PN-ABA-628
ISN 57449

World Bank Study
Vol # VII

APPENDIX

3.8.5-2

EGYPT

INVESTMENT REVIEW

POWER SUBSECTOR ISSUES

February 13, 1984

Project No. 263-0123.1

PASA No. IEG-0123-P-34-3089-00

THE WORLD BANK

CONFIDENTIAL

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EGYPT

INVESTMENT REVIEW

POWER SUBSECTOR ISSUES

February 13, 1984

Projects Department
Europe, Middle East and North Africa
Regional Office

EGYPT

INVESTMENT REVIEW

POWER SUBSECTOR ISSUES

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ANNEX 1 - Power Subsector Investment Program 1982/83 - 1986/87

(1633P)

EGYPT

INVESTMENT REVIEW

POWER SUBSECTOR ISSUES

I. INTRODUCTION AND SUMMARY

Introduction

1.01. This paper has the main objective of analysing power subsector issues for the FY84 Investment Review. As well as describing the power investment program it is also intended to provide background data on the subsector, e.g. electricity consumption, tariffs. The paper draws from the Power Subsector Study (Report 4165-EGT) prepared in 1982 and raises few issues that were not raised in that report. Some issues, such as investment planning and pricing, where more information is now available, are treated in greater depth. The main themes of the report are summarized below.

Investment Program

1.02. Chapter II first examines the projected demand for electricity and concludes that EEA's forecasts are reasonable for the current plan period 1982/87. After 1986/87 there is a strong possibility that the growth in demand for electricity will slow down and that the introduction of demand management policies would lead to an even slower growth in demand.

1.03. The generation investment program for the 1982/83 - 1986/87 plan appears sound and should lead to an improvement in the quality of electricity supply. However, the lower growth in demand projected by the mission could lead to savings from postponing the Kuraimat oil/gas fired power station beyond 1991/92, a major slowing down of the rate of implementing the Sidi Kreir coal fired station and a minor slowing of the Sinai coal power station. In the mission's view it is unrealistic to expect the first nuclear power station to be completed in 1991/92. A more feasible date would be 1993/94.

1.04. At present EEA does not have a least cost development program, although because of project lead time constraints, the program up to 1991/92 is reasonably well defined. For the longer term it is necessary for a least cost program to be prepared that would establish priorities and balance among imported coal, nuclear, small hydro and natural gas options. The detailed feasibility study of the Qattara hydrosolar project showed an economic rate of return of only 10% for the least cost option, which involved excavation using nuclear charges and had a lead time of 13 years. Unless the current feasibility study indicates a higher economic return to justify the risks of the project and shows a role for the project in the least cost development program, the mission considers that the preparatory studies on this project be wound down and the funds directed to demand management.

Demand Management

1.05. Chapter III uses recent information on electricity tariffs and costs available from a consultants study to illustrate the well known serious

distortions of electricity prices in Egypt. The average tariff level is in the order of only 12% of economic cost, with fuel valued at international prices. Distortions of fuel prices amount to 84% of the difference between electricity prices and long run marginal cost (LRMC) but existing tariffs would need to double to achieve parity with LRMC calculated using local fuel prices. The paper sets out suggestions for elements which would be included in a package of electricity pricing reforms.

1.06. Load management, which is normally complementary to efficient pricing, has an additional role in Egypt since tariffs are unlikely to reach the levels of LRMC before 10 years. During the period of price adjustment, the implementation at the recommendations of the current load management studies would enable some of the savings from efficient pricing to be achieved before tariffs have reached the level of LRMC. Similarly, energy conservation measures implemented using non-price incentives could lead to some savings before prices have adjusted.

1.07. Major savings in power subsector investment could be made through industrial restructuring. Two notable examples are the Kima fertilizer plant and Nag Hamadi aluminium smelter. While these industries are financially viable at subsidized energy prices, they are not economically viable at international energy prices. Closure or restructuring of these industries would lead to a saving of over 600 MW, equivalent to two new 300 MW power generating units.

Institutions and Manpower

1.08. Chapter IV examines the problems in co-ordination among energy sector institutions. These may be reduced when the Supreme Council to Energy and its technical support group, the Organization for Energy Planning, mature into viable institutions. Within the power subsector, the paper reviews the issues of co-ordination among the various organizations which are complicated by the multiplicity of agencies and the inadequate exchange of information.

1.09. Shortages of skilled technical manpower are a major power subsector issue. These are due primarily to civil service salary scales which are inadequate compared to the private sector or work abroad. Because of the projected increase in requirements to technical staff to operate plant under construction, there is an urgent need to strengthen the implementation of the power subsector training program prepared with assistance from consultants and make conditions of service, including salaries, sufficiently attractive to retain the newly trained staff.

1.10. By contrast, there is a large surplus of non-technical staff covered by Government obligations to employ university graduates and discharged servicemen. This surplus reduces the efficiency and morale of subsector institutions and there are grounds for a freeze on the employment of unskilled staff and the upgrading of their skills through implementing the training programs prepared by EEA's consultants.

Relations with Other Sectors

1.11. Chapter V examines the relations between the power subsector and its fuel suppliers. A major issue is the quantity of gas available for power

generation. Gas reserves are presently estimated to be 6 to 9 trillion ft^3, with an upper bound of about 30 trillion ft^3. The economic cost of gas, and hence the degree to which it will be needed for power generation in the 1990's, depends on the size of the reserves. More gas exploration is needed to reduce the uncertainty about reserves so as to determine whether natural gas will be a major fuel for power generation in the 1990's, or whether gas consumption would decline. The long lead times for power stations indicate the need for urgent action on gas exploration.

1.12. The consumption of oil for power generation is projected to decline drastically in the 1980's as natural gas becomes the main fuel for power generation. This would lead to a national surplus of fuel oil and would indicate that cracking this oil to lighter products should be considered.

1.13. There is a need to systematically evaluate options involving fuel supplies for power generation. Such options include the development of the small Sinai coal reserves, the use of existing port facilities for importing coal and the exploitation of the small remaining hydro resources on the Nile.

Financial Requirements

1.14. Chapter VI establishes that investment in electricity supply during the 1982/83 - 1986/87 plan would amount to LE 3.8 billion at current prices. This is about LE 1.3 billion greater than the LE 2.47 billion allocated for electricity supply in the 5-year plan. This discrepancy is caused mainly by under-provision for expenditure on projects completed after the plan and for actual expenditure on combustion turbines caused by delays in completing steam plant. Furthermore, expenditure on transmission and distribution seems low (26%) compared to generation (72 %).

1.15. The mission was unable to obtain a clear picture of how this investment program was to be financed. Cash flow has been insufficient to meet debt service in 1980/81, 1981/82 and 1982/83 and there appears to be a shortfall in new loans required to finance projects of at least $1 billion. Some of the uncertainty over future financing could be resolved by a firm decision by the Government to commit itself to a program to increase energy prices. There is an urgent need for a realistic financing plan to be prepared and for actions to be taken, e.g. implementation of demand management policies, to achieve a balance between investment and available finance, as well as between capacity and electricity demand.

