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ELECTRICITY PRICING STRATEGY STUDY

Final Report

Prepared for:

EGYPTIAN ELECTRICITY AUTHORITY
Cairo, Egypt

HBI Reference No. 90-9215

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Arun P. Sanghvi, Ph.D.
Senior Vice President

January 20, 1992

Dr. Moustafa Swidan
Deputy Chairman
Egyptian Electricity Authority
Abbassia
Cairo, Egypt

Dear Dr. Swidan:

RCG/Hagler, Bailly, Inc. is pleased to submit herewith eight copies of the final report on *Electricity Pricing Strategy Study*.

We received the comments from EEA on the draft final report during November and December 1991, and have addressed the overwhelming majority in the main body of this report. A brief attachment provides clarifications about the remaining comments.

Coincidentally, we have reached the contract budget ceiling. Our final invoice reflecting this will be forwarded shortly.

We truly appreciate the opportunity to assist EEA and look forward to the prosepct of working for EEA again in the future.

With best wishes for the New Year.

Yours sincerely,

Arun P. Sanghvi

Arun P. Sanghvi
Senior Vice President

cc: Mr. John Hunt, USAID/Cairo
Dr. Mark Gellerson, USAID/Cairo

Memorandum

TO: Dr. Moustafa Swidan, Deputy Chairman

FROM: Arun P. Sanghvi

DATE: January 20, 1992

SUBJECT: Comments on Draft Final Report

The purpose of this memo is to transmit our clarification of those financial and reliability analysis-related comments received from EEA that are not directly addressed in the Final Report.

A. The exchange rates utilized in the analysis are not calculated by a formula within the model, but are exogenously specified, based upon data received from the World Bank. More specifically, the history of the projected exchange rates and inflation rates (Egyptian and international) used in the model is as follows:

		90	91	92	93	94	95	96
1 World Bank (per G. Stuggins) Oct. 26, 1990	Exchange Rate Inflation - Intl. Egypt	2.75	3.10 8.70 40.0	4.41 6.20 22.0	4.83 2.20 12.0	5.21 1.70 10.0	5.43 2.50 7.0	5.65 3.10 7.0
2 Case EEA-100 Dec. 14, 1990 (per discussion with EEA Finance (Dec. 8, 1990)	Exchange Rate Inflation - Intl. Egypt	2.75	3.10 8.70 20.0	3.45 6.20 18.0	3.88 2.20 15.0	4.20 1.70 10.0	4.51 2.50 10.0	4.81 3.10 10.0
3 Case EEA-210 April 10, 1991 Case EEA X210 May 27, 1991 Case EEA Y201 August 21, 1991	Exchange Rate Inflation - Intl. Egypt	2.75	3.33 8.70 20.0	4.31 6.20 20.0	4.94 2.20 15.0	5.35 1.70 9.0	5.56 2.50 6.0	5.65 3.10 5.0

(These exchange rates have been maintained in our analysis since April, following a review with EEA management on April 8, 1991)

The following points should be noted:

1. In the January presentation, it is evident that the forecast exchange rate (as reviewed with the EEA Finance Department) was a result of applying the ratio of Egyptian to international inflation rates to the estimated 1991 exchange rate of 3.10 LE per $.

(Although the model could be programmed to do this, the forecast exchange rates are inserted manually.)

This approach is frequently encountered, as it is based on the notion of long-run purchasing power parity. However, it is not the only approach -- and is not necessarily valid in the near- to mid-term. The World Bank's Original Forecast (Item 1) does not follow this relationship.

2. The Exchange Rate Forecast, which has been consistently used since April, reflects information made available by EEA during our March/April visit, following a Bank mission. It is close to the Bank's original forecast. It has been retained in all cases run since that time.

B. The EDA selling price of 16.03 P/kWh in the EDA tariff allocation model is different from the value of 15.34 P/kWh in file EDAYLR2 because the two yields utilize different weighting schemes. The former is derived from individual tariff class yields by DC, whereas the latter is an aggregate yield. The tariff allocation model uses as input data an approximate disaggregation of system sales data by DC and further disaggregated by tariff class. In addition, BFAs are input for the residential and commercial tariffs for each DC. These are approximations as well, again reflecting the best available information. Consequently, when the individual tariff class yields are determined by DC and then aggregated to the system level, the resultant yield of 16.03 is not exactly equal to 15.43.

C. As regards the last transmittal received on comments of the Financial Department, we would like to note the following:

1. The interest ratio of 11.25 percent used in the study is based upon discussions and agreement reached during the April Mission when the financial parameters were finalized.

2. Local borrowing in the period 1985 to 1990 reflected an inadequate self-financing ratio (SFR), particularly with respect to Egyptian Pounds. Because the primary financial objective of the tariff study is to increase the SFR, it follows that local borrowing will be at much lower levels than in the past, and any such borrowing is implicit in the bank overdraft line in the model.

3. Our definition of the debt service coverage ratio is based upon the definition in the Fourth Power Loan Agreement. It is possible that IBRD is using a modified definition now.

4. Assuming that annual addition to fixed assets is based upon transferring 25 percent of work-in-progress annually, is a simplifying convenience that does not affect the model results since the analysis is driven by the self-financing ratio criterion. However, if an ROR criterion were to be used, then it would be more accurate to use the procedure described by the Finance Department.

D. To ensure that the REM 1-2-3 spreadsheet and its Fortran subroutine SREL find the correct copies of the temporary files TEMPOUT.DAT and TEMPIN.DAT, respectively, keep your REM spreadsheet and SREL.EXE file together in the same directory, and start 1-2-3 from this directory (see the start of Chapter 2 of the REM User's Guide). Otherwise, either an obsolete temporary file could be used incorrectly, or a temporary file could be missed by REM, as in your experience.

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ACKNOWLEDGEMENTS

The project team members responsible for undertaking this study and identified below would like to express our sincere gratitude for the cooperation and assistance received from EEA management and staff throughout the conduct of this study. In particular, we would like to acknowledge the single-minded dedication and energy brought to bear in this effort by Mme. Eng. Fawzia Abou-Neima and her staff. Her tireless efforts and sense of professionalism were critical to the successful completion of this study.

We would also like to acknowledge the efforts of EEA's financial and commercial staff, and EDA in providing the necessary data. In addition, we benefitted from the insights about the Egyptian economy and power sector provided by Dr. Robert Adler and Mr. John Hunt of USAID/Egypt.

Team Member	Role
Dr. Arun Sanghvi	Team Leader
Dr. Charles Zimmermann	Resource Economist
Mr. Carlos Yermoli	Power System Planner
Mr. Robert Vernstrom	Power System Economist
Mr. Harry Norris	Financial Analyst
Mr. Jeff Erickson	Data Base and Software Design
Dr. William Loehr	Macroeconomist
Mr. Barry Holsombeck	Utility Rate Specialist (Alabama Power)
Mr. Bill Poland	Reliability Analyst

EXECUTIVE SUMMARY

S.1 STUDY BACKGROUND AND OBJECTIVES

The Egyptian Electricity Authority (EEA), by virtue of its mandate, occupies a central role and responsibility in the country's development and future prosperity. Electricity is a crucial input for most sectors and for private consumers. Demand has grown very rapidly in the past decade, at an annual rate of over 8.5 percent. Because of its capital intensity, the power sector commands a disproportionate share of national investment. Further, because electricity use is subsidized directly and, even more importantly, indirectly, it represents a major source of fiscal spending by the government.

To provide for the growing electricity needs of the country in an economic and reliable manner, the power sector generation investment program in Egypt calls for capacity additions on the order of 7,500 MW and capital expenditures on the order of US $4 billion through 2000. An overwhelming percentage of this amount will represent foreign exchange-related expenses. Such investments represent a significant capital burden for the country. They are also associated with a high opportunity cost in that essential development projects in other sectors, such as health, education, and agriculture, may have to be postponed or sacrificed entirely.

Because of the high capital intensity of this sector, EEA must strive to ensure that the net national benefits derived from electricity consumption are maximized. As a pre-condition, electricity consumers must receive clear and correct price signals that reflect the true economic cost of supply. Only in this manner can economic waste and resource misallocation be minimized and the efficient utilization of resources -- in the production and consumption of electricity -- be maximized.

Undoubtedly, the rapid growth in electricity demand has been encouraged by its low price. Since the price of electricity is substantially below its economic (long-run marginal) cost, consumers receive misleading signals as to how much electricity to use. Raising prices to the level of long-run marginal cost is a major challenge to policy makers.

Besides their allocative function, electricity prices (more generally, prices for all goods and services) also perform two other critical functions in the economy. Prices have a distributive effect in that, to a great extent, they determine the effective consumption level of electricity and other goods by consumers in different economic and social groups and geographic regions. Thus, since the government exercises control over electricity prices and recognizes the basic right of all citizens to be supplied with enough energy to meet at

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least their minimum needs, then the social objective of meeting these minimum requirements also enters into the development of electricity prices.

A further consideration is that electricity prices determine the continued financial viability of the electricity producer. In particular, electricity prices should be set high enough so that the EEA and the distribution companies can at the very least self-finance an acceptable portion of the investments required to develop future resources. Only then can EEA and the distribution companies ensure adequate and reliable power supplies in the future.

Finally, in terms of planning future capacity additions, it is critical that every cost-effective alternative to the traditional approach of supply enhancement be explored. These alternative approaches will allow the nation to meet its growing electricity needs while reducing capital expenditure requirements, by increasing the system annual load factor from the current level through load/demand management, and by increasing the daily load factor by peak shaving as well as by shifting load to off-peak periods.

With this as a brief background, the broad objectives of this study are:

- review the existing tariff structure (for bulk supply and retail)
- on the basis of long-run marginal costs, and financial and social considerations, make appropriate recommendations for restructuring electricity prices together with an implementation plan.
- conduct the necessary transfer of methodology and software and training of selected EEA staff
- develop time-of-day tariff options for inducing customer load/demand management to enhance the efficiency of electricity consumption.

S.2 OVERVIEW OF APPROACH

The essence of our methodology for the pricing study is based upon the recognition that an effective and acceptable set of tariffs can only be arrived at by a compromise between the following set of multiple objectives, some of which may be conflicting:

- encourage economic efficiency in resource utilization
- provide adequate revenue to EEA so that it can

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- -- function in a financially sound manner
- -- maintain efficient and reliable electricity operation
- -- finance future resource mobilization
- -- meet its financial obligation to international lending institutions

- ▸ distribute costs in an equitable and fair manner among the different customer segments

- ▸ give due recognition to the social welfare consequences of the tariff as well as any other socio-political priorities.

Exhibit S-1 presents a schematic of the methodological framework employed for arriving at our recommended tariffs, based upon the balancing considerations just outlined.

The first step involves the estimation of the marginal cost of supplying electricity. The marginal cost of electricity is the opportunity cost of producing one more unit. Marginal cost pricing ensures that society's resources and needs are balanced in the most efficient manner. As noted by the Nobel Prize winning economist, Professor P. Samuelson of the Massachusetts Institute of Technology, "only when prices of goods are equal to marginal costs is the economy squeezing from its scarce resources and limited technical knowledge the maximum of output." Marginal costs were estimated in this study separately for capacity and energy, plus voltage of service and by time-of-day.

The financial analysis (step 2) estimates the average revenue requirement target (P/kWh) to ensure that sufficient revenues are generated to enable EEA and EDA to function efficiently. This analysis incorporates all income and expense factors projected for the next five years, including projections of sales, capital expenditure plan, debt service, and operation and maintenance cost. A driving criterion is the self-financing ratio covenant of EEA's World Bank loan: that EEA achieve by FY 96 a self-financing ratio of 35 percent. For this analysis, a PC-based financial model was developed that has the capability to prepare financial forecasts for a five-year horizon.

The bill frequency analysis (BFA) utilizes customer billing records to develop the profile of sales to customers under each tariff class (step 3). The BFA provides estimates of the distribution of bills by consumption level, e.g., the fraction of all bills rendered that had a billed consumption level of 50 kWh or less per month. The BFA also estimates distribution of sales, e.g., the fraction of all sales accounted for in the consumption block 0 to 50 kWh per month. This analysis is conducted for each tariff category.

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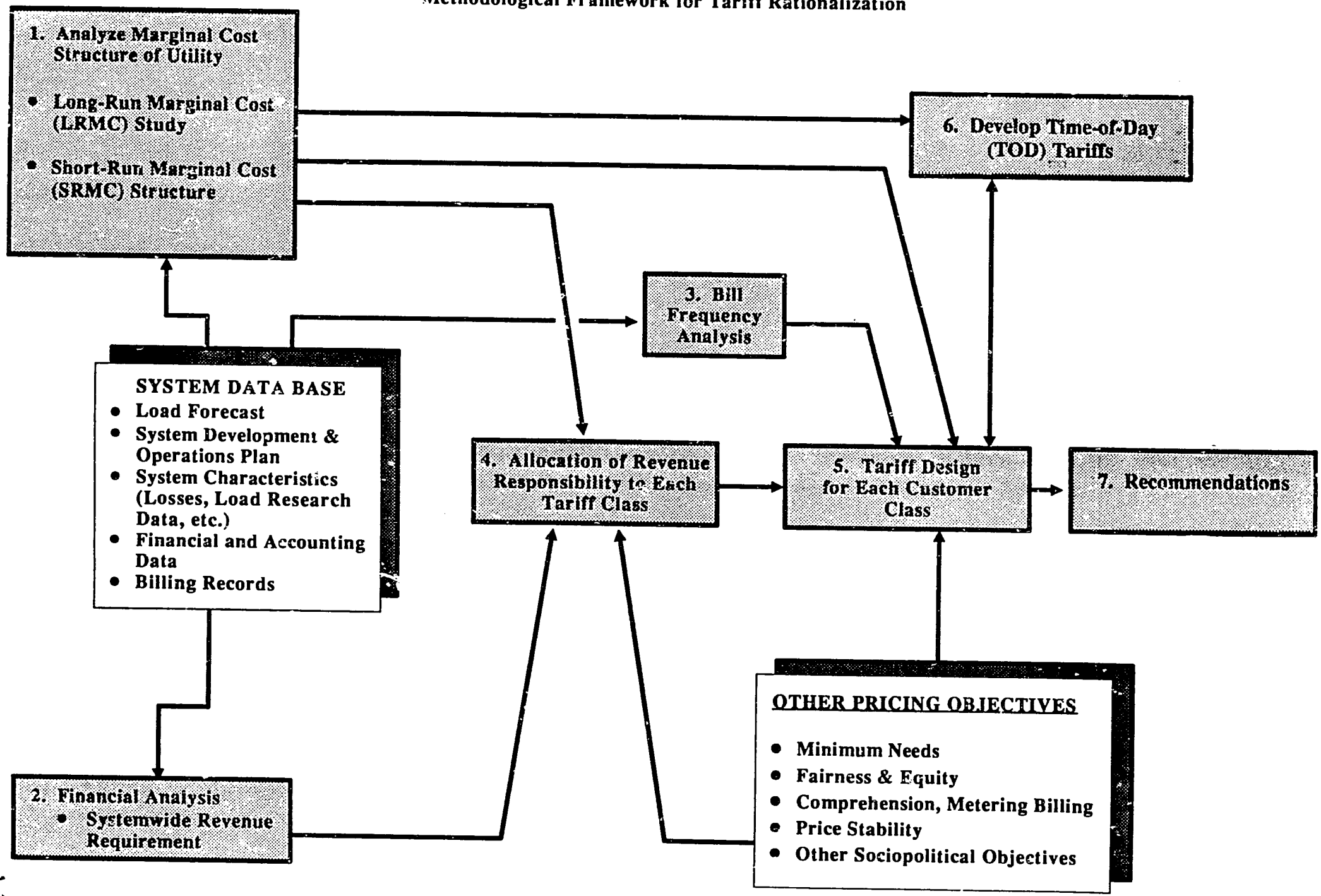
Exhibit S-1

Methodological Framework for Tariff Rationalization



Step 4 represents the adjustment process for allocating revenue responsibilities by tariff class. It includes balancing the goals of economic efficiency and other desired objectives. Revenue responsibilities based strictly upon marginal cost considerations were formulated as a first step. These "strict LRMC tariffs" emphasize economic efficiency considerations in tariff restructuring, but were scaled downwards to ensure that the system-wide revenue requirement was just met. Further adjustments were made to determine the final revenue responsibility of each tariff class. These adjustments factored in social and other objectives. The individual class revenue responsibilities provide the basis for developing the tariff structures for each category (step 5). These tariff designs were developed to strike an acceptable balance between economic efficiency and social objectives, taking into consideration bill impacts for different customer segments. Finally, time-of-day (TOD) tariff options (step 6) were formulated for bulk supply as well as for large industrial customers of Distribution Companies. These optional tariffs provide incentives for load management.

S.3 ECONOMIC COST OF SUPPLY AND DISTORTIONS IN EXISTING TARIFFS

The efficiency pricing objective in electricity pricing is embedded in the economic theory of efficient allocation of resources and can be theoretically linked to the marginal cost structure of the supply system. These costs typically vary by service voltage level and by time of day.

Put very simply, the marginal cost of electricity represents the cost of an increment of demand. The rationale for marginal cost pricing emanates from the economic theory of efficient allocation of resources in competitive markets. Prices that are equal to marginal cost provide the correct signals to decision makers -- producers and consumers -- and should result in a market equilibrium at a level and pattern of electricity supply that result in the best allocation of scarce resources.

For this study, a PC-based model was developed to estimate the long-run marginal cost (LRMC) of supplying power to the various consumer segments summarized in Exhibit S-2. A detailed description of the analysis is contained in Chapter 5. The data in Exhibit S-2 highlight the following:

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Exhibit S-2
EEA/Unified Power System
Strict Long-Run Marginal Cost-Based Tariff by Tariff Class - Entire Class*

TARIFF CLASS	SERVICE VOLTAGE	FY91/H1 SALES GWH	URRENT YIELD LE/KWH	CAPACITY COST/MONTH---- GEN LE/KW	ETWORK LE/KW	APACITY LE/KW	ENERGY COST LE/KWH	STRICT LRMC LE/KWH
VHV INDUSTRY								
KIMA CO.	VHV	824	0.0170	10.43	4.45	14.88	0.0782	0.1008
ALUMINUM CO.	VHV	1485	0.0460	10.01	4.28	14.29	0.0779	0.0996
ASSUIT CEM (1)	VHV	86	0.0632	9.91	4.23	14.14	0.0779	0.0994
ASSUIT CEM (2)	VHV	59	0.0632	9.91	4.23	14.14	0.0779	0.0994
FERROSILICON	VHV	153	0.0577	9.91	4.23	14.14	0.0779	0.0994
SOMED CO.	VHV	162	0.0632	9.91	4.23	14.14	0.0779	0.0994
DEKHILA FERRO	VHV	449	0.0632	9.91	4.23	14.14	0.0779	0.0994
AMERIA SPIN	VHV	53	0.0632	9.91	4.23	14.14	0.0779	0.0994
HV INDUSTRY/AGRI	HV	1218	0.0807	10.51	10.82	21.33	0.0819	0.1236
MV INDUSTRY/AGR	MV	126	0.1355	11.32	18.74	30.07	0.0879	0.1565
HOUSING COS.	HV	350	0.0600	10.51	10.82	21.33	0.0838	0.1228
MV MOVING POWE	MV	3891	0.1416	11.32	18.74	30.07	0.0879	0.1565
LV MOVING POWE	LV	833	0.0979	12.75	28.12	40.87	0.0985	0.2003
LV OTHER PURPOS	LV	734	0.1353	12.75	28.12	40.87	0.0985	0.2003
MV FREE ZONE	MV	6	0.1264	11.32	18.74	30.07	0.0879	0.1565
LV FREE ZONE	LV	6	0.1843	12.75	28.12	40.87	0.0985	0.2003
RESIDENTIAL	LV	5602	0.0421	12.75	28.12	40.87	0.1007	0.2126
COMMERCIAL	LV	885	0.1083	12.75	28.12	40.87	0.1007	0.2251
GOVT LIGHTING	LV	286	0.1855	12.75	28.12	40.87	0.0941	0.2185
STREET LIGHTING	LV	589	0.1855	13.42	29.60	43.02	0.0993	0.2172
SYSTEM AVERAGE		17797	0.0846	11.76	20.15	31.91	0.0916	0.1711
Equivalent LE/KWH				0.0293	0.0502	0.0795	0.0916	0.1711
% of System Average				17%	29%		54%	100%

* In FY 91 currency.

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- On average, the economic cost of supplying electricity (LRMC) is 17.11 P/kWh.

- Of the system LRMC of 17.11 P/kWh, about 54 percent represents energy (primarily fuel) related costs, 29 percent is attributable to the cost of network capacity, and the remaining 17 percent represents marginal generation capacity costs.

- The LRMC varies from a low of approximately 10.00 P/kWh for the largest customers supplied by EEA at very high voltage (VHV) to a high of about 20.00 P/kWh for residential, commercial, and low voltage (LV) moving power customers.

- In contrast to the economic cost of supply of 17.11 P/kWh, the current average system yield is approximately 8.46 P/kWh. In other words, the economic cost of supply is slightly over twice as large as the current average yield.

- Distortions between the economic cost of supply and the yield are more pronounced for some tariff categories than for others. The worst distortion on a tariff class basis exists in the residential tariff, where the economic cost of supply is over 400 percent higher than the present tariff yield. The lowest distortions can be found in the case of the MV Moving Power Tariff (10 percent), MV Free Zone (23 percent), and streetlighting (17 percent).

- The single-worst instance of distortion is the Kima fertilizer plant in which the economic cost of supply (10.08 P/kWh) is about 500 percent higher than the present yield of 1.70 P/kWh.

- In connection with the existing tariff structures (as opposed to levels), the following represent the major distortions:

  -- In the first block of the residential tariff, which accounts for slightly over half of all sales under that tariff, the current price is 3.0 P/kWh in comparison to the economic cost of supply of 21.26 P/kWh, i.e., a distortion of over 600 percent.

  -- There are too many blocks in the residential and commercial tariffs, thus disabling totally the ability of the tariff to convey the right price signals regarding the true economic cost of supply.

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-- The declining block structure of the energy charge in the Moving Power Tariff is contrary to the economic cost structure, which is flat.

- There is no economic basis for rationalizing the price discrimination inherent in the present tariffs for agriculture, industry, and between private sector investment companies and public sector customers, and between the Free Zone and non-Free Zone customers.

- There is no economic justification for pricing electricity differentially for moving power and for lighting end-use.

S.4 FINANCIAL ANALYSIS

In recent years, EEA's financial performance, as measured by most commonly accepted indicators -- e.g., operating ratio, self-financing ratio, debt service rate, current ratio, cash at bank to sales (months), accounts receivable to sales (days), debt to equity ratio -- has deteriorated significantly.

With local inflation running at 15 to 20 percent per annum and significant increases in foreign indebtedness because of changes in the exchange rates, the tariff increases of 3 to 5 percent per year in real terms have been insufficient to support EEA's debt servicing requirements, let alone support the capital expenditures incurred for system expansion. The fundamental problem is one of grossly inadequate cash flow from operations, even to service the interest and principal repayments of existing debt.

A detailed financial analysis of EEA's historical and projected performance was conducted and is described in Chapter 6. A key objective of this analysis was to determine the average tariff ("financial revenue requirement") needed to enable EEA to function in a financially sound manner on a cash flow basis. The criterion utilized for this purpose is the self-financing ratio (SFR), which is essentially the ratio of net cash flow from operations (after payments for debt interest and amortization) to the three-year (last, current, and next years) average capital expenditure.

Under EEA's Fourth Power Loan with IBRD, the revenue requirement (average system tariff) should be set to derive the covenanted SFRs of 20 percent in FY 92, 30 percent in FY 93, and 35 percent in subsequent years. Exhibit S-3 shows that the corresponding revenue requirements for the system are 17.94 P/kWh in FY 93, rising up to 32.06 P/kWh in FY 96. This implies an average nominal increase of 121 percent for FY 93 from the current year's expected system yield. Subsequent annual increases are on the

Exhibit S-3
Financial Revenue Requirement*

	Current Year FY 92	FY 93	FY 94	FY 95	FY 96
1. Self-Financing Ratio					
▸ Target	20.0%	30.0%	35.0%	35.0%	35.0%
▸ Projected	-29.6%	30.0%	34.9%	35.3%	35.3%
2. Revenue Requirement (P/kWh)**					
▸ EEA	5.95	12.55	15.70	18.55	22.25
▸ EDA	9.14	19.78	24.74	29.23	35.06
▸ System	8.12	17.94	22.51	26.66	32.06
3. Nominal Increase Required from Previous Year					
▸ EEA		111%	25%	18%	20%
▸ EDA		116%	25%	18%	20%
▸ System		121%	25%	18%	20%

* Inflation rates assumed in the analysis are as follows: 20 percent in FY 92, 15 percent in FY 93, 9 percent in FY 94, 6 percent in FY 95, and 5 percent in Fy 96.

** For current year, numbers denote expected yield.

order of 20 percent in nominal terms. In real terms, the required increases in system revenue requirements are as follows:

Year	FY 93	FY 94	FY 95	FY 96
Real increase required in system average tariff	73%	15%	10%	13%

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Systemwide Average Yield Requirements Utilized for Tariff Design

The financial revenue requirements defined in Exhibit S-3 normally determine the starting point for establishing the revenue responsibilities of each tariff class, which provide the basis for developing the tariff design in each case. However, we were advised that under an agreement reached with IBRD, the system average yields in future years are to be based on certain percentages of system long-run marginal cost (LRMC) as agreed to by EEA and IBRD. These target percentages and the corresponding system yields (P/kWh) are shown in Exhibit S-4.

Exhibit S-4
System Yield as Determined by LRMC-Based Targets

Year	FY 93	FY 94	FY 95	FY 96
Yield as a % of LRMC	69%	80%	90%	100%
System Average Yield (P/kWh)	14.17	18.88	23.16	27.27
Nominal Increase Required from Previous Year	67%	33%	23%	18%

The LRMC-based system yield requirements used for tariff design (Exhibit S-4) are substantially lower than the corresponding financial revenue requirements (Exhibit S-3). Financial simulations were undertaken to estimate the resultant deterioration in financial performance in comparison to the projected performance under the financial analysis-based revenue requirements. The results indicate that SFRs achieved under this case are as follows: 7.6 percent in FY 93, 9.6 percent in FY 94, 5.1 percent in FY 95, and -14.0 percent in FY 96. Further, EEA is projected to record positive net income only in 1993.

EEA's Income from Operations (before Interest) is forecast to decline from LE 1,115.9 million (or 17.4 percent of revenues) in 1994 to LE 633.4 million (or 6.1 percent of revenues in 1996. In addition, due to inadequate cash flow relative to EEA's working capital and investment needs, its borrowing requirement (expressed as bank overdrafts in the financial model) will increase significantly -- from LE 6.0 billion at 1993 year end to LE 14.1 billion at the 1996 year end. Hence, the net interest expense is projected to increase from LE 833 million in 1993 to LE 1,987 million in 1986.

The analysis shows that the LRMC-based system yield requirements case is financially viable only if it is accompanied by a massive reduction in EEA's capital investment program to about 50 percent of levels used in the financial analysis, i.e., a reduction in the capital expenditure program during the period 1993 through 1996 from a level (before IDC) of approximately LE 4.8 billion annually to LE 2.4 billion annually. Under those conditions, the SFR would improve to about 35 percent in 1994 and 1995, and EEA would be financially self-sustaining over the period 1992 through 1996 (other than borrowing to finance the foreign exchange portion of its reduced capital program).

The financial implications for EDA under this case are seriously adverse as well. If EDA were to stick to its presently projected capital expenditure plan of LE 1,874 million over the period 1993-1996, its overdraft will have increased by approximately LE 700 million, from LE 1,125 million at year-end 1992 to LE 1,792 million at year-end 1996. This means that a 40 percent cutback in EEA's capital program would be required to avert such a poor financial picture.

System Average Yield Based on "Low LRMC Case"

In addition to the preceding case, EEA requested an alternate tariff design that follows the same procedure and process, but starting with yields derived from an alternate LRMC estimation, with the latter corresponding to the 6 percent discount rate case in contrast to the 10 percent discount rate utilized for the Base Case LRMC analysis. This alternate case LRMC design is referred to in the report as the "Low LRMC Case" or the "alternate case" to the Base LRMC Case yields defined in Exhibit S-4.

The system average yields in the alternate case are as follows:

Year	FY 93	FY 94	FY 95	FY 96
Yield as a % of LRMC	69%	80%	90%	100%
System Average Yield (P/kWh)	12.31	16.41	20.12	23.70
Nominal Increase Required from Previous Year	52%	33%	23%	18%

This case is even less financially viable than the Base Case discussed above. The SFR for EEA is negative in all years: -0.3 percent in FY 93, -2.8 percent in FY 94, -13.6 percent

in FY 95, and -41.4 percent in FY 96. Furthermore, due to inadequate cash flow relative to EEA's working capital and investment needs, its bank overdraft by year-end 1996 will increase to LE 17 billion (as compared to LE 14.1 billion in the Base Case).

Similarly, for EDA, the situation is projected to be extremely adverse. For example, EDA's overdraft would amount to LE 3.9 billion by year-end 1996 on the basis of average system yields in the Low-LRMC Case.

S.5 REVENUE RESPONSIBILITIES BY TARIFF CLASS

Exhibit S-5 indicates the revenue responsibility by tariff class given the LRMC-based yield requirements derived in Exhibit S-4. If the allocation of this responsibility were based strictly upon the relative LRMC structure for EEA sales, this would imply, for example, that the average price (yield) from EEA sales to all distribution companies be increased from 6.24 P/kWh to 9.83 P/kWh (i.e., a 58 percent increase). At the retail level, this would mean an increase in the residential tariff yield from 4.21 P/kWh today to 9.97 P/kWh (i.e., a 137 percent increase). On a total system basis, the average increase required is 69 percent.

The class revenue responsibilities in Exhibit S-5 (the last two columns) were developed with the following rationale in mind: (1) deviate as little as possible from the relative LRMCs across class, (2) moderate as far as possible the rate increase to the distribution companies, and as a pass through to the residential tariff, (3) revenue responsibility should not be set below off-peak marginal energy costs, and (4) an intra-class comparison of increasing bills should not be perceived as "unfair."[1]

An additional consideration was that the Free Zone tariffs have the same revenue responsibilities as their counterpart tariffs for customers located outside the Free Zone. This principle is in keeping with the recommendations of new retail tariff classes, as rationalized in the previous section.

The class revenue responsibilities shown in Exhibit S-5 minimize the distortions in the sense that average yields for over 60 percent of all final sales are set at LRMC levels, and for the remaining units of sales, the average yields have increased substantially relative to LRMC. This change represents a very significant decrease in the extent of distortion in tariff levels that exist today.

[1] For example, no class should receive a decrease when most others are facing increases.

Exhibit S-5
Revenue Responsibility by Customer/Tariff Class
(FY 93)

EEA/UNIFIED POWER SYSTEM
REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – BULK

CUSTOMER/ TARIFF CLASS	FY91/H1 SALES GWH	CURRENT YIELD2/ LE/KWH	STRICT LRMC3/ LE/KWH	REVENUE NEUTRAL STRICT LRMC LE/KWH	% CHNG	REVENUE RESPONSIBILITY LE/KWH	% CHNG
VHV INDUSTRY	3271	0.0435	0.1198	0.0827	90%	0.0862	98%
HV INDUSTRY/AGRI	1218	0.0807	0.1483	0.1023	27%	0.1483	84%
MV INDUSTRY/AGRI	126	0.1355	0.1878	0.1296	-4%	0.1878	39%
DISTRIBUTION COS.	14615	0.0624	0.1498	0.1034	66%	0.0983	58%
TOTAL EEA BULK	19229	0.0608	0.1449	0.1000	64%	0.1000	64%

EEA/UNIFIED POWER SYSTEM
REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – RETAIL

CUSTOMER/ TARIFF CLASS	FY91/H1 SALES GWH	CURRENT YIELD2/ LE/KWH	STRICT LRMC3/ LE/KWH	REVENUE NEUTRAL STRICT LRMC LE/KWH	% CHNG	REVENUE RESPONSIBILITY LE/KWH	% CHNG
LARGE IND/AG	3891	0.1416	0.1878	0.1296	-8%	0.1878	33%
MEDIUM IND/AG	139	0.1202	0.2403	0.1658	38%	0.2403	100%
SMALL IND/AG	1772	0.1261	0.2439	0.1683	33%	0.2439	93%
FREE ZONE - MV	6	0.1264	0.1878	0.1296	3%	0.1878	49%
FREE ZONE - LV	6	0.1843	0.2403	0.1658	-10%	0.2403	30%
RESIDENTIAL	5602	0.0421	0.2552	0.1761	318%	0.0997	137%
COMMERCIAL	827	0.1083	0.2701	0.1864	72%	0.1864	72%
STREET LIGHTING	589	0.1855	0.2607	0.1799	-3%	0.2607	41%
SALE FOR RESALE	350	0.0600	0.1474	0.1017	69%	0.1246	108%
TOTAL DC RETAIL	13183	0.0947	0.2319	0.1600	69%	0.1600	69%
TOTAL SYSTEM	17797	0.0846	0.2053	0.1416	67%	0.1458	72%

S.6 TARIFF DESIGN RECOMMENDATIONS

This section presents recommendations for tariffs to be introduced in May 1992. These tariffs were designed to achieve the class-specific revenue responsibilities identified in Exhibit S-5. In order to restrict this Executive Summary to a reasonable length, only the essential features of the tariff recommendations are highlighted here. Details, including implementation issues and TOD tariff options, can be found in Chapters 7, 8, and 9.[2]

Bulk Supply Tariffs

Exhibit S-6 presents the proposed tariff for EEA sales. EEA's objective should be to sell every kWh on a time-of-day (TOD) tariff. EEA sells power at approximately 3,000 delivery points. It should be possible to proceed in a phased manner to procure and install TOD meters at each delivery point within the next three years, i.e., by year-end 1993.

In the interim, because of metering considerations, it is proposed to maintain the present tariff design -- i.e., a pure energy tariff -- but adjust the levels upwards to ensure that the designated revenue responsibilities are attained.

The average selling price from EEA to the DCs is 9.83 P/kWh, as can be seen from Exhibit S-6. The DC-specific average prices shown in Exhibit S-6 were derived by utilizing the EDA Tariff Allocation Model described in Chapter 6.

From the point of view of efficiency and transparency, it is preferable to maintain the same transfer price to all DCs -- i.e., 9.83 P/kWh in the present situation -- and have EDA manage a price stabilization fund to address the problem of cross-subsidization that arises because of the Government's desire to maintain geographically uniform tariffs. To illustrate this in the context of the numbers in Exhibit S-6, Cairo and El Behera DCs would pay into the fund an amount equal to the "excess revenue" calculated, i.e., 1.47 P/kWh sales (11.30 - 9.83) in the case of Cairo DC and 0.92 P/kWh sales in the case of El Behera DC. The total amount paid-in would be used to offset the "losses" incurred by the other DCs.

This approach offers the dual advantage of conveying to each DC the correct price signals for purchased power costs, and simultaneously provides a transparent mechanism to make each DC "financially whole." An added advantage is that at some later date, if the

[2] The tariff design for the alternate "Low LRMC Case" is contained in Appendix U.

Exhibit S-6
Proposed Tariffs for EEA Sales[1]

Consumer/ Category	Service Voltage	Demand Charge (LE/kW/Month)	Energy Charge (P/kWh) Peak	Off-Peak
KIMA	VHV	0.0	6.50	6.50
ALUMINUM	VHV	0.0	9.00	9.00
ASSUIT CEMENT [1]	VHV	0.0	10.00	10.00
ASSUIT CEMENT [2]	VHV	0.0	10.00	10.00
FERROCILICON	VHV	0.0	10.00	10.00
SOMED	VHV	0.0	10.00	10.00
IRON & STEEL	VHV	0.0	10.00	10.00
AMIRIA SPINING	VHV	0.0	10.00	10.00
Industry and Agriculture	HV	0.0	13.80	13.80
Industry and Agriculture	MV	0.0	15.00	15.00
Distribution Companies				
CAIRO		0.0	10.10	10.10
ALEX		0.0	8.80	8.80
NORTH DELTA		0.0	7.40	7.40
SOUTH DELTA		0.0	8.10	8.10
EL BEHERA		0.0	9.80	9.80
AL CANAH		0.0	7.80	7.80
NORTH UPPER EGYPT		0.0	5.90	5.90
SOUTH UPPER EGYPT		0.0	8.20	8.20

* Until such time as TOD tariffs are implemented

Government wishes to consider privatization of one or more DCs, it will be in a better position to figure out what the true cost of service is.

Retail/EDA Tariff Design

The following pages highlight the proposed restructuring of tariffs for all sales made by EDA, given the individual class revenue responsibilities developed in Exhibit S-5.

Residential Tariff

The proposed residential tariff (Exhibit S-7) has been simplified by reducing the number of blocks. The block sizes and energy charge for each block have been selected to restrict the size of bill increases to the small users and yet achieve, as far as possible, parity between the tariff design and the economic cost structure.

Exhibit S-7
Proposed Residential Tariff Design (Effective FY 93)

Block		New Tariff (P/kWh)
Starting kWh	Ending kWh	
0	100	6.00
101	250	14.00
251	600	22.00
601	1,000	24.00
1,001		26.00

The first ("lifeline") block of 100 kWh continues to be subsidized in a financial and economic sense, albeit to a reduced extent than at present. All consumption in the second block, i.e., in excess of 100 kWh/month, is priced slightly over class revenue responsibilities to pay for the financial subsidies associated with consumption in the first block. Further, the marginal price in the last block is pegged to the LRMC.

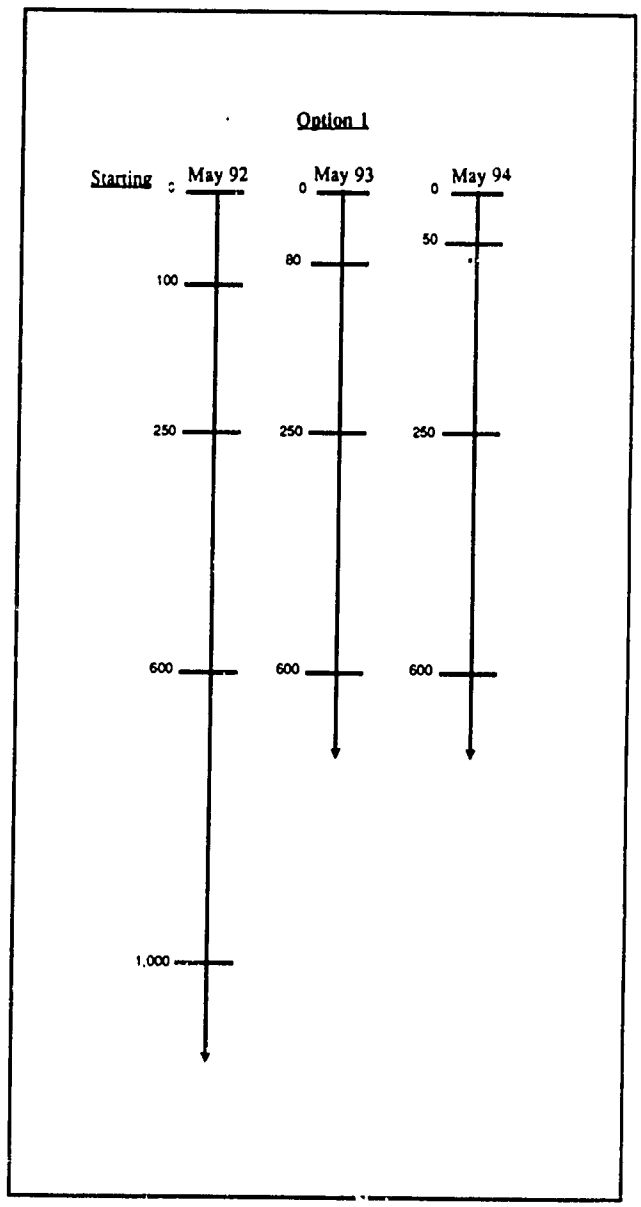
Typical bill impacts under the proposed tariff are summarized in Exhibit S-8. For example, a low-income household that consumes 50 kWh/month faces a bill increase of LE 1.50/month. About 64 percent of all households have consumption under 100 kWh. The maximum bill increase for this segment is a modest LE 3.00/month. Households with larger usage -- and presumably middle and higher income -- face somewhat larger increases. The very largest users -- presumably high-income households -- face the largest monthly bill increases in magnitude, but the lowest in terms of percentages, since they are currently paying substantially higher energy charges than other residential segments.

Exhibit S-8
Typical Bill Impacts: Residential Tariff

Consumption (kWh/Month)	Bill: Present (LE/Month)	Bill: Proposed (LE/Month)	Change (LE/Month)	Change (%)	Cumulative Bills (%)
50	1.50	3.00	1.50	100.0%	43.5%
60	1.80	3.60	1.80	100.0%	48.7%
70	2.10	4.20	2.10	100.0%	52.7%
80	2.40	4.80	2.40	100.0%	56.5%
90	2.70	5.40	2.70	100.0%	60.0%
100	3.00	6.00	3.00	100.0%	63.7%
150	5.25	13.00	7.75	147.6%	78.2%
200	7.50	20.00	12.50	166.7%	86.7%
250	10.75	27.00	16.25	151.2%	91.3%
300	14.00	38.00	24.00	171.4%	93.8%
350	17.25	49.00	31.75	184.1%	95.7%
400	21.00	60.00	39.00	185.7%	97.0%
450	24.75	71.00	46.25	186.9%	97.8%
500	28.50	82.00	53.50	187.7%	98.4%
750	55.50	140.00	84.50	152.3%	99.5%
1,000	89.50	200.00	110.50	123.5%	99.8%
2,000	249.50	460.00	210.50	84.4%	100.0%
3,000	424.50	720.00	295.50	69.6%	100.0%
4,000	599.50	980.00	380.50	63.5%	100.0%
5,000	784.50	1240.00	455.50	58.1%	100.0%

The implementation plan for this tariff -- described further in Chapter 7 -- calls for successively reducing the number of blocks to four, and more importantly, reducing the first block size to 50 kWh starting with the tariffs to be introduced in May 1994. This phase-in is highlighted in the following schematic.

Block Sizing Options and Phase-In Plan for Residential Tariff Structure



Commercial Tariff

The proposed commercial tariff (Exhibit S-9) has been simplified and structured along the lines of the residential tariff.

A three-year Phase-in plan to eventually reduce the number of blocks to four, and to reduce the first block size -- that is subsidized -- to 50 kWh is also recommended. The implementation plan schematic shown previously under the residential tariff discussion applies in this case as well.

Exhibit S-10 also shows the corresponding bill impacts. Bill increases are modest for smaller customers. For example, a consumer whose monthly consumption is 50 kWh faces a bill increase of LE 3.75/month. Middle-sized customers face higher increases, and the very largest customers face large increases in magnitude, but lower in percentages terms, because these customers are presently paying much higher energy charges than other commercial customers.

Exhibit S-9
Proposed Commercial Tariff Design (Effective FY 93)

Block		New Tariff (P/kWh)
Starting kWh	Ending kWh	
	100	12.00
101	250	17.00
251	600	23.00
601	1,000	25.00
> 1,001		27.00

Exhibit S-10
Typical Bill Impacts: Commercial Tariff

Consumption (kWh/Month)	Bill				Cumulative Bills (%)
	Present (LE/Month)	Proposed (LE/Month)	Change (LE/Month)	Change (%)	
50	2.25	6.00	3.75	166.7%	--
60	2.70	7.20	4.50	166.7%	--
70	3.15	8.40	5.25	166.7%	--
80	3.60	9.60	6.00	166.7%	--
90	4.05	10.80	6.75	166.7%	--
100	4.50	12.00	7.50	166.7%	77.4%
150	6.75	20.50	13.75	203.7%	77.4%
200	10.00	29.00	19.00	190.0%	89.0%
250	13.25	37.50	24.25	183.0%	89.0%
300	16.50	49.00	32.50	197.0%	89.0%
350	21.40	60.50	39.10	182.7%	94.9%
400	26.30	72.00	45.70	173.8%	94.9%
450	31.20	83.50	52.30	167.6%	94.9%
500	37.70	95.00	57.30	152.0%	96.9%
750	70.20	157.50	87.30	124.4%	96.9%
1,000	107.70	220.00	112.30	104.3%	98.9%
2,000	292.70	490.00	197.30	67.4%	99.6%
3,000	477.70	760.00	282.30	59.1%	99.6%
4,000	687.70	1030.00	342.30	49.8%	99.9%
5,000	897.70	1300.00	402.30	44.8%	99.9%

It is recommended that the coverage of this tariff be reduced to be exclusively applicable to business activities that are at present construed to be "commercial shops"; that all the consumption of such customers -- whether for lighting, motive power, or other purposes -- be billed on this tariff. Furthermore, all the excess lighting load of customers on the present moving power tariff, which is currently billed on the commercial tariff, should also be transferred to the appropriate new tariff categories discussed below: large power service, medium power service, and small power service.

Large Power Service

This proposed tariff is to be applied for all electricity consumption of customers with contract demands in excess of 500 kW. In other words, this tariff would be immediately applied to all accounts currently billed under the large moving power tariff, including all of their lighting-related consumption as well.

Eventually, all these customers (estimated to be about 2,000) should be on a mandatory time-of-day (TOD) tariff. These tariffs are developed in Chapter 9. However, that wide-scale implementation of TOD pricing will require time for various preparatory activities, including meter procurement, testing, calibration, implementation, training of meter readers and testers, altering billing procedures, etc. This process is likely to take two years.

Therefore, in the interim, and most immediately, it is recommended that the present two-part tariff structure be continued based upon a simple maximum demand charge (i.e., a non-coincident demand based charge) and a non-differentiated but flat energy charge as shown in Exhibit S-11. The demand and energy charges have been aligned closely to the economic cost of supply. In addition, a flat energy charge structure is recommended in keeping with the long-run marginal cost structure.

Exhibit S-11
Proposed Tariff Structure: Large Power Service

Service Voltage	Demand Charge (LE/kW/month)*	Energy Charge (P/kWh)
MV	8.00	17.00

* Non-coincident demand

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Medium Power Service

This tariff is proposed to be applied to all consumption -- motive power and lighting, process needs, etc. -- of customers with estimated demands of 100 kW or more, but under 500 kW. Further, it is recommended that the present differentiation between the agriculture and industry and public sectors be abandoned because this practice has no cost basis and is discriminatory. Thus, what is proposed is a merging of all accounts currently billed under the moving power (<500 kW) tariff -- agriculture, industry, government, public, private, investment -- and reclassifying the entire group into two segments differentiated by size. Those with estimated maximum demands under 100 kW should be classified under the Small Power Service Tariff discussed below and the remainder should be classified under the Medium Power Service Tariff category.

The recommended tariff design is defined in Exhibit S-12.

Exhibit S-12
Proposed Tariff Structure: Medium Power Service

Customer Type	Demand Charge (LE/kW/Month)	Energy Charge (P/kWh)
Agriculture (Private, Investment)	--	11.80
Industry (Private, Investment)	--	24.70
Public Sector	--	24.70

The three-way distinction between agriculture (private, investment), industry (private, investment), and the public sector is shown in Exhibit S-12 in contrast to the long-term objective enunciated above of eliminating discriminatory pricing. This distinction should be maintained only in the short-term for otherwise, a common tariff structure implemented immediately would result in substantially higher bill impacts upon the first consumer category. It is recommended that in subsequent tariff adjustments that the agriculture tariff should be increased proportionately much more than for the other two segments and that

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with the third adjustments beginning with FY 95, all price discrimination across consumer segments served under the Medium Power Service tariff be eliminated.

Small Power Service

As noted above, this tariff should be applied to all customers -- agriculture, industry, government -- regardless of whether they are "public," "private," or "investment" companies, and whose maximum demand is estimated to be under 100 kW. This category would represent approximately 95 percent of the estimated 60,000 accounts at present in the moving power (<500 kW) tariff, and three-fourths have maximum demands under 100 kW.

Because of low consumption levels, a one-part flat energy tariff is proposed for this category (Exhibit S-13).

Exhibit S-13
Proposed Tariff Structure: Small Power Service

Service Voltage	Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
LV	--	25.00

Free Zone Tariffs

Three categories of tariffs are proposed for companies located in a Free Zone:

- Free Zone - Large Power Service
- Free Zone - Medium Power Service
- Free Zone - Small Power Service

These designations parallel the corresponding customer classification for companies located outside the Free Zone. This segmentation is introduced because the objective is to eliminate any difference in tariff levels and structure between Free Zone tariffs and comparable tariffs for customers outside the Free Zone. Such differences cannot be rationalized on a cost basis and are discriminatory under commonly accepted principles of tariff rationalization.

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Exhibit S-14 presents the recommended Free Zone tariffs by power service category. Two options are proposed for medium and large customers.

Exhibit S-14
Proposed Tariff Structures: Free Zone Tariffs (Effective FY 93)

Tariff Category	Service Voltage	Option	Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
1. Free Zone Large Power Service (> 500 kW)	VHV	1	8.99	7.30
		2	--	8.62
	HV	1	9.39	13.00
		2	--	14.83
	MV	1	16.63	15.00
		2	8.00	17.00
2. Free Zone Medium Power Service (≥ 100 kW, but < 500 kW)	LV	1	4.16	23.00
		2	--	24.70
3. Free Zone Small Power Service (< 100 kW)	LV	--	--	25.00

To illustrate, consider Large Power Service - MV. Option 1 preserves the demand charge value in the present tariff (i.e., LE 16.63/kW/month), and the energy price has been raised to achieve revenue responsibility. Tariff Option 2 also ensures the desired responsibility, but is identical to the tariff proposed for Large Power Service for companies located outside the Free Zone. Similar considerations guided the design of all the other tariff designs proposed in Exhibit S-14.

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Street Lighting Tariff

It is recommended that the existing government and public lighting tariffs be redefined to be applicable for street lighting consumption only. The lighting consumption of government accounts should be transferred to the appropriate tariff within one of the three power service tariff categories.

The recommended street lighting tariff is shown in Exhibit S-15. This tariff is designed to recover the economic cost of supply. It is understood that the capital and O&M costs associated with the installation of street lighting -- poles, fixtures, luminaries, photovoltaic cells, conductors, etc. -- and directly borne by the respective municipalities concerned. Consequently, the tariff is intended to recover only the cost of generation and distribution of electricity.

Exhibit S-15
Proposed Street Lighting Tariff (Effective FY 93)

Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
--	26.07

Sales for Resale Tariff

The recommended tariff for sales for resale is shown in Exhibit S-16. At present, the tariff for this category of sales is an energy-only charge and the meters in-place at the various delivery points are energy meters. It is recommended that in the long run, all sales in this category be priced on a TOD tariff (as discussed further in Chapter 9). However, it is recognized that the implementation of such a scheme could take some time. In the interim, therefore, a pure energy tariff will need to be applied, as shown in Exhibit S-16.

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Exhibit S-16
Proposed Tariff for Sales for Resale (Effective FY 93)

Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
--	12.50

S.7 OTHER RECOMMENDATIONS

We offer the following supplementary recommendations for EEA's consideration. The general thrust of these recommendations is to facilitate more effective and quicker tariff planning in the future as well as to take the key first steps toward increasing the efficiency of power consumption in Egypt.

Load Research

To better facilitate future tariff revisions, we suggest that EEA expand its ongoing load research activities to develop relevant information on customer load shapes, coincidence factors, peak energy shares, and load factors for each tariff class, as well as for the typical customer segments within each class.

There is a need to put in place a well designed and on-going load research program and a more fully staffed load research function to be responsible for the program. Such a program should be based upon a sample design that can support the development of statistically valid estimates for the types of data noted above, with a degree of precision that conforms to load research norms in the industry today. Furthermore, it is important that this type of load research is pursued in a systematic manner and that the program is staffed accordingly. By contrast, sporadic load research activities, whereas useful, do not provide a statistically valid basis for developing estimates of key variables, noted above, that are essential in tariff planning, load forecasting, and system planning.

Database

Future tariff planning will be better served if load forecasting were undertaken in a manner consistent with the customer class segmentation that corresponds to the individual tariff categories proposed in this report. In this connection, it is also recommended that

historical data on electricity sales, revenues, and customer accounts be assembled in an electronic data base that permits quick access -- preferably in real time. The basic data elements should be sufficiently disaggregated so that they can be easily re-aggregated to different levels. At a minimum, this should be possible by each tariff class (as well as by major sub-segments within each tariff class)[3] and by Distribution Company. Such a data base could be very useful in supporting a wide variety of planning functions including load forecasting, tariff planning, financial planning, and system planning.

Demand-Side Management (DSM)

We recommend that EEA embark aggressively on a national demand-side management (DSM) program to increase the efficiency of electricity consumption and to modulate the pattern of such consumption. Given that EEA is embarking on a tariff restructuring program, and with the introduction of TOD pricing options, the incentive for demand/load management and for DSM will be enhanced. However, tariff reform is a necessary condition for inducing proper DSM. Experience shows that because of a variety of reasons, EEA will need to develop programs and work in partnership with its customers to help them respond to the new tariffs.

The proposed DSM strategy and implementation plan should be designed to provide the following benefits:

1. good public relations by helping customers reduce their electricity bills

2. load management through customer actions
   - demand control and peak shaving
   - energy saving

3. loss reduction through customer actions
   - power factor improvement
   - installation of high efficiency equipment

4. information about EEA customers for
   - system planning
   - load shedding
   - TOD and interruptible tariffs
   - possible power purchases

[3] i.e., service voltage, customer size, industry type.

EEA has conducted studies to assess the load management potential in several industry segments. That information provides a base to develop detailed DSM program design for the industry sector. However, DSM programs should encompass other sectors as well.

The development of a proper DSM program will need to begin with an identification of the DSM strategy that is appropriate for Egypt. This requires a preliminary assessment of the current situation in all consumer sectors and a broad-brush evaluation of the DSM options and potential in each major segment. Following this initial scoping phase, more detailed designs and evaluations -- costs and expected benefits -- should be conducted for a selected few DSM programs that are best suited for Egypt.

This DSM program design phase should also address the key issues of program delivery, and a system for program performance monitoring and subsequent evaluation. Once a detailed DSM design and implementation plan is in place, test programs will need to be carried out on a limited basis to refine the program designs from field experience, following which full-scale implementation of "production grade" DSM programs would begin.

EEA should consider announcing the key elements of such a DSM strategy and future implementation plans simultaneously with the announcement of new tariffs next year.

Water Pumping Load

In future forecast exercises, EEA should consider separately forecasting the water pumping load. Equally vital is the need to conduct load research to establish the load shape for this load. In the team's experience in other countries, it has been observed that this load tends to be a substantial portion (i.e., 10+ percent) of the total system load. This load represents a potentially attractive candidate for DSM programs that are based upon interruptible tariffs, direct load control, as well as DSM programs targeted to improve pump efficiency. In addition, with TOD tariffs, it may be attractive to modulate the pumping load by exploiting existing water storage and in the longer run, by building such stage capability into the supply system.

CHAPTER 1: INTRODUCTION

1.1 STUDY BACKGROUND AND OBJECTIVES

The Egyptian Electricity Authority (EEA) is a government-owned organization with responsibility for all bulk power generation and transmission in the country. By virtue of its mandate, EEA occupies a central role and responsibility in the country's development and future prosperity.

To provide for the growing electricity needs of the country in an economic and reliable manner, the power sector generation investment program in Egypt calls for capacity additions on the order of 7,500 MW and capital expenditures on the order of US $4 billion through 2000. An overwhelming percentage of this amount will represent foreign exchange-related expenses. Such investments represent a significant capital burden for the country. They are also associated with a high opportunity cost in that essential development projects in other sectors, such as health, education, and agriculture, may have to be postponed or sacrificed entirely.

Because of the high capital intensity of this sector, EEA must strive to ensure that the net national benefits derived from electricity consumption are maximized. As a pre-condition, electricity consumers must receive clear and correct price signals that reflect the true economic cost of supply. Only in this manner can economic waste and resource misallocation be minimized and the efficient utilization of resources -- in the production and consumption of electricity -- be maximized.

The importance of the electricity sector for Egypt cannot be overstated. Electricity is a crucial input for most sectors and for private consumers. Demand has grown very rapidly in the past decade, at an annual rate of over 8.5 percent. Because of its capital intensity, the power sector commands a disproportionate share of national investment. Further, because electricity use is subsidized directly and, even more importantly, indirectly, it represents a major source of fiscal spending by the government.

The problem of electricity pricing arises at several levels. Fuels are sold to the Egyptian Electricity Authority at below the price at which they could be sold internationally and below the price that others pay. These subsidies amount to billions of pounds annually for the Government. In official accounts, these subsidies are implicit and do not show up on the government budget or elsewhere as losses. When fuel inputs are valued at the correct prices, valued added in electricity appears negative. This way of accounting illustrates the subsidy problem.

The other important aspect of pricing is its linkage with consumer demand. Undoubtedly, the rapid growth in electricity demand has been encouraged by its low price. Since the price of electricity is substantially below its economic (long-run marginal) cost, consumers receive misleading signals as to how much electricity to use. Raising prices to the level of long-run marginal cost is a major challenge to policy makers.

One of the adverse effects of subsidized energy prices is that consumers have little incentive for energy conservation or for improving the efficiency of energy utilization. Low energy prices provide price signals to the economy, promoting higher energy intensity in production, consumption, and investment than is sustainable. This has led to massive misallocation of resources. Moreover, a large amount of energy savings could be obtained through effective demand management policies designed to increase the efficiency of energy use. Retrofitting and technical improvements can lead to substantial savings in energy use. However, improvements would entail large amounts of investment, and such investments will not appear financially attractive if electricity prices are kept artificially low. On the other hand, any immediate realignment of prices to the efficiency prices of electricity has the potential for creating substantial dislocation to consumers. This tradeoff is at the core of the electricity pricing strategy problem facing Egypt today.

Besides their allocative function, electricity prices (more generally, prices for all goods and services) also perform two other critical functions in the economy. Prices have a distributive effect in that, to a great extent, they determine the effective consumption level of electricity and other goods by consumers in different economic and social groups and geographic regions. Thus, if the government exercises control over electricity prices and recognizes the basic right of all citizens to be supplied with enough energy to meet at least their minimum needs, then the social objective of meeting these minimum requirements would enter into the development of electricity prices.

A further consideration is that electricity prices determine the continued financial viability of the electricity producer. In particular, electricity prices should be set high enough so that the EEA and the distribution companies can earn a fair rate of return on assets and to self-finance an acceptable portion of the investments required to develop future resources. Only then can EEA and the distribution companies ensure adequate and reliable power supplies in the future.

Finally, in terms of planning future capacity additions, it is critical that every cost-effective alternative to the traditional approach of supply enhancement be explored. These alternative approaches will allow the nation to meet its growing electricity needs while reducing capital expenditure requirements, by increasing the system annual load factor from

the current level through load/demand management, and by increasing the daily load factor by peak shaving as well as by shifting load to off-peak periods.

With this as a brief background, the broad objectives of this study are:

- review the existing tariff structure (for bulk supply and retail)
- on the basis of long-run marginal costs, and financial and social considerations, make appropriate recommendations for restructuring electricity prices together with an implementation plan.
- conduct the necessary transfer of methodology and software and training of selected EEA staff
- develop time-of-day tariff options for inducing customer load/demand management to enhance the efficiency of electricity consumption.

1.2 OVERVIEW OF APPROACH

The terms of reference (TOR) for this study are included as Appendix A. The following specific tasks were undertaken to accomplish the objectives outlined above.

Task 1: Review of Load Forecast

This task developed the load forecast input used for the study for the period 1990-1999. EEA's most recent forecast was reviewed, adjusted as appropriate, and disaggregated by customer/tariff class and by voltage of service.

Task 2: Review of Least-Cost Development Program

In this task we reviewed the existing expansion plan and reviewed its suitability for use in the tariff study.

Task 3: Economic Cost of Gas in the Power Sector

In this task we conducted the necessary review and analysis to establish the economic cost (as opposed to financial cost) of natural gas. This information was input in the marginal cost analysis task.

Task 4: Analysis of Marginal Cost Structure

In this task we developed estimates of the long-run marginal cost (LRMC) of capacity and energy by voltage of service, by season, and by time-of-day. In addition, these estimates of "strict" LRMC were established at busbar, as well as at different points of delivery.

Task 5: Financial Analysis

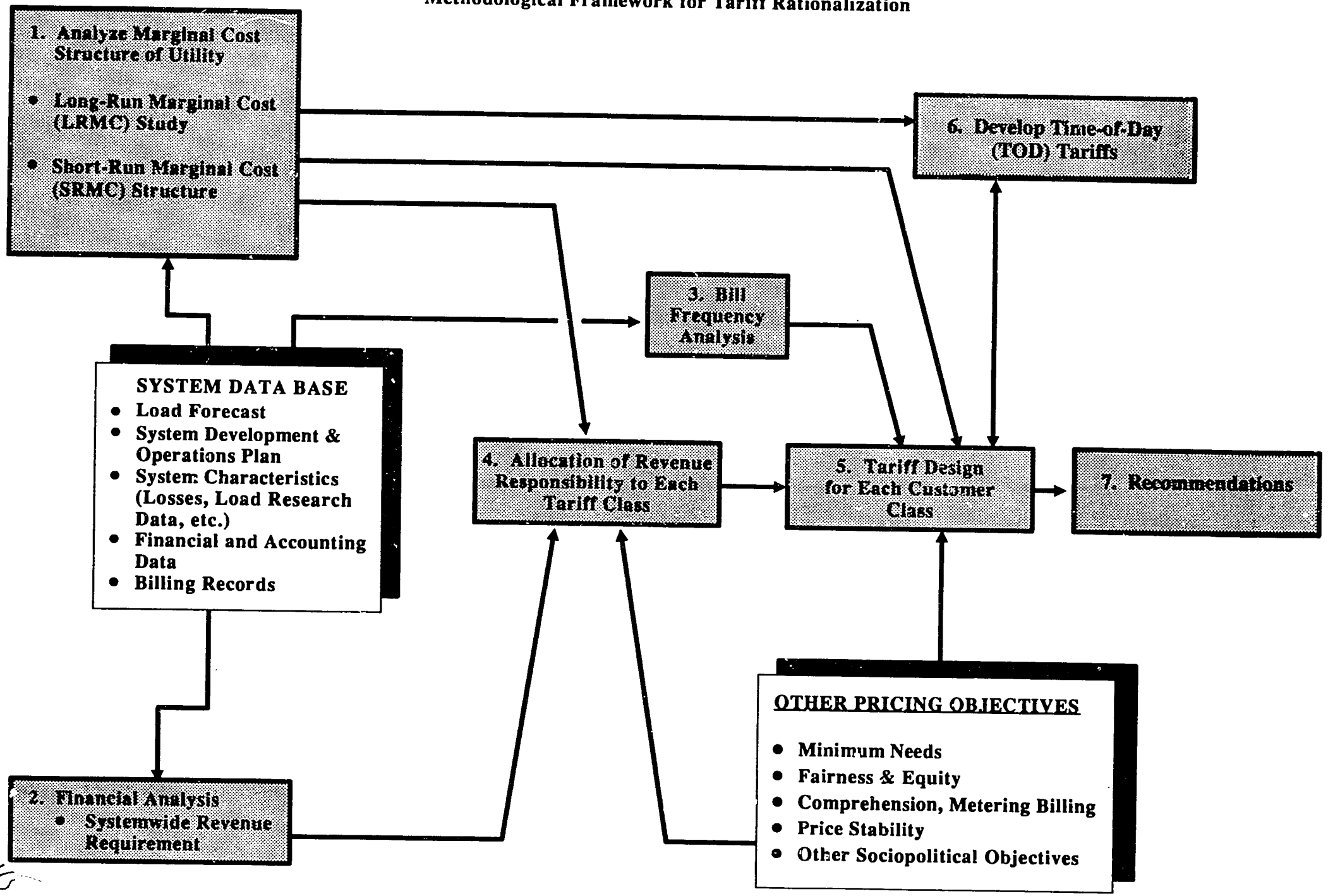
This task involved the estimation of average tariffs (LE/kWh) that are necessary to ensure that sufficient revenues are generated to enable EEA and the distribution companies to function as a viable commercial operation. For this purpose, a PC-based financial model was developed that has the capability to prepare financial forecasts for a five-year horizon.

Tasks 6,7,8,9: Tariff Evaluation, Restructuring, and Implementation

These tasks began with an evaluation of existing tariffs -- bulk and retail -- in light of the economic (marginal) cost structure developed in Task 4 and the financial revenue requirement developed in Task 5. Next, a pricing strategy based strictly upon marginal cost considerations was formulated. These "strict LRMC tariffs" emphasize economic efficiency considerations in tariff restructuring. They were scaled downwards to ensure that the system-wide revenue requirement -- as established in Task 5 -- was just met. Further adjustments were made to determine the revenue responsibility of each tariff class. These adjustments factored in social and other objectives. The individual class revenue responsibilities provide the basis for developing the tariff structures for each category. These tariff designs were developed to strike an acceptable balance between economic efficiency and social objectives. Exhibit 1-1 summarizes these steps of our methodological framework for the pricing study.

Exhibit 1-1

Methodological Framework for Tariff Rationalization



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Task 10: Tariffs for Load/Demand Management

In this task we utilized information on the marginal cost structure developed in Task 4 to define time-of-day (TOD) tariff options that provide strong incentives for load/demand management.

Task 11: Model and Methodology Transfer and Training

This task involved all activities related to the transfer of software, hardware, and the methodology employed in the study, as well as the required training.

1.3 ORGANIZATION OF REPORT

This report is organized as follows. Chapters 2 and 3, respectively, describe the load forecast review and review of the least-cost development program. Chapter 4 presents the analysis performed to establish the economic cost of gas to the power sector. Chapter 5 describes the marginal cost analysis that was undertaken to establish the economic cost of power supply. The financial analysis of revenue requirements is presented in Chapter 6. Chapter 7 contains the analysis related to tariff evaluation and recommendations for tariff restructuring and implementation. Chapter 8 discusses the potential impacts of the proposed price increases on the economy and specific consuming sectors. Chapter 9 develops recommendations for time-of-day pricing, including a supporting reliability analysis, as well as a short-run marginal cost analysis.

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CHAPTER 2: REVIEW OF LOAD FORECAST

This chapter focuses on our efforts in the first study task, whose primary objective was to review and adapt the official EEA load forecast for the Unified Power System (UPS) for use in subsequent activities within the overall study. This chapter is organized as follows. Following a brief background discussion (Section 2.1), Section 2.2 contains a review of the current forecast and the methodology used to develop it. Key uncertainties that may cause actual sales to diverge from those forecast are discussed in Section 2.3. Specifically, these uncertainties include assumptions regarding national economic growth and proposed major industrial restructuring. The EEA load forecast was then disaggregated by voltage level and tariff group for subsequent use in calculating the economic costs of serving different customer groups. This is discussed in Section 2.4 and 2.5.

2.1 BACKGROUND

The Egyptian economy grew rapidly during the decade following the first oil price rise (1974-1986). As summarized in Exhibit 2-1, real GDP grew at an average annual rate of 9 percent during this period. This rapid growth was fueled by many factors, including oil exports, Suez Canal revenues, workers' remittances from the Gulf, and substantial levels of foreign assistance.

The recent past, however, has been characterized by less rapid economic growth. Average annual real growth leveled to 6 percent from FY86 to FY89. Depressed oil prices affected all of Egypt's major sources of revenue. Currently, the on-going Gulf crisis portends an economy with slower real growth in the near-term, despite rising oil prices.

EEA sales growth has generally mirrored the economy. Exhibit 2-2 summarizes total UPS sales, gross generation, and peak demand for FY81 through FY90. From FY81 to FY86, total sales and peak demand increased by 11 percent annually. In marked contrast, total sales grew at an annual rate of less than 7 percent, and peak demand at less than 5 percent, from FY87 through FY90.

The overall slowdown is confirmed when sales are analyzed by customer class. Exhibit 2-3 shows a pattern of decreasing growth rates of consumption for most customer

Exhibit 2-1
Egypt's Gross Domestic Product (LE million)

YEAR	GDP (market prices)	Real GDP (1980/81 prices)	Real GDP (1984/85 prices)1/	Avg Real GDP Growth Rate % 2/	Implicit GDP Deflator
1974	4,190	9,595	13,841		30.3
1975	5,247	10,967	15,820	14.3%	33.2
1976	6,705	11,759	16,962	7.2%	39.5
1977	8,210	12,690	18,305	7.9%	44.9
1978	9,788	13,974	20,157	10.1%	48.6
1979	12,610	15,186	21,906	8.7%	57.6
FY80	15,470				
FY81	17,343	17,343	25,017	9.3%	69.3
FY82	20,290	18,305	26,405	5.5%	76.8
FY83	24,834	19,953	28,782	9.0%	86.3
FY84	28,600		30,511	6.0%	93.7
FY85	34,211		34,211	12.1%	100.0
FY86	38,221		37,313	9.1%	102.4
FY87	44,050		39,701	6.4%	111.0
FY88	52,100		42,148	6.2%	123.6
FY89			44,394	5.3%	
FY90					

Source: FY83 to FY90, International Financial Statistics, August 1990
1974 to FY82, International Financial Statistics, 1986 Yearbook

1/ 1974 to FY82 values derived from 1980/81 series.
2/ For growth rate calculations, year-end 1979 to year-end FY81 assumed to be 1.5 years.

groups. Only the VHV (very high voltage) Industrial and Government groups experienced a more rapid growth of sales from FY87 to FY90 than in preceding years. An analysis of consumption shares by customer class over the past decade reveals a clear trend (Exhibit 2-3). Residential and commercial sales increased from 25 to 37 percent of total sales. Industry's share of sales has fallen from nearly 60 percent of total sales in FY81 to only 48 percent today. While still very significant, the share of VHV Industrial sales fell by nearly a third, to 19 percent of total consumption. Other customer class shares have remained relatively constant over the decade.

Exhibit 2-2
Growth in Actual UPS Sales, Generation
and Peak Demand (FY81 - FY90)

Year	UPS Total Sales (GWh)	Annual Rate %	Gross Gen (GWh)	Annual Rate %	Peak Demand (MW)	Annual Rate %
FY81	15600		19870		3179	
FY82	17200	10.3%	22543	13.5%	3694	16.2%
FY83	19461	13.1%	25044	11.1%	3981	7.8%
FY84	22179	14.0%	27797	11.0%	4672	17.4%
FY85	23674	6.7%	30599	10.1%	5158	10.4%
FY86	26092	10.2%	32854	7.4%	5361	3.9%
FY87	28197	8.1%	35494	8.0%	5803	8.2%
FY88	30349	7.6%	37844	6.6%	6152	6.0%
FY89	32107	5.8%	39580	4.6%	6279	2.1%
FY90	34180	6.5%	41649	5.2%	6664	6.1%

2.2 REVIEW OF EEA'S FORECASTING METHODOLOGY

EEA's current load forecasting methodologies were developed by EEA and Stone & Webster Engineering Inc. under projects sponsored by the UNDP. The present assessment is based on EEA's most recent forecasting reports: *Study on Load and Energy Forecast Using Different Methodologies* (September 1990) and *Load and Energy Forecast* (March 1990), published by the EEA Planning and Economic Studies Department. These reports focus on two different methodologies that are applied to produce EEA's current forecasts:[1]

[1] Two other methods are also used by EEA, the Growth Rate Specific Consumption Model (GRSC) and the Model for Analysis of Energy Demand (MAED). These methods are not detailed in the report, and are therefore not included in the subsequent discussion.

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Exhibit 2-3
Historic Sales and Consumption Shares by Customer Class (GWh)

	FY81	Annual Rate %	FY84	Annual Rate %	FY87	Annual Rate %	FY90	Annual Rate % FY81-90
Sales by Customer Class (GWh)								
VHV Industrial	4186	4.5%	4774	4.0%	5371	7.3%	6629	5.2%
Non-VHV Industrial	5023	10.0%	6688	7.5%	8315	6.7%	10096	8.1%
Agriculture	777	9.0%	1007	5.0%	1166	4.9%	1344	6.3%
Public Utilities	1159	14.5%	1739	8.0%	2192	2.6%	2369	8.3%
Commercial	423	27.9%	885	16.0%	1380	5.7%	1631	16.2%
Residential	3355	23.0%	6237	12.4%	8864	7.2%	10931	14.0%
Government	672	11.4%	929	3.9%	1041	10.2%	1392	8.4%
Total Sales (GWh) 1/	15600	12.6%	22258	8.4%	28328	6.7%	34392	9.2%
Sales to Isol Sys.	0		79	18.5%	132	17.3%	212	
UPS Sales (GWh)	15600	12.4%	22179	8.3%	28197	6.6%	34180	9.1%
Sys. Losses (% of Gen)	21.5%		20.2%		20.6%		17.9%	
Total Generation (GWh)	19870	11.8%	27797	8.5%	35494	5.5%	41649	8.6%
Peak Load (MW)	3179	13.7%	4672	7.5%	5803	4.7%	6664	8.6%

Consumption Shares by Class								
VHV Industrial	0.27		0.21		0.19		0.19	
Non VHV Industrial	0.32		0.30		0.29		0.29	
Agriculture	0.05		0.05		0.04		0.04	
Public Utilities	0.07		0.08		0.08		0.07	
Commercial	0.03		0.04		0.05		0.05	
Residential	0.22		0.28		0.31		0.32	
Government	0.04		0.04		0.04		0.04	
Total Sales (GWh) 1/	1.00		1.00		1.00		1.00	

1/ Total final sales of EEA and EDA, including sales to isolated systems.

(1) the econometric method, which employs multi-variate regression to forecast sales (GWh) for all customer classes (except VHV Industrial)

(2) the hours-use method, which uses estimates of average annual hours of use for each customer class to project class demand, and then applies a diversity factor to forecast system peak demand (MW).

A third method, the end-use method, which relies on estimates of appliance saturation to forecast residential sector sales, has also been utilized, but it is not applied in EEA's most recent projections.[2]

These methods (especially the first) are common in the literature on load forecasting. We therefore discuss the methods only as applied by EEA to produce sales forecasts by customer class.

Customer Class Forecasts by the Econometric Method

Sales to most customer groups (Residential, Commercial, Non-VHV Industrial, Agriculture, Government, and Public Utilities) were projected using econometric models. Data on each sector's historic behavior and its correlation to past economic activity served as the basis for these forecasts.

The advantage of the econometric approach is that it quantifies the relationship between the demand for electricity in a given class and the major structural determinants of that demand, including income and price. Although EEA has not incorporated a price variable in any of its econometric equations, most of these equations include a measure of economic growth. In fact, all selected equations include national gross domestic product (GDP) or GDP per capita as the explanatory variables. Appendix B includes the econometric equations on which the forecast is based. The

[2] The end-use method is not driven by either of the two key determinants of demand, i.e., income and electricity price. If the economic climate were to change dramatically (for better or worse), the forecast would not be affected under this methodology. Similarly, the forecast is unaffected by changes in the real price of electricity, despite considerable worldwide evidence that significant price increases induce conservation.

End-use methods are most suitable when some survey work has been done to establish current saturation and usage patterns. Otherwise, the saturation assumptions employed are extremely dependent on the forecaster's judgment.

economic and demographic assumptions that drive the econometric forecasts are summarized in Exhibit 2-4.

Exhibit 2-4
Basic Assumptions for Econometric Forecasts

Real GDP Growth Rate (annual rate, FY1991-FY2015)	
Medium Forecast	6.0%
High Forecast	7.5%
Low Forecast	4.5%
Population (FY86 Census)	48.205 million
Population Growth Rate (annual rate, FY1986-FY2015)	
All Forecasts	2.8%

The medium (base case), high, and low load forecasts for each class, as prepared by EEA, are reprinted in Appendix B.

While it is beyond the scope of this effort to develop alternative model formulations, we can offer some general comments on the methodology and the models chosen:

- In logarithmic formulations, the coefficients of independent income and price variables represent income and price elasticities of demand. When alternative formulations give us consistent elasticities, our confidence in the results is increased.

- We would be the first to admit that data deficiencies may ultimately prevent incorporating price variables in all equations. Nevertheless, every attempt should be made to do so. If valid equations cannot be found, alternative models should be considered, such as the "consensus elasticity" model.[3]

[3] Westley, Glenn, *Forecasting Electricity Demand: A General Approach and Case Study in the Dominican Republic*, Inter-American Development Bank, Project Analysis Department Report No. 26, October 1984.

VHV Industrial Forecast (No Formal Methodology)

Very High Voltage (132 kV and above) industrial sales have been forecast on a customer-by-customer basis. Initial forecasts were provided by the Ministry of Industry and reviewed by EEA. The final forecast represents a consensus between the two agencies.

VHV sales are expected to increase at an average annual rate of 1.7 percent from FY90 to FY96, and to increase at a constant rate of 5 percent annually in subsequent national development plans. The near-tern growth represents a considerable reduction from historic trends (see Exhibit 2-3). In the absence of detailed national planning information, VHV sales growth after FY96 is assumed to mirror the performance of recent years.

The same sales projections are used in the High, Medium, and Low forecasts through FY96. In subsequent years, the Low forecast assumes no growth, while the High forecast assumes 7.5 percent annual growth. We recommend that the Low scenario explicitly consider the possibility that fuel substitution or demand management efforts might take place.

Collectively, VHV sales represent nearly 20 percent of final consumption on the UPS. In view of these customers' importance, it would be appropriate to detail plans for each company, and to consider high and low cases for each. Again, the electricity demand of these very large customers should be linked to expectations regarding economic growth and electricity price.

Peak Demand Forecast Using the Hours-Use Method

EEA converted annual energy sales by customer class to non-coincident class peaks by estimating an annual hours-use factor for each. The following factors were assumed:

Residential	3000 hours
Commercial	3000 hours
VHV Industrial	7000 hours
Non-VHV Industrial	4200 hours
Public Utilities	6000 hours
Other EDA Sales	3000 hours

System Losses	6100 hours
Isolated System	3500 hours

By calculating the total system non-coincident peak according to this method for previous years and then comparing it to the actual system peak, a coincidence factor was estimated: 68 percent. All of the foregoing assumptions were then held constant to forecast peak demand from the sales forecast.

The advantage of this method from EEA's point of view is that it results in a gradual shift in load factor. Some shift might be expected as the residential/commercial sector continues to grow in relative importance.

One concern about the hours-use method is that it relies considerably on forecaster judgment. We suggest that a simple trend analysis of the system load factor would also yield a reasonable result without the need for so many assumptions.

2.3 KEY UNCERTAINTIES AFFECTING THE LOAD FORECAST

Today, the Egyptian economy and the electricity sector in particular are at a crossroads. Fundamental uncertainties will directly affect future requirements for electricity. National economic growth has slowed from its lofty post-1974 expansion. If slower growth continues, it will certainly be reflected in overall energy demand.

Similarly, within the electricity sector, additional uncertainties have the potential to dramatically affect demand. These include (1) the potential for industrial restructuring (fuel switching and/or conservation) among major VHV Industrial customers, and (2) the probable need for significant and sustained real electricity price increases across all customer classes in the near term.

The load forecast must be capable of reflecting the impact of these adjustments on demand. In the paragraphs that follow, we discuss each of the three key uncertainties identified above, and consider how they should be addressed in the load forecast.

Economic Growth Rate

All of EEA's forecast scenarios assume a stable economic growth of GDP at an annual rate of 4.5 to 7.5 percent. By comparison, recent economic assessments prepared by

staff of international agencies have assumed average annual GDP growth in the range of 3.7 to 4.7 percent over the next 7 to 10 years.[4]

While these are unofficial views, a consensus seems to be emerging that Egypt will experience lower than historical rates of growth in the near term. Fortunately, however, EEA's forecast of electricity demand is not inconsistent with these estimates. These studies have generally found a long-run income elasticity of approximately 1.5; thus, EEA's Medium (base case) forecast would be reasonably consistent with average annual economic growth expectations of 4.0 percent during the next decade.

Industrial Sector Restructuring

Much of Egypt's industrial sector developed in a period of perceived abundant energy at low prices. The result has been a number of large, energy-inefficient industrial customers. Two public sector companies are frequently singled out for criticism: Kima Fertilizer Plant and Nag Hammadi Aluminum Smelter. Together, they represent over 70 percent of EEA's VHV Industrial sales, and 14 percent of total consumption on the Unified Power System.

Proposed solutions to current inefficiencies could have a dramatic impact on the EEA forecast. For example, it has been suggested that Kima could be modified for conversion to fuel oil or even natural gas, at tremendous savings in total energy. (The plant currently consumes about 200 MW and 1600 GWh annually.) Similarly, it has been suggested that Nag Hammadi's total electricity consumption could be reduced by 20 percent if it were to invest in modern smelter technology.

We understand why EEA has not included this industrial restructuring in its forecast. EEA has no direct control over these plants, and the Ministry of Industry has not confirmed plans to implement the above-cited recommendations. Further, the forecast is conservative when compared with historic trends (Exhibit 2-3). As noted previously, growth is assumed to be held to 1.7 percent annually until FY96. Even if fuel substitution/conservation is realized, EEA expects growth in consumption of new or existing VHV customers to consume any additional savings.

Due to the foregoing considerations, we have no basis to recommend a revision to the Medium load forecast due to industrial restructuring. Suffice to say, potential changes in consumption by large loads must be monitored continuously, so that any revisions can immediately be incorporated into a new forecast. The potential for such changes argues

[4] See, for example, *A Survey of the Economics of Electrical Energy in Egypt*, internal document, Economics Office, USAID, Cairo, April 1990; *Fourth Power Project*, Staff Appraisal Report, World Bank, May 30, 1989; and Internal working document, World Bank, undated, circa September 1990.

that EEA should incorporate capacity (demand) as well as energy charges into its industrial tariff structure.

Price of Electricity

EEA and the Egyptian Government have been under tremendous pressure during the last several years to bring electricity prices into line with the economic cost of supply. It has been estimated by several analysts that current average prices are one-quarter to one-third of marginal economic cost. To correct this inefficient pricing, EEA is very likely to require dramatic real price increases over the next five years. The path of these price increases is a matter to be decided at the highest levels of government; indeed, specific recommendations as to the appropriate level for tariffs, and the implementation strategy for required increases, form an important part of this study.

Unfortunately, EEA's current forecast cannot provide any guidance as to the impact of price increases on demand. Price was not used as a variable in the analysis.

We understand that good price data may not be available for different customer classes. Further, there is minimal experience with real price increases, so reliable estimates of price elasticity may be difficult to obtain through econometric modeling. Nevertheless, the demand response to real price change is an important factor that should be incorporated in all EEA forecasts as soon as data permit.

2.4 RECOMMENDED LOAD FORECAST

RCG/Hagler, Bailly has conducted a complete review of the current EEA forecasting methodology. Briefly, our major concern is that the forecast is not adequately linked to key structural determinants of demand, notably income and price. Specifically, almost 20 percent of total sales (notably VHV Industrial consumption) are projected through models or assumptions that are not related to either sectoral or overall economic activity. Further, the entire forecast is not linked to expected future electricity prices.

There is another potential problem regarding the VHV Industrial forecast. Although this forecast was developed by the Ministry of Industry with close EEA scrutiny, it does not explicitly take into account either fuel conversion or demand management/ conservation options that have been proposed for several large energy-inefficient facilities.

In light of these concerns, we decided to compare the overall EEA Medium forecast (the "base case") as summarized in Exhibit 2-5 with alternative forecasts recently developed by independent sources. We considered two such forecasts: (1) the forecast for the El Arish Project, prepared for the African Development Bank (1989), and (2) an

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Exhibit 2–5

EEA Sales and Generated Energy Forecast by Customer Class (Medium Scenario)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00
VHV Industrial	6628.6	6770.0	6980.0	7054.0	7144.0	7294.0	7344.0	7711.20	8096.76	8501.60	8926.68
Non VHV Industrial	10096.0	10831.5	11630.8	12489.1	13410.7	14400.3	15463.0	16604.1	17829.4	19145.1	20557.9
Total Industrial	16724.6	17601.5	18610.8	19543.1	20554.7	21694.3	22807.0	24315.3	25926.1	27646.7	29484.6
	6.6%	5.2%	5.7%	5.0%	5.2%	5.5%	5.1%	6.6%	6.6%	6.6%	6.6%
Agriculture	1344.4	1420.5	1499.1	1582.1	1669.6	1762.1	1859.6	1962.5	2071.1	2185.8	2306.8
Public Utilities	2369.0	2586.3	2765.0	2955.3	3158.8	3376.3	3608.7	3857.1	4122.7	4406.5	4709.9
Subtotal	20438.0	21608.8	22874.9	24080.5	25383.1	26832.7	28275.3	30134.9	32120.0	34239.0	36501.2
	6.9%	5.7%	5.9%	5.3%	5.4%	5.7%	5.4%	6.6%	6.6%	6.6%	6.6%
Commercial	1631.0	1716.8	1881.8	2056.9	2236.2	2425.0	2623.2	2831.0	3048.2	3274.6	3510.6
Residential	10931.0	11822.2	12777.7	13749.9	14734.7	15728.4	16727.1	17727.4	18725.9	19719.3	20704.8
Government	1392.0	1452.2	1560.5	1676.9	1802.0	1936.4	2080.8	2236.0	2402.8	2582.1	2774.7
Subtotal	13954.0	14991.1	16220.1	17483.7	18772.9	20089.7	21431.2	22794.5	24177.0	25576.2	26990.0
	5.8%	7.4%	8.2%	7.8%	7.4%	7.0%	6.7%	6.4%	6.1%	5.8%	5.5%
Total Sales (GWh)	34392.0	36600.0	39094.9	41564.2	44156.0	46922.4	49706.5	52829.4	56296.9	59815.2	63491.3
	6.5%	6.4%	6.8%	6.3%	6.2%	6.3%	5.9%	6.5%	6.4%	6.2%	6.1%
Sales to Iso. Sys.	212.2	232.0	343.0	508.0	600.0	708.0	837.0	427.0	491.0	564.0	649.0
UPS Sales	34179.8	36368.0	38751.9	41056.2	43556.0	46214.4	48869.5	52502.4	55805.9	59251.2	62842.3
System Losses	7469.2	7929.2	8449.0	8890.5	9367.5	9939.2	10438.1	11136.9	11755.7	12394.7	13054.2
(% of Gen)	17.9%	17.9%	17.9%	17.8%	17.7%	17.7%	17.6%	17.5%	17.4%	17.3%	17.2%
Total Generation (GWh)	41649.0	44297.2	47200.9	49946.7	52923.5	56153.5	59307.6	63639.3	67561.6	71645.9	75896.4
G.R %	5.2%	6.4%	6.6%	5.8%	6.0%	6.1%	5.6%	7.3%	6.2%	6.0%	5.9%
Peak Load (MW)	6664	7152	7644	8123	8640	9189	9736	10461	11108	11778	12472
G.R %	6.1%	7.3%	6.9%	6.3%	6.4%	6.4%	6.0%	7.4%	6.2%	6.0%	5.9%
Load Factor	71.35%	70.70%	70.49%	70.19%	69.93%	69.76%	69.54%	69.44%	69.43%	69.44%	69.47%

unpublished World Bank forecast prepared in conjunction with a recent appraisal mission (1990). The comparison is shown in Exhibits 2-6 and 2-7. The former study projected near-term rapid growth, moderating in the latter half of the decade. The more recent World Bank study projects the opposite: slower growth in near-term sales, with more rapid growth thereafter.

In summary, we have concerns about certain aspects of the forecasting methodologies employed. However, after our review, we conclude that EEA's "Medium" forecast (Exhibit 2-5) is an appropriate basic case for use in the tariff study. The reasonableness of this forecast is bolstered by the fact that this is closely bracketed by two independent assessments of future loads on the Unified Power System.

2.5 DISAGGREGATION OF THE LOAD FORECAST BY VOLTAGE LEVEL AND CUSTOMER CLASS

For the long-run marginal cost analysis, it is necessary to disaggregate the EEA load forecast by voltage level and customer class. We have allocated loads according to the following distinct service voltage levels:

VHV	132 kV and above
HV	66/33 kV
MV	20/11/6.6 kV
LV	below 6.6 kV

This task is complicated by the lack of a single, comprehensive database on UPS customers. To illustrate, the load forecast is based on the more typical "natural" categories of customers, e.g., residential/commercial, industrial, agriculture, public utilities, and government. Tariffs, on the other hand, are set based on a completely different combination of categories, including public and private sector industry, moving power greater than or less than 500 kW, sales for resale, etc. Given these differences, it is not always possible to precisely map historical sales data with the load forecasting categories, or to subsequently re-allocate the load forecast by tariff classes.

We have disaggregated the UPS load forecast by voltage level in two steps. First, we mapped actual FY90 sales for each tariff category to both the load forecast classifications and the voltage level groups. Then, for each forecast category, we calculated the percentage share of FY90 sales occurring at each voltage. These FY90 shares were applied to disaggregate forecast sales by voltage level over the entire study period.

Since this procedure is somewhat confusing, we describe the breakdown for each forecast category. The reader can most easily follow this discussion with reference to the data presented in Exhibit 2-8.

Exhibit 2-6
Comparison of Recent Sales and Demand Forecasts

YEAR	TOTAL SALES FORECASTS (GWh)			MAXIMUM DEMAND FORECASTS (MW)		
	1990 EEA 1/ MEDIUM	1989 ADB 2/ EL ARISH	1990 IBRD	1990 EEA MEDIUM	1989 ADB EL ARISH	1990 IBRD
FY90 3/	34180	36032	34062	6664	7519	6944
FY91	36368	38888	34304	7152	8115	6993
FY92	38752	41908	36160	7644	8745	7371
FY93	41056	44667	38155	8123	9298	7778
FY94	43556	47507	40300	8640	9889	8215
FY95	46214	50605	42606	9189	10508	8685
FY96	48869	53731	45087	9736	11157	9191
FY97	52502	57140	47758	10461	11836	9735
FY98	55806	59781	52520	11108	12383	10706
FY99	59251	62674	57856	11778	12950	11794
FY00	62842	65512	63840	12472	13537	13014
Average Growth %						
FY90-95	6.2%	7.0%	4.6%	6.6%	6.9%	4.6%
FY95-00	6.3%	5.3%	8.4%	6.3%	5.2%	8.4%
FY90-00	6.3%	6.2%	6.5%	6.5%	6.1%	6.5%

1/ The EEA forecast of UPS total sales.
2/ ADB generation forecast reduced by EEA loss forecast.
3/ For FY90, EEA sales and peak are actual.

(1) **VHV Industrial.** Obviously, all EEA direct sales to VHV Industries were assumed to be at very high voltage. The allocation of sales to different voltage levels is therefore unnecessary.

(2) **Non-VHV Industrial.** Forecast sales, to both EEA and EDA customers, fall into three different voltage levels. EEA bulk industrial customers are served at both HV and MV. (In Exhibit 2-8, these are referenced as I-1 and I-2.) EDA non-VHV industry sales are made at both MV and LV to public sector, private sector, free zone and investment companies (I-3 and I-4 in Exhibit 2-8). For the purposes of this analysis, we have assumed that all EDA industrial accounts with demand above 500 kW (including both moving power and lighting) are served at MV, and accounts with demand below 500 kW are served at LV. Further, non-VHV industry

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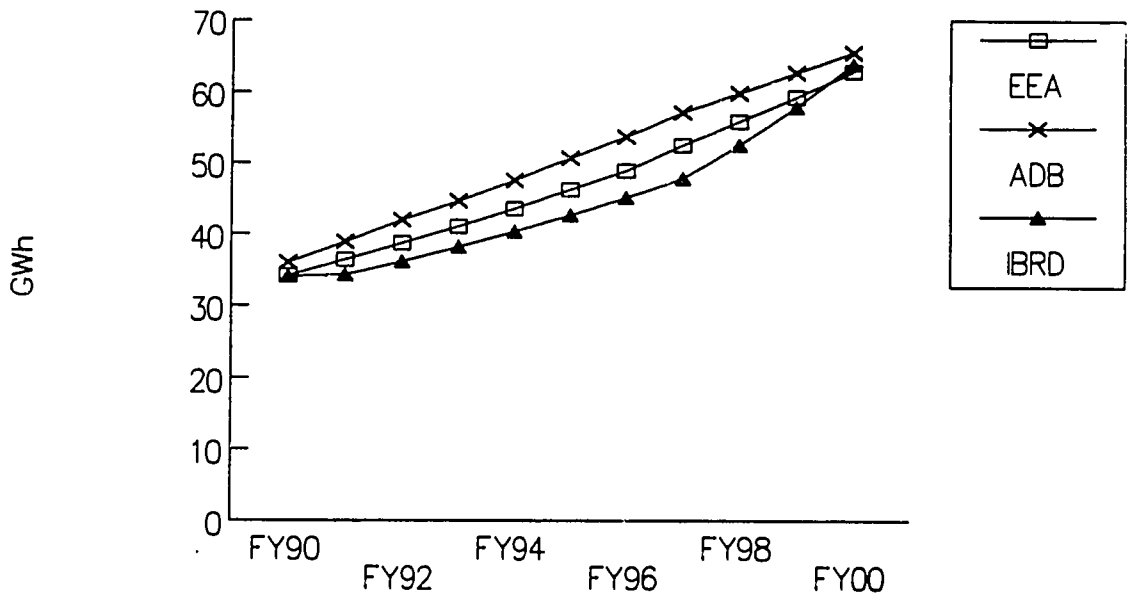
Exhibit 2-7

Comparative Sales Forecasts (FY1990-FY2000)



sales include that portion of Sales for Resale (i.e., distribution company sales to the housing companies) which are ultimately consumed by industry.[5]

Of the total of 10,096 GWh sold to non-VHV industry in FY90 (i.e., the sum of I-1 through I-4), 15.5 percent were made at high voltage, 1.6 percent at medium voltage by EEA, 65.2 percent at medium voltage by distribution companies, and the remaining 17.8 percent at low voltage by distribution companies. As noted above, we have assumed that forecast

5 Detailed final consumption data for Heliopolis in FY90 were used to allocate FY90 Sales for Resale to forecast categories. Heliopolis accounts for over 80 percent of all sales for resale, and is representative of other housing company sales. FY90 sales for resale totaled 681 GWh, and have been allocated as follows: 11 percent to MV Industry (I-3) and 89 percent to LV sales categories, including 12.9 percent to Government, 56.6 percent to Residential, and 19.5 percent to Commercial.

Exhibit 2-8
Bulk and Final Sales by Voltage Level (GWh)

		Forecast Categories 1/	Class Share	Actual 1989/90	Forecast 1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00
		EEA Bulk Sales												
VHV	VHV:	Industry	1.000	6629.0	6770.0	6980.0	7054.0	7144.0	7294.0	7344.0	7711.2	8096.8	8501.6	8926.7
I-1	HV:	Industry	0.155	1566.0	1680.1	1804.1	1937.2	2080.1	2233.7	2398.5	2575.5	2765.5	2969.6	3188.8
A-1		Agriculture	0.541	727.0	768.4	810.9	855.8	903.1	953.1	1005.9	1061.6	1120.3	1182.3	1247.8
I-2	MV:	Industry	0.016	157.0	168.4	180.9	194.2	208.5	223.9	240.5	258.2	277.3	297.7	319.7
A-2		Agriculture	0.068	91.0	96.2	101.5	107.1	113.0	119.3	125.9	132.9	140.2	148.0	156.2
		EDA Purchases 2/		28259.0	30380.9	32734.4	35197.6	37764.3	40443.4	43236.9	46148.0	49130.5	52338.9	55628.6
		EDA Final Sales 3/												
I-3		Industry	0.652	6580.3	7059.7	7580.6	8140.1	8740.7	9385.8	10078.4	10822.1	11620.7	12478.3	13399.1
A-3		Agriculture	0.156	210.0	221.9	234.2	247.1	260.8	275.3	290.5	306.6	323.6	341.5	360.4
G-1		Government	0.219	305.1	318.0	341.8	367.2	394.6	424.1	455.7	489.7	526.2	565.5	607.6
PU-1		Public Utilities	0.355	841.0	918.3	981.6	1049.3	1121.4	1198.6	1281.1	1369.3	1463.5	1564.3	1672.0
R	LV	Residential	1.000	10931.0	11822.2	12777.7	13749.9	14734.7	15728.4	16727.1	17727.4	18725.9	19719.3	20704.8
C		Commercial	1.000	1631.0	1716.8	1881.8	2056.9	2236.2	2425.0	2623.2	2831.0	3048.2	3274.8	3510.6
I-4		Industry	0.178	1792.7	1923.3	2065.2	2217.6	2381.3	2557.0	2745.7	2948.3	3165.9	3399.5	3650.4
A-4		Agriculture	0.235	316.0	334.0	352.5	372.0	392.6	414.3	437.3	461.5	487.0	514.0	542.4
G-2		Government	0.781	1087.9	1134.2	1218.8	1309.7	1407.4	1512.3	1625.1	1746.3	1876.6	2016.6	2167.0
PU-2		Public Utilities	0.645	1528.0	1668.5	1783.4	1906.3	2037.4	2177.7	2327.6	2487.6	2659.1	2842.2	3037.9
		EEA Bulk Sales		37429.0	39863.9	42611.8	45345.9	48213.2	51267.4	54351.6	57887.3	61580.6	65438.2	69467.7
		EDA Sales		25223.0	27116.9	29217.6	31416.2	33707.1	36098.3	38591.7	41190.1	43896.8	46715.9	49652.2
		Final Sales by Voltage												
		VHV(132kv and above)		6629.0	6770.0	6980.0	7054.0	7144.0	7294.0	7344.0	7711.2	8096.8	8501.6	8926.7
		HV(66kv and 33kv)		2293.0	2448.4	2615.0	2793.0	2983.3	3186.8	3404.4	3637.0	3885.9	4152.0	4436.5
		MV(11kv and 6.6kv)		8184.3	8782.6	9420.5	10105.1	10839.2	11626.9	12472.0	13378.7	14351.5	15395.2	16515.0
		LV(below 6.6kv)		17286.7	18599.0	20079.5	21612.4	23189.5	24814.7	26486.1	28202.4	29962.8	31766.4	33613.1
		Total (EEA+EDA)		34393.0	36600.0	39094.9	41564.5	44156.0	46922.4	49706.5	52929.4	56296.9	59815.2	63491.3
		Sales to Isolated		212	232	343	508	600	708	837	427	491	564	649
		UPS Total Sales		34180	36368	38752	41056	43556	46214	48869	52502	55806	59251	62842
		System Losses		7469	7929	8449	8891	9367	9939	10438	11137	11756	12395	13054
		Gross Generation		41649	44297	47201	49947	52923	56154	59308	63639	67562	71646	75896
		Peak Demand		6664	7152	7644	8123	8640	9189	9736	10461	11108	11778	12472

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NOTES TO EXHIBIT 2-8

1/ All tariff categories have been allocated to forecast categories. Their percentage of total 1989/90 sales within each forecast category has then been maintained for the entire forecast period. As a cross-check, note that the sum of shares within each forecast category totals 1.000.

- VHV =	1.000
- I-1 through 1-4 =	1.000
- A-1 through A-4 =	1.000
- G-1 through G-2 =	1.000
- PU-1 through PU-2 =	1.000
- R =	1.000
- C =	1.000

Loads are allocated to forecast groups as follows:

VHV and I-1 through I-4 include:
- EEA direct industry sales, public and private, inside and outside free zone (VHV, HV and MV)
- EEA sales to industrial societies
- EDA industry sales, including investment companies (above 500 kW is MV, below 500 kW is LV, including both moving power and lighting)

A-1 through A-4 include:
- EEA direct agriculture sales (HV and MV)
- EDA agriculture sales (above 500 kW is MV, below 500 kW is LV, including both moving power and lighting)

G-1 through G-2 include:
- EDA government sales (above 500 kW is MV, below 500 kW is LV, including both moving power and lighting)

PU-1 through PU-2 include:
- EDA public utility sales (above 500 kW is MV, below 500 kW is LV, including both moving power and public lighting)

R and C include:
- EDA sales to residential and commercial customers (LV)

2/ EDA purchases are calculated from the proportion of 1989/90 purchases to sales.

3/ Sales for Resale were not forecast separately. Actual 1989/90 Sales for Resale (681 GWh) have been allocated to other forecast categories based on Heliopolis final sales for 1989/90 (Residential 56.6%, Commercial 19.9%, MV Industry 11.0%, LV Public Utilities 4.2%, and LV Government 8.4%).

sales to non-VHV industrial users from FY91 through FY2000 will be allocated by voltage in the same proportions.

(3) **Agriculture.** Total forecast sales for agriculture must be allocated to four different voltage levels: EEA bulk sales at HV and MV (identified as A-1 and A-2 in Exhibit 2-8), and distribution company sales at MV and LV (A-3 and A-4 in Exhibit 2-8). Agriculture customers include public, private, and government sector entities. Of the total of 1,344 GWh sold to agriculture in FY90 (the sum of A-1 through A-4), 54.1 percent were made at high voltage by EEA, 6.8 percent at medium voltage by EEA, 15.6 percent at medium voltage by distribution companies, and the remaining 23.5 percent at low voltage by distribution companies. Again, we assume that forecast sales (FY91-2000) will maintain this same allocation across voltage levels.

(4) **Government.** All sales under the government classification are made by the distribution companies. As with industry, we have assumed that all government users above 500 kW are served at medium voltage, and all others at low voltage. In FY90, of the total of 1,393 GWh sold to government consumers, 21.9 percent were sold at medium voltage (G-1), and the remaining 78.1 percent at low voltage (G-2).

(5) **Public Utilities.** This classification includes public lighting, sewage, and transportation utilities. Of a total of 2,329 GWh sold to this tariff class in FY90, 35.5 percent were sold at medium voltage (PU-1) and 64.5 percent at low voltage (PU-2).

(6) **Residential and Commercial.** Distribution company sales to residential customers totaled 10,931 GWh in FY90, and commercial sales totaled 1,631 GWh. These sales are assumed to be entirely at low voltage.

The assumption of constant consumption shares by voltage level within each forecast category for all forecast years is, of course, a simplification. This assumption is considered reasonable because shifts in relative shares are gradual, and not expected to be significant over the ten-year time horizon of this study. Based on very limited historical data, forecasting trends would be less reliable than the constant share assumption.

Exhibit 2-8 presents the EEA medium load forecast disaggregated by voltage level and customer class.

EEA's databases for statistical reporting, system planning, forecasting, and tariff-setting activities provide extensive support for these activities. As the preceding discussion illustrates, however, the information could become even more powerful if linkages

between these databases were enhanced. For example, the mapping of forecast categories to different voltage levels and tariff classifications takes considerable time and judgment. If certain "cross references" were tracked for each customer, this process could be simplified and largely automated.

For example, every customer billing record might have associated with it (1) a unique customer number and (2) a code that identifies the customer's tariff classification (i.e., which tariff he is billed under). Further, in the case of non-residential users, there might be a code that classifies the customer according to industry type. With these classifiers, the pooling of the data for forecasting or other analysis would be a straightforward task.

CHAPTER 3: REVIEW OF LEAST-COST GENERATION DEVELOPMENT PROGRAM

This chapter describes the work conducted under Task 2 in the study, whose aim was to review EEA's generation expansion plan and, if necessary, adjust the program from the perspective of defining a plant line-up and the staging required to support the marginal cost and financial analysis subsequently performed for the tariff study.

Our review of EEA's least-cost expansion plan initially focused on an examination of the key input assumptions used in the analysis in order to check for consistency and appropriateness (Section 3.1). Next, a screening analysis was conducted to verify the relative economics of different plant addition options (Section 3.2). Section 3.3 presents an analysis of projected gas requirements of the generation development program. This is followed in Section 3.4 by a description of additional runs of EEA's Wien Automatic System Planning Package (WASP), under different assumptions on selected inputs, to gauge the influence of such changes on the results. Finally, Section 3.5 presents our overall assessment.

This review and evaluation supports the general conclusion that EEA's planned generation mix and the magnitude and timing of capacity additions provide an appropriate basis for conducting this tariff study, i.e., the long-run marginal cost analysis (LRMC) and the financial analysis.

3.1 PRELIMINARY REVIEW AND APPROACH SELECTED

EEA has prepared its generation expansion plan using the WASP model to select among the following alternatives:

- 600 MW nuclear units
- 600 MW and 300 MW coal-fired steam turbines
- 600 MW and 300 MW gas- or oil-fired steam turbines
- 120 MW gas or gas/oil-fired combustion turbines.

The WASP solution to the generation expansion plan, excluding committed additions before 1996, is shown in Exhibit 3-1. This solution recommends that by the year 2000, 480 MW of gas turbines, 2,100 MW of gas- or oil-fired steam turbines, and 1,500 MW of

Exhibit 3-1 Original EEA Solution						
YEAR	STEAM COAL	STEAM GAS	GAS TURBINE	TOTAL	LOLP	TOTAL COST 1990-2000
	MW	MW	MW	MW		MILLION US$
1996		600	120	720	0.226	
1997		1200		1200	0.238	
1998				0	0.238	
1999	900		360	1260	0.205	
2000	600	300		900	0.257	
sol. 1	1500	2100	480	4080	0.233	8361
sol. 2	900	2700	480	4080	0.231	8361
sol. 3	1500	2100	600	4200	0.221	8364

Key Parameters Used by EEA to Develop Its Least-Cost Plan					
FUEL PRICES					
Oil and gas price	$/MBtu	2.14			
Coal price	$/MBtu	1.94			
Uranium	$/MBtu	0.73			
CANDIDATE GENERATION ALTERNATIVES					
		A	B	C	D
Capital cost	$/kW	1560	800	717	436
Economic life	years	30	30	30	20
Fixed operating cost	$/kW/y	6.5	7.2	7.2	8.5
Variable operating cost	$/MWh	1.9	1.9	1.9	5.5
Full load heat rate	btu/kWh	8868	8868	8868	14777
Maintenance outage	days/y	42	42	30	14
Forced outage rate	%	10	8	8	10

A = 600 MW Nuclear
B = 600 MW Coal-Fired Steam
C = 600 MW Gas- or Oil-Fired Steam
D = 120 MW Combustion Turbine

coal-fired steam turbines should be added, for a total of 4,080 MW of new capacity additions.

In addition to the optimum solution shown as "Solution 1" in Exhibit 3-1 are the capacity additions corresponding to two other solutions. WASP provides results for up to ten solutions because frequently, the difference in total present value cost of these solutions is smaller than the accuracy that can be claimed for the analysis. In this case, it can be noted that Solution 2 has the same cost as Solution 1, which results from a tradeoff between coal-fired and gas-fired steam thermal capacity with a small increase in reliability. Solution 3 is slightly more expensive because it involves an additional gas turbine for added system reliability.

A preliminary review of the data and assumptions used to prepare the EEA plan shown in Exhibit 3-1 focused on several parameters, including fuel prices and availability, dependable capacity of the hydroelectric system, the cost and operating characteristics of candidate generation, and dispatch constraints. These aspects were investigated by different means, including meetings with EEA's generation planning staff, reviews of operating and cost data for existing plants, discussions with dispatch center staff, visits to thermal and hydroelectric plants, meetings with the Egyptian General Petroleum Corporation (EGPC), reviews of existing feasibility studies for future plants, and world-wide data on generating plant characteristics from the consultant's records. A list of individuals interviewed other than EEA planning staff is included as Appendix C.

As a result of these investigations, a set of data was developed for each alternative used by EEA plus a combined-cycle alternative added by the consultant. These values are shown in Exhibit 3-2. The nature of the concerns to be addressed determined that three types of analyses were necessary for an adequate review of EEA's least-cost plan.

The first is a screening analysis to compare the long-term cost of each generation alternative for different capacity factors. This analysis serves as a rough guide to determine if the characteristics of the generation mix resulting from the WASP model are reasonable. The second is a gas requirements analysis, which was performed to estimate the level of generation that could be supported by gas reserves available to the power sector. The third is a least-cost plan analysis, which involved new runs of the WASP model using revised data for the characteristics and costs of candidate plants. A description of these three analyses follows.

Exhibit 3-2

Revised Parameters For Least-Cost Plan

FUEL PRICES		
Oil and gas price	$/MBtu	2.43 (real 3% growth after 2000)
Coal price	$/MBtu	1.80
Uranium	$/MBtu	0.74

Candidate Generation Alternatives		A	B	C	D	E
Capital cost	$/kW	2491	830	718	650	298
Economic life	years	30	30	30	25	25
Fixed operating cost	$/kW/y	14.2	7.3	4.1	2.6	1.9
Variable operating cost	$/MWh	1.6	0.4	0.2	0.1	nil
Full load heat rate	btu/kWh	10600	9500	9800	9800	14000
Maintenance outage	days/y	35	28	28	28	14
Forced outage rate	%	14	12	8	10	11

A = 600 MW Nuclear
B = 600 MW Coal-Fired Steam
C = 600 MW Gas- or Oil-Fired Steam
D = 450 MW Combined Cycle
E = 120 MW Combustion Turbine

Note: The distribution between fixed and variable operating costs is consistent with accounting records of Egyptian plants and may be different from international experience due to the treatment of spare parts inventory.

3.2 SCREENING ANALYSIS

The screening analysis was conducted at discount rates of 10 percent and 6 percent; the latter was conducted for sensitivity analysis purposes. The corresponding results are shown in Exhibits 3-3 and 3-4. These exhibits show the annual cost of using one kilowatt of effective capacity from each alternative as a function of the amount of time in operation. Because the cost already includes the effect of maintenance and forced outage, each effective kilowatt can be used up to 100 percent of the time.

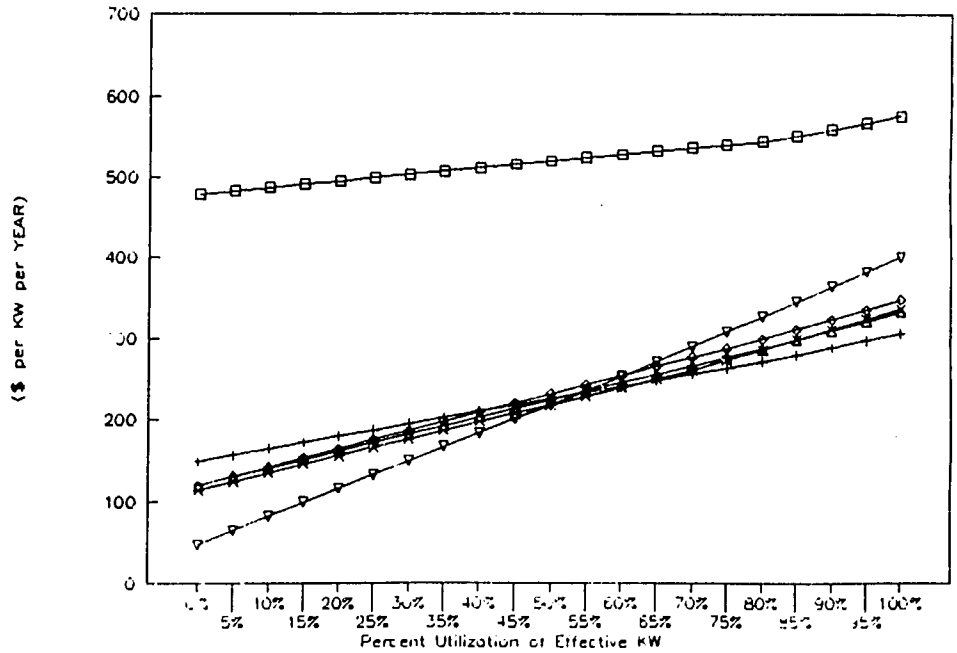
Each figure in these exhibits has two plots. The upper plot corresponds to a zero real escalation rate in the price of gas and oil; this situation is deemed representative of conditions up to the year 2000. The lower plot corresponds to power costs levelized for the period 2000-2020 for which a 3 percent real escalation rate in the price of gas and oil has been assumed.

The analysis shows that only combustion turbines are competitive for peaking operation and only coal-fired steam turbines are competitive for base load operation. The level of utilization at which these widely different types of generation have the same cost is between 20 and 60 percent, depending on fuel price escalation and discount rate. Near the breakeven point for combustion turbines and coal-fired steam generation, the gas- and oil-fired alternatives come very close to the lowest cost, particularly in the analysis for the conditions in 1990-2000. It is also worth noting that gas- and oil-fired steam turbines and gas-fired combined cycle show similar costs at all levels of utilization and therefore can be considered to be equally attractive in cost at the level of accuracy involved in this analysis.

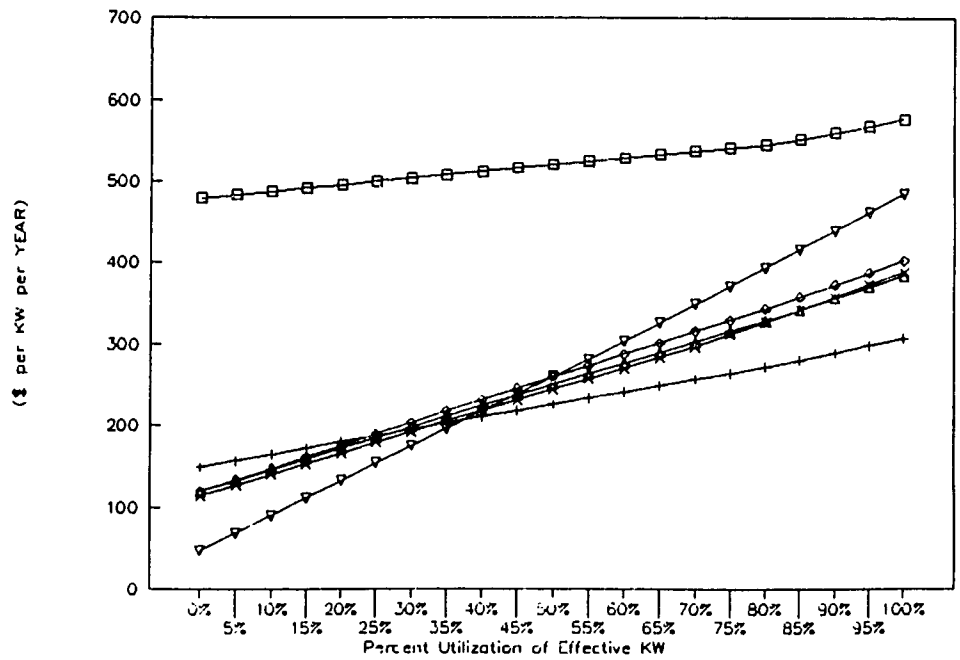
The nuclear alternative is more expensive than other forms of generation under most cases and more expensive than coal-fired generation under all cases. Even a substantial reduction in capital cost would not make it attractive. This is noteworthy because the capital cost of nuclear has been set deliberately high to account for several factors. One factor is the North American experience with regulatory delays, which has resulted in very high capital costs for nuclear plants. While this experience need not be repeated in other parts of the world, certainly it will be some time before regulatory constraints at the international level can be safely relaxed. A second consideration in introducing nuclear generation in Egypt is the lead time needed to establish a regulatory structure, waste fuel disposal sites, and nuclear plant decommissioning allowances in the capital cost. Consequently, in our judgment, nuclear generation is not a short-term option for Egypt, but may be an attractive option in the next century. However, without a very specific analysis of the economic implications of this technology, it is necessary to adopt a conservative posture guided by recent experience.

Exhibit 3-3
Levelized Cost of Generation Under Different Options
Discount Rate 10%

Period 1990–2000



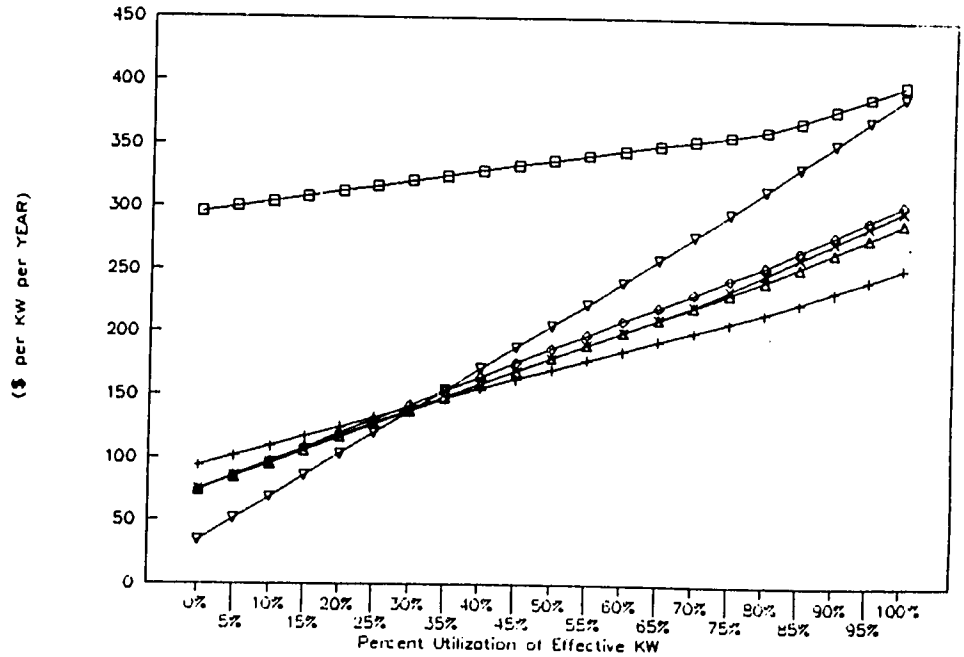
Period 2000–2020



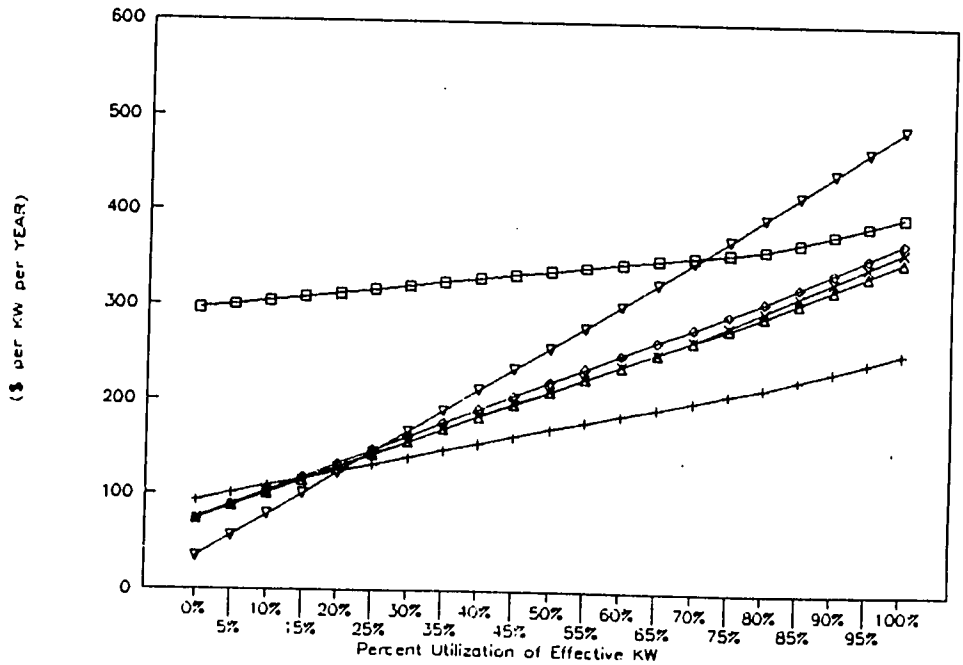
Key: □ = nuclear-fired steam, + = coal-fired steam, ◇ = gas-fired steam, ▵ = oil-fired steam
X = combined cycle, and ▿ = gas-fired combustion turbine

Exhibit 3-4
Levelized Cost of Generation Under Different Options
Sensitivity Analysis Discount Rate 6%

Period 1990-2000



Period 2000-2020



Key: □ = nuclear-fired steam, + = coal-fired steam, ◇ = gas-fired steam, ▵ = oil-fired steam
X = combined cycle, and ▿ = gas-fired combustion turbine

From the screening analysis, it is possible to expect that a detailed least-cost expansion sequence such as those prepared using WASP will show a fair amount of combustion turbines and coal-fired steam generation. The further the analysis looks into the future, the more it will lean towards coal-fired generation.

The actual proportion between base and peak load thermal generation will be heavily influenced by the size and load factor of the demand above minimum load and not served by peaking hydroelectric resources. By 2000, that fraction of the demand will still be very small because of the substantial amount of hydro in the peak load. Thus, it is likely that combustion turbine capacity will show a small proportion in the mix. EEA's plans call for 12 percent of added capacity to be combustion turbines; this is consistent with findings of the screening analysis.

Finally, the results indicate that the influence of discount rate does not significantly alter the choice of base load generation, but will result in different proportions of base load and peak load generation favoring the low-cost combustion turbines at higher discount rates.

3.3 GAS REQUIREMENTS ANALYSIS

An analysis was carried out to obtain an appropriate estimate of the extent to which generation can be supported by natural gas through a conservative estimate of the evolution of reserves of this resource. A discussion of available reserves is presented in Chapter 4 and thus, only the implications in terms of support for generating capacity will be addressed in this chapter.

The gas requirements analysis (Exhibit 3-5) was conducted under the assumption that existing generation that currently burns both gas and residual oil (mazout) will gradually increase the gas component until, by the year 1994, it will be burning gas only (line 1 of Exhibit 3-5). Furthermore, for the purposes of this analysis, no coal-fired generation is assumed; thus, all new generation will burn only gas, and the use of distillate fuel (solar) for start-up is neglected. Thus, after 1994, mazout will be used only by those units that currently burn mazout exclusively.

In line 4 of Exhibit 3-5 it is shown that, as the older mazout-fired units are retired from service and newer units shift to a larger proportion of gas use, the use of mazout by EEA drops rapidly so that by 2000, it will be only 8 percent of its current level. The requirements of gas in peak and base load generation are shown in lines 2 and 3,

Exhibit 3-5

Gas Utilization Analysis

			1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
1.	ratio gas/mazout in existing thermal	ratio	0.35	0.40	0.50	0.70	0.90	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2.	annual gas required for peak	M m3/y	2375	2599	2816	3015	3251	3494	3754	3993	4277	4553	4878	5197
3.	annual gas required for base	M m3/y	1770	1945	2848	4587	6306	7574	8464	9375	10359	11378	12482	13626
4.	mazout utilization	T ton	4071	4329	3982	2917	1922	1366	1195	1024	854	683	512	341
5.	daily gas supply required	M m3/d	11	12	16	21	26	30	33	37	40	44	48	52
6.	life expectancy peak capacity gas	years	15.30	15.32	15.50	15.76	16.09	16.44	16.82	17.20	17.59	17.97	18.34	18.38
7.	life expectancy base capacity gas	years	26.00	25.00	24.60	24.72	24.92	25.15	25.40	25.66	25.94	26.22	26.51	23.58
8.	gas reserves allocated to power	M m3	198806	211654	225429	238369	250493	261762	272170	281701	290375	298147	305025	310960
9.	added reserves allocated to power	M m3	16992	16374	15756	15138	14520	13903	13285	12667	12049	11431	10813	10195
10.	total reserves of gas to power	M m3	211654	225429	238369	250493	261762	272170	281701	290375	298147	305025	310960	315958
11.	peak gas guarantee requirements	M m3	36337	39829	43537	47499	52295	57455	63146	68682	75219	81800	89480	95529
12.	peak gas long-term reserve	M m3	89	87	85	83	81	78	75	73	70	67	64	61
13.	full gas guarantee requirements	M m3	82357	88455	113684	160877	209419	247917	278172	309294	342975	380168	420360	416773
14.	full gas guarantee reserve	M m3	39	39	32	25	20	18	17	16	15	14	14	14

respectively, of Exhibit 3-5, and the daily gas supply required by EEA is shown in line 5. Under these assumptions the daily supply requirements will increase from the recent consumption levels of about 11 million cubic meters per day (MCM/day) to about 52 MCM/day by 2000. From the information received at the Egyptian General Petroleum Corporation, it appears that it is possible to increase supply capacity five-fold over a period of 10 years, as this would represent an annual increase on the order of 18 percent. Over the following decade -- 2000 to 2010 -- the comparable increase in gas requirements (if all new generation is to be gas-fired) will closely track the forecast growth in energy generation. This implies gas requirements on the order of 72 MCM/day by 2004 and 100 MCM/day by the year 2010. These levels of gas requirements can only be sustained by gas discoveries that substantially exceed the discovery rates realized in recent years.

The aggregated life expectancy of peak and base installed capacity burning natural gas is shown in lines 6 and 7. As the hydro system covers a smaller fraction of the peak load, peaking thermal capacity will have a larger share of the total installed thermal capacity and its aggregated life expectancy will increase with the newer units. The life expectancy of base load capacity (currently very high on account of newer units) will gradually decrease to an asymptotic level not much higher than its half-life.

Line 10 of Exhibit 3-5 shows the total reserves of gas available to the power sector at the end of each year. This is the result of adding to the existing reserves at the beginning of the year (line 8) the estimated new discoveries (line 9) and subtracting the total annual consumption (lines 2 and 3). The assumption, supported by discussions with EGPC, is that the power sector will maintain the current allocation of 60 percent of available gas. New discoveries are assumed to decrease slowly.

The results of the analysis are shown in lines 12 and 14 of Exhibit 3-5. Line 12 shows, for each year, the number of years beyond that point that the system can maintain the same level of use of gas for peak generation. Line 14 shows the number of years that the system can maintain the same level of gas use for both peak and base generation.

These numbers show that it is prudent to plan on introducing non-gas-fueled base load generation between now and 2000 because gas reserves cannot be conservatively estimated to support, for their lifetime, all generation added before 2000. On the other hand, there appears to be very little risk of running out of gas to support peaking generation any time soon, which would be a serious event due to the high price of distillate oil (solar), the only alternative fuel for peaking units.

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3.4 LEAST-COST PLAN ANALYSIS

A comprehensive least-cost plan analysis involves many activities that could not be included in the brief time allowed for this review. These include a very detailed analysis uof the reliability of each unit in the system, a thorough investigation of the cost and characteristics of candidate generation, a determination of optimum reliability targets, and accurate benchmarking of the simulated generation of each unit to actual operation records. Furthermore, if the WASP model is used, the analysis should involve a period of at least 20 years to avoid a characteristic end-effect distortion consisting of a bias towards adding smaller units at the end of the period, as well as to include the impact of assumptions about real escalation in the price of fuel.

In the context of the review of the least-cost plan, the least-cost plan analysis is merely a duplication of the WASP runs made by EEA with data revised according to the consultant's recommendations regarding load forecast, fuel prices, and the characteristics and costs of candidate generating units.

Before discussing the results of the WASP analysis using these revised data, it is relevant to discuss the reliability target used by EEA.

System Reliability

The reliability criterion to be adopted for generation expansion planning remains one of the most elusive parameters, both because the value of reliability to the public is difficult to establish and because the level of reliability itself is difficult to estimate. EEA uses loss-of-load probability (LOLP) as a criterion and has adopted a LOLP target of one day/year. This value is reasonable because it compares well with similar systems around the world, but it appears that the expansion, based on a WASP evaluation of LOLP, leads to a relatively high effective capacity reserve (the ratio of capacity derated by maintenance and forced outage to the peak load).

This can be seen from the projected power balance for the Unified Power System, which is summarized in Exhibit 3-6. Normally, for a system of this size, the effective capacity reserve should be near zero percent.

An evaluation of generation reliability in Egypt must pay careful attention to the capability of the High Dam power plant at low elevations of the Lake Nasser reservoir. This reservoir is operated exclusively to meet irrigation and riparian flow demands; thus, it is outside the control of EEA, which only generates power with the short-term water

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Exhibit 3–6

Unified Power System
Power Balance (FY89–90)

YEAR	PEAK LOAD MW	ENERGY LOAD GWH	CAPACITY ADDITIONS MW	AVAILABLE CAPACITY		EFFECTIVE CAPACITY		ECONOMIC ENERGY POTENTIAL	
				MW	% RESERVE	MW	% RESERVE	GWH	% RESERVE
1989	6726	41858	10098	10098	33.4%	7277	7.6%	43613	4.0%
1990	7134	44397	730	10828	34.1%	7890	9.6%	47883	7.3%
1991	7594	47260	880	11708	35.1%	8618	11.9%	58054	18.6%
1992	8088	49739	370	12078	33.0%	8930	9.4%	60199	17.4%
1993	8634	53095	360	12438	30.6%	9219	6.3%	62728	15.4%
1994	9211	56643	390	12828	28.2%	9543	3.5%	66990	15.4%
1995	9211	60462	810	13638	32.5%	10219	3.8%	72910	17.1%
1996	10472	64398	1140	14778	29.1%	11151	6.1%	81078	20.6%
1997	11176	67695	1152	15930	29.8%	12080	7.5%	89497	24.4%
1998	11911	72147	86	16016	25.6%	12154	2.0%	89484	19.4%
1999	12721	76455	914	16930	24.9%	12871	1.2%	95488	19.9%
2000	13568	81545	810	17740	23.5%	13535	-0.2%	100048	18.5%

Source: Appendix C

allocations to meet those demands. The High Dam power plant consists of 12x175 MW turbogenerators that are currently undergoing rehabilitation to replace turbine runners with the objective of, among other things, increasing their capability at low heads. However, the runners were designed before a series of low water years brought the reservoir, in 1988, to its lowest level since initial fill-up, defining the critical plant capability for planning purposes. EEA considers the 1988 event to be rare enough to be disregarded for planning, and currently, the High Dam plant's capability is considered to be 1,750 MW based on two units out. With the new runners, a recurrence of 1988 reservoir levels would mean a reduction of the capacity of each machine to less than 90 MW or, for the entire plant, 850 MW less than EEA's assumed capability.

Thus, while it appears that the WASP model leads to excessive thermal capacity reserve, this may be balanced by EEA's assumptions of normal capability at High Dam. For the purposes of this study, it has been assumed that WASP's derived reserve margins are adequate. However, it is recommended that EEA conduct a reservoir operation analysis based on long-term flow series with the objective of developing a duration curve of capability at High Dam to properly account for this risk in its future capacity planning.

Revised WASP Optimization

As in the case of the screening analysis, the revised WASP optimization was carried out for discount rates of 10 percent and a sensitivity case corresponding to 6 percent. Capacity additions under the two discount rates are shown in Exhibits 3-7 and 3-8, respectively, which can be readily compared against Exhibit 3-1 showing the original solution (in fact, the first three solutions) obtained by EEA prior to this review.

The revised analysis conducted using a discount rate of 10 percent shows very little difference with respect to EEA's original solution. In fact, solution 3 of this analysis is identical to solution 2 of the original EEA analysis although, due to different assumptions about unit availability and cost, the system reliability and the present value cost are higher. As in the original EEA analysis, the three best solutions reflect some indifference regarding additional gas turbine capacity for an increase in reliability.

3.5 CONCLUSIONS

From the analysis described in the preceding sections, it is concluded that EEA's generation expansion plan is reasonable given the current outlook for gas reserves and fuel prices. In the absence of an overwhelming economic advantage, it appears prudent

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Exhibit 3-7

Revised Wasp Analysis at 10% Discount Rate

YEAR	STEAM COAL	STEAM GAS	GAS TURBINE	TOTAL	LOLP	TOTAL COST 1990-2000
	(MW)	(MW)	(MW)	(MW)		(MILLION US$)
1996		600		600	0.240	
1997		1200		1200	0.258	
1998			120	120	0.110	
1999	900		240	1140	0.135	
2000		600	240	840	0.188	
sol. 1	900	2400	600	3900	0.186	8559
sol. 2	900	2400	720	4020	0.177	8561
sol. 3	900	2700	480	4080	0.174	8565

Exhibit 3-8

Sensitivity Analysis at 6% Discount Rate

YEAR	STEAM COAL	STEAM GAS	GAS TURBINE	TOTAL
	(MW)	(MW)	(MW)	(MW)
1996		600		600
1997		1200		1200
1998	900			900
1999	900		480	1380
2000	1200		120	1320
sol. 1	3000	1800	600	5400

to avoid further planning on combined-cycle generation until the performance of this type of technology can be tested through the additions and conversions that have been committed through 1995, and until gas reserves can be solidly established, since this resource cannot operate economically on any other fuel.

The screening analysis shows that it is economic to introduce coal as a base load fuel and the gas requirements analysis shows that it would be prudent to consider alternative fuels, even if gas were priced at the level of coal. If anything, it is surprising that the WASP solutions, based entirely on economics, do not lean more strongly towards coal. This result is fortunate in that it shows that a firm commitment to coal-fired generation in Egypt is not necessary for at least another two years when better information will be available on the likely evolution of gas reserves and when fuel price distortions from the current Gulf crisis may disappear.

In the final analysis, we conclude that all things considered, there are no significant differences between EEA's generation expansion plan (Exhibit 3-1) and the plan in Exhibit 3-7 that was developed under our alternate assumptions for key input parameters.

This is particularly true from the perspective of subsequent work elements involved in the tariff study. More specifically, the planning horizon for the financial analysis of revenue requirements is the next five years: 1990/91 - 1995/96. This represents a time frame where fuel costs and capital expenditures are largely, if not totally, defined by the existing power system augmented by generation that has already been committed (Appendix D). From the point of view of the short-run (1991-1992) marginal cost structure, again, any differences between the two plans are immaterial.

Finally, the LRMC analysis is insensitive to which of the two plans is utilized. This is clearly true for the marginal generation capacity cost component of LRMC, since the need for peaking capacity occurs well before 1996 (specifically, sometime during the 1993-1995 time frame). Further, marginal costs of transmission and distribution are estimated based upon incremental capital expenditures over the ten-year horizon 1990-2000. Again, these investments are largely determined by expenditures in the early years of the horizon since the expenditures in the last few years are heavily discounted in the calculation. From an implementation standpoint, where required, parameter values from Exhibit 3-2 are utilized.

CHAPTER 4: ECONOMIC COST OF GAS IN THE POWER SECTOR

This chapter describes the efforts undertaken to assess whether the economic cost of gas to the power sector may differ substantially from its presently pegged value at 100 percent thermal parity to fuel oil. The cost of oil and natural gas represents a significant portion of the financial cost of electricity sold by EEA. This is because EEA has no coal or nuclear capacity, and because hydroelectric generation represents less than one-third of its total annual generation. Further, agreement has been reached in principle between the Government of Egypt and certain international lending institutions that domestic oil prices will be increased to achieve parity with international oil prices by the mid 1990s. Since natural gas prices are currently tied to mazout (residual fuel oil) prices, the cost of oil and gas will become an even larger component of the financial cost of electricity generation in the future. In addition, the cost of oil and gas is a major component of the long-run marginal cost (LRMC) of electricity.

The "economic cost of gas" in any future year is the optimal gas price, i.e., the price that is consistent with equilibrium in both the natural gas and electricity markets (i.e., scenarios in which gas prices yield a balance between supply and demand for gas while electricity prices yield a balance between supply and demand for electricity). In theory, it would be possible to develop a model in which both markets are represented and an iterative procedure is used to search for the optimal set of gas and electricity prices. The model would have to include both a gas utilization study and an electricity utilization study. The development of such a model was outside the scope of this study. Instead, we have resorted to a simpler approach, albeit one that is adequate for this study and importantly, yields a result that would be the likely outcome of a comprehensive sector study of the type outlined above.

This chapter is organized as follows. Section 4.1 sets the stage with a discussion of the structure and role of the natural gas sector in Egypt. This is followed by an overview of the alternative theoretical approaches for the economic pricing of gas (Section 4.2). Results under different assumptions regarding future gas reserve additions are presented in Section 4.3. The analysis in Section 4.4 shows that from a financial perspective, the minimum financial price of gas delivered to a mazout boiler should be equal to the price of mazout in the domestic market. Finally, Section 4.5 presents our major conclusions.

4.1 STRUCTURE AND ROLE OF THE EGYPTIAN NATURAL GAS INDUSTRY

The Egyptian natural gas industry developed in the late 1970s as an offshoot of the Egyptian oil industry, which has been producing oil since 1909. Although Egypt had a commercial oil industry many years before oil was discovered in Saudi Arabia and Libya, its oil reserves have never been vast. Egypt's oil reserves today (4.5 billion barrels) are roughly the same size as its oil reserves in 1970, and are only one-fifth the size of Libya's reserves. By international standards, Egypt's year-end 1989 gas reserves of 11.72 trillion cubic feet (332 billion cubic meters) are also modest -- one-tenth the size of Algeria's gas reserves and one-fifteenth the size of Saudi Arabia's gas reserves. However, oil production and oil exports play a very important role in the Egyptian economy. The principal advantage of gas development to Egypt is that natural gas displaces petroleum product consumption in the domestic economy and therefore enables the country to export greater quantities of oil for foreign exchange earnings.

Quantitative indicators of the role of the Egyptian natural gas industry are presented in Exhibit 4-1, which is based upon energy equivalents (1 toe = 10 million kcal) rather than measures of weight or volume. Natural gas consumption in 1975 and earlier years was very small. By 1988, natural gas accounted for 20 percent of the energy equivalent of oil and gas consumption in the Egyptian economy (excluding the petroleum refining sector) and 35.6 percent of the energy equivalent of oil and gas consumption in the power sector. Natural gas consumption would have to increase substantially to achieve the maximum possible displacement of petroleum products in the domestic economy.

In the 1984-1988 period, net exports of oil fluctuated between 21.8 and 25.2 million toe annually (see Exhibit 4-1). There is some concern at the World Bank that Egyptian oil exports may fall to zero in the 2000-2010 period. Without oil exports it would be practically impossible for Egypt to maintain a disparity between domestic prices (excluding excise taxes) and international prices of petroleum products.

The bulk of the capital expenditures for oil and gas exploration and production in Egypt are made by private firms, including the largest multinational oil companies -- Amoco, Agip, Arco, BP, Elf, Marathon, Mobil, Phillips, Shell, Exxon, and Conoco -- and a few other companies such as British Gas, Gulf Resources Canada, Hispanoil, and Clyde Petroleum. Without the influx of foreign capital, the Egyptian oil industry would have great difficulty sustaining the present level of exploration and development activity. Several domestic firms are subsidiaries of foreign firms or joint ventures with foreign firms. For example, International Egyptian Oil Co. is a subsidiary of Agip; Gupco is a

Exhibit 4-1

Trends in Egyptian Oil and Gas Production and Consumption

	1971	1973	1975	1977	1979	1980
Oil and natural gas liquids						
Net exports, 000 toe	8,856.3	1,871.7	3,189.0	10,633.2	15,459.6	17,408.9
Percent of production	*58.3%*	*21.7%*	*26.6%*	*50.1%*	*58.2%*	*56.4%*
Total consumption including the power sector, 000 toe	5,982.9	6,201.2	7,386.7	9,189.7	10,337.1	11,576.3
Growth rate		*1.8%*	*9.1%*	*11.5%*	*6.1%*	*12.0%*
Power sector share	*16.5%*	*15.3%*	*15.7%*	*17.5%*	*20.8%*	*19.1%*
Natural gas						
Total consumption including the power sector, 000 toe	2.3	1.7	3.0	356.4	866.4	1,619.6
Growth rate		*–14.0%*	*32.8%*	*990.0%*	*55.9%*	*86.9%*
Power sector share	*0.0%*	*0.0%*	*0.0%*	*47.6%*	*42.3%*	*52.7%*
Oil and gas combined						
Production, 000 toe	15,273.0	8,714.4	12,000.5	21,585.4	27,424.3	32,495.3
Growth rate		*–24.5%*	*17.3%*	*34.1%*	*12.7%*	*18.5%*
Natural gas share	*0.5%*	*0.9%*	*0.3%*	*1.6%*	*3.1%*	*5.0%*
Total consumption including the power sector, 000 toe	5,985.2	6,202.9	7,389.7	9,546.1	11,203.5	13,195.9
Growth rate		*1.8%*	*9.1%*	*13.7%*	*8.3%*	*17.8%*
Power sector share	*16.5%*	*15.3%*	*15.7%*	*18.6%*	*22.4%*	*23.2%*
Natural gas share	*0.0%*	*0.0%*	*0.0%*	*3.7%*	*7.7%*	*12.3%*
Percent of production	*39.2%*	*71.2%*	*61.6%*	*44.2%*	*40.9%*	*40.6%*
Power sector consumption, 000 toe	988.6	949.8	1,159.9	1,775.9	2,514.1	3,066.8
Growth rate		*–2.0%*	*10.5%*	*23.7%*	*19.0%*	*22.0%*
Natural gas share	*0.0%*	*0.0%*	*0.0%*	*9.6%*	*14.6%*	*27.8%*

Source: International Energy Agency, "World Energy Statistics and Balances."

Exhibit 4-1

Trends in Egyptian Oil and Gas Production and Consumption (continued)

	1982	1983	1984	1985	1986	1987	1988	1989*
Oil and natural gas liquids								
Net exports, 000 toe	17,821.6	17,441.4	21,836.3	24,959.4	21,807.1	25,188.4	24,017.2	
Percent of production	*52.7%*	*47.1%*	*51.4%*	*54.5%*	*52.2%*	*53.6%*	*51.9%*	
Total consumption including the power sector, 000 toe	14,516.7	16,406.1	17,952.1	18,136.8	17,914.5	19,395.1	19,594.9	
Growth rate	*12.0%*	*13.0%*	*9.4%*	*1.0%*	*−1.2%*	*8.3%*	*1.0%*	
Power sector share	*23.8%*	*24.5%*	*24.0%*	*22.4%*	*24.4%*	*25.5%*	*25.7%*	
Natural gas								
Total consumption including the power sector, 000 toe	2,026.9	2,288.9	2,997.5	3,569.4	4,141.7	4,536.5	4,907.0	
Growth rate	*11.9%*	*12.9%*	*31.0%*	*19.1%*	*16.0%*	*9.5%*	*8.2%*	
Power sector share	*41.8%*	*48.4%*	*51.0%*	*58.9%*	*62.9%*	*61.2%*	*56.9%*	
Oil and gas combined								
Production, 000 toe	35,870.0	39,388.9	45,551.4	49,521.0	46,099.2	51,773.9	51,438.5	52,440.0
Growth rate	*5.1%*	*9.8%*	*15.6%*	*8.7%*	*−6.9%*	*12.3%*	*−0.6%*	*1.9%*
Natural gas share	*5.3%*	*6.0%*	*6.7%*	*7.5%*	*9.3%*	*9.2%*	*10.1%*	*10.8%*
Total consumption including the power sector, 000 toe	16,543.6	18,695.0	20,949.6	21,706.2	22,056.2	23,931.6	24,501.9	
Growth rate	*12.0%*	*13.0%*	*12.1%*	*3.6%*	*1.6%*	*8.5%*	*2.4%*	
Power sector share	*26.0%*	*27.4%*	*27.9%*	*28.4%*	*31.6%*	*32.2%*	*32.0%*	
Natural gas share	*12.3%*	*12.2%*	*14.3%*	*16.4%*	*18.8%*	*19.0%*	*20.0%*	
Percent of production	*46.1%*	*47.5%*	*46.0%*	*43.8%*	*47.8%*	*46.2%*	*47.6%*	
Power sector consumption, 000 toe	4,302.5	5,125.3	5,835.8	6,159.6	6,969.2	7,717.4	7,834.5	
Growth rate	*18.4%*	*19.1%*	*13.9%*	*5.5%*	*13.1%*	*10.7%*	*1.5%*	
Natural gas share	*19.7%*	*21.6%*	*26.2%*	*34.1%*	*37.4%*	*36.0%*	*35.6%*	

* 1989 oil production estimated from BP Statistical Review of World Energy; gas production estimated from EGPC data.

Source: International Energy Agency, "World Energy Statistics and Balances."

joint venture between Amoco and the Egyptian General Petroleum Corporation (EGPC); Webco is a joint venture between Phillips, Hispanoil, and EGPC; and Geisum Oil is a joint venture between Conoco and EGPC.Domestic prices of mazout, solar, and several other petroleum products are below international price levels. Therefore, when a foreign firm discovers oil in Egypt, it is typically in that firm's interest to maximize the percentage of the oil that is sold (as crude or products) in the export market rather than the domestic market. The foreign firms have a very strong interest in maintaining a level of Egyptian oil export earnings sufficient to repay (in hard currency) the investments these firms have already made in the Egyptian oil sector. By displacing domestic oil consumption, gas consumption sustains oil exports. Therefore, increases in domestic gas consumption are consistent with the interests of foreign firms as well as the Egyptian government.

EGPC manages all gas development in Egypt as well as all oil development.[1] To obtain rights to oil and/or gas resources, foreign firms must negotiate exploration agreements or production agreements with EGPC. All wellhead prices of gas are established by EGPC, and all gas pipelines in the country are owned by EGPC. At present EGPC has not expressed interest in transporting gas for end users who negotiate directly with producers. There are no plans for EGPC to become merely a transmission and distribution company in the natural gas sector.

In terms of foreign exchange transactions, natural gas is purchased at the wellhead as if it were an imported commodity. Under the new Model Exploration Agreement developed in 1987, EGPC purchases gas from foreign firms and pays them in barrels of oil or in hard currency. This method of payment is not surprising because a large portion of the costs of gas exploration and production involve payments to foreigners in hard currency. Foreign equipment is purchased or leased, and expatriates are hired to operate the equipment. In remote locations the oil workers' housing and food may also be imported. Although the Egyptian economy provides some support services, such as a portion of the food and housing (or hotel) accommodations for employees of foreign firms, it is likely that domestic value added represents only a fraction of the actual costs of wellhead gas production in Egypt.

By negotiating agreements that entitle EGPC to 25 percent of any gas produced, EGPC can sell almost 100 percent of the gas to EEA and other customers, but pay for only 75

[1] In particular, EEA does not own any oil and gas resources, gas wells, gas gathering lines, gas processing plants, gas transmission systems, or gas distribution systems. EEA does not negotiate gas purchase agreements with any of the foreign firms that explore and develop gas resources. Moreover, EEA would have difficulty paying for gas supplies in hard currency because it does not sell any goods or services in export markets that generate foreign exchange.

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percent. Where gas is found in association with oil, EGPC typically receives a 25 percent share of the oil as well. EGPC receives a 25 percent share of liquefied petroleum gases (LPGs) produced by foreign oil and gas companies, and purchases LPG at 95 percent of the international price of average sulfur residual fuel oil (a product that is priced well below LPG in international markets). We suspect that EGPC sells LPG at prices well above EGPC's cost. Thus, EGPC captures economic rent from oil and gas deposits. None of this economic rent is passed on to EEA in the form of transfer payments or gas price discounts.

In summary, Egypt's natural gas industry can be characterized as a spinoff of the oil industry that has been created to sustain or increase oil exports. Although Egyptian gas is sold only to domestic users, it is an oil substitute; and the fact that gas is produced in Egypt does not make it more "affordable" than oil.

4.2 ALTERNATIVE APPROACHES TO ECONOMIC PRICING OF GAS

Fundamentally, there are four possible approaches to determining the economic price of gas:

1) Gas Utilization Study approach: An analysis is conducted to find the price at which gas supply and gas demand are in balance, i.e., neither a shortage nor a surplus develops in the future. Some components of the demand curve (e.g., the demand for gas used in mazout boilers) may be estimated on the basis of the prices of fuels displaced by gas. The supply curve represents a description of the behavior of gas producers, and is not necessarily derived from production cost data. The Gas Utilization Study is the most rigorous approach in the Egyptian context.

2) Avoided Cost approach: The price of gas to the power sector is determined by the value of fuels displaced by gas, given alternative assumptions about the quantity of gas supplied to the power sector. This is less rigorous but simpler and quicker than the Gas Utilization Study, and should yield the same conclusions (unless gas supplies are so large that gas can displace all other fuels).

3) Market Price approach: If the price of gas is determined in a competitive market with many gas producers and many purchasers, the analytical task is to try to predict the market outcome. The important distinction is not the analytical approach -- either a gas utilization study or an avoided cost

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approach may be used -- but the fact that the market is self-correcting. The analyst may be an observer rather than a central planner.

4) LRMC approach: If oil and gas development is conducted entirely by a national oil company and gas reserves are very large, gas may be priced on the basis of production cost data. In theory, the price of gas should equal the LRMC of gas plus a "depletion premium" based upon the prospect of substitution of other fuels for gas in the distant future. If gas can displace all other fuels, except in remote locations or in the transportation sector, the price of gas may fall below the Btu equivalent of substitute fuels.

The Market Price and LRMC approaches are simply not relevant to Egypt. Egypt does not have a competitive gas market in which many producers negotiate gas sales contracts with many purchasers, as in the United States. Moreover, Egypt does not have enough gas to bring the price below the Btu equivalent of fuels displaced by gas. In 1988 gas accounted for only 20 percent of the energy content of oil and gas consumed in Egypt (excluding the refining sector).

The Gas Utilization Study approach is too complex and time-consuming for our project, which is essentially an electricity tariff study and not a gas sector study. The Avoided Cost approach was selected by process of elimination. Using this approach we conclude in the next section that at present, the price of gas should be tied to the price of mazout because marginal supplies of gas displace mazout. Because EEA accounts for roughly 60 percent of natural gas consumption in Egypt, and because marginal supplies of gas displace mazout over a wide range of annual gas allocation levels for EEA, a Gas Utilization Study should reach the same conclusion, that in the 1990s marginal supplies of gas displace mazout. Therefore, we believe that the Avoided Cost approach is not only expedient but also adequate in the context of this project, and produces results that are consistent with the likely findings of a comprehensive gas sector analysis of demand and supply.

The LRMC approach merits further discussion because it is easily misunderstood. When oil and gas exploration and development is undertaken by the private sector, the LRMC of gas development varies from project to project and is determined by each firm's investment decision. Some firms may pursue higher-cost projects, anticipating higher oil prices, while others may be more cautious. A market economy generates a range of economic thresholds or "breakeven" criteria for gas exploration and production investments. When the price of gas is tied to 85 percent of the Btu equivalent of the international price of fuel oil, as in the Model Exploration Agreement, the likely response of private firms is to invest in any project whose LRMC is expected to be equal

to or less than 85 percent of the price of fuel oil. For countries in which gas reserves are not large enough for gas to displace all other fuels (e.g., in Egypt), the LRMC approach to gas pricing should yield the same result as the other approaches.

We can make a rough estimate of the LRMC of non-associated gas on the basis of the response of foreign oil companies to the Model Exploration Agreement drafted in 1987. The spot price of 3.5 percent sulfur heavy fuel in Mediterranean markets averaged about $1.60 per MMBtu in 1986, $2.34 per MMBtu in 1987, $1.59 per MMBtu in 1988, and $2.09 per MMBtu in 1989. In 1987, therefore, foreign oil companies may have assumed a price floor around $1.60 per MMBtu, with significant price volatility but a potential for price increases over the long term. Because producers are paid for only three out of every four units of gas produced under the Model Exploration Agreement, and because the gas price is 85 percent of the average sulfur fuel oil price, a non-associated gas well with very little LPG would yield revenues of about $1.02 per MMBtu when residual fuel is priced at $1.60 per MMBtu and $1.49 per MMBtu when residual fuel is priced at $2.34 per MMBtu. A cautious oil firm might pursue gas exploration and development only for gas prospects that are attractive at $1.00 per MMBtu, while a risk-taking firm might pursue projects that require $1.50 per MMBtu. The lower-cost gas deposits are inframarginal and have no effect on LRMC.

There is no single LRMC used by all firms to identify the gas prospects worth pursuing. Firms anticipating high oil prices will invest in prospects that are higher on the long-run supply curve; firms anticipating low oil prices will limit their investments to the lower portion of the long-run supply curve. All firms deal with geological uncertainty and may therefore overestimate or underestimate gas costs per Mcf produced.

In 1989 the World Bank estimated the LRMC of non-associated gas at Abu Qir to be 97.5 LE per tonne fuel oil equivalent. If we assume 6.66 barrels heavy fuel oil per tonne and 6.287 MMBtu per barrel heavy fuel oil, and an exchange rate of 2.5 LE per dollar, this price is equivalent to $0.94 per MMBtu, which is roughly consistent with the lower bound of our range of LRMC values. It is in EEA's interest, however, for firms to use a higher LRMC (e.g., $1.50 per MMBtu) and pursue marginal gas exploration or development prospects that would not be pursued at $1.00 per MMBtu. Higher LRMC values are associated with more aggressive gas development efforts, but have no effect on the wellhead price of gas specified in the Model Exploration Agreement.

The Model Exploration Agreement gives producers an incentive to raise their LRMC threshold in the event that their oil price expectations are raised. This is a desirable result, for it suggests that gas supply investment programs will be accelerated if oil market conditions indicate a sustained increase in oil prices. To maximize Egypt's oil

export earnings, it is necessary to have private firms raise the LRMC threshold for gas investments when oil price expectations are raised.

4.3 ECONOMIC COST OF GAS UNDER DIFFERENT ASSUMPTIONS REGARDING FUTURE RESERVE ADDITIONS

Under the Avoided Cost approach to gas pricing, the economic price of gas is determined by the price of the fuel that is displaced by marginal supplies of gas. At present it is clear that in the power sector mazout is displaced by gas, on the margin. A reduction in EEA's gas allocation leads to an increase in domestic mazout consumption and a reduction in oil exports; an increase in EEA's gas allocation leads to a decrease in domestic mazout consumption and an increase in oil exports. For simplicity we assume that refinery runs are unchanged and the incremental barrel of mazout is used domestically or exported, depending on gas availability. The value of this incremental barrel to the Egyptian economy is its value in the export market, i.e., the spot price of high-sulfur residual fuel oil in Mediterranean markets.

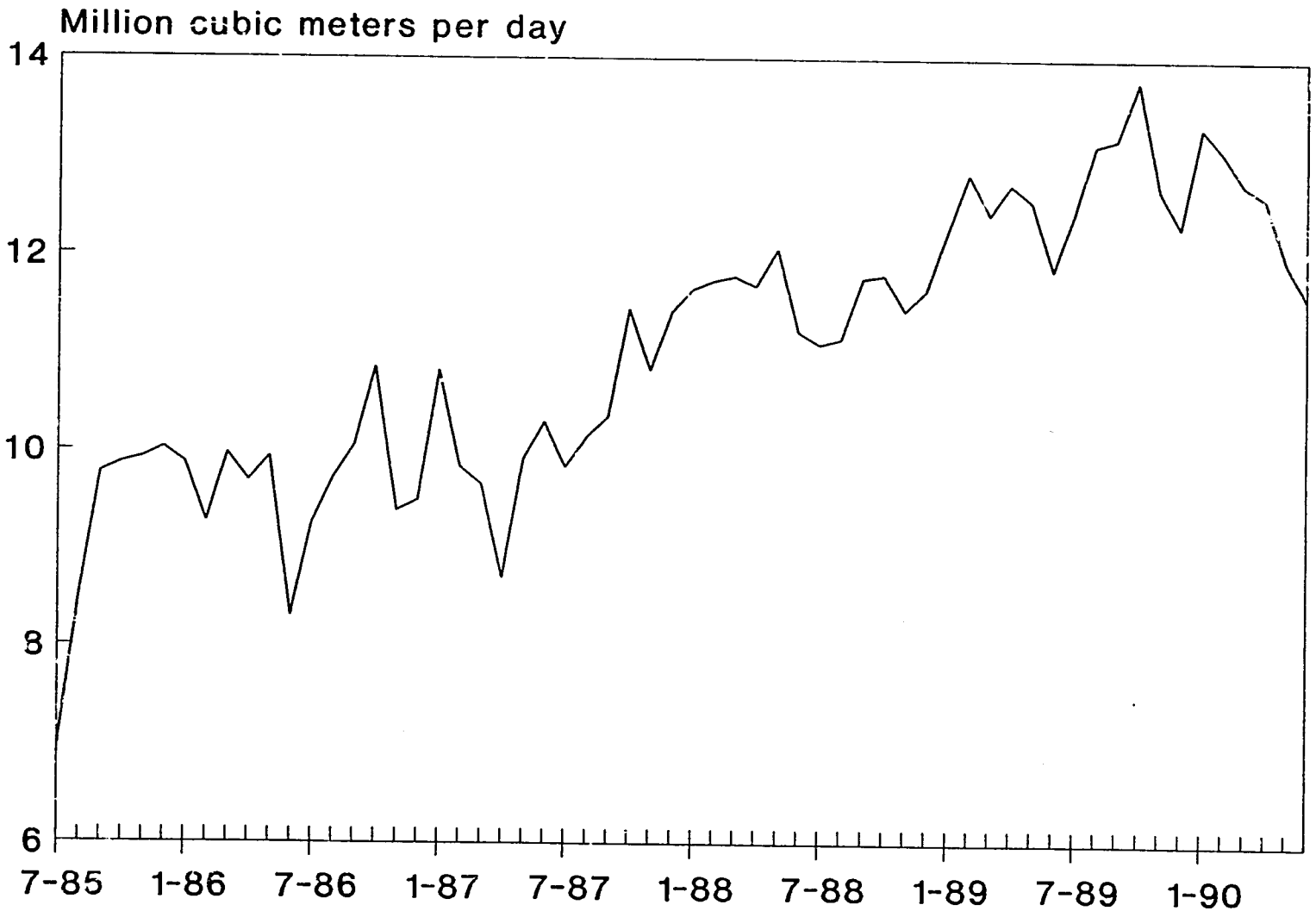
In the future, mazout is not necessarily the fuel displaced by marginal supplies of gas. The identification of this fuel depends on many variables, including the level of gas reserve additions. The larger the reserve additions, the greater the likelihood that gas will displace lower-valued fuels. If small reserve additions are assumed, it is necessary to add a "depletion premium" to the price of gas to reflect the present value of the savings associated with holding gas reserves for future use. If EEA expected to run out of gas in the next decade, for example, it would probably be economic to use gas reserves to displace solar in future years rather than burn gas today in mazout-capable boilers.

In recent years gas consumption by EEA has been in the range of 7 to 14 million cubic meters per day, or MCM/d (see Exhibit 4-2). Under our moderate oil price projection, any consumption level above 14 MCM/d in the 2000-2010 period will be sufficient to cover EEA's combustion turbine requirements, but gas supply would have to exceed 60 MCM/d by the year 2000 in order to displace coal in the 2000-2010 period. Given the lead time for coal plant construction, it is very unlikely that gas reserve additions will be large enough in the early 1990s to displace coal before the year 2000.

Because gas reserve additions and allocations to the power sector are uncertain, we projected gas supplies available to EEA under three sets of assumptions: Low Reserves, Medium Reserves, and High Reserves (see Exhibit 4-3). In the base case, annual reserve additions were assumed to follow a trend in which the decline rate is constant

Exhibit 4-2

Gas Consumption by EEA



Source: Monthly fuel consumption reports prepared by EEA.

Exhibit 4-3

Likely Range of Future Reserve Additions

	ASSUMPTIONS USED IN PROJECTIONS	Low Reserves	Medium Reserves	High Reserves
1.	Reserve additions projected for 1990:*	1,000 Bcf, or 28.3 BCM	1,000 Bcf, or 28.3 BCM	1,500 Bcf, or 42.5 BCM
2.	Decline rate of future reserve additions:**	-10.0%	-3.8%	-2.0%
3.	Projected reserve additions, 1990-2040:	9,954 Bcf	22,667 Bcf***	48,234 Bcf
4.	Reserves at January 1, 1990 (OGJ estimate):	11,720 Bcf	11,720 Bcf	11,720 Bcf
5.	Projected reserve additions, 1990-2020:	9,618 Bcf	18,397 Bcf	34,907 Bcf
6.	Sum of reserves plus projected additions:	21,338 Bcf	30,117 Bcf	46,627 Bcf
7.	30-year levelized dry gas production from reserves plus projected reserve additions, 1990-2020:	711 Bcf/y or 55 million m3/d	1,004 Bcf/y or 78 million m3/d	1,554 Bcf/y or 121 million m3/d
8.	Share of reserves plus reserve additions available to the power sector:	50%	60%	70%
9.	Power sector share of levelized production, assuming new reserve additions:	356 Bcf/y or 28 million m3/d	602 Bcf/y or 47 million m3/d	1,088 Bcf/y or 84 million m3/d

* Average annual reserve additions, 1980-1989: 1,037 Bcf/y or 80 million m3/d

** Decline rate derived from data in lines 1 and 3 as per the formula in Appendix E

*** Ultimate total reserve additions, from 1990 forward, indicated by World Energy Conference: 22,712 Bcf or 643 BCM

Source: RCG/Hagler, Bailly, Inc.

and the cumulative total reserve additions over the 1990-2040 period closely conform to the World Energy Conference's 1989 estimate of "Estimated Additional Reserves Recoverable," i.e., "the volume included in Additional Amount in Place which geological and engineering information indicate with reasonable certainty might be recovered in the future."[2] Under Medium Reserves, the power sector's share of existing reserves plus reserve additions is assumed to match the power sector's share of current gas consumption (60 percent).

Our assumptions regarding future reserve additions are illustrated in Exhibits 4-4 through 4-7. While no one can confidently predict reserve additions over such long time periods, we feel that the Medium Reserves is a "most likely" case and the other cases provide a reasonable range of assumptions for use in capacity planning. The results, summarized in Exhibit 4-3, indicate a 30-year average production level of 28 MCM/d for Low Reserves, 47 MCM/d for Medium Reserves, and 84 MCM/d for High Reserves.

To illustrate the calculation in Exhibit 4-3, consider the Medium Reserves scenario. The 1990 reserve additions estimate of 1,000 Bcf (line 1), the projected reserve additions estimate for 1990-2040 of 22,667 Bcf (line 3), and the decline rate of 3.8 percent (line 2) can be linked using the formula defined in Appendix E. Given the 1990 reserve additions and the decline rate, the cumulative additions through 2020 (line 5) are then estimated, again by utilizing the formula in Appendix E. The sum of projected reserve additions of 18,397 Bcf through the year 2000 (line 6) and the reserves as of January 1, 1990 (from the *Oil and Gas Journal*) yields a total reserves plus projected additions (line 6) of 30,117 Bcf. This level can sustain a 30-year levelized gas production of 78 million m^3/day and assuming a 60 percent allocation to the power sector (based upon discussions with EGPC), results in a power sector share of gas supply of 47 million m^3/day under the Medium Reserves case. Comparably derived values for the Low and High Reserves scenarios are 28 million m^3/day and 84 million m^3/day, respectively. These correspond roughly to projected reserve additions that are approximately two-fold higher or about half as large as the reserve additions (line 3) under the medium case.

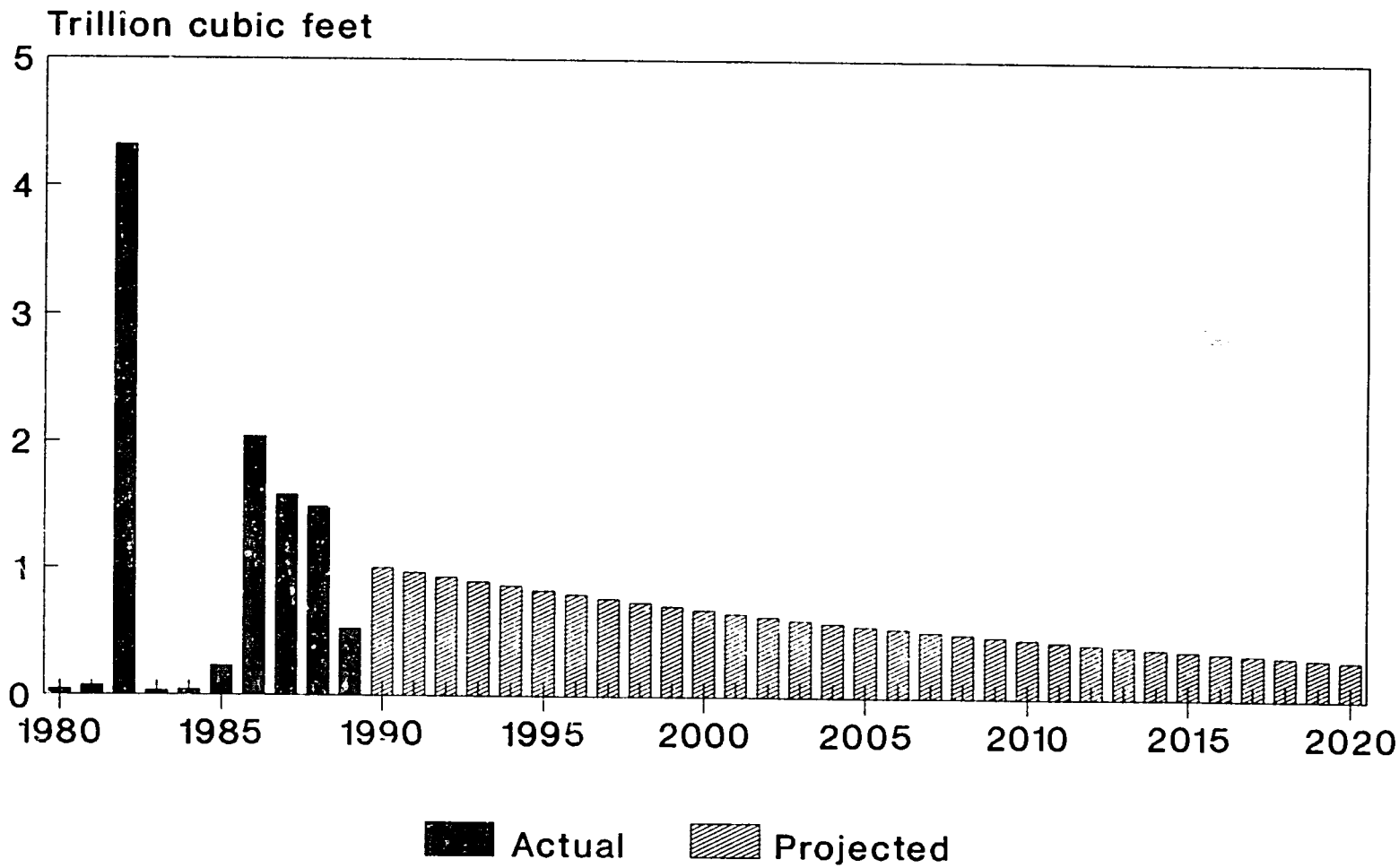
The key variables affecting the supply and demand for gas in the power sector, and hence, its economic values to the sector, are the level of future reserve additions and international oil prices. These influences can be broadly qualified as follows:

1) Very low oil prices tend to reduce the economic attractiveness of coal-fired capacity additions and improve the economics of combined-cycle or

[2] A copy of that document has been provided to EEA under separate cover.

Exhibit 4-4

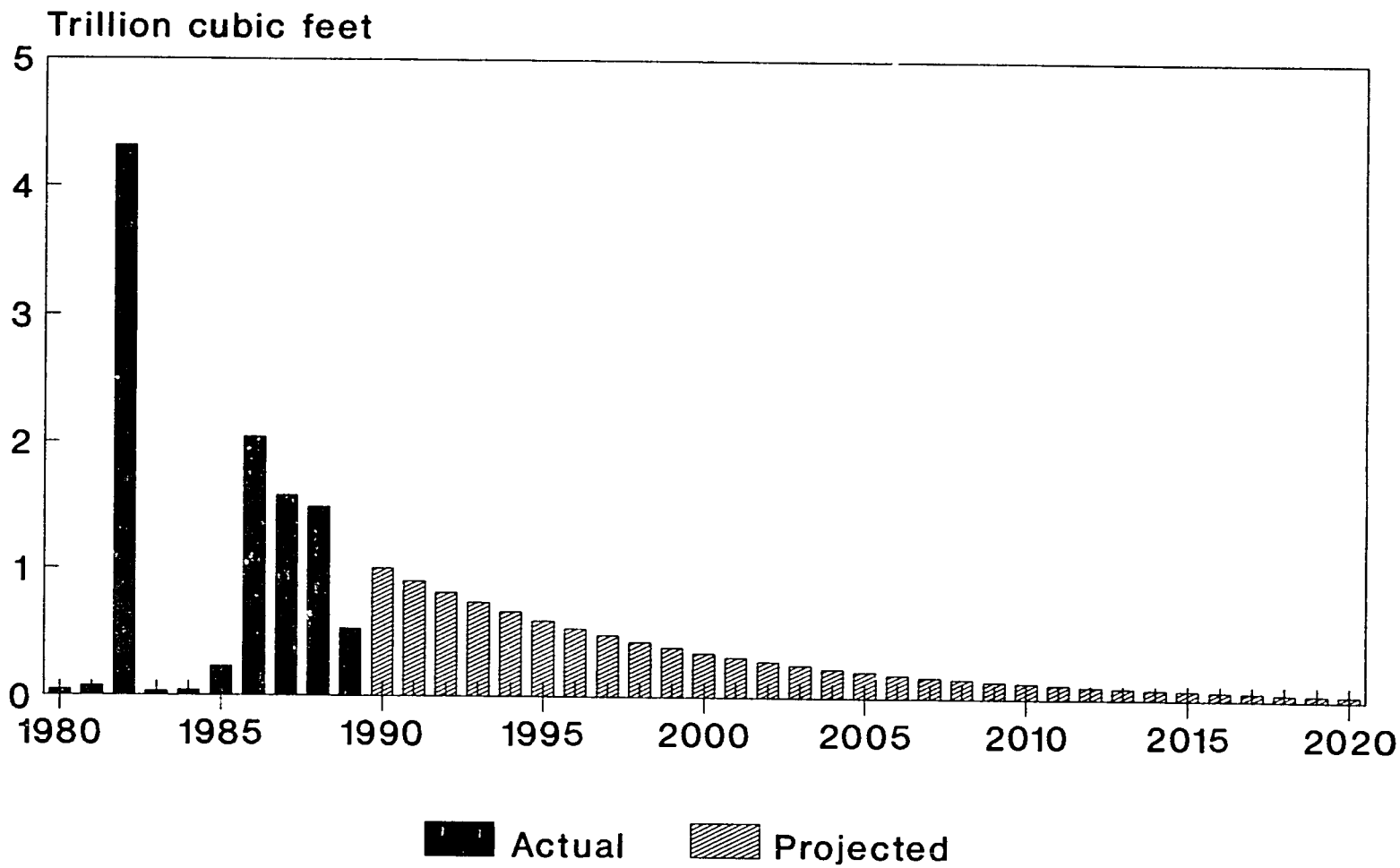
Annual Gas Reserve Additions
MEDIUM RESERVES



Source: Historical data based upon gas reserve estimates published by the *Oil and Gas Journal* and gas production data from EGPC.

Exhibit 4-5

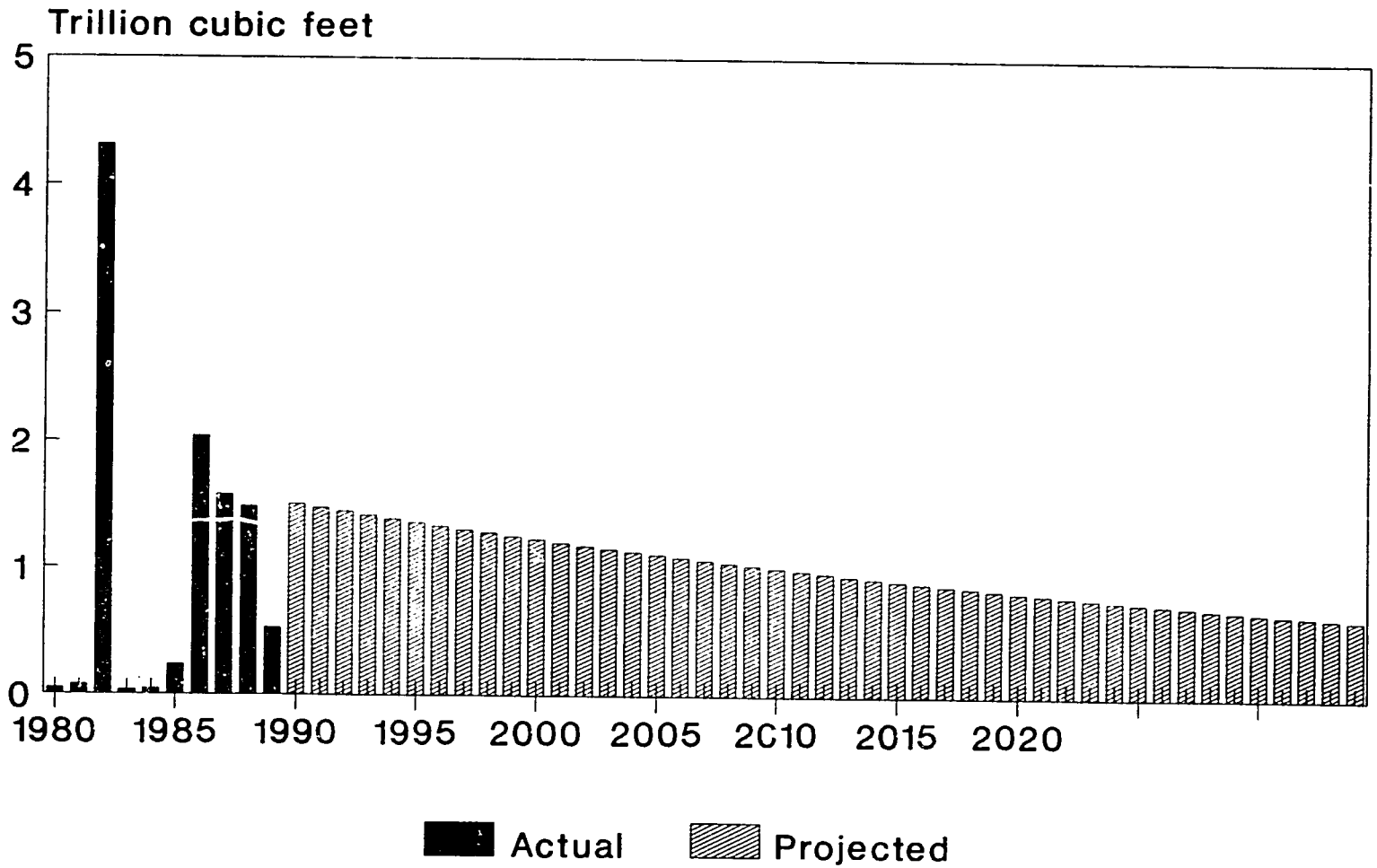
Annual Gas Reserve Additions
LOW RESERVES



Source: Historical data based upon gas reserve estimates published by the *Oil and Gas Journal* and gas production data from EGPC.

Exhibit 4-6

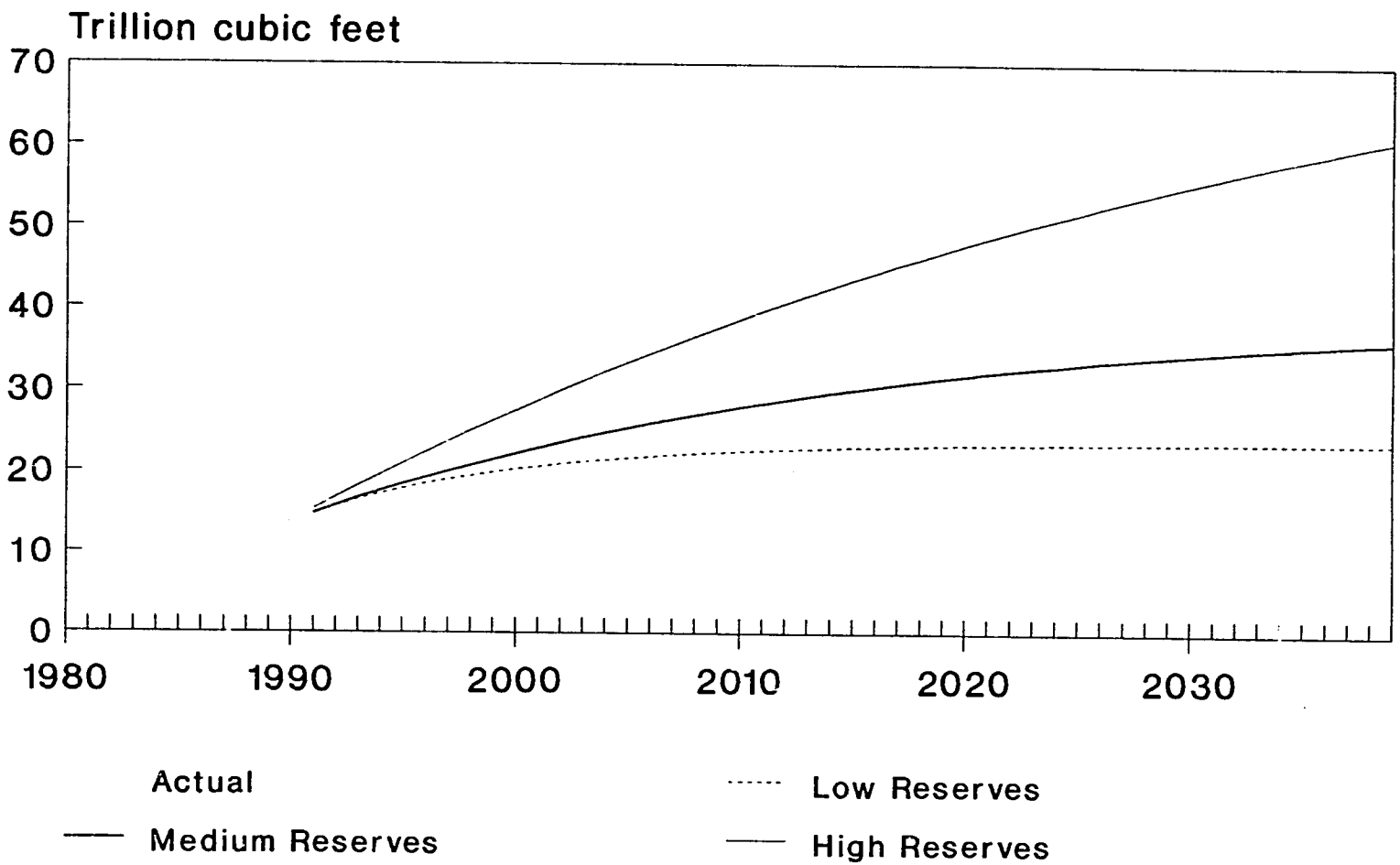
Annual Gas Reserve Additions
HIGH RESERVES



Source: Historical data based upon gas reserve estimates published by the *Oil and Gas Journal* and gas production data from EGPC.

Exhibit 4-7

Cumulative Gas Reserve Additions
LIKELY RANGE



Source: Exhibits 4-4, 4-5, and 4-6.

single-cycle turbines fueled by natural gas and/or distillate oil. In a combined-cycle turbine, distillate oil is the "backstop" fuel that would have to replace gas in the event that gas supplies are limited. When future gas supplies are uncertain, therefore, the economic attractiveness of combined cycle plants is very sensitive to assumptions regarding the future path of oil prices. The low heat rate and high efficiency of combined-cycle turbines makes them very competitive with boilers when either gas or distillate is available at low prices. Very low oil prices therefore increase the demand for gas.

2) Very high oil prices make coal-fired capacity additions more attractive, but also raise the "depletion premium" associated with natural gas use. This depletion premium is the premium above the current mazout-equivalent price that reflects the present value of savings associated with holding gas reserves for the future. Gas reserves may be held either to displace mazout in the future (if oil prices are expected to increase sharply in the future) or to displace solar in the future (if future gas supplies are uncertain and there may not be enough gas to meet all the fuel requirements of combustion turbines and combined-cycle turbines over their operating lifetimes).

3) High natural gas reserve additions increase the supply of gas, thereby increasing the likelihood that gas will completely displace oil consumption and begin to displace coal. Low reserve additions have the opposite effect; they reduce the supply of gas, thereby increasing the likelihood that gas will have to be conserved for future use.

We have identified a range of possible assumptions and tried to estimate the outcome associated with each of these assumptions (see Exhibit 4-8). Our findings, shown in Exhibit 4-8, can be summarized as follows:

- If low reserve additions are projected, the economic cost of gas will be pegged to the price of solar, sooner or later. The timing of the transition from a mazout-based price to a solar-based price depends largely on the oil projection assumed.

- If reserve additions are realized in accordance with the medium case, the economic cost of gas will be pegged to mazout indefinitely unless very low or very high oil prices are projected.

Exhibit 4-8

Sensitivity of Gas Pricing to Assumptions Regarding Oil Prices and Gas Reserves

Oil Price Assumption for 2000–2030	Assumptions Regarding Gas Reserve Additions		
	Low Reserve Additions	Medium Reserve Additions	High Reserve Additions
Low oil prices; $15/bbl in 2000, 1% escalation	Btu equivalent of solar	Btu equivalent of solar; reserves held for future	Btu equivalent of mazout, then solar after 2010
Moderate prices; $20/bbl in 2000; 3% escalation	Btu equivalent of mazout, then solar after 2000	Btu equivalent of mazout	Btu equivalent of mazout, then coal after 2000
High oil prices; $35/bbl in 2000; 0% escalation	Btu equivalent of solar; reserves held for future	Btu equivalent of mazout, then solar after 2000	Btu equivalent of mazout; reserves held for future

Source: RCG/Hagler, Bailly, Inc.

- If high reserve additions are realized, and if moderate or high oil prices are projected, the economic cost of gas could eventually be pegged to coal rather than mazout. The timing of this transition would also be sensitive to the load growth assumption.

These results are based upon insights developed by juxtaposing data contained in Exhibit 3-5 and Exhibits 4-2 and 4-3. More specifically, Exhibit 4-3 shows that in recent years, EEA's gas utilization has been around 13 million m3/day. Further, the gas utilization and requirements analysis in Exhibit 3-5 (see line 5) indicates that were EEA to substantially convert existing oil-fired plant to gas and use gas in all new generation, the daily requirement of gas is predicted to increase to 33 million m^3/day by 1995 and approximately 50 million m^3/day by the year 2000.[3]

When these data are reviewed in light of the information on projected gas reserves and availability to the power sector (Exhibit 4-3), it can be readily seen that under the Medium Reserve addition scenario, which we believe to be supportable given the information today, gas supplies will be adequate substitutions for mazout but are insufficient for displacing the base load coal-fired generation that is predicted to start coming on line towards the end of this century.

However, if gas reserve additions should turn out to conform more closely with the high case, then the quantity of gas available to EEA could be around 84 million m^3/day. Under these circumstances and given the gas requirements indicated in Exhibit 3-5, it can be seen that sufficient quantities of gas will be available to start displacing significant quantities of coal-fired generation beyond 2000.

Gas Imports

The economic cost of gas, at which gas supply and demand are in balance, could be reduced by the introduction of additional supplies. In the analysis above, we did not consider the possibility of natural gas imports, which would require a major change in the Egyptian gas industry. Under a scenario with high oil prices, however, the alternative of importing natural gas by pipeline (e.g., from Algeria or Saudi Arabia) may be economically attractive.

[3] Note that the gas requirements analysis summarized in Exhibit 3-5 represents, in essence, the equivalent of an analysis whenever multiple WASP model runs are made with increasing amounts of gas availability specified.

Whereas EEA's mandate is for the power sector, it is in EEA's interest to evaluate the technical, economic, and political feasibility of importing gas. It is quite possible that imported gas may be economically competitive with imported coal, in a generation planning context. If this turns out to be true, EEA should be able to negotiate a price for gas at or even below coal parity. Of course, the acceptability of this option will need to be gauged from a political standpoint as well.

Another potential area of future study is an analysis of the potential financial impact on EEA of high international oil prices. Today, EEA is in the unusual position of being heavily dependent on oil, yet insulated from price fluctuations on the world oil market. This comfortable situation is not likely to continue indefinitely.

Influence of Load Growth

Assumptions regarding future oil prices are particularly important when very pessimistic assumptions are made concerning future reserve additions or future gas supply allocations to the power sector. Among the scenarios in Exhibit 4-8, four scenarios may require that the economic cost of gas be pegged to solar rather than mazout:

1) Under high load growth, low oil prices, and very low gas reserve additions, gas-fired combined-cycle turbines and combustion turbines absorb all of the available gas supply. Under low oil prices, EEA's average cost of fuel per MMBtu may be relatively low, even if the price of gas is pegged to the price of solar.

2) Under high load growth, high oil prices, and low gas reserves, gas becomes a "premium fuel" valued more highly than mazout. Under these assumptions, gas is used in the Egyptian economy to displace solar and LPG, and gas reserves may be set aside to ensure that the nation does not run out of gas supplies for customers who would use solar or LPG if gas were not available. The short-term benefits associated with using gas to displace mazout in the early 1990s are offset by the long-term financial penalty (to the Egyptian economy) associated with using solar to run combined-cycle plants in future years.

3) Under high load growth, low oil prices, and reserve additions in the range that we consider likely, the present value of savings associated with displacing solar in the future are large enough to justify holding gas

reserves for future use. This scenario involves all of the factors described in 1) and 2) above.

4) Under low load growth, high oil prices, and low gas reserves, gas reserves may be held for future use, just as in scenario 2) with high load growth.

A scenario with high oil prices and very low gas reserve additions would be very harmful to EEA, but probably beneficial to EGPC. It may be appropriate for EEA to conduct a study to assess the likelihood of such a scenario. We assume that the probability of this scenario is low, but it may deserve the same level of analytical effort as an analysis of adverse hydro conditions.

4.4 CONSTRAINTS ON DOMESTIC FINANCIAL PRICES OF GAS

At present, EGPC is selling natural gas to EEA at the Btu equivalent of the domestic price of mazout, and is selling mazout at domestic prices well below the international price of residual fuel. If EGPC could raise the gas price to parity with the international price of residual fuel, EGPC would clearly make a profit on gas sales that displace domestic mazout consumption, even if EGPC's accounts showed no profit on the purchase, transmission, and resale of gas. By exporting a barrel of mazout rather than selling it in the domestic market, EGPC can receive much higher revenue per barrel. The incremental revenues associated with exports of mazout would make natural gas sales very attractive to EGPC even if the natural gas side of the transaction was a "breakeven" operation.

Arguably, therefore, a policy of pricing gas at parity with the international price of residual fuel creates a windfall for EGPC. As long as the domestic price of mazout is below the international price, EEA might claim that this windfall is unfair (whatever the economic efficiency benefit may be); or that EEA's customers should also share in the benefit of such a windfall. On these grounds, EEA could try to negotiate a gas price below the international price of residual fuel. An interesting question, from a political standpoint, is how low a price EGPC could obtain based solely on such financial considerations.

If the domestic price of mazout is below the international price, the minimum financial price of gas is probably the price at which EGPC is indifferent between selling mazout to EEA and selling gas to EEA. At this gas price, EGPC's gains on the export of mazout are wiped out by EGPC's losses on the sale of gas to EEA:

$$(P_{me} - P_{md}) + (P_{gb} - P_{gw} - T) = 0$$

where:

P_{me} = price of mazout in the export market, in $/MMBtu

P_{md} = price of mazout in the domestic market, in $/MMBtu

P_{gb} = price of gas at the mazout boiler, in $/MMBtu

P_{gw} = price of gas at the wellhead, in $/MMBtu

T = transmission and distribution cost of gas, in $/MMBtu

Therefore, the minimum financial price of gas is given by:

$$P_{gb} = P_{gw} + T - (P_{me} - P_{md})$$

Under the Model Exploration Agreement developed in 1987, the wellhead price of gas is 85 percent of the Btu equivalent of the international price of mazout. The 15 percent differential was intended to enable EGPC to recover the cost of gas transmission and distribution and sell gas at the Btu equivalent of the international price of mazout. (At high oil prices, EGPC obviously makes a profit on this transaction because its transmission and distribution revenue is tied to oil prices.) Let us assume, for simplicity, that transmission and distribution costs equal 15 percent of the international price of mazout. The wellhead price in the Model Exploration Agreement is then given by:

$$P_{gw} = .85 * P_{me} = P_{me} - T$$

where: $T = .15 * P_{me}$

It follows that the minimum financial price of gas delivered to the mazout boiler equals the Btu equivalent of the domestic price of mazout:

$$P_{gb} = P_{gw} + T - (P_{me} - P_{md}) = P_{md}$$

EEA therefore appears to have a short-term financial interest in keeping the domestic price of mazout below the international price of residual fuel. Without this differential, EGPC has very little flexibility to offer EEA anything but a gas price tied to the international price of residual fuel. Under these conditions, EGPC might offer a

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discount if its transmission and distribution costs are less than 15 percent of the international price of residual fuel, since EGPC's wellhead cost of gas is tied, however, to 85 percent of the international price of residual fuel.

The short-term financial benefit to EEA of low domestic prices of mazout and gas may be offset, however, by economic penalties in the long term to the nation as a whole. Any policies that artificially increase Egypt's oil and gas consumption will reduce oil exports and thereby depress the value of the Egyptian pound in international transactions. A lower value for the Egyptian pound effectively raises the price of all goods and services imported by Egypt, including power generation equipment and electrical equipment. Furthermore, a policy that leads to declining oil exports, or zero oil exports, will ultimately lead to (a) the elimination of the differential between domestic and international prices of petroleum products, and (b) an exchange rate that yields very high oil, gas, and imported coal prices to EEA, in Egyptian pounds. It is difficult to see how any generating capacity expansion can be financed -- coal, nuclear, or gas -- unless the export sector of the Egyptian economy is expected to remain strong.

Economic efficiency is achieved when the price of gas to EEA is tied to the international price of residual fuel, regardless of domestic mazout prices. The true value of incremental energy supplies to the Egyptian economy is the value associated with incremental exports of crude oil or petroleum products. We do not recommend financial prices below the economic cost of gas.

4.5 CONCLUSIONS

The review and analysis presented in this report indicate that if projected gas reserve additions correspond to the medium case scenario identified, then the fuel displaced by gas would be residual fuel oil. Under these conditions, the economic value (cost) of gas to the power sector should be pegged at thermal parity to residual fuel oil.

Further, the analysis indicates that if the projected gas reserve additions correspond to the high scenario identified, or alternatively, if the medium reserve scenario were complemented by augmented imported gas supplies, then the marginal fuel displaced by gas in the power sector could be coal. Under these conditions, the economic cost of gas to the power sector should be pegged at a value that makes EEA indifferent, in a strict economic sense, between coal plant additions and gas-fired plants.

Our analysis leads to the conclusion that the economic cost of gas to the power sector is bounded by the border price of mazout on the upper end, and by the price of coal on the

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lower end, depending upon the reserves of gas. Given the best available information as of this writing, the economic cost of gas to the power sector is determined by the equivalent border price for mazout. If gas reserves increase appreciably, at such a future time, a case could be made to peg the economic cost of gas to coal equivalency. In light of this, the long-run marginal cost (LRMC) calculation described in this chapter is carried out using two values for the price of gas: (1) the projected border price of mazout, which is estimated to be $1.97/MMBtu over the period 1993-1995 (see Appendix F) and (2) the projected price of coal of $1.80/MMBtu (see Appendix G).

Finally, it should be emphasized at this juncture that this analysis has been conducted strictly from the perspective of economic efficiency. From a financial and distributional perspective, departures from these price levels may be justified, at least in the near- to mid-term.

Institutionally speaking, at present, EEA pays a gas price comparable to the Btu equivalent of the domestic price of mazout, which is well below the corresponding international border price. This pricing scheme, we understand, is the outcome of a political process determined at the highest levels of the government. We also understand that at these very levels of government, an understanding has been reached with the International Monetary Fund (IMF) and other leading international funding agencies that domestic energy prices -- to direct end-users as well as transfer prices -- are to be escalated in real terms to bring them in alignment with international prices by the mid-1990s.

Thus, EEA may wish to consider influencing this domestic political process in order to stretch out, as much as is feasible, the time period over which the realignment of domestic transfer price of mazout is to be achieved. This will help buffer electricity consumers from the very large and one-time price shocks. Consumers will have more time to adapt to the new price signals by making the appropriate long-term responses in a more gradual and phased manner.

CHAPTER 5: LONG-RUN MARGINAL COST ANALYSIS

This chapter describes the methodology employed and the analysis undertaken to estimate long-run marginal costs (LRMCs) for the Egyptian power system. These estimates provide the necessary economic benchmark and establish the point of departure in tariff design that is required to accommodate financial and equity objectives. Specifically, average tariff yield is governed by the financial revenue requirement, whereas the allocation of this revenue responsibility by customer class and the individual customer class tariff structure are affected by the LRMC structure.

The chapter is organized as follows. Section 5.1 describes the overall marginal cost methodology. Section 5.2 illustrates the application of this methodology to Egypt through the use of an LRMC computer model tailored specifically to the Unified Power System (UPS). This section contains actual model printouts and results. Section 5.3 discusses the sensitivity of the results to alternative modeling assumptions. Section 5.4 reports our estimation of LRMC for the isolated electricity network, which is not linked to the Unified Power System.

5.1 MARGINAL COST PRICING METHODOLOGY

The efficiency pricing objective in electricity tariff planning is embedded in the economic theory of efficient allocation of resources and can be theoretically linked to the marginal cost structure of the supply system. These costs typically vary by service voltage level and by time of day, and spatial characteristics in cost structure may exist due to differential losses.

Put very simply, the marginal cost of electricity represents the cost of an increment of demand. Whereas the interpretation of marginal cost is not unique, the alternative definitions are similar in that they are all forward looking. They consider only future costs related to future output as opposed to embedded cost-of-service methods.

The rationale for marginal cost pricing emanates from the economic theory of efficient allocation of resources in competitive markets. Prices that are equal to marginal cost provide the correct signals to decision-makers -- producers and consumers -- and should result in a market equilibrium at a level and pattern of electricity supply that result in the best allocation of scarce resources.

A crucial distinction exists between short-run marginal cost (SRMC) and long-run marginal cost (LRMC). Briefly, LRMC can be defined as the incremental costs of all adjustments in the system development plan and system operations attributable to an incremental increase in demand that is sustained indefinitely into the future. The latter requirement distinguishes LRMC and SRMC; for in the case of temporary demand increments, a different set of adjustments may be optimal.

LRMC pricing emphasizes the trade-off between the need to give correct signals and the importance of prices that are also relatively stable over time. Tariff policy-makers and most electricity consumers prefer a reasonable degree of price predictability and stability in order to facilitate long-term planning. This stability is generally obtained at some loss in short-run allocative efficiency.

A long-run perspective also reflects long-term effects such as increasing (or decreasing) costs of electricity supply. Ignoring such signals in favor of short-run costs can result in electricity consumers making suboptimal decisions as regards their choice of electricity-using capital stock that typically has a long life.[1]

5.2 MARGINAL COST PRICING MODEL AND RESULTS

For this study, a PC-based model was developed to estimate the LRMC for the UPS. Illustrative model results and their implications are discussed in detail in the following sections. Briefly, the model's structure embodies the theoretical considerations outlined in the preceding discussion and facilitates the calculation of marginal energy costs for up to three rating periods (peak, mid-peak, and off-peak). In addition, the model incorporates the calculations necessary to estimate marginal generation capacity cost utilizing the peaker method, and as a user option affords the same calculation using the next-plant method. Estimates from the second approach serve as a useful point of comparison. Also contained in the model are calculations of long-run average incremental costs (LRAIC) for various network voltage levels selected by the user.

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[1] In contrast, SRMC-based rates are more capable of accurately reflecting system operating conditions that are revealed only in the short run, such as generation and transmission forced outages, demand levels that are weather related, hydro conditions, etc. In practical rate design, the choice is not either/or. Rather, the challenge is to identify a menu of rate design options, some that are weighted more towards LRMC and others that emphasize the SRMC structure. Another key input that will have a large impact on designing such a portfolio is the customer mix and response capability to such tariffs. Some customers may elect an LRMC-based tariff, whereas others may find an SRMC-based tariff to be more responsive to their needs and circumstances. Still other customers may elect to subscribe to both for different portions of their load.

It should be noted that the model calculates long-run marginal costs in "border prices." These are the world market prices of the goods and services (delivered to the Egyptian border) needed to provide marginal energy and capacity. Border prices exclude the effects of taxes, duties and subsidies that distort the prices of these goods in the domestic market.

A standard conversion factor (SCF) is used to adjust the costs of local goods to border prices. This factor has been approximated as .95 based upon discussions with USAID economists.[2] A foreign conversion factor is included in the model in order to account for the average duties/taxes on imported equipment; this factor is assumed to be 1.00 because taxes and duties are excluded from all cost streams. A local labor conversion factor is also included in the model to adjust for cases in which the opportunity cost of domestic labor employed on power projects diverges from its market wage. We have not applied this factor in Egypt because local labor was not separated in the cost streams. After LRMCs are calculated at border prices, they are finally restated at domestic prices (using the same SCF) to derive appropriate LRMCs at market efficiency prices.

In order to parallel the logical flow of the LRMC model, the remainder of this section is organized into four subsections:

- marginal energy cost
- marginal generation capacity cost
- marginal network capacity cost
- results.

The first three sections demonstrate how the model uses basic assumptions about the system to calculate energy (LE/kWh) and capacity (LE/kW) costs. The results section presents the additional calculations required to integrate these component costs into the model's estimation of the long-run marginal cost of electricity delivered to different voltages and tariff classes.

Marginal Energy Cost

The first component is essentially the variable cost (fuel and variable O&M) of the most expensive generating unit that is running for the purpose of "picking up incremental load at the margin." Once this plant is identified, the marginal energy cost at that instant is

[2] The SCF is defined as the official exchange rate divided by the shadow exchange rate (OER/SER); an SCF of .95 implies a shadow exchange rate of approximately LE 3.50 per U.S. dollar.

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straightforward to calculate given the unit fuel price, heat content of the fuel, and the incremental heat rate of the generating unit.

Exhibit 5-1 helps to illustrate the concept of marginal energy cost and its variation by time-of-day (TOD). The exhibit depicts a schematic of a typical daily load curve for the UPS. Also shown in the exhibit is a 1995 merit order stacking of generating units classified into seven homogeneous groups, ranked from the cheapest to the most expensive fuel group. At the bottom (i.e., the first to be dispatched) is the base hydro energy. The variable cost of operation for this group is essentially any non-fuel variable O&M expense. Therefore, the total variable cost for this group is close to zero.

Stacked immediately above the base hydro are the coal units, which are expected to be on-line by then, under today's least-cost development program. The variable cost of coal-fired energy is estimated to be 5.77 piasters/kWh. As one goes higher up in the stacking order, the variable (fuel plus other O&M) costs become progressively higher. In practice, a production simulation model could be utilized to determine the optimal stacking. Indeed, Exhibit 5-1 has been constructed on the basis of a review of the production simulations embedded within the WASP model as well as a first-hand understanding of power system operation today. The exhibit indicates that generating units belonging to the gas-steam group are expected to be "at the margin" during the off-peak hours, whereas gas turbines are typically at the margin during the evening peak hours. The corresponding marginal energy costs in this illustration are P 6.43/kWh off-peak and P 9.11/kWh on-peak.

For the purposes of estimating long-run marginal energy costs, the following data were reviewed during the course of Task 2 (reported in Chapter 3):

- projected load resource balances (MW) through the year 2000 (see Exhibit 3-8)
- system dispatch (GWh generation by fuel type) at present and projected for the future.

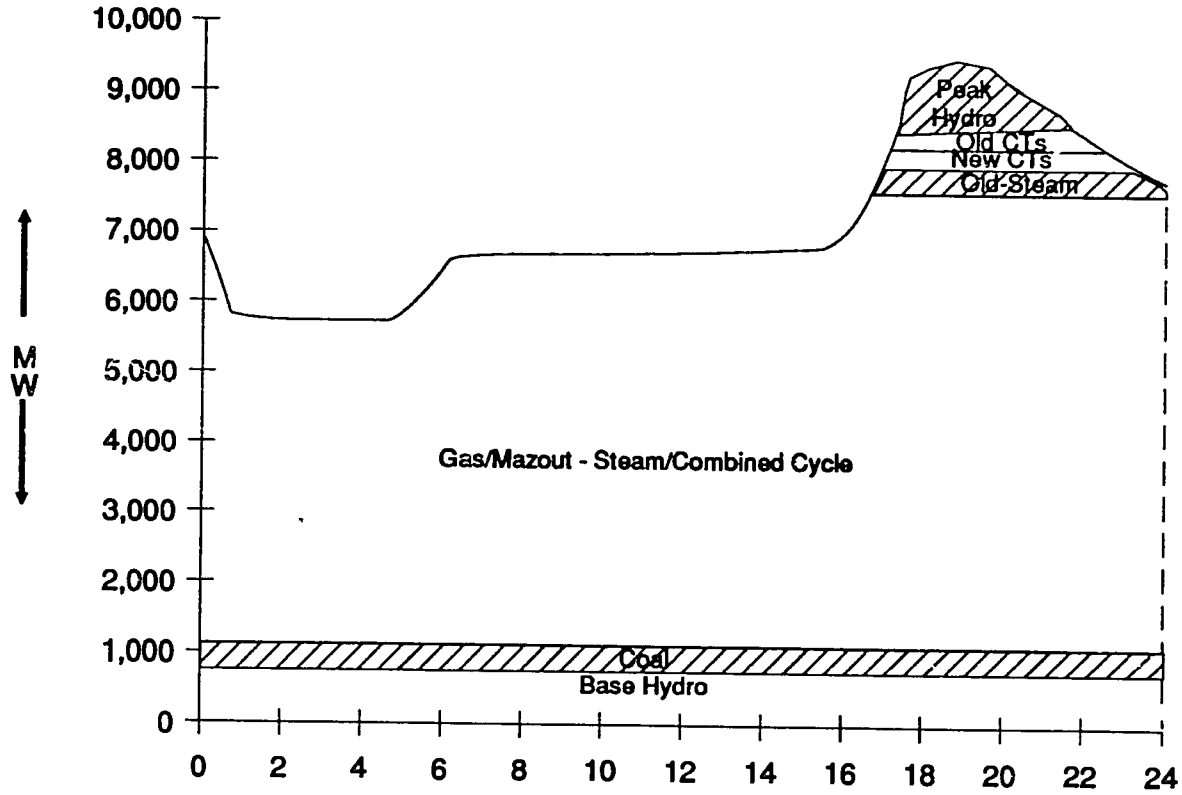
EEA's system planning department was also requested to prepare detailed production costing runs for the years 1993 and 1995.[3] These runs provided the following information:

- by generating unit, the number of hours of utilization and MWh generation.

[3] In the final analysis, we relied on the year 1995 as a representative snapshot of system characteristics and conditions for the purpose of estimating long-run marginal costs.

Exhibit 5-1

Schematic of Typical Daily Load for the UPS in 1995 and Merit Order Stacking of Marginal Plants



Variable Cost by Plant Group (Piasters/kWh)
--
10.42
9.11
6.96
6.43
5.77

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In addition, we reviewed system hourly load data for the last several years and arrived at the following conclusions:

- There is very little month-to-month variation in the daily system load shape. Further, the time-of-day (TOD) variation in the daily load shapes has remained fairly constant, as can be seen, for example, from the evolution of the peak day load curves in recent years, which are depicted in Exhibit 5-2.

- There is little or no variation in the plants that are likely to be at the margin at different hours of the day and in each season.

Finally, a separate analysis was conducted to identify those hours of each day that contribute most towards the annual loss-of-load probability (LOLP). In this manner, the peak period was identified. Based on the preceding considerations, the following assumptions were made for estimating long-run marginal energy costs:

- A peak period of 5:00 p.m. to 10:00 p.m., including Fridays. The LOLP analysis described in Chapter 9 provides a basis for this definition.

- Peak period marginal energy cost is determined by a gas turbine, whereas off-peak period marginal energy cost is determined by a typical generating unit in the new gas-steam category of plants grouped by fuel type and comparable heat rates (Exhibit 5-3). These assumptions are input to the LRMC model.

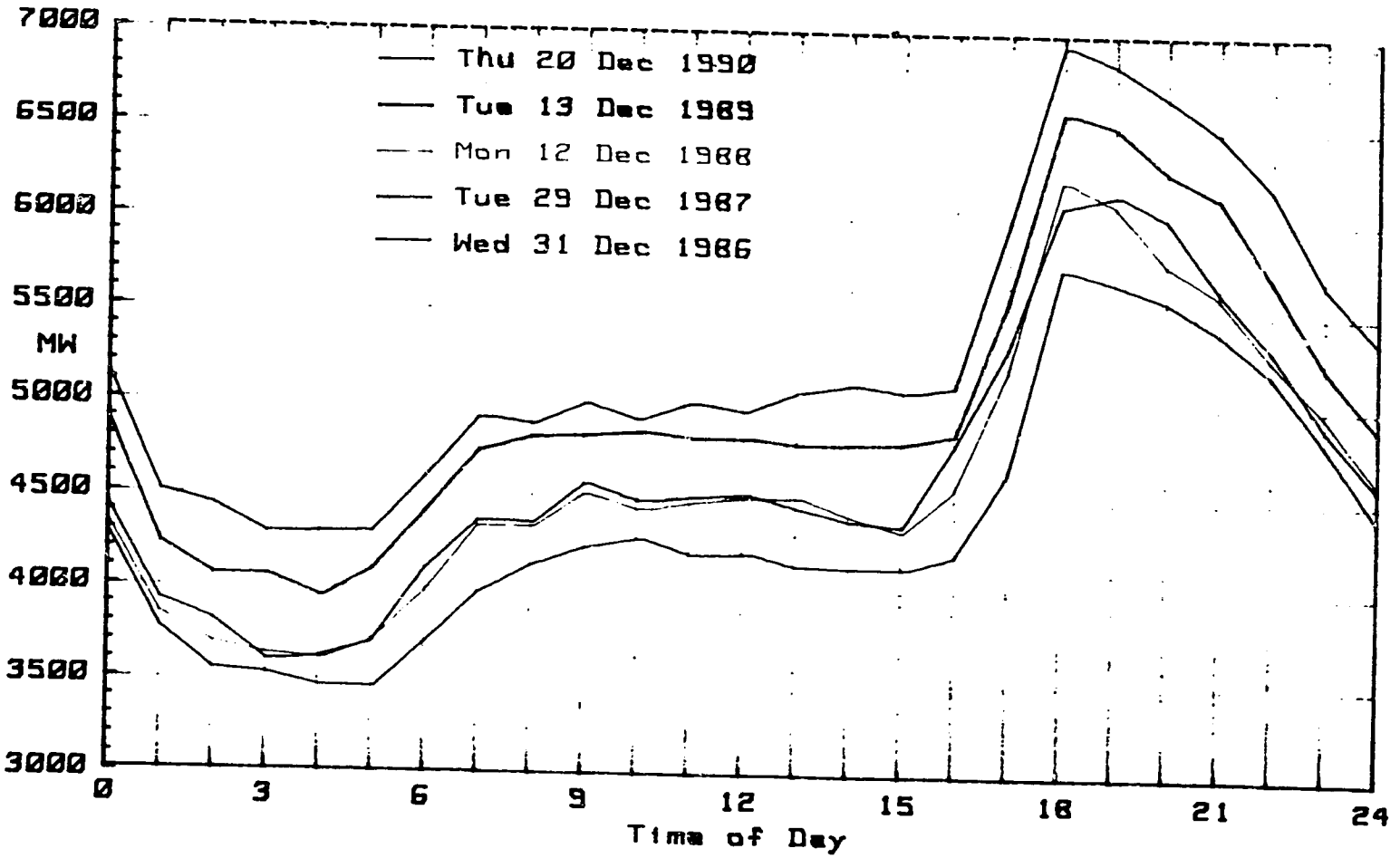
- Fuel costs used in the marginal energy cost analysis are summarized below:

Fuel Cost[4]	$/MMBtu	LE/Tonne
Coal	1.80	160.38
Gas/Mazout	1.97	269.75

[4] When real prices are forecast to change over the study horizon, the fuel cost represents the 1993-1995 average. Further details of the basis for fuel costs can be found in Chapter 3 and its supporting appendices.

Exhibit 5-2

National Power System Generation -- Daily System Demand Profiles - Hourly Instantaneous Values



(FIVE SYSTEM PEAK DAYS)

Exhibit 5-3
Ranking of Generating Plants by Variable Cost - 1995

GENERATING PLANT GROUPS	TYPE	MEGAWATTS (MW) 1/	ANNUAL USE HRS/YR	VARIABLE COST $/KWH	VARIABLE COST LE/KWH	HEAT RATE TU/KWH	FUEL COST $/MMBtu	AR. O&M (% FUEL COST)	ARIABLE O&M 3/ $/KWH
BASE HYDRO 2/	B-HYD	600	-	-	-	-	-	-	-
COAL	COAL	220	7000	0.0175	0.0577	9500	1.80	2.3%	0.00039
GAS-STEAM, COMBINED CYC	GS-CC	5934	7000	0.0195	0.0643	9800	1.97	1.0%	0.00019
OLD GAS-STEAM	OLD-GS	1408	1600	0.0211	0.0696	10500	1.97	2.0%	0.00041
NEW COMBUSTION TURBINE	NEW-CT	349	1300	0.0276	0.0911	14000	1.97	0.1%	0.00003
OLD COMBUSTION TURBINES	OLD-CT	348	350	0.0316	0.1042	16000	1.97	0.2%	0.00006
PEAK HYDRO (3977 GWh) 2/	PK-HYD	1559	-	-	-	-	-	-	-

1/ For thermal plants, represents effective capacity.
2/ Installed hydro capacity = 2750 MW; dependable capacity = 2159 MW.
3/ Based on recent EEA experience.

Exhibit 5-4, taken from the model, summarizes results and specific assumptions used in calculating marginal energy costs: heat rate, fuel types, heat content, variable O&M expenses, etc. for the marginal plants during on-peak and off-peak hours. To illustrate, the exhibit indicates that peak period marginal energy costs are determined as fuel and O&M costs (per kWh) for operating a new combustion turbine. In contrast, off-peak costs are determined solely by typical plant from the new gas-steam group.[5]

Thus, the border price long-run marginal cost of energy at generation (before losses) is:

$$\textit{On-Peak Energy (LE/kWh)} = \left(\frac{14000 Btu}{kWh} \times \frac{\$1.97}{MMBtu} + \$0.00003\right) \times \frac{LE\ 3.30}{\$}$$
$$= LE 0.0911/kWh$$

$$\textit{Off-Peak Energy (LE/kWh)} = \left(\frac{9{,}800 Btu}{kWh} \times \frac{\$1.97}{MMBtu} + \$0.00019\right) \times \frac{LE\ 3.30}{\$}$$
$$= LE\ 0.0643/kWh$$

Subsequently, these estimates are further adjusted to local prices and losses at each voltage level for our first estimate of the strict LRMC of electricity as shown in the lower panel of Exhibit 5-4.

Marginal Generation Capacity Cost

In contrast to the marginal energy cost calculation and marginal cost calculation for the T&D network, there is no universally accepted method for estimating the LRMC for generation capacity. Whereas there is general agreement at a conceptual level, when it comes to estimation, a consensus is lacking. Several methods have been proposed. Three methods frequently mentioned are:

- peaker method
- next-plant method
- incremental revenue requirements method.

[5] The LRMC model also includes a provision for separate treatment of mid-peak (sometimes known as "shoulder" hours) for cases in which there is a distinct "second peak." This categorization is not currently necessary for the UPS grid.

Exhibit 5-4
Marginal Energy Cost by Voltage Level

ASSUMPTIONS:	PEAK	OFF-PEAK
Marginal Plant	NEW-CT	NEW-GS
Heat Rate (BTU/kWh)	14000	9800
Fuel Used	GAS/SOL	GAS/MAZ
Fuel Cost (US$/unit)	1.97	1.97
Heat Content (MMBtu/unit)	1.00	1.00
Variable O&M ($/MMBtu)	0.002	0.020

FUEL COSTS	$/MMBtu	$/Tonne	LE/Tonne
Coal	1.80	48.60	160.38
Gas/Mazout	1.97	81.74	269.75
Sollar	4.36	189.49	625.30

MARGINAL ENERGY COST (LE/KWH): 1/

	PEAK	OFF-PEAK
GEN	0.1002	0.0708
(adjusted to local prices and for station losses)		
VHV	0.1021	0.0718
HV	0.1083	0.0752
MV	0.1167	0.0798
LV	0.1314	0.0875

1/ Energy Costs derived directly from basic assumptions regarding marginal plant, heat rate, fuel cost, fuel heat content, and variable O&M.

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It is beyond the scope of this report to provide a detailed description of these methods, the subtleties involved, and their relative merits and disadvantages. Briefly, however, long-run marginal generational capacity cost is defined as the changes in total future costs associated with a 1 kW increase in peak demand, sustained indefinitely into the future. The methods noted above differ in what they assume to be hypothetical system response to the hypothetical increment in peak load.

The peaker method is rationalized on the basis that the least-cost means of securing capacity is a peaking unit and the reason any other type of generation is built is to derive the energy savings. The annualized cost of such a unit -- adjusted for reserve margin and losses, and appropriately discounted from the year of first need to today -- is the marginal cost of generation capacity. The following equation captures this calculation:

Marginal Generation Capacity Cost (LE/coincident kW/yr) = $[(K)\ (1 + RM/100)/(1 - SL/100)]$

where
- K = Annualized cost of peaking unit (LE/kW/yr)
- RM = Planning reserve margin (%)
- SL = Station losses (%)

This cost (in constant prices) is subsequently discounted from the first year in the future when the reserve margin constraint (or the design loss-of-load probability criterion) is binding, and adjusted upwards for incremental fixed O&M expenses, as well as any downstream losses up to the point of delivery. Finally, this cost can be allocated to different rating periods in the study (e.g., peak and off-peak) using a number of different methods. A common allocation method is on the basis of the contribution of each rating period to the annual loss-of-load probability (LOLP).

Under the next-plant method, it is assumed that the 1 kW load increment (decrement) will be met by appropriately advancing forward (delaying) whichever power plant is planned to come on-line next. For example, if the next plant is a 300 MW baseload coal unit planned for 1994, then its annualized cost can be used to establish a LRMC, after assigning credit for any fuel savings as a result of having a more fuel-efficient plant come on-line earlier.

Exhibit 5-5 helps to illustrate the fuel savings adjustment that is required when using the next-plant method to estimate marginal generation capacity cost. The exhibit shows an annual load duration curve with a merit order stacking of generating plant. If the "next plant" in the least-cost expansion program is a baseload unit (a coal unit in Exhibit 5-5), then 1 kW of additional capacity from such a unit will have the effect of displacing

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generation of all more expensive units, i.e., units higher up in the stacking order. In the illustration in Exhibit 5-5, this is depicted as reducing 1 kW of gas-steam generation for 7000 hours, 1 kW of old gas-steam for 1600 hours, 1 kW of new gas turbine generation for 1300 hours, and 1 kW of old gas turbine generation for 350 hours. Thus, the annual fuel savings that should be credited against the annualized capital cost of the coal plant are given by the calculation [7000 x (6.43 - 5.77) + 1600 x (6.96 - 6.43) + 1300 x (9.11 - 6.96) + 350 x (10.42 - 9.11)] piasters/kW/year. Therefore, the marginal generation capacity cost under the next-plant method is inferred as the annualized capital cost of a coal plant (expressed in LE/kW/year) less the fuel savings estimated as above.

In contrast to the two methods described above, the incremental revenue requirements method re-optimizes the entire expansion plan and estimates the incremental difference in the present value of two expenditure streams. Reoptimization of the expansion plan requires the use of sophisticated optimization system expansion planning models.[6]

Implementation of the incremental revenue requirements method requires a substantial commitment of resources. More fundamentally, however, the incremental revenue requirements method is characterized by a conceptual flaw. Estimates of "marginal cost" developed by this method are weighted averages of capacity costs of a diverse mix of marginal as well as inframarginal plant types: peaking, intermediate, and baseload. Such a basis is contrary to the notion of marginal capacity cost, i.e., the cost of meeting a marginal increment of demand on-peak.

As a practical matter, the three methods should yield similar estimates of LRMC under conditions where the utility's generating mix is not substantially different from the least-cost mix and the reserve margin is just adequate. For, under such conditions, the "next

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[6] e.g., International Atomic Energy Agency's WASP model for optimal generation expansion planning. Specifically, three "WASP model runs" are required as follows. Run 1 corresponds to optimizing the system generation expansion plan to the base load forecast. Model run 2 reoptimizes the system expansion plan with the peak load forecast used in Run 1 incremented by the equivalent of one year's load growth. Finally, Run 3 is a production simulation (e.g., WASP in a "pre-specified pathway" mode) to estimate the fuel costs associated with the load forecast used in Run 1, but unit stagings determined in Run 2. Thus, LRMC for generation capacity can be estimated by calculating the following quantity and levelizing it:

$$[(CR_1 - CR_2) + (FC_3 - FC_1)]/DMW$$

where CR_i is the capital investment associated with model run i (i = 1, 2, 3), FC_i is the fuel (production) cost associated with the expansion plan model run i, and DMW is the megawatt incremental difference in peak load between runs 1 and 2.

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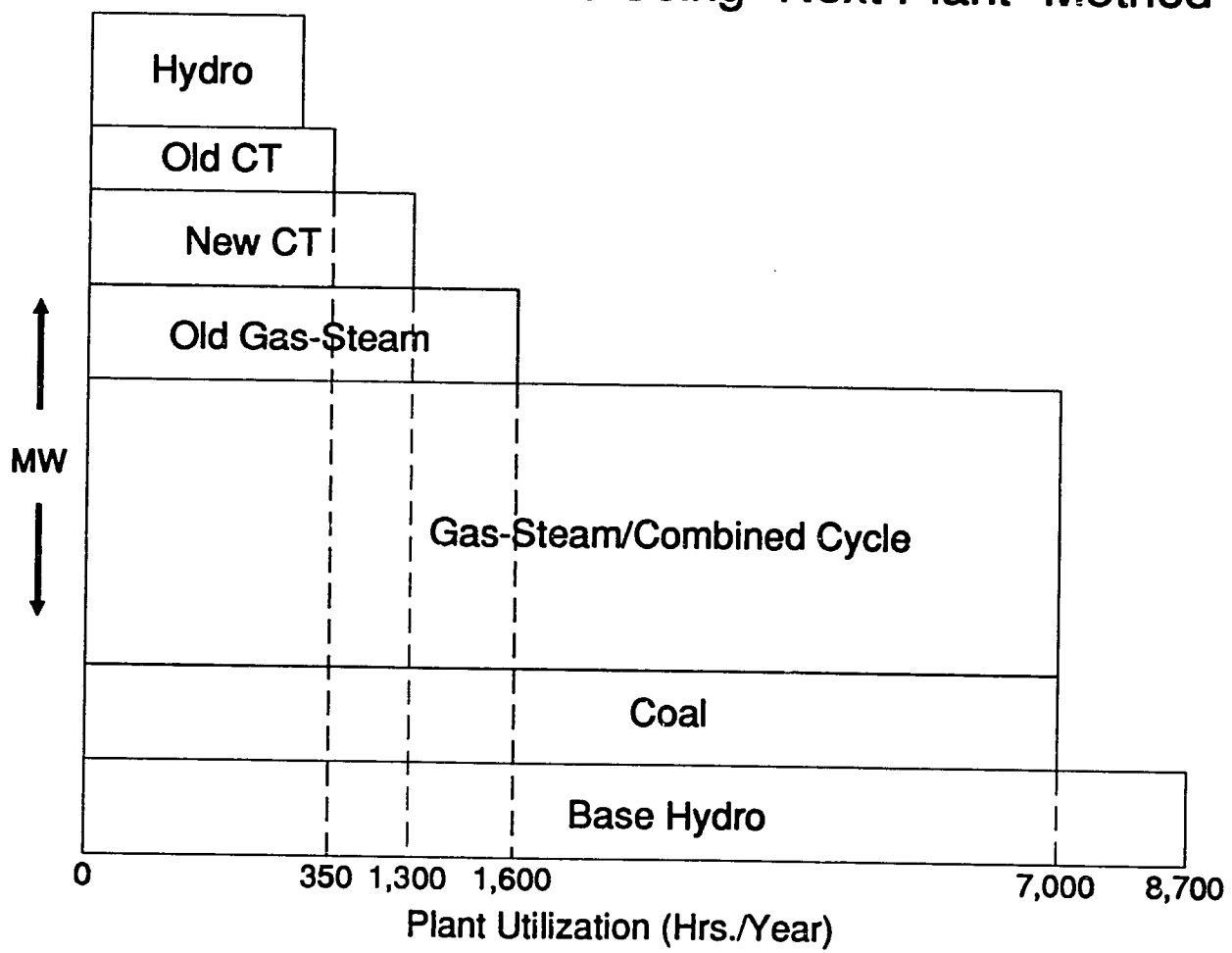
Exhibit 5-5
Marginal Generating Capacity Costs Using "Next Plant" Method



Piasters/kWh
--
10.42
9.11
6.96
6.43
5.77
--

Marginal capacity cost = Annualized capital cost of coal plant minus fuel savings

Fuel Savings = [7000 x (6.43 - 5.77) + 1,600 x (6.96 - 6.43) + 1,300 x (9.11 - 6.96) + 350 x (10.42 - 9.11)] Piasters/kW/yr

unit" for capacity purposes will indeed be a peaker and the system reoptimization method should also elect to advance the peaker.

In practice, the peaker method is by far the most frequently used method in the U.S. and worldwide, with the "next-plant" method next in frequency of usage. Use of the incremental revenue requirements method for estimating LRMC is very infrequent for the reasons noted above. However, this method is more commonly (and appropriately) utilized in the context of estimating "avoided costs" for estimating payments for power purchases from large independent power projects and cogeneration projects.

Based upon our review of the expansion plan, we believe that the peaker method is appropriate for estimating the marginal cost of generation capacity. However, for the purposes of comparison, and since the last tariff study had utilized the next-plant method, we have also estimated generation capacity cost using this method. For this purpose, a coal plant provides a suitable proxy.

Exhibit 5-6 depicts key input assumptions and results for the LRMC model for the marginal generation capacity cost calculation. At an exchange rate of LE 3.30 to US$1.00 and a standard conversion factor of 0.95, the border prices discounted back from 1993, are (1) 798 LE/kW for a peaker[7] and (2) 2,227 LE/kW less associated fuel savings of 87 LE/kW/year for the coal plant. These costs are subsequently annualized over the respective plant lifetimes, adjusted to local prices and for reserve margin, station losses, and incremental O&M expense.

Marginal Network Capacity Cost

The transmission and distribution (T&D) network's capacity is designed to accommodate peak demand power flows from generation to end users. Further, in a growing system, such network capacity is sized and sequenced recognizing future growth potential as well. Generally, all investment costs for T&D are allocated to incremental capacity since the designs of these facilities are determined principally by the peak kilowatts that they carry rather than by kilowatt-hours. The most frequently used approach for estimating marginal T&D capacity cost, and the one which we have also used, is the long-run average incremental cost (LRAIC) method.

The LRAIC represents the present value of all T&D investments over the planning horizon divided by the present value of the corresponding annual increments in peak load. This

[7] i.e., $(654.9 + 327.5 \times .95) \times (1/(1.1)^2)$

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Exhibit 5-6
Marginal Generation Capacity Cost

ASSUMPTIONS:	---------GENERATION---------- PEAKER METHOD	"NEXT PLANT"
Marginal Plant	NEW-CT	COAL
Life (years)	25	30
O&M and A&G (% of capital cost)	0.64%	0.88%
T&D Construction Lag (years)	-	-
Year Generation Required	1993	1993
Capital Cost:		
Foreign (LE/KW or %)	654.9	1826.5
Local Materials	327.5	913.3
Local Labor (d)	0.0	0.0

ASSOCIATED FUEL SAVINGS ("NEXT PLANT" METHOD)

---UNIT TYPE--- NEW	DISPL	COST (LE/KWH) NEW	DISPL	HRS/YR	SAVINGS/KW
COAL	GS-CC	0.0577	0.0643	7000	46.33
GS-CC	OLD-GS	0.0643	0.0696	1600	8.45
OLD-GS	NEW-CT	0.0696	0.0911	1300	27.92
NEW-CT	OLD-CT	0.0911	0.1042	350	4.59
TOTAL FUEL SAVINGS (LE/KW/YR)					87.29

	PEAKER METHOD	"NEXT PLANT"
CAPITAL COST (LE/KW) (adjusted to local prices and for reserve margin and station losses at peak)	1053.84	2939.16
CAPITAL COST PER YEAR (LE/KW/YR)	116.10	311.78
ASSOCIATED FUEL SAVINGS (LE/KW/YR) (adjusted to local prices and for station losses)	-	96.03
CAPITAL COST NET OF FUEL SAVINGS (LE/KW/YR)	116.10	215.76
O&M COST PER YEAR (LE/KW/YR)	6.74	25.86
TOTAL CAPITAL COST PER YEAR (LE/KW/YR)	122.84	241.62
CAPACITY COST PER MONTH	10.24	20.14

value, expressed in LE per incremental kW, is then annuitized over the life of the facilities, resulting in the annuitized capacity cost, expressed in LE/kW/year.

Separate LRAICs must be estimated for each major voltage level of the UPS -- very high voltage (VHV), high voltage (HV), medium voltage (MV), and low voltage (LV) -- as depicted schematically in Exhibit 5-7. To estimate separate LRAICs for each voltage, capital expenditures, lines, and loads must be estimated for each voltage level. Exhibit 5-8 displays the incremental investments by voltage. These were derived from data provided by EEA, EDA, and REA on its investment program for network capacity expansion (Appendix H).

Forecasts of sales by voltage level are shown in Exhibit 5-9. These allocations were derived from EEA's forecast of sales and peak demand for the UPS (see Chapter 2). Energy sales are built up from individual customer class analyses rather than by voltage level. System peak loads are derived from total sales by applying a system load factor since peak load forecasts are not available by voltage. The FY 1990 proportion of total sales for each consumer/tariff category at each voltage level were maintained through the study horizon, applied to each year's sales forecast.

The model also requires estimates of peak and average loss coefficients at each voltage level as a percent of incoming load. Energy losses by voltage were developed as follows. Historically, we know that EEA's station losses have been in the range of 4 to 4.5 percent, that average losses as a percent of net generation (after station use) in its bulk system (predominantly VHV and HV) have been on the order of 6 to 7 percent per year, and that total UPS network losses have been 14 to 15 percent (see Chapter 2). These are consistent with EEA's current loss projections:

	Station Use (%)	Total Network Losses (%)
FY91	4.1%	14.4%
FY92	4.2%	14.3%
FY93	4.2%	14.2%
FY94	4.3%	14.1%
FY95	4.3%	14.0%
FY96	4.3%	14.0%
FY97	4.4%	13.8%
FY98	4.4%	13.8%
FY99	4.4%	13.7%
FY2000	4.5%	13.6%

Exhibit 5-7

Schematic Representation of the UPS Grid

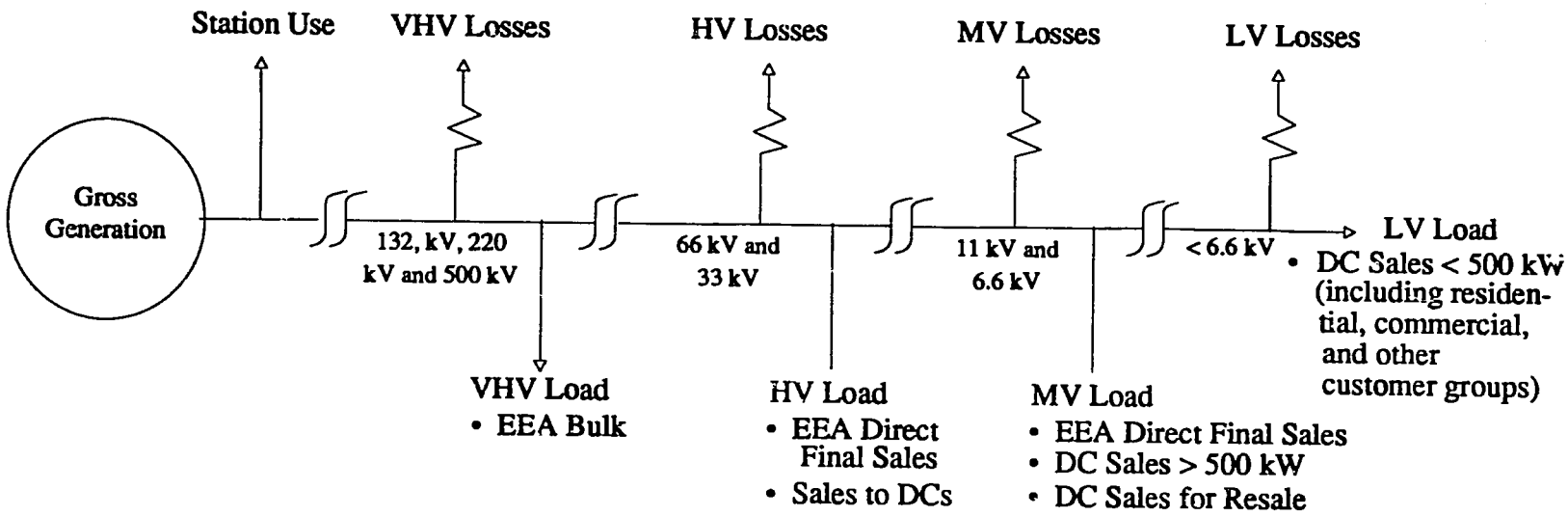

Exhibit 5-8
Unified Power System
Network Capacity Cost (LE Million)

YEAR	VHV COSTS				HV COSTS			
ENDING	TOTAL	FOREIGN	LOC MAT	C LABOR	TOTAL	FOREIGN	LOC MAT	C LABOR
1991	264.81	228.13	36.67	0.00	145.57	95.9[illegible]	49.65	0.00
1992	451.35	345.05	106.30	0.00	610.21	561.80	48.41	0.00
1993	224.43	202.39	22.04	0.00	582.81	518.93	63.88	0.00
1994	469.96	340.14	129.81	0.00	296.80	259.95	36.85	0.00
1995	105.26	89.69	15.57	0.00	48.46	24.56	23.90	0.00
1996	0.00	0.00	0.00	0.00	109.71	81.09	28.63	0.00
1997	9.94	6.19	3.75	0.00	91.42	66.32	25.10	0.00
1998	0.00	0.00	0.00	0.00	124.41	103.31	21.10	0.00
1999	0.00	0.00	0.00	0.00	181.89	156.42	25.47	0.00
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

YEAR	MV COSTS				LV COSTS			
ENDING	TOTAL	FOREIGN	LOC MAT	C LABOR	TOTAL	FOREIGN	LOC MAT	C LABOR
1991	242.12	78.91	163.21	0.00	131.55	0.00	131.55	0.00
1992	265.56	92.24	173.32	0.00	136.15	0.00	136.15	0.00
1993	269.40	99.22	170.18	0.00	140.92	0.00	140.92	0.00
1994	240.08	78.15	161.94	0.00	145.85	0.00	145.85	0.00
1995	235.94	68.96	166.98	0.00	150.95	0.00	150.95	0.00
1996	236.17	71.04	165.13	0.00	156.24	0.00	156.24	0.00
1997	226.05	61.58	164.47	0.00	161.71	0.00	161.71	0.00
1998	238.87	65.60	173.27	0.00	167.37	0.00	167.37	0.00
1999	220.39	46.72	173.67	0.00	173.22	0.00	173.22	0.00
2000	41.16	41.16	0.00	0.00	0.00	0.00	0.00	0.00

Exhibit 5-9
EEA/Unified Power System Grid Sales and Loss Forecast

YEAR ENDING	PEAK (MW)	GROSS GEN (GWH)	LOAD FACTOR	TOTAL SALES (GWH)	------SALES BY VOLTAGE LEVEL (GWH)------					---AVERAGE LOSSES BY VOLTAGE LEVEL (GWh)--- Allocation of network losses (%)---------					
					GEN	VHV	HV	MV	LV	STN USE	VHV	HV	MV	LV	TOTAL
											1.5%	4.0%	4.4%	4.5%	14.4%
1991	7152	44297	70.7	36368	0	6770	2448	8783	18367	1816	637	1698	1868	1910	7929
1992	7644	47201	70.5	38752	0	6980	2615	9421	19736	1982	674	1796	1976	2021	8449
1993	8123	49947	70.2	41056	0	7054	2793	10105	21104	2098	708	1887	2075	2123	8890
1994	8640	52923	69.9	43556	0	7144	2983	10839	22590	2276	739	1970	2167	2216	9367
1995	9189	56154	69.8	46214	0	7294	3187	11627	24107	2415	784	2090	2299	2351	9939
1996	9736	59308	69.5	48869	0	7344	3404	12472	25649	2550	822	2191	2410	2465	10438
1997	10461	63639	69.4	52502	0	7711	3637	13379	27775	2800	868	2316	2547	2605	11137
1998	11108	67562	69.4	55806	0	8097	3886	14352	29472	2973	915	2440	2684	2745	11756
1999	11778	71646	69.4	59251	0	8502	4152	15395	31202	3152	963	2567	2824	2888	12385
2000	12472	75896	69.5	62842	0	8927	4437	16515	32964	3415	1004	2677	2945	3012	13054

Based upon this background and discussions with EEA's network planning staff, these were split for FY91 as 1.5 percent for VHV and 4.0 percent for HV (i.e., the EEA bulk system), 4.4 percent for MV, and 4.5 percent for LV (for a total of 14.4 percent). For subsequent years, these values were proportioned downward to match the total network loss forecast.

For peak losses, we began with a review of the results of load flow simulations conducted by the Network Planning Department. Peak loss calculations in the modelwere determined according to the following empirical formula that has been developed based upon experience with a wide variety of situations:

Peak Losses = Average Losses / (.3 + (.7 x Load Factor))

Estimates of average and peak loss factors by voltage level are shown in Exhibit 5-10.

Estimates of incoming peak load, losses, and consumption in MW at each voltage level as calculated by the model are shown in Exhibit 5-11. The exhibit displays the predicted coincident power balance under each voltage for the years 1991 through 2000. To illustrate, in the year 1991 the gross peak level of 7,152 MW, after adjusting to 293 MW of station use (based upon application of the peak station use factors in Exhibit 5-10), and after adjusting for VHV network losses of 129 MW, results in a VHV peak of 6,730 MW. Of this amount, 1,093 MW of load is supplied at this voltage, with the remaining power transmitted to the HV network. The HV peak is estimated to be 5,293 MW, after adjusting for losses of 343 MW. In this manner, the power balance is sequentially derived to arrive at an estimated LV network peak of 2,739 MW.

Next, Exhibit 5-12 shows the calculation of separate LRAICs for the four voltage levels. Incremental peak loads are calculated from Exhibit 5-11, whereas incremental expenditures are calculated from Exhibit 5-8. These costs are subsequently annualized over their respective lifetimes, an then adjusted to local prices and for incremental O&M expense as shown in Exhibit 5-13.

Results

Estimates of marginal generation capacity cost and network capacity cost (expressed as LE/coincident kW) are summarized in Exhibit 5-14. In the model and the foregoing discussion, both capacity and energy costs are calculated at border prices. In order to estimate the long-run marginal cost as seen by the customer, these border prices must be re-expressed in terms of local prices (i.e., divided by the SCF). The capital cost of generation capacity must also be adjusted to account for the desired reserve margin and station losses

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Exhibit 5-10
EEA/Unified Power System Average and Peak Loss Factors

YEAR	--STATION USE---		------VHV-------		------HV--------		------MV--------		------LV--------	
ENDING	VERAGE	PEAK	VERAGE	PEAK	VERAGE	PEAK	VERAGE	PEAK	VERAGE	PEAK
1991	0.041	0.041	0.015	0.019	0.048	0.061	0.060	0.076	0.094	0.119
1992	0.042	0.042	0.015	0.019	0.048	0.060	0.060	0.075	0.093	0.117
1993	0.042	0.042	0.015	0.019	0.047	0.059	0.059	0.074	0.091	0.115
1994	0.043	0.043	0.015	0.018	0.046	0.058	0.057	0.073	0.089	0.113
1995	0.043	0.043	0.015	0.019	0.046	0.058	0.057	0.072	0.089	0.113
1996	0.043	0.043	0.014	0.018	0.045	0.057	0.056	0.071	0.088	0.111
1997	0.044	0.044	0.014	0.018	0.044	0.056	0.055	0.070	0.086	0.109
1998	0.044	0.044	0.014	0.018	0.044	0.056	0.054	0.069	0.085	0.108
1999	0.044	0.044	0.014	0.018	0.043	0.055	0.054	0.069	0.085	0.108
2000	0.045	0.045	0.014	0.018	0.043	0.054	0.053	0.068	0.084	0.106
Average	0.043	0.043	0.014	0.018	0.045	0.058	0.057	0.072	0.088	0.112

Exhibit 5-11
EEA/Unified Power System Demand and Loss Forecast at Time of System Peak (MW)

YEAR	PEAK	STATION	GEN	---------VHV----------			----------HV----------			----------MV----------			-----LV------	
ENDING		USE	CONSUM	LOSS	PEAK	CONSUM	LOSS	PEAK	CONSUM	LOSS	PEAK	CONSUM	LOSS	PEAK
1991	7152	293.2	0.0	129.3	6729.6	1093.1	343.3	5293.2	395.3	372.1	4525.8	1418.0	368.3	2739.4
1992	7644	321.1	0.0	137.5	7185.6	1130.4	364.9	5690.3	423.5	395.6	4871.2	1525.7	391.6	2953.9
1993	8123	341.2	0.0	145.4	7636.4	1147.2	386.0	6103.2	454.2	418.4	5230.6	1643.4	414.3	3172.9
1994	8640	371.5	0.0	152.8	8115.5	1166.3	405.5	6543.7	487.0	439.7	5617.1	1769.5	435.4	3412.2
1995	9189	395.1	0.0	162.7	8631.3	1193.6	431.9	7003.8	521.5	468.3	6016.0	1902.7	463.7	3649.6
1996	9736	418.7	0.0	171.4	9146.2	1205.6	455.1	7485.4	558.9	493.5	6433.0	2047.5	488.7	3896.8
1997	10461	460.3	0.0	181.6	9819.4	1267.6	482.1	8069.7	597.9	522.9	6949.0	2199.3	518.1	4231.6
1998	11108	488.7	0.0	191.4	10427.6	1331.2	508.0	8588.4	638.9	551.1	7398.5	2359.5	546.2	4492.8
1999	11778	518.2	0.0	201.3	11058.2	1397.6	534.5	9126.1	682.5	579.9	7863.7	2530.8	574.8	4758.2
2000	12472	561.2	0.0	209.8	11700.7	1466.9	557.1	9676.7	729.0	604.6	8343.1	2713.8	599.4	5029.8

Exhibit 5-12
EEA/Unified Power System
Average Incremental Network Capacity Costs by Voltage Level (LE Million)

VHV NETWORK

YEAR ENDING	PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1991	0.00	0.00	264.81	262.97	262.97
1992	456.09	414.62	451.35	446.04	405.49
1993	450.75	372.52	224.43	223.33	184.57
1994	479.08	359.94	469.96	463.47	348.21
1995	515.82	352.31	105.26	104.48	71.36
1996	514.88	319.70	0.00	0.00	0.00
1997	673.23	380.02	9.94	9.75	5.50
1998	608.19	312.10	0.00	0.00	0.00
1999	630.59	294.17	0.00	0.00	0.00
2000	642.52	272.49	0.00	0.00	0.00
Lagged Total		3077.88 (1992-2000)			1278.10 (1991-99)

AVERAGE INCREMENTAL VHV CAPACITY COST/KW 415.25

HV NETWORK

PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
0.00	0.00	131.25	143.09	143.09
397.09	360.99	610.21	607.79	552.53
412.93	341.26	582.81	579.62	479.02
440.53	330.98	296.80	294.96	221.61
462.04	315.58	48.46	47.26	32.28
479.65	297.82	109.71	108.28	67.23
584.30	329.82	91.42	90.16	50.90
518.67	266.16	124.41	123.35	63.30
537.72	250.85	181.89	180.62	84.26
550.56	233.49	0.00	0.00	0.00
	2726.95 (1992-2000)			1694.22 (1991-99)

AVERAGE INCREMENTAL HV CAPACITY COST/KW = 621.29

MV NETWORK

YEAR ENDING	PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1991	0.00	0.00	242.12	233.96	233.96
1992	345.42	314.02	265.56	256.89	233.54
1993	359.38	297.01	269.40	260.89	215.61
1994	386.52	290.40	240.08	231.99	174.30
1995	398.92	272.47	235.94	227.59	155.45
1996	417.05	258.95	236.17	227.91	141.51
1997	515.96	291.25	226.05	217.83	122.96
1998	449.46	230.64	238.87	230.21	118.13
1999	465.25	217.04	220.39	211.71	98.76
2000	479.36	203.29	41.16	41.16	17.46
Lagged Total		2375.07 (1992-2000)			1494.22 (1991-99)

AVERAGE INCREMENTAL MV CAPACITY COST/KW 629.13

LV NETWORK

PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
0.00	0.00	131.55	124.97	124.97
214.46	194.96	136.15	129.34	117.59
218.99	180.99	140.92	133.87	110.64
239.29	179.78	145.85	138.56	104.10
237.42	162.16	150.95	143.41	97.95
247.23	153.51	156.24	148.43	92.16
334.79	188.98	161.71	153.62	86.72
261.18	134.03	167.37	159.00	81.59
265.37	123.79	173.22	164.56	76.77
271.64	115.20	0.00	0.00	0.00
	1433.41 (1992-2000)			892.48 (1991-99)

AVERAGE INCREMENTAL LV CAPACITY COST/KW = 622.63

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Exhibit 5-13
EEA/Unified Power System
Marginal Network Capacity Cost

	VHV	HV	MV	LV
CAPITAL COST (LE/KW) (adjusted to local prices)	437.11	653.98	662.24	655.40
CAPITAL COST PER YEAR (LE/KW/YR)	44.70	66.88	72.96	72.20
O&M COST PER YEAR (LE/KW/YR)	8.74	13.08	16.56	16.38
TOTAL CAPITAL COST PER YEAR (LE/KW/YR)	53.44	79.96	89.51	88.59
CAPACITY COST PER MONTH	4.45	6.66	7.46	7.38

Exhibit 5-14
EEA/Unified Power System Summary of Capacity Costs

ERATION:	PEAKER METHOD	"NEXT PLANT"
CAPITAL COST (LE/KW) (adjusted to local prices and for reserve margin and station losses at peak)	1053.84	2939.16
CAPITAL COST PER YEAR (LE/KW/YR)	116.10	311.78
ASSOCIATED FUEL SAVINGS (LE/KW/YR) (adjusted to local prices and for station losses)	-	96.03
CAPITAL COST NET OF FUEL SAVINGS (LE/KW/YR)	116.10	215.76
O&M COST PER YEAR (LE/KW/YR)	6.74	25.86
TOTAL CAPITAL COST PER YEAR (LE/KW/YR)	122.84	241.62
CAPACITY COST PER MONTH	10.24	20.14

TRANSMISSION & DISTRIBUTION:	VHV	HV	MV	LV
CAPITAL COST (LE/KW) (adjusted to local prices)	437.11	653.98	662.24	655.40
CAPITAL COST PER YEAR (LE/KW/YR)	44.70	66.88	72.96	72.20
O&M COST PER YEAR (LE/KW/YR)	8.74	13.08	16.56	16.38
TOTAL CAPITAL COST PER YEAR (LE/KW/YR)	53.44	79.96	89.51	88.59
CAPACITY COST PER MONTH	4.45	6.66	7.46	7.38

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at peak. The "summary of capacity costs" in Exhibit 5-14 makes these adjustments, annualizes investment costs, adds in an appropriate factor for annual O&M (including administrative and general expenses), and estimates a capacity cost per month for generation and network at each voltage level. To illustrate, the marginal generation capacity cost (peaker method) is 10.24 LE/coincident kW/month. By way of comparison, the next-plant method yields an estimate of 20.14 LE/kW/month.

Similarly, Exhibit 5-14 derives the marginal cost of network capacity (LE/coincident kW/month) at each voltage level. These costs range from 4.45 LE/kW/month at VHV to approximately 7.40 LE/kW/month at both MV and LV.

Exhibit 5-15 presents estimates of strict long-run marginal costs by voltage level. To illustrate, marginal capacity costs (generation plus network) using the peaker method range from 14.88 LE/coincident kW/month for load served at VHV to 43.02 LE/coincident kW/month for LV load. Similarly, marginal energy costs at LV are .1314 LE/kWh during the peak period and .0875 LE/kWh during off-peak hours. These costs are progressively lower (reflecting reduced losses) as service is taken at higher voltages. For example, these supply costs at VHV are .1021 LE/kWh and .0718 LE/kWh, respectively.

In order to apply the strict marginal cost estimates discussed above to each tariff class, additional factors must be considered. These are: (1) the coincidence of peak for each class in relation to the system peak, (2) the load factor for each type of customer, and (3) the split of total energy between peak and off-peak. Applying the coincidence factors results in an estimate of total marginal capacity cost per month for each customer class.[8] These results are shown for EEA's bulk customers in Exhibit 5-16, for EDA's retail customers in Exhibit 5-17, and for the entire UPS in Exhibit 5-18. In these exhibits, marginal energy cost is a weighted average of peak and off-peak costs. The class load factors are used to express capacity costs in terms of kWh.[9] The final line of each exhibit derives average system-wide strict LRMC estimates.

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8 In arriving at these assumptions, the study team members first reviewed and analyzed the load research made available to us (see Appendix I2). In the final analysis, the assumptions made are also conditioned upon the team members' experience and judgment. This conditioning became necessary because the available load research data do not provide a statistically valid basis for extrapolating from the sample to the corresponding sub-populations.

9 To avoid unnecessary confusion, the printed table shows strict LRMC for the peaker method. For comparative purposes, parallel results for the "next-plant" method appear in the model spreadsheet to the right of these printed data. A complete printout of the LRMC model results is contained in Appendix I.

Exhibit 5-15
EEA/Unified Power System
Strict Long-Run Marginal Cost-Based Tariff by Voltage Level

MARGINAL CAPACITY COST (LE/COINCIDENT KW/MONTH):

	---------GENERATION---------		-------TRANSMISSION & DISTRIBUTION-------					TOTAL MARGINAL CAPACITY COST	
	PEAKER METHOD	"NEXT PLANT"	VHV	HV	MV	LV	TOTAL	PEAKER METHOD	"NEXT PLANT"
VHV	10.43	20.51	4.45				4.45	14.88	24.96
HV	11.07	21.77	4.73	6.66			11.39	22.45	33.15
MV	11.92	23.45	5.09	7.18	7.46		19.73	31.65	43.17
LV	13.42	26.40	5.73	8.08	8.40	7.38	29.60	43.02	56.00

MARGINAL ENERGY COST (LE/KWH): 1/

	PEAK	OFF-PEAK
GEN	0.1002	0.0708
(adjusted to local prices and for station losses)		
VHV	0.1021	0.0718
HV	0.1083	0.0752
MV	0.1167	0.0798
LV	0.1314	0.0875

1/ Energy Costs derived directly from basic assumptions regarding marginal plant, heat rate, fuel cost, fuel heat content, and variable O&M.

Exhibit 5-16
EEA/Unified Power System
Strict Long-Run Marginal Cost-Based Tariff by Tariff Class - Bulk

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	TOTAL MARGINAL COST/MONT CAPACITY LE/KW	ENERGY LE/KWH	TOTAL LE/KWH	DEMAND CHARGE SHARE	FY91/H1 SALES GWH	URRENT YIELD LE/KWH
VHV INDUSTRY										
KIMA CO.	VHV	1.00	0.90	0.21	14.88	0.0782	0.1008	22%	824	0.0170
ALUMINUM CO.	VHV	0.96	0.90	0.20	14.29	0.0779	0.0996	22%	1485	0.0460
ASSUIT CEM (1)	VHV	0.95	0.90	0.20	14.14	0.0779	0.0994	22%	86	0.0632
ASSUIT CEM (2)	VHV	0.95	0.90	0.20	14.14	0.0779	0.0994	22%	59	0.0632
FERROSILICON	VHV	0.95	0.90	0.20	14.14	0.0779	0.0994	22%	153	0.0577
SOMED CO.	VHV	0.95	0.90	0.20	14.14	0.0779	0.0994	22%	162	0.0632
DEKHILA FERRO	VHV	0.95	0.90	0.20	14.14	0.0779	0.0994	22%	449	0.0632
AMERIA SPIN	VHV	0.95	0.90	0.20	14.14	0.0779	0.0994	22%	53	0.0632
HV INDUSTRY/AGRI	HV	0.95	0.70	0.20	21.33	0.0819	0.1236	34%	1218	0.0807
MV INDUSTRY/AGR	MV	0.95	0.60	0.22	30.07	0.0879	0.1565	44%	126	0.1355
DISTRIBUTION COS.										
CAIRO	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	6449	0.0667
ALEXANDRIA	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	1619	0.0630
DELTA NORTH	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	1099	0.0514
DELTA SOUTH	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	1158	0.0542
BEHEIRA	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	716	0.0647
CANAL	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	1548	0.0644
N. UPPER EGYPT	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	1008	0.0488
S. UPPER EGYPT	HV	1.00	0.75	0.26	22.45	0.0838	0.1249	33%	1018	0.0643
EEA SYSTEM AVERAGE				0.25	21.06	0.0827	0.1207		19229	0.0608
Equivalent LE/KWH					0.0380	0.0827	0.1207			
% of System Average					31%	69%	100%			

Exhibit 5-17
EEA/Unified Power System
Strict Long-Run Marginal Cost-Based Tariff by Tariff Class - Retail

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	TOTAL MARGINAL COST/MONT CAPACITY LE/KW	ENERGY LE/KWH	TOTAL LE/KWH	DEMAND CHARGE SHARE	FY91/H1 SALES GWH	URRENT YIELD LE/KWH
HOUSING COS.	HV	0.95	0.75	0.26	21.33	0.0838	0.1228	32%	350	0.0600
MV MOVING POWE	MV	0.95	0.60	0.22	30.07	0.0879	0.1565	44%	3891	0.1416
LV MOVING POWE	LV	0.95	0.55	0.25	40.87	0.0985	0.2003	51%	833	0.0979
LV OTHER PURPOS	LV	0.95	0.55	0.25	40.87	0.0985	0.2003	51%	734	0.1353
MV FREE ZONE	MV	0.95	0.60	0.22	30.07	0.0879	0.1565	44%	6	0.1264
LV FREE ZONE	LV	0.95	0.55	0.25	40.87	0.0985	0.2003	51%	6	0.1843
RESIDENTIAL	LV	0.95	0.50	0.30	40.87	0.1007	0.2126	53%	5602	0.0421
COMMERCIAL	LV	0.95	0.45	0.30	40.87	0.1007	0.2251	55%	885	0.1083
GOVT LIGHTING	LV	0.95	0.45	0.15	40.87	0.0941	0.2185	57%	286	0.1855
STREET LIGHTING	LV	1.00	0.50	0.27	43.02	0.0993	0.2172	54%	589	0.1855
DISTRIBUTION COMPANY AVERAGE				0.26	37.25	0.0960	0.1934		13183	0.0947
Equivalent LE/KWH					0.0974	0.0960	0.1934			
% of System Average					50%	50%	100%			

Exhibit 5-18
EEA/Unified Power System
Strict Long-Run Marginal Cost-Based Tariff by Tariff Class - Entire System

TARIFF CLASS	SERVICE VOLTAGE	FY91/H1 SALES GWH	URRENT YIELD LE/KWH	CAPACITY COST/MONTH---- GEN LE/KW	ETWORK LE/KW	APACITY LE/KW	ENERGY COST LE/KWH	STRICT LRMC LE/KWH
VHV INDUSTRY								
KIMA CO.	VHV	824	0.0170	10.43	4.45	14.88	0.0782	0.1008
ALUMINUM CO.	VHV	1485	0.0460	10.01	4.28	14.29	0.0779	0.0996
ASSUIT CEM (1)	VHV	86	0.0632	9.91	4.23	14.14	0.0779	0.0994
ASSUIT CEM (2)	VHV	59	0.0632	9.91	4.23	14.14	0.0779	0.0994
FERROSILICON	VHV	153	0.0577	9.91	4.23	14.14	0.0779	0.0994
SOMED CO.	VHV	162	0.0632	9.91	4.23	14.14	0.0779	0.0994
DEKHILA FERRO	VHV	449	0.0632	9.91	4.23	14.14	0.0779	0.0994
AMERIA SPIN	VHV	53	0.0632	9.91	4.23	14.14	0.0779	0.0994
HV INDUSTRY/AGRI	HV	1218	0.0807	10.51	10.82	21.33	0.0819	0.1236
MV INDUSTRY/AGR	MV	126	0.1355	11.32	18.74	30.07	0.0879	0.1565
HOUSING COS.	HV	350	0.0600	10.51	10.82	21.33	0.0838	0.1228
MV MOVING POWE	MV	3891	0.1416	11.32	18.74	30.07	0.0879	0.1565
LV MOVING POWE	LV	833	0.0979	12.75	28.12	40.87	0.0985	0.2003
LV OTHER PURPOS	LV	734	0.1353	12.75	28.12	40.87	0.0985	0.2003
MV FREE ZONE	MV	6	0.1264	11.32	18.74	30.07	0.0879	0.1565
LV FREE ZONE	LV	6	0.1843	12.75	28.12	40.87	0.0985	0.2003
RESIDENTIAL	LV	5602	0.0421	12.75	28.12	40.87	0.1007	0.2126
COMMERCIAL	LV	885	0.1083	12.75	28.12	40.87	0.1007	0.2251
GOVT LIGHTING	LV	286	0.1855	12.75	28.12	40.87	0.0941	0.2185
STREET LIGHTING	LV	589	0.1855	13.42	29.60	43.02	0.0993	0.2172
SYSTEM AVERAGE		17797	0.0846	11.76	20.15	31.91	0.0916	0.1711
Equivalent LE/KWH				0.0293	0.0502	0.0795	0.0916	0.1711
% of System Average				17%	29%		54%	100%

The strict LRMC values by tariff class shown in Exhibits 5-16 through 5-18 establish an economic benchmark for the purpose of evaluating the extent of distortions in the present tariffs. In the case of EEA, the system average[10] LRMC is .1207 LE/kWh in comparison with the post May 1, 1991 estimated average tariff yield of .0608 LE/kWh. For the distribution companies, the system average LRMC is .1934 LE/kWh in comparison with an average tariff yield of .0947 LE/kWh. For the entire UPS, the system-wide average LRMC is .1711 LE/kWh in comparison with an average tariff yield of .0846 LE/kWh.

Strict LRMC is a pure economic cost and as such does not represent what must be collected from electricity customers. Rather, tariffs must collect the financial revenue requirement (see Chapter 6), which is generally less than the strict long-run marginal cost.

5.3 SENSITIVITY ANALYSIS

It is useful to test the sensitivity of results to key input variables. This exercise helps to identify those assumptions with a significant impact on final LRMC calculations.

We have analyzed the sensitivity of the UPS system-wide average LRMC tariff to changes in (1) the price of gas/mazout, (2) the discount rate, (3) the LE/US$ exchange rate, and (4) the planning reserve margin. The following ranges of values were considered:

Variable	Sensitivity Range
Gas/Mazout Price	$1.00 - $3.00/MMBtu
Discount Rate	6% to 12%
Foreign Exchange Rate	3.00 - 3.75 LE/US$
Planning Reserve Margin	15% to 25%

Exhibit 5-19 graphs the impact of these alternative values on average LRMC. The UPS average LRMC is most sensitive to gas price. As gas price rises from $1.00 to $3.00 per MMBtu, the LRMC increases from 13 to 22 piasters/kWh.

To a lesser extent, the system-wide LRMC is sensitive to changes in the discount rate and the foreign exchange rate. As the discount rate is varied between 6 percent and 12 percent, the average LRMC increases from 15 to 18 poasters/kWh. Similarly, as the exchange rate is changed from 3.00 to 3.75 LE/US$, the system average LRMC gradually increases from 16 to 19 piasters/kWh.

[10] Weighted by billed sales by tariff class recorded for the first half of FY 91 (i.e., July through December 1990).

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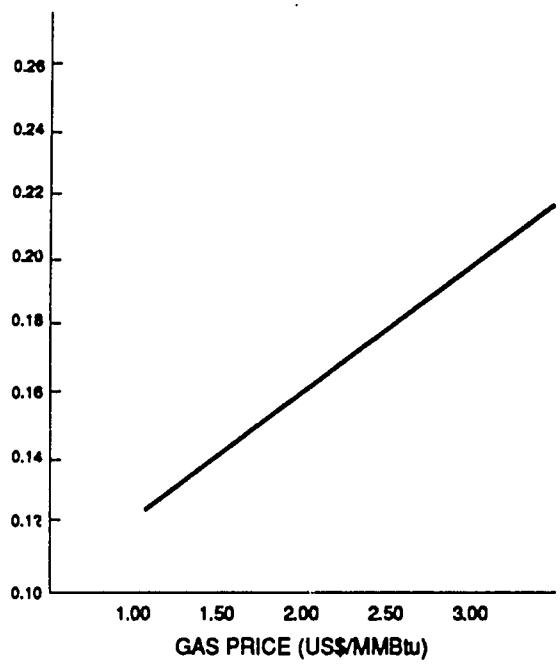
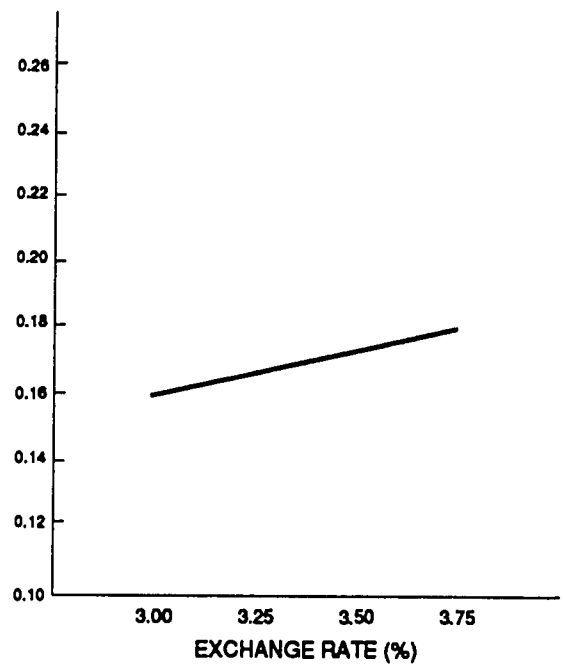
Exhibit 5-19
Long-Run Marginal Cost Sensitivity Analysis

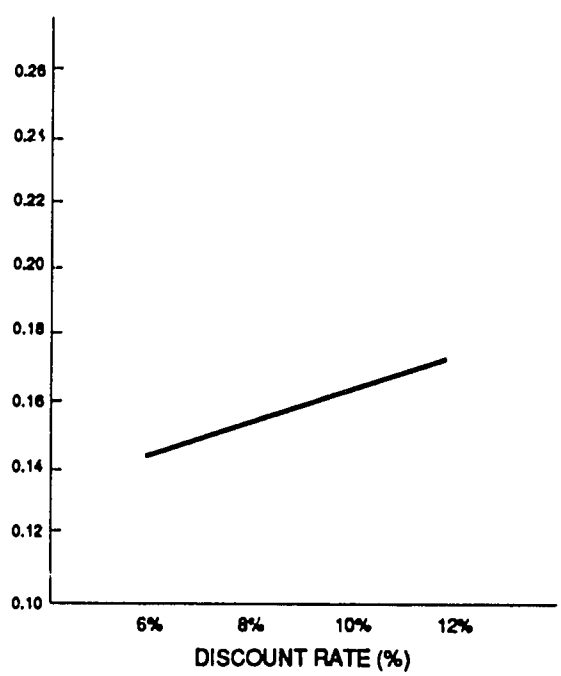
LRMC Sensitivity to Gas Price



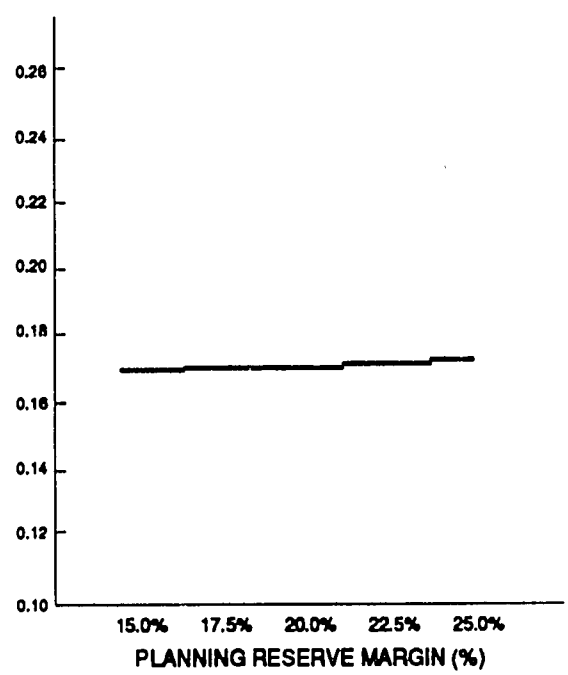
LRMC Sensitivity to Exchange Rate



LRMC Sensitivity to Discount Price



LRMC Sensitivity to Reserve Margin



Surprisingly, LRMC is relatively insensitive to differing reserve margin assumptions. At planning reserve margins in the range of 15 to 25 percent, the system-wide LRMC varies by only a fraction of one piaster per kWh.

We did not calculate the sensitivity of LRMC to changes in projected load growth that might ocur as a result of required electricity tariff increases. There are two major reasons not to do so: (1) no reliable Egypt-specific price electricity data are available from which to estimate demand response, and (2) any demand response will require a revised investment in order to calculate the LRAIC of network capcity.

From the point of view of immediate tariff planning, we believe that it would be important to consider alternate tariff structures until the precise level and phase-in of any demand response has been clearly demonstrated, i.e., ex-post following an observed reduction in system load growth. For the present, tariff planning should continue based on the Medium EEA load forecast.

5.4 MARGINAL COSTS FOR THE ISOLATED SYSTEM

The isolated (non-UPS) power system is small in comparison to the national grid; as noted in Chapter 2 and its appendices, isolated system sales account for less than 1 percent of national electricity consumption. Not surprisingly, marginal costs of capacity and energy for isolated consumption differ significantly from those reported for the UPS in Section 5.2.

We applied the LRMC model to the isolated system in order to quantify these differences. For this model run, all macroeconomic assumptions remain unchanged from the UPS case. Loss coefficients are assumed to be 4.5 percent for station use, and 4.5 percent (7.7 percent on peak) at LV. All consumption is assumed to be at low voltage.

Marginal generation capacity is estimated as the annuitized cost per kW of a diesel unit. These units are priced at US $1200 per kW based on recent EEA experience. Similarly, the capacity cost of LV distribution is estimated at LE 925 per kW installed. Marginal energy costs are estimated as the running cost of this same diesel unit fueled by sollar. (Appropriate fuel prices are discussed in Chapter 3 and its appendices.)

Major assumptions and resulting marginal costs are summarized in Exhibits 5-20 and 5-21. Total marginal capacity cost is estimated at LE 78.5 per coincident kW per month, approximately 80 percent higher than the marginal cost of capacity on the UPS grid. Marginal energy delivered to LV customers on the isolated system costs LE 0.158 on peak

Exhibit 5-20
Marginal Capacity Costs for the Isolated System

ASSUMPTIONS	-GENERATION- PEAKER METHOD	-T&D- LV
Marginal Plant	DIESEL	-
Life (years)	20	25
O&M and A&G (% of capital cost)	3.00%	2.5%
T&D Construction Lag (years)	-	1
Year Generation Required	1991	-
Capital Cost:		
Foreign (LE/KW)	495.0	555.0
Local Materials	3465.0	370.0
Local Labor	0.0	-

GENERATION:	PEAKER METHOD
CAPITAL COST (LE/KW) (adjusted to local prices and for reserve margin and station losses at peak)	5008.65
CAPITAL COST PER YEAR (LE/KW/YR)	588.31
O&M COST PER YEAR (LE/KW/YR)	150.26
TOTAL CAPITAL COST PER YEAR (LE/KW/YR)	738.57
CAPACITY COST PER MONTH	61.55

TRANSMISSION & DISTRIBUTION:	LV
CAPITAL COST (LE/KW) (adjusted to local prices)	1049.20
CAPITAL COST PER YEAR (LE/KW/YR)	115.59
O&M COST PER YEAR (LE/KW/YR)	26.23
TOTAL CAPITAL COST PER YEAR (LE/KW/YR)	141.82
CAPACITY COST PER MONTH	11.82

MARGINAL CAPACITY COST AT LV (LE/COINCIDENT KW/MONTH):

-GENERATION- PEAKER METHOD	-T&D-	TOTAL MARGINAL CAPACITY COST
66.72	11.82	78.53

Exhibit 5-21
Marginal Energy Cost for the Isolated System

ASSUMPTIONS	PEAK	OFF-PEAK
Marginal Plant	DIESEL	DIESEL
Heat Rate (BTU/kWh)	9200	9200
Fuel Used	SOLLAR	SOLLAR
Fuel Cost (US$/unit)	4.36	4.36
Heat Content (MMBtu/unit)	1.00	1.00
Variable O&M ($/MMBtu)	0.004	0.004

FUEL COSTS	$/MMBtu	$/Tonne	LE/Tonne
Coal	1.80	48.60	160.38
Gas/Mazout	1.97	81.74	269.75
Sollar	4.36	189.49	625.30

MARGINAL ENERGY COST (LE/KWH): 1/

	PEAK	OFF-PEAK
GEN	0.1460	0.1460
(adjusted to local prices and for station losses)		
LV	0.1583	0.1529

1/ Energy Costs derived directly from basic assumptions regarding marginal plant, heat rate, fuel cost, fuel heat content, and variable O&M.

and LE 0.153 off peak. These marginal energy costs exceed the UPS estimates by 20 percent on peak and 75 percent off peak.

5.5 IMPACT OF POTENTIAL INTERCONNECTION

In recent years, EEA has evaluated the feasibility of an interconnection of the UPS system with Jordan. The impact of an interconnection on the grid LRMC methodology will depend upon the manner in which the interconnection is eventually used. If it is operated largely as a provider of emergency reliability support, then there is no change in methodology required, especially since at this stage, it is only prudent to assume that such support will be available on a non-firm (i.e., as available) basis.

If the interconnection is used largely for medium to longer-term power purchases and if such purchases are substantial, then they may change the EEA plant at the margin in certain hours of the day. This may have an impact on the marginal energy costs. This impact can be analyzed by conducting a production simulation which models the power purchases appropriately characterized.

If the interconnection is used largely for short-term, non-firm purchases (e.g., economy interchange), then there will be no impact on the long-run marginal energy costs since such short-term, non-firm transactions do not enter into a long-term equilibrium-type situation assumed for the LRMC analysis.

In short, unless the interconnection is substantial compared to the UPS system size and unless large-scale power transactions are undertaken on a firm and long-term basis, its impact on the marginal cost calculation is unimportant.

Finally, as regards the methodological principles underlying the development of a power purchase tariff via an interconnection, the marginal cost structure should provide a basis for determining EEA's maximum willingness to pay. This will vary depending upon the specific nature of the power purchase. In all cases, however, and as a general principle, the transaction price will be somewhere between the seller's cost of generation and EEA's "avoided cost," i.e., the cost that EEA would have to incur absent the purchase under consideration. The final contract price within this range is an outcome of negotiation and cannot be determined by a formula. However, EEA's avoided cost can be determined using a framework tied to the concept of marginal costs.

For short-term non-firm power purchases, EEA's avoided cost is simply the incremental fuel and variable cost of the most expensive units on the margin during the hours of the

transactions. A commonly used approach to set a transaction price under such circumstances would be "split-the-savings." Under this scheme, the purchase price is the mid-point of EEA's short-run incremental energy cost and the seller's incremental energy cost.

For medium and longer-term firm power transactions, capacity-related payments would be required by the seller. For smaller purchases, the maximum payment would be EEA's long-run marginal capacity cost; and the energy price pegged to, but not exceeding, the short-run incremental fuel and O&M costs by time-of-day.

For firm power transactions involving a substantial block of power (at least 100 MW), it is recommended that the incremental revenue requirements method (described earlier in this chapter) be used to compute the avoided cost.

CHAPTER 6: FINANCIAL ANALYSIS

The objective of the financial analysis was to determine the total revenue requirements (LE) and average revenue requirements that will generate sufficient revenues to enable EEA and the distribution companies to function as independent and viable commercial operations and hence, enable them to provide adequate, economic, and reliable electricity service.

Prudent financial practice requires that a well-managed utility meet certain financial objectives that are aimed at ensuring adequate revenues to not only cover their operating costs -- fuel, administrative, salaries, O&M, etc. -- and debt service and obligations, but also to enable the utility to self-finance a substantial portion of the local costs of the investment program from internal cash generation. When all these costs are provided for in the tariff, then all consumption at these tariff levels meets the desired criterion that customers are willing to pay for such service; in other words, the perceived benefit of consuming electricity is equal to or exceeds its costs to the consumers.

This chapter describes our efforts to date in this task. Specifically, it describes the financial planning model -- logic, data inputs, and outputs -- developed for this study (Section 6.1). This is followed in Section 6.2 with a review of EEA's historical financial performance. Section 6.3 presents financial projections and describes the analysis undertaken to compute the revenue requirements.

6.1 INTRODUCTION AND OVERVIEW OF THE FINANCIAL PLANNING MODEL

Model Purpose

A major component in the development of an appropriate tariff structure for Egypt's electricity sector has been the setting-up of computerized financial planning models for EEA and EDA (on a consolidated basis). The purpose of these models is to facilitate the identification of the EEA revenue requirement and average tariff designed to enable EEA to meet its financial covenants under various assumed conditions. In turn, once the average financially-required EEA tariff has been determined, a tariff structure designed to distribute this tariff over the customer service classes can be derived according to the principles of long-run marginal cost. In the final step, the tariff recommended for EEA sales to EDA is then inserted into a separate model for EDA, and the tariff required to meet EDA's financial objectives can be determined under various forecast conditions.

Other Uses of the Model

While the immediate purpose of the EEA and EDA models is to facilitate the rapid identification of the required tariff to meet the financial criteria -- specifically the self-financing ratio for EEA covenanted in the most recent World Bank loan agreement -- the model can be adapted for other applications and uses. These are discussed in the descriptive manual accompanying this report.

Input Data

The model, as configured for the tariff study, requires data to be input in six broad areas:

Historic Financial Data

- These include EEA's historical information for the last four years, which is input to the income statement, balance sheet, and sources and uses statement that are in the format established by EEA for reporting to the World Bank.

- Forecast amortization and interest for existing or committed loans is input to the loan amortization schedule.

- The "existing" and committed approved capital expenditure program is input to the capital expenditure forecast schedule; related physical plant capacity additions are input to the "load dispatch" module.

- "New" capital expenditures derived from the WASP model are input to the capital expenditure forecast schedule.

- Forecast net energy sales and peak demand are input to the energy sales forecast schedule.

- Forecast assumptions are input to the assumptions schedule. These are designed to be more readily varied than the other inputs. They include forecasts with respect to foreign and local inflation, foreign exchange rates, fuel prices, station losses, system losses, average interest rate on new foreign loans, average interest rate on new local loans, average depreciation rate, and days' sales in accounts receivable.

Of particular note is that the model is designed to run in either an "inflationary" or "non-inflationary" mode. Thus, although the forecast financial tariff requirement must include provision for forecast inflation, it is nevertheless possible to isolate the effect of forecast future inflation.

With all other data input, the average EEA tariff is entered manually on a trial-and-error basis until the particular desired financial objective -- the specified self-financing ratio for each year -- is achieved when the model is run.

Detailed instructions and data input schedules are discussed in the descriptive manual.

Output Data

The principal output of the model consists of four schedules (plus the statement of assumptions):

- Income Statement
- Balance Sheet
- Statement of Sources and Uses of Funds
- Trends and Ratios.

In addition to these principal schedules, one can print out:

- a suite of capital expenditure and loan schedules, or
- a full set of principal schedules and supporting schedules (approximately 20 pages).

The model generates ratios for the historical input data, which are displayed in the output schedule and/or in the assumptions schedule. This facilitates both the financial analysis of past performance as well as the identification of trends that bear on future assumptions (e.g., depreciation rates, system losses, days' sales in accounts receivable).

The critical forecast output is contained in the schedule of Trends and Ratios -- organized by sales ratios, operating ratios, cash flow ratios, and balance sheet ratios.

In particular, the average tariff versus the resulting self-financing ratio (using the World Bank definition) and an alternative self-financing ratio (using an alternative, commonly accepted definition, the "RCG" definition) is shown. The self-financing ratio, as defined in the World Bank covenant, is described in detail in Appendix J. The alternative "RCG"

definition is also disucssed, together with the reasons for its adoption. Essentially, the self-financing ratio (SFR) is the ratio of net cash flows from operating (after paying for debt interest and amortization) to the three-year (last, current, and next year) average capital expenditure. The difference between the two definitions is that the more conservative World Bank definition also requires the provision of changes in working capital.

6.2 HISTORIC PERFORMANCE

This section draws on the information contained in the historical section of the model to analyze EEA's recent historical financial performance. The historical data were provided by EEA's Finance Department or obtained from EEA's published reports.

The examples of reports that are shown in the financial planning model are based on the Base Case identified as "EEA-Y210," which contains the following with respect to fuel price and targets with respect to the self-financing ratio:

- EEA fuel price is projected to reach full parity with the forecast international price by 1996, following a compounding trajectory between 1992 and 1996. This is in accordance with EEA's proposal.

- Tariffs have been set to achieve the covenanted self-financing ratio (SFR) of 30 percent in 1993 and 35 percent in subsequent years (but using the "RCG" definition). In 1992, an SFR of -39.2 percent is achieved versus the required 20 percent because the tariffs for 1992 have already been proposed for introduction by EEA in May and June 1991.

Operating Income and Cash Flow (Exhibits 6-1 and 6-2)

Over the period 1987 to 1990, the net energy sales of EEA have grown from 31,212 GWh to 37,429 GWh -- which is an average compound annual growth rate of approximately 6.3 percent. In the same period, revenues from the sale of electricity have grown from LE 513.2 million to LE 1142.9 million -- or by a compound average annual increase of 30.4 percent. The significant growth in sales revenues relative to energy sales results from an increase in the average tariff from 16.4 mills/kWh in 1987 to 30.5 mills/kWh in 1990. (The tariff was increased to its present average level of 59.5 mils/kWh in May 1991.) The average tariff was thus raised by approximately 23 percent per year over this period. (It should be noted that for the full 12 months of FY 1991, the average tariff will amount to

Exhibit 6-1
Egyptian Electricity Authority
Historical Income Statement
(Millions of L.E)

	Year end June 30	1987	1988	1989	1990
		----------Actual----------			
1					
2	Gross Generation (Gwh)	35202	37847	39583	41649
3	Net Energy Sent Out (Gwh)	33794	36216	37790	39950
4	Net Energy Sold (Gwh)	31212	33420	35084	37429
5	Average Tariff (Millimes/Kwh)	16.4	22.0	24.0	30.5
6					
7					
8	OPERATING REVENUE				
9	Sales of Electricity	513.2	734.9	840.4	1142.9
10	Other Operating Revenue	0.2	0.4	0.9	0.9
11		---	---	---	---
12	TOTAL OPERATING REVENUE	513.5	735.3	841.3	1143.8
13		---	---	---	---
14	OPERATING EXPENSES				
15	Fuel	147.5	256.1	265.9	330.8
16					
17	Purchases from Sales		0.7	0.4	1.6
18					
19	Salaries & Wages (Operation only)	48.3	58.1	69.5	82.3
20					
21	Materials & Services Input	80.6	62.1	112.0	138.2
22					
23	Other Operating Expenses (Admin)	38.2	42.7	52.1	60.9
24					
25	Depreciation -- Historical	152.8	133.1	180.3	243.2
26					
27		---	---	---	---
28	TOTAL OPERATING EXPENSES	467.3	552.8	680.3	957.0
29		---	---	---	---
30					
31	INCOME FROM OPERATIONS	46.2	182.5	161.1	286.8
32					
33	Gross Interest	148.7	247.1	284.3	432.1
34	Interest During Construction	34.5	76.0	116.3	168.9
35		---	---	---	---
36	KEY INTEREST EXPENSE	114.2	171.1	168.1	263.2
37		---	---	---	---
38					
39	NET OPERATING INCOME	-68.0	11.5	-7.0	23.6
40					
41	Non-Operating Income	103.1	51.0	82.4	88.4
42	Less: Non-Operating Expenses	22.0	49.1	51.4	87.9
43		---	---	---	---
44	Net Non-Operating Income (Loss)	81.1	2.0	31.0	0.5
45		---	---	---	---
46	NET INCOME (LOSS)	13.0	13.4	24.0	24.1
		======	======	======	======

Exhibit 6-2
Egyptian Electricity Authority
Historical Balance Sheet
(Millions of L.E)

	Year end June 30	Actual 1987	1988	1989	1990
1	ASSETS				
2	FIXED ASSETS				
3	Gross Fixed Assets in Service	3082.0	4090.2	4896.0	6928.4
4	Less - Accumulated Depreciation	629.8	746.6	924.9	1165.6
5					
6	Net Fixed Assets in Service	2452.2	3343.6	3971.1	5762.8
7	Capital Work-in-Progress	1054.7	1661.0	2537.0	2468.9
8					
9	TOTAL NET FIXED ASSETS	3506.9	5004.6	6508.1	8231.6
10					
11	RESERVE FOR FOREIGN DEBT		1544.0	1544.0	1544.0
12					
13	INVESTMENTS	53.5	56.5	56.5	56.5
14					
15	LONG TERM RECEIVABLES	36.1	105.7	131.4	173.0
16					
17	CURRENT ASSETS				
18	Cash	165.9	139.3	134.5	192.5
19	Inventories	197.0	242.1	344.0	433.6
20	Customer Accts. Receivable	191.5	305.0	387.9	524.3
21	Other Accounts Receivable	210.1	204.4	253.0	260.3
22					
23	TOTAL CURRENT ASSETS	764.4	890.9	1119.5	1410.7
24					
25	TOTAL ASSETS	4361.0	7601.8	9359.4	11415.9
26					

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Exhibit 6-2 (continued)
Egyptian Electricity Authority
Historical Balance Sheet
(Millions of L.E)

	Year end June 30	Actual 1987	1988	1989	1990
27					
28	LIABILITIES AND EQUITY				
29	EQUITY				
30	Capital	651.0	651.0	651.0	1570.0
31	Reserves	401.7	409.7	425.8	464.6
32	Foreign Grants for Fixed Assets				
33	Other Provisions	4.0	3.3	5.4	5.5
34	Retained Earnings - prior years	35.7	48.7	62.1	86.1
35	Profit (Loss) - current year	13.1	13.4	23.9	24.1
36					
37	TOTAL EQUITY	1105.4	1126.1	1168.3	2150.3
38					
39	LONG-TERM DEBT				
40	Foreign Long-Term Debt	1428.4	3277.4	3739.2	4839.7
41	Local Long-Term Debt	1103.6	1489.4	1922.4	1600.1
42					
43	TOTAL LONG-TERM DEBT	2532.0	4766.9	5661.6	6439.9
44					
45	CURRENT LIABILITIES				
46	Foreign Debt due within one year	145.6	329.3	423.2	655.0
47	Local Debt duo within one year	28.0	52.1	64.5	90.8
48	Accounts Payable - Suppliers	18.1	23.6	22.3	33.5
49	Ministry of Finance	339.9	590.1	870.0	1189.8
50	Other Accounts Payable	147.8	604.3	996.0	739.7
51	Deferred Liabilities	22.8	79.7	106.6	76.3
52	Deposits	20.8	25.2	41.2	34.8
53	Provision for Taxes	0.0	0.0	2.1	2.1
54	Overdraft/Cash Requirement	0.6	4.5	3.6	3.7
55					
56	TOTAL CURRENT LIABILITIES	723.6	1708.8	2529.5	2825.7
57					
58	TOTAL LIABILITIES	4361.0	7601.8	9359.4	11415.9

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a weighted average of 43.1 mills as tariffs were raised on May 1, 1991.)

Within the average annual tariff increase of 23 percent, there has been some relative movement between the tariffs to various customer classes. Relatively greater tariff increases have been borne by the Ultra High Voltage industrial customers, whose average tariff increased from 10.0 mills/kWh in 1986/87 to 20.9 mills/kWh in 1989/90, or by 27.8 percent per year. The average tariff to Middle Voltage industrial customers was 57.3 mills/kWh in 1989/90, which continues to significantly exceed the average system tariff. However, by far the major influence on revenues is the sale of electricity to the distribution companies, which accounts for approximately 75 percent of energy sales and 80 percent of revenues received by EEA.

Although the significant tariff increases were sufficient to ensure that the 1987 operating loss (amounting to LE 68 million) did not recur, even this level of tariff increase has not been sufficient to generate an adequate cash flow from operations for EEA. This is because during this period, local inflation has been running at 15-20 percent per annum, thus reducing the tariff increases to 3-5 percent per year in real terms.

All categories of expense have increased. Salaries, wages, and other operating costs have increased at rates roughly in line with local inflation.

Fuel costs have been increasing at roughly the same overall rate as EEA tariffs (with fuel cost at 28.7 percent of revenues in 1987 and 28.9 percent of revenues in 1990; see Exhibit 6-4), and net interest expense has risen from LE 114.2 million in 1987 to LE 263.2 million in 1990. The increases in fuel costs and in interest expense reflect the change in the exchange rate for the Egyptian pound from LE 1.35 equals US $1.00 in 1987 to LE 2.75 equals US $1.00 at the 1990 fiscal year end.

Thus, even though tariffs have increased in real terms, the increase has not been at a high enough level (net of inflation) to either make significant progress towards the real increase agreed to be implemented by 1995/96, or to significantly improve EEA's real financial position.

Of particular concern is that EEA has consistently failed to generate sufficient cash flow from its operations, even to service the interest and principal repayments on its debt (compare Total Internal Cash Generation [Exhibit 6-3, Line 7] with Total Net Debt Service [Exhibit 6-3, Line 30].) Its debt service ratio deteriorated to 0.51 (in 1989) and 0.63 (in 1987) -- see Exhibit 6-4, Line 23. Because of the continuing change in the exchange rate, this performance indicator is likely to deteriorate further in the current year to

Exhibit 6-3
EGYPTIAN ELECTRICITY AUTHORITY
PROJECTED SOURCES AND USES OF FUNDS
(Millions of L.E)

	Year end June 30	1987	1988	1989	1990	Est. 1991
		----------Actual----------				
1	SOURCES OF FUNDS					
2						
3	INTERNAL CASH GENERATION					
4	Gross Income before Interest	127.2	184.5	192.0	287.3	603.1
5	Depreciation	148.6	116.8	178.3	240.7	253.3
6		---	---	---	---	---
7	TOTAL INTERNAL CASH GENERATION	275.9	301.3	370.3	528.0	856.3
8		---	---	---	---	---
9	EXTERNAL SOURCES					
10	Increase in Equity Capital	0.0	0.0	0.0	919.0	-527.7
11	Change in Reserves & Provisions	129.8	7.3	18.2	38.9	2.5
12	Foreign Grants					242.9
13						
14	New Long Term Debt -- Foreign	238.6	2163.3	887.6	1692.6	1376.6
15	New Long Term Debt -- Local	267.6	420.4	495.2	-167.6	0.0
16		---	---	---	---	---
17	Total New Long Term Debt	506.2	2583.7	1382.8	1524.9	1376.6
18		---	---	---	---	---
19	TOTAL SOURCES OF FUNDS	911.9	2892.3	1771.4	3010.8	1950.6
20						
21	APPLICATIONS OF FUNDS					
22						
23	CAPITAL EXPENDITURES (incl. IDC)	498.2	3158.5	1681.7	1964.3	2295.1
24						
25	DEBT SERVICE					
26	Foreign Debt Repayment	121.3	130.7	331.9	360.3	655.0
27	Local Debt Repayment	44.6	10.4	49.8	128.3	90.8
28	Interest (Net of IDC)	114.2	171.1	168.1	263.2	472.5
29		---	---	---	---	---
30	TOTAL NET DEBT SERVICE	280.1	312.2	549.8	751.7	1218.3
31		---	---	---	---	---
32	INCREASE IN INVESTMENTS	0.0	3.0	0.0	0.0	0.0
33						
34	INCREASE IN LONG TERM RECEIVABLE	-3.0	69.6	25.7	41.6	3.9
35						
36	NET INCREASE IN WORKING CAPITAL	121.7	-620.6	-481.9	195.2	56.8
37	(Excluding Cash, Overdraft, LTD)					
38		---	---	---	---	---
39	TOTAL APPLICATIONS OF FUNDS	897.0	2922.7	1775.4	2952.9	3574.1
40						
41	NET CHANGE IN CASH	14.8	-30.4	-4.0	58.0	-1623.4
42		---	---	---	---	---
43	OPENING CASH	150.5	165.3	134.9	130.9	188.8
44						
45	CLOSING CASH	165.3	134.9	130.9	188.8	-1434.7
		======	======	======	======	======

approximately 0.31. The World Bank Fourth Power Loan has a covenant requiring that EEA achieve a value of 1.5 for this ratio.

A related performance indicator is the self-financing ratio, which is a measure of the contribution to a utility's capital expenditure program that can be provided from operating cash flow (after making provision for debt service). This ratio is usually expected to be in the 30-40 percent range for a financially healthy and expanding utility. The World Bank loan covenants call for EEA to achieve 20 percent in 1992, 30 percent in 1993, and 35 percent in 1994 and thereafter. In 1988, 1989, and 1990 for EEA, this figure was negative (using a definition of this ratio that excludes changes in working capital) -- see Exhibit 6-4, Line 24.

Balance Sheet and Financial Structure (Exhibits 6-2 and 6-4)

The result of inadequate cash generation from operations has been an increasing reliance on funding from the Government of Egypt. This funding has taken two forms:

- A subsidy to prevent EEA from incurring actual losses in its Profit and Loss account, which is included as revenue in "Non-Operating Income" (Exhibit 6-1, Line 41).

- An increasing reliance on short-term advances (included under Current Liabilities on the Balance Sheet) from the Ministry of Finance. These short-term advances have increased from LE 339.9 million at the 1987 year end to LE 1189.9 million at June 30, 1990 (Exhibit 6-2, Line 49).

  In addition, long-term borrowing from the National Investment Bank has increased from LE 1103.6 million to LE 1600.1 million over the 1987-90 period (Exhibit 6-2, Line 41).

The changes in the exchange rate have resulted in a significant increase in foreign indebtedness (both long-term and due-within-one-year) when expressed in Egyptian currency. Additionally, the commissioning of major plants with the expiration of grace periods on related loans has also contributed to the significant increase in foreign indebtedness due-within-one-year (Schedule 2, Line 46).

"Other Accounts Payable" have also grown, reflecting the increasing cost of the construction program, from LE 147.8 million in 1987 to LE 739.7 million in 1990.

Exhibit 6-4
EGYPTIAN ELECTRICITY AUTHORITY

Trends and Ratios

	Year end June 30	1987	1988	1989	1990	Est. 1991
		----------Actual----------				
1	Exchange Rate -- L.E./US$	1.350	2.310	2.599	2.750	3.100
2						
3	SALES RATIOS					
4						
5	Energy Sales (GWh)-Annual Growth - %		7.07%	4.98%	6.68%	6.51%
6	Sales Revenue (EL)-Annual Growth - %		43.19%	14.36%	35.99%	50.21%
7						
8	Average Tariff -- EL mills/kWh	16.4	22.0	24.0	30.5	43.1
9						
10	OPERATING RATIOS					
11						
12	Fuel Cost to Sales - %	28.7%	34.8%	31.6%	28.9%	32.2%
13	Operating Income to Sales - %	9.0%	24.8%	19.2%	25.1%	17.9%
14	Operating Income to Gross Assets					
15	in Service (Average) - %					
16	- historical	2.5%	4.3%	3.0%	4.1%	6.7%
17	Net Income to Equity - %					
18	- historical	2.3%	1.2%	2.1%	1.5%	6.5%
19						
20	CASH FLOW RATIOS					
21						
22	Self-Financing Ratio (WB) - %	0.0%	35.2%	13.4%	-20.5%	-12.1%
23	Debt Service Ratio (WB)	0.63%	0.81%	0.51%	0.58%	0.31%
24	Self-Financing Ratio (RCG) - %		0.3%	-7.8%	-10.9%	-10.2%
25						
26	BALANCE SHEET RATIOS					
27						
28	Current Ratio	1.1	0.5	0.4	0.5	0.4
29	Cash at Bank to Sales - months	3.9	2.3	1.9	2.0	-11.8
30	Accts. Receivable to Sales - days	136	151	168	167	160
31	Debt to Equity Ratio - %					
32	- historical	244.8%	457.2%	526.4%	334.2%	395.7%

In summary, for the reasons outlined above -- namely, reliance on short-term advances from the Ministry of Finance, increased long-term debt due-within-one-year, and increased other accounts payable -- the current liabilities have increased much faster than activity levels (represented by sales) and much faster than current assets.

Total current liabilities have increased by 290.5 percent from LE 723.6 million at June 30, 1989 to LE 2825.7 million at year-end 1990. On the other hand, current assets have grown from only LE 764.4 million to LE 1410.7 million (i.e., by 84.5 percent) over the same period. Thus, there has been a significant deterioration in the current ratio (current assets to current liabilities), which has fallen from 1.1 in 1987 to 0.5 as of June 30, 1990 (Exhibit 6-4, Line 28).

The lack of adequate profitability has meant that virtually the only increase in EEA's equity capital base in the last three years was due to an increase in EEA's paid-in capital, from LE 651.0 million to LE 1570.0 million in 1990. Thus, in total, equity increased from LE 1105.4 million in 1987 to LE 2150.3 million in 1990. Nevertheless, in conjunction with excessive reliance on borrowing rather than retained earnings, the debt-to-equity ratio deteriorated from 244.8 percent to 334.2 percent in this period.

Overall Ratios and Performance (Exhibit 6-4)

Reference to "Trends and Ratios" (Exhibit 6-4) as well as the foregoing analysis, confirms the following:

- There is an immediate requirement for the refinancing of EEA by means of converting approximately LE 1200 million of short-term indebtedness to the Ministry of Finance into equity capital.

  The result of this measure, if implemented, would be to improve the current ratio to approximately 1.6, and the debt-to-equity ratio to approximately 200 percent.

- However, the fundamental problem is one of grossly inadequate cash flow and profitability from operations.

  This is shown in the ratio of operating income to gross assets in service (at historical book value), which has averaged approximately 3.5 percent per year over the last four years. Depending on local inflation and past growth

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patterns with respect to assets in service, this ratio should be expected to be in the 15-30 percent range.

As mentioned previously, with a debt service ratio of less than 1.0 (0.58 in 1990), cash flow from operations is inadequate to service EEA's debt and EEA is, in effect, required to borrow to service its existing debt.

- A substantial tariff increase in real terms has already been identified by the African Development Bank and World Bank as the fundamental measure required to improve the rate of return, debt service and self-financing ratios.

  However, it will also be necessary to implement measures to ensure that EEA actually benefits by collecting the increased billings that would result from such a tariff increase.

  There is concern that the number of days' sales in accounts receivable (Exhibit 6-4, Line 30) has increased from 136 days in 1987 to 167 days in 1990, reversing the trend of the early 1980s, which saw a drop to less than 90 days in 1984 from 180 days in 1980.

6.3 FINANCIAL PROJECTIONS AND REVENUE REQUIREMENTS

The purpose underlying the development of financial projections for EEA and EDA is to determine the average tariff for EEA and EDA, respectively, which will enable them to meet selected financial criteria or financial objectives, given various assumptions with respect to future operations.

In most utilities (because the installed capacity base was purchased at lower prices, was installed at more efficient locations, or has been substantially paid for), the tariff required for financial purposes will be lower than the tariff based on strict long-run marginal cost.

Key Criteria

The financial projection was designed to determine the tariffs required for EEA to meet the following objectives:

- Purchase prices for mazout and for natural gas to increase progressively until they reach projected international prices in 1996. Thus, the forecast is

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based on the price of mazout increasing (in 1991 prices) from LE 50 per tonne (or about 25 percent of international prices) in early 1991 to LE 298.5 per tonne (or 100 percent of projected international prices converted at an exchange rate of LR 3.30 = US$1) in 1996. The price for gas purchased by EEA is set to increase from LE 60 per tonne in early 1991 to LE 298.5 per tonne in 1996. (Note: mazout price had increased to LE 80 per ton, and gas price had increased to LE 98 per tonne as of May 1991.)

- In conjunction with the least-cost expansion plan required to meet EEA's projected annual energy sales growth of approximately 6.4 percent per year from 1991 through 1996, a self-financing ratio ranging from 20 percent in 1992 to 35 percent in 1994-1996 is to be met (as specified by the covenants contained in the World Bank Fourth Power Loan agreement).

For EDA, the criterion adopted is that EDA's tariffs be sufficient to both pay the required EEA tariff and to fully fund its capital expenditure program over the period 1992-1996 as a whole.

Overview/Index of Cases

In fact, it became necessary to modify or adapt the criteria given above in the course of the study:

- It became evident during the course of our analysis that the definition of the "self-financing ratio" provided by the World Bank is unstable and would tend to lead to a highly volatile or fluctuating tariff. On the other hand, an alternative, commonly accepted definition of the self-financing ratio (identified, for convenience, as the "RCG" definition) is more useful because it produces a less volatile tariff, although not as conservative a tariff.

  Two cases were developed to demonstrate this point: cases EEA-2WB and EEA-2RC.

Exhibit 6-5 provides an index to the cases. Cases EEA-2WB and EEA-2RC, which have been referred to above, are included in Appendix J, with further commentary. Cases EEA-Y200 and EEA-Y210 are the case at 1991 prices (without inflation) and the Base Case at current or inflated prices, respectively. Further commentary on these cases is given below.

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Exhibit 6-5
Egyptian Electricity System: Index to Cases

File #	Appendix Reference	Case Description	Definition of SFR Covenant	Constant 1991 or Inflated Prices	International Fuel Price Parity?
EEA-2WB EEA-2WBV EDA-2WB EDA-2WBV SYS-2WB SYS-2WBV TAB-2WB	Appendix J	Tariffs required to fully satisfy World Bank covenants commencing in 1992	"World Bank" definition	1991 prices and exchange rates	EEA pays a gradually rising percentage of international prices until 100% parity is achieved in 1996
EEA-2RC EEA-2RCV EDA-2RC EDA-2RCV SYS-2RC SYS-2RCV TAB-2RC	Appendix J	Tariffs required to fully satisfy World Bank covenants commencing in 1992	"RCG" definition	1991 prices and exchange rates	EEA pays a gradually rising percentage of international prices until 100% parity is achieved in 1996
EEA-Y210 EEA-Y210V EDA-Y210 EDA-Y210V SYS-Y210 SYS-Y210V TAB-Y210	Appendix K	Base Case with inflation. Tariffs required to fully satisfy World Bank covenants commencing in 1993	"RCG" definition	Incorporates World Bank forecast of exchange rates and inflation	EEA pays a gradually rising percentage of international prices until 100% parity is achieved in 1996

Note: Files with suffix "V" (e.g., EEA-Y200V) represent files (e.g., EEA-Y200) whose formulas have been converted to values. This is desirable in order to facilitate combining data between files.

Exhibit 6-5
Egyptian Electricity System: Index to Cases (Continued)

File #	Appendix Reference	Case Description	Definition of SFR Covenant	Constant 1991 or Inflated Prices	International Fuel Price Parity?
EEA-Y200 EEA-Y200V EDA-Y200 EDA-Y200V SYS-Y200 SYS-Y200V TAB-Y200	Appendix L	Case without inflation. Tariffs required to fully satisfy World Bank covenants commencing in 1993	"RCG" definition	1991 prices and exchange rates	EEA pays a gradually rising percentage of international prices until 100% parity is achieved in 1996
EEA-Y220 EDA-Y220 SYS-Y220 TAB-Y200	Appedix S	Case with inflation. Tariffs required to fully satisfy World Bank covenants by 1995	"RCG" definition	Incorporates World Bank forecasts of exchange rates and inflation	
EEA-YLR2V EDA-YLR2V	Appendix R	Case with inflation. Revenues set to LRMC-based targets	"RCG" definition	World Bank forecasts of exchange rates and inflation	

Note: Files with suffix "V" (e.g., EEA-Y200V) represent files (e.g., EEA-Y200) whose formulas have been converted to values. This is desirable in order to facilitate combining data between files.

A variation on Case EEA-Y210 was also run, which is labelled as Case EEA-Y220. This case is similar to Case EEA-Y210, except that the self-financing ratio has been "smoothed" to meet the World Bank covenant in 1995, but does not meet it in years 1992, 1993, and 1994 (this is shown in Appendix S).

Base Case (Adjusted for Inflation)

Assumptions

The key financial assumptions for the Base Case (Y210), which is adjusted for inflation, are shown in the input assumptions (see Exhibit 6-6). These assumptions are the same as for the case at 1991 prices (Y200), except that assumptions with respect to exchange rates, foreign inflation and local inflation are built into the model for the Base Case. The sources of these assumptions are the World Bank and EEA's Finance Department. These inflation assumptions affect the fuel cost, operating costs, depreciation expense (which is based on inflated asset values), and the capital expenditure program. The assumptions with respect to exchange rates, and international and Egyptian inflation are given in lines 1, 2, and 3 of the Case EEA-Y210 Input Assumptions Schedule (see Exhibit 6-6).

Station losses are projected to remain in 4.10 percent, which is essentially at the 1990 level.

EEA system losses are projected to continue making a gradual improvement, from 6.31 percent in 1990 to 4.44 percent in 1996, resulting from system reinforcement, location of new generation, etc.

International fuel prices are projected in constant dollars to follow a "saucer"-shaped trajectory, rising more steeply in 1995 and 1996. These prices are derived from the energy price component of this study.

Interest rates used in the forecast are based on EEA's recent experience. The interest rate of 7.0 percent on new foreign loans represents the weighted average interest rate on EEA's recent loans, which are currently being drawn down. The forecast interest rate of 11.25 percent on Egyptian loans is the rate payable on borrowing from the National Investment Bank.

The depreciation expense rate of 3.5 percent per year is based on the average of the composite depreciation expense rate for the years 1988-1990.

Exhibit 6–6
EGYPTIAN ELECTRICITY AUTHORITY
INPUT ASSUMPTIONS – Base Case Y210

	Actual					Est.	Forecast				
	1987	1988	1989	1990	Year end June 30	1991	1992	1993	1994	1995	1996
1	1.350	2.310	2.599	2.750	Exchange Rate -- L.E./US$	3.300	4.310	4.940	5.350	5.560	5.650
2				3.70%	Inflation Rate -- International %	8.70%	6.20%	2.20%	1.70%	2.50%	3.10%
3				15.00%	-- Egyptian %	20.00%	20.00%	15.00%	9.00%	6.00%	5.00%
4			0.8868	0.9200	Inflation Index -- International	1.0000	1.0620	1.0854	1.1038	1.1314	1.1665
5			0.7246	0.8333	Inflation Index -- Egyptian	1.0000	1.2000	1.3800	1.5042	1.5945	1.6742
6	4.00%	4.31%	4.53%	4.08%	Station Losses -- %	4.10%	4.10%	4.10%	4.10%	4.10%	4.10%
7	7.64%	7.72%	7.16%	6.31%	System Losses -- %	6.16%	5.86%	5.33%	5.00%	4.80%	4.44%
8					International Fuel Prices ($/MBTU) --						
9			4.69	4.69	-- Distillate	4.14	3.93	4.18	4.37	4.51	4.71
10			2.43	2.43	-- Residual	1.69	1.56	1.80	2.03	2.09	2.18
11			2.43	2.43	-- Natural Gas	1.69	1.56	1.80	2.03	2.09	2.18
12			1.80	1.80	-- Coal	1.80	1.80	1.80	1.80	1.80	1.80
13					* IF INFLATION IS TO BE PUT INTO *	******	*				
14					* FORECAST, INSERT "1" HERE >>>>>>	1	<<<<<< OTHERWISE, SET AT "0"				
15						******	*				
16					Interest Rate on New FX Loans -%	7.00%	******	******	******	******	******
17					Interest Rate on New EL Loans -%	11.25%	******	******	******	******	******
18	5.0%	3.3%	3.7%	3.5%	Depreciation Expense Rate %	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
19	136	151	168	167	Customer Accts Rec. -- days' sales	160	110	90	90	90	90
20	149	102	110	83	Other Accts Rec. -- days' sales	48	30	20	11	7	6
21	6.4%	5.9%	7.0%	6.3%	Inventories -- % of G F A	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
22					TARGET SELF-FINANCING RATIO % (WB)		20.0%	30.0%	35.0%	35.0%	35.0%
23					EEA Fuel Price as % Int'l Price	26.8%	43.8%	50.0%	63.0%	80.0%	100.0%

The remaining major elements of operating expense for EEA (excluding fuel, depreciation, and interest) are:

- Salaries and Wages (Operations only)
- Materials and Services Inputs
- Other Operating Expenses (Administration).

These are projected as follows:

- *Salaries/Wages (Operations) and Materials/Services Input*

  1. Coefficients were developed by EEA's Commercial Department in October 1990 which analyzed these expenses for each type of generation (by individual plant) and by each level of transformation/ transmission for the three years 1986/87, 1987/88, and 1988/89. These coefficients were then adjusted to 1990 levels (using a 15 percent average annual inflation factor), and an average value for existing plant in service and an incremental value for new plant in service were derived. (The incremental value was based on the most representative new plant, as identified by ECG's power engineer.)

  2. The application of these coefficients to 1990 was checked against the preliminary 1990 results for reasonableness.

  3. The average and incremental coefficients were then applied to the projected generation and transmission capacities by individual type of facility to derive a forecast of each category of expense at 1990 price levels.

- *Other Operating Expenses (Administration*

  These are projected to increase at the same rate of growth as electricity sales (in GWh) based on the sales growth forecast of approximately 6.4 percent per year, being used in December 1990. The 1990 result was derived from the 1989 actual and checked against the 1990 preliminary actual for reasonableness.

Note: the forecasts for operating expenses were made manually outside the model and were then inserted into the manual as input. They therefore do

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not change automatically with changes in sales volume. This is reasonable, however, as they are "fixed" or "semi-fixed" costs.

Customer accounts receivable are based on the requirement of IBRD that EEA reduce customer accounts receivable to 90 days' sales by September 1992.

Other accounts receivable are projected to remain at existing monetary values, thereby resulting in a decline from 83 days in 1990 to 6 days in 1996.

Inventories of spare parts, etc. are projected to be maintained at 5.0 percent of gross fixed assets, which is somewhat lower than historical experience.

The major elements of expense for EDA (excluding purchased electricity, depreciation, and interest) are:

- materials
- services
- wages.

All of these expenses have been forecast to grow in direct proportion to the increase in sales of electricity, based on 1990 results (as provided in December 1990) to give a forecast at 1990 price levels. In the "inflation" model, the forecast is also adjusted for projected inflation.

The capital expenditure forecast includes 10 percent import duty on the foreign cost component, representing the introduction of duty on purchases of parastatals in early 1991.

Results

A summary of the results of the Base Case forecast at inflated or current year prices is found in Exhibit 6-7 (see Appendix K for a printout of the full details of this case). In 1993, based on anticipated Egyptian inflation of 20 percent in 1992 and 15 percent in 1993, together with an anticipated exchange rate of EL 4.94 to U.S. $1,00, an average EEA tariff of 125.5 milliemes/kWh will be required. In total, an average EDA tariff of 197.8 milliemes/kWh to EDA's customers will be required.

Insofar as EEA has proposed an average tariff of 59.5 milliemes/kWh for 1992, the required tariff increase in 1993 will amount to an increase of 110.9 percent. This compares with an increase of 62.2 percent (i.e., from 59.5 milliemes to 96.5 milliemes/kWh) if there

Exhibit 6-7
EGYPTIAN ELECTRICITY SYSTEM

TABULATION OF KEY RESULTS – Base Case Y210

Year end June 30	Est. 1991	Forecast 1992	1993	1994	1995	1996
1 Border Price -- Mazout -- $/Tonne	70.1	64.7	74.7	84.2	86.7	90.5
LE/Tonne	231.4	279.0	369.0	450.6	482.2	511.1
2 Exchange Rate	3.300	4.310	4.940	5.350	5.560	5.650
3 Mazout Transfer Price to EEA						
--LE/Tonne	55.0	83.7	184.5	283.9	385.7	511.1
4 Gas Transfer Price to EEA						
--LE/Tonne	66.0	98.3	184.5	283.9	385.7	511.1
5 Mazout price to EEA as % Mazout Border Price	23.8%	30.0%	50.0%	63.0%	80.0%	100.0%
Gas price to EEA as % Mazout Border Price	28.5%	35.2%	50.0%	63.0%	80.0%	100.0%
6 Target Self-finacing Ratio (WB) - %	0.0%	20.0%	30.0%	35.0%	35.0%	35.0%
7 Self-financing Ratio -- WB Definition	-32.9%	-39.2%	13.6%	21.9%	21.7%	18.0%
-- RCG Definition	-11.0%	-29.6%	30.0%	34.9%	35.3%	35.3%
8 Revenue Requirement for Above Assumptions (Milliemes / kwh)						
-- EEA Requirement	43.1	59.5	125.5	157.0	185.5	222.5
-- EDA Requirement	70.2	91.4	197.8	247.4	292.3	350.6
-- System Requirement	61.6	81.2	179.4	225.1	266.6	320.6
9 % Real Increase Required						
-- EEA		38.2%	110.9%	25.1%	18.2%	19.9%
-- EDA		30.1%	116.4%	25.1%	18.2%	19.9%
-- System		31.9%	120.8%	25.5%	18.4%	20.3%

were no inflation in 1991, 1992 and 1993. In effect, EEA's last tariff adjustment made in June 1990 and the new tariff proposed for May/June 1991 have not made sufficient allowance for the continuing cumulative impact of annual inflation.

Although this case will require an additional cash injection of approximately 8 billion Egyptian pounds by 1996, it produces generally acceptable financial results with a ratio of net income to revalued equity in the 4 percent range, and debt to revalued equity declining to 65 percent by 1996.

Case at Constant (1991) Price Levels

The forecast for EEA at 1991 prices is Case EEA-Y200. In turn, given the relationship between the average EEA tariff and the EEA tariff to EDA (which is derived in the LRMC analysis and inserted in the EEA financial model), the required average EDA tariff to EDA's customers is derived in the EDA model (EDA-Y200) and the overall average system tariff is determined in SYS-200.

Assumptions

The key financial assumptions in the EEA Non-Inflationary Case are shown in the input assumptions (see Exhibit 6-8).

The exchange rate of LE 3.30 to U.S. $1 is the rate as of April 1, 1991. Because this case's forecast is at constant prices, the exchange rate remains unchanged throughout the forecast. (The forecast inflation rates shown in lines 2 and 3 are not used in this case.)

Results

A summary of the results of the Y200 case forecast at constant prices is included in Exhibit 6-9 (see Appendix L for a printout of the full details of this case). For 1992, EEA has already proposed an average tariff of 59.5 milliemes/kWh, and a tariff to EDA of 62.0 milliemes/kWh. This will result in a self-financing ratio of -27.2 percent (using the "RCG" definition), before considering the effects of inflation on operating expenses. The World Bank covenant called for a self-financing ratio of 20 percent in 1992.

In 1993, to achieve the targeted self-financing ratio of 30 percent with fuel at 50 percent of international prices, an EEA average tariff of 96.5 milliemes/kWh would be required. The

Exhibit 6-8
EGYPTIAN ELECTRICITY AUTHORITY
INPUT ASSUMPTIONS – Base Case Y200

	Actual					Est.	Forecast				
	1987	1988	1989	1990	Year end June 30	1991	1992	1993	1994	1995	1996
1	1.350	2.310	2.599	2.750	Exchange Rate -- L.E./US$	3.300	4.310	4.940	5.350	5.560	5.650
2				3.70%	Inflation Rate -- International %	8.70%	6.20%	2.20%	1.70%	2.50%	3.10%
3				15.00%	-- Egyptian %	20.00%	20.00%	15.00%	9.00%	6.00%	5.00%
4			0.8868	0.9200	Inflation Index -- International	1.0000	1.0620	1.0854	1.1038	1.1314	1.1665
5			0.7246	0.8333	Inflation Index -- Egyptian	1.0000	1.2000	1.3800	1.5042	1.5945	1.6742
6	4.00%	4.31%	4.53%	4.08%	Station Losses -- %	4.10%	4.10%	4.10%	4.10%	4.10%	4.10%
7	7.64%	7.72%	7.16%	6.31%	System Losses -- %	6.16%	5.86%	5.33%	5.00%	4.80%	4.44%
8					International Fuel Prices ($/MBTU) --						
9			4.69	4.69	-- Distillate	4.14	3.93	4.18	4.37	4.51	4.71
10			2.43	2.43	-- Residual	1.69	1.56	1.80	2.03	2.09	2.18
11			2.43	2.43	-- Natural Gas	1.69	1.56	1.80	2.03	2.09	2.18
12			1.80	1.80	-- Coal	1.80	1.80	1.80	1.80	1.80	1.80
13					* IF INFLATION IS TO BE PUT INTO *	******	*				
14					* FORECAST, INSERT "1" HERE >>>>>>	1	<<<<<< OTHERWISE, SET AT "0"				
15						******	*				
16					Interest Rate on New FX Loans -%	7.00%	******	******	******	******	******
17					Interest Rate on New EL Loans -%	11.25%	******	******	******	******	******
18	5.0%	3.3%	3.7%	3.5%	Depreciation Expense Rate %	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
19	136	151	168	167	Customer Accts Rec. -- days' sales	160	110	90	90	90	90
20	149	102	110	83	Other Accts Rec. -- days' sales	48	30	20	11	7	6
21	6.4%	5.9%	7.0%	6.3%	Inventories -- % of G F A	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
22					TARGET SELF-FINANCING RATIO % (WB)		20.0%	30.0%	35.0%	35.0%	35.0%
23					EEA Fuel Price as % Int'l Price	26.8%	43.8%	50.0%	63.0%	80.0%	100.0%

Exhibit 6-9
EGYPTIAN ELECTRICITY SYSTEM

TABULATION OF KEY RESULTS – Base Case Y200

Year end June 30	Est. 1991	Forecast 1992	1993	1994	1995	1996
1 Border Price -- Mazout -- $/Tonne	70.1	64.7	74.7	84.2	86.7	90.5
LE/Tonne	231.4	279.0	369.0	450.6	482.2	511.1
2 Exchange Rate	3.300	4.310	4.940	5.350	5.560	5.650
3 Mazout Transfer Price to EEA						
--LE/Tonne	55.0	83.7	184.5	283.9	385.7	511.1
4 Gas Transfer Price to EEA						
--LE/Tonne	66.0	98.3	184.5	283.9	385.7	511.1
5 Mazout price to EEA as % Mazout Border Price	23.8%	30.0%	50.0%	63.0%	80.0%	100.0%
Gas price to EEA as % Mazout Border Price	28.5%	35.2%	50.0%	63.0%	80.0%	100.0%
6 Target Self-finacing Ratio (WB) - %	0.0%	20.0%	30.0%	35.0%	35.0%	35.0%
7 Self-financing Ratio -- WB Definition	-12.1%	-27.8%	22.3%	27.9%	27.4%	24.5%
-- RCG Definition	-10.2%	-27.2%	30.2%	34.9%	35.3%	35.0%
8 Revenue Requirement for Above Assumptions (Milliemes / kwh)						
-- EEA Requirement	43.1	59.5	96.5	110.5	121.5	136.5
-- EDA Requirement	70.2	91.4	155.5	178.0	195.7	219.9
-- System Requirement	61.6	81.2	140.5	161.4	177.9	200.4
9 % Real Increase Required						
-- EEA		38.2%	62.2%	14.5%	10.0%	12.3%
-- EDA		30.1%	70.1%	14.5%	10.0%	12.3%
-- System		31.9%	72.9%	14.9%	10.2%	12.7%

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corresponding average tariff for EDA's customers would be 155.5 milliemes/kWh (ignoring the effects of inflation).

While the foregoing analysis illustrates the relative magnitude of the tariff adjustments required at 1991 prices, it is not sufficient as a basis for practical action.

For financial management purposes, it is necessary to achieve tariffs and revenues that actually produce a sufficient quantity of Egyptian pounds to meet inflated expenditure requirements and the related self-financing ratio that will exist in 1993. It is also necessary -- because of the delays in the tariff approval process and the relatively infrequent adjustments to the tariff schedule -- to anticipate future inflation.

Therefore, the proposed tariffs for FY 1992-93 should be based on the inflation-adjusted Base Case.

Summary

Both the constant price and the inflated price Base Cases discussed above necessitate substantial tariff increases from 1992 to 1993.

The constant (1991 price levels) case indicates a 70.1 percent increase in the average EDA tariff to EDA's customers (see Exhibit 6-9, item 9).

The projected actual, or current price (at 1993 prices) case indicates a 116.4 percent increase in the average EDA tariff, from 91.4 milliemes/kWh in 1992 to 197.8 milliemes/kWh in 1993. This is the situation that has to be faced if a self-financing ratio of 30 percent and an EEA fuel cost at 50 percent of the forecast international price are to be achieved (see Exhibit 6-7, item 9).

6.4 SIMULATION OF FINANCIAL PERFORMANCE UNDER LRMC-BASED YIELD TARGETS SET IN ACCORDANCE WITH IBRD AGREEMENT

The financial revenue requirements determined in the preceding section (Case Y210) provide the starting point for establishing the revenue responsibility of each tariff class, which provides the basis for developing the tariff design in each case. However, we were advised that under an agreement reached with IBRD, the system average yields in future years are to be based on the following percentage of system LRMC computed in Chapter 5.

Year	FY 93	FY 94	FY 95	FY 96
Yield as a % of LRMC	69%	80%	90%	100%

This decoupling results in system yield targets (P/kWh) that are substantially lower than those called for under the financial analysis of revenue requirements described earlier in the chapter. This section describes the results of financial simulations that were undertaken to estimate the resultant deterioration of EEA's financial performance in comparison to the projected performance if class revenue responsibilities were based upon the financial analysis-based revenue requirements.

Specifically, the tariff yields (P/kWh) based upon the percentage of LRMC targets are as follows:

		(milliemes/kWh)			
		1993	1994	1995	1996
1.	System -- Average Tariff (LRMC Based)	141.7	188.8	231.6	272.7
2.	EEA -- Average Tariff	99.9	133.3	163.4	192.4
3.	EEA Transfer Price to EDA	98.3	134.6	167.3	199.1
4.	EDA -- Average Tariff	153.4	207.5	256.4	303.3

Detailed outputs of the model runs under these conditions are contained in Annex R. The following discussion highlights the implications of adjusting the "LRMC Case."

Financial Implications for EEA (Case EEA-YLR2)

1. Self-Financing Ratio

There is a gradual improvement in the projected self-financing ratio (SFR) from -29.6 percent in 1992 to 9.6 percent in 1994. Therefore, the SFR declines to 5.1 percent in 1995 and to -14.0 percent in 1996.

The primary reason for the sharp deterioration in the SFR in 1996 is that the net operating loss is projected to deteriorate from a loss of LE 421.1 million (or 5.0 percent of revenue) in 1995 to a loss of LE 1,353.4 million (or 12.9 percent of revenue) in 1996.

2. Income Statement

Of the basis of tariffs set at 69 percent of LRMC in 1993, increasing to 100 percent of LRMC in 1996, and assuming no reduction in EEA's captital investment program from levels proposed earlier, EEA is projected to record positive net income only in 1993. Therefor, as a result of fuel prices which are projected to increase by 35.8 percent from 1994 to 1995 and by 32.5 percent from 1995 to 1996, EEA's tariffs are projected to increase by 22.6 percent and 17.7 percent, respectively. EEA's Fuel Cost to Sales ratio is projected in increase from 45.5 percent in 1993 to 70.1 percent in 1996. Consequently, EEA's Income from Operations (before Interest) is forecast to decline from LE 1,115.9 million (or 17.4 percent of revenues) in 1994 to LE 633.4 millon (or 6.1 percent of revenues) in 1996.

In addition, due to inadequate cash flow relative to EEA's working capital and investment needs, its borrowing requirement (expressed as bank overdrafts in the model) will increase significantly -- from LE 6.0 billion at the 1993 year end to LE 14.1 billion at the 1996 year end. Hence, the net interest expense is projected to increase from LE 833 million in 1993 to LE 1987 million in 1996.

The foregoing are the principal factors leading to deterioration in earnings and in the self-financing ratio.

Capital Investment Program

A reduction in the capital expenditure program by 50 percent in the period 1993 through 1996 from a level (before IDC) of approximately LE 4.8 billion annually to LE 2.4 billion annually should have a significant positive effect on EEA's medium-term financial viability (Case EEA-YLR3).

The self-financing ratio would improve to about 33 to 37 percent in 1994 and 1995, falling to 19 percent in 1996. Similarly, the cumulative financing requirement (represented by the bank overdraft) should fall from the previous LE 14 billion to under LE 3 billion in 1996. Indeed, EEA would be financially self-sustaining over the period 1992 through 1996 (other than borrowing to finance the foreign exchange portion of its capital program).

Conclusions

The "LRMC Case" is not financially viable unless it is accompanied by a massive reduction in EEA's capital investment program to about 50 percent of projected levels.

Financial Implications for EDA (Case EDA-YLR2)

The ratio between the EDA Average Selling Tariff and the EDA Purchase Tariff varies from 1.56 in 1993 to 1.52 in 1996. This is not sufficient to enable EDA to meet its Working Capital and Capital Expenditure Requirements over the period unless EDA's capital expenditure program is also significantly reduced.

EDA's capital expenditure program is projected at LE 1,874 million in the period 1993-1996, and its overdraft will have increased by approximately LE 700 million, from LE 1,125 million at year-end 1992 to LE 1,792 million at year-end 1996. Thus, either a 40 percent cut-back in EDA's capital program would be required, or an expansion in the EDA margin to a ratio in the 1:60 range (consistent with historical practice) is required.

6.5 EDA TARIFF ALLOCATION MODEL

This section briefly describes a model that was developed to address the issue of tariff allocation across the Distribution Companies; more details are provided in a separately bound manual.

Background: The Policy Framework

For all EDA customers, there is a national policy of uniform electricity tariffs from similar classes of customers purchasing similar quantities of power. Therefore, differences in system losses and other costs of distribution between the eight Distribution Companies are not reflected in the tariffs charged to customers. Conversely, load factor and mix of load between various customer classes and within customer classes will cause variations in the effective average tariff yields of the various Distribution Companies.

Within this context, so as to ensure the financial viability of each Distribution Company, a policy of cross-substitution between the DCs has been adopted.

The Mechanism for Cross-Subsidization

The mechanism presently employed for cross-subsidization begins with an average transfer price for EEA's electricity sales to EDA being determined, agreed between EEA and EDA, and approved by the Government of Egypt.

The national retail tariffs to be charged by EDA are determined (based on EDA's consolidated costs and financing agreements) and approved by the Government of Egypt.

EDA's commercial department then makes the projected revenues (based on the national tariff) and costs for each Distribution Company and determines a tariff that the particular Distribution Company can pay to EEA in order to achieve a target margin between revenues and expenses. This tariff will vary according to the costs and system losses for each DC.

Once the various tariffs to each DC are determined, the resulting average tariff is checked to ensure that it corresponds to the agreed-upon average tariff from EEA to EDA.

The result of the above is that the more efficient DCs pay a higher tariff to EEA than do the less efficient DCs. Thus, the more efficient DCs cross-subsidize the less efficient DCs.

Purpose of the Model

The purpose of the EEA Tariff Allocation Model is to replicate and automate the cross-subsidization mechanism outlined above. The model's financial criterion is that each Distribution Company should achieve a ratio of Operating Income (after depreciation

expense) to Revenue from Electricity Sales which is equal to this ratio for EDA on a total consolidated basis.

This approach will ensure that cash flow from operations is positive for each DC. However, it permits a variation in return-on-assets between the various companies, depending on the nature of the system. Also, it assumes that the cash flow for capital expenditures is managed for EDA as a whole rather than at the individual DC level.

CHAPTER 7: TARIFF RESTRUCTURING AND IMPLEMENTATION

This chapter develops our recommendations for tariff restructuring. Section 7.1 presents a review and evaluation of existing tariffs in light of information on the long-run marginal cost (LRMC) structure and financial revenue requirements as determined in Chapters 5 and 6, respectively.

The tariff restructuring begins with a determination of individual tariff class revenue responsibilities in Section 7.2. This is followed by a presentation of the tariff structures for the bulk (Section 7.3) and retail (Section 7.4) categories that recover the class-specific revenue responsibility. Finally, Section 7.5 contains some comparative information on tariff yields and LRMC values for selected utilities in other countries.

7.1 REVIEW OF EXISTING TARIFFS

Exhibits 7-1 and 7-2 present the essential features of bulk and retail electricity tariffs that were recently initiated on May 1, 1991.

Nearly 76 percent of EEA's sales are for resale and are to eight Distribution Companies (DCs). The remaining 24 percent represents direct sales to large customers (industry and agriculture).

More specifically, EEA sells power directly to eight large customers at very high voltage (220 kV, 132 kV) that represent about 17 percent of its total sales. In addition, EEA directly serves at high voltage (66 kV, 33 kV) a few industrial customers and several hundred agricultural accounts (mostly water pumping). These HV customers account for over 6 percent of EEA's sales. The remaining sales (under 1 percent) are accounted for by a few industry and agricultural accounts served at medium voltage (11 kV, 6.6 kV). These customers pay the moving power retail tariff discussed below.

Exhibit 7-2 highlights key aspects of retail electricity tariffs in Egypt. Based upon the billed sales data for the second half of FY 91 (i.e., the six-month period July through December 1990), it is estimated that approximately 43 percent of the total DC sales are sold under the residential tariff, 6+ percent sold under the commercial tariff, 44 percent under one of the moving power tariffs, 4+ percent for street lighting, and the remainder (less than 3 percent) represent sales to housing companies.

Exhibit 7-1
EEA's Electricity Tariffs for Bulk Sales
to Distribution Companies and to Direct Service Industries
(Effective May 1, 1991)*

Tariff Class	Service Voltage	Demand Charge (LE/kW/Yr)	Energy Charge (Milliemes/kWh)
Direct Service Industry	VHV	--	
Kima		--	17.00
Aluminum		--	46.00
Assuit Cement (1)		--	63.20
Assuit Cement (2)		--	63.20
Ferrocilicon		--	57.70
Somed		--	63.20
Iron and Steel		--	63.20
Amiria Spinning		--	63.20
Direct Service Industry	HV	--	80.70
Distribution Companies**	MV	--	average 62.44
Cairo		--	69.22
Alexandria		--	64.40
N. Delta		--	50.32
S. Delta		--	49.73
Behira		--	62.74
Canal		--	64.88
N. Upper Egypt		--	51.03
S. Upper Egypt		--	60.61

* Direct Service Industry customers of EEA served at MV are charged the moving power tariff (>500 kW) shown in Exhibit 7-2.
** Preliminary proposed prices.

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Exhibit 7-2
Electricity Tariffs of Distribution Companies (Effective Since May 1, 1991)

Tariff Class	Service Voltage	Customer Segments	Demand Charge (LE/kW/Yr)	Energy Charge (Milliemes/kWh)		
1. Residential	LV	Residential	--	First 100 kWh	--	30
				101-200	--	45
				201-350	-	65
				351-500	--	75
				501-650	--	100
				651-800	--	120
				801-1,000	--	140
				1,001-2,000	--	160
				2,001-4,000	--	175
				> 4,000	--	185
2. Commercial	LV	Shops and Excess Lighting Consumption of Accounts Billed Under the Moving Power Tariff	--	First 100 kWh	--	45
				101-200	--	65
				201-350	--	98
				351-500	--	130
				501-1,000	--	150
				1,001-2,000	--	185
				2,001-4,000	--	210
				> 4,000	--	230

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Exhibit 7-2 (continued)
Electricity Tariffs of Distribution Companies (Effective Since May 1, 1991)

Tariff Class	Service Voltage	Customer Segments	Demand Charge (LE/kW/Yr)	Energy Charge (Milliemes/kWh)	
3. Moving Power (> 500 kW)	MV	All Non-Residential	82.1	First 1,000 hours/year --	147.1
				Next 500 hours/year --	138.4
				Next 1,000 hour/year --	120.7
				Next 1,000 hours/year --	103.7
				Next 1,500 hours/year --	78.8
				> 5,000 hours/year --	67.3
4. Moving Power (< 500 kW)	LV	Agriculture (Private Sector and Investment)	--	First 70,000 kWh/year --	73.7
				Next 100,000 kWh/year --	60.2
				> 170,000 kWh/year --	57.3
		Industry (Private Sector and Investment)	--	First 70,000 kWh/year --	102.1
				Next 100,000 kWh/year --	83.4
				> 170,000 kWh/year --	79.4
		Public Sector, Industry and Motive Power Needs of Commercial Class	--	First 70,000 kWh/year --	169.4
				Next 100,000 kWh/year --	138.5
				> 170,000 kWh/year --	131.9
5. Government Lighting and Public Lighting	LV	Street Lighting and Lighting in Government Buildings	--	185.5	

Exhibit 7-2 (continued)
Electricity Tariffs of Distribution Companies (Effective Since May 1, 1991)

Tariff Class	Service Voltage	Customer Segments	Demand Charge (LE/kW/Yr)	Energy Charge (Milliemes/kWh)
6. Free Zone (> 500 kW)	VHV	Private "Investment Companies" Located in the Free Zone	107.9	57.5
	HV	Private "Investment Companies" Located in the Free Zone	112.7	66.9
	MV	Private "Investment Companies" Located in the Free Zone	199.5	102.6
7. Free Zone (< 500 kW)	MV	Private "Investment Companies" Located in the Free Zone	49.9	131.8
	LV	Private "Investment Companies" Located in the Free Zone	--	192.8
8. Housing Companies	--	Sales for Resale	--	60.0

Exhibit 7-3 provides a further breakdown of sales under the moving power tariff. The data reveal the dominance of the public sector in Egypt. This sector accounts for nearly 77 percent of sales under the moving power tariff; over 62 percent of total sales in this tariff category are accounted for by large accounts (i.e., greater than 500 kW).

Overall Assessment of Tariff Levels

From a resource allocation and purely economic efficiency point of view, tariffs should be set at parity to the economic cost of supply. In practice, other considerations must also be balanced. This means that any restructuring of tariffs should strive to bring tariffs at each voltage level in closer alignment with the true cost of supply. Therefore, as a starting point, it is useful to examine the efficiency implications of existing tariff levels vis-a-vis the marginal cost, as defined earlier in Chapter 5 and reproduced here in Exhibit 7-4.

At the EEA level, the data highlight the fact that the estimated current yield (i.e., following the May 1, 1991 tariff increase) is 6.08 P/kWh. By comparison, the economic cost of supply is 12.07 P/kWh and the FY 93 financial revenue requirement has been estimated in Chapter 5 to be 9.65 P/kWh. At the retail level the current yield is 9.47 P/kWh, the strict economic cost of supply is 19.34 P/kWh, and the financial revenue requirement is estimated to be 15.55 P/kWh. In terms of final sales, the estimated current yield is 8.46 P/kWh, the economic cost of supply is 17.11 P/kWh, and the FY 93 financial revenue requirement is 14.05 P/kWh. These data reveal a financial subsidy for all final sales on the order of LE 2 billion per year, or equivalently, about US $600 million per year at an exchange rate of 3.3 to 1.

The economic subsidy -- measured as the difference between current yield and LRMC -- for all final sales is on the order of LE 3.1 billion per year, or equivalently, about US $1 billion per year. The incidence of these subsidies is widespread, with the most extreme case of distortions to be found among the following groups/categories of consumption: the first four blocks of consumption in the residential and commercial tariffs, and sales to private and investment companies in agriculture and industry.

Generally speaking, it is not prudent economic policy or financial policy to price electricity -- or for that matter any other good or service -- such that a very high percentage of customers and sales are subsidized substantially. Any subsidies received by one customer segment must be made up by charging more than otherwise to another customer segment. This distorts the price signals to all customers. Those who are being subsidized will not make efficient consumption decisions because the price they pay is lower than the

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Exhibit 7-3
Approximate Shares of Consumption Within Moving Power Tariff by Industry Type
(July-December 1990)

Customer Category	Sales (Million kWh)											Share of System Sales*
	"Public"			"Private"			"Investment"			Total Class Sales	Share of Class Sales	
	> 500 kW	< 500 kW	Sub-Total	>500 kW	< 500 kW	Sub-Total	>500 kW	<500 kW	Sub-Total			
Industry	2,686	244	2,930	251	581	832	--	--	--	3,762	64.7%	28.5%
Agriculture	--	--	224	--	--	3	--	--	70	297	5.1%	2.3%
Public Utilities	--	--	628	--	--	--	--	--	--	628	10.8%	4.8%
Government (Including Lighting)	305	383	688	--	--	--	--	--	--	688	10.8%	5.2%
Investment Company	--	--	--	--	--	--	353	88	441	441	7.6%	3.3%
Total			4,470			835			511	5,816	100%	44.1%
Share of Class Sales			76.9%			14.3%			8.8%	100%		

* Billed sales for July-December 1990 of 13,183 million kWh.

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Exhibit 7-4
Strict Long-Run Marginal Costs (FY 91 Currency)

EEA Bulk Supply

TARIFF CLASS	SERVICE VOLTAGE	TOTAL MARGINAL COST/MONTH CAPACITY LE/KW	ENERGY LE/KWH	TOTAL LE/KWH	DEMAND CHARGE SHARE	FY91/H1 SALES GWH	CURRENT YIELD LE/KWH
VHV INDUSTRY							
KIMA CO.	VHV	14.88	0.0782	0.1008	22%	824	0.0170
ALUMINUM CO.	VHV	14.29	0.0779	0.0996	22%	1485	0.0460
ASSUIT CEM (1)	VHV	14.14	0.0779	0.0994	22%	86	0.0632
ASSUIT CEM (2)	VHV	14.14	0.0779	0.0994	22%	59	0.0632
FERROSILICON	VHV	14.14	0.0779	0.0994	22%	153	0.0577
SOMED CO.	VHV	14.14	0.0779	0.0994	22%	162	0.0632
DEKHILA FERRO	VHV	14.14	0.0779	0.0994	22%	449	0.0632
AMERIA SPIN	VHV	14.14	0.0779	0.0994	22%	53	0.0632
HV INDUSTRY/AGRI	HV	21.33	0.0819	0.1236	34%	1218	0.0807
MV INDUSTRY/AGRI	MV	30.07	0.0879	0.1565	44%	126	0.1355
DISTRIBUTION COS.							
CAIRO	HV	22.45	0.0838	0.1249	33%	6449	0.0667
ALEXANDRIA	HV	22.45	0.0838	0.1249	33%	1679	0.0630
DELTA NORTH	HV	22.45	0.0838	0.1249	33%	1099	0.0514
DELTA SOUTH	HV	22.45	0.0838	0.1249	33%	1158	0.0542
BEHEIRA	HV	22.45	0.0838	0.1249	33%	716	0.0647
CANAL	HV	22.45	0.0838	0.1249	33%	1548	0.0644
N. UPPER EGYPT	HV	22.45	0.0838	0.1249	33%	1008	0.0488
S. UPPER EGYPT	HV	22.45	0.0838	0.1249	33%	1018	0.0643
EEA SYSTEM AVERAGE		21.06	0.0827	0.1207		19229	0.0608

EDA Retail Supply

TARIFF CLASS	SERVICE VOLTAGE	TOTAL MARGINAL COST/MONTH CAPACITY LE/KW	ENERGY LE/KWH	TOTAL LE/KWH	DEMAND CHARGE SHARE	FY91/H1 SALES GWH	CURRENT YIELD LE/KWH
HOUSING COS.	HV	21.33	0.0838	0.1228	32%	350	0.0600
MV MOVING POWER	MV	30.07	0.0879	0.1565	44%	3891	0.1416
LV MOVING POWER	LV	40.87	0.0985	0.2003	51%	833	0.0979
LV OTHER PURPOSE	LV	40.87	0.0985	0.2003	51%	734	0.1353
MV FREE ZONE	MV	30.07	0.0879	0.1565	44%	6	0.1264
LV FREE ZONE	LV	40.87	0.0985	0.2003	51%	6	0.1843
RESIDENTIAL	LV	40.87	0.1007	0.2126	53%	5602	0.0421
COMMERCIAL	LV	40.87	0.1007	0.2251	55%	885	0.1083
GOVT LIGHTING	LV	40.87	0.0941	0.2185	57%	286	0.1855
STREET LIGHTING	LV	43.02	0.0993	0.2172	54%	589	0.1855
DISTRIBUTION COMPANY AVERAGE		37.25	0.0980	0.1934		13183	0.0947
SYSTEMWIDE AVERAGE		31.91	0.0916	0.1711	46%	17797	0.0846

cost to the nation in providing the service. Additionally, efficiency losses also occur because others must pay more. This distorts their consumption levels and patterns as well. This is in addition to the potential for significant distortionary impacts economy-wide and efficiency losses because of resource and capital mis-allocation.

Residential Tariff

The residential tariff structure is an increasing block, with the first block priced at 30 mills/kWh. This price is only 14 percent of the economic cost of supply, 212.6 mills/kWh. The tail block price of 185 mills/kWh is about 87 percent of LRMC. Whereas this situation is substantially better, unfortunately, less than 0.01 percent of class sales are in the tail block, as discussed in the bill frequency analysis described in the following paragraphs.

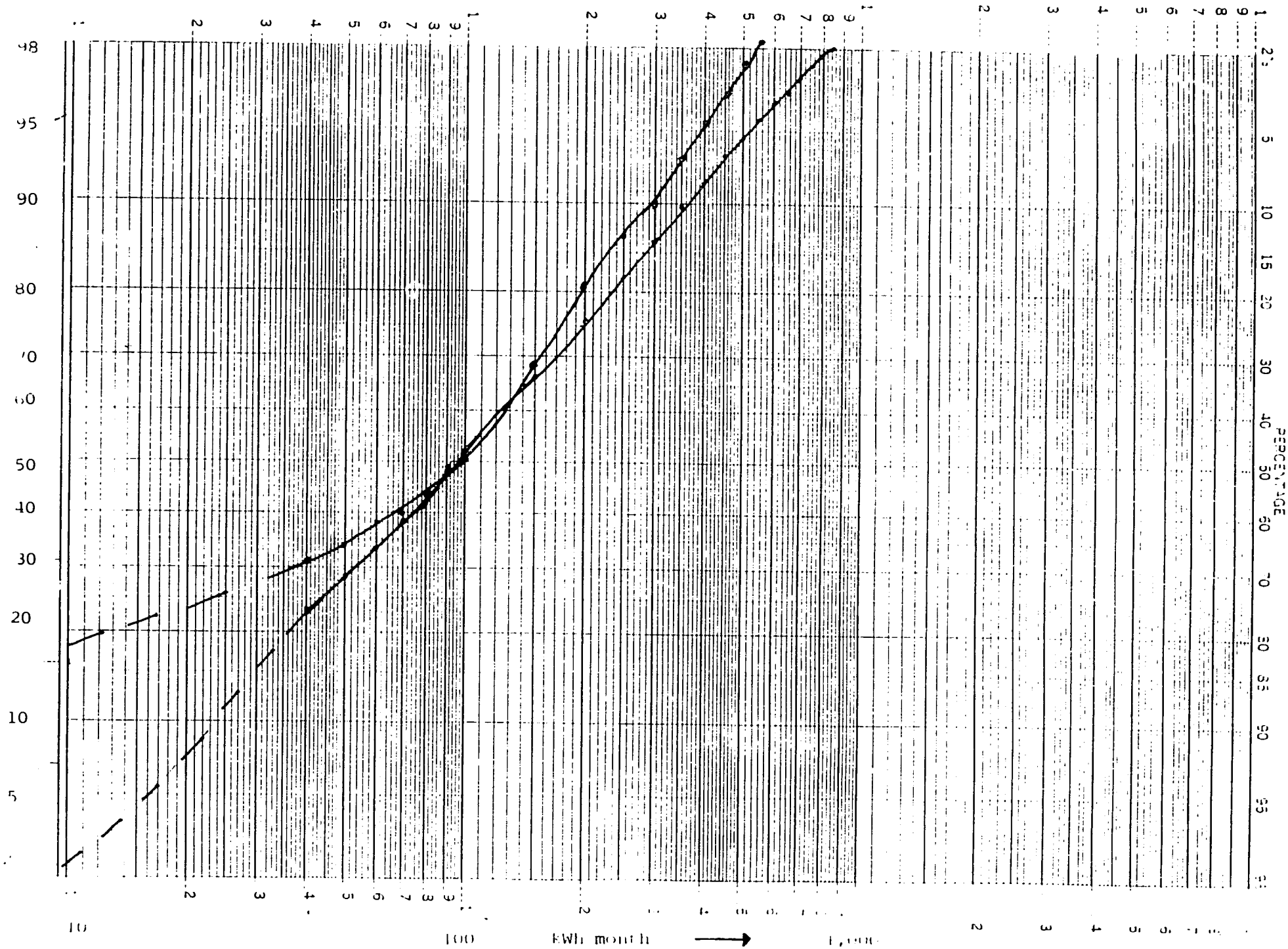
Bill Frequency Analysis of Residential Tariff

One component of our review relies on a bill frequency analysis (BFA) of the existing tariffs. The BFA utilizes customer billing records to develop two summary characteristics. The BFA provides estimates of the distribution of bills by consumption level, e.g., the fraction of all bills rendered that had a billed consumption level of 50 kWh or less per month. The BFA also estimates the distribution of sales, e.g.,the fraction of all sales accounted for up to the 50 kWh per month consumption block. This analysis provides useful insights for tariff block sizing and in simulating future revenues from new tariff structures.

The BFA uses a concept called the "consolidated factor." This factor distinguishes between the two components of sales at any particular interval, and is estimated as the sum of all kilowatt-hours in bills rendered from zero consumption up to that interval but only up to that interval. Consider, for example, the sales in kilowatt-hours at 100 kWh per month. A portion of the sales at 100 kWh is made up of the sum of all kilowatt-hours in bills rendered under that amount. The second portion of the consolidated factor is 100 kWh in every bill rendered in excess of the 100 kWh.

The profiles of bills rendered and sales of electrical energy to residential customers of the Cairo Distribution Company are shown in Exhibit 7-5, between 10 and 10,000 kWh per

Exhibit 7-5. Residential Bill Frequency: Cairo Distribution Company



month. Some of the points shown in the tabulation below can be located in Exhibit 7-5 as well.[1]

Sales Interval in KWh/Month	Cumulative Percent of Bills	Cumulative Percent of Sales (kWh)	Cumulative Percent of Non-Zero Bills
0	16.02	0.00	--
40	30.90	23.44	14.88
50	33.95	28.66	17.93
80	43.32	42.86	27.30
100	50.53	51.05	34.51
200	80.57	75.94	64.55
500	97.56	94.61	81.54
1,000	99.76	98.65	83.74
2,000	99.96	99.54	83.94
4,000	99.99	99.85	83.97

The median points of bills rendered to customers (the point at which 50 percent of the bills are rendered over and 50 under) is approximately 100 kWh per month. The median point of sales in kilowatt-hours per month is about 80 kWh per month. The significance of the chart can be further understood by reviewing the characteristics of sales to residential customers at several intervals.

The billing data indicate that the fraction of bills rendered at zero kWh is 16.02 percent. This is a high number. We suggest that an exception report be derived automatically from the billing records so that these premises can be reviewed by a meter inspector.

[1] A detailed tabulation of the data underlying Exhibit 7-5 is contained in Appendix K. Appendix K also contains BFAs for Alexandria and South Delta DCs as well as the aggregate national level BFA for the residential class.

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At the other end of the spectrum (see Appendix M), there are 189 bills per year rendered over 4,000 kWh per month, and 23 bills over 10,000 kWh per month. Again, an exception report should be prepared identifying these very large accounts to ensure that they are not misclassified commercial accounts.

Under the present tariff structure, the price of electricity in the last tariff blocks is higher in the commercial tariff than the residential tariff. Thus, it is more advantageous for very large commercial customers to be classified as residential. Furthermore, many of the very large "residential" accounts may, in fact, be embassies, which in reality are a commercial/business entity. Ultimately, any incentive for strategic misclassification on the part of a large customer can be eliminated by making the tail block prices more or less identical in the residential and commercial tariffs. Indeed, the economic cost structure supports this parity.

With the BFA data, it can be seen that in the case of Cairo Distribution Company, about 50 percent of bills are in the first block, which represents about 51 percent of all residential sales in that distribution company. Further, nearly 98 percent of all bills and 95 percent of all sales are under 500 kWh/month. The price level of this 500 kWh block is 7.5 P/kWh, again, an order of magnitude below the economic cost of 21.26 P/kWh. In other words, the present residential tariff structure is highly distorted in terms of the magnitude of deviation between actual prices and economic prices as well as in terms of the coverage of these distortions, i.e., the numbers of customers and kWh involved.

The economic subsidy inherent in all sales in the first block is estimated to be LE 1.3 billion/year (equivalent to US $384 million/year) and on a financial basis, this subsidy for the first block sales is estimated to be LE 823 million/year (or equivalently, US $249 million/year).[2]

Such high subsidy levels place an unfair burden on other consuming sectors of the economy. Electricity is an expensive good in that it requires substantial commitments of the nation's productive resources. Thus, subsidies, if necessary, should be confined solely to the poorest of the poor. In this regard, 50 kWh/month is more than sufficient to meet the basic needs of lighting, fans, radio, and television, with some left over for other uses.

[2] The first block (0 to 100 kWh) sales represent approximately 62 percent of all residential sales. Annualizing FY 91 first-half residential sales (July through December 1990) of 5,602 GWh and at an LRMC value of 21.26 P/kWh, a revenue neutral LRMC of 17.11 P/kWh, and a current yield of 4.2 P/kWh, provides the basis for inferring that all sales in the first block are being subsidized to the tune of LE 1.4 billion/year in an economic sense and by LE 727 million/year in a financial sense.

Yet another major distortion in the residential tariff stems from the fact that there are too many blocks. This has the effect of completely masking the true economic cost of electricity to most of the customers. Consider a customer in the first block. His perception of the marginal cost of electricity is the cost of the next block, i.e., 45 mills/kWh. Similarly, for a customer in the 201-3500 kWh block, the block structure signals a marginal price of 75 mills/kWh. These signals are grossly incorrect. Even if the tail block of the present ten-block tariff were priced at strict LRMC, i.e., 212.6 mills/kWh, such a marginal cost signal would not be perceived by the vast majority of consumers in the first four blocks. This situation can only be remedied by limiting the number of blocks to three, or at most, four.[3]

Commercial Tariff

The commercial tariff structure is an increasing eight-block structure. An evaluation of this tariff is very similar to that indicated above for the residential tariff: namely, this tariff suffers from too many blocks, and that the price levels for the first four blocks are an order of magnitude lower than the LRMC of 225.1 mills/kWh. Appendix M contains the national BFA for this tariff.

The current yield from this tariff is estimated to be 108.3 mills/kWh, as compared to the economic cost of 222.5 mills/kWh and a revenue-neutral LRMC of 181.1 mills/kWh. At an estimated annual sale of 1,654 GWh, these numbers imply a financial subsidy of approximately LE 120 million per year and an economic subsidy of LE 189 million per year.

Moving Power Tariff (> 500 kW)

This tariff is applicable for the motive power needs of all non-residential customers with contract demands in excess of 500 kW and excluding commercial "shops" and the Free Zone.

Exhibit 7-6 shows the size distribution of accounts and corresponding average monthly load factors within each size segment developed from a large sample of accounts. To illustrate, the data indicate that nearly 50 percent of all accounts have average annual billed sales

[3] Interestingly, the residential tariff "evolved" over the years from a two-block structure to the present ten blocks. From 1975 through early 1982, the tariff had a first block up to 45 kWh and the second block represented all consumption in excess of 45 kWh per month. During the course of successive tariff restructuring over the period 1982 through 1987, the number of blocks was increased steadily to the present ten.

between 1,001 and 5,000 MWh, and the average annual class load factor is 0.36 for this group of customers. About 24 percent of all accounts -- those with annual consumption in the range of 5,001 to 100,000 MWh -- have annual load factors in the 52 to 56 percent range.

For example, for a customer on this rate with a monthly load factor of 0.60, the demand charge represents about 14 percent of his average monthly bill. By contrast, the economic cost structure indicates that this share should be about 48 percent.

Exhibit 7-6
Size Distribution and Load Factors for Customers with Contract Demand Greater than 500 kW

Annual MWh		Average Load Factor	Number of Customers		
Start	End		in Block	% of Total	Cumulative %
0	1,000	0.158	173	26.02	26.02
1,001	5,000	0.356	332	49.92	75.94
5,001	10,000	0.523	78	11.73	87.67
10,001	25,000	0.557	56	8.42	96.09
25,001	50,000	0.556	17	2.56	98.65
50,001	75,000	0.515	5	0.75	99.40
75,001	100,000	0.543	2	0.30	99.70
100,001	125,000	0.817	2	0.30	100.00
Total: 655					

From a strict economic efficiency perspective, a serious distortion that is embedded in the present tariff is the declining block structure for the energy price. The present tariff structure sends a price signal which conveys that marginal units of consumption are cheaper to produce; that by consuming more, the user can reduce his average cost consumption (mills/kWh), as well as reduce the average cost to the system.

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The historical justification for a declining block structure was that the utility should recover most of its capital costs in the first block of consumption. According to this logic, marginal units of consumption for large users can be priced lower because they need to recover only the variable cost of production. This argument embodies a short-term viewpoint that is contradictory to a situation where the long-run cost structure is no longer decreasing. This historical argument is a holdover from the very early days of the electric utility industry in the U.S. (i.e., the first half of this century) when technological progress, together with dynamic rate promotion, worked in sync to help reduce the average cost of power supply and raise consumption levels as well as increase the standard of living. This is not true any longer.

Specifically, for a power system with more than adequate capacity, it is true that increased capacity utilization would lead to lower average cost per unit, because the fixed costs can be recovered over more kWh of sales. However, if the increased sales necessitate capacity additions, then it is the long-run cost structure, which reflects the associated costs of supplying such incremental sales, that is the relevant price signal. In the case of Egypt, indeed, for most utilities worldwide, this long-run marginal cost structure is no longer decreasing. The present energy pricing structure is at fundamental odds with the globally recognized desirability of energy conservation.

Yet another archaic aspect of the moving power tariff is the feature that all lighting-related consumption in excess of 5 percent is billed under the commercial tariff, whereas the first 5 percent is billed under the moving power tariff. Differential pricing of electricity by end use -- especially for lighting -- is again a phenomenon that is a carry over from the early days of the utility industry.

Around the turn of the century when electricity was sold commercially for the first time, the only end use was lighting and small power plants operated for a few hours in the evening each day to supply a small neighborhood. Since other lighting substitutes were clearly inferior, consumers were willing to pay a premium for electricity for lighting. Electricity producers very quickly realized that if they could promote other uses for electricity, then the average unit price could be reduced because the fixed costs could be allocated over a larger number of kWh (i.e., via higher plant utilization). In the ensuing promotions, differential pricing of electricity by end use emerged, reflecting differences in willingness to pay for electricity because of the competitive substitute energy sources available for non-lighting end uses. These realities of the market environment that typified the early stages of the industry were reflected in the classical rate making philosophy, which permeates in many instances, even today, in spite of the fact that the cost structure and market realities are vastly different now. In short, at present, there is no economic justification for pricing electricity differentially for moving power purposes over lighting.

Moving Power Tariff (< 500 kW)

This tariff is applicable for electricity consumption for motive power purposes by all non-residential customers and also excludes accounts classified as "commercial shops" and Free Zone accounts. It differs from the large moving power tariff in that accounts under this tariff have a contract demand of under 625 kVA (i.e., under 500 kW, assuming a power factor of 0.8). Data made available on the kVA size distribution of accounts for Cairo Distribution Company and South Delta Distribution Company indicate that slightly over 95 percent of the customers in these two distribution companies (about 60,000) have contract demands under 100 kW, with about 92 percent having contract demands under 50 kW. In these two distribution companies, slightly over three-fourths of all customers have contract demands under 10 kW, and about 93 percent have contract demands under 50 kW.

This tariff is marked by the same basic distortion already discussed in the context of the large moving power tariff: namely, the declining block energy pricing structure sends the wrong signal and indeed works against energy conservation, and again, there is no theoretical basis for rationalizing different tariffs for lighting[4] and motive power.

A further aspect of the less than 500 kW moving power tariff is its preferential treatment of agricultural customers (private sector and investment companies) and industry (again, private sector and investment companies) over other customers, i.e., public sector customers (agriculture, industry, government) and other Free Zone companies. Government interventions of this nature -- even though they may be well intentioned and welcome as far as the beneficiaries are concerned -- ultimately distort the tariff for all customers and lead on net to more efficiency losses than can be offset by any gains to the recipients of the subsidy.

There is a widely held misbelief that cheap power supplies will help promote industrial development and export-oriented industry, and that this is good for the nation since export industry earns valuable foreign exchange.

Industrial development is more properly viewed as a function of available investment, manpower resources, and technology. The net contribution (benefit) of subsidized power to industrial development is not likely to be positive in most instances. More effective means to promote industrial development than cheap power generally exist.

[4] For customers under 500 kW, all their lighting consumption is charged on the commercial tariff. Again, there is no economic rationale for doing this or for that matter, using a different criterion than for the large (> 500 kW) customers who pay the first 5 percent of their lighting consumption in accordance with the moving power tariff.

If any subsidy is essential, then more direct and effective fiscal and/or tax policies can be employed by the government such as accelerated depreciation, investment tax credits, tax holidays, lower corporate income tax rates, etc. Such inducements are direct, can be extremely effective, and do not create the efficiency distortions inherent in subsidizing electricity prices. Even in the few instances where the manufacturing process is electricity intensive,[5] we believe that rather than subsidizing electricity prices and thereby distorting the relative prices of all goods and services, some of the other mechanisms noted above for providing subsidies will be more effective and less distortionary to the economy.

As regards the foreign exchange earning power of export industries, this is true. However, whether the availability of cheap electricity supplies has any significant effect in the creation or maintenance of such industry is dubious at best. As in the case of mature industry that produces for the domestic market, unless the industry is highly electricity intensive, it is unlikely that the net benefit attributable to the availability of cheap electricity exceeds the cost of the subsidy as well as the distortionary effects that are created by the necessity to charge higher prices to others. Even in the case of highly electricity-intensive industries, it should be recognized that by subsidizing a key high-cost input, any incentive for the industry to stay competitive -- i.e., by reducing the level of electricity intensity of the process to economic levels maintained by other firms worldwide that face market competition -- is totally lost.

Free Zone Tariff

Electricity consumers located in one of several designated Free Zones are charged in accordance with one of two applicable tariffs (numbers 6 and 7 in Exhibit 7-2). The Free Zone tariffs largely parallel the moving power tariffs in terms of structure. However, the former have substantially higher demand charges, have a flat energy price structure, and have higher average yield and are closer to their LRMC than corresponding customers on the moving power tariff. There is no economic basis for such price discrimination against customers on the Free Zone tariff and in favor of those on the moving power tariff. Both tariff classes are populated by customers who impose a similar cost burden (LRMC) on the power system.

[5] The following are examples of industrial processes that have electricity costs that are 10 percent or more of total production costs: metal smelting (aluminum, copper, zinc, etc.), chlori-alkali plants, air separation plants, paper and pulp mills.

7.2 REVENUE RESPONSIBILITY BY TARIFF CLASS

The financial analysis in Chapter 6 specifies the average revenue requirements for EEA, EDA, and for all final system sales. These requirements for FY 93 and the corresponding implications for percentage increases that could be required are summarized in the following table.

	FY 93 Financial Revenue Requirement		
	Nominal FY 93 LE (P/kWh)	Estimated Current Yield (P/kWh)	Percent Increase Required
EEA	12.55	6.08	106%
EDA	19.78	9.47	109%
System	17.94	8.46	112%

The class revenue responsibility analysis as well as the subsequent tariff design described in the remainder of this chapter is carried out in nominal terms because the tariffs being developed are for a one-year period starting on July 1 (or May 1) 1992.

The above data show that on a total system basis, the financial revenue requirement of 17.94 P/kWh for FY 93 implies an average tariff increase of approximately 112 percent. Under normal circumstances, the procedure employed for tariff design would be to allocate this revenue requirement to each tariff class, thereby defining the revenue responsibility for each class as a first step and then undertaking the tariff design for each class to match the revenue responsibility.

However, we have been advised that under EEA's agreement with IBRD, the system yields in future years -- i.e., average billed revenue per kWh sales -- have been set to the following targets that are specified as a percentage of system LRMC in each of years FY 93 through FY 96.

	System Yield Targets -- IBRD			
Year	FY 93	FY 94	FY 95	FY 96
Yield % of LRMC	69%	80%	90%	100%

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In light of these agreements, the study team was directed to develop the tariff design and implementation plan in conformity to the LRMC-based target yields shown above. The corresponding yields are displayed in Exhibit 7-7. For ease of comparison, the exhibit also shows the financial model-based revenue requirement. In each case, the LRMC-based target yields are lower than the comparable financial revenue requirement, resulting in a significant dilution of EEA's projected financial performance. Chapter 5 discusses the findings of financial simulations that were undertaken to assess EEA's performance under these conditions.[6]

Exhibit 7-8 indicates the revenue responsibility by tariff class based strictly upon the relative LRMC structure. For EEA sales, this would imply, for example, that the average price (yield) from EEA sales to all distribution companies be increased from 6.24 P/kWh to 9.83 P/kWh (i.e., a 58 percent increase). At the retail level, this would mean an increase in the residential tariff yield from 4.21 P/kWh today to 9.97 P/kWh (i.e., a 137 percent increase). On a total system basis, the average increase required is about 67 percent.[7]

The class revenue responsibilities in Exhibit 7-8 (the last two columns) were developed with the following rationalization in mind: (1) deviate as little as possible from the relative LRMCs across class, (2) moderate as far as possible the rate increase to the distribution companies, and as a pass through to the residential tariff, (3) revenue responsibility should not be set below off-peak marginal energy costs, and (4) an intra-class comparison of increasing bills should not be perceived as "unfair."[8]

An additional consideration was that the Free Zone tariffs have the same revenue responsibilities as their counterpart tariffs for customers located outside the Free Zone. This principle is in keeping with the recommendation of new retail tariff classes, as rationalized in the previous section.

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[6] To reiterate briefly, the IBRD agreement-based yield targets result in EEA achieving self-financing rate (SFR) targets that are well below the SFR targets specified through FY 95 in IBRD's Power-4 loan to EEA.

[7] One point to be noted in connection with Exhibit 7-8 is that the system yield of 8.46 P/kWh is slightly different than the comparable estimate of 8.12 P/kWh that the reader will find in the financial analysis chapter. The primary reason for this divergence is in the weightings used to compute this yield. Exhibit 7-8 (which is based upon the LRMC model output) uses as weights customer/tariff class sales for the first half of FY 91. By contrast, the estimated FY 92 yield in the financial model uses the sales forecast numbers for EEA and EDA in the weight averaging. Furthermore, the individual class yields used in Exhibit 7-8 are based on data on EEA and EDA revenues and sales for the first six months of FY 92 provided to us. By contrast, the EEA and EDA yields (P/kWh) used in the financial model were provided directly by the Finance Department.

[8] For example, no class should receive a decrease when most others are facing increases.

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Exhibit 7-7
Target Yields for Tariff Design*

Fiscal Year	LRMC Average Revenue in Current Year Currency (P/kWh)		EEA	EDA	System
1. 1993	1.	LRMC	14.49	23.21	20.53
	2.	Target Yield = 69% of LRMC	9.99	16.01	14.17
	3.	Revenue Requirement from Financial Model	12.55	19.78	17.94
2. 1994	1.	LRMC	16.66	26.69	23.61
	2.	Target Yield = 80% of LRMC	13.33	21.35	18.88
	3.	Revenue Requirement from Financial Model	15.70	24.74	22.51
3. 1995	1.	LRMC	18.15	29.09	25.73
	2.	Target Yield = 90% of LRMC	16.34	26.18	23.16
	3.	Revenue Requirement from Financial Model	18.50	29.23	26.66
4. 1996	1.	LRMC	19.24	30.83	27.27
	2.	Target Yield = 100% of LRMC	19.24	30.83	27.27
	3.	Revenue Requirement from Financial Model	22.25	35.06	32.06

* Inflation rates utilized to convert LRMC estimates originally determined in FY 91 currency are as follows: FY 92 (20%), FY 93 (15%), FY 94 (9%), and FY 95 (6%). These result in the following overall multipliers for converting LRMC values in FY 91 P/kWh to current year P/kWh: FY 93 (1.200), FY 94 (1.380), FY 95 (1.504), and FY 96 (1.594).

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Exhibit 7–8. Revenue Responsibility by Customer/Tariff Class

EEA/UNIFIED POWER SYSTEM
REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – BULK

BILLING YEAR	FY93
TOTAL GRID SALES (GWH)	19229
REVENUE REQUIREMENT	
TOTAL (LE MILLION)	1922
AVERAGE (LE/KWH) 1/	0.1000

CUSTOMER/ TARIFF CLASS	FY91/H1 SALES GWH	CURRENT YIELD2/ LE/KWH	STRICT LRMC3/ LE/KWH	REVENUE NEUTRAL STRICT LRMC LE/KWH	% CHNG	REVENUE RESPONSIBILITY LE/KWH	% CHNG
VHV INDUSTRY	3271	0.0435	0.1198	0.0827	90%	0.0862	98%
HV INDUSTRY/AGRI	1218	0.0807	0.1483	0.1023	27%	0.1483	84%
MV INDUSTRY/AGRI	126	0.1355	0.1878	0.1296	-4%	0.1878	39%
DISTRIBUTION COS.	14615	0.0624	0.1498	0.1034	66%	0.0983	58%
TOTAL EEA BULK	19229	0.0608	0.1449	0.1000	64%	0.1000	64%

1/ Approximate revenue target for FY93.
2/ Estimated average current yield after May 1991.
3/ Escalated to FY93 prices, a 20.00% increase

EEA/UNIFIED POWER SYSTEM
REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – RETAIL

BILLING YEAR	FY93
TOTAL GRID SALES (GWH)	13183
REVENUE REQUIREMENT	
TOTAL (LE MILLION)	2109
AVERAGE (LE/KWH) 1/	0.1600

CUSTOMER/ TARIFF CLASS	FY91/H1 SALES GWH	CURRENT YIELD2/ LE/KWH	STRICT LRMC3/ LE/KWH	REVENUE NEUTRAL STRICT LRMC LE/KWH	% CHNG	REVENUE RESPONSIBILITY LE/KWH	% CHNG
LARGE IND/AG	3891	0.1416	0.1878	0.1296	-8%	0.1878	33%
MEDIUM IND/AG	139	0.1202	0.2403	0.1658	38%	0.2403	100%
SMALL IND/AG	1772	0.1261	0.2439	0.1683	33%	0.2439	93%
FREE ZONE - MV	6	0.1264	0.1878	0.1296	3%	0.1878	49%
FREE ZONE - LV	6	0.1843	0.2403	0.1658	-10%	0.2403	30%
RESIDENTIAL	5602	0.0421	0.2552	0.1761	318%	0.0997	137%
COMMERCIAL	827	0.1083	0.2701	0.1864	72%	0.1864	72%
STREET LIGHTING	589	0.1855	0.2607	0.1799	-3%	0.2607	41%
SALE FOR RESALE	350	0.0600	0.1474	0.1017	69%	0.1246	108%
TOTAL DC RETAIL	13183	0.0947	0.2319	0.1600	69%	0.1600	69%
TOTAL SYSTEM	17797	0.0846	0.2053	0.1416	67%	0.1458	72%

1/ Approximate revenue target for FY93.
2/ Estimated average current yield after May 1991.
3/ Escalated to FY93 prices, a 20.00% increase

The class revenue responsibilities shown in Exhibit 7-8 minimize the distortions in the sense that average yields for over 60 percent of all final sales are set equal to their respective LRMCs, and for the remaining units of sales, the average yields have increased almost 100 percent, from 24 percent of strict LRMC at present to 46 percent of strict LRMC. This change represents a very significant decrease in the extent of distortion in tariff levels that exist today.

Revenue responsibilities -- LRMC-based -- for future years 1994 through 1996 are shown in Annex T in nominal terms.

7.3 BULK/EEA TARIFF DESIGN

This section develops the proposed restructuring of existing tariff schedules for all sales-for-resale and final sales made by EEA.

The basic approach for arriving at our tariff recommendations has been outlined earlier in Chapter 1. Revenue requirement targets for this analysis were developed as described in the financial analysis of Chapter 6. Economic efficiency considerations in developing the proposed tariff revision were based on: (1) estimates of LRMC obtained as described in Chapter 5, and (2) the insights obtained from the analysis of existing tariffs as described in the preceding section.

The incorporation of other objectives -- such as equity, fairness, stability, and simplicity in the tariff design, and the promotion of energy conservation and load management -- were based upon the analysis of existing tariffs as well as EEA information.

These considerations involved the specification of tariff class-specific revenue responsibilities (see Section 7.2), which provide the revenue basis for developing the tariff structures in this section as well as in Section 7.4.

EEA's objective should to sell every kWh on a time-of-day (TOD) tariff. EEA sells power at approximately 3,000 delivery points. It should be possible to proceed in a phased manner to procure and install TOD meters at each delivery point within the next three years, i.e., by year-end 1993. Chapter 9 describes the recommended TOD tariff design.

In the interim, because of metering considerations, it is proposed to maintain the present tariff design -- i.e., a pure energy tariff -- but adjust the levels upwards to ensure that the designated revenue responsibilities are attained. Exhibit 7-9 defines the proposed tariffs for final sales made by EEA, as well as bulk sales for resale to the distribution companies. Bill

Exhibit 7-9
Proposed Tariffs for EEA Sales*

Consumer/ Category	Service Voltage	Demand Charge (LE/kW/Month)	Energy Charge (P/kWh) Peak	Off-Peak
KIMA	VHV	0.0	6.50	6.50
ALUMINUM	VHV	0.0	9.00	9.00
ASSUIT CEMENT [1]	VHV	0.0	10.00	10.00
ASSUIT CEMENT [2]	VHV	0.0	10.00	10.00
FERROCILICON	VHV	0.0	10.00	10.00
SOMED	VHV	0.0	10.00	10.00
IRON & STEEL	VHV	0.0	10.00	10.00
AMIRIA SPINING	VHV	0.0	10.00	10.00
Industry and Agriculture	HV	0.0	14.83	14.83
Industry and Agriculture	MV	0.0	17.00	17.00
Distribution Companies				
CAIRO		0.0	11.30	11.30
ALEX		0.0	9.90	9.90
NORTH DELTA		0.0	8.30	8.30
SOUTH DELTA		0.0	9.00	9.00
EL BEHERA		0.0	10.80	10.80
AL CANAH		0.0	8.90	8.90
NORTH UPPER EGYPT		0.0	6.90	6.90
SOUTH UPPER EGYPT		0.0	9.20	9.20

* Until such time as TOD tariffs are implemented

Exhibit 7-10
Bill Impacts: EEA Tariffs

Consumer/ Category	Sales 1990 July-Dec (Million kWh)	Average Price (P/kWh) Present	Average Price (P/kWh) Proposed	Increase (% Change)
KIMA	824	1.70	6.50	282%
ALUMINUM	1,485	4.60	9.00	96%
ASSUIT CEMENT [1]	86	6.32	10.00	58%
ASSUIT CEMENT [2]	59	6.32	10.00	58%
FERROCILICON	153	5.77	10.00	73%
SOMED	162	6.32	10.00	58%
IRON & STEEL	449	6.32	10.00	58%
AMIRIA SPINING	53	6.32	10.00	58%
Subtotal	3,271	4.35	8.66	99%
Industry/Agriculgure - HV	1,218	8.07	14.83	84%
Industry/Agriculgure - MV	126	13.60	17.00	25%
Distribution Companies				
CAIRO	6,449	6.75	11.30	67%
ALEX	1,619	6.45	9.90	53%
NORTH DELTA	1,099	4.85	8.30	71%
SOUTH DELTA	1,158	5.05	9.00	78%
EL BEHERA	716	6.50	10.80	66%
AL CANAH	1,548	6.60	8.90	35%
NORTH UPPER EGYPT	1,008	4.70	6.90	47%
SOUTH UPPER EGYPT	1,018	6.50	9.20	42%
Subtotal	14,615	6.25	10.01	60%
TOTAL	19,229	6.09	10.13	66%

impacts are displayed in Exhibit 7-10. Then these tariffs were set to recover the revenue responsibilities determined earlier and also shown in Exhibit 7-10 under the class average price column.

The average selling price from EEA to the DCs is 9.83 P/kWh, as can be seen from Exhibit 7-8. The DC-specific average prices shown in Exhibit 7-9 were derived by utilizing the EDA Tariff Allocation Model described in Chapter 5.

From the point of view of efficiency and transparency, it is preferable to maintain the same transfer price to all DCs -- i.e., 9.83 P/kWh in the present situation -- and have EDA manage a price stabilization fund to address the problem of cross-subsidization that arises because of the Government's desire to maintain geographically uniform tariffs. To illustrate this in the context of the numbers in Exhibit 7-9, Cairo and El Behera DCs would pay into the fund an amount equal to the "excess revenue" calculated, i.e., 1.47 P/kWh sales (11.30 - 9.83) in the case of Cairo DC and 0.92 P/kWh sales in the case of El Behera DC. The total amount paid-in would be used to offset the "losses" incurred by the other DCs.

This approach offers the dual advantage of conveying to each DC the correct price signals for purchased power costs, and simultaneously provides a transparent mechanism to make each DC "financially whole." An added advantage is that at some later date, if the Government wishes to consider privatization of one or more DCs, it will be in a better position to figure out what the true cost of service is.

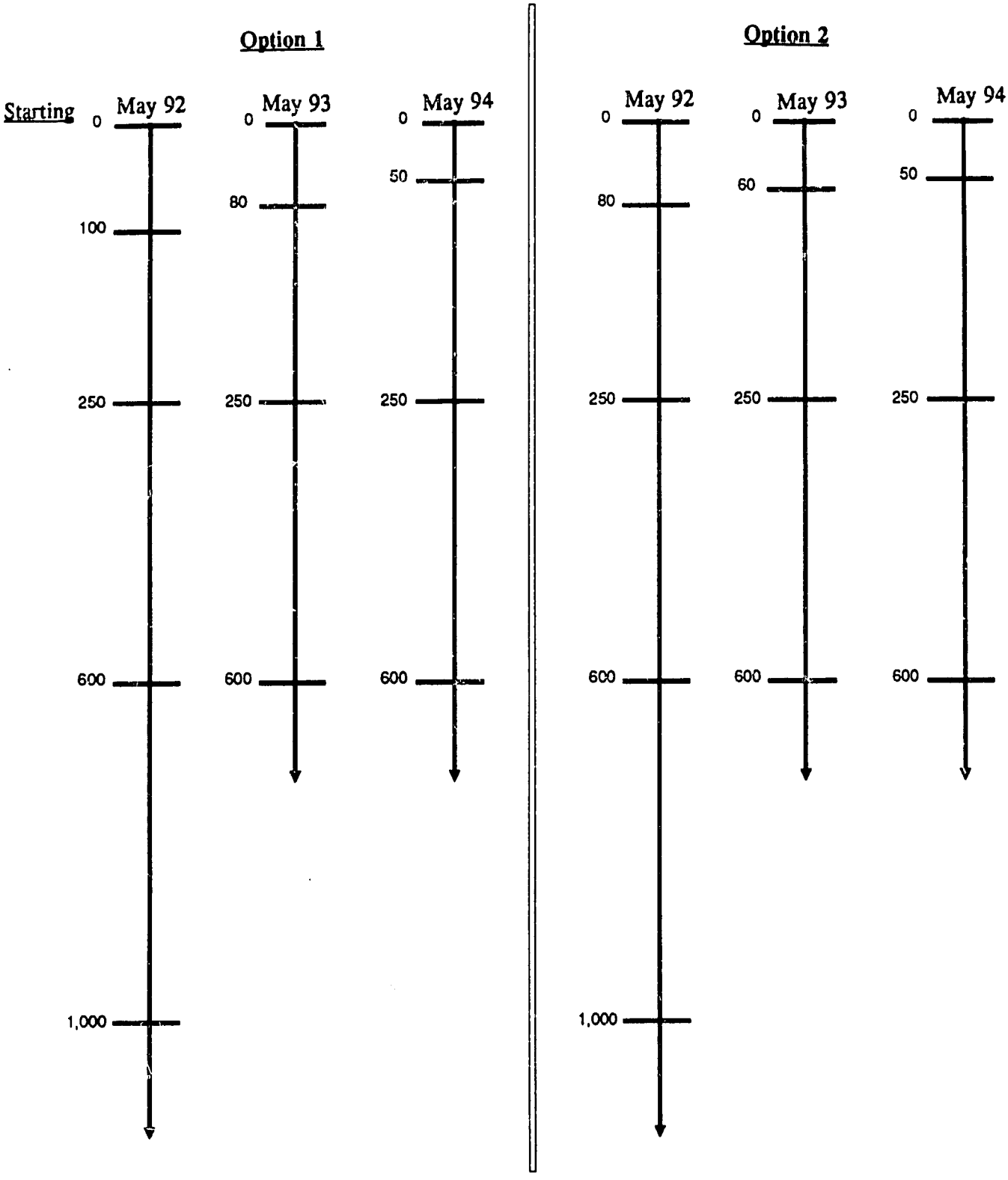
7.4 RETAIL/EDA TARIFF DESIGN

This section discusses the proposed restructuring of tariffs for all sales made by EDA, given the individual class revenue responsibilities developed in Section 7.2.

Residential Tariff

For this tariff, we propose a restructuring that (1) reduces the first block to 50 kWh per month and (2) a reduction in the number of blocks, initially to five and eventually to three. Two options for a three-year phased change of the block sizing structure are shown in Exhibit 7-11. The most important efficiency enhancements of the residential tariff are to reduce the magnitude of subsidy involved at present -- overall as well as to the first block -- and to reduce the number of blocks. From the first standpoint, Option 2 is clearly preferred.

Exhibit 7-11
Block Sizing Options and Phase-In Plan for Residential and Commercial Tariff Structures



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Option 1 defers the first block size restructuring to year 2, and delays addressing a fundamental problem with the residential tariff. Furthermore, the following data on bill impacts under the two options more explicitly reveal that under Option 2 the smaller consumers face lower bill increases, even though both tariffs are designed to generate the same class revenue responsibility of 9.97 P/kWh.

More specifically, Exhibits 7-12 and 7-13, respectively, identify the tariff structure under each option, and the corresponding bill impacts. The tail block is priced to reflect strict LRMC. Once this is fixed, the prices for the first two blocks were adjusted until the desired yield (revenue responsibility) is achieved. Since about 88 percent of all residential sales are in the first two blocks, the prices for the two blocks largely determine the realized yield. Specifically, changing the price levels of blocks 3, 4, and 5 has a minimal impact on the overall yield. Indeed, once the prices in these blocks are set at LRMC levels, the only "degrees of freedom" left require increasing the prices in the first two blocks in order to achieve the target revenue responsibilities.

The major considerations in this tariff design process were to (1) moderate, as far as possible, increases in the first block, and (2) strive to ensure that the first block price is at least equal to the variable cost of providing electricity (i.e., fuel and variable O&M) or certainly not at substantial variance from this cost.

Under Option 2, fewer kWh are in the first block. Consequently, a lower block price can be charged to recover the tariff class revenue responsibility of 9.97 P/kWh. The resultant reduction in bill impacts is significant. For example, a customer with a 50 kWh/month consumption will face a LE 1.50/month increase in his bill under Option 1, and only a LE 1.00/month increase under Option 2.

Another point worth emphasizing in connection with the percentage increases shown in Exhibit 7-13 is that whereas the absolute magnitude of percentage increases appears to be substantial, this is largely because the base, i.e., existing bill, is very low in magnitude. In absolute terms, the bill change numbers convey a much better picture. For example, under Option 2, a household with 100 kWh/month consumption faces a 127 percent increase. Whereas on first appearance this strikes one as a very large increase, the magnitude of increase (LE 3.80) would be perceived by most as a modest increase. Finally, Exhibit 7-14 shows the bill impacts in graphical form under the two options.

In the final analysis, EEA indicated a strong preference for the tariff design Option 1. From an implementation standpoint, the preference can be rationalized by the argument that rather than simultaneously reducing the number of blocks and reducing the first block size,

it may be less confusing to consumers if these charges are decoupled and handled one at a time.

Exhibit 7-12
Proposed Residential Tariff Design (Effective FY 93)

Option 1

Block		New Tariff (P/kWh)
Starting kWh	Ending kWh	
0	100	6.00
101	250	14.00
251	600	22.00
601	1,000	24.00
1,001		26.00

Option 2

Block		New Tariff (P/kWh)
Starting kWh	Ending kWh	
0	80	5.00
81	250	14.00
251	600	22.00
601	1,000	24.00
1,001		26.00

Exhibit 7-13. Typical Bill Impacts: Residential Tariff

Option 1

Consumption (kWh/Month)	Bill: Present (LE/Month)	Bill: Proposed (LE/Month)	Change (LE/Month)	Change (%)	Cumulative Bills (%)
50	1.50	3.00	1.50	100.0%	43.5%
60	1.80	3.60	1.80	100.0%	48.7%
70	2.10	4.20	2.10	100.0%	52.7%
80	2.40	4.80	2.40	100.0%	56.5%
90	2.70	5.40	2.70	100.0%	60.0%
100	3.00	6.00	3.00	100.0%	63.7%
150	5.25	13.00	7.75	147.6%	78.2%
200	7.50	20.00	12.50	166.7%	86.7%
250	10.75	27.00	16.25	151.2%	91.3%
300	14.00	38.00	24.00	171.4%	93.8%
350	17.25	49.00	31.75	184.1%	95.7%
400	21.00	60.00	39.00	185.7%	97.0%
450	24.75	71.00	46.25	186.9%	97.8%
500	28.50	82.00	53.50	187.7%	98.4%
750	55.50	140.00	84.50	152.3%	99.5%
1,000	89.50	200.00	110.50	123.5%	99.8%
2,000	249.50	460.00	210.50	84.4%	100.0%
3,000	424.50	720.00	295.50	69.6%	100.0%
4,000	599.50	980.00	380.50	63.5%	100.0%
5,000	784.50	1240.00	455.50	58.1%	100.0%

Option 2

Consumption (kWh/Month)	Bill: Present (LE/Month)	Bill: Proposed (LE/Month)	Change (LE/Month)	Change (%)	Cumulative Bills (%)
50	1.50	2.50	1.00	66.7%	43.5%
60	1.80	3.00	1.20	66.7%	48.7%
70	2.10	3.50	1.40	66.7%	52.7%
80	2.40	4.00	1.60	66.7%	56.5%
90	2.70	5.40	2.70	100.0%	60.0%
100	3.00	6.80	3.80	126.7%	63.7%
150	5.25	13.80	8.55	162.9%	78.2%
200	7.50	20.80	13.30	177.3%	86.7%
250	10.75	27.80	17.05	158.6%	91.3%
300	14.00	38.80	24.80	177.1%	93.8%
350	17.25	49.80	32.55	188.7%	95.7%
400	21.00	60.80	39.80	189.5%	97.0%
450	24.75	71.80	47.05	190.1%	97.8%
500	28.50	82.80	54.30	190.5%	98.4%
750	55.50	140.80	85.30	153.7%	99.5%
1,000	89.50	200.80	111.30	124.4%	99.8%
2,000	249.50	460.80	211.30	84.7%	100.0%
3,000	424.50	720.80	296.30	69.8%	100.0%
4,000	599.50	980.80	381.30	63.6%	100.0%
5,000	784.50	1240.80	456.30	58.2%	100.0%

For FY 94, under Option 1, the first block would be reduced to 80 kWh and the last two blocks would be merged. The tariff design process would follow the same procedure utilized to develop the FY 93 residential tariff design. Essentially, this means that the last block price would be pegged to the residential LRMC. The price of the first block should be raised to the maximum extent possible to reduce -- and eventually eliminate -- any gap between the off-peak marginal energy cost and the first block price.

In the long run, the first block price should be set at least equal to the weighted average marginal energy costs on peak and off-peak, using the peak energy shares that characterize the first-block consumers. The latter information will need to be developed from load research.

Commercial Tariff

It is proposed that the coverage of this tariff be reduced to be exclusively applicable to business activities that are at present construed to be "commercial shops"; that all the consumption of such customers -- whether for lighting, motive power, or other purposes -- be billed on this tariff. Furthermore, as rationalized earlier in this chapter, all the excess lighting load of customers on the moving power tariff should also be transferred to the appropriate new tariff categories discussed subsequently: large power service, medium power service, and small power service.

For the new commercial tariff, we propose a restructuring that parallels the revisions discussed above for the existing residential tariff: (1) a reduction in the number of blocks to three and (2) a reduction in the size of the first block.

The three-year phase-in plan proposed is identical to that shown in Exhibit 7-11 for the residential case. Again, as in the residential case, Option 2, with a smaller first block size, is preferable from an efficiency standpoint and results in overall lower price impacts as well. However, as in the residential case, EEA indicated a strong preference for Option 1 for the commercial tariff as well. The first-year tariff design under this case is shown in Exhibit 7-15. The corresponding bill impacts are shown in Exhibits 7-16 and 7-17.

For FY 94, under Option 1, the first block would be reduced to 80 kWh and the last two blocks would be merged. The tariff design process would follow the same procedure utilized to develop the FY 93 commercial tariff design. Essentially, this means that the last block price would be pegged to the commercial LRMC. The price of the first block should, at a minimum, be set at the off-peak marginal energy cost.

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Exhibit 7-14

Residential Tariff
Typical Bill Impacts Under Options 1 and 2

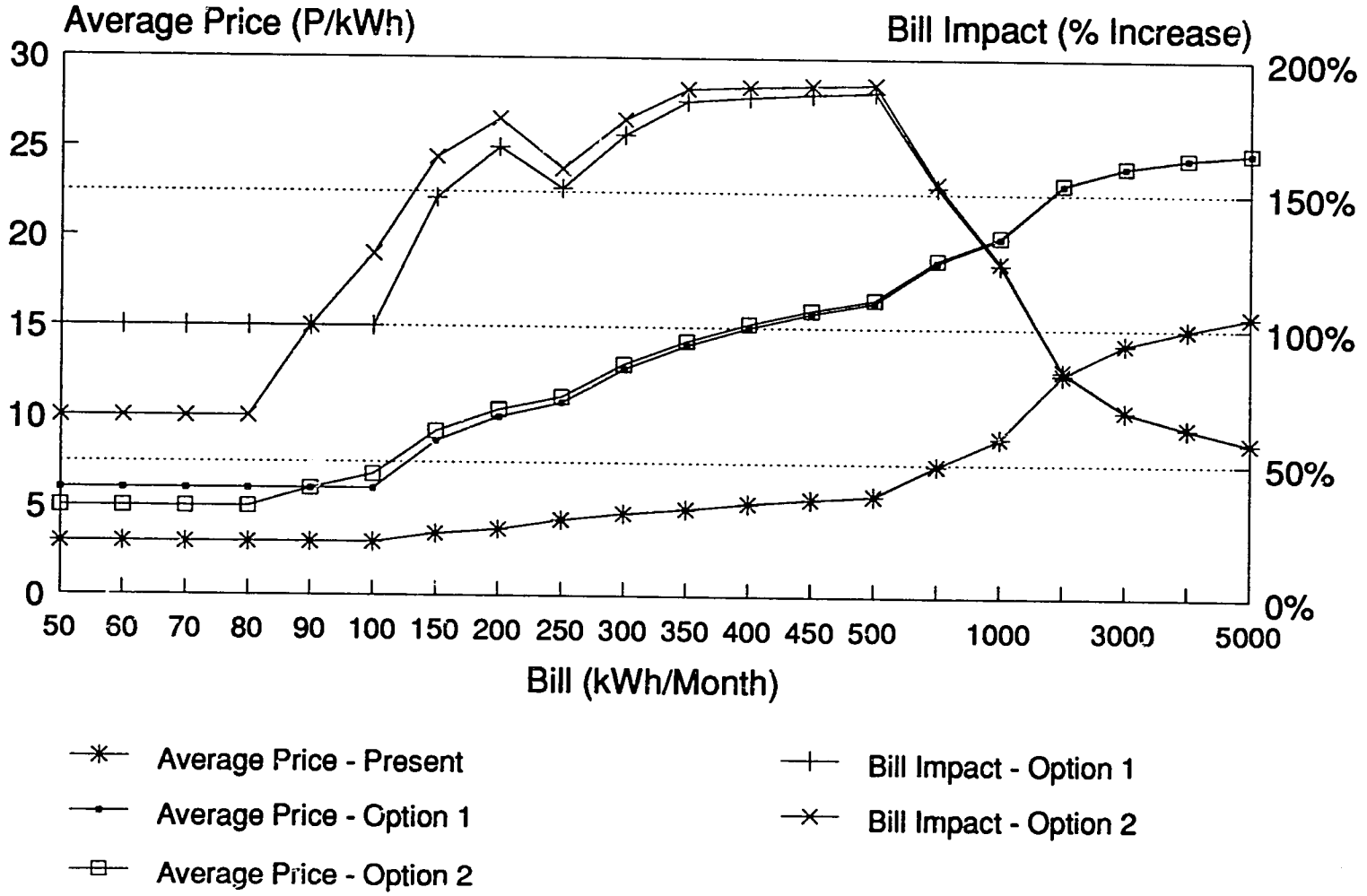

Exhibit 7-15
Proposed Commercial Tariff Design (Effective FY 93)

Option 1

Block		New Tariff (P/kWh)
Starting kWh	Ending kWh	
	100	12.00
101	250	17.00
251	600	23.00
601	1,000	25.00
> 1,001		27.00

Option 2

Block		New Tariff (P/kWh)
Starting kWh	Ending kWh	
0	80	9.00
81	250	17.00
251	600	23.00
601	1,000	25.00
> 1,001		27.00

In the long run, the first block price should be set at least equal to the weighted average marginal energy costs on peak and off-peak, using the peak energy shares that characterize the first-block consumers. The latter information will need to be developed from load research.

Large Power Service

This proposed tariff is to be applied for all electricity consumption of customers with contract demands in excess of 500 kW. In other words, this tariff would be immediately

Exhibit 7-16
Typical Bill Impacts: Commercial Tariff

Option 1

Consumption (kWh/Month)	Bill: Present (LE/Month)	Bill: Proposed (LE/Month)	Change (LE/Month)	Change (%)	Cumulative Bills (%)
50	2.25	6.00	3.75	166.7%	--
60	2.70	7.20	4.50	166.7%	--
70	3.15	8.40	5.25	166.7%	--
80	3.60	9.60	6.00	166.7%	--
90	4.05	10.80	6.75	166.7%	--
100	4.50	12.00	7.50	166.7%	77.4%
150	6.75	20.50	13.75	203.7%	77.4%
200	10.00	29.00	19.00	190.0%	89.0%
250	13.25	37.50	24.25	183.0%	89.0%
300	16.50	49.00	32.50	197.0%	89.0%
350	21.40	60.50	39.10	182.7%	94.9%
400	26.30	72.00	45.70	173.8%	94.9%
450	31.20	83.50	52.30	167.6%	94.9%
500	37.70	95.00	57.30	152.0%	96.9%
750	70.20	157.50	87.30	124.4%	96.9%
1,000	107.70	220.00	112.30	104.3%	98.9%
2,000	292.70	490.00	197.30	67.4%	99.6%
3,000	477.70	760.00	282.30	59.1%	99.6%
4,000	687.70	1030.00	342.30	49.8%	99,9%
5,000	897.70	1300.00	402.30	44.8%	99.9%

Option 2

Consumption (kWh/Month)	Bill: Present (LE/Month)	Bill: Proposed (LE/Month)	Change (LE/Month)	Change (%)	Cumulative Bills (%)
50	2.25	4.50	2.25	100.0%	--
60	2.70	5.40	2.70	100.0%	--
70	3.15	6.30	3.15	100.0%	--
80	3.60	7.20	3.60	100.0%	--
90	4.05	8.10	4.05	100.0%	--
100	4.50	9.80	5.30	117.8%	77.4%
150	6.75	18.30	11.55	171.1%	77.4%
200	10.00	26.80	16.80	168.0%	89.0%
250	13.25	35.30	22.05	166.4%	89.0%
300	16.50	46.80	30.30	183.6%	89.0%
350	21.40	58.30	36.90	172.4%	94.9%
400	26.30	69.80	43.50	165.4%	94.9%
450	31.20	81.30	50.10	160.6%	94.9%
500	37.70	92.80	55.10	146.2%	96.9%
750	70.20	155.30	85.10	121.2%	96.9%
1,000	107.70	217.80	110.10	102.2%	98.9%
2,000	292.70	487.80	195.10	66.7%	99.6%
3,000	477.70	757.80	280.10	58.6%	99.6%
4,000	687.70	1027.80	340.10	49.5%	99.9%
5,000	897.70	1297.80	400.10	44.6%	99.9%

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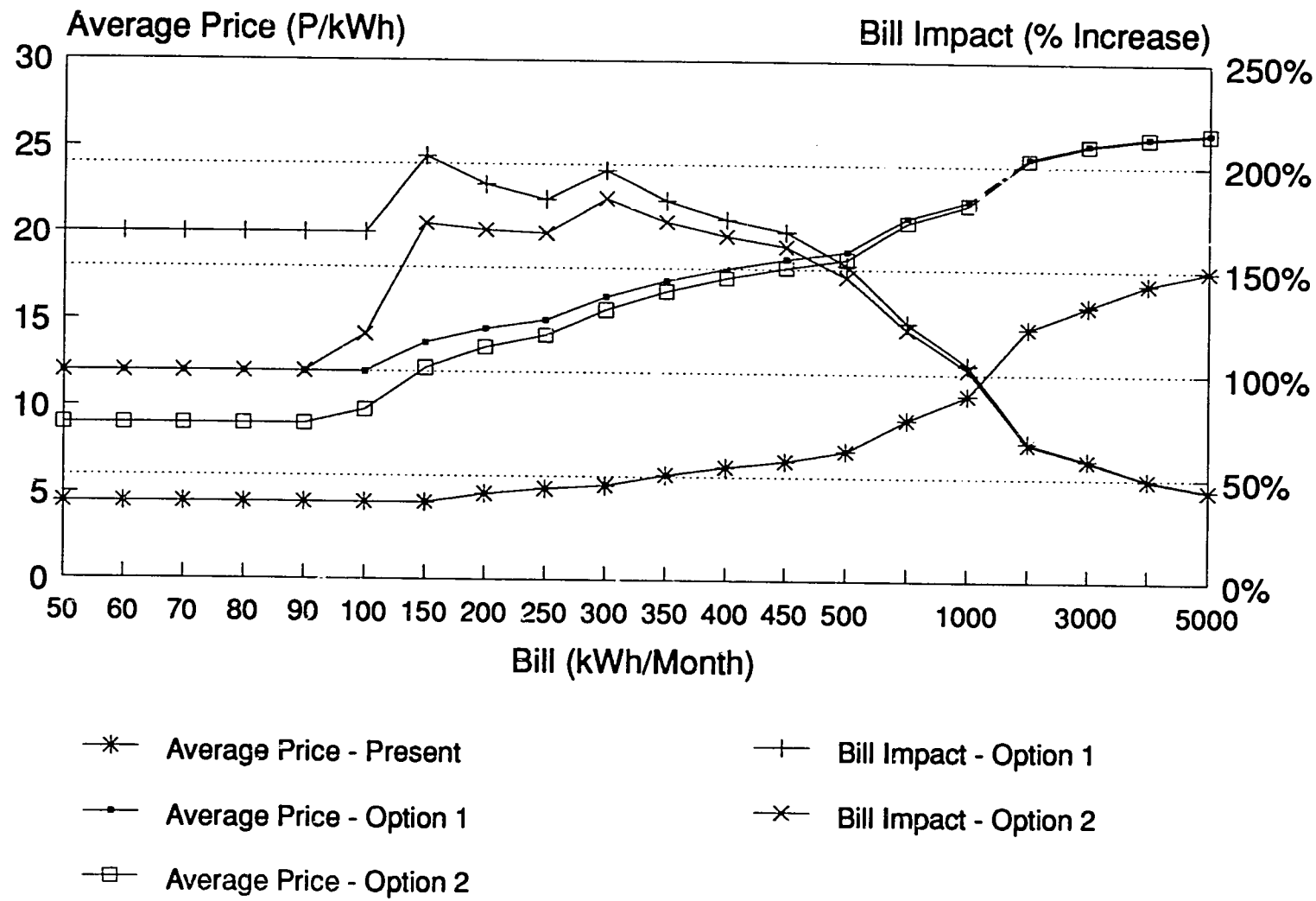
Exhibit 7-17

Commercial Tariff
Typical Bill Impacts Under Option 1 and 2



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applied to all accounts currently billed under the large moving power tariff, including all of their lighting-related consumption as well.

Eventually, all these customers (estimated to be about 2,000) should be on a mandatory time-of-day (TOD) tariff. These tariffs are developed in Chapter 9. However, that wide-scale implementation of TOD pricing will require time for various preparatory activities, including meter procurement, testing, calibration, implementation, training of meter readers and testers, altering billing procedures, etc. This process is likely to take two years.

Therefore, in the interim, and most immediately, it is recommended that the present two-part tariff structure be continued based upon a simple maximum demand charge (i.e., a non-coincident demand based charge) and a non-differentiated but flat energy charge as shown in Exhibit 7-18. The demand and energy charges have been aligned closely to the economic cost of supply and assuming a class load factor of 0.6, would result in meeting the class revenue responsibilities of 18.78 P/kWh. In addition, a flat energy charge structure is recommended in keeping with the long-run marginal cost structure. Typical impacts are illustrated in Exhibits 7-19 and 7-20. The data show that the percentage changes are driven by the customer's load factor rather than the size of the customer. Higher bill impacts will result for customers with load factors substantially below the class average. This should provide the necessary signal and incentive for

Exhibit 7-18
Proposed Tariff Structure: Large Power Service

Service Voltage	Demand Charge (LE/kW/month)*	Energy Charge (P/kWh)
MV	8.00	17.00

* Non-coincident demand

introducing some form of load management. We also understand that many accounts at present have a maximum demand much lower than their contract demands, but have not bothered to adjust their contract demands because the demand charge share of this bill at present is negligible.

Exhibit 7-19
Typical Bill Impacts: Large Power Servie

Customer Demand (kW)	Consumption (MWh/Month)	Monthly Load Factor	Bill (LE/Month) Present	Proposed	Percent Change
500	73	0.2	13,701	16,410	20%
	110	0.3	18,016	22,615	26%
	146	0.4	21,796	28,820	32%
	183	0.5	24,673	35,025	42%
	292	0.8	32,339	53,640	66%
700	102	0.2	19,181	22,974	20%
	153	0.3	25,222	31,661	26%
	204	0.4	30,515	40,348	32%
	256	0.5	34,542	49,035	42%
	409	0.8	45,275	75,096	66%
1,000	146	0.2	27,401	32,820	20%
	219	0.3	36,031	45,230	26%
	292	0.4	43,593	57,640	32%
	365	0.5	49,345	70,050	42%
	584	0.8	64,678	107,280	66%
2,000	292	0.2	54,803	65,640	20%
	438	0.3	72,062	90,460	26%
	584	0.4	87,186	115,280	32%
	730	0.5	98,691	140,100	42%
	1,168	0.8	129,356	214,560	66%

Medium Power Service

This tariff is proposed to be applied to all consumption -- motive power and lighting, process needs, etc. -- of customers with estimated demands of 100 kW or more, but under 500 kW. Further, it is recommended that the present differentiation between the agriculture and industry and public sectors be abandoned because this practice has no cost basis and is discriminatory. Thus, what is proposed is a merging of all accounts currently billed under the moving power (<500 kW) tariff -- agriculture, industry, government, public, private, investment -- and reclassifying the entire group into two segments differentiated by size. Those with estimated maximum demands under 100 kW should be classified under the Small Power Service Tariff and the remainder should be classified under the Medium Power Service Tariff category.

The recommended tariff design is defined in Exhibit 7-21. Based upon consumption shares of 5 percent for agriculture, 30 percent for industry, and 65 percent for public sector, this tariff is adequate for the desired revenue responsibility of 24.03 P/kWh.

The three-way distinction between agriculture (private, investment), industry (private, investment), and the public sector is shown in Exhibit 7-21 in contrast to the long-term objective enunciated above of eliminating discriminatory pricing. This distinction should be maintained only in the short-term for otherwise, a common tariff structure implemented immediately would result in substantially higher bill impacts upon the first consumer category (Exhibit 7-22). It is recommended that in subsequent tariff adjustments that the agriculture tariff should be increased proportionately much more than for the other two segments and that with the third adjustments beginning with FY 95, all price discrimination across consumer segments served under the Medium Power Service tariff be eliminated.

Small Power Service

As discussed previously, this tariff should be applied to all customers -- agriculture, industry, government -- regardless of whether they are "public," "private," or "investment" companies, and whose maximum demand is estimated to be under 100 kW. It was noted earlier that this category would represent approximately 95 percent of the estimated 60,000 accounts at present in the moving power (<500 kW) tariff, and three-fourths have maximum demands under 100 kW.

Because of low consumption levels, a one-part flat energy tariff is proposed for this category (Exhibit 7-23). The energy charge is pegged to the class revenue responsibility. Typical bill impacts are shown in Exhibit 7-24.

Exhibit 7-20
Average Price and Bill Impact
Large Power Service

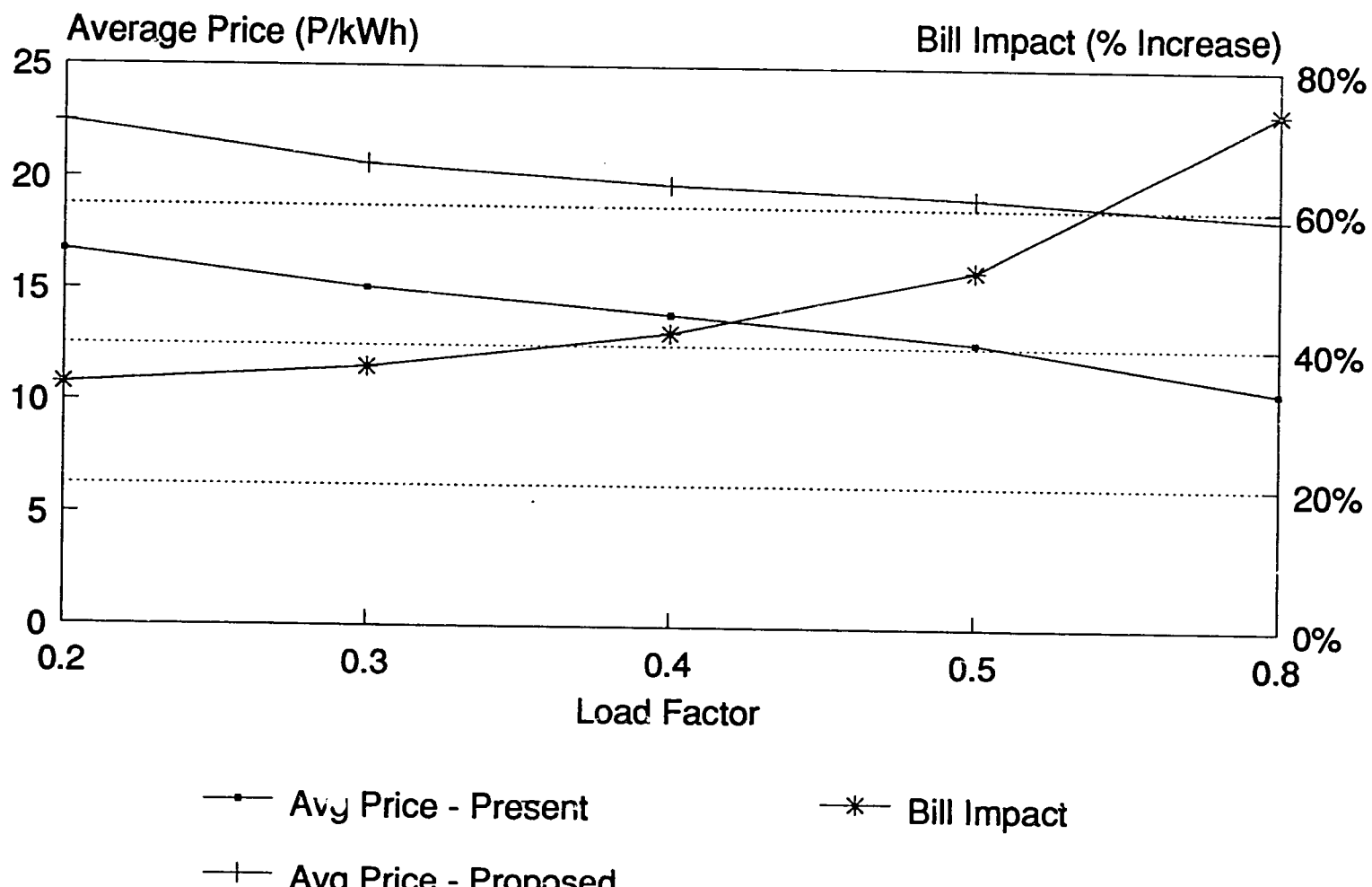

Exhibit 7-21
Proposed Tariff Structure: Medium Power Service

Customer Type	Demand Charge (LE/kW/Month)	Energy Charge (P/kWh)
Agriculture (Private, Investment)	--	11.80
Industry (Private, Investment)	--	24.70
Public Sector	--	24.70

A point worth mentioning at this juncture relates to the very small difference in the proposed Medium Power Service tariff for industry (private, investment) and the public sector (24.7 P/kWh as per Exhibit 7-21) and the Small Power Tariff (25.0 P/kWh as per Exhibit 7-23) This situation has arisen because the Medium Power Service agriculture segment tariff is still being subsidized, albeit to a lesser extent. As noted earlier, in subsequent adjustments of the Medium Power Service tariff, this price discrimination should be successively reduced and eventually eliminated. As such actions are implemented, the absolute difference in the magnitude of the Medium Power Service tariffs will increase over time.

We understand that a new law has been recently passed that precludes price discrimination between agriculture and other customer segments. Were this law to be enforced immediately, the FY 93 tariffs for Medium Power Service would have to be set as shown in Exhibit 7-21A.

Exhibit 7-21A
Proposed Tariff Structure: Medium Power Service
(Assuming Immediate Enforcement of
Non-Price Discrimination Principle)

Customer Type	Demand Charge (LE/kW/Month)	Energy Charge (P/kWh)
Agriculture (Private, Investment)	--	24.03
Industry (Private, Investment)	--	24.03
Public Sector	--	24.03

The corresponding typical bill impacts are shown in Exhibit 7-22A.

Free Zone Tariffs

Three categories of tariffs are proposed for companies located in a Free Zone:

- Free Zone - Large Power Service
- Free Zone - Medium Power Service
- Free Zone - Small Power Service

These designations parallel the corresponding customer classification for companies located outside the Free Zone. This segmentation is introduced because the objective is to eliminate any difference in tariff levels and structure between Free Zone tariffs and comparable tariffs for customers outside the Free Zone. Such differences cannot be rationalized on a cost basis and are discriminatory under commonly accepted principles of tariff rationalization.

Exhibit 7-25 presents the recommended Free Zone tariffs by power service category. As a practical matter, we understand that as of this writing, there were no customers under the Large Power Service category at VHV or HV.

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Exhibit 7-22
Typical Bill Impacts: Medium Power Service

	Consumption (kWh/Month)	Bill (LE/Month) Present	Proposed	Percent Change
Agriculture	10,000	680.8	1,180.0	73%
	20,000	1,265.8	2,360.0	86%
	40,000	2,411.8	4,720.0	96%
	60,000	3,557.8	7,080.0	99%
	80,000	4,703.8	9,440.0	101%
	100,000	5,849.8	11,800.0	102%
	120,000	6,995.8	14,160.0	102%
	140,000	8,141.8	16,520.0	103%
	160,000	9,287.8	18,880.0	103%
	180,000	10,433.8	21,240.0	104%
	200,000	11,579.8	23,600.0	104%
Industry	10,000	943.1	2,470.0	162%
	20,000	1,753.8	4,940.0	182%
	40,000	3,341.8	9,880.0	196%
	60,000	4,929.8	14,820.0	201%
	80,000	6,517.8	19,760.0	203%
	100,000	8,105.8	24,700.0	205%
	120,000	9,693.8	29,640.0	206%
	140,000	11,281.8	34,580.0	207%
	160,000	12,869.8	39,520.0	207%
	180,000	14,457.8	44,460.0	208%
	200,000	16,045.8	49,400.0	208%
Public Sector	10,000	1,565.3	2,470.0	58%
	20,000	2,911.8	4,940.0	70%
	40,000	5,549.8	9,880.0	78%
	60,000	8,187.8	14,820.0	81%
	80,000	10,825.8	19,760.0	83%
	100,000	13,463.8	24,700.0	83%
	120,000	16,101.8	29,640.0	84%
	140,000	18,739.8	34,580.0	85%
	160,000	21,377.8	39,520.0	85%
	180,000	24,015.8	44,460.0	85%
	200,000	26,653.8	49,400.0	85%

Exhibit 7-22A. Typical Bill Impacts: Medium Power Service (Assuming Implementation of Non-Price Discrimination Principle)

	Consumption (kWh/Month)	Bill (LE/Month) Present	Proposed	Percent Change
Agriculture	10,000	680.8	2,403.0	253%
	20,000	1,265.8	4,806.0	280%
	40,000	2,411.8	9,612.0	299%
	60,000	3,557.8	14,418.0	305%
	80,000	4,703.8	19,224.0	309%
	100,000	5,849.8	24,030.0	311%
	120,000	6,995.8	28,836.0	312%
	140,000	8,141.8	33,642.0	313%
	160,000	9,287.8	38,448.0	314%
	180,000	10,433.8	43,254.0	315%
	200,000	11,579.8	48,060.0	315%
Industry	10,000	943.1	2,403.0	155%
	20,000	1,753.8	4,806.0	174%
	40,000	3,341.8	9,612.0	188%
	60,000	4,929.8	14,418.0	192%
	80,000	6,517.8	19,224.0	195%
	100,000	8,105.8	24,030.0	196%
	120,000	9,693.8	28,836.0	197%
	140,000	11,281.8	33,642.0	198%
	160,000	12,869.8	38,448.0	199%
	180,000	14,457.8	43,254.0	199%
	200,000	16,045.8	48,060.0	200%
Public Sector	10,000	1,565.3	2,403.0	54%
	20,000	2,911.8	4,806.0	65%
	40,000	5,549.8	9,612.0	73%
	60,000	8,187.8	14,418.0	76%
	80,000	10,825.8	19,224.0	78%
	100,000	13,463.8	24,030.0	78%
	120,000	16,101.8	28,836.0	79%
	140,000	18,739.8	33,642.0	80%
	160,000	21,377.8	38,448.0	80%
	180,000	24,015.8	43,254.0	80%
	200,000	26,653.8	48,060.0	80%

Exhibit 7-23
Proposed Tariff Structure: Small Power Service

Service Voltage	Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
LV	--	25.00

Exhibit 7-24
Typical Bill Impacts: Small Power Service

Consumption (kWh/Month)	Bill (LE/Month)		
	Present	Proposed	Percent Change
1,500	254	375	47.6%
2,000	339	500	47.6%
3,000	508	750	47.6%
4,000	678	1,000	47.6%
5,000	847	1,250	47.6%
6,000	1,011	1,500	48.3%
7,000	1,150	1,750	52.2%
8,000	1,288	2,000	55.2%
9,000	1,427	2,250	57.7%
10,000	1,565	2,500	59.7%
15,000	2,252	3,750	66.5%
20,000	2,912	5,000	71.7%
25,000	3,571	6,250	75.0%
30,000	4,231	7,500	7[illegible]%
35,000	4,890	8,750	78.9%
40,000	5,550	10,000	80.2%

Exhibit 7-25
Proposed Tariff Structures: Free Zone Tariffs (Effective FY 93)

Tariff Category	Service Voltage	Option	Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
1. Free Zone Large Power Service (> 500 kW)	VHV	1	8.99	7.30
		2	--	8.62
	HV	1	9.39	13.00
		2	--	14.83
	MV	1	16.63	15.00
		2	8.00	17.00
2. Free Zone Medium Power Service (≥ 100 kW, but < 500 kW)	LV	1	4.16	23.00
		2	--	24.70
3. Free Zone Small Power Service (< 100 kW)	LV	--	--	25.00

Exhibit 7-26
Proposed Street Lighting Tariff (Effective FY 93)

Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
--	26.07

To illustrate, consider Large Power Service - MV. Option 1 preserves the demand charge value in the present tariff (i.e., LE 16.63/kW/month), and the energy price has been raised to achieve revenue responsibility. Tariff Option 2 also ensures the desired responsibility, but is identical to the tariff proposed for Large Power Service for companies located outside the Free Zone. Similar considerations guided the design of all the other tariff designs proposed in Exhibit 7-25.

Street Lighting Tariff

It is recommended that the existing government and public lighting tariffs be redefined to be applicable for street lighting consumption only. The lighting consumption of government accounts should be transferred to the appropriate tariff within one of the three power service tariff categories.

The recommended street lighting tariff is shown in Exhibit 7-26. This tariff is designed to recover the economic cost of supply. It is understood that the capital and O&M costs associated with the installation of street lighting -- poles, fixtures, luminaries, photovoltaic cells, conductors, etc. -- and directly borne by the respective municipalities concerned. Consequently, the tariff is intended to recover only the cost of generation and distribution of electricity.

Sales for Resale

Approximately 2.5 percent of Distribution Company sales are for resale. Over 85 percent of these sales are to "Housing Companies," of which the Heliopolis Distribution Company is by far the largest customer. Housing Companies, in turn, distribute power mostly to households, but also some commercial "shops" and other non-residential customers at the posted retail tariffs of EEA/EDA.

The recommended tariff for sales for resale is shown in Exhibit 7-27.

At present, the tariff for this category of sales is an energy-only charge and the meters in-place at the various delivery points are energy meters. It is recommended that in the long run, all sales in this category be priced on a TOD tariff (as discussed further in Chapter 9). However, it is recognized that the implementation of such a scheme could take some time. In the interim, therefore, a pure energy tariff will need to be applied, as shown in Exhibit 7-27.

Exhibit 7-27
Proposed Tariff for Sales for Resale (Effective FY 93)

Demand Charge (LE/kW/month)	Energy Charge (P/kWh)
--	12.50

Alternate Tariff Design Based on "Low LRMC Case"

The tariff design presented so far in this chapter has been developed from the Base Case LRMC-derived yields and revenue responsibilities. EEA requested an alternate tariff design that follows the same procedure and process, but starting with yields derived from an alternate LRMC estimation, with the latter corresponding to the 6 percent discount rate case in contrast to the 10 percent discount rate utilized for the Base Case LRMC analysis. This alternate case LRMC design is referred to in the text as the "Low LRMC Case." To avoid clutter and confusion in the main body of this report, the alternate tariff design is presented in Appendix U.

The study team would like to note for the record its position regarding the "Low LRMC Case." In our professional judgment, and based upon our experience, a 6 percent discount rate for LRMC calculation is unrealistic and therefore, the rationalization of the Low LRMC Case based upon the choice of a low discount rate is inappropriate. On the other hand, we believe it is perfectly valid to develop an alternate tariff design -- identical to that presented in Appendix U -- but where the rationalization is direct and defensible, i.e., that the revenue targets are set at levels such that the year-to-year average increases required from today's level to FY 93, from FY 93 to FY 94, and so on, are politically and socially the maximum that are feasible.[8]

7.5 OTHER TARIFF CLAUSES/PROVISIONS

This section contains a discussion of selected provisions/clauses related to the proposed tariffs other than demand and energy charges.

[8] If it so happens that this approach implies tariff yield targets that are comparable to those derived using the low (6 percent) discount rate basis for estimating LRMC, this is mere coincidence, and not vice versa. The reverse chain of thought for rationalizing the alternate tariff design case is inappropriate.

Customer Charge

Under tariff rationalization employing marginal cost principles, a customer charge can be applied to reflect costs that are directly attributable to a specific user such as the cost of metering, meter reading, meter maintenance, bill preparation, and revenue collection. The table below shows estimates of these costs for FY 93.[10]

Tariff Category	Customer Charge FY 93 LE/Customer/Month
Residential	
Single Phase	2.50
Three Phase	5.50
Commercial	
Single Phase	2.75
Three Phase	6.00
Small Power Service (< 100 kW)	4.25
Medium Power Service (100 to 500 kW)	27.50
Large Power Service (> 500 kW)	49.50

From a practical standpoint, we do not propose a customer charge in the tariff. Analysis reveals that low-usage customers (who presumably include low-income households and very small shops) experience negative bill impacts. This is because, even though the charge is small in absolute terms, expressed on a per kWh basis for low-usage customers,

[10] The "connection charge" that existing customers have already paid supposedly reflected the cost of a service drop. That charge needs to be paid only once. However, the "customer charge" concept of this section reflects the components noted above other than the cost of service drop. This charge is attributable to all customers -- new and existing -- and on a recurring basis.

the cost becomes substantial.[10] For large customers, on the other hand, the customer charge is very small in magnitude in comparison to their total bill.

Fuel Adjustment Clause

At present, there is no fuel adjustment clause (FAC) in place, except for accounts classified as "Investment Companies." For these accounts, the following adjustment is made to the price of each kWh:

For VHV and HV:	=	0.38 mills/kWh x	(International price of fuel oil - subsidized price of fuel oil)
For MV:	=	0.40 mills/kWh x	(International price of fuel oil - subsidized price of fuel oil)
For LV:	=	0.42 mills/kWh x	(International price of fuel oil - subsidized price of fuel oil).

The purpose of a FAC is to ensure that the utility recovers actual fuel costs incurred. Energy costs in posted tariffs must be developed based upon expectations of average fuel prices that will prevail over the tariff cycle duration; this is one year in the case of Egypt.

Deviations between actual fuel prices paid by the utility and the reference price on which the base energy tariff is based can be adjusted for on a regular basis through the FAC. Such ex-post "true ups" may be an upward or downward adjustment of the bill, depending upon the direction of deviation between the actual fuel price and the reference price.

In the case of EEA, the price of fuel is set by EGPC and is not subject to significant fuel cost variations in real time that many utilities elsewhere face. Further, EEA's operates on an annual tariff cycle. These two factors together limit -- indeed virtually eliminate -- the risk exposure to adverse cost variances stemming from fuel price considerations. Consequently, a FAC is not required at present.

[10] Indeed, under the present tariff, customers with monthly consumption under 80 kWh have a monthly bill under the LE 2.50/month customer charge shown in the table above. In other words, at present, it costs more to simply meter and bill such customers than what they pay in total. Thus, there is no recovery of any costs for the generation and delivery of electricity to this customer segment.

Further, our tariff proposal calls for eliminating any discrimination in tariffs that presently exist by customer segments variously labelled as "industry," "agriculture," "private," "investment," "public," "investment company," "joint venture company," "Free Zone company," etc. As a consequence, we recommend that the FAC noted above for "investment companies" be dropped as well.

Metering Point

In the foregoing, it can be assumed that for Large Power Service (LPS) customers and Medium Power Service (MPS) customers, the recommended tariffs are applicable when sales are metered on the primary side and the customer owns the transformer (or equivalently, pays for the transformer in the connection charge).

In those circumstances where metering is undertaken on the secondary side of the transformer, it is recommended that the energy charge component of the tariffs be increased by 1.0 percent to provide for transformer losses. The one percent figure is reflective of losses under half-load conditions for transformers between 50 kVA and 1,500 kVA.

The Small Power Service (SPS) tariff assumes a secondary-side metering point. In addition, the tariff allows for the utility (i.e., DC) to provide the necessary transformer capacity (i.e., the cost of distribution transformer capacity is not directly collected via the connection charge but via the tariff itself).

In the case of DCs, since the Cairo and Alexandria DCs are financially responsible for the investment in 66/11 kV substations, it can be assumed that the recommended tariff is applicable at a primary-side delivery point and hence, a primary metering point. For DCs where EEA will be responsible for the investment in 66/11 kV substations, the recommended tariff can be assumed to apply at a primary metering point. In such cases, if metering is on the secondary side, the energy charge component of the tariff can be increased by about 1.0 percent to reflect transformer losses under design loading conditions (typically one-half load).

7.6 TARIFF YIELDS AND LRMC: A COMPARISON WITH SELECTED COUNTRIES

This section presents information on tariff yields and economic cost of supply in selected countries -- developed and developing. These data are of comparative interest. They provide an economic frame of reference against which the current Egyptian tariff yields, and the revenue requirement and economic the cost of supply estimates can be assessed.

It is important to state the obvious at this juncture. The cost structure of electricity supply naturally varies from country to country, and is a function of a host of variables, including generation resource mix, customer mix, income, geography, climate, industry mix, and level of electrification and development. By the same token, the data presented below show that in spite of these differences, this cost of supply varies within a fairly narrow band across a wide range of countries. This is not surprising given that broadly speaking, equipment cost for power supply -- generation and network -- is typically on the order of 75 to 80 percent of the total cost of supply. These equipment are generally purchased under international competitive tender, and inter-country differences in such costs are not likely to be significant. Thus, most of the differences in the economic cost of power supply across countries will stem from what is the "marginal fuel" for power generation and its economic cost.

Exhibit 7-28 provides data on tariff yields and economic cost of supply -- bulk and retail -- in selected countries. The customers shown were selected based upon availability of fairly current data (i.e., 1989 and more recent data). Where the original data are not for 1991, they have been escalated to 1991 US$.

The system-wide average LRMC values for Egypt are comparable, but somewhat lower than for countries/power systems reported in Exhibit 7-28. This is because of the fact that the marginal fuel in Egypt is mazout (i.e, residual fuel oil) or gas, whose economic cost is pegged to its substitute (i.e., mazout). The economic cost of supply is very close to those reported for the Alabama Power Company. Interestingly, the two power systems are also comparable in terms of system size, peak load, and fuel mix.

By contrast, the system-wide average tariff yield at present in Egypt is an order of magnitude below the economic cost of supply as noted earlier, but also well below the average yields in the other countries shown in the exhibit.

Exhibit 7-29 provides current data on average tariff yields in selected countries for the industrial and commercial customer segment. Yields in April 1991 ranged from a low of about 4 US ¢/kWh in Australia to a high of about 10 US ¢ in Germany and Italy. By

comparison, the average current yields in Egypt and revenue responsibilities are shown in Exhibit 7-30.

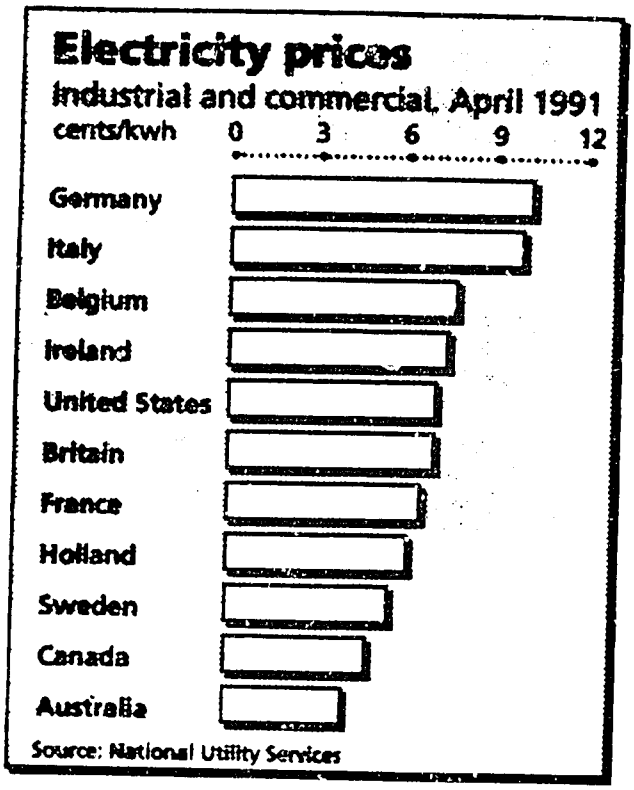
Finally, Exhibit 7-31 shows average electricity prices for residential, commercial, and industrial customers in a number of North, Central and Latin American countries. By comparison, the current residential tariff yield in Egypt is 1.28 US ¢/kWh and the current commercial tariff yield is about 3.28 US ¢/kWh.

Exhibit 7-28
Tariff Yields and LRMCs for Selected Countries
(US cents per kWh; 1991$)

	Average Yield	LRMC
BULK TARIFFS		
1. USA		
Typical range for a large number of utilities	3 - 4	--
Alabama Power	4 - 4.5	3 - 3.5
2. Canada (Ontario Hydro)	3.3	--
3. Philippines (NAPOCOR, 1980)	4.6	6 - 7
EGYPT - EEA	1.8	3.7
RETAIL TARIFFS		
1. USA		
Typical range for a large number of utilities	6 - 8	--
Alabama Power	6 - 7	6 - 8
2. United Kingdom	7 - 8	--
3. Germany	8 - 11	--
4. France (EDF)	6	--
5. Italy (Enel)	7	--
6. Canada (Ontario Hydro)	6	--
7. India (4 electricity boards)	2.5 - 3.5	8 - 10
EGYPT		
EDA	2.9	5.9
All Final Sales	2.6	5.2

Source: RCG/Hagler, Bailly, Inc., based upon published and unpublished data.

Exhibit 7-29
International Industrial and Commercial
Average Electricity Prices, April 1991 (US ¢/kWh)



Source: *The Economist*, May 25, 1991.

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Exhibit 7-30
Current Yield and Revenue Responsibility for Industrial Customers in Egypt (US ¢/kWh)*

Tariff Category	Estimated Average Current Yield	Revenue Responsibility for FY 93
EEA		
VHV	1.32	2.11
HV	2.45	3.75
Large Moving Power Tariff (> 500 kW)	4.29	4.74
Moving Power Tariff (< 500 kW)	3.81	6.17

* Exchange rate 3.3-to-1 US$.

Exhibit 7-31
Average Electricity Prices in Selected Countries in North, Central and Latin America (June 1991 US ¢/kWh)

Country	Average Price Per kWh		
	Residential	Commercial	Industrial
Argentina	9.49	10.69	6.36
Brazil	4.86	5.71	2.82
Colombia	2.35	7.02	5.24
Costa Rica	5.10	7.85	2.54
Chile	10.63	10.37	6.41
Mexico	5.14	11.24	5.11
Peru	4.74	4.71	2.36
USA (various utilities)	4.5 - 10.00	4.5 - 10.00	3.0 - 8.00

CHAPTER 8: ECONOMIC IMPLICATIONS OF PROPOSED TARIFFS

The objective of this chapter is to evaluate the macroeconomic impacts of the electricity rate changes recommended in this report. This evaluation was hindered by several important factors:

- There are currently no comprehensive macroeconomic models available with which to evaluate the changes of interest here. Creating such models was beyond the scope of this study.

- Data on the Egyptian economy are poor. Good current data are simply not available on such important variables as income distribution, cost structure within industry, production functions, etc.

- Important sectors of the economy are not driven by normal economic prices. Rather, prices of both inputs and outputs are controlled by public intervention. In those cases, it is not possible to say exactly what the effect of electricity costs (or any other costs) will be on ultimate prices and competitiveness because these are not determined by purely economic forces.

- No statements can be made about employment. Employment in Egypt, especially in manufacturing, is not determined by economic conditions, but by the state. Even if it were not, no information exists that would allow us to make quantitative statements about the employment effects of changes in electricity tariffs.

Our approach uses the fragments of information that are available. Often we have pieced things together using information from several sources. None of our calculations can pretend to lead to precise estimates. *Thus, our objective was to make estimates that are within a reasonable range.* A general assumption made throughout this evaluation is that there is no phase-in of the real tariff increases. This was done for two reasons:

- First, there are no models available that would allow us to spread the impact of tariff increases in anything other than an arbitrary, proportional manner. Therefore, if we were to consider a phase-in, the effects would be proportional to the pace of the phase-in.

- Second, a one-step tariff increase assumption allows us to see the maximum impact of the tariff changes. In this way, we are creating a "worst case" scenario.

Our main attention is focused on the impact of the tariff changes on inflation, industrial growth and exports, and on residential customers. We also comment on the way in which electricity rate reform fits in with other reforms contemplated in Egypt.

8.1 INFLATION

Ideally, if we had a comprehensive transactions matrix for Egypt, we would be able to begin to estimate the impact of electricity prices on overall prices. A transactions matrix divides the economy into important economic activities, and shows, for each, the purchases of inputs that are made to produce one unit of output. When the transactions matrix includes all economic activities, it can be presented as a standard input-output (I/O) matrix, the properties of which are well known. Assuming that the production and sale of electricity is one of the economic activities represented in the matrix, the impact of electricity price changes could be decomposed into two parts. First, there is a direct impact. That is, to the extent that each activity uses electricity, its production cost rises when the electricity price rises. Second, there is an indirect impact. Because the costs of all inputs that use electricity rise, the costs associated with any given activity rise through the cost increases passed on by input suppliers.

Having an I/O matrix for Egypt would be only a beginning. Within an I/O matrix, the coefficients relating to the production and consumption of inputs are fixed. The use of such a matrix carries an implicit assumption that no matter what the prices of inputs, the proportional relationships among inputs remain fixed. But we know that if there are relative price shifts, producers have an incentive to reallocate inputs, thereby changing the coefficients in the matrix. Indeed, it is this reallocation that is one of the important changes that we expect from raising electricity prices to LRMC. Thus, an I/O matrix alone will give us only a limited view of how costs are affected. That view is a short-run one, covering the period of time within which no significant resource reallocation can occur.

Exhibit 8-1 shows part of a very aggregated transactions matrix for Egypt developed by Eckaus et al. (1988), based on data collected in 1983. The matrix has aggregated all economic activity into only eight categories that are of interest here, but one of them is the production and use of electricity. Reading down each column, one sees the proportion of the value of final output of the activity of the column, which is attributable to purchases

Exhibit 8-1
Aggregated Transactions Matrix

	Agri-culture	Crude Oil	Fuel	Mnfg.	Con-struc-tion	Trans-port	Ser-vices
Agriculture	0.26	0	0	0.117	0	0.001	0.007
Crude Oil	0	0	0.619	0	0	0	0
Fuel	0.002	0	0.015	0.022	0.022	0.128	0.001
Manufacturing	0.048	0.01	0.067	0.259	0.325	0.049	0.037
Construction	0.002	0.005	0.003	0.012	0.003	0.003	0.005
Transport	0.009	0.001	0.004	0.023	0.024	0.036	0.004
Services	0.037	0.187	0.063	0.076	0.078	0.111	0.089
Electricity	0.002	0	0.008	0.013	0.002	0	0.001

Source: Eckaus et al., 1988.

of inputs shown in the rows. For example, the production of one unit of agricultural output requires inputs of .26 (26 percent) from agriculture itself, 0.002 (0.2 percent) from the electricity sector, and so forth.

We have used this matrix in the following way to estimate the impact on sector prices of a given change in electricity costs. First, we have assumed that there is a 62 percent increase in the cost of electricity for all sectors.[1] This alone gives a *direct impact* on the costs of the sectors using significant amounts of electricity as an input. Second, we went through an iterative procedure to obtain the *indirect impact*. In the first step of the iteration, we plugged in the direct impact that electricity prices had on each input sector. This gave a "first round" indirect impact on output sectors. In the second step, we plugged in the "first round" indirect impacts to obtain a "second round" indirect impact, and so forth. Finally, because the indirect cost impact decreases with each iteration, the procedure quickly converges on the final indirect impact, and therefore on the total impact.[2]

[1] 62 percent was selected because this is approximately the real rate increase recommended for the productive sectors. 62 percent is approximately the unweighted, real price increase for Industry (exclusive of very large customers) plus commercial customers.

[2] After five iterations, there is no further appreciable effect on the calculation.

The impacts on each sector, of assuming a 62 percent increase in electricity prices, that are implied by the transaction coefficients in Exhibit 8-1, are as follows:

Agriculture	0.3%
Crude Oil	0.1
Fuel	1.6
Manufacturing	1.2
Construction	0.6
Transportation	0.2
Services	0.2

In all cases, the figures presented have been rounded up, in keeping with the approximate nature of our calculations and erring on the side of the "worst case." As one can easily see, even a substantial electricity tariff increase has only a modest impact on most productive sectors. In the most-affected case, manufacturing costs increase by about 1.2 percent. In general, the indirect effects are no more than the direct effects. For example, in the manufacturing sector the direct effect of the 62 percent rise in electricity cost raises manufacturing costs by about 0.8 percent. The indirect effects add another 0.4 percent (i.e., it raises the direct effect by an additional 50 percent), for a total price increase of 1.2 percent.[3]

The manufacturing sector is of particular concern. We therefore consider the additional information on that sector shown in Exhibit 8-2, which gives a disaggregation of some manufacturing activities in Egypt. Information is provided for five industrial subgroups: spinning and weaving, food processing, chemicals, engineering goods (i.e., capital goods), and the metallic industry. In the first column are the proportions of production accounted for by each of the subcategories shown. These can be used to form a weighted average for electricity intensity for the group. Column 2 shows the percentage of total cost in each industry that is the cost of electricity. When these percentages are weighted by the contribution of each industry to the total and summed, it can bee seen that on average,

[3] These results are fairly typical of this kind of analysis. For example, in the case of Indonesia, the indirect effects tended to double the direct effects (for example, see Indonesia, 1989 or Hughes, 1987).

Exhibit 8-2
Selected Industries and Electricity Costs (1989-90)

	Proportion in Production	Electricity as a % of Costs	Direct Impact of 62% Electricity Price Increase	Total Impact of 62% Electricity Price Increase
Spinning and Weaving	0.26	2.70	1.67	2.51
Food	0.31	0.62	0.38	0.57
Chemicals	0.16	2.20	1.36	2.05
Engineering	0.12	0.43	0.27	0.40
Metallics	0.15	5.10	3.16	4.74
Weighted Average		2.06	1.28	1.91

Source: EEA

electricity accounts for about 2 percent of the costs of industry.[4] In Column 3, we show the direct effect on those industries of a 62 percent increase in the cost of electricity.1

There is a considerable range to these direct impacts, ranging from about 0.3 percent for engineering goods to over 3 percent for the metallics sector. On average, for the aggregated industrial group, the direct impact of a 62 percent electricity price increase would be to increase costs by about 1.3 percent. If these direct effects were subject to indirect effects as calculated above, the indirect effects would raise these costs by about another 50 percent. Thus, weighted average costs overall would rise by a total of about 1.9 percent.

Considering the price changes resulting from the iterations with the transactions table and some of the information from Exhibit 8-2 on more specific industries, we have made some estimates of the effect on prices of a 62 percent increase in electricity prices for several

[4] There is good consistency between the matrix put together by Eckaus et al. (1988) and the additional information provided by EEA. In the Eckaus transactions matrix, the manufacturing sector is represented as having 1.3 percent of its costs accounted for by electricity. For a similar period, 1987-88, EEA data on the industries shown in Exhibit 8-2, which are not quite the same as the Eckaus grouping, showed an electricity intensity of 1.5 percent (see Exhibit 8-5). In Exhibit 8-2, overall electricity intensity is about 2 percent, but that is for 1989/90, after significant electricity price increases. Much of the problem with dealing with these figures is related to the way in which product prices are set.

categories of goods. These are summarized in Exhibit 8-3. The reader should recall that these are very general approximations, derived from incomplete and probably inaccurate data. Nevertheless, they should give some idea of the orders of magnitudes involved.

How would these cost increases, if fully passed on to consumers, affect inflation? Exhibit 8-4 shows the makeup of the Egyptian consumer price index (CPI). Note that within the CPI, the largest weight by far (55 percent) is on the category "food, beverages and tobacco." This category is one that is not very electricity intensive in its production, and our transactions table calculations show that the agricultural prices have a tendency to rise

Exhibit 8-3
Estimated Ranges for Price Increases

	Percentages
Spinning and Weaving	2.5
Food	0.3 to 0.6
Manufacturing	1.2 to 2.0
Construction	0.6
Transport	0.2
Services	0.2

by only about 0.3 percent should there be a 62 percent increase in electricity costs. Observations in Exhibit 8-3 indicated that food prices may rise by about 0.3 to 0.6 percent. Prices of manufactured goods, which are most affected by electricity prices, carry a relatively small weight in the CPI. To calculate the impact on the CPI of price increases for specific categories, we have made the following assumptions:

- The categories "furniture and equipment" and "miscellaneous" are manufactured goods.

- The components in "rent/power/fuel" are in the proportions rent (50 percent), power (10 percent), and fuel (40 percent). Rent is assumed to increase at the same rate as construction (0.6 percent), power by the rate of increase for electricity (62 percent), and fuels by 0.6 percent.

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Exhibit 8-4
Egypt's Consumer Price Index

Component	Weight	Est. Price Increases
Food, Beverage, Tobacco	0.555	0.3 to 0.6
Clothing, Footwear	0.109	2.5
Rent/Power/Fuel*	0.104	6.7
Furniture, Equipment	0.051	1.2 to 2.0
Medical Care	0.027	0.2
Transport and Comm.	0.048	0.2
Rec. and Education	0.033	0.2
Misc.	0.073	1.2 to 2.0
Total	1	1.3 to 1.6

* Assumes that within the category the weights are: rents (.5), power (.1), and fuel (.4). Assumed price increases are rents (16 percent), fuel (0.6 percent), and power (62 percent).

Source: CPI weights, AID.

In Exhibit 8-4, we have shown, along with the weights for each item in the CPI, the range of price increase that we have assumed will occur due to a 62 percent rise in electricity prices. The result of these assumptions is that the CPI would rise by only about 1.3 percent to 1.6 percent over what it would have seen had no real price increase occurred for electricity.

One could easily question whether the full extent of these price increases would be felt in the markets where these goods are sold. Normally, price increases of this type are only partially passed on to consumers because initial price increases will encounter some reduced demand or competition from imports. In Egypt, it is likely that much of the price increase will be felt for the following reasons:

- Most economic activities are in the public sector or are subject to price controls. Prices are set on a "cost plus" basis. Presumably, as costs increase due to electricity price changes, prices will be adjusted accordingly. We comment more on this below.

- Import competition is weak. High duties and the selective use of import bans would probably prevent imports from dampening the tendency for domestic prices to rise.

Thus, it is likely that the price increases estimated will be largely reflected in local markets. To the extent that price increases are dampened by normal market activities, our estimates will turn out to be slightly on the high side.

8.2 INDUSTRIAL SECTOR

Of major concern in Egypt is the impact that increased electricity prices would have on industrial production. Implicit in this concern is that electricity is a significantly large proportion of production costs and that the prices of electricity are important in determining the competitiveness of Egyptian industrial goods. We will examine both of these contentions in this section. In separate discussions, we will examine industrial pricing in Egypt and the importance of electricity in industrial costs.

Industrial Pricing

Most industrial activity in Egypt is publicly owned and operated. Prices of inputs and of industrial outputs at all levels are controlled by the public sector, and many prices require cabinet-level approval before they can be changed. The result has been prices that are set and changed arbitrarily. The rationale for changing prices is supposed to be that costs have changed, but this principle is frequently distorted by other considerations. Often, firms are expected to subsidize other firms when supplying inputs, on the grounds that their own input prices are subsidized. Social objectives often enter the picture. The accounting costs that prices are usually based upon reflect embedded book values, not true economic values, which tend to diverge widely during periods of significant inflation. Finally, the whole pricing setting has been overlaid by a protectionist tariff structure and the imposition of import prohibitions. In short, prices in Egypt do not often reflect economic rationality.

To illustrate pricing problems, several examples are offered below. These are not offered as full industrial case studies, for the resources allocated to this study were not sufficient

for that.[5] Nevertheless, they show that pricing is the main problem for Egyptian manufacturing. The specific pricing of electricity is a much less significant problem.

- **Aluminum:** The aluminum company exports 45 percent of its production, at world prices, without subsidies or other special export promotion. It must sell 55 percent of its output in the domestic market at about 30 percent of world prices.[6] The weighted average price would therefore be about 62 percent of the world price, which was listed in the *Wall Street Journal* (April 25, 1991) at about $1,400 per ton on the LME.

- **Fertilizer:** Kima makes nitrogenous fertilizer, 90 percent of which must be sold to the agricultural credit bank at a price of $72 per ton. The world price was stated as being about 112 Sterling/ton (about $190). Kima claims that electricity is its main purchased input and is 35 percent of its costs.[7] Abou Zhabal claims that electricity is about 5 percent of total costs.[8] Neither fertilizer producer uses gas as a feedstock.

- **Steel:** Re-bar is the main steel product. The domestic re-bar market is about 2 million tons. Public enterprises sell about 350,000 tons, most of the rest is supplied by private companies, and a small balance is imported, carrying a 15 percent import duty. The public sector producer must sell to the Ministry of Housing at LE 760/ton; the Ministry resells it at LE 825. Private firms sell at about LE 1,000/ton (this implies a world price of LE 870, or $264/ton).

- **Ferro Silicon:** This is sold by Ferro Alloys, which currently sells about 40,000 tons annually. Eighty percent is exported, at fob $600/ton. The

[5] The information provided came from interviews with representatives of the Metallurgical Industries Corporation, Egyptalum, Kima Fertilizer, Abou Zhabal Fertilizer, and with Professor Hanna Kheir-El-Din, a specialist in the textile industry.

[6] There were also some sales to investment companies (joint ventures) at world prices (i.e., LME prices) minus 15 percent. In general, the information given by the industry representative was consistent with information provided by EEA for the year 1987/88. At that time, 45 percent of aluminum sales occurred in the domestic market; the rest was exported. Sales to investment companies (9 percent of the total) occurred at about world prices minus 15 percent. Other domestic sales occurred at between 27 percent and 36 percent of the export price, depending on the product.

[7] This is consistent with other statements made about costs; see below.

[8] This, too, is consistent with statements reviewed below.

remaining 20 percent must be sold in the local market at LE 1,500/ton ($455/ton).

In general, what these examples show is that through pricing, the government is forcing these companies to subsidize other parts of the economy. The rationale sometimes is that these firms receive subsidized inputs prices, so they too should give subsidized prices. In the examples given, the subsidies are sometimes quite large.

The firms in these industries are naturally concerned about electricity costs. Kima, Egyptalum, and the Iron and Steel Company are the most electricity-intensive firms in the country. In all cases, officials of these firms monitor the relationship between their costs and electricity consumption. Some of their observations are:

- **Abou Zhabal** estimates that a 40 percent increase in the cost of power implies a cost increase of LE 10/ton. Because the price they receive is now LE 420/ton, the increase would be 2.4 percent. However, compared to the world price of about LE 700/ton, the cost increase would be 1.4 percent.

- **Kima** estimates that a 1 mill increase in electricity implied a cost increase of LE 6/ton. At an electricity price of 12.2 mills/kWh, a 40 percent increase[9] in the rate would be a 5 mill increase, implying a cost increase of LE 30/ton. They now must sell most of their output at $72, or LE 238/ton, implying a cost increase of 12.6 percent. However, compared to world prices ($190 or about LE 630/ton), the price increase would be 4.8 percent.

- **Egyptalum** said that a 1 mill increase implied a cost increase of LE 18/ton. Their current electricity cost is 28.89 mills per kWh, implying that a 40 percent increase in the electricity price would be 11.5 mills. This implies a cost increase of LE 207/ton. Their average price for aluminum is $910, or LE 3003/ton. Thus, the cost increase from a 40 percent rise in the electricity price would be about 6.9 percent. However, our view of the price increase changes sharply if we distinguish between the world price of aluminum ($1,400/ton or LE 4,620) and the domestic price (30 percent of the world price, or about LE 1,386/ton). Relative to the world price, the cost increase is 4.4 percent; relative to the domestic price, it is 15 percent.

In general, the potential increases for the products of these firms looks large only if we focus on the artificially low prices that they are forced to charge in the domestic market. If

[9] A 40 percent increase is used here to make the example consistent with Abou Zhabal's case.

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we can focus on what world market prices would be, the cost increases implied are much more modest.

The textiles industry is probably the most important industry in Egypt. It supplies almost all domestically consumed clothing and over 50 percent of Egypt's non-petroleum exports. Within the textile industry there are tremendous price distortions affecting both inputs and outputs. Observations on the textiles industry are:

- Marketing of raw cotton fiber is 100 percent public sector controlled. Farmers are paid a price far below world prices. Data from Kheir-El-Din (1991) for 1989/90 show that while the export price for extra-long staple cotton (ELS) is LE 296/kantar, farmers are paid only LE 216. Furthermore, when the cotton is sold to spinning mills, the price to the mills is lower yet, LE 197. This is the equivalent to a tax on farmers of about 27 percent and a subsidy to mills of about 33 percent. Not surprisingly, the production of cotton fiber has declined precipitously in recent years.

- Before August 1989, there was also a special, very overvalued exchange rate applying to the exports of raw cotton, penalizing exports. The exchange rate for cotton has been unified with the market rate since then. The old special rate was LE 0.70/$ compared to a market rate in 1989/90, averaging about LE 2.5/$.

- Spinning is mainly a public sector activity, but since the late 1980s three private JVs have developed in spinning. Prices for spun yarn are controlled on an accounting cost-plus basis.

- Weaving is about 50 percent public sector. Woven fabric is not price controlled, but there is a high tariff on competing imports. Furthermore, each weaver receives a quota of yarn at the controlled prices, from the spinners. Several problems arise from this arrangement.

  -- Since the yarn price is controlled and kept artificially low, there is excess demand for yarn.

  -- Because some of the public sector spinning operations also weave cloth, they provide themselves with the highest-quality yarn, leaving lower quality for the private sector spinners.

- -- Public sector spinners/weavers also provide their own needs first. If there is a delay in delivery, it is the private sector that is delayed.

- Clothing production is 60-70 percent private. Clothing prices are not set by the government, but, since there are public and private sector producers in the same market, and public sector costs and margins are held below market rates, there is downward price pressure on private sector producers through normal price competition. Also, the clothing market is protected by import duties of about 50 percent.

- A main problem in the textiles industry is that, because of the artificially low price of the raw cotton, and with controlled public sector firms having an implicit priority in receiving raw materials, high-quality inputs end up being used for low-quality products. Indeed, Egypt's cotton fiber is the highest quality fiber in the world, yet much of it is used for ordinary and low-quality fabrics. On a true economic cost basis, it is often more efficient to export the cotton fiber than to use it as it is used now (Kheir-El-Din, 1991). A better alternative is to change incentives so that high-quality fiber is used to produce high-quality fabric.

In general, the way the cotton textile industry is organized and regulated provides extremely high protection for final products. The marketing sequence starts out with a large subsidy to spinning and ends up with high protection on clothing. Furthermore, the price of electricity, and of most inputs other than raw cotton fiber, have little to do with final product prices.

In conclusion, one observes that public intervention in price setting in Egypt makes pricing rather arbitrary. Large subsidies and other distortions are rife. In some cases (e.g., textiles), the prices of electricity are of little quantitative importance. In other cases, industries have been forced to give subsidies to domestic consumers of their products (e.g., aluminum, fertilizer, ferro silicon, steel), which exaggerates the importance of electricity prices for these producers.

Electricity Intensity in Industry

The electricity intensity of Egyptian industry is often exaggerated because of the preponderance of a few large electricity consumers in the industrial sector. Three firms, Kima Fertilizer, Egyptalum, and the Iron and Steel Company of Egypt are such large consumers of electricity that when they are included in aggregate data for "industry," they

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distort the view that one has of industrial electricity consumption. This is not meant as a criticism of these three firms. It is a simple statement of fact that these three use production techniques that are particularly electricity intensive when compared to the others. These three are special cases and should be dealt with as such.

To illustrate this point, we have developed Exhibit 8-5 using data for 1987/88. The exhibit shows aggregated data for 105 of Egypt's publicly owned industrial firms, separated into five sub-sectors. The sub-sectors (and number of firms) are Metallics (9), Food (19), Weaving and Textiles (31), Engineering (19), and Chemicals (27). The right-hand column shows the proportion of total costs accounted for by electricity for each of the five sub-sectors and for the aggregate. The lower half of the exhibit shows the effect of removing Kima from Chemicals, and Eyyptalum and the Iron and Steel Company from Metallics. Note that removing these three drops the proportion of electricity costs in the total from 1.5

Exhibit 8-5
Electricity Intensity for Selected Industries, 1987/88

	Total Product	Electric Consumption	Ratio
Metallics	1545313	62296	0.0403
Food	3108730	11546	0.0037
Textiles	2650354	38422	0.0145
Engineering	1180656	3222	0.0027
Chemicals	1621936	40452	0.0249
Total	10106989	155938	0.0154
Metallics A*	514178	8839	0.0172
Food	3108730	11546	0.0037
Textiles	2650354	38422	0.0145
Engineering	1180656	3222	0.0027
Chemicals B*	1574954	20366	0.0129
Total Adjusted	9028872	82395	0.0091

* Metallics A is without Aluminum Company of Egypt and Iron and Steel Company of Egypt; Chemicals B is without Kima.

Source: EEA

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percent to only 0.9 percent. That is, the removal of these three reduces the apparent electricity intensity of the group by about 40 percent. Within the subgroups from which they come, the removal of these three drops the energy intensity by large proportions. Within the Metallic sub-sector, removing Egyptalum and Iron and Steel reduces the electricity proportion from 4.0 percent to 1.7 percent, almost a 60 percent reduction. In Chemicals, the removal of Kima from the data reduces the energy intensity of the group by about half: from 2.5 percent to 1.3 percent.

The conclusions on the electricity intensity of Egyptian industry are:

- Kima, Egyptalum, and the Iron and Steel Company are special cases. They should be analyzed as such.

- The rest of industry is much less electricity-intensive than normally thought.

Negative Value-Added Industries

One often reads comments about industries in Egypt that operate at negative value added when economic pricing is applied to their activities (Richter, 1986; Adler, 1990; World Bank, 1984, 1990). It has not been the purpose of this study to identify those activities that have negative value added. However, if firms operate with negative value added, the questions of what would occur should the cost of electricity rise is economically irrelevant. If a firm experiences negative value added, economic logic says that it should not operate. If electricity prices (or any other prices) rise, it should still not operate. Electricity prices have no effect whatsoever.

Two of the firms that were singled out above as being special cases, Kima and Egyptalum, have often been thought to operate with negative value added. However, these cases are not clear. Kima is currently in the process of being converted from using electricity for power to using fuel oil, which will presumably correct its operating cost structure. The World Bank (1990, p. 37) has recently observed that "the Nag Hamadi smelter could be viable based on full cost recovery." Abdel-Khalek (1991) shows that productivity at Nag Hamadi has increased in recent years. World aluminum and oil prices determine Nag Hamadi's value added at world prices, and occasionally these prices move adversely (e.g., during 1981-85). Other firms, too, may be operating at negative value added, especially in the metallurgical and chemical industries (see World Bank, 1984). Until the question of negative value added for these firms is resolved, no statements about the economic effect of electricity prices can be made.

Summary on Industry

In general, the following points can be made about the industrial sector:

- The energy intensity of Egyptian industry is less than is normally thought.
- Increases in costs for the manufacturing sector in Egypt, from a 62 percent increase in the real price of electricity, should be in the range of 1.2 percent to 2.0 percent (from Section 8.2).
- Three large industrial users of electricity -- Kima, Egyptalum, and the Iron and Steel Company -- should be dealt with as special cases. Electricity tariff increases will affect them adversely and strongly.
- Studies of energy and electricity conservation potential show that Egyptian firms have great room for energy conservation, should prices provide proper incentives (see Adler, 1990, Table IV).

8.3 EXPORTS

Only a very small part of Egyptian exports would be significantly affected by increases in electricity prices. Adler (1991) has shown that non-petroleum exports amount to only 27 percent of total export earnings. This 27 percent is made up of the following:

Agricultural goods	3.5%
Cotton	10.8%
Garments	3.0%
Industrial goods	9.7%

Prices of agricultural goods and cotton are little affected by the cost of electricity. Also, as the paper by Kheir-El-Din (1991) shows, the export potential of cotton garments is dependent on a set of policies that have nothing to do with electricity. As discussed above, the costs of many industrial goods are little affected by electricity prices. Exceptions are the costs associated with aluminum, an important export commodity.

Studies that have been made of Egypt's export performance almost never identify the cost of electricity as being of overriding importance, and we have found no reason to disagree with them. Studies such as Adler's (1990 and 1991) show that the main hindrances to

exporting are bureaucratic and regulatory. Production costs per se may have little to do with export incentives.

Even after Egyptian electricity prices reach the levels recommended in this report, electricity prices in Egypt will still be low by international standards. The data in Chapter 7 show that Egypt's power costs are often less than half of what they are in other countries. Therefore, Egypt should not be at a disadvantage in world markets because of the price of electricity.

8.4 RESIDENTIAL SECTOR

The objective here was to estimate the impact that our rate recommendation would have on residential rate payers. Again, the reader should keep in mind that we are not dealing with very precise data. Any quantitative statements must be interpreted as approximations. The total impact on households will be estimated in two parts. First, there is a direct impact of having to pay a higher electricity bill. Second, there is an indirect effect of having to consume items, the prices of which are higher due to electricity price increases elsewhere in the economy. Below, we relate the impact that the electricity price increases will have on private consumption because it is that figure which comes closest to approximating each household's budget. To further our calculations, we observe the following:

- If residential electricity rates are raised to full LRMC, the rate will be raised to LE .213/kWh in FY 1992 values, by FY 1996, from the current yield of LE .0421/kWh.
- Private consumption expenditures in Egypt in late 1990 were about 53 billion pounds (IMF, IFS, 1991).
- Population is about 53 million (IFS, 1991).
- There were 7,804,000 residential electric customers as of December 1989 (EEA).

If we assume that all residences are served with electricity,[10] then the average residence contains approximately 6.8 persons.

[10] As of 1986, CAPMAS reports that of the 4,310 villages in Egypt, only 22 (0.6 percent) are without electricity. EEA officials believe that very few households do not have electricity, and that those that do not are normally newly formed households in a queue waiting for a hookup. This does not tell us that all households have electricity, but most probably do.

Average household private consumption would be about LE 6,800.[11] In the year 1989/90, residential customers consumed 10,789 million kWh, for an average of 1,384 kWh per residential customer. Our current yield calculation indicates that the average current yield is LE .0421/kWh. Our recommendation is that this be raised to LE .213/kWh in terms of FY 1992 LE. The question of primary importance is, how would this price increase affect residential customers?

Direct Effects

Let us consider two cases, the average residential customer and the "poor" residential customer. How either is affected depends on the price rise that is contemplated and on the own-price elasticity that is assumed for electricity. We will assume that the price elasticity falls somewhere in the range -.1 to -.5. The lower figure is one that has been mentioned from time to time (e.g., see Richter, 1986) as a lower limit, and the higher elasticity has been assumed by the World Bank (1990). Making an estimate in which one has confidence is hindered by data problems, but evidence from Egypt and elsewhere would indicate that the range -.1 to -.5 is likely to contain true residential price elasticity.[12] In making the estimates shown below, we assume a constant price elasticity form for the demand function where:

$$\text{kWh/customer} = (a)(P^e)$$

where P is the average price of electricity per kWh and e is the price elasticity.

For the average residential customer, an increase in price from LE .0421 to LE .213/kWh will decrease real, per household private consumption by between 1.1 percent and 2.8 percent. These figures represent the difference between the residential bill before and after the price increase as a percentage of average private consumption. Prior to the price

[11] One cannot fully support these assumptions. However, we have little else to go on and we recognize the approximate character of these calculations. Even if we were making an error of 5-10 percent at this point, our general results would be little affected.

[12] The main data problem is that data on residential customers and consumption date from only about 1980. In that year, the distribution companies were formed and the servicing of residential customers was shifted to them. Before then, EEA served residential customers, but the residential and commercial rate classes were mixed together. Also, in the early 1980s, there was a significant expansion of service to residential customers who had never been served before, and data on per customer consumption are blurred by mixing data on new and existing accounts. Nevertheless, if one estimates a price elasticity, via regression equations on data from 1980 on, using real per capita income and price on the right-hand side of the equation, one gets a price elasticity of about -.37, which is within the range assumed here.

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increase, the average residential customer consumes 1,384 kWh and spends LE 58.27 per year. After the price is raised, consumption drops to 615 kWh/year with e = -.5 and to 1,077 kWh with e = -.1. The electricity bills in each case are LE 131.10 and LE 250.70, respectively, implying changes in the electricity bill of LE 72.83 and LE 192.43.

The average poor residential customer is difficult to define. Egypt is typical of developing countries in that data on income distribution are hard to obtain. However, the World Bank lists some income distribution data for Egypt.[13] Those data show that the poorest 60 percent of Egypt's households receive 31.2 percent of the country's income. If we define "poor households" as being those in the poorest 60 percent of households, then there are about 4.7 million poor households in Egypt.[14] If we assume that they also account for 31.2 percent of the country's private consumption, then private consumption per poor household os around LE 3,530.

Data from EEA indicate that 65 percent of all residential customers consume fewer than 100 kWh per month (as of the end of 1989). It is probably safe to assume that the 60 percent of customers who are the poorest are among the 65 percent of the customers who consume fewer than 100 kWh per month. Here, we carry out our calculation as if a poor family consumes 100 kWh per month, and in so doing, we will be over-estimating the impact on the typical poor family's private consumption. Many families in the "poor" category consume much less than 100 kWh per month.[15]

Currently, the annual bill for a residential customer using 100 kWh per month is about LE 36.00. We assume the same form for the demand curve as was used above, and again assume that the price elasticity is in the range -.1 to -.5. We assume that the electricity price rises from LE .03 to LE .18/kWh,[16] and that when the elasticity is -.5, the annual bill becomes LE 88.16; the lower elasticity sets consumption at 83.6 kWh per month and

[13] These data are from the *World Development Report, 1989*, but they refer to data measured in the mid 1970s. Since then, income distribution could have changed in Egypt. However, income distributions normally do not change rapidly in the absence of major economic or political upheaval, and the data for Egypt are similar to those for other countries at a similar stage of development. In any event, these are the only data we have.

[14] This definition is entirely arbitrary. However, the World Bank data show that there is not much extreme income inequality within the second and third quintiles of income distribution. These two quintiles receive 10.7 and 14.7 percent of income, respectively. The lowest quintile is poor by any standard, receiving only 5.8 percent of total income. Thus, the picture is one of poverty extending evenly, well up into the middle of the distribution.

[15] Thirty-one percent of residential customers consume fewer than 40 kWh per month, and 55 percent fewer than 80 kWh per month.

[16] We assume that the average rate for consumption under 100 kWh/month rises from about LE .03 now to about LE .18 in 1996. The actual increase will depend upon subsidy decisions.

the annual bill is about LE 180.50. The change in the annual bill under the two elasticity assumptions is LE 52.16 to LE 144.50. This puts the loss to poor families at between 1.4 percent and 4.1 percent of their private consumption.

Indirect Effects

Family private consumption is affected indirectly by electricity price increases, as the prices of things that are consumed rise when their electricity prices rise. In Section 8.2, we estimated ranges for the price increases that could occur in Section 8.2. In Exhibit 8-7, we show the average household consumption patterns that the World Bank reports for Egypt.

Exhibit 8-7
Impact of Price Increases on Egyptian Households

Category	Proportion in Budget	Price Increases in Category
Food	0.36	0.3 to 0.6%
Clothing	0.04	2.5
Rent	0.04	0.6
Fuel and Power	0.01	0.6
Medical	0.14	0.2
Education	0.11	0.2
Transportation	0.03	0.2
Other	0.26	1.2 to 2.0
Total		0.6 to 0.9%

Source: World Bank, *World Development Report*, 1989.

For each category of consumption, the exhibit also shows the price increase expected.[17] The weighted average price increase for household consumption goods is in the range of 0.6 to 0.9 percent. That is, all else equal, price increases in the productive sectors, caused

[17] The price increase for the "fuel and power" category is a bit different than the figure we showed before. We are dealing with the "power" component separately, and so the figure shown here approximates the effect of "fuel" alone.

by electricity price increases there, will cause the real value of the average household's consumption to fall by between 0.6 and 0.9 percent.

The total effect on household consumption is as follows:

	Average Household	Poor Household
Direct Effect Indirect Effect	1.1 to 2.8% 0.6 to 0.9%	1.4 to 4.1% 0.6 to 0.9%
Total Effect	1.7 to 3.7%	2.0 to 5.0%

The ranges shown indicate the reductions in real consumption per household that might be expected from the electricity tariff reforms that have been discussed here. The figures probably overstate the real private consumption reductions for poor families. Poorer families generally have a larger proportion of their expenditures devoted to food than does the average family. Thus, if we had the data (which we do not), greater weight would apply to price changes for food items than to other items. Food items are little affected by increases in electricity prices.

8.5 ECONOMIC REFORM IN EGYPT

The electricity tariffs recommended in this report, if adopted, will not occur alone. Egypt has recently reached agreement with the World Bank and the IMF[18] to begin a series of reforms. The reform of electricity tariffs would be only a part of the reform package. Other elements of price reform include:

- adjustment of all fuel prices to reflect world prices by mid-1995
- revise the structure of protection by removing import bans and reducing the level and dispersion of import duties
- do away with the subsidies and cross subsidies associated with the public control over domestic prices

[18] We have been told that Egypt has signed a "letter of intent" with the IMF. No text of any agreement was available at the time of this writing.

- create an increasing role for the private sector, including the privatization of much of Egypt's manufacturing sector

- allow the exchange rate to reflect changes in the supply and demand of foreign exchange

- control public sector deficits and monetization of public debt.

This is clearly an ambitious set of objectives, despite the lack of explicit time lines for achieving some of them. This list of objectives gives some perspective of where electricity pricing reform fits into the overall strategy of reform in Egypt. It is clear that the first priority for the country is to move toward a more market-oriented, competitive market. A second priority, which is a subset of the first, is that fuel prices and markets should be rationalized. A third priority, and a subset of the second, is that electricity pricing be done on an economic basis. Thus, reforms of electricity pricing fit naturally as only one component, albeit an important one, in the overall reform strategy.

One of the most important effects that is expected from the Egyptian reform program is a realiocation of resources. In deed, that same objective is one of the main reasons for moving toward LRMC in the electricity sector. It would be reasonable that Egypt go through the resource allocation process once, rather than do it in piecemeal fashion. Thus, we recommend that the movement in electricity tariffs toward LRMC be done in coordination with the other reforms, particularly with the reforms in the prices of other fuels. Electricity price reform should be seen as a part of overall fuel price rationalization. Real tariff adjustments should be scheduled to occur at a predetermined pace, ending with full implementation of the recommended tariffs no later than mid-1995.

Spreading real electricity tariff changes over several years had advantages over a one-time-only change, for reasons other than those associated with resource allocation. Three observations are important:

- First, the comprehensive reform program that Egypt is embarking on will probably bring temporarily higher inflation.

- Second, raising real electricity tariffs to the recommended levels will probably have to be based upon the argument that once electricity prices are adjusted (i.e., raised), they will not require further adjustment.

- Third, as elsewhere, discussion of electricity tariffs in Egypt suffers from a kind of money illusion. People respond more to the nominal price than they

do the real price. Given that we expect significant inflation in the next few years, we would be unwise to opt for a one-time-only increase to the recommended tariffs, if we believed that we were only going to have one opportunity to commit ourselves to tariff adjustments.

The kind of political support that is likely to be necessary is that which promises that once the adjustment is over, it will not be needed again. We know now (i.e., in 1991) that significant inflation is likely in the 1991-96 period. Thus, to achieve long-run reforms in real electricity rates, we must leave ourselves room for maintaining real rates in the face of inflation. It is therefore best politically, and practically, to build the case for real rate reform over the inflationary period, so that as the inflation occurs, nominal rates can be properly adjusted to achieve real rate targets.

8.6 SUMMARY

This chapter has analyzed several issues related to the macroeconomic impact of the electricity tariff increase recommended in Chapter 7. Only partial and approximate data are available to assess these impacts, and so our estimates should be interpreted as being approximations. Some macroeconomic impacts cannot be addressed at all, most importantly, the impact on employment. Of the factors that have been addressed, the following observations are noteworthy:

- The inflationary impact of the tariff increases should be moderate. Overall inflation, as measured by the CPI, should increase by 1.3 to 1.6 percent. However, this is a one-time-only increase.

- Prices of manufactured items should increase by about 1.2 to 2.0 percent.

- Electricity price increases in the manufacturing sector are of less concern than the arbitrary, publicly administered price setting system that the sector is subject to.

- Our view of the manufacturing sector's electricity intensity is distorted if Kima Fertilizer, Nag Hamadi Aluminum, and the Iron and Steel Company of Egypt are part of the manufacturing group. The distortion is caused by the particularly high electricity requirements of those firms. These firms should be treated as special cases. Remaining industry, including over 100 firms in the public sector, is less electricity intensive than is commonly thought.

- Exports should be little affected by the recommended tariff increases.
- The cost of electricity tariff increases for the average residential customer will amount to about 1.7 to 3.7 percent of average private consumption. For households in the poorest income strata, those losses will be about 2.0 percent to 5.0 percent at most. Again, these are one-time-only changes.
- Tariff increases should be phased in at a pace that corresponds with the general economic reforms occurring in Egypt.

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CHAPTER 9: TIME-OF-DAY (TOD) TARIFFS

This chapter develops time-of-day (TOD) tariffs for business and industry. First, Section 9.1 presents the results of a detailed reliability evaluation. These data provide a basis for identifying peak and off-peak periods for price differentiation as well as a quantitative basis for allocating marginal generation capacity costs to peak and off-peak periods. Next, Section 9.2 describes the analysis of EEA's short-run marginal cost structure. The insights gained from Sections 9.1 and 9.2 and the LRMC analysis described earlier in Chapter 5 provide the basis for formulating the TOD tariffs presented in Section 9.3.

9.1 RELIABILITY ANALYSIS FOR DETERMINING RATING PERIODS FOR TOD TARIFFS

A generation reliability model was developed and used to determine time-of-use (TOU) tariff periods and capacity cost allocations among these periods. Different tariffs can be assigned to different periods of the day, days of the week, and seasons of the year to send customers price signals reflecting fluctuating marginal costs. Based on our analysis, just two periods are needed: a peak period of 5 p.m. to 10 p.m. and an off-peak period of 10 p.m. to 5 p.m. every day of the year. About 97 percent of the capacity cost should be allocated to the peak period, with the remainder allocated to the off-peak period.

The procedure for developing the TOU periods and allocation factors was as follows. The reliability model was run on fiscal year 1994-95, to determine the relationship between loss-of-load probability/expectation (LOLP/LOLE) and available reserve. This relationship was used to convert hourly load files for recent past years to files of hourly relative LOLEs. The hourly LOLEs were aggregated to monthly totals and to yearly totals by hour and by Friday vs. other days of the week. The monthly totals were used to determine whether to define seasonal TOU periods; seasonal periods were not used because no seasonality was apparent. In particular, relative LOLEs were calculated for each rating period of interest, as the sum of LOLEs for each hour in the rating period, expressed as a percentage of total LOLE for all hours of the year.

Totals of LOLE on Fridays vs. non-Fridays were used to determine whether or not to put Fridays in a shoulder or off-peak period. LOLE is lower on Fridays, but the hourly shape is similar to that of non-Fridays. To keep the rating period definitions as simple as possible, Fridays were not treated differently. Off-peak treatment of Fridays could be reconsidered in the future.

Finally, the LOLE totals by hour (see the table below) were used to select the TOU periods within each day. No shoulder period was needed because the LOLE on either side of the evening peak declines rapidly. Because of the rapid rise in LOLE after 5 p.m., 5 p.m. was included in the peak period despite a low LOLE.

Instantaneous Hourly Relative LOLEs (%) for 5 p.m. to Midnight Using Load Shapes of Three Recent Years

Fiscal Year	5 pm	6 pm	7 pm	8 pm	9 pm	10 pm	11 pm	Mid-night
1986-1987	0.0%	7%	28%	37%	21%	5%	1%	0.3%
1987-1988	0.0%	21%	42%	29%	7%	1%	0.4%	0.0%
1988-1989	0.1%	18%	38%	24%	15%	3%	0.5%	0.1%

The sensitivity analyses employed and described later in this chapter included the use of expected unserved energy (EUE) instead of LOLE, a no-maintenance analysis, generic additions of load and capacity, and the inclusion of load growth uncertainty. The hourly contributions to LOLE and the capacity cost allocation factors proved to be relatively insensitive to these changes.

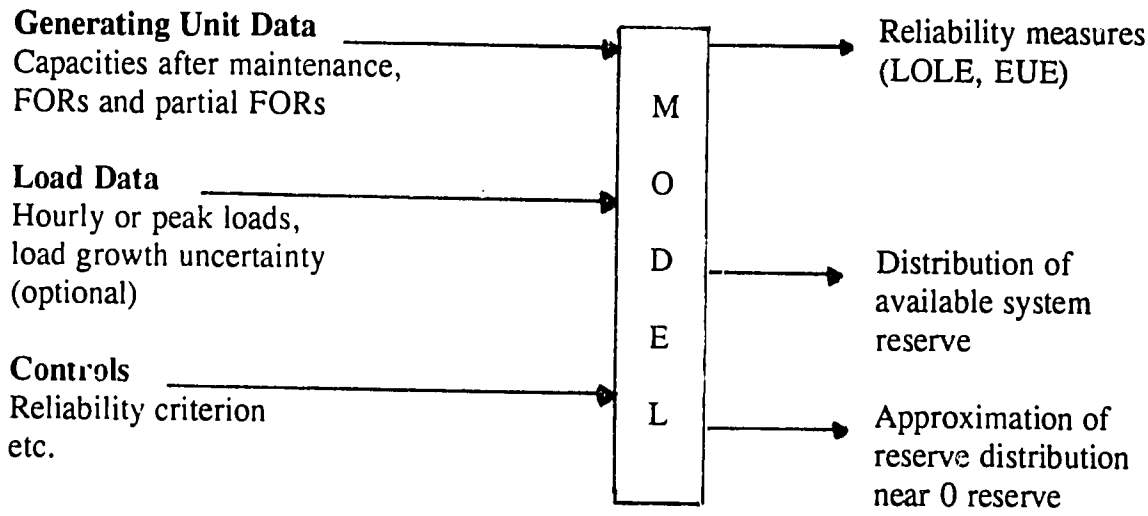
Reliability Measures and Model

The electric generation reliability model used for the analysis, REM (Reliability Evaluation Model), calculates loss-of-load expectation (LOLE) and expected unserved energy (EUE). These measures can be accumulated over a period of any length, e.g., an annual peak hour or an entire year. Loss of load means load in excess of available generating capacity, resulting in unmet load. LOLE is the expected duration of loss of load over the period, and EUE is the expected unmet energy load over the period. Loss-of-load probability (LOLP) is LOLE divided by the period length, and therefore, it differs from LOLE only in its units (see Appendix O for more detail).

Exhibit 9-1 shows REM's inputs and outputs. The basic operation of the model is as follows. For each period, a probability distribution of total available system capacity is calculated by probabilistic addition of the capacity of each generating unit (after maintenance), accounting for its full and partial forced outage rates. Then, the distribution

of loads for the period is convolved with the probability distribution of available capacity, giving the distribution of available system reserve. LOLE is then calculated as the sum of the probabilities of negative available reserves, times the period length, and EUE is calculated as the expected negative reserve times the period length.

Exhibit 9-1
Reliability Model Inputs and Outputs



Finally, REM makes a two-parameter approximation of the reserve distribution in the region near zero reserve (see Appendix O). This can be used to estimate efficiently the reliability in each hour of a year, based on the reliability in the peak hour. However, the results shown in this report did not rely on this approximation.

Load Inputs

Fiscal year 1994-95 (July 1994-June 1995) was selected as a representative period for the analysis. Forecast annual peak loads and load factors had been developed separately. However, reliability measures are sensitive to the shape of the load duration curve (especially near the peak load) as well as the peak, so forecast hourly load files were developed based on the load shapes of recent historical years. Three historical years were used for comparison purposes: fiscal years 1986-87, 1987-88, and 1988-89.

Because these years had different (slightly higher) load factors than the forecast year, the forecast loads could not be simply scaled up uniformly. Instead, the loads were scaled so as to achieve the desired peak and load factor in a simple way: a correction to each load for the different load factor was applied to increase in proportion to the difference between the peak and the hourly load. This scaling was achieved with the following formula, where d denotes hourly load, ' denotes forecast, p denotes peak load, and LF denotes load factor:

$$d' = \frac{p'}{p} \left\{ d + \frac{LF' - LF}{1 - LF} \right\} (p - d)$$

Load uncertainty, which can have a significant impact on reliability, is addressed in the sensitivity analysis discussion that follows.

Generating Unit Inputs

Appendix P shows the generating unit data supplied to the reliability model, except for the scheduled maintenance assumptions, which are discussed at the end of this section. The units at each plant were modeled separately to capture the reliability benefits of independent operation. Generic forced outage rates were used due to limited historical records of individual unit forced outages. The forced outage rate assumptions were: 8 percent for steam turbines (6 percent for the steam turbine components of combined cycle units, discussed below), 11 percent for gas turbines, and 1 percent for hydro units.

Special attention was given to combined cycle and hydro units. For each combined cycle unit, the dependence of the steam turbine capability on the gas turbine availabilities was represented in a probability tree, which was solved for the distribution of total available capacity (see the example in Appendix O). This provided the partial capacities and forced outage rates shown in Appendix P, after some aggregation of low-probability states for simplicity.

The dependence of the High Dam hydro unit capabilities on hydrologic conditions was an important consideration. The following judgmental distribution was used for hydrologic availability, given full mechanical availability:

% of Rated Capability	Capability of a 175 MW Unit	Probability
100%	175 MW	90%
74%	130 MW	5%
63%	110 MW	3%
51%	90 MW	1%
40%	70 MW	1%
		100%

To account for the simultaneous, independent risks of forced outage of each of the High Dam units, the total available capacity distribution for these units, given full hydrologic availability, was calculated and simplified (only 0 to 2 units simultaneously on forced outage had significant probability), and this distribution was combined with the hydrologic availability distribution via a probability tree, similar to that used for the combined cycle plants. The resulting distribution was combined with the distribution of outage for the Aswan Dam units, which were assumed to be limited by mechanical availability only, and simplified to the states shown in Appendix P. Appendix P also provides the details of the hydro probability distribution calculation.

The probability of loss of some or all of the hydro system capacity due to transmission outage was a candidate for incorporation in the probability tree. However, the probabilities were deemed insignificant because the unavailabilities of the two 500 kV lines and the 132 kV line from Aswan to Cairo were very low: well under 0.1 percent in an average of five recent years.

The maintenance assumptions used were: 14 days/year for gas turbines and 28 days/year for steam turbines and hydro units. A detailed simulation of annual maintenance would involve: (1) breaking the year into intervals of two weeks, (2) using LOLE (or another measure) to allocate maintenance over the intervals so as to levelize reliability, (3) calculating reliability in each interval separately, and (4) aggregating the results to determine annual reliability. A common alternative in reliability analyses is to approximate maintenance by derating the capacity of each unit uniformly over the year, by the percent of time required for its maintenance. (A similar alternative, increasing the forced outage rates, tends to be less accurate.) This approach avoids the computational burden and possible arbitrary jumps in reliability that accompany the first approach, and is reasonably accurate for long-term analyses in the absence of very large or long-maintenance-period units. Therefore, the derating approach was used, and a no-maintenance run was included as a sensitivity case.

Base Case Results

The base case reliability analysis used LOLE rather than EUE because LOLE is the marginal rate of increase in EUE with load (see Figure O-1 in Appendix O), and therefore reflects the marginal cost of an increment of load. However, EUE has the advantage of reflecting the magnitudes as well as the durations of loss-of-load events, so it was used also in a sensitivity case.

Hourly LOLEs were calculated for fiscal year 1994-95 and were aggregated in various ways. Exhibits 9-2 and 9-3 show aggregations by hour of day, with separate totals for Fridays (multiplied by 7 for comparison). The LOLE is lower on Fridays, but the hourly shape is similar to that of non-Fridays, and to keep the rating period definitions as simple as possible, Fridays were not treated differently. Off-peak treatment of Fridays could be reconsidered in the future.

The 5 p.m.-10 p.m. period was selected as the peak period because of the high concentration of LOLE in these hours; 5 p.m. was included because of the rapid increase of LOLE after 5 p.m. A shoulder period was not used because the LOLE declines rapidly on either side of the evening peak.

Exhibit 9-4 shows aggregations by month. Though load growth tends to drive up LOLE over each year, no consistent seasonality is apparent, so seasonally varying rating periods

Exhibit 9-2
Base Case LOLEs (% of Annual Total) by Hour of Day

Load Shape	5 pm	6 pm	7 pm	8 pm	9 pm	10 pm	11 pm	12 am	24 hr Total
FY 1986-7									
Fridays x 7	0.0%	0.8%	7%	8%	4%	0.7%	0.1%	0.0%	22%
All Days	0.0%	7%	28%	37%	21%	5%	1%	0.3%	100%
FY 1987-8									
Fridays x 7	0.0%	3%	3%	3%	1%	0.2%	0.0%	0.0%	11%
All Days	0%	21%	42%	29%	7%	1%	0.4%	0.0%	100%
FY 1988-9									
Fridays x 7	0.0%	2%	3%	3%	2%	0.5%	0.1%	0.0%	11%
All Days	0.1%	18%	38%	24%	15%	3%	0.5%	0.1%	100%

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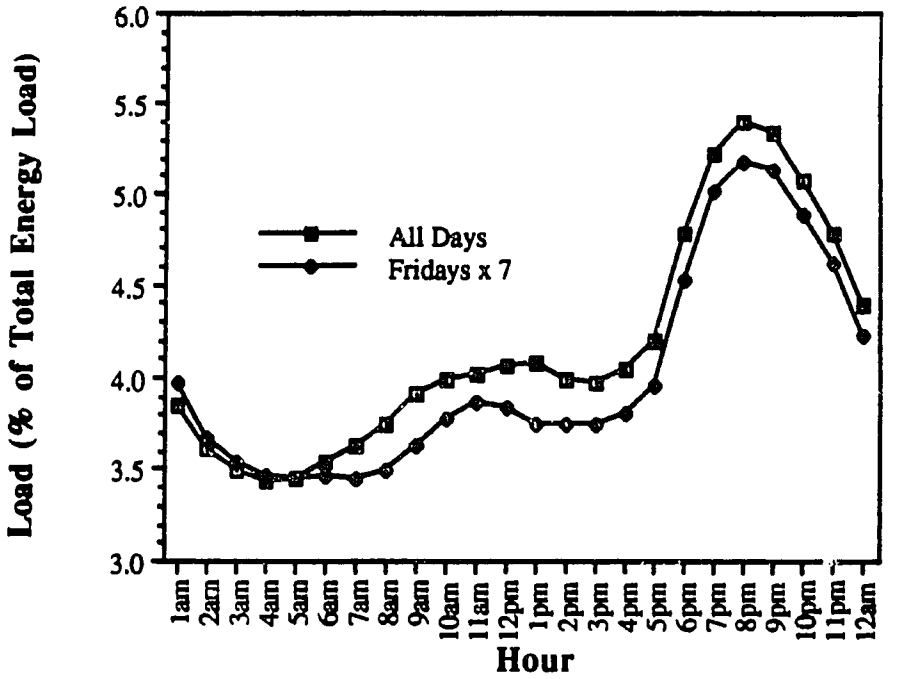
Exhibit 9-3
Loads and Loss-of-Load Expectations by Hour of Day
(% of Annual Total) for Fiscal Year 1994-95 Using Load Shape of 1987-88



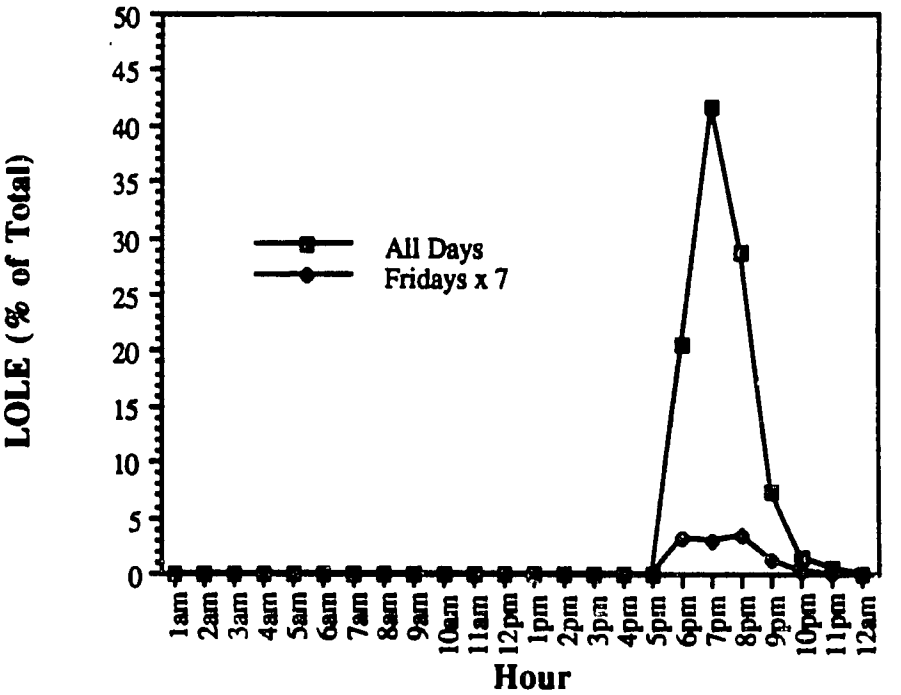


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Exhibit 9-4
Base Case LOLEs (% of Annual Total) by Month

Load Shape	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
FY 1986-7	0	0	2	2	1	8	14	6	11	14	24	18	100
FY 1987-8	5	5	9	7	11	27	8	9	9	5	4	1	100
FY 1988-9	0	1	2	4	7	9	24	13	7	22	6	3	100

were not used. Exhibit 9-5 shows the relative contribution of the peak period to the annual LOLE, which provides a basis for allocating capacity cost to this period vs. the off-peak period. The average relative contribution is about 97 percent from 5/24 (about 21 percent) of all hours, and if Fridays were moved to the off-peak period, this would become 95 percent from 30/168 (about 18 percent) of all hours.

Exhibit 9-5
Relative Contribution of 5 p.m.-10 p.m. Period by Annual LOLE

Load Shape	Contribution	Contribution Excluding Fridays
FY 1986-87	95.7%	92.6%
FY 1987-88	98.9%	97.3%
FY 1988-89	97.4%	95.8%
Average	97.3%	95.2%

Note: since the hourly loads represent instantaneous loads at the start of each hour, the 5 p.m.-10 p.m. period LOLE is approximated as 1/2(5 p.m. LOLE) + (6 p.m. LOLE) + ... + (9 p.m. LOLE) + 1/2(10 p.m. LOLE).

Sensitivity Analysis and Recommendations

Exhibit 9-6 shows the sensitivity of the relative contribution of the 5 p.m.-10 p.m. period to annual reliability as various assumptions are varied. The first case is the base case from

Exhibit 9-5. The second case shows the effect of choosing EUE rather than LOLE as the reliability measure. The third case shows the effect of removing the capacity derating for scheduled maintenance in the reliability analysis. This adds capacity to the system and improves reliability, as in the next case, which, however, adds exactly 500 MW of perfectly reliable capacity. The next case removes this amount of capacity, and the last case includes a simple model of load growth uncertainty: a normally distributed uncertainty with a 90 percent confidence range of the forecast peak plus or minus 5 percent, constant in all hours of the year.

The results appear fairly robust to changes in assumptions. Consequently, the rating periods developed for the base case--a peak period of 5 p.m.-10 p.m. and an off-peak period of all other hours--are recommended, with about 97 percent of capacity cost allocated to the peak period.

Exhibit 9-6
Relative Contribution of 5 p.m.-10 p.m. Period to Annual LOLE by Case

Case	Contribution
Base	98.9%
EUE Measure	99.0%
No Maintenance	99.3%
500 MW Increment	99.3%
500 MW Decrement	98.3%
Load Uncertainty Included	98.0%

Note: The load shape of FY 1987-88 was assumed.

Additional Sensitivity Analysis with Historical Forced Outage Rates

The preceding analyses have used generic forced outage rates, such as 8 percent for steam turbines and 11 percent for gas turbines. Since the draft report was completed, unit-by-unit historical forced outage rates have become available for the steam and gas turbines, and are considerably higher on the average than the generic rates. Five-year average rates through fiscal year 1989-90 were assembled; they averaged 17 percent for steam turbines and 21 percent for gas turbines. Although the preceding sensitivity analysis suggests that the contribution of the recommended 5 p.m. to 10 p.m. peak period would show little

sensitivity to such changes, an additional analysis with the historical rates was warranted in light of new data. This analysis was performed, with the changes shown in Exhibit 9-7.

Exhibit 9-7
Changes from Generic to Historical Forced Outage Rates

Plant	Generic F.O.R.	Historical F.O.R.
Cairo West (st)	0.08	.114
Cairo South (st)	0.08	.040
Cairo North (st)	0.08	.306
El Tebbin (st)	0.08	.266
New Talkha (st)	0.08	.236
Old Talkha (st)	0.08	.236
New Damanhour (st)	0.08	.538
Old Damanhour (st)	0.08	.538
Kafr El Dawar (st)	0.08	.242
Suif (st)	0.08	.510
Suez (st)	0.08	.672
Assiut (st)	0.08	.084
Abu Kir (st)	0.08	.184
Abu Soltan (st)	0.08	.164
Shoubrah (st)	0.08	.048
Attaka (st)	0.08	.186
Helwan (gt)	0.11	.088
El Tebbin (gt)	0.11	.292
Cairo East (gt)	0.11	.280
Ismailia (gt)	0.11	.030
Port Said (gt)	0.11	.046
Mahmoudia 1 (gt)	0.11	.072
Mahmoudia 2 (gt)	0.11	.072
Shabab (gt)	0.11	.162
Suif (gt)	0.11	.210
Damanhour (gt)	0.11	.014
Wadi Hof (gt)	0.11	.060
Demietta (gt)	0.11	.436
Cairo South (gt)	0.11	.192
1990-91: Heliopolis: 4+5 (gt)	0.11	.542

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The contribution of the 5 p.m. to 10 p.m. period to annual LOLE was re-computed for the base case load shape (FY 1987-88) and was found to be 98.4 percent (excluding Fridays, 96.2 percent). This compares to 98.9 percent for the Base Case and 98.3 percent for the 500 MW Decrement Case (see Exhibit 9-6). The result is similar to the latter case because both cases use a less reliable system than the Base Case. Because the new results, like the other sensitivity cases, are close to the Base Case results, no change in the recommendations is warranted.

9.2 SHORT-RUN MARGINAL COST STRUCTURE

This section describes the analysis undertaken to determine EEA's short-run marginal cost (SRMC) structure.

Background and Theoretical Rationale

The cost of providing electricity -- generation and delivery -- generally varies with time, location, supply voltage, weather, hydrologic phenomena, and other system and customer characteristics. "Real time" (spot) prices reflect the price of electric energy based on this short-run marginal cost (SRMC) of production and delivery plus any shortage cost. The SRMC at time t is defined by the following equation:

$$\text{SRMC}(t) = \lambda(t) + \gamma(t) + \eta_{QS}(t) + \alpha_{QS}(t)$$

where

$\lambda(t)$	=	Generation Fuel and Variable Costs (also known as "system lambda")
$\gamma(t)$	=	Marginal Network Loss Cost
$\eta_{QS}(t)$	=	Network Quality of Supply
$\alpha_{QS}(t)$	=	Generation Quality of Supply

Generation fuel and variable maintenance costs are the marginal production costs calculated using a production costing model described subsequently.

Losses can be modelled as a quadratic function of demand such that:

$$\text{Losses} = B_{loss} \times D(t)^2$$

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where B_{loss} = loss constant.

The marginal cost of losses is the marginal production cost times the marginal losses. Marginal losses are calculated by taking the derivative of the equation above:

$$\text{Marginal cost of losses (t)} = \lambda(t) \times 2 \times B_{loss} \times D(t)$$

The network quality of supply and the generation quality of supply components can be estimated as the marginal cost of unserved energy. Sometimes, this concept is also referred to as failure cost, outage cost, or interruption costs. This cost reflects the monetary value to consumers of electricity as a consequence of the disruption they experience because of power supply interruptions.

Such interruptions may arise due to a network or generation deficiency, or because of an external disturbance that triggers load shedding. Such situations can become chronic if there is continued under-investment in generation and network facilities and in other operating facilities and procedures. Outages resulting from network capacity deficiencies typically result in total loss of load for a customer and are not accompanied by any advance notification. Generation capacity deficiencies, if properly managed, would manifest as partial loss of load with some advance notification for customers on load management programs. If such programs do not exist or are insufficient to balance load and supply, then load shedding is required on a rotational basis. This results in full outages -- i.e., complete loss of load for a customer -- though accompanied by some advance notification.

Outage costs for industrial customers and businesses can be measured by the impact of such service interruptions on productive resources -- labor, capital, land, etc. -- made forcibly idle as well as any extraordinary costs such as product and equipment spoilage and damage, process re-start, etc. For residential customers, these costs reflect their willingness to pay to avoid the inconvenience, discomfort, annoyance, disruption, etc. that arises as a result of the outage.

In this study, failure cost is assumed to be $0.55/unserved kWh based on a review of the literature.[1]

The formula for the calculation of SRMC is:

$$SRMC(t) = \lambda(t) [1 + 2 \times B_{loss} \times D(t)] + 0.50 \times EUE(t)$$

where EUE(t) is the expected unserved energy in hour t.

From the preceding discussion, it is clear that the incremental operating cost is a function of the load being carried, the loss coefficient in the system, and the operating cost of the unit that is at the margin for that particular load level. Thus, the determination of time-differentiated incremental operating cost is the determination of the operating cost of the unit that is at the margin during each hour. The framework for this analysis is described next.

Monte Carlo Production Cost Simulation Model

A production cost model was utilized to determine the hourly variation in the marginal cost of energy generation. In a real system, there are a number of random occurrences, including mechanical breakdown of generating units and different levels of hydroelectric output due to water availability. This, together with the planned maintenance schedule of generating units, causes many alternative stacks of generating units to carry a given load level economically, and each of these alternative stacks has a specific probability of being called upon at a given hour.

To take this into account, analytical and numerical techniques have been developed. In this study, a numerical technique known as Monte Carlo has been used and is the driving principle of the Monte Carlo Production Cost Simulation Model (MCPCSM).

[1] We are not aware of any studies of failure costs specific to Egypt. Accordingly, these estimates are based upon a review of the U.S. and worldwide literature. Two review papers that we have relied on are:

Sanghvi, Arun P. "Cost of Electricity Supply Interruptions: U.S. and Foreign Experience." *Energy Economics*, 1983.

Sanghvi, Arun P. "Impacts of Power Supply Inadequacy in Developing Countries." Paper to appear in *Energy Policy*, July 1991.

Basically, the Monte Carlo Production Cost Simulator (MCPCS) requires as input hourly load data for typical day types in each month. On the resources side, it requires unit-specific data such as unit capacity (MW), forced outage rate, maintenance downtime, heat rate and fuel costs (where appropriate), variable O&M costs, and for hydro units, typical daily energy limitations. Hydro unit capabilities -- MW and MWh -- can be separately defined for normal and dry water conditions if conditions indicate that this variation is sufficient to cause a resultant and significant variation in SRMC.

The model operates on the basis of a dispatch (stacking) of generating units over a daily period. The model can use different typical days to represent different load conditions. In this study, two typical days, one representing Friday loads and one representing work day loads, were initially defined for each month of the fiscal year (1991/92). The analysis was independently performed for each typical day as follows.

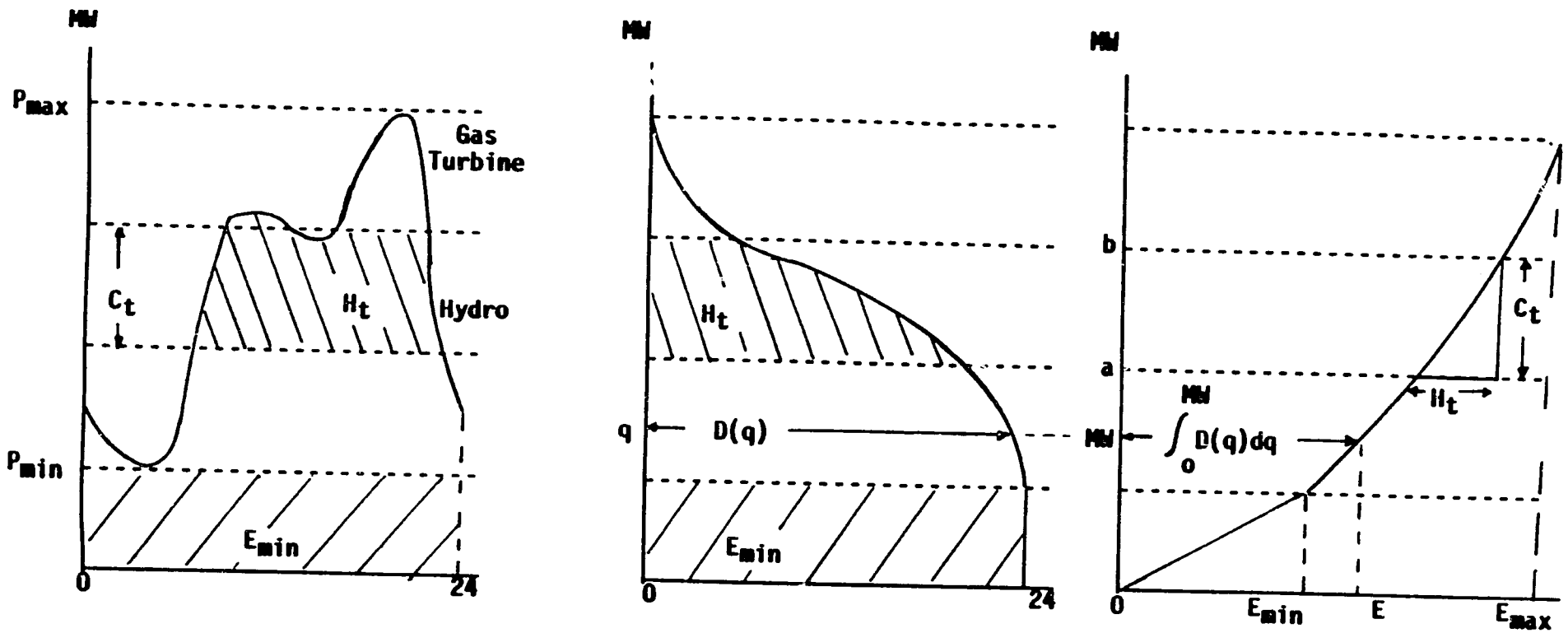
The dispatch (stacking) of generating units for a given system condition (i.e., configuration) within MCPCSM essentially employs the analytical procedure originally proposed by Jacoby.[2] It employs the integrated load function. This curve, which is schematically depicted in Exhibit 9-8, relates power demand and energy. At each ordinate, the abscissa is defined as the integral of the load duration curve up to the given demand level.

To illustrate, the integrated load function is linear over the domain on E_{min}, where E_{min} denotes the minimum daily energy requirements. The domain of this function extends up to E_{max}, which is defined as the total area under the load duration curve, or equivalently, the area under the daily load curve. Put simply, E_{max} is the energy requirement for the day. Intermediate points on the integrated load function are defined over the domain (E_{min}, E_{max}, in accordance with the integral defined in Exhibit 9-9. In MCPCS, a parabolic function is fitted between the points (E_{min}, P_{min}), and (E_{max}, P_{max}).

Exhibit 9-8 schematically indicates how an energy constrained hydro unit is "inserted" under the load duration curve. Its placement is situated at the location where the entire capacity and energy output of the unit is utilized. After hydro insertion, the thermal units are stacked under the "residual load duration curve" in their merit order. Jacoby has shown that this procedure is theoretically equivalent to operating the power system so as to minimize total production costs.

[2] See, for example, Jacoby, H. "Analysis of Investments in Electric Power." PhD thesis, Harvard University, 1967. Reproduced in *Water and Power Resources of West Pakistan*, Lieftnick, Sandove, and Creyke, eds. Baltimore: Johns Hopkins Press, 1969.

Exhibit 9-8
Jacoby's Integrated Load Function



Using as input the characteristics of the generating system, the model produces a configuration of the system selected at random on the basis of the probability of outage of each generating unit. This configuration is then dispatched (stacked) in order of increasing operating cost, as shown in Exhibit 9-9. The marginal unit corresponding to each hour of the day is determined and thus, the incremental operating cost is obtained from the dispatch.

This process is repeated many times until a representative sample of all possible configurations of the system is obtained. The incremental operating cost of the system for each hour is calculated as the average of all the incremental costs obtained for that hour under the randomly selected configurations. In this study, it was determined that the average operating cost of the system became stable with a sample of 300 configurations.

The model uses load data calculated at power station bus bars and thus includes losses in the transmission and distribution network. However, the model will use information on historical losses to determine a loss coefficient that will then be applied to determine the component of incremental cost due to power losses.

It is possible that some of the configurations selected at random to meet the load of each typical day may not contain a sufficient amount of capacity to meet the load above a certain level. Such a situation results in a deficit of energy or unserved energy load. The model receives input data on the value of this unserved energy (failure cost/outage cost) and allocates the cost of unserved energy to the different hours as a function of the respective hourly loads. However, the characteristics of the EEA system for the fiscal year 1991/92 are such that the model does not report any observable amount of unserved energy and thus there is no unserved energy cost to allocate in the present context.

Results

The data in Exhibit 9-10 define the hourly short-run marginal cost structure for each of the twelve months in fiscal year 1991-92 and for each of two days types: weekdays and Fridays. The tables in Appendix Q provide information about the data inputs (generation resources and loads) used for this analysis, as well as a breakdown of the hourly cost

Exhibit 9-9
Operation of the Monte Carlo
Production Cost Simulation Model

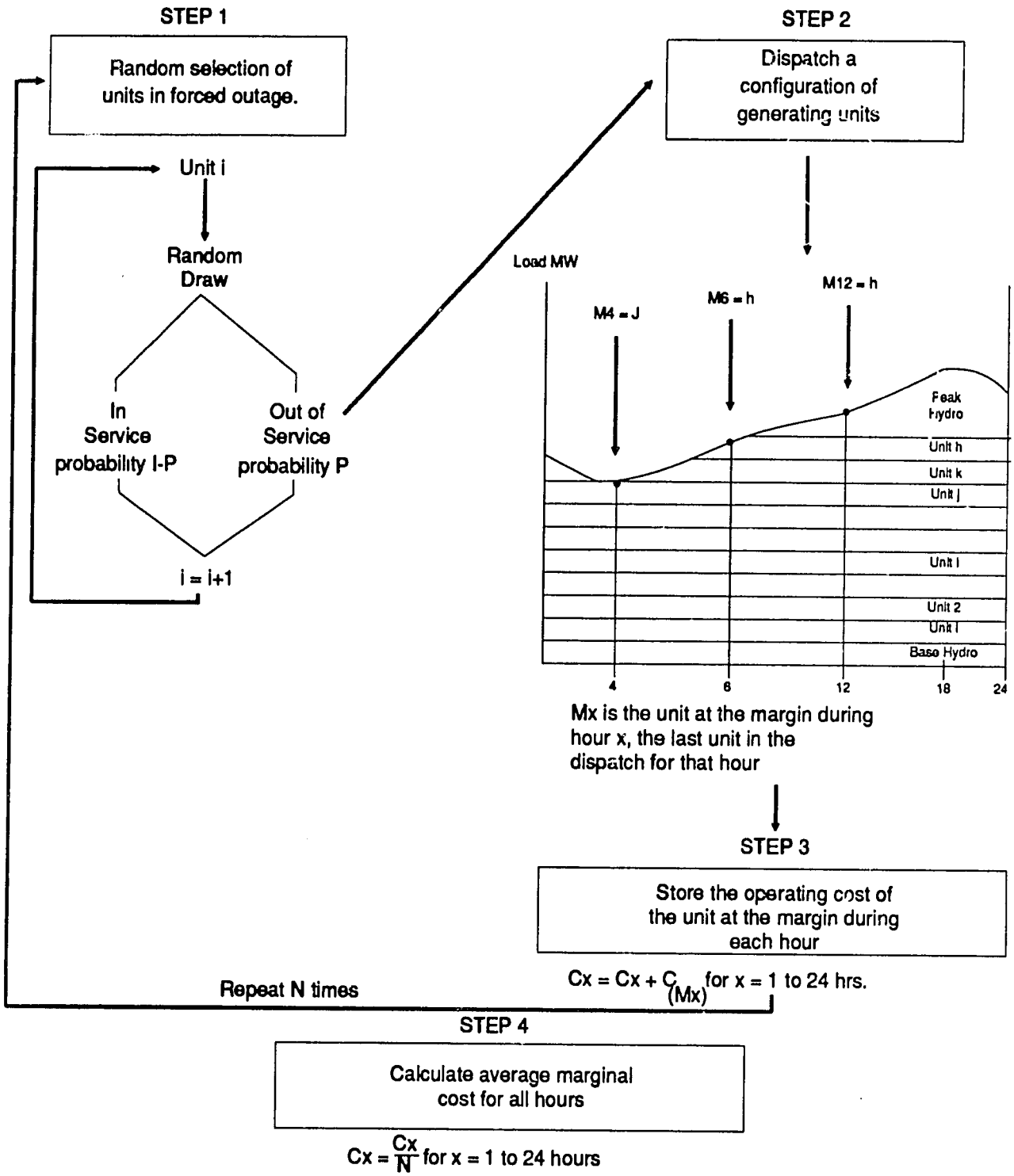


Exhibit 9-10
Short-Run Marginal Costs by Hour and Day Type ($/MWh)

MONTH	DAY	HOUR 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	Weekday	20.72	20.58	20.51	20.46	20.41	20.35	20.36	20.55	20.73	20.81	20.85	20.91	20.92	20.85	20.81	20.84	20.87	20.91	21.26	22.58	22.40	21.48	21.22	21.07
January	Friday	19.97	19.76	19.68	19.62	19.59	19.51	19.50	19.52	19.60	19.67	19.77	19.79	19.74	19.78	19.80	19.80	19.80	19.89	20.15	21.33	21.25	20.69	20.40	20.08
February	Weekday	20.51	20.36	20.28	20.26	20.21	20.16	20.14	20.28	20.44	20.51	20.56	20.62	20.65	20.55	20.54	20.55	20.55	20.63	21.32	21.53	21.26	21.14	21.00	20.79
February	Friday	19.98	19.81	19.77	19.70	19.69	19.56	19.56	19.59	19.66	19.78	19.84	19.85	19.82	19.84	19.83	19.86	19.85	19.93	20.91	21.77	21.37	20.51	20.35	20.17
March	Weekday	21.09	20.96	20.89	20.86	20.85	20.84	20.83	20.94	21.09	21.16	21.20	21.27	21.30	21.18	21.17	21.20	21.21	21.54	22.60	22.46	21.95	21.80	21.60	21.38
March	Friday	23.25	23.05	22.96	22.91	22.89	22.81	22.75	22.77	22.89	22.94	23.01	23.03	23.05	23.07	23.02	23.06	23.08	23.43	24.15	24.17	23.99	23.79	23.60	23.36
April	Weekday	21.25	21.13	21.07	21.05	21.07	21.13	21.17	21.21	21.30	21.35	21.40	21.43	21.42	21.38	21.36	21.40	21.51	22.36	22.66	22.43	22.16	21.96	21.79	21.49
April	Friday	19.80	19.65	19.61	19.58	19.59	19.58	19.55	19.54	19.64	19.69	19.77	19.73	19.73	19.72	19.73	19.76	19.81	20.34	20.70	20.60	20.51	20.33	20.11	19.86
May	Weekday	22.06	21.95	21.88	21.88	21.93	22.07	22.16	22.17	22.23	22.25	22.27	22.28	22.27	22.21	22.22	22.31	22.63	23.02	22.80	23.25	23.09	22.86	22.61	22.34
May	Friday	20.20	20.07	19.99	20.02	20.05	20.08	20.08	20.10	20.19	20.23	20.28	20.23	20.22	20.22	20.19	20.25	20.56	21.16	21.14	21.07	20.98	20.77	20.53	20.30
June	Weekday	22.00	21.89	21.78	21.72	21.84	22.02	22.20	22.20	22.24	22.26	22.25	22.27	22.27	22.21	22.21	22.31	22.68	23.20	23.30	23.14	23.02	22.80	22.58	22.30
June	Friday	22.09	21.89	21.81	21.77	21.78	21.89	21.92	21.93	22.00	22.09	22.11	22.08	22.05	22.06	22.08	22.11	22.37	23.19	23.06	22.95	22.87	22.63	22.40	22.16
July	Weekday	20.95	20.33	20.12	20.07	20.22	20.80	21.18	21.24	21.31	21.31	21.28	21.32	21.31	21.24	21.27	21.35	21.51	22.18	22.21	22.14	22.05	21.85	21.62	21.37
July	Friday	21.92	21.78	21.64	21.47	21.48	21.70	21.74	21.76	21.83	22.02	22.06	21.90	21.81	21.88	21.85	21.90	22.06	22.82	22.88	22.81	22.74	22.34	22.32	22.06
August	Weekday	20.80	20.68	20.63	20.61	20.66	20.79	20.99	20.98	21.06	21.06	21.05	21.02	21.10	21.03	21.03	21.11	21.19	21.77	22.66	22.24	21.90	21.67	21.43	21.15
August	Friday	20.51	20.32	20.23	20.20	20.22	20.30	20.32	20.35	20.45	20.50	20.53	20.55	20.42	20.45	20.43	20.45	20.70	21.20	21.51	21.35	21.26	21.10	20.91	20.60
September	Weekday	20.95	20.79	20.72	20.71	20.77	20.88	20.99	21.03	21.09	21.06	21.05	21.09	21.14	21.07	21.07	21.11	21.17	21.54	23.34	23.10	22.42	21.75	21.53	21.30
September	Friday	20.02	19.82	19.77	19.73	19.79	19.79	19.77	19.80	19.89	19.98	20.03	20.00	19.91	19.89	19.93	19.93	19.99	20.29	21.31	21.09	20.86	20.58	20.35	20.11
October	Weekday	22.20	22.05	21.98	21.86	21.76	21.73	21.72	21.84	21.96	22.00	21.98	22.06	22.07	22.02	22.01	22.08	22.06	22.28	23.13	24.16	23.71	23.12	22.71	22.51
October	Friday	20.71	20.58	20.47	20.37	20.23	20.20	20.14	20.19	20.31	20.37	20.44	20.44	20.39	20.42	20.44	20.44	20.45	20.63	21.45	22.00	21.77	21.39	21.04	20.83
November	Weekday	20.49	20.35	20.28	20.27	20.30	20.41	20.57	20.62	20.66	20.72	20.68	20.71	20.65	20.68	20.64	20.68	20.69	20.71	20.92	22.27	23.40	22.81	21.88	21.42
November	Friday	21.26	21.07	21.02	20.98	21.00	21.16	21.34	21.39	21.47	21.48	21.46	21.42	21.25	21.26	21.29	21.30	21.28	21.25	21.53	22.49	22.02	22.82	22.50	22.00
December	Weekday	19.92	19.72	19.63	19.61	19.60	19.57	19.52	19.68	19.86	19.93	19.83	19.87	19.50	19.87	19.94	19.84	19.85	19.86	19.88	20.31	21.12	21.04	20.67	20.29
December	Friday	20.21	19.66	19.54	19.51	19.50	19.44	19.34	19.33	19.37	19.51	19.62	19.66	19.64	19.57	19.57	19.62	19.65	19.64	19.62	19.96	22.52	22.08	21.52	20.82

structure in Exhibit 9-10 into its three major components -- incremental fuel costs, cost of incremental losses, and expected outage cost.[3]The cost structure variation is easier to interpret visually by plotting the data in Exhibit 9-10. Specifically, Exhibit 9-11 shows a comparison of the weekday cost structure by month. Further, the curves in Exhibit 9-12 and in the table in Exhibit 9-12 facilitate comparisons of the weekday versus Friday cost structure as well as the seasonal cost structure.

Finally, Exhibit 9-13 shows the cost duration curve, and a detailed "blow up" of the curve for the first 1000 hours is shown in Exhibit 9-14.

The data support the conclusion that based solely upon energy cost-related differentials (e.g., excluding capacity costs), there is very little variation in the SRMC either by season or time of day. This result derives from two major driving considerations: (1) the "fuel at the margin" is always mazout or gas which is equivalently priced, and furthermore, (2) at present, from a capacity perspective, EEA has adequate resources, resulting in imperceptible differences in EUE across the peak and off-peak hours. However, when viewed on a total cost basis, i.e., energy and demand-related costs (see Chapter 5), there is significant diurnal variation in the cost of supplying power. This provides the basis for developing the TOD tariff options described in the next section.

9.3 TOD TARIFF OPTIONS

An analysis of the marginal cost structure of bulk electricity supply in Egypt indicates a significant difference in marginal costs on a diurnal basis. Whereas certain structural factors unique to Egypt tend to dampen the rates of marginal cost between peak and off-peak hours -- namely incremental fuel costs in peak and off-peak periods -- the difference is sufficiently large as to merit a time-differentiated based tariff. Further, absent such a tariff at the bulk level, there is no incentive to the distribution companies to promote TOD prices or other forms of load management in their respective retail customer segments. Therefore, the first priority should be to move towards a pricing regime where every unit of electricity sold by EEA, either directly to a final user or for resale by the distribution

[3] A point to note here is that the fuel prices assumed in this analysis ($1.560/MBtu for gas and $3.90/MBtu for sollar) are diffeent from those used in the LRMC analysis described in Chapter 5 ($1.97/MBtu for gas and $4.36/MBtu for sollar). This is because the short-run marginal cost analysis reflects the power system's cost structure in the immediate near term, i.e., next year. By contrast, and as explained earlier, the LRMC analysis reflects a longer-term cost structure, reflective of projected fuel price over the 1993 to 1995 time frame.

Exhibit 9-11

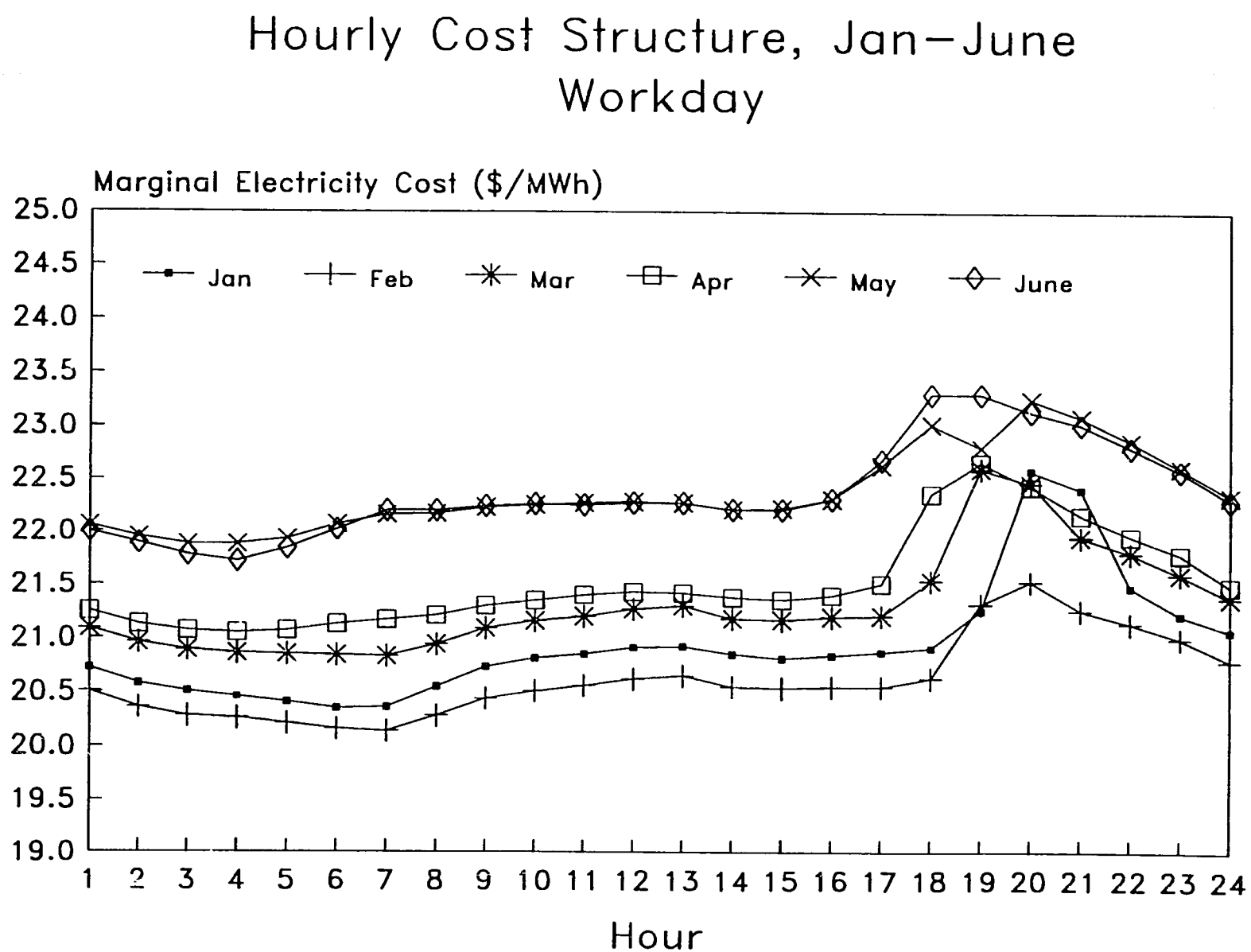

Hourly Cost Structure, Jan–June
Workday
Marginal Electricity Cost ($/MWh)
25.0
24.5
24.0
23.5
23.0
22.5
22.0
21.5
21.0
20.5
20.0
19.5
19.0
Jan
Feb
Mar
Apr
May
June
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Exhibit 9-11 (continued)

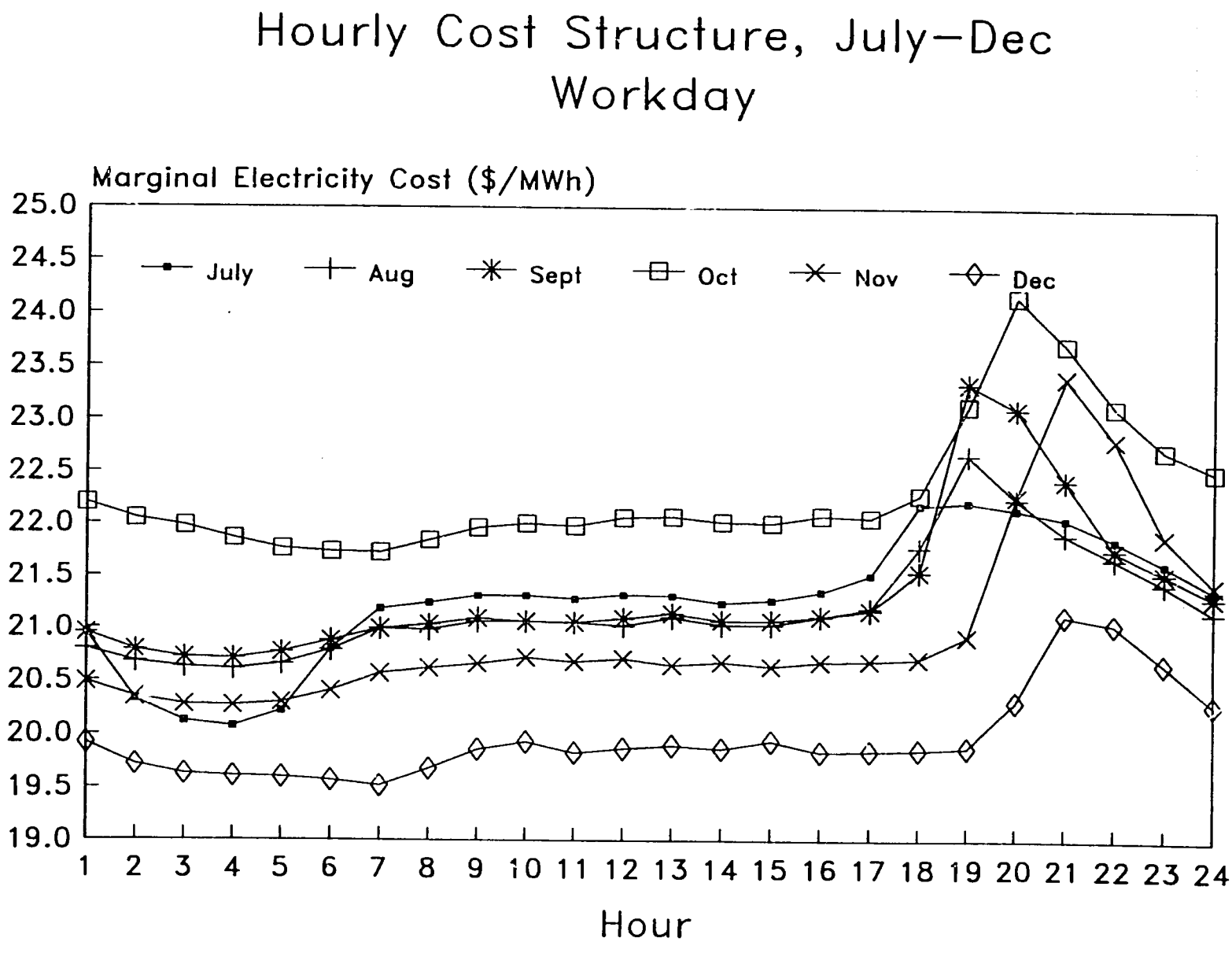
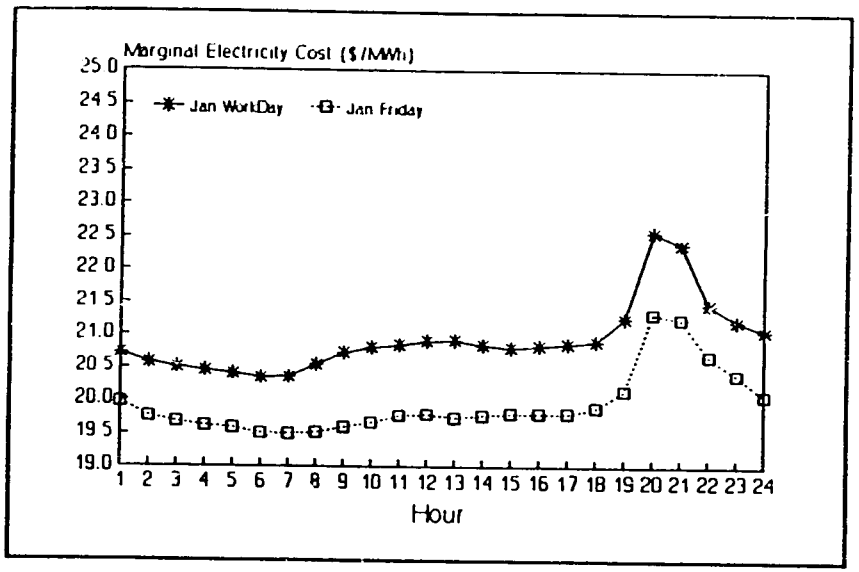
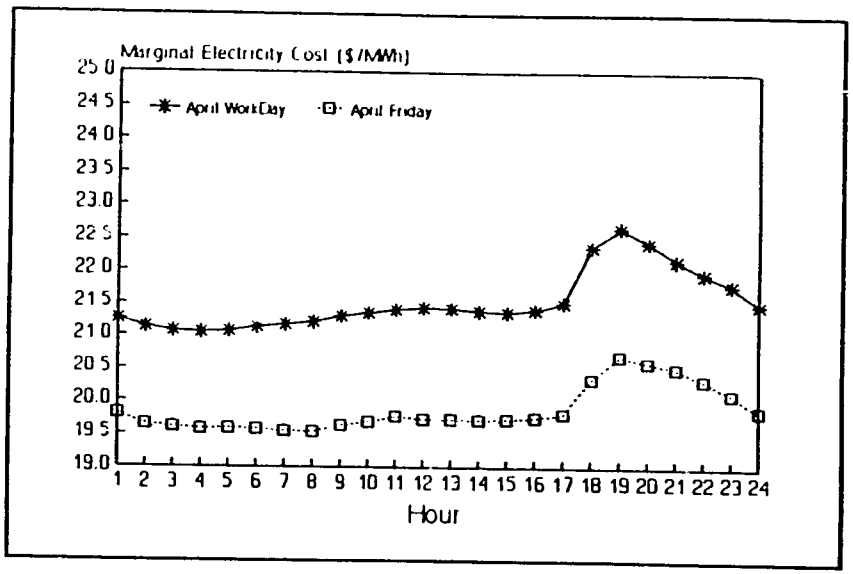
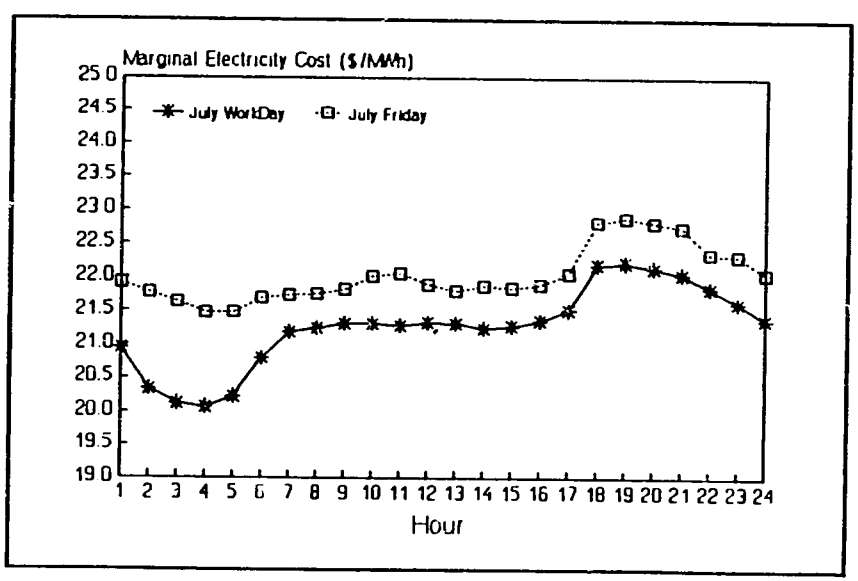


Exhibit 9-12. Short-Run Marginal Cost by Season and Day Type







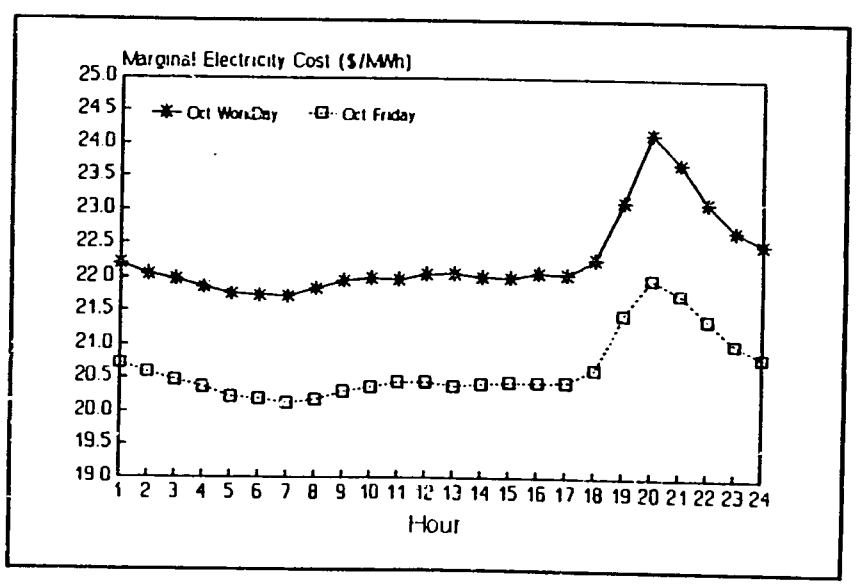


Exhibit 9-12 (continued)
Short-Run Marginal Energy Costs, $/MWh, (FY 1991/92)

	Peak (17-21)			Off-Peak		
	Weekday	Friday	Average	Weekday	Friday	Average
January 1992	21.60	20.48	21.42	20.76	19.80	20.61
February 1992	21.06	20.77	21.02	20.50	19.85	20.41
March 1992	21.95	23.76	22.19	21.14	23.06	21.39
April 1992	22.22	20.39	21.98	21.33	19.74	21.12
May 1992	22.96	20.98	22.64	22.21	20.21	21.89
June 1992	23.09	22.89	23.06	22.18	22.04	22.16
July 1991	22.02	22.66	22.10	21.06	21.87	21.16
August 1991	21.95	21.20	21.83	20.99	20.47	20.91
September 1991	22.31	20.71	22.10	21.06	19.95	20.91
October 1991	23.07	21.26	22.83	22.09	20.49	21.88
November 1991	21.60	21.71	21.62	20.78	21.45	20.89
December 1991	20.20	20.28	20.21	19.91	19.87	19.90
Total	22.01	21.40	21.92	21.17	20.71	21.10

companies, is sold on a TOD tariff. Time-differentiated tariffs for the large power class should be introduced simultaneously as well.

In the following, the peak period is defined as the hours between 5 p.m. and 10 p.m.

TOD Rate Design Philosophy

The following paragraphs lay out our basic approach for developing a TOD tariff, which is summarized in Exhibit 9-15. This approach is appropriate for a power system such as that in Egypt, where there is a well-defined and relatively short on-peak period and with no significant seasonal variations in the cost structure.

Basis for Off-Peak Energy Price

The basis for the off-peak energy price is the strict marginal cost of energy in the off-peak period. This value should not be reduced in any subsequent tariff revision adjustments because it represents a minimum variable cost.

Exhibit 9-13

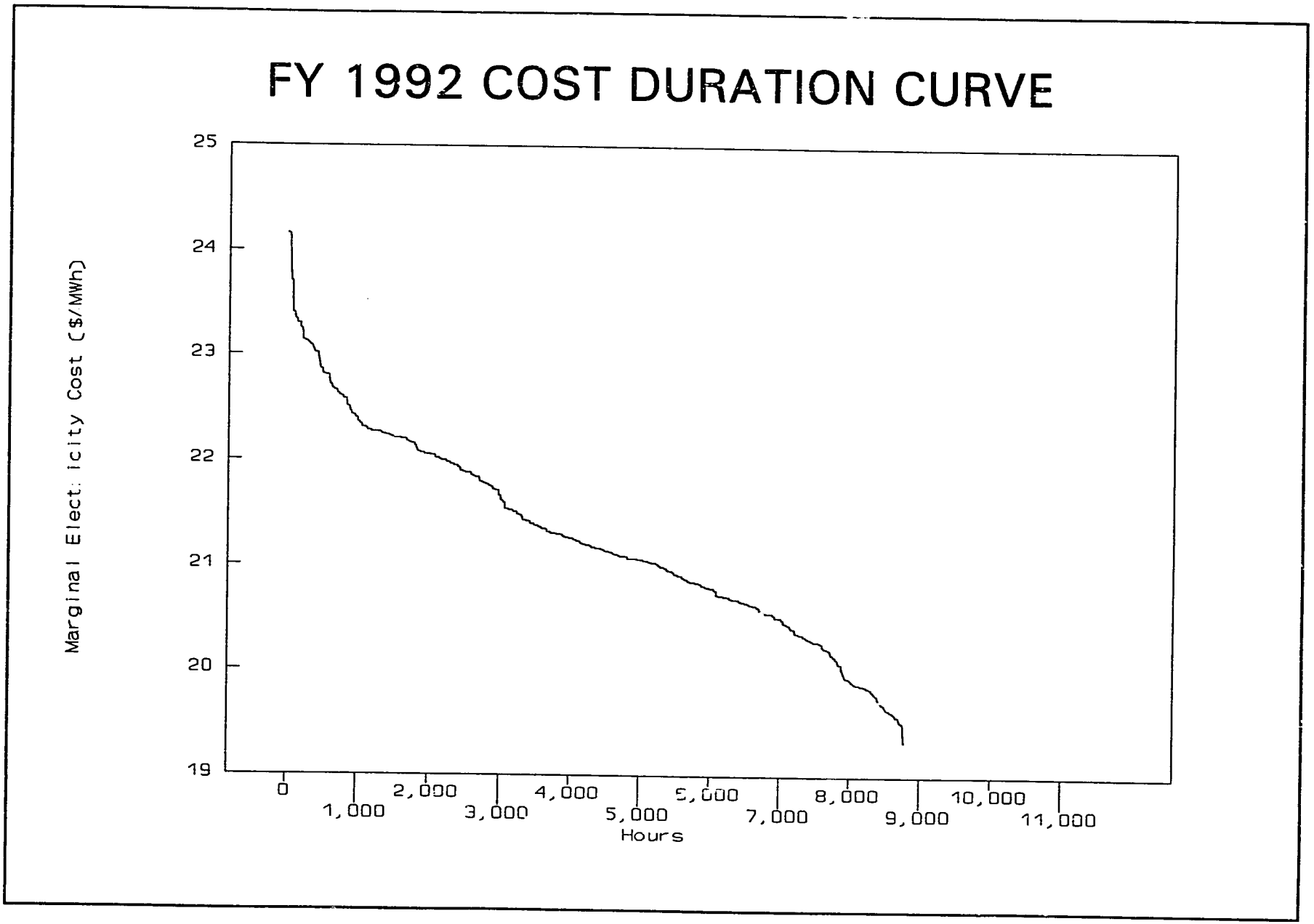

FY 1992 COST DURATION CURVE
Marginal Electricity Cost ($/MWh)
25
24
23
22
21
20
19
0
1,000
2,000
3,000
4,000
5,000
5,000
7,000
8,000
9,000
10,000
11,000
Hours

Exhibit 9-14

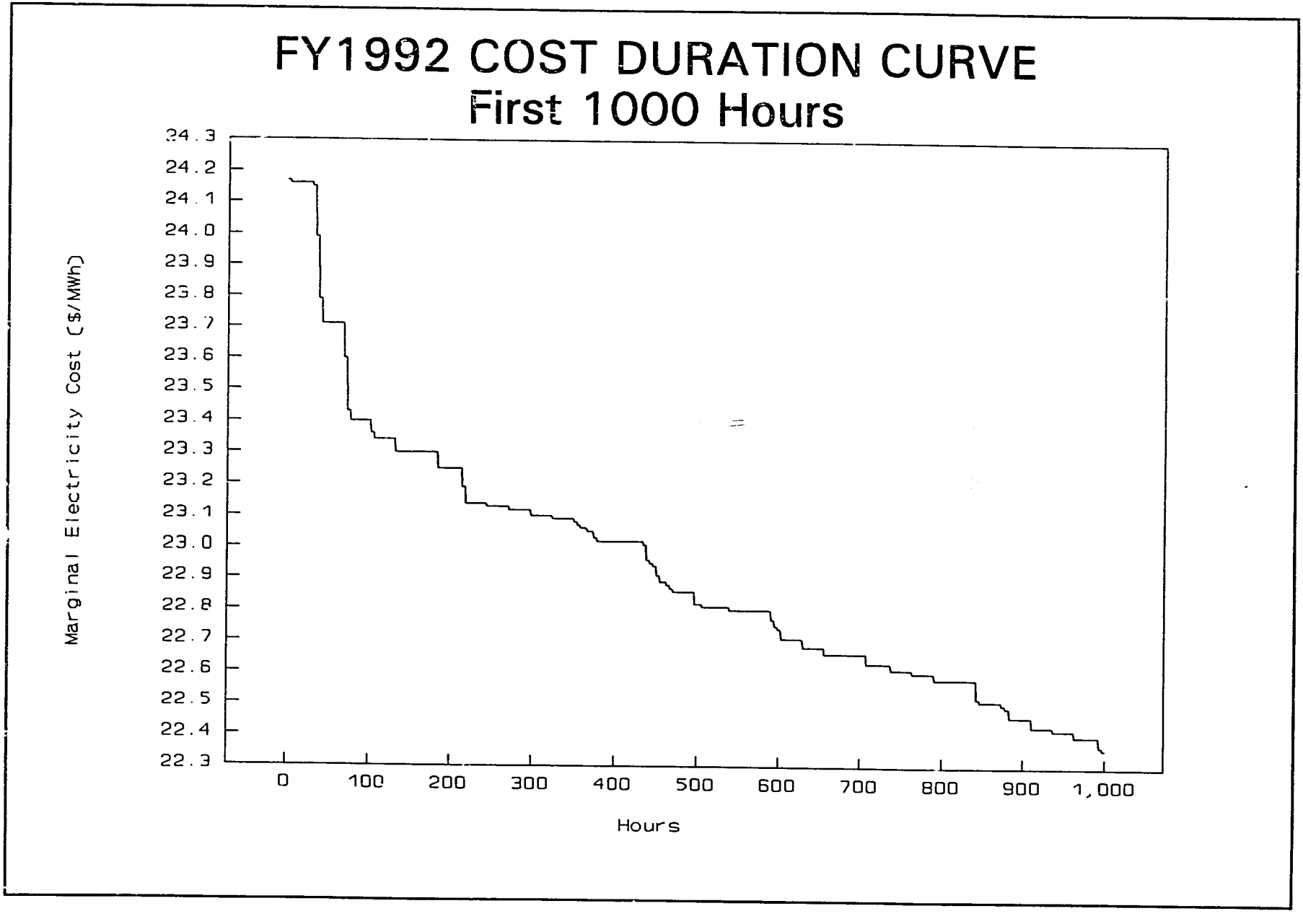

FY1992 COST DURATION CURVE
First 1000 Hours
Marginal Electricity Cost ($/MWh)
24.3
24.2
24.1
24.0
23.9
23.8
23.7
23.6
23.5
23.4
23.3
23.2
23.1
23.0
22.9
22.8
22.7
22.6
22.5
22.4
22.3
0
100
200
300
400
500
600
700
800
900
1,000
Hours

Exhibit 9-15
Allocation of Marginal Cost Components for TOD Rate Design

Marginal Cost Component	Demand Charge	Peak Energy Price	Off-Peak Energy Price
A. 2-part tariff with demand and energy charge			
1. Strict marginal energy cost (not to be adjusted)	--	X	X
2. Demand charge on maximum kW in peak hours only (i.e., coincident maximum demand charge)			
a. marginal cost of generation capacity	97% allocated to peak period. Can be recovered through energy charge of demand charge.		3%
b. marginal cost of network capacity - transmission (VHV, HV) cost	100% recovery through energy charge or demand charge		--
- distribution (MV, LV) cost	--	X	X
3. Demand charge on maximum kW in all hours (i.e., simple maximum demand charge)			
a. marginal cost of generation capacity	--	97%	3%
b. marginal cost of network capacity - transmission (VHV, HV) cost	--	100%	--
- distribution (MV, LV) cost	Either 100% in demand charge or recovered fully through peak and off-peak energy charge.		
B. Pure energy tariff (i.e., no demand charge)			
Marginal energy cost	--	On-peak strict marginal energy cost	Off-peak strict marginal energy cost
Generation capacity cost	--	97% of generation capacity cost	3% of generation capacity cost
Transmission capacity cost	--	100% of energy transmission marginal capacity cost	
Distribution capacity cost	--	Distribution network marginal capacity cost spread equally across all kWh in peak and off peak periods.	

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In addition, the portion of the marginal cost of generation capacity allocated by LOLP to the off-peak period must be spread across all kWh in that period.

The marginal cost of transmission related to high voltage and very high voltage is a function of peak period usage and, therefore, should not be included in the off-peak energy price.

In the case that the rate does not include a separate demand charge, it is desirable that the marginal cost of transmission and distribution related to the low voltage and/or medium voltage portion of the network system be spread equally over all kWh (both peak and off peak). This prevents a customer from avoiding all costs associated with the local distribution system, by limiting his usage to only the off-peak hours. Other costs further up the system (i.e., transmission cost at high and very high voltage, generation capacity cost) avoided by limiting usage to the off-peak hours are freed to serve new load. However, local facilities not used during peak hours are of little or no use to serve other load.

In the case that a separate demand charge is included in the rate and the maximum demand is measured only during the peak period, the method described in the previous paragraph must be used because, again, all costs of local facilities could be avoided if those costs were all reflected in the peak period demand charge.

If the rate includes a separate demand charge that is based on the maximum kW in <u>any</u> hour of the month, then the local facilities cost (LV and/or MV) can be recovered through either the demand charge or spread equally across all kWh in the year. While recovering these costs through the demand charge is definitely the best method, this cost component alone, without other considerations, may not be sufficient to justify the additional complication and expense of a separate demand charge.

In theory, a simple maximum demand charge-based tariff design is totally contrary to the philosophy underlying TOD tariffs. From a practical standpoint as well, this option is largely irrelevant in today's metering environment where TOD metering of energy and demand can be accomplished with one meter and at a cost that is not significantly different than the cost of TOD energy only metering. Consequently, a discussion of this tariff design is included here for the sake of completeness only. The TOD tariff recommendations presented later in this section do not incorporate this design, and instead are based upon coincident demand charges.

Basis for Peak Energy Price

The strict marginal cost of energy in the peak period should obviously be included here.

If the rate does not include a separate demand charge or if it includes a demand charge that is based on the maximum demand in any hour of the month, then the portion of the marginal cost of generation capacity allocated by LOLP to the peak period must be spread across all kWh in that period. If the rate includes a demand charge that is based on the maximum demand measured in only the peak period, then that portion of capacity cost can be recovered through a separate demand charge or through the energy charge. On a system with broad, less well-defined peak periods and significant seasonal variations, recovering these costs through the separate demand charge may be preferable. However, for a system such as the one we have defined here, either method should provide the desired results. Often, the use of an energy charge is understood better than the use of a demand charge.

If the rate does not include a separate demand charge or if it includes a demand charge that is based on the maximum demand in any hour of the month, then the marginal cost of transmission related to high voltage and very high voltage should be recovered through the peak period energy price. If the rate includes a demand charge that is based on the maximum demand measured during the peak hours, then these costs can be properly recovered through either the peak energy charge or the demand charge (again keeping in mind the daily, weekly, and seasonal load pattern we are assuming here).

The marginal cost of transmission and distribution related to medium voltage and low voltage must be spread equally across all kWh in the year (both peak and off peak) if there is no demand charge or if the demand charge is based on the maximum demand charge measured only during the peak period hours (for reasons set forth in the discussion of the off-peak energy price).

If the rate includes a separate demand charge that is based on the maximum kW in <u>any</u> hour of the month, then the local facilities cost (LV and/or MV) can be recovered through either the demand charge or spread equally across all kWh in the year (see explanation in the off-peak energy price discussion).

Basis for Demand Charge

A discussion of the appropriate use of a separate demand charge has been incorporated into the explanation of the peak energy price and off-peak energy price. However, an additional discussion may be helpful.

As is often the case when incorporating cost analysis into rate design, there is an inherent conflict between short-run and long-run considerations. In the case of generation capacity cost, recovering this cost through a separate demand charge may result in a more appropriate short-run price signal, while recovering these costs through the energy charge may give a more appropriate long-run price signal. (In the short run, a large portion of cost is fixed, while in the long run, all costs are variable.)

Other factors to be considered when making the decision on the use of a demand charge are as follows:

1. seasonal load variations
2. duration of daily peak period
3. metering cost
4. customer understanding and acceptance
5. probability of shifting peak or off-peak period rather than reducing peak
6. probability of creating an even higher "needle" peak in the peak period (if probability is high, use a separate demand charge)
7. variation of load between peak and off-peak periods
8. variation of cost between peak and off-peak periods

These and other factors must be carefully weighed when rates are designed. A delicate balance between economic efficiency, fairness and practicality must be achieved.

TOD Tariffs for EEA Supply

TOD tariff considerations outlined in the preceding provide the basis for defining the proposed tariffs for EEA sales shown in Exhibit 9-16. The corresponding "bill impacts" can be inferred by looking at the potential changes in the average price of electricity as shown in Exhibit 9-17. The proposed tariff design recovers the revenue responsibility from the VHV, HV, MV and Distribution Company sales categories.

Exhibit 9-16
Proposed Tariff for EEA Sales
TOD Option 1: Pure Energy Tariff Option*

Consumer/ Category	Service Voltage	Demand Charge (LE/kW/Month)	Energy Charge (P/kWh) Peak	Off-Peak
KIMA	VHV	0.0	8.62	8.62
ALUMINUM	VHV	0.0	8.62	8.62
ASSUIT CEMENT [1]	VHV	0.0	8.62	8.62
ASSUIT CEMENT [2]	VHV	0.0	8.62	8.62
FERROCILICON	VHV	0.0	8.62	8.62
SOMED	VHV	0.0	8.62	8.62
IRON & STEEL	VHV	0.0	8.62	8.62
AMIRIA SPINING	VHV	0.0	8.62	8.62
Industry and Agriculture	HV	0.0	38.00	9.10
Industry and Agriculture	MV	0.0	44.00	12.00
Distribution Companies				
CAIRO		0.0	12.00	9.10
ALEX		0.0	12.00	9.10
NORTH DELTA		0.0	12.00	9.10
SOUTH DELTA		0.0	12.00	9.10
EL BEHERA		0.0	12.00	9.10
AL CANAH		0.0	12.00	9.10
NORTH UPPER EGYPT		0.0	12.00	9.10
SOUTH UPPER EGYPT		0.0	12.00	9.10

* Until such time as TOD tariffs are implemented

* TOD tariffs for VHV customers in FY 93 are not feasible because revenue responsibility is equal to off-peak marginal energy cost.

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Exhibit 9-17
Bill Impacts: EEA TOD Option 1

Consumer/ Category	Sales 1990 July-Dec (Million kWh)	Average Price (P/kWh) Present	Proposed	Increase (% Change)
KIMA	824	1.70	8.62	407%
ALUMINUM	1,485	4.60	8.62	87%
ASSUIT CEMENT [1]	86	6.32	8.62	36%
ASSUIT CEMENT [2]	59	6.32	8.62	36%
FERROCILICON	153	5.77	8.62	49%
SOMED	162	6.32	8.62	36%
IRON & STEEL	449	6.32	8.62	36%
AMIRIA SPINING	53	6.32	8.62	36%
Subtotal	3,271	4.35	8.62	98%
Industry/Agriculgure - HV	1,218	8.07	14.88	84%
Industry/Agriculgure - MV	126	13.60	19.04	40%
Distribution Companies				
CAIRO	6,449	6.75	9.85	46%
ALEX	1,619	6.45	9.85	53%
NORTH DELTA	1,099	4.85	9.85	103%
SOUTH DELTA	1,158	5.05	9.85	95%
EL BEHERA	716	6.50	9.85	52%
AL CANAH	1,548	6.60	9.85	49%
NORTH UPPER EGYPT	1,008	4.70	9.85	110%
SOUTH UPPER EGYPT	1,018	6.50	9.85	52%
Subtotal	14,615	6.25	9.85	58%
TOTAL	19,229	6.09	10.02	65%

Exhibit 9-18
Proposed Tariff for EEA Sales
TOD Option 2: Demand and Energy Charge

Customer/ Category	Service Voltage	Demand Charge (LE/kW/Month)*	Energy Charge (P/kWh)	
			Peak	Off-Peak
--	HV	25.50	13.00	9.10
--	MV	27.00	16.00	12.00
Distribution Companies	--	--	11.90	9.10

* coincident demand

Once TOD metering capability is operational at EEA, a demand charge-based tariff can be introduced on a mandatory basis. Because of the range of situations and response capability that potentially characterize customer diversity, a second TOD design based upon a coincident demand charge is proposed as well (Exhibit 9-18). Low load factor customers who have the potential for substantial load shifting are likely to prefer the demand charge-based tariff option.

A demand charge-based TOD tariff for VHV has not been proposed for two reasons. First, the existing VHV customers all have extremely high (90+ percent) load factors. Such customers, who are highly electricity intensive, tend to view a pure energy tariff and a demand charge-based tariff with a consistent design basis, as essentially the same. A second reason is that when the pure TOD tariff design is adjusted downwards for ensuring revenue responsibility of 8.62 P/kWh, the demand charge has to be reduced to almost zero. The alternative of preserving the demand charge but reducing peak and off-peak energy tariffs yields revenue neutrality only when these energy prices are below the respective marginal costs. This situation, where the energy prices do not recover variable costs, is not acceptable on tariff design principles.

In the case of DCs, again because the revenue responsibility of 9.83 P/kWh is low in comparison to the peak and off-peak marginal energy cost, a demand charge is not possible at present. However, starting in FY 94, it will be possible to develop a demand charge.

TOD Tariff Design for Large Power Service

It was stated earlier in Chapter 7 that once appropriate metering capability is acquired and operational at EEA, mandatory TOD tariffs should be introduced for the large power service tariff category. Exhibit 9-19 presents the proposed TOD tariff design.

Option 1 (LPS-TOD1) is a two-part tariff with a coincident demand charge of LE 27/coincident kW/month, and LPS-TOD2 is a pure energy-based tariff. Whereas TOD pricing should be mandatory for large power service customers, two options are offered to accommodate the range of customer-specific situations and response capabilities.

Exhibit 9-19
Large Power Service: TOD Tariff Options

Option	Demand Charge (LE/kW/Month)*	Energy Charge (P/kWh)	
		Peak	Off-Peak
1. LPS-TOD1	27.00	16.0	12.0
2. LPS-TOD2	--	44.0	12.0

* coincident demand

Tariff Promotion and Marketing

In the case of TOD tariff options, EEA should design, develop, and implement the necessary programs to help customers under this tariff. These programs should also help customers to reduce their coincident demand in ways that are best suited to their specific needs and situations. Simply enrolling customers into these tariffs will not in itself provide any significant load reduction on-peak.

There is ample evidence of instances where a utility has designed and offered such tariff options but has achieved little or no load response. This has been found to be true even in instances where a significant number of customers subscribed to the tariff.

In light of this, we recommend that EEA offer information programs, provide technical assistance and design support such as conduct audits, conduct training, and possibly even assist in hardware and software procurement where necessary. Such programs must stress the partnership between EEA and its customers and demonstrate how both parties stand to benefit in a concrete financial sense.

9.4 INTERRUPTIBLE TARIFFS

At some point following the introduction of TOD tariffs, EEA should consider the introduction of interruptible tariffs on an optional basis. The potential class of such customers -- typically a subset of the Large Power Service tariff class -- will have to be determined based upon a detailed market survey and the considerations outlined in the following.

Interruptible service (IS) is a demand-side option that is widely used and accepted by electric utilities and utility customers in many countries. Interruptible service allows a utility to interrupt load to a customer in accordance with specified provisions. For this privilege, the utility reduces the customer's bill by a specified amount each month. In regard to the daily operations of generation facilities, IS improves reliability and operating flexibility. In the longer term, IS allows the utility to build less generating capacity. A well designed IS tariff provides substantial benefits to both the utility and the customer.

Under an IS tariff, the customer contracts with the utility for an amount of load the customer is willing to remove from the system when requested to do so. This load is then considered to be non-firm. The IS tariff will specify an advance notice period that may be as long as 24 hours to as little as 15 minutes. While the utility may, in some cases, have direct control over the customer's load, most often the interruption is triggered by a phone call from the utility to the customer. This requires a dedicated phone line which is manned constantly to ensure timely communication. Special metering equipment that records usage on a continuous basis is also required to ensure compliance with the magnitude and time of requested interruption.

As mentioned earlier, IS allows the utility to install less generating capacity while maintaining a target level of reliability. Since IS can be called a for a limited number of hours, it displaces peaking capacity in the generation mix. Therefore, the interruptible credit given to the customer should be based on the long-run marginal cost of peaking capacity, generally assumed to be combustion turbines (CT). While the credit should be <u>based</u> on this cost, it may <u>not</u> <u>equal</u> the LRMC of a CT because the IS capacity may not be

of equal value to the utility as the same amount of CT capacity. For example, an IS tariff that allows only 300 hours per year of interruption would not be as valuable to the utility as a CT that can run 2000 or more hours per year. In this case, the $/kW credit for IS should be less than the same $/kW LRMC of a CT.

The IS tariff should include specification of the interruption period. Generally, a maximum number of hours of interruption per year, week, and day will be given. This provision has a major impact on the value of the IS to the utility.

The IS tariff should include a substantial penalty for non-compliance. The utility has foregone building capacity and paid significant amounts to the customer for the right to interrupt the load. Customers must be discouraged from contracting for non-firm load and receiving credits when they have little intention or ability to interrupt load.

Since the influence of IS has a long-term impact on the utility's generation expansion plan, a three-year notice of contract cancellation on the part of the customer may be appropriate.

Specification of the various parameters of an interruptible tariff would begin with the consideration and types of calculations discussed above. Once a preliminary menu of interruptible tariffs is developed on this basis, it will be necessary to conduct a survey of the target population to test the concept. Information gathered in this process can be valuable in subsequently "fine tuning" the preliminary menu.