fuel Caloric Rate	kcal/kg	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366	10,366
Fuel Heat Rate	kcal/kWh	1,861	1,763	1,706	1,861	1,763	1,706	1,861	1,763	1,706	1,861	1,763	1,706
Fuel Price	US$/kg	0.3211	0.3211	0.3211	0.4357	0.4357	0.4357	0.254	0.254	0.254	0.2659	0.2659	0.2659
Unit Fuel Cost	US$/kWh	0.058	0.055	0.053	0.078	0.074	0.072	0.046	0.043	0.042	0.048	0.045	0.044
Variable O/M Cost	US$/kWh	0.004	0.003	0.003	0.004	0.003	0.003	0.004	0.003	0.003	0.004	0.003	0.003
Variable Cost Total	US$/kWh	0.061	0.058	0.056	0.082	0.078	0.075	0.049	0.047	0.045	0.051	0.049	0.047
Total Cost	US$/kWh	0.079	0.073	0.069	0.099	0.093	0.088	0.067	0.062	0.058	0.069	0.064	0.060
Operating Hours													
1000	US$/kWh	0.1844	0.1652	0.1472	0.2050	0.1847	0.1661	0.1724	0.1538	0.1362	0.1745	0.1558	0.1381
3000	US$/kWh	0.1024	0.0938	0.0865	0.1229	0.1133	0.1053	0.0903	0.0824	0.0754	0.0924	0.0844	0.0774
5000	US$/kWh	0.0859	0.0795	0.0743	0.1065	0.0990	0.0932	0.0739	0.0681	0.0633	0.0760	0.0701	0.0652
7000	US$/kWh	0.0789	0.0734	0.0691	0.0995	0.0929	0.0880	0.0669	0.0620	0.0581	0.0690	0.0640	0.0600
8000	US$/kWh	0.0767	0.0715	0.0675	0.0973	0.0910	0.0864	0.0647	0.0601	0.0564	0.0668	0.0621	0.0584
8760	US$/kWh	0.0754	0.0703	0.0665	0.0959	0.0898	0.0854	0.0633	0.0589	0.0555	0.0655	0.0609	0.0574

Table 8.3 COMPARISON OF GENERATION COST OF DIESEL

Item	Unit	Financial			Ecconomic		
Plant Type		Diesel	Diesel	Diesel	Diesel	Diesel	Diesel
Fuel		HFO	HFO	HFO	HFO	HFO	HFO
Unit Capacity	MW	30	40	50	30	40	50
Number of Unit		1	1	1	1	1	1
Annual Plant Factor	%	77	77	77	77	77	77
Annual Energy	GWh	202	270	337	202	270	337
Service Life	Years	25	25	25	25	25	25
Scheduled Outage Ratio	%	12	12	12	12	12	12
Forced Outage Ratio	%	5	5	5	5	5	5
Construction Cost	US$/kW	1,530	1,480	1,450	1,530	1,480	1,450
Discount Rate	%	12	12	12	12	12	12
Capital Recovery		0.143	0.143	0.143	0.143	0.143	0.143
Capital Cost	US$/kW	218.79	211.64	207.35	218.79	211.64	207.35
O/M Annual Fixed Cost	US$/kW	20.54	17.55	15.34	20.54	17.55	15.34
Fixed Cost Total	US$/kW	239.33	229.19	222.69	239.33	229.19	222.69
	US$/kWh	0.035	0.034	0.033	0.035	0.034	0.033
Fuel Caloric Rate	kcal/kg	9,673	9,673	9,673	9,673	9,673	9,673
Fuel Heat Rate	kcal/kWh	1,841	1,841	1,841	1,841	1,841	1,841
Fuel Price	US$/kg	0.1529	0.1529	0.1529	0.121	0.121	0.121
Unit Fuel Cost	US$/kWh	0.029	0.029	0.029	0.023	0.023	0.023
Variable O/M Cost	US$/kWh	0.003	0.003	0.002	0.003	0.003	0.002
Variable Cost Total	US$/kWh	0.032	0.032	0.031	0.026	0.026	0.025
Total Cost	US$/kWh	0.067	0.066	0.064	0.061	0.060	0.058
Operating Hours							
1000	US$/kWh	0.2713	0.2608	0.2538	0.2653	0.2547	0.2477
3000	US$/kWh	0.1118	0.1080	0.1053	0.1057	0.1019	0.0993
5000	US$/kWh	0.0799	0.0774	0.0756	0.0738	0.0714	0.0696
7000	US$/kWh	0.0662	0.0643	0.0629	0.0601	0.0583	0.0568
8000	US$/kWh	0.0619	0.0602	0.0589	0.0558	0.0542	0.0529
8760	US$/kWh	0.0593	0.0578	0.0565	0.0532	0.0517	0.0505

Table 8.4 COMPARISON OF GENERATION COST OF COAL

Item	Unit	Financial			Ecconomic		
Plant Type		Coal	Coal	Coal	Coal	Coal	Coal
Fuel		Coal	Coal	Coal	Coal	Coal	Coal
Unit Capacity	MW	100	200	300	100	200	300
Number of Unit		1	2	3	1	2	3
Annual Plant Factor	%	71	71	71	71	71	71
Annual Energy	GWh	622	1,244	1,866	622	1,244	1,866
Service Life	Years	25	25	25	25	25	25
Scheduled Outage Ratio	%	12	12	12	12	12	12
Forced Outage Ratio	%	6	6	6	6	6	6
Construction Cost	US$/kW	1,390	1,270	1,190	1,390	1,270	1,190
Discount Rate	%	12	12	12	12	12	12
Capital Recovery		0.09	0.09	0.09	0.09	0.09	0.09
Capital Cost	US$/kW	125.10	114.30	107.10	125.10	114.30	107.10
O/M Annual Fixed Cost	US$/kW	26.9	18.27	12.41	26.9	18.27	12.41
Fixed Cost Total	US$/kW	152	132.57	119.51	152	132.57	119.51
	US$/kWh	0.024	0.021	0.019	0.024	0.021	0.019
Fuel Caloric Rate	kcal/kg	6,160	6,160	6,160	6,160	6,160	6,160
Fuel Heat Rate	kcal/kWh	2,799	2,799	2,799	2,799	2,799	2,799
Fuel Price	US$/kg	0.0775	0.0775	0.0775	0.0574	0.0574	0.0574
Unit Fuel Cost	US$/kWh	0.035	0.035	0.035	0.026	0.026	0.026
Variable O/M Cost	US$/kWh	0.001	0.001	0.001	0.001	0.001	0.001
Variable Cost Total	US$/kWh	0.037	0.037	0.037	0.028	0.027	0.027
Total Cost	US$/kWh	0.061	0.058	0.056	0.052	0.049	0.047
Operating Hours							
1000	US$/kWh	0.1887	0.1692	0.1561	0.1795	0.1601	0.1469
3000	US$/kWh	0.0873	0.0808	0.0764	0.0782	0.0717	0.0673
5000	US$/kWh	0.0671	0.0631	0.0605	0.0579	0.0540	0.0513
7000	US$/kWh	0.0584	0.0556	0.0536	0.0492	0.0464	0.0445
8000	US$/kWh	0.0557	0.0532	0.0515	0.0465	0.0441	0.0424
8760	US$/kWh	0.0540	0.0518	0.0502	0.0449	0.0426	0.0411

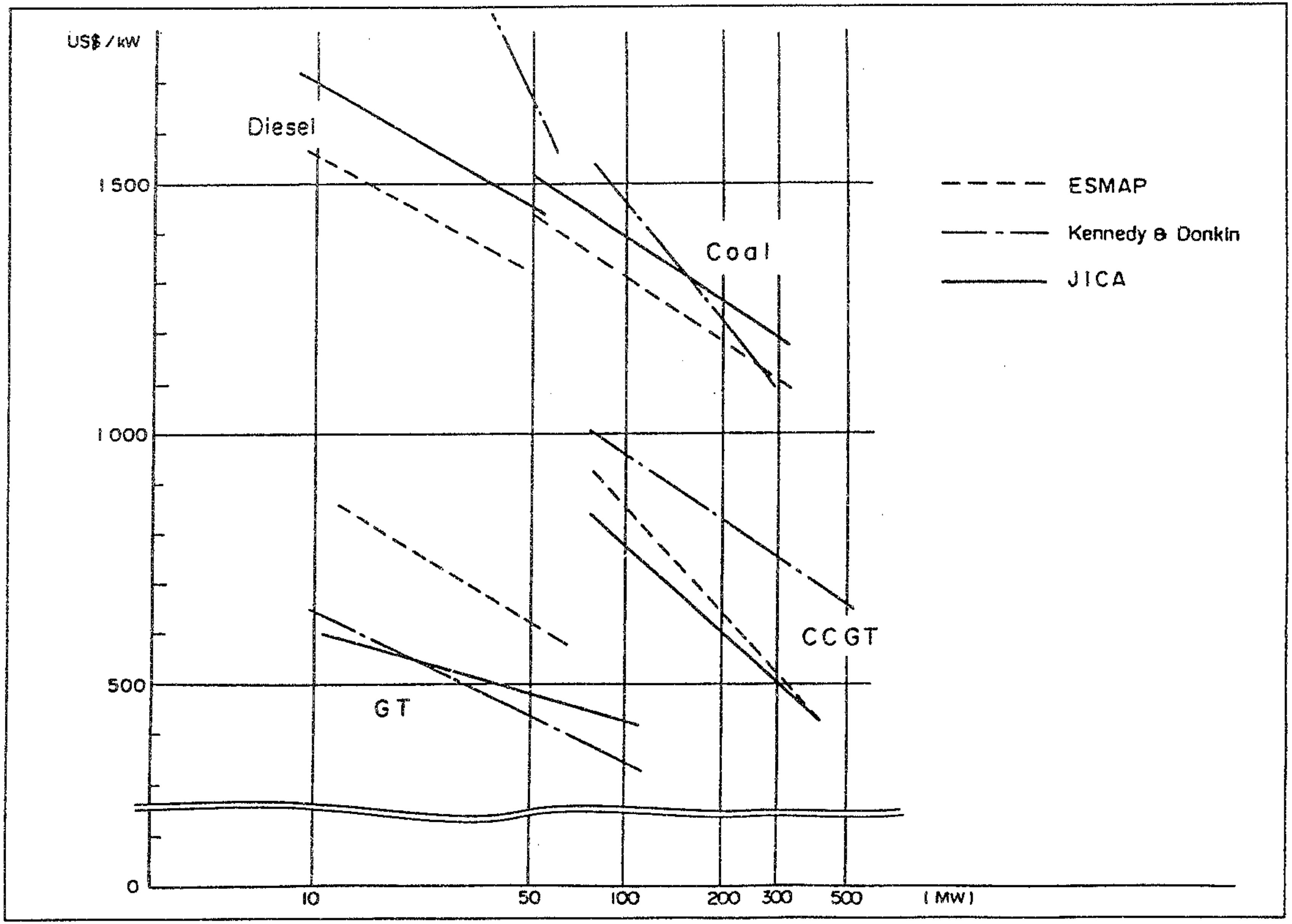

Figure 8.1 COMPARISON OF CONSTRUCTION COST

(2) Transport System for Petroleum Products and Coal

With improving living standard, diversification of energy to electric power is progressing. To cope with electric power demand, power plant is required in east side of the island to supply electric power efficiently and in higher reliability. This power plant is planned to use coal taking account of contribution in energy security in addition to economic point.

According to oil company, a study was made about transportation of jet fuel to air port by sea through new port in same location of the above, however that plan was not economically feasible due to high investment cost at that time. Now investment can be reduced by utilizing jetty for power plant mentioned above for putting a few lines for unloading petroleum products including jet fuel and oil terminal adjacent area to the plant. In this plan, petroleum products will be unloaded from ocean tanker and energy saving against present system is equivalent to energy consumption corresponding to difference of distance of inland transportation. Difference is 40 km for jet fuel and 30 km for others and corresponding energy saving is estimated as below.

- 100% of jet fuel, 20% of other petroleum products, except bunker and power generation use, of demand in 2025 are distributed from new terminal
- length of journey to air port is 10 km and average 20 km to other consumers
- size of lorry truck is 30 kl (10 ton for LPG)
- lorry truck energy consumption : 700 kcal/ton-km,(2000 kcal/truck-km for return way)

<u>New Mass Transport System Between Port Louis and Curepipe</u>

Motor way between Port Louis and Curepipe is critical condition and serious congestion is observed at the rush hour. Congestion and environmental pollution are concerned growing worse due to increasing vehicles. To prevent more critical condition, the government is planning to improve existing road and to construct new road. In addition to improvement of road net work, new mass-transport system is being studied to construct along the key motor way as substitution of transportation from personal car and public bus. Detail of new transport system is not available, however electricity is expected for driving power sources because of higher overall energy efficiency including power generation.

(3) Energy Conservation and the Development of Related Technology

1) Energy Conservation Activities in Mauritius

a) Bagasse Energy Development Project (BEDP)

The importance of efficient use of bagasse, which is a by-product of sugar production in the country, as the major indigenous energy source of the country is considered as the way to reduce the production cost of sugar for improving cost competitively of sugar in the international market is well recognized in the country, and the government of Mauritius obtaining the co-operation of sugar industry positively promoting use of bagasse energy for power generation in these years. (Ref: Chapter 5)

The capacity of bagasse power will exceed 20% of total generation capacity by AD 2000.

b) Energy Conservation in Electrical Sector.

At present, CEB is intending to replace old diesel engine power generators, which were built in 1970's and its energy efficiency is inferior to modern machine, by the latest design machines with power generation efficiency 45 ~ 46%. The introduction of high efficiency machine will reduce fuel consumption by 30~40%, but the financial justification of this improvement is difficult under present low oil price unless low cost fund is available.

As the renewable energy development, the development of wind power generation are continuing, but further technology improvement seems required to realize the commercial operation in large scale. (Ref: Para 4.5)

The reduction of energy loss by the transmission system has improved significantly in these years by replacement of old 33KV transmission system by 66KV system.

c) Energy Conservation in Industrial Sector

The current development of energy conservation in industrial sectors of Mauritius is not clear because of lack of reliable information. The JICA study team with assistance of the MEW counter team conducted "enquête" to collect information from major factory, but only 10% of the inquiry sent was responded. According to that limited amount of information, following estimation were made but accuracy is not high.

* The improvement of power efficiency, to above 90%, of almost all the factory were completed. The tax exemption of import of necessary equipment and the merit of tariff reduction by power efficiency improvement encouraged the improvement.
* The application of modern high efficiency lighting fixture is used by many industrial facility. The use of high frequency fluorescent seems more than 60% of the lighting.
* However, the application of high energy efficiency technology such as flow control by mean of the control of pump/blower speed by thyrister seems very limited. A report of University of Mauritius in relation to the energy efficiency improvement on steam boiler also indicating the majority of plants are still working on improvement of insulation and prevention of steam leak, and the energy saving, which require significant investment such as combustion air pre-heater, are not implemented by the most of plant. The response to JICA team inquiries also indicated the similar status as described in the report of U. M. on present energy conservation in most of industries.

d) Domestic Energy Use

The use of solar energy water heater is pretty well developed in the country. The present estimate of total number in use is 18,000. (The total household in Mauritius is 240,000) The increase of use is slowed down because of maintenance problem and the high initial cost for the low income house hold.

(4) The Bottle-neck of Energy Conservation Activities in Mauritius and Its Solution.

1) The lack of national consensus on the importance of energy conservation as the element of national energy policy

It is very desirable that the national energy policy, which will be promoted by MLGPU, will include the strategy for activating the energy conservation. The strategy must include two measures mentioned in the followings.

2) Set-up of a core organization for the energy conservation

It is recommended that the MLGPU should set up a core organization for long term national energy conservation program, we may name the organization as "the energy conservation center" with the participation of private sectors. This center will function as the spear-head of the national program of energy conservation/environment management to activate energy conservation in the broad scenes.

This center should be the center point of collecting data & information of the country and of abroad relating to the energy conservation continuously, and the collected useful information should be distributed to the concerned party as required from this center.

3) The comprehensive and continuous collection of energy related information from all the public and private sectors.

The Government provides the incentive for sumission of reliable data from related parties. Take for an example when the submitted information indicates excellent performance in respect of energy conservation, Government send prize to such party or the low cost fund will be provided for the project implementation of the party which is positively co-operating to provide the data & information useful to promote the energy conservation of the country.

Suggestion on Practical Plan for Energy Conservation

1) Promotion of Cogeneration of Electricity and Heat
2) Diversification of Energy Resources
3) Development of Non-traditional Energy

Chapter 9 Optimum Investment Plan

(1) Power development plan

We prepared the power development plan up to 2025. The JICA study team paid attention to the supply reserve capacity and formulated a plan aiming at bringing the reserve capacity to between minimum 10% and 20% (including 5% of spinning reserve), as a more realistic approach.

From chart 7, the power demand forecast is estimated as Table 9.1. The capacity of the existing facilities is shown in Table 9.2. No maintenance work is scheduled for the maximum consumption months of December. The forced-outage rates are shown in Table 9.2. The retirement plan of power plants was formulated on the basis of the site survey and through discussion with the CEB. Due to their extensive deterioration, and especially with Fort victoria (Mirrlees), of the constant outage of one or two units because of failure, it was decided to decommission Fort Victoria and St. Louis according to the schedule shown in Table 9.3.

From above condition, for Base Case and High Case of demand forecast, following three scenario is assumed.

Scenario 1

From 2021 to 2025, Coal-fired plant with 100 MW will be started to operate every year.

Scenario 2

In 2013 and 2014, Coal-fired plant with 100 MW will be started to operate and from 2023 to 2025, Coal-fired plant with 100 MW will be started to operate every year.

Scenario 3

From 2002 to 2006, Diesel with 50 MW will be stated to operate and from 2021 to 2025, Coal-fired plant with 100 MW will be started to operate every year

For reference, forecasted typical operation pattern on maximum load day is shown as Table

9.4~9.6.

1. Short-term Plan (from 1996 to 2000)

Tables 9.7 shows the power development plans for the 5 years between 1996 and 2000. The power demands for the respective months were estimated on the basis of load curves obtained on the basis of the assumed demand for the respective years.

As there are several months with shortage of electricity in 1998 according to Table 9.7, an additional 34 MW GT should be considered urgently.

2. Medium and Long term Plan

After 2001, Fort George Unit #5 will start operation in 2001, followed by the development of 50 - 75 MW GT and 150 - 225 MW CCGT in combination in the course of time.

As the power system is expected to increase to 1,100 - 1,600 MW by 2020 to 2025, the installation of 100 MW power supply units becomes feasible, and the JICA study team recommends the introduction of coal-only thermal power stations to reduce generation cost.

(2) Transmission Line and Substation Plan

Recommendations or expansion planning are summarized as follows,

1) Short-term(1996-2000)

The result of the analysis carried out for the short-term indicate that the 66kV voltage can be maintained in the period to the year 2000.

In evaluating the costs, it has been assumed that all of the future transmission lines will be constructed in accordance with 132kV design standards, to facilitate upgrading to the higher voltage in the longer term.

From a technical point of view, given that the short-term generation plan indicates that Fort-George should continue to be extended, and that energy needs to be transmitted to the Curepipe area.

Scenario 1 will be recommended for the transmission development in the short-term after economic evaluation of three alternative scenarios.
Breakdown of scenario 1 is shown in Table 9.8 and the drawing in Figure 9.1.

The distributed forecast of evening peak loads, 1995-1999 is shown in Table 9.9.

2) Medium & long-term(2001-2015)

The result of the long-term transmission planning analysis suggest that the 132kV voltage should be introduced for the part of the system during the medium-term between years 2005 and 2008, with the precise timing depending on the load forecast scenario assumed. Under the base load forecast, the first upgrade to 132kV operation on the system would be required in 2007.

This scenario turns out to be the optimum from the transmission viewpoint, with generation at Fort-William initially connected to the 66kV network. In the period between 2005 and 2008 part of the network is uplifted to 132kV voltage level.

(3) Purpose

The purpose of this chapter is to select through econometric comparative evaluation the investment plan that is the most advantageous in terms of finance and economy from among the power supply investment plans which have been proposed from the technical perspective to meet the projected total power demand.

(4) Evaluation and selection methods

Comparative evaluation models shall be used to select the plan that is the most advantageous in terms of finance and economy from among the proposed power supply plans to meet power demand in the future. Since the power demand to be met (direct benefit) in the future is the same in any of the cases under consideration, the minimum cost method shall be used in comparative evaluation of the proposed plans.

(5) Outline of evaluation models

For the purpose of financial and economic evaluation of the proposed investment plans, evaluation models built for the present project shall be used. The outline of the models prepared using MS/EXCEL is given below.

1) Financial cost evaluation model

* Input the disbursement amount for each year, including the escalation, to the investment schedule sheet that covers the entire investment period starting from the base year.
* Input all the operating costs (variable and fixed) over the entire period of evaluation, starting from the base year, to prepare a summary table of operating costs, including the escalation.
* Obtain the present values of those costs using a program for calculating present values by a certain discount rate.
* Prepare a comparison table of the alternative cases (for selecting the optimum case).
* Work out a method of sensitivity analysis for confirming the variation of evaluation results due to changes of major cost items or evaluation conditions.

2) Economic cost evaluation model

* Build an automatic calculation model which excludes the transfer costs included in all cost items and makes necessary adjustments of the individual cost items to convert the financial costs into economic costs.
* The calculation models for the investment schedule and cost summary table shall be the same as the ones for the financial evaluation model.

Table 9.1 ELECTRICITY PEAK DEMAND FORECAST

Unit : MW

Years	Base case	High case	Low case
1995	200	200	200
1996	222	222	222
1997	241	242	241
1998	257	257	256
1999	271	272	271
2000	288	289	287
2001	315	323	313
2002	344	358	339
2003	372	395	364
2004	402	435	390
2005	428	474	413
2006	455	515	435
2007	485	563	460
2008	516	615	485
2009	549	672	512
2010	584	735	539
2011	601	755	565
2012	655	772	612
2013	711	842	660
2014	770	916	709
2015	831	993	760
2016	895	1,076	813
2017	963	1,163	868
2018	1,035	1,256	925
2019	1,110	1,356	985
2020	1,191	1,462	1,048
2021	1,276	1,576	1,114
2022	1,367	1,698	1,184
2023	1,465	1,829	1,257
2024	1,569	1,970	1,334
2025	1,680	2,122	1,415

Note: refer to Chapter 7

Table 9.2 CONDITION OF POWER GENERATION FACILITIES

Plant Name & Type	Unit Capacity	Available Units	Effective Capacity	Forced Outage
	MW		MW	p.u.
St. Louis	10	6	60	0.25
Fort Victoria (New)	9	2	18	0.15
Fort Victoria (Old)	4	7	28	0.25
Nicolay	23	1	23	0.04
	23	1	23	0.04
	34	1	34	0.04
Fort George 1&2	24	2	48	0.05
Fort George 3,4&5	29	3	87	0.05
Hydro	10		10	0.01
Bagasse cum coal	---	-	---	0.15
GT (new)				0.03
CCGT (new)				0.03
Coal (new)				0.03

1. Service Life
   - Diesel : 25 years
   - GT : 20 years
   - CCGT : 20 years
   - Coal : 25 years
2. Forced Outage
   - St. Louis : fixed
   - Fort Victoria : fixed
   - others : 1% increses by 5 years

Table 9.3 RETIREMENT PROGRAM

Year	Plant Name	Retired Capacity (MW)	
		Unit	Total
1995			
1996			
1997			
1998			
1999	St. Louis 3	10	10
2000	Fort Victoria 6	4	28
	Fort Victoria 5	4	
	St. Louis 1& 2	20	
2001	Fort Victoria 4	4	18
	Fort Victoria 7	4	
		10	
2002	Fort Victoria 8	4	8
	Fort Victoria 9	4	
2003	Fort Victoria 10	4	14
	St. Louis 4	10	
2004	St. Louis 5	10	10
2005	St. Louis 6	10	10
2006	Fort Victoria MAN 1	9	9
2007	Fort Victoria MAN 2	9	9

Table 9.4 POWER DEVELOPMENT PLAN (BASE CASE-1)

as of end Dec.

Year	Peak Demand Forecast (MW) (a)	Added Capacity (MW)	Added Units	Retired or Transferred Capacity (MW)	Retired or Transferred Units	Total Capacity (MW) (b)	Biggest Unit (MW) (c)	Available Capacity (MW) (d)=(b)-(c)	Margin (e)=(d)-(a) (MW)	Margin (e)=(d)-(a) (%)
1996	222	29	FG3(29)			285	34.0	251.0	29.0	13.1
1997	241	15	Beau Champ(15), Bagasse Replace(3.5)*			300	34.0	266.0	25.0	10.4
1998	257	34	Bagasse Replace(9)* #GT(34)			334	34.0	300.0	43.0	16.7
1999	271	29	FG4	10	St.L.(10)	353	34.0	319.0	48.0	17.7
2000	288	40	Belle Vue	28	2F.V.(4, 4), 2St.L.(10,10)	365	34.0	331.0	43.0	14.9
2001	315	29	FG5	8	2F.V.(4, 4)	386	34.0	352.0	37.0	11.7
2002	344	50	GT*	8	2F.V.(4, 4)	428	50.0	378.0	34.0	9.9
2003	372	50	GT*	14	F.V.(4), St.L.(10)	464	50.0	414.0	42.0	11.3
2004	402	150	CCGT	110	St.L.(10),2GT(50, 50)*	504	50.0	454.0	52.0	12.9
2005	428	50	GT*	10	St.L.(10)	544	50.0	494.0	66.0	15.4
2006	455	50	GT*	9	F.V.(9)	585	50.0	535.0	80.0	17.6
2007	485	150	CCGT	109	F.V.(9),2GT(50, 50)*	626	50.0	576.0	91.0	18.8
2008	516	50	GT*	23	Nicolay(23)	653	50.0	603.0	87.0	16.9
2009	549	50	GT*			703	50.0	653.0	104.0	18.9
2010	584	150	CCGT	100	2GT(50, 50)*	753	50.0	703.0	119.0	20.4
2011	601	50	GT*	23	Nicolay(23)	780	50.0	730.0	129.0	21.5
2012	655	50	GT*			830	50.0	780.0	125.0	19.1
2013	711	150	CCGT	100	2GT(50, 50)*	880	50.0	830.0	119.0	16.7
2014	770	75	GT*			955	75.0	880.0	110.0	14.3
2015	831	75	GT*	34	Nicolay(34)	996	75.0	921.0	90.0	10.8
2016	895	225	CCGT	150	2GT(75, 75)*	1,071	75.0	996.0	101.0	11.3
2017	963	200	2GT(75, 75)*,GT(50)	24	FG1(24)	1,247	75.0	1,172.0	209.0	21.7
2018	1,035	225	CCGT	174	FG2(24), 2GT(75, 75)*	1,298	75.0	1,223.0	188.0	18.2
2019	1,110	150	2GT(75, 75)*	34	GT(34)	1,414	75.0	1,339.0	229.0	20.6
2020	1,191	225	CCGT	150	2GT(75, 75)*	1,489	75.0	1,414.0	223.0	18.7
2021	1,276	100	Coal(2*100)			1,589	100.0	1,489.0	213.0	16.7
2022	1,367	150	GT(50),Coal(100)*	29	FG3(29)	1,710	100.0	1,610.0	243.0	17.8
2023	1,465	100	Coal(3*100)			1,810	100.0	1,710.0	245.0	16.7
2024	1,569	150	GT(50),Coal(100)*			1,960	100.0	1,860.0	291.0	18.5
2025	1,680	100	Coal*			2,060	100.0	1,960.0	280.0	16.7

Table 9.5 POWER DEVELOPMENT PLAN (BASE CASE-2)

as of end Dec.

Year	Peak Demand Forecast (MW) (a)	Added		Retired or Transferred		Total Capacity (MW) (b)	Biggest Unit (MW) (c)	Available Capacity (MW) (d)=(b)-(c)	Margin (e)=(d)-(a)	
		Capacity (MW)	Units	Capacity (MW)	Units				(MW)	(%)
1996	222	29	FG3(29)			285	34.0	251.0	29.0	13.1
1997	241	15	Beau Champ(15), Bagasse Replace(3.5)*			300	34.0	266.0	25.0	10.4
1998	257	34	Bagasse Replace(9)* #GT(34)			334	34.0	300.0	43.0	16.7
1999	271	29	FG4	10	St.L.(10)	353	34.0	319.0	48.0	17.7
2000	288	40	Belle Vue	28	2F.V.(4, 4), 2St.L.(10,10)	365	34.0	331.0	43.0	14.9
2001	315	29	FG5	8	2F.V.(4, 4)	386	34.0	352.0	37.0	11.7
2002	344	50	GT*	8	2F.V.(4, 4)	428	50.0	378.0	34.0	9.9
2003	372	50	GT*	14	F.V.(4), St.L.(10)	464	50.0	414.0	42.0	11.3
2004	402	150	CCGT	110	St.L.(10),2GT(50, 50)*	504	50.0	454.0	52.0	12.9
2005	428	50	GT*	10	St.L.(10)	544	50.0	494.0	66.0	15.4
2006	455	50	GT*	9	F.V.(9)	585	50.0	535.0	80.0	17.6
2007	485	150	CCGT	109	F.V.(9),2GT(50, 50)*	626	50.0	576.0	91.0	18.8
2008	516	50	GT*	23	Nicolay(23)	653	50.0	603.0	87.0	16.9
2009	549	50	GT*			703	50.0	653.0	104.0	18.9
2010	584	150	CCGT	100	2GT(50, 50)*	753	50.0	703.0	119.0	20.4
2011	601	50	GT*	23	Nicolay(23)	780	50.0	730.0	129.0	21.5
2012	655	50	GT*			830	50.0	780.0	125.0	19.1
2013	711	150	CCGT	100	2GT(50, 50)*	880	50.0	830.0	119.0	16.7
2014	770	100	Coal(2*100)			980	100.0	880.0	110.0	14.3
2015	831	100	Coal*	34	Nicolay(34)	1,046	100.0	946.0	115.0	13.8
2016	895	75	GT			1,121	100.0	1,021.0	126.0	14.1
2017	963	125	GT(75)*,GT(50)	24	FG1(24)	1,222	100.0	1,122.0	159.0	16.5
2018	1,035	225	CCGT	174	FG2(24), 2GT(75, 75)*	1,273	100.0	1,173.0	138.0	13.3
2019	1,110	150	2GT(75, 75)*	34	GT(34)	1,389	100.0	1,289.0	179.0	16.1
2020	1,191	225	CCGT	150	2GT(75, 75)*	1,464	100.0	1,364.0	173.0	14.5
2021	1,276	150	2GT(75, 75)*			1,614	100.0	1,514.0	238.0	18.7
2022	1,367	275	GT(50),CCGT(225)	179	FG3(29), 2GT(75, 75)*	1,710	100.0	1,610.0	243.0	17.8
2023	1,465	100	Coal(3*100)			1,810	100.0	1,710.0	245.0	16.7
2024	1,569	150	GT(50),Coal(100)*			1,960	100.0	1,860.0	291.0	18.5
2025	1,680	100	Coal*			2,060	100.0	1,960.0	280.0	16.7

Table 9.6 POWER DEVELOPMENT PLAN (BASE CASE-3)

as of end Dec.

Year	Peak Demand Forecast (MW) (a)	Added Capacity (MW)	Added Units	Retired or Transferred Capacity (MW)	Retired or Transferred Units	Total Capacity (MW) (b)	Biggest Unit (MW) (c)	Available Capacity (MW) (d)=(b)-(c)	Margin (e)=(d)-(a) (MW)	Margin (%)
1996	222	29	FG3(29)			285	34	251.0	29.0	13.1
1997	241	15	Beau Champ(15), Bagasse Replace(3.5)*			300	34	266.0	25.0	10.4
1998	257	34	Bagasse Replace(9)* #GT(34)			334	34	300.0	43.0	16.7
1999	271	29	FG4	10	St.L.(10)	353	34	319.0	48.0	17.7
2000	288	40	Belle Vue	28	2F.V.(4, 4), 2St.L.(10,10)	365	34	331.0	43.0	14.9
2001	315	29	FG5	8	2F.V.(4, 4)	386	34	352.0	37.0	11.7
2002	344	50	Diesel	8	2F.V.(4, 4)	428	50	378.0	34.0	9.9
2003	372	50	Diesel	14	F.V.(4), St.L.(10)	464	50	414.0	42.0	11.3
2004	402	50	Diesel	10	St.L(10)	504	50	454.0	52.0	12.9
2005	428	50	Diesel	10	St.L.(10)	544	50	494.0	66.0	15.4
2006	455	50	Diesel	9	F.V.(9)	585	50	535.0	80.0	17.6
2007	485	50	Diesel	9	F.V.(9)	626	50	576.0	91.0	18.8
2008	516	50	GT*	23	Nicolay(23)	653	50	603.0	87.0	16.9
2009	549	50	GT*			703	50	653.0	104.0	18.9
2010	584	150	CCGT	100	2GT(50, 50)*	753	50	703.0	119.0	20.4
2011	601	50	GT*	23	Nicolay(23)	780	50	730.0	129.0	21.5
2012	655	50	GT*			830	50	780.0	125.0	19.1
2013	711	150	CCGT	100	2GT(50, 50)*	880	50	830.0	119.0	16.7
2014	770	75	GT*			955	75	880.0	110.0	14.3
2015	831	75	GT*	34	Nicolay(34)	996	75	921.0	90.0	10.8
2016	895	225	CCGT	150	2GT(75, 75)*	1,071	75	996.0	101.0	11.3
2017	963	200	2GT(75, 75)*,GT(50)	24	FG1(24)	1,247	75	1,172.0	209.0	21.7
2018	1,035	225	CCGT	174	FG2(24), 2GT(75, 75)*	1,298	75	1,223.0	188.0	18.2
2019	1,110	150	2GT(75, 75)*	34	GT(34)	1,414	75	1,339.0	229.0	20.6
2020	1,191	225	CCGT	150	2GT(75, 75)*	1,489	75	1,414.0	223.0	18.7
2021	1,276	100	Coal(2*100)			1,589	100	1,489.0	213.0	16.7
2022	1,367	150	GT(50),Coal(100)*	29	FG3(29)	1,710	100	1,610.0	243.0	17.8
2023	1,465	100	Coal(3*100)			1,810	100	1,710.0	245.0	16.7
2024	1,569	150	GT(50),Coal(100)*			1,960	100	1,860.0	291.0	18.5
2025	1,680	100	Coal*			2,060	100	1,960.0	280.0	16.7

Table 9.7 POWER DEMAND AND SUPPLY IN 1998 (BASE CASE)

Unit : MW

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Fort George 1	24	24	24	24	24	24	24			24	24	24
Fort George 2	24	24	24	24			24	24	24	24	24	24
Fort George 3	29	29			29	29	29	29	29	29	29	29
St. Louis	50	50	50	50	60	50	50	50	50	50	50	50
Fort Victoria 1	28	28	28	28	28	28	24	24	24	24	24	24
Fort Victoria 2	9	9	18	18	18	18	9	18	18	18	18	18
Nicolay 1	23	23	23	23	23	23	23	23	23	23	23	23
Nicolay 2	23	23		23	23	23	23	23	23	23	23	23
Nicolay 3	34	34	34	34	34	34	34	34	34		34	34
Hydro	10	25	45	45	30	30	15	15	15	10	10	10
FUEL	15	15	15			15	18	18	18	18	18	18
Medine							4	4	6	6	6	
Riche en Eau							5	5	5	5	5	
Union St. Aubin							5	5	5	5	5	
Mon Desert Alma							4.5	4.5	4.5	4.5	4.5	
Mon Tresor Mon Desert							2	2	2	2	2	
Mon Loiser							4.5	4.5	4.5	4.5	4.5	
Beau Champ			15	15	15	15	12	12	12	12	12	15
Savannah							5	5	5	5		
Other Bagasse							1.1	1.1	1.1	1.1	1.1	
Total Supply Capacity (a)	269.0	284.0	276.0	284.0	284.0	289.0	316.1	301.1	303.1	288.1	317.1	292.0
Biggest Unit Capacity (b)	34	34	34	34	34	34	34	34	34	29	34	34
Available Supply Capacity (c)=(a)-(b)	235.0	250.0	242.0	250.0	250.0	255.0	282.1	267.1	269.1	259.1	283.1	258.0
Peak Demand (d)	230.9	234.4	237.9	242.6	239.1	236.9	236.7	238.2	238.8	242.0	249.5	246.6
Spinning Reserve (5%) (e)	11.5	11.7	11.9	12.1	12.0	11.8	11.8	11.9	11.9	12.1	12.5	12.3
Total Demand (f)=(d)+(e)	242.4	246.1	249.8	254.7	251.1	248.7	248.5	250.1	250.7	254.1	262.0	258.9
Margin (g)=(c)-(f)	-7.4	3.9	-7.8	-4.7	-1.1	6.3	33.6	17.0	18.4	5.0	21.1	-0.9
Margin (%) (g)/(d)	-3.2	1.7	-3.3	-1.9	-0.4	2.6	14.2	7.1	7.7	2.1	8.5	-0.4

Table 9.8 SHORT TERM TRANSMISSION PLANNING

SCENARIO-1

NO	PROJECT		FOREIGN	LOCAL	1994	ENGINEERING	TOTAL COST			PHASING					
							COSTS IN 1994 PRICES			96	97	98	99	00	TOTAL
			COSTS IN US$ 1000			5%	TOTAL	FOREIGN	LOCAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	1995-2000
1	132kV OH LINE NOCOLAY/L'AVENIR/WOOTON	MATERIAL	1180		1738	87	1825	1239	0			1825			1825
	19.5KM	ERECTION	311	247				327	259						0
2	132kV OH LINE L'AVENIR/AMOURY	MATERIAL	907		1337	67	1404	952	0			1404			1404
	15KM	ERECTION	240	190				252	200						0
3	132kV TRANSFORMERS ROSE HILL	MATERIAL	815	215	1200	60	1260	856	226						0
		ERECTION		170				0	179						0
4	66kV OH LINE NICOLAY-MONT CHOIS	MATERIAL	1089		1605	80	1685	1143	0						0
	18KM	ERECTION	288	228				302	239						0
5	66/132kV SUBSTATION NICOLAY	MATERIAL	5225	1742	10450	550	11000	5486	1829		5500	5500			11000
		ERECTION	1742	1742				1829	1829						0
6	132kV SUBSTATION L'AVENIR	MATERIAL	2195	732	4389	231	4620	2304	768		2310	2310			4620
		ERECTION	732	732				768	768						0
7	66/132kV SUBSTATION WOOTON	MATERIAL	349	116	697	37	734	366	122		367	367			734
		ERECTION	116	116				122	122						0
8	132/66kV SUBSTATION AMOURY	MATERIAL	1164	388	2328	123	2450	1222	407		1225	1225			2450
		ERECTION	388	388				407	407						0
9	132kV SUBSTATION ST. LOUIS	MATERIAL	118	39	236	12	248	124	41		124	124			248
		ERECTION	39	39				41	41						0
10	132kv SUBSTATION ROSE HILL	MATERIAL	118	39	236	12	248	124	41		124	124			248
		ERECTION	39	39				41	41						0
11	132kV OH LINE ST. LOUIS/ROSE HILL	MATERIAL	454		669	33	702	477	0				702		702
	7.5KM	ERECTION	120	95				126	100						0
12	132kV OH LINE ROSE HILL/WOOTON	MATERIAL	605		891	45	936	635	0				936		936
	10KM	ERECTION	160	126				168	132						0
13	66kV OH LINE /CABLE WOOTON/HENRIETTA	MATERIAL			0	0	0	0	0						0
		ERECTION						0	0						0
14	66kV OH LINE BELLE VUE/MONT CHOIS	MATERIAL	140		215	11	226	147	0						0
	5KM	ERECTION	40	35				42	37						0
15	66kV OH LINE HENRIETTA/CHAMAREL	MATERIAL	420		645	32	677	441	0						0
	15KM	ERECTION	120	105				126	110						0
															24167
17															
	CAPITAL COST									0	9650	12879	1638	0	24167
	MAINTENANCE									0	193	450.58	483.34	483.34	
	SYSTEM LOSSES									492	578	670	782	918	
	TOTAL									492	10421	14000	2903	1401	
	NPV IN MILLION US$	21.35													

Table 9.9 DISTRIBUTED FORECAST OF EVENING PEAK LOADS, 1995-1999

YEAR	Feb-95	MVA	PEAK 95	MVA	PEAK 96	MVA	PEAK 97	MVA	PEAK 98	MVA	PEAK 99	MVA
BELLE VUE	853	33	925	36	1000	39	1070	41	1140	44	1220	47
BELLE VUE-2												
AMOURY												
GOODLANDS												
FUEL	494	19	555	21	555	21	610	24	665	26	720	28
FUEL-2												
FERNEY	488	19	557	22	626	24	695	27	764	30	833	32
WOOTON	767	30	829	32	891	34	953	37	1015	39	1077	42
FLOREAL												
ROSE HILL	432	17	492	19	534	21	576	22	618	24	660	25
CANDOS												
HENRIETTA	544	21	600	23	650	25	700	27	755	29	810	31
COMBO												
CHAUMIERE	583	23	647	25	709	27	771	30	833	32	895	35
PALMA												
ST. LOUIS	506	20	528	20	546	21	565	22	585	23	606	23
PORT LOUIS												
FT. GEORGE												
NICOLAY	727	28	810	31	890	34	960	37	1030	40	1110	43
ARSENAL												
TOTAL FEEDERS	5394		5943		6401		6900		7405		7931	
MVA	208	208	230	230	247	247	267	267	286	286	306	306
MW LOAD	177		195		210		227		243		260	

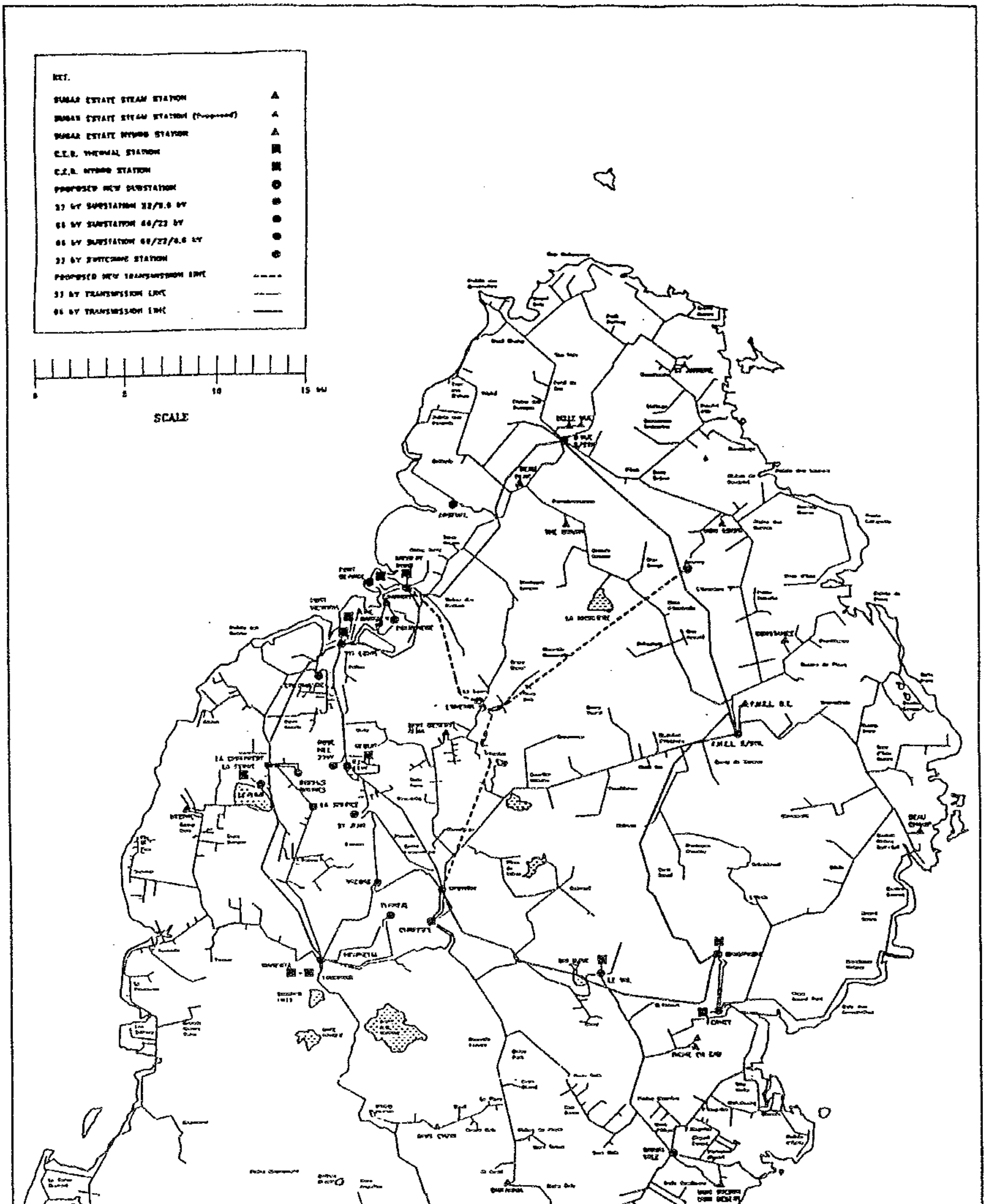

Figure 9.1 EXISTING TRANSMISSION LINE & PROPOSED NEW TRANSMISSION LINE (2000)

(6) Calculated cumulative costs of individual plans

Concerning the three power supply plans (Cases I-1, II-1, and III-1) for base power demand and the three power supply plans (I-2, II-2, and III-3) for high power demand, the costs of investment and operation in terms of finance and economy were calculated.

(7) Present values of total costs and selection of minimum investment cost case

1) The total costs by year in each of the cases were converted into present values using the discount rates described below. The results are shown in Table 9.10 and Figures 9.2 through 9.5. From the results, with the discount rate fixed at 12.5%, in the case of base demand, Scenario 1 is the minimum cost case in terms of both financial cost and economic cost, whereas in the case of high demand, Scenario 1 is the minimum cost case in terms of financial cost, but in terms of economic cost, there is minimal difference between Scenarios 1 and 3. In any case, Scenario 2 cannot be the minimum cost case.

2) In the case of base demand, Scenario 1 and Scenario 3 reverse in economic cost advantage with the discount rate of 11.43% as the border line. At a discount rate below 11.43%, Scenario 3 has the cost advantage, whereas at a higher discount rate, Scenario 1 is advantageous.

3) In the case of high demand, the advantages in terms of financial and economic costs shift from Scenario 3 to Scenario 1 at certain discount rates--4.86% for financial cost and 11.43% for economic cost.

4) In view of the current financial situation, the most reasonable discount rate is considered to be about 16% for investment by CEB (government agency) and about 21% for private investment (BOT, BOO, etc.).

(8) Conclusion

The results of the present study show that Scenario 1 is the most advantageous in terms of financial and economic costs in both cases of base demand and high demand.

Table 9.10 ANALYTICAL STUDY ON THE PRESENT VALUE OF TOTAL COST OF THE CASES

(1) COMPARISON OF CALCULATED PRESENT VALUE

Case	Discount Rate :	0.00%	2.50%	5.00%	7.50%	10.00%	12.50%	15.00%	17.50%	20.00%	22.50%	25.00%	27.50%	30.00%
Base Case	Financial													
	I-1	9,914	6,073	3,876	2,578	1,787	1,288	963	746	596	489	411	353	309
	II-1	11,348	6,937	4,413	2,921	2,011	1,438	1,066	817	646	525	438	373	324
	III-1	9,984	6,140	3,939	2,638	1,842	1,339	1,010	789	635	525	444	384	337
Base Case	Economic													
	I-1	7,990	4,902	3,135	2,090	1,453	1,050	789	613	492	406	343	298	260
	II-1	9,206	5,636	3,592	2,383	1,645	1,180	878	676	536	438	366	313	273
	III-1	7,858	4,838	3,110	2,088	1,464	1,069	811	637	516	429	366	318	281
High Case	Financial													
	I-2	11,775	7,173	4,555	3,017	2,083	1,498	1,118	865	690	566	475	408	356
	II-2	11,749	7,173	4,567	3,033	2,100	1,513	1,132	876	699	573	481	412	360
	III-2	11,694	7,142	4,557	3,039	2,117	1,537	1,160	907	731	606	513	444	390
High Case	Economic													
	I-2	9,552	5,825	3,704	2,457	1,701	1,226	918	713	571	470	396	342	299
	II-2	9,512	5,816	3,710	2,470	1,715	1,239	930	723	579	477	402	346	303
	III-2	9,271	5,665	3,619	2,419	1,690	1,232	935	735	596	496	423	368	325

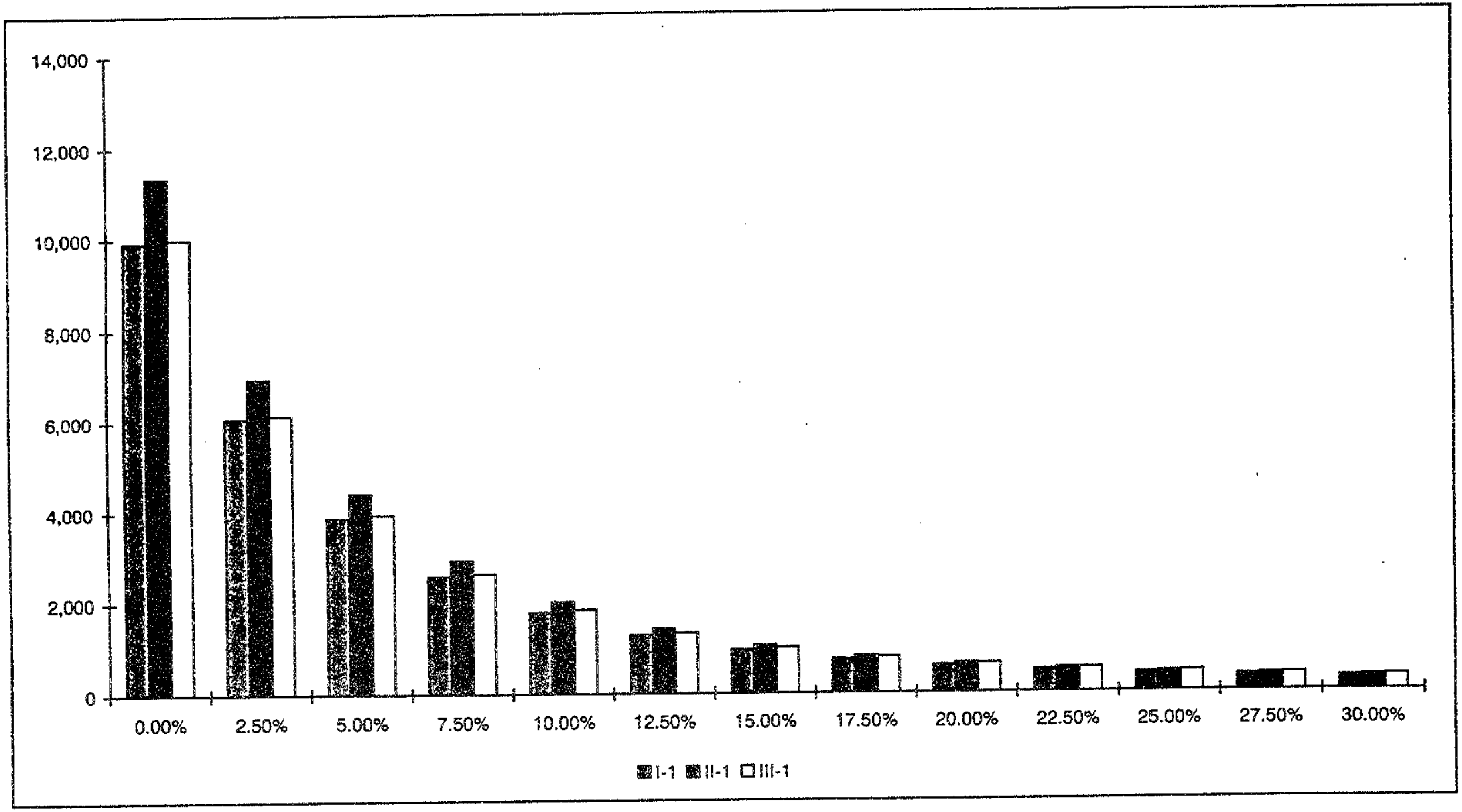

Figure 9.2 COMPARISON OF CALUCULATED PRESENT VALUE - BASE CASE FINANCIAL

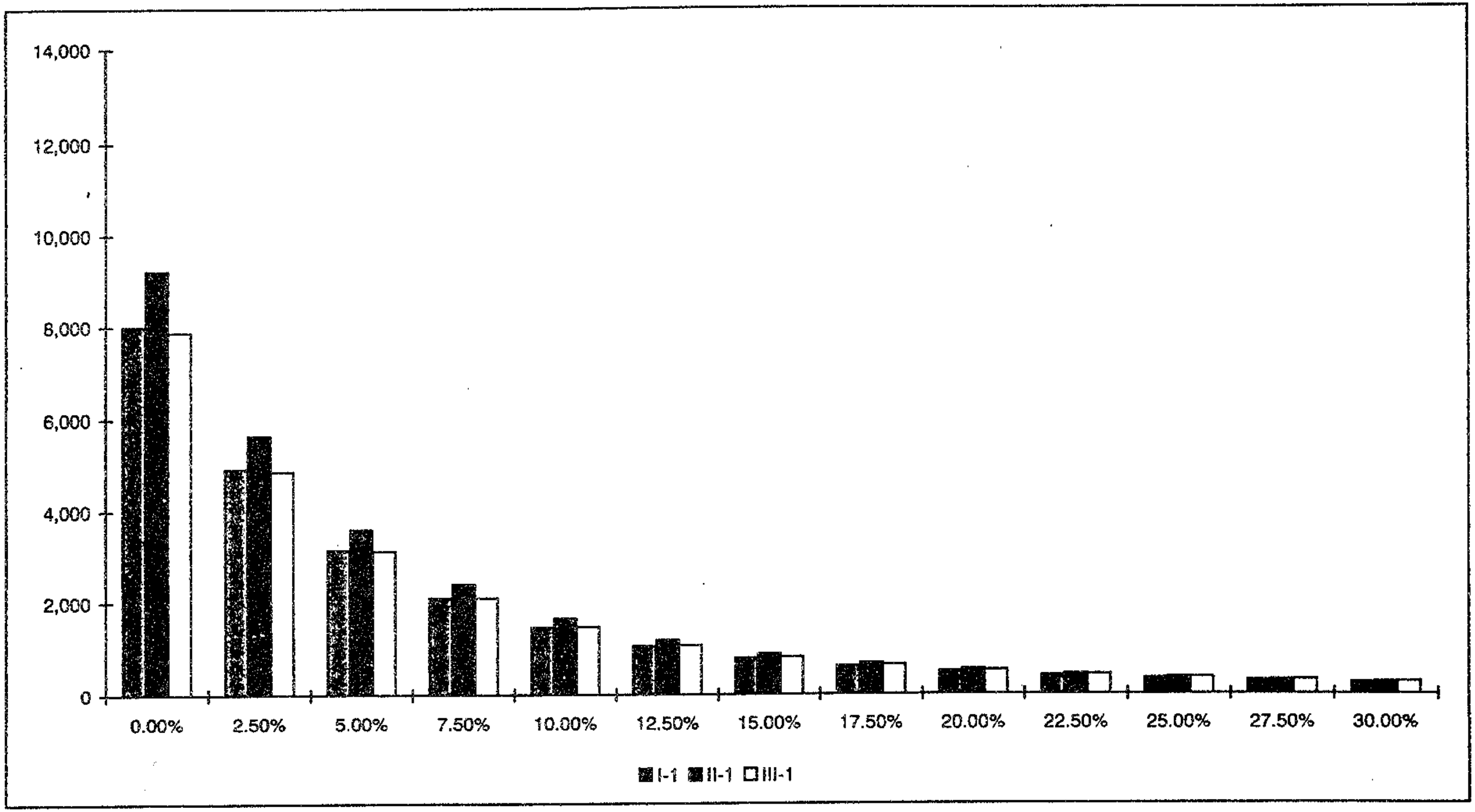

Figure 9.3 COMPARISON OF CALUCULATED PRESENT VALUE - BASE CASE ECONOMIC

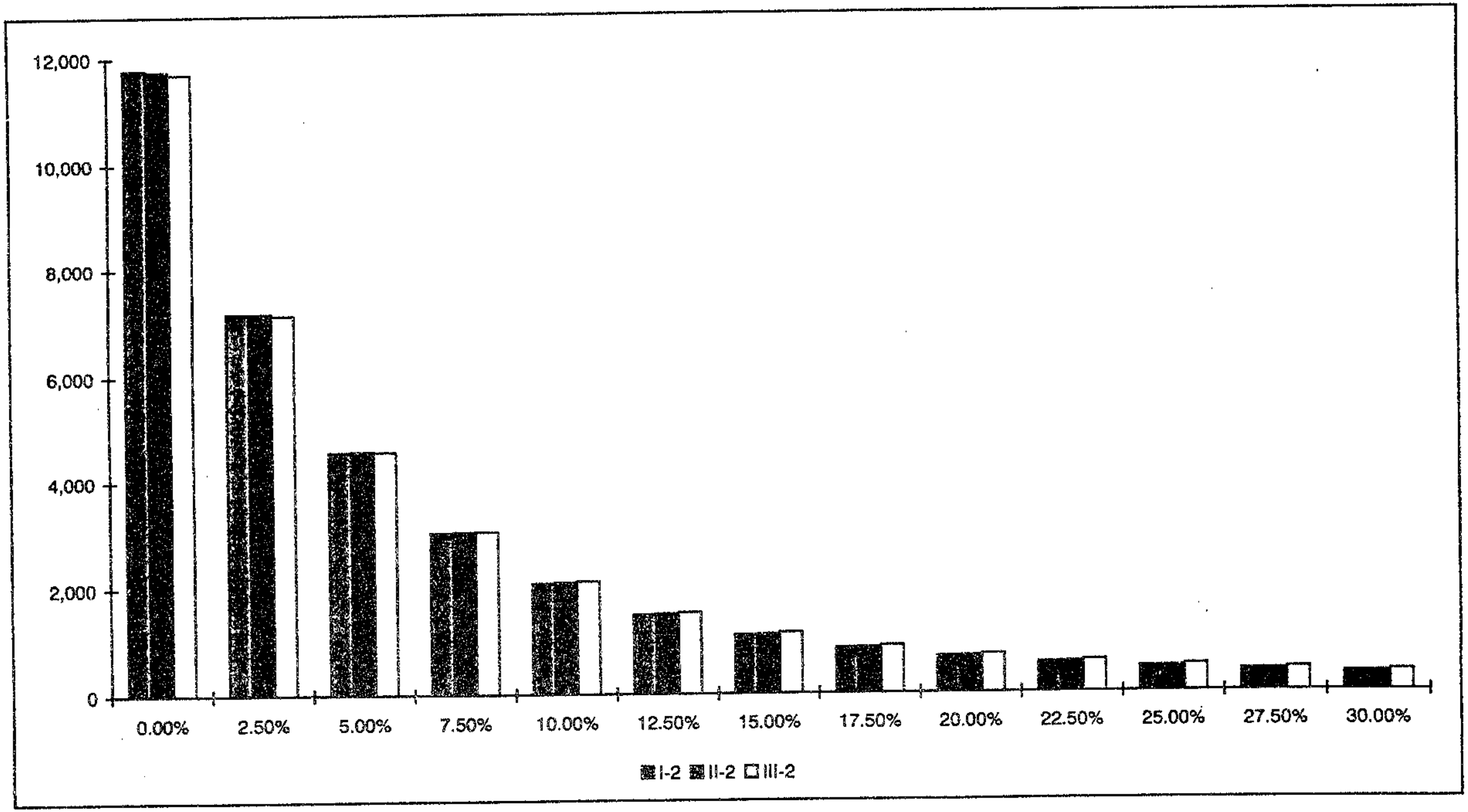

Figure 9.4 COMPARISON OF CALUCULATED PRESENT VALUE - HIGH CASE FINANCIAL

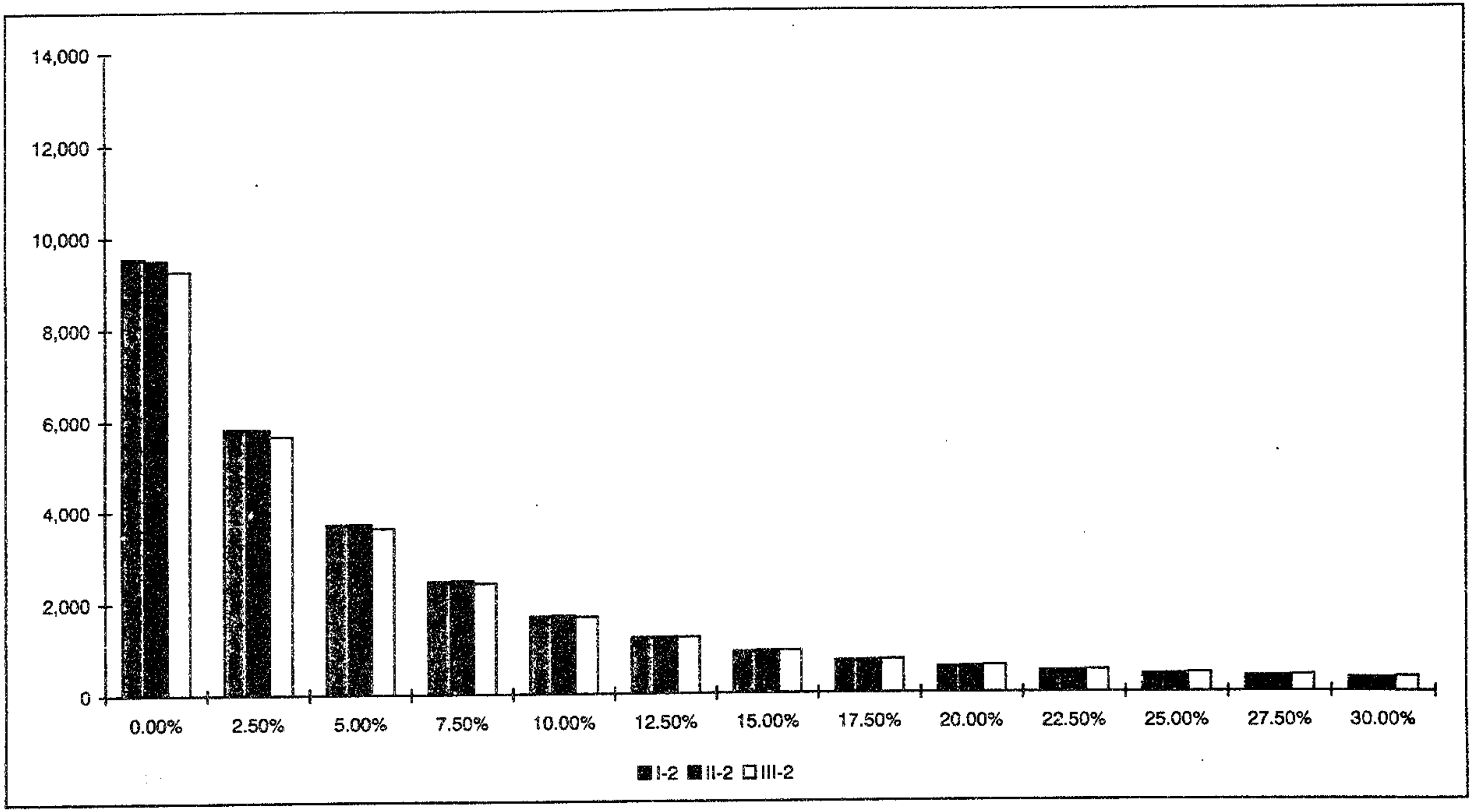

Figure 9.5 COMPARISON OF CALUCULATED PRESENT VALUE - HIGH CASE ECONOMIC

Best mix

Long-term scenarios (drafts) incorporating power generating equipment having those comparative advantages were subjected to an economic evaluation in the preceding section (9.4). From the evaluation results, it may be said that Scenario 1 (base case) in which power demand for the moment is to be met with GT and CCGT and coal-fired thermal power generation is to be introduced in 2021 is the most economical.

The energy balances for 2000, 2010, and 2025 prepared from Scenario 1 (base case) are shown in Tables 9.11 the own use of a bagasse at sugar mill is excluded from the table. The supply of new energy, including solar energy, is left out of consideration since it is difficult to predict its share, though such new energy could be put to practical use by the year 2025. Nevertheless, in view of the scenario of energy optimization in Mauritius, it is considered idealistic that 10% of the total power demand will be covered by new sources of energy by 2020 to 2025.

As a tendency in the future energy mix, it can be said that a kerosene and fuel wood will be gradually substituted by LPG. Meanwhile the yield of sugar cane will be going down, so that utilization of bagasse remain on the same level of the present. Other energy sources are also gradually increased at the almost same proportion.

However, after applied a coal-fired station in power generating system, a balance of energy sources will be substantially changed. That is, proportion in mauritius TPES depends on what a kind of energy sources convert into electricity

Table 9.11 ESTIMATED TOTAL PRIMARY ENERGY SUPPLY

Year	Coal	Gasoline	Diesel	Kerosene	Fuel Oil	LPG	Fuel Wood	Charcoal	Hydro	Bagasse	Total
2000	59,133	115,210	158,796	38,743	286,027	53,395	1,792	421	11,180	61,384	924,137
	6.40%	12.47%	17.18%	4.19%	30.95%	5.78%	0.19%	0.05%	1.21%	6.64%	100%
2010	109,734	197,233	191,754	32,938	668,793	90,911	192	313	11,180	78,137	1,549,474
	7.08%	12.73%	12.38%	2.13%	43.16%	5.87%	0.01%	0.02%	0.72%	5.04%	100%
2025	2,252,877	352,393	264,991	32,265	1,049,930	227,410	7	300	1,180	162,440	4,570,288
	49.29%	7.71%	5.80%	0.71%	22.97%	4.98%	0.00%	0.01%	0.03%	3.55%	100%

Note: Excluding a jet fuel, own use portion of a bagasse and new energy.

Source: JICA Study Team

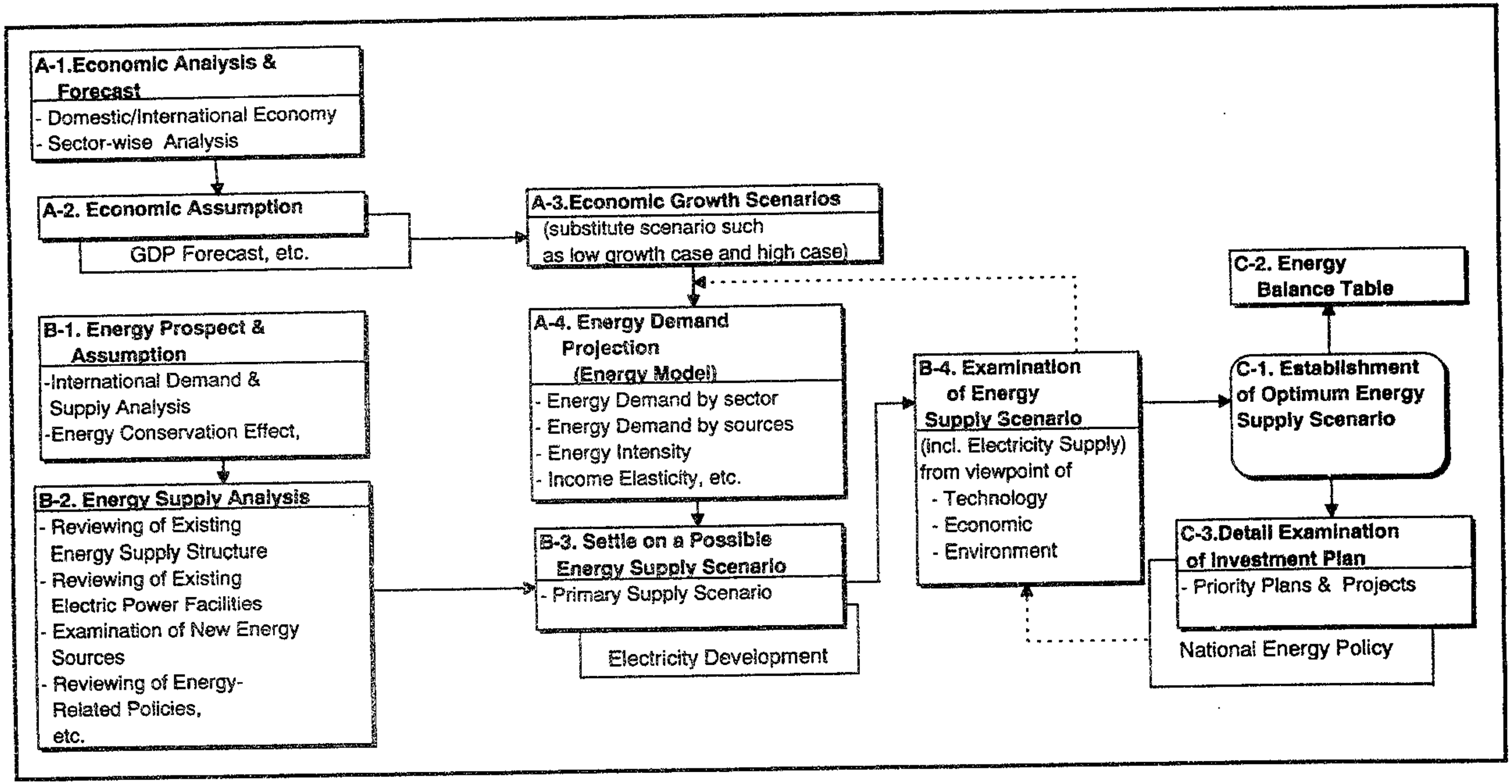

Figure 9.6 CONCEPTUAL WORK FLOW FOR MAKING AN OPTIMUM ENERGY SUPPLY SCENARIO

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