II. POWER SUBSECTOR INVESTMENT PROGEAM

A. Past and Projected Electricity Consumption

Historical Trends in Electricity Consumption and Supply

2.01. Total electrical energy produced by EEA increased rapidly during the period 1960-1965 at an annual rate of 19.5%. During this period the Aswan hydroelectric power station was commissioned. An electrochemical fertilizer factory at Kima in upper Egypt was completed around the same time and which accounted for the major part of the increased consumption. In 1965, the various government, municipal and private organizations were combined into the precursor of EEA and the Government initiated a major expansion of the electric power infrastructure,

Table 2.1

Past Consumption of Electricity

Year	Energy Sold to Final Consumers (GWh)					Energy Generated (GWh)	Maximum Demand (MW)
	Industry	Kima & Aluminum	Agriculture	Others	Total		
1974	3,789	1,422	684	2,422	6,895	8,519	1,433
1975	4,804	1,713	677	2,826	8,307	9,800	1,733
1976	5,247	2,572	671	3,143	9,661	11,646	1,909
1977	7,180	3,317	698	3,611	11,489	13,517	2,284
1978	7,553	3,446	697	4,473	12,723	15,013	2,564
1979	7,995	3,366	704	4,494	13,193	16,359	2,829
1980/81	9,186	3,993	777	5,628	15,591	19,866	3,179
1981/82	9,593	3,993	836	6,737	17,166	21,896	3,694
1982/83	..	3,934	..	..	..	..	3,981
Annual Growth Rate (% p.a.)							
1974-1981/82	13.2	14.8	2.7	14.6	12.9	13.4	13.5

Source: EEA
Note: .. means not available.

which was exemplified by the commissioning of the Aswan High Dam between 1967 and 1970. During the period 1965-70, electricity production increased at 8.3% p.a., but the rate declined somewhat, to 5.4% p.a. during the period 1970-1974.

2.02. Between 1974 and 1981/82 electrical energy generated increased at 13.4% p.a., considerably faster than in the previous decade. Total electricity sold to final consumers increased at a slower rate of 12.9% p.a., since losses and power station use increased from 19% to 22%. Electricity sold to industry, which accounted for 56% of electricity sold in 1981/82, increased at 13.2% p.a., irrigation and land reclamation pumping at 2.7% p.a. and other consumers (residential, commercial and government) at 14.6% p.a. (Table 2.1). The rapid increase in electricity consumption in 1974 to 1981/82 was due mainly to four factors:

(a) The high rates of economic growth during the period. Between 1974-1981/82 real GDP increased at an average rate of 8.9% p.a. This high rate of economic growth was a result of remittances from Egyptians working in the Arab oil exporting countries, revenues from the re-opened Suez Canal, the expansion of Egyptian oil production and increasing levels of foreign assistance;

(b) the low and falling level of electricity tariffs, which are among the lowest in the world and declined in real terms by 31% between 1970 and 1982/83 (Table 3.1);

(c) expansion of electricity distribution networks throughout the country, so that by end 1983 virtually all towns with more than 1,000 inhabitants had public electricity supply; and

(d) the completion of 3 potlines at the Nag Hamadi aluminum smelter in 1975, with a further potline commissioned in 1980, which in 1981/82 accounted for 2,381 GWh, or nearly 14% of all electricity sold to final consumers.

It is significant that the intensity of electricity use 1/ increased substantially by 31% between 1974 and 1981/82, although the rate of increase has leveled off since 1978. This is not only due to the aluminum smelter entering production, since the intensity of other industries increased by 37% during the same period (Table 2.2). These large increases in intensity are, at least in part, a consequence of the low prices of electricity, which contribute to electricity intensive investment, and which neither encourage the purchase of efficient appliances nor discourage waste.

1/ Electricity intensity is defined as electricity consumption divided by Gross Domestic Product and is expressed here as kWh per LE of GDP.

Table 2.2

Relation Between Electricity Consumption and GDP
(kWh per LE of GDP, 1975 prices)

Year	All Industry	Less Intensive Industry /1	All Consumers
1974	4.59	2.87	1.49
1975	5.46	3.51	1.64
1976	6.17	3.45	1.76
1977	7.10	3.82	1.89
1978	7.07	3.85	1.94
1979	6.94	4.02	1.83
1980/81	7.03	3.97	1.91
1981/82	6.73	3.93	1.95
Increase 1974-1981/82	47%	37%	31%
GDP Elasticity	1.62	1.48	1.35

Source: Mission estimates.

/1 Total industrial consumption excluding Kima fertilizer and Nag Hamadi aluminum smelter.

Projected Electricity Consumption

2.03. As the preceding paragraph has indicated, the growth in electricity consumption is particularly sensitive to the rate of economic growth. Since the level of electrification is already high in Egypt, the connection of new consumers to the network will be less of a source of growth than in the past. However, three areas of Goverment policy could affect future consumption: (a) restructuring of electricity intensive industries; (b) electricity price increases that revised tariffs towards the level of long run marginal cost (LRMC); and (c) the introduction of load management to shift consumers' peak demand to system off-peak periods. We have evaluated the potential effect of these three policy changes against the background of a "reference case" that assumes a continuation of existing policies. It should be noted that the projections described below are scenarios to indicate the impact of certain policies. These are not intended to substitute for a demand forecast, which would require extensive data collection and more rigorous analysis.

2.04. Because of the severe limitations to past data on electricity consumption due to consumer reclassification, projections of sales of electricity were made for only four sectors: (a) large industry, comprising the Kima fertilizer factory and the Nag Hamadi aluminum smelter; (b) other industry; (c) agriculture, consisting almost entirely of water pumping; and (d) other consumers, comprising residences, commercial, Government

institutions, public utilities and streetlighting. Consistent data for a more detailed breakdown for more than a few years did not exist. Time series of the number of consumers, either in total or by sector are not readily available or do not exist, so that the impact of population growth, household formation and housing change on electricity consumption could not be identified. These severe data restrictions limit the potential accuracy of electricity demand projections. The Government recognizes this problem and UNDP is preparing a technical assistance project to establish a power subsector data base which would enable the forecasting methodology to be improved. Projections of electricity consumption for the three sectors other than the large industries were made using elasticities with respect to appropriate macroeconomic aggregates, e.g. industrial GDP. The consumption of Kima and the aluminum smelter were projected by EEA.

2.05. The Reference Case assumes a continuation of present policies such that the elasticities remain constant over the forecast period. Industry, other than Kima and aluminum, was forecast in relation to industrial GDP, with an elasticity of 1.48, estimated from 1974-1981/82 data. Agricultural consumption was forecast in relation to agricultural GDP, with an elasticity of 0.89. Consumption expenditure was used to explain the electricity consumption of the remaining consumers, since the purchase of electricity consuming appliances would be related to private consumption expenditure, as would the output of shops and much commercial activity, whereas the consumption of electricity by central and local Government offices, institutions and services could be expected to be linked to public consumption expenditure. Obviously, this approach is far from ideal, but poor data precluded a more rigorous approach to forecasting. Projections of industrial GDP, agricultural GDP and consumption expenditure were taken from 1983 Bank economic reports.

2.06 Economic growth projections on which the reference case electricity consumption forecast is based are shown in Table 2.3. Obviously, the

Table 2.3

Economic Growth Projections
(% p.a.)

Year	Total GDP	Industrial GDP	Agricultural GDP	Consumption
1982/83	6.9	8.5	2.5	5.5
1983/84	6.0	8.4	2.4	6.0
1984/85	6.6	7.8	2.6	6.2
1985/86	6.4	7.7	2.7	6.0
1986/87	6.0	7.5	2.8	5.5
1987/88-1991/92	4.9	8.2	2.5	5.9
1992/93-1996/97	3.7	4.7	2.5	3.6
1997/98-2001/92	4.0	5.0	2.5	3.2
2002/03-2011/12	4.6	5.8	2.5	3.2

Sources: World Bank, "Current Economic Situations and Growth Projects" (Report 44998-EGT) and "Issues of Trade Strategy and Investment Planning" (Report 4136-EGT).

forecasting errors of GDP projections increase as one looks further into the future. Consequently, electricity demand forecasts based on such GDP projections will also be subject to error. However, the key electricity demand forecasts are for the years when new capacity is required that requires investment decisions today. Forecasts for these years influence the timing and size of the investment. Errors in long range forecasts affect the operating assumptions about such investment and consequently would generally have a smaller impact on the decision. The reference case scenario is shown in Table 2.4. Electricity sold is projected to increase at 9.3% p.a. during the period 1981/82 - 1986/87, slow down to 7.2% p.a. during the period 1986/87 - 1991/92 and then grown at 5.8% p.a. for the remainder of the century. Maximum demand is projected to increase at a slightly faster rate of 10.4% p.a. during the period 1981/82-1986/87 since new consumers would lead to a decline in system load factor which is presently strongly influenced by the large industrial consumer. In the longer term, the effect of these large consumers would be proportionally less and was assumed that measures would be initiated to reduce losses. Maximum demand would therefore increase at slower rates than consumption, 6.4% p.a. during 1986/87 - 1991/92 and 5.1% p.a. during the period 1991/92 to 2001/02. Six sensitivity studies based on alternative policy assumptions were examined and these are discussed below.

Table 2.4

Reference Case Demand Scenario
(GWh)

Year	Electricity Sold				Gross Generation	Maximum Demand (MW)
	Industry	Agriculture	Others	Total		
	Actual					
1980/81	9,186	777	5,628	15,591	19,866	3,179
1981/82	9,593	836	6,737	17,166	21,896	3,694
	Projected					
1982/83	10,679	852	7,341	18,872	24,041	3,981
1983/84	12,229	870	8,062	21,161	26,786	4,564
1984/85	13,126	889	8,884	22,899	28,986	5,091
1985/86	14,112	910	4,760	24,782	30,978	5,525
1986/87	15,185	930	10,644	26,759	33,449	6,061
1991/92	21,106	1,033	15,824	37,963	46,296	8,258
1996/97	27,767	1,149	21,120	50,036	60,284	10,587
2001/02	37,827	1,277	27,335	66,439	78,164	13,519
2011/12	81,053	1,580	45,841	128,474	149,388	25,453

Source: Mission Estimates.

2.07 Case A assumes that the Kima fertilizer plant would be converted to natural gas during the period 1986/87 to 1991/92. Alternatively, the Kima plant could be considered to have been closed down and a new fertilizer plant established at the gas field. In either case, some requirement for electricity would remain. We assume it to be 10% of the present consumption. The consequence of phasing out the electrolytic process at Kima would be to reduce the maximum demand for electricity by about 197 MW so that the maximum demand for electricity would grow by 5.9% p.a. during the 5-year period 1986/87 - 1991/92 instead of 6.4% p.a. as in the Reference Case (Table 2.5).

2.08. Case B also assumes that the Kima demand would be reduced by 90% but, in addition, assumes that production would cease at the Nag Hamadi aluminum smelter. Egypt no longer has surplus hydro energy. Electricity will be generated at the margin in oil or gas-fired plants for the foreseeable future. 1/ The economic viability of aluminum smelting is therefore uneconomic, especially considering the locational disadvantage of the plant in terms of local transport costs for imported aluminum and aluminum ingot produced, as well as the depressed state of the world market for aluminum. 2/ Ceasing production at the aluminum smelter would lower the maximum demand for electricity by about 411 MW, which together with the 197 MW saved at Kima would lead to an overall reduction of 608 MW or 7.4% of the 1991/92 Reference Case demand.

2.09. Case C and Case D examine the sensitivity to electrcity prices increasing by a factor of 4 in real terms over a 10-year period. Electricity tariffs in Egypt are on average about 12% of LRMC calculated at international prices (Table 2.3). Correcting this distortion would appear to involve real prices rising about 8 times. However, the four-fold increase assumes that investment and operating savings arising from lower demand energy conservation electricity load management and lower cost fuels such as coal and possible abundant natural gas would eventually lower LRMC. Establishing the appropriate price elasticity and dynamic response of demand to a four-fold price increase is particularly difficult. Historic electricity consumption trends in Egypt are a consequence of real prices falling from an already low level and would not provide a reliable guide to the response to large price increases. Moreover, some of the policy assumptions e.g. closure of Kima and Nag Hamadi could be interpreted as a response to higher electricity prices. Econometric studies available mainly from developed countries do not provide evidence of the response of demand to very large real price increases. We have therefore calculated electricity demand assuming price elasticities of -0.1 (Case C) and -0.3 (Case D) which are at the mid to lower range of typical electricity price elasticities estimated elsewhere. The full effect of the price increases is assumed to have taken place by 1996/97, since Government

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1/ In 1983 and 1984 combustion turbines were being operated on base load and some combustion turbines were burning distillate oil and naphtha. Even though natural gas amounted to about 20% of EEA's fuel consumption, the economic cost of gas is equivalent to thermal parity with fuel oil, at least until about 1990.

2/ See "Issues of Trade Stragegy and Investment Planning" for a discussion of the economics of aluminum smelting in Egypt.

Table 2.5

Electricity Demand Scenarios

	1981/82	1986/87	1991/92	1996/97	2001/02
Energy Sold (GWh)					
Reference case	17,166	26,759	37,963	50,036	66,439
A. Kima - 90% lower	17,166	26,759	36,523	48,596	64,999
B. Kima - 90%, aluminum closed	17,166	26,759	33,523	45,596	61,999
C. Tariff increases, e = -0.1	17,166	25,689	34,167	43,558	57,839
D. Tariff increases, e = -0.3	17,166	25,421	31,509	33,011	43,833
E. Combined effect Kima - 90% price e = 0.1	17,166	26,689	32,871	42,305	56,585
Energy Generated (GWh)					
System losses (%)	21.6	20	18	17	15
Reference case	21,896	33,449	46,296	60,284	78,164
A. Kima - 90%	21,896	33,449	44,540	58,549	76,469
B. Kima - 90%, aluminum closed	21,896	33,449	40,882	54,935	72,940
C. Tariff increases, e = -0.1	21,896	32,111	41,667	52,480	68,046
D. Tariff increases, e = -0.3	21,896	31,776	38,426	39,772	51,568
E. Combined effect A+C	21,896	33,361	40,087	50,970	66,571
Maximum Demand (MW)					
Reference case	3,694	6,061	8,258	10,587	13,519
A. Kima - 90%	3,694	6,061	8,061	10,390	13,322
B. Kima - 90%, aluminum closed	3,694	6,061	7,650	9,979	12,911
C. Tariff increases, e = -0.1	3,694	5,818	7,432	9,217	11,769
D. Tariff increases, e = -0.3	3,694	5,730	6,854	6,985	8,919
E. Combined effect A+C	3,694	5,818	7,235	9,020	11,572
F. Combined A+C and load management	3,694	5,818	6,873	8,569	10,993
EEA forecast	3,694	6,418	9,933	14,055	19,712

Source: Mission estimates.

commitment to a 10-year program of energy price reform would soon encourage expectations of the adjusted prices which would influence the purchases of electricity consuming equipment. With a low price elasticity of -0.1 (Case C), demand in 1996/97 would be 13% below the Reference Case. During the period 1981/82 to 1996/97, maximum demand would grow at an average annual rate of 6.3%, compared to 7.5% in the Reference Case. The accumulated saving over the period would be about 1,370 MW, equivalent to the capacity of a large power station. With the higher elasticity of -0.3 (Case D), demand in 1996/97 would be 34% below the Reference case and the average rate of growth in maximum demand up to then would be 4.3% p.a. The accumulated saving would be about 3,600 MW, or about three large power stations. A rough estimate of the investment saved at 1983 prices would amount to US$4.3 billion in Case D.

2.10. Case E considers the combined effect of reducing the consumption of the Kima fertilizer plant by 90% and a fourfold real tariff increase with the lower -0.1 price elasticity. This would result in a maximum demand of 6,973 MW in 1991/92, about 17% below the 8,258 MW of the Reference Case. Maximum demand would increase at an average rate of 4.5% p.a. during the preiod 1986/87 to 1996/97, compared to 5.7% p.a. in the Reference Case.

2.11. Case F considers load management, along with the 90% reduction in the Kima load and tariff increases with the lower -0.1 price elasticity. Analysis of load management options is presently being studied by consultants and information on the potential reduction in demand will be contained in their report. However, it is assumed here that load management would enable 5% of the peak demand to be transferred to off-peak times, with no change in the total GWh generated or sold. In this case 1991/92 maximum demand would be about 360 MW less than in Case E, or 1385 MW below the Reference Case. Load management measures are assumed to be implemented first between 1988/89 and 1991/92. The resulting growth in maximum demand during this period would fall to 3.4% p.a., compared to 4.5% p.a. in Case E and 6.4% p.a. in the Reference Case.

Conclusion

2.12. The Reference Case shows that even under the assumption of unchanged policies for electricity pricing, industrial restructuring and load management, the slower rates of economic growth projected by the Bank after 1986/87 would lead to a slowdown in the present rate of growth of electricity demand. EEA has projected past trends in electricity demand to continue and this, in or view, would overestimate demand (Table 2.5).

2.13. If the Government were to implement policies to restrain the growth of electricity demand, the sensitivity studies above would indicate that the reduction in maximum demand could be considerable, e.g., 17% or 1385 MW below the Reference Case by 1991/92 for Case F. The effect of combined demand management policies, taken with the Bank's economic growth projections would lead to demand in 1991/92 of about 6873 MW (Case F), or about 30% less than the EEA trend projection of 9,933 MW.

B. Past and Projected Electricity Supply

Past Trends in the Supply of Electricity 1/

2.14. Generating capacity remained substantially in excess of maximum demand throughout the 1970s, but the margin of reserve capacity declined markedly. 1/ As shown in Table 2.6, installed capacity was more than three times the maximum demand in 1970 but in 1983 the gross reserve margin had fallen to 36%. After allowing for the derating of plant due to age, condition, hydrology and operating conditions, the net capacity in 1983 was roughly equal to demand, with little spare capacity available to cover maintenance outages and breakdowns. Because of the huge surplus capacity at the beginning of the period, no new capacity was added until 1976. All plant commissioned after 1976 was thermal, with the result that the share of hydro plant fell from 65% in 1970 to 43% in 1983.

Table 2.6

Electricity Supply, 1970-1980

	1970	%	1975	%	1980	%	1981	%	1982	%	Estimate 1983	%
Installed Generating Capacity (MW)												
Hydropower	2,445	65	2,445	65	2,445	52	2,445	50	2,445	48	2,445	4[illegible]
Thermal	1,330	35	1,330	35	2,261	48	2,469	50	2,685	52	3,250	5[illegible]
Total	3,775	100	3,775	100	4,706	100	4,914	100	5,130	100	5,695	10[illegible]
Maximum Demand	1,100		1,733		3,239		3,553		3,900		4,200	
Reserve Margin (%)	243		118		45		39		32		36	
Generation (GWh)												
Hydro	4,690	68	6,790	69	9,801	53	10,215	49	10,484	45	..	
Thermal	2,225	32	3,009	31	8,628	47	10,532	51	12,869	55	..	
Total	6,915	100	9,799	100	18,429	100	20,747	100	23,353	100	..	

Source: EEA

2.15. Most of the additional thermal capacity installed after 1975 was gas turbines, because of: (a) their short lead time compared with steam plant; (b) the need to install additional capacity as quickly as possible to meet the rapid growth of demand; and (c) their low capital cost to a utility that was

1/ Public supply data throughout the section relate to the interconnected EEA system. Information on public supply at isolated centers was not fully available, but it is small in comparison.

chronically short of finance. As a result, there was a marked change in the mix of thermal plant, as shown in Table 2.7.

Table 2.7

Thermal Plant Mix, 1975-1983

	1975		1980		1983	
	MW	%	MW	%	MW	%
Steam Generating Plant	1,302	98	1,674	74	2,346	66
Combustion Turbines	28	2	587	26	1,207	34
Total	1,330	100	2,261	100	3,553	100

Source: EEA

2.16. The greatly increased contribution of thermal generation to total electricity supply has been accompanied by a corresponding increase in oil and gas consumption, which increased almost 4 times between 1975 and 1981/82 (1,034 to 4,005 thousand toe). There were two significant changes in the fuel mix, with increasing consumption of gas oil and natural gas, as a result of the growing availability of natural gas for electricity generation and the growth of combustion turbine capacity (Table 2.8). In 1981/82, consumption of residual fuel oil, natural gas and gas oil for electricity generation represented respectively about 33%, 28% and 16% of total Egyptian production of these fuels.

Table 2.8

Fuel Consumption for Electricity Generation
1971-1980

	1971		1975		1980		1981/82	
	'000 toe	%	'000 toe	%	'000 toe	%	'000 toe	%
Residual Fuel Oil	742	93	1,023	99	1,991	68	2,398	60
Naptha	55	7	11	1	61	2	67	2
Gas Oil	-	-	-	-	215	7	616	15
Natural Gas	-	-	-	-	675	23	913	23
Coke Oven Gas	-	-	-	-	-	-	11	-
Total	797	100	1,034	100	2,942	100	4,005	100

Source: EEA

2.17. Certain industries, notably the sugar, cement, fertilizer, paper and textile industries, generate electricity from captive generating plant for their own use. Complete data are not available but data for about 20 industrial plants show a declining trend of output, from this source, from 640 GWh in 1970, or 9% of EEA output, to 513 GWh in 1980, or 3% of EEA output .

2.18 In 1982 and 1983 there was a severe supply shortfall in the interconnected system which necessitated load shedding. This may seem surprising in view of the relatively high gross reserve margin (36% in 1983) of installed capacity over maximum demand. However, the installed capacity figure is somewhat misleading; this is because it includes the twelve 175 MW sets at the High Dam, whereas two of these are always our of service 1/, and it also includes the rated output of 345 MW at the Aswan Dam whereas this can generate only 200 MW because of the reduction in head caused by the tailrace of the High Dam. Moreover, a relatively high proportion of plant tends to be de-rated or out of service at any time, either for scheduled maintenance or because of breakdowns, and there are delays in restoring it to service because of shortages of essential spare parts. 2/ This tends to create a vicious circle, shortage of capacity in relation to demand leading to deferral of essential maintenance, which results in turn in plant failures.

2.19. The high level of system losses is also a factor in the inability of the interconnected system to meet all requirements. These are estimated at about 22% of gross generation. Losses in the distribution companies' networks represent nearly 15% of their bulk purchases from EEA. Only part of these represent technical losses, since part is due to theft of electricity, tentatively estimated by consultants at about 43% of total distribution losses.

2.20 A prominent feature of the electrification program in recent years has been the rapid extension of supplies to rural areas. By end 1981 nearly all of the approximately 6,000 villages with populations over 1,000 had been connected to the public electricity supply under the rural electrification program. About 80% of the rural population and almost all the urban population had access to electricity supply.

Power System Planning

2.21. Generation planning is carried out by EEA's planning department, although it has been assisted by consultants, usually financed by bilateral aid, in project feasibility studies. EEA uses the WASP computer program supplied by the International Atomic Energy Agency (IAEA) for generation

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1/ One unit is always down for maintenance and, since there are two units per penstock, this means in effect that two units are down at any time. EEA is carrying out a program to replace turbine runners.

2/ Some de-rating of combustion turbines is inevitable because of the difference in ambient temperature in Egypt from the ISO Standard on which rated capacity is based.

planning. EEA's planning department has difficulty in running this program since it has been run at a commercial computer bureau on a machine not ideal for the program at high cost and at considerable inconvenience to EEA's staff. Despite having well qualified and trained staff in the planning department, practical computing difficulties have meant that they have been able to examine only a few alternatives. Moreover, key assumptions, such as the scale and timing of the nuclear program and the role of the Qattara Depression project appear to have been taken as policy decisions without being subject to recent economic analysis. Some of the economic analysis that has been carried out by consultants has not analysed alternatives in relation to the long term development of the system. For example, several recent studies have "justified" projects by comparing them to the cost/kWh of an oil fired power station when EEA's policy is to start no more new oil fired steam stations. The lack of a least cost generation program is a major obstacle to the economic evaluation of individual projects. The consultant's study of the Qattara Depression project 1/ recognized this and made a strong recommendation for a least cost program to be prepared to serve as the basis for a thorough evaluation of the project.

Medium Term Generation Development 1983-1991

2.22. Generation projects for the medium term are generally under construction, committed, or in an advanced state of preparation. In 1982/83 there was a critical shortage of generating capacity with effective capacity about equal to demand and no spare to allow for breakdown or sufficient maintenance. In 1983/84 the position will be improved only slightly, despite the commissioning of 320 MW of steam plant, and 267 MW of combustion turbines. By 1984/85 capacity should be in an acceptable balance with demand, when the reserve margin should be 24%. In that year an extra 900 MW of natural gas/oil steam plant is scheduled to be commissioned, including the first units at Shoubrah El Kheima (300 MW) and Ataqa (Suez) (150 MW); third unit at Abu Sultan (Ismailya) (150 MW); and fourth and fifth units at Abu Qir (2 x 150 MW). In addition, 100 MW of new combustion turbine plant is planned to be completed at Damanhour and Wadi Houf. No further combustion turbine capacity is planned. Between 1984/85 and 1986/87 completion of projects under construction will add a further 1,420 MW of steam capacity and the completion of the Aswan II project will add a further 220 MW of hydro capacity. Over the period 1982/83 to 1986/87 about 200 MW of old steam plant is scheduled for retirement, but this is almost offset by the additional 185 MW gained from rehabilitating the hydroelectric machines at the Aswan I and Aswan High Dam stations (Table 2.09).

2.23. For the period after 1986 a number of options exist which are in varying stages of preparation:

(a) a total of two additional 300 MW natural gas/oil fired units at the Damanhour and Assiut steam stations. Bid documents for these units are ready for issuing to potential suppliers, but finance has not been secured;

1/ Joint Venture Qattara, "Study Qattara Depression. Draft Feasibility Report" (October 1980).

(b) a 4 x 300 MW coal fired steam station on the Gulf of Suez coast of the Sinai peninsula. This station would burn primarily imported coal, but would also use local Sinai coal and could also have dual firing for natural gas. A consultants project feasibility study has been prepared and the Government is attempting to arrange finance for the project;

(c) a 900 MW PWR nuclear station planned for El Daaba 165 km west of Alexandria on the Mediterranean coast. The Government received bids from potential suppliers in November 1983;

(d) a natural gas/oil fired power station at Kuraimat, south of Cairo having either 300 MW or 600 MW units and a capacity of 1200 MW. Imported coal has been suggested as a fuel for this station, but its location 300 km from Alexandria and 230 km from Suez would not appear ideal;

(e) a station on the Mediterranean coast at Sidi Kreir, west of Alexandria, that would burn imported coal and have an ultimate capacity of 3,000 MW with either 300 MW or 600 MW units; and

(f) conversion of single cycle combustion turbines to combined cycle operation. Existing combustion turbines at Talkha, Mahmoudia and possibly Damanhour have been identified for conversion, but no detailed studies have been carried out. About 200 MW of existing combustion turbine plant at each site would be converted to supply steam to a 100 MW steam unit.

2.24. EEA projects a maximum demand of about 9933 MW in 1991/92. The EEA generation program based on this forecast is shown in Table 2.09. Our demand Scenario A shows a 1991/92 maximum demand of 8061 MW. This difference of 1872 MW or nearly 19% would enable some projects to be delayed (Table 2.10). The Kuraimat natural gas/oil fired steam station could be the first project for delay for the following reasons: (a) imported coal and nuclear options are believed to be more economic than oil by EEA, and this is supported by experience elsewhere; (b) natural gas has an economic cost equivalent to the price of fuel, at least at present; and (c) the first units at a new station usually cost more than duplicate units at an existing station, so that extending the Damanhour, and Assiut stations would have higher priority among the oil/gas options.

2.25 A key issue is when a nuclear power station could begin operation. Assuming a quick evaluation of bids, timely decision by the Government and sufficient finance being available, construction is unlikely to begin until 1985. IAEA give the mean construction time (defined as the time before the first pour of concrete and the connection of the reactor to the grid) for nuclear power stations as 100 months, although some countries have an average completion time as low as 63 months and some as high as 130 months. On one hand the record of EEA in project implementation has greatly improved e.g. Shoubrah El Kheima, but on the other, MEE has no experience of building nuclear power stations. On balance, it would appear prudent to assume an average construction time of at least 100 months. Based on construction starting in December 1984, the expected commissioning date for the first nuclear power station would be March 1993. Nuclear can therefore be disregarded as an option for the medium term 1984-1992.

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Table 2.09

EEA Generation Development Program 1982/83 - 1991/92

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Maximum Demand (MW)	4,036	4,564	5,125	5,778	6,418	7,038	7,670	8,360	9,113	9,933
Energy Generated (GWh)	24,041	26,786	-	-	-	-	-	-	41,625	44,540
Available Gross Capacity (MW)										
Existing steam	1,510	1,490	1,490	1,372	1,316	1,236	1,191	1,191	1,163	1,115
Abu Sultan	-	300	450	450	600	600	600	600	600	600
Abu Qir	-	300	600	600	600	600	600	600	600	600
Kafr El Dawar	-	220	220	330	440	440	440	440	440	440
Ataqa	-	-	150	300	600	600	600	600	600	600
Shoubrah El Kheima	-	-	300	600	900	900	900	900	900	900
Damanhour	-	-	-	-	-	300 /2	300	300	300	300
Assiut	-	-	-	-	-	-	300 /2	300	300	300
Sinai	-	-	-	-	-	-	-	600 /2	900	1,200
Kuraimat	-	-	-	-	-	-	-	600 /2	1200	1200
Sidi Kreir	-	-	-	-	-	-	-	-	600 /2	600
Total Steam	1,510	2,310	3,210	3,652	4,456	4,676	4,931	6,131	7,303	7,955
Existing combustion turbine	810	810	810	810	810	610 /3	610	610	610	610
El Sayouf	-	67	67	67	67	67	67	67	67	67
Mahmudia	-	200	200	200	200	200	200	200	200	200
Damanhour	-	-	100	100	100	100	100	100	100	100
Kafr Rouf	-	-	100	100	100	100	100	100	100	100
Total Combustion Turbine	810	1,077	1,277	1,277	1,277	1,077	1,077	1,077	1,077	1,077
Combined cycle	-	-	-	-	-	300 /2	300	300	300	300
Nuclear	-	-	-	-	-	-	-	-	-	900
Existing hydro	1,724	1,764	1,809	1,859	1,909	1,950	1,950	1,950	1,950	1,950
Aswan II	-	-	-	110	220	220	220	220	220	220
Total Hydro	1,724	1,764	1,809	1,969	2,129	2,170	2,170	2,170	2,170	2,170
TOTAL CAPACITY	4,044	5,151	6,296	6,898	7,862	8,223	8,478	9,678	10,850	12,302
Reserve Margin (%)	0.2	12.1	22.6	19.4	22.5	16.8	10.5	15.8	19.1	23.8

Source: EEA, Mission estimates.

/1 Capacities shown at middle (December) of fiscal year.
/2 Projects for which bids have not been received.
/3 Decrease in combustion turbine capacity is due to conversion of units to combined cycle.

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EGYPT

INVESTMENT SECTOR

Table 2.10

Generation Development 1982/83 - 1991/92
(Demand Scenario A)

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Maximum Demand	4,036	4,564	5,091	5,525	6,061	6,447	6,859	7,296	7,565	8,061
Energy Generated (GWh)	24,041	26,786	28,986	30,978	33,449	35,695	38,093	40,651	41,625	44,540
Available Gross Capacity (MW)										
Existing steam	1,510	1,500	1,500	1,250	1,310	1,190	1,145	1,145	1,115	1,115
Abu Sultan	-	300	450	450	600	600	600	600	600	600
Abu Qir	-	300	600	600	600	600	600	600	600	600
Kafr El Dawar	-	220	220	330	440	440	440	440	440	440
Ataqa	-	-	150	300	600	600	600	600	600	600
Shoubrah El Kheima	-	-	300	600	900	900	900	900	900	900
Damanhour	-	-	-	-	-	300 /2	300	300	300	300
Assiut	-	-	-	-	-	-	300 /2	300	300	300
Sinai	-	-	-	-	-	-	-	300 /2	900	1,200
Kuraimat	-	-	-	-	-	-	-	-	-	-
Sidi Kreir	-	-	-	-	-	-	-	-	-	300 /2
Total Steam	1,510	2,320	3,220	3,630	4,450	4,630	4,885	5,185	5,755	6,355
Existing combustion turbine	810	810	810	810	810	810	610 /2	610	610	610
El Sayouf	-	67	67	67	67	67	67	67	67	67
Mahmoudia	-	200	200	200	200	200	200	- /3	-	-
Damanhour	-	-	100	100	100	100	100	100	100	100
Wadi Hoof	-	-	100	100	100	100	100	100	100	100
Total Combustion Turbine	810	1,077	1,277	1,277	1,277	1,277	1,077	877	877	877
Combined cycle	-	-	-	-	-	-	300 /2	600 /2	600	600
Nuclear	-	-	-	-	-	-	-	-	-	-
Existing hydro	1,724	1,764	1,809	1,859	1,909	1,950	1,950	1,950	1,950	1,950
Aswan II	-	-	-	110	220	220	220	220	220	220
Total Hydro	1,724	1,764	1,809	1,969	2,129	2,170	2,170	2,170	2,170	2,170
TOTAL CAPACITY	4,044	5,161	6,306	6,879	7,856	8,077	8,432	8,832	9,502	10,002
Reserve Margin (%)	0.2	13.1	23.9	24.5	29.6	25.3	22.9	21.1	24.3	24.1

Source: Mission estimate, EEA.

/1 Capacities shown at middle (December) of fiscal year.
/2 Projects for which bids have not been received.
/3 Decrease in combustion turbine capacity is due to conversion of units to combined cycle.

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2.26 By the end of 1984 combustion turbines will account for an excessive 20% of installed capacity. Given the availability of natural gas at a price equivalent to fuel oil, there is probably a good case for converting some of the modern combustion turbines to combined cycle wherever this is technically feasible. In projecting capacity for the medium term, we have assumed that the Talkha and Mahmoudia conversion projects would be completed in 1988 and 1989. It should not be necessary for EEA to commission any more combustion turbines during the period up to 1991 unless demand increases faster than expected or new plant is delayed. However, in these circumstances, we would argue strongly that it would be more economic for other measures to be adopted, such as the temporary or permanent suspension of aluminium production. By 1991, simple cycle gas turbines would amount to only 8.7% of EEA's capacity.

Projected Fuel Consumption

2.27. A marked shift is likely in the pattern of fuel consumption for electricity generation during the 1980's. New power stations will be predominately gas fired and most existing stations will be converted from fuel oil, or gas oil in the case of combustion turbines, to run on natural gas. Consequently, natural gas would increase its share of total fuel use from 26% in 1982/83 to about 89% in 1986/87. At the end of the decade the Sinai coal fired power station will result in coal accounting for about 23% of fuel consumption in 1991/92 and the share of natural gas declining to 77%. Providing supplies become available on time, gas consumption is likely to increase by about 3.5 times between 1982/83 to 1986/87, but the advent of coal and the improved thermal efficiency of new power stations would result in gas consumption increasing by about 35% between 1986/87 and 1991/92. Fuel oil consumption is likely to decline in absolute terms as existing stations are converted to natural gas, oil fired stations are retired and more efficient base load plant displaces old oil fired stations down the merit order. Consumption of oil products could fall from 3465 thousand toe in 1982/83 to only 400 thousand toe in 1991/92 (Table 2.11).These projections of fuel consumption are subject to a wide margin of error due to the lack of a firm investment program and the lack of reliable projections of generating unit dispatch based on the most likely load forecast. More reliable estimates should be prepared as part of EEA's investment and operational planning.

Sensitivity to Demand Forecast

2.28 Scenario F (Table 2.12) was used to indicate how the generation investment program might change under alternative demand management policies. This scenario assumes that the Government would begin a program to eliminate distortions to energy prices, commence a load management program and restructure or close the Kima plant.

Under this scenario the following savings could be achieved (Table 2.12):

Table 2.11

Projected Fuel Consumed in Power Generation

	Actual 1982/83	Projected 1986/87	Projected 1991/92
Original Units			
Fuel Oil (t'000)	2,948	560	420
Gas Oil (t'000)	620	1	1
Naptha (t'000)	69	-	-
Natural Gas (M^3 million)	1,365	4,730	6,360
Coal (t'000)	-	-	2,680
Energy Equivalent (toe '000)			
Fuel Oil	2,775	530	400
Gas Oil	620	1	1
Naptha	70	-	1
Natural Gas	1,213	4,200	5,650
Coal	-	-	1,710
Total	4,678	4,730	7,360

Source: EEA, Mission estimates

Notes: Conversion factors 1 toe = 10.2 million kcal, fuel oil 9,600 kcal/kg, Gas oil 10,200 kcal/kg, Naptha 10,300 kcal/kg, natural gas 9,067.kcal/kg
Coal 6,500 kcal/kg

(a) one 300 MW additional steam unit at Damanhour (1987) would not be required during the period;

(b) 300 MW additional steam capacity at Assiut (1988) would not be required;

(c) combined cycle plant conversion could be delayed by one year;

(d) Sinai coal could be delayed from 1989 to 1990, with a slower rate of completing the station;

(e) Sidi Kreir coal could be delayed beyond 1991; and

(f) despite delaying these plants, the reliability of supply would be slightly higher.

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INVESTMENT REVIEW

Table 2.12

Generation Development 1982/83 - 1991/92
Low Load Forecast
(Demand Scenario F)

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Maximum Demand	4,036	4,564	4,949	5,366	5,818	5,854	6,098	6,345	6,605	6,873
Energy Generated (GWh)	24,041	26,518	28,406	30,048	32,111	33,910	35,807	35,529	37,742	39,932
Available Gross Capacity (MW)										
Existing steam	1,510	1,500	1,500	1,250	1,210	1,190	1,145	1,145	1,115	1,115
Abu Sultan	-	300	450	450	600	600	600	600	600	600
Abu Qir	-	300	600	600	600	600	600	600	600	600
Kafr El Dawar	-	220	220	330	440	440	440	440	440	440
Ataqa	-	-	150	300	600	600	600	600	600	600
Shoubrah El Kheima	-	-	300	600	900	900	900	900	900	900
Damanhour	-	-	-	-	-	-	-	-	-	-
Assiut	-	-	-	-	-	-	-	-	-	-
Sinai	-	-	-	-	-	-	-	-	300 /2	600
Kuraimat	-	-	-	-	-	-	-	-	-	-
Sidi Kreir	-	-	-	-	-	-	-	-	-	
Total Steam	1,510	2,320	3,220	3,630	4,450	4,330	4,285	4,285	4,555	4,855
Existing combustion turbine	810	810	810	810	810	810	810	610 /3	610	610
El Sayouf	-	67	67	67	67	67	67	67	67	67
Hamroudia	-	200	200	200	200	200	200	200	- /2	-
Damanhour	-	-	100	100	100	100	100	100	100	100
Wadi Houf	-	-	100	100	100	100	100	100	100	100
Total Combustion Turbine	810	1,077	1,277	1,277	1,277	1,277	1,277	1,077	877	877
Combined cycle	-	-	-	-	-	-	-	300 /2	600	600
Nuclear	-	-	-	-	-	-	-	-	-	-
Existing hydro	1,724	1,764	1,809	1,859	1,909	1,950	1,950	1,950	1,950	1,950
Aswan II	-	-	-	110	220	220	220	220	220	220
Total Hydro	1,724	1,764	1,809	1,969	2,129	2,170	2,170	2,170	2,170	2,170
TOTAL CAPACITY	4,044	5,161	6,306	6,879	7,856	7,777	7,732	7,732	8,202	8,502
Reserve Margin (%)	0.2	13.1	27.4	28.2	35.0	32.8	26.8	23.4	24.2	23.7

Source: Mission estimates, EEA.

/1 Capacities shown at middle (December) of fiscal year.
/2 Projects for which bids have not been received.
/3 Decrease in combustion turbine capacity is due to conversion of units to combined cycle.

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2.29 Potential savings would be even greater if further industrial restructuring were implemented e.g. closing the aluminium smelter, or if demand were more sensitive to tariff changes than the -0.1 elasticity assumed.

C. Long Term Generation Investment Issues

Overview

2.30. EEA's long term investment program envisages eight nuclear power stations (4x900 MW and 4x1,200 MW) being commissioned in the 1990's, along with 4,200 MW of coal and gas fired capacity. In addition the Qattara Depression hydrosolar project is expected to be commissioned in stages between 1995 and 1999. (Table 2.13). However, this program is based on a demand forecast that has a 2001/02 maximum demand of 19,710 MW, compared to 13,520 MW in our Reference Case and 10,990 MW in Scenario F (Table 2.5). Although the period 1992-2002 seems a long way in the future, the long lead times of large power stations mean that preparatory work and decisions on some projects will need to be taken during the current plan period and substantial expenditure will be incurred during the next plan (1987/88-1992/93). Five main issues need to be considered in preparing a revised long term program that is based on a more realistic demand forecast: (a) the role of nuclear power; (b) the use of natural gas for power generation; (c) future hydro development; (d) planning under uncertainty; and (e) the Qattara Depression hydro solar project

Table 2.13

EEA Long Term Generation Program
(MW)

	New Capacity Additions					
Year	Kuraimat Oil/Gas	Sinai Coal	Sidi Kreir Coal	Nuclear	Qattara HYdro	Retirements
1990	600	-	600	-	-	- 28
1991	-	600	-	900	-	- 48
1992	-	-	600	900	-	-
1993	-	-	-	900	-	-
1994	-	-	-	900	-	-
1995	-	-	600	-	300	-120
1996	-	-	-	1200	300	-225
1997	-	-	600	-	300	-171
1998	-	-	600	1200	300	-168
1999	-	-	-	1200	300	- 75
2000	-	-	-	1200	-	-463
Total	600	600	3000	8400	1500	1298

Source: EEA

Role of Nuclear Power

2.31. Even if EEA's demand forecast is correct, the eight nuclear power station program is unlikely to be implemented within the planned 10 years. The financial requirements are likely to be enormous, amounting to at least $10 billion at 1983 prices, before allowing for physical and price contingencies, engineering and interest during construction. These could increase the amount to be financed to $25 billion. MEE is having considerable difficulty financing the first nuclear power station, as well as conventional stations. If the nuclear program were to procede as planned MEE would need to repeat these financing operations each year. Prospective lenders would be hesitant to commit such large amounts when EEA's self financing ratio is so low (para. 6.05). If finance could be arranged there would remain the problem of manning the stations with adequately trained and experienced staff. Egypt has a pool of nuclear scientists and conventional plant engineers who could be drawn upon to man the first two or so stations if sufficient incentives were offered. The 8 years required to build a nuclear power station, in principle, gives sufficient time for the supplier to train operators. However, considering the difficulties EEA has in training and retaining staff for conventional power stations and the limited pool of nuclear engineers and technicians, it seems unlikely that staff of adequate calibre could be found to man an 8 nuclear power station program in the 1990's.

2.32. A more fundamental issue concerns the economic viability of nuclear power compared to other options. Studies carried out elsewhere have shown that nuclear power is generally preferable to oil fired power stations. So long as natural gas in Egypt has an economic cost equal or close to parity with fuel oil, nuclear would be preferred to gas fired power stations also. However, the relative economics of nuclear versus imported coal are much less clear cut and there is probably a case for both in a balanced power system. Nuclear has disadvantages of large lumpy units that require greater reserve to guard against plant outages. Nuclear is also less flexible in implementation, since each reactor is one unit of say 900 MW, unlike conventional plant where there may be 3x300 MW units, some of which could be delayed if demand were overestimated. Once the bids for the first nuclear station are received, it is recommended that the economics of the project be re-appraised before a final decision to procede is taken.

Use of Natural Gas

2.33. As mentioned above, natural gas is unlikely to be competitive with coal or nuclear for new investment if its economic cost is equal to or greater than the thermal equivalent price of fuel oil. Possible exceptions to this are the use of natural gas in combined cycle and industrial CHP plant, both of which have high thermal efficiencies to offset the hight cost of fuel.

2.34. If present estimates of gas reserves of 6 to 9 trillion ft^3 were increased substantially (reserves as high as 30 trillion ft^3 have been quoted, although insufficient exploration has been done to prove this) the economic cost of natural gas might fall to the LRMC of production and transmission plus a depletion allowance, possibly about 40% of the price of equivalent fuel oil. This would make natural gas cheaper than coal and possibly also nuclear power. Gas would then be the favored fuel for new power stations. However, the economic cost of gas would rise steeply in real terms

towards fuel oil parity as the gas became depleted, so that new plant might consist of a mixture of combined cycle and dual gas/coal fired plant.

2.35. EEA is apparently planning for new thermal power stations to be able to burn both coal and fuel oil. However, it would be technically feasible to make these stations capable of burning gas also and in view of the uncertainty about gas reserves and the economic costs of gas this would seem a prudent strategy. In order to have natural gas/coal burning capability without loss of station capability it would be necessary to design the boiler to burn the two fuels. It would be unwise for EEA to build natural gas/oil power stations, which are 10-15% cheaper than coal plants, without concrete assurances that gas supplies would be available and a reasonable prospect that gas prices would remain substantially below the price of fuel oil and be competitive with coal. It probably would not be in the national interest for EEA to build a gas fired power station which had to run on oil because of insufficient gas supplies. Because of the potentially large savings from delaying the nuclear program if large reserves of cheap gas are proven, it is suggested that EGPC intensify its exploration to prove suspected gas reserves.

Future Hydro Development

2.36. With the exception of the Qattara project (para. 2.37) almost all of Egypt's hydro potential has been developed. However, a number of small schemes exist at existing Nile barrages: Esna (100 MW); Nag Hammadi (53 MW); and Assiut (48 MW). As with the Aswan II project, adding small hydroelectric power stations to existing barrage produces cheap electricity. The capital cost/kW of such schemes is roughly comparable to a thermal power station, but there are no fuel costs. Although the output of these hydro projects is small, they offer high economic returns and should be implemented where this is technically feasible. Some pumped storage options exist near the Red Sea, e.g. Ain Sukhna, but would only be economic if cheap pumping energy were available. This would appear to require a large nuclear program, which we consider unlikely to be implemented.

Uncertainty

2.37. Long term generation development in Egypt is subject to more than the usual amount of uncertainty. The main areas of uncertainty are: (a) future electricity demand; (b) fuel supplies and costs; and (c) power station lead times. Demand is not only uncertain because of the usual uncertainty about economic growth, but also because it is not clear what demand management policies will be adopted by the Government and what the response of consumers to these policy changes would be, e.g. the influence of tariff changes on demand. The Government could partly reduce this source of uncertainty by taking early decisions, on demand management. Uncertainty about fuel supplies and prices primarily applies to natural gas (para. 2.32). Delays in implementing projects make it difficult to ensure that sufficient plant is available to meet demand. EEA's record in constructing plant is much improved, but delays in arranging finance are common so that construction often begins late.

2.38. MEE's long term planning will need to investigate ways of dealing with uncertainty such as not relying too much on long lead time plant, e.g. nuclear; ensuring that fuels can be switched easily if necessary; and avoiding

changing to larger unit sizes too quickly. In project implementation MEE should ensure contractual arrangements are sufficiently flexible to postpone, cancel or advance units where it appears that this could be necessary and that all steps are taken to speed up the implementation of projects, particularly in arranging finance.

Qattara Hydro-Solar Project

2.39. This project consists of a canal or tunnel from the Mediterranean Sea to a hydroelectric power station by the Qattara Depression. Output from the station would decline as the Depression becomes filled until equilibrium is reached between inflow and evaporation. Some variants of the project have a pumped storage alternative. The project has been the subject of an exhaustive pre-feasibility study which concluded that a canal excavated by nuclear charges was the least cost solution. This option would have 600 MW run of river hydro and ultimately 4,800 MW of pumped storage capacity. The consultants estimated that the project would cost US$4.7 billion at February 1979 prices, take 13 years for design and the construction of the first stages and an additional 13 years to complete the project. The internal economic rate of return was calculated by the consultants to be only 10% when benefits were valued at the savings from the best alternative conventional power program. 1/ The best alternative using conventional excavation techniques (320 MW hydro, 4,800 MW pumped storage) was estimated by the consultants to cost US$8.4 billion on the same cost basis and would take 10 years to construct. The consultants did not calculate an internal economic rate of return, since the alternative was clearly not preferred to the nuclear excavation and pumped storage options. QPA has commissioned another study which is investigating the conventional excavation of a shorter route. This study is expected to be completed in 1984.

2.40. It is clear that the Qattara Depression project has not so far been proven an economic and technically viable option for producing electricity, although the current study may disprove this. The project is inherently risky given its apparently low rate of return, long lead time and the technical uncertainties inherent in a novel project with a high civil works content. The potential power output is small in relation to the cost of the project. The first phase of preferred scheme had 1,800 MW installed capacity producing 3,964 GWh net initially. When the third phase is completed, 13 years after the completion of the first phase, the station would change to pumped storage operation and would would be a net consumer of 1,400 GWh/a. Because of the change in role from hydro to pumped storage operation, the Qattara project would require the development of conventional generation with low energy costs to provide the pumping energy, i.e. a large nuclear program that would result in nuclear capacity exceeding the system demand (excluding pumping) at night. Unless the new study can show high rates of return to justify the risks involved and demonstrate that the project belongs in the least cost investment program, it is recommended that the Government wind down the Qattara studies and devote the resources to demand management and conventional electricity supply.

1/ This is equivalent to stating that the project had a place in the "least cost" development program, but that it could be substituted by the next best project without having much effect on the net present value of the investment program, calculated at 10% discount rate.

D. Generation Investment Priorities

2.41. EEA lacks a least cost generation development program that is based on economic analysis of alternatives (para. 2.21). Such a programme is a pre-requisite for establishing priority among the generation alternatives described above. The Government faces a number of major investment decisions in electricity supply. These immediate investment decisions are shown in Table 2.10 and listed below:

(a) extensions to Damanhour and Assiut gas/oil steam stations would probably be required if demand management policies (substantial increases to real tariffs, restructuring/closing Kima Fertilizer plant and implementing load management) are not implemented. We would recommend the demand management option. If the Government does not start a program of demand management in 1984, an early decision to proceed with these stations would be required;

(b) The Sinai coal fired station is the best prepared coal option. A coal fired power station with the capability to burn gas also would appear to be part of a least cost program for the medium term, given that a nuclear station could probably not be completed before 1993 and the uncertainty about natural gas supplies and costs. However, EEA should investigate the technical and economic aspects of dual gas/coal firing during the design studies for the project since conversion to dual coal/gas firing after the station is built will result in loss of station output during conversion and the converted station would have reduced capability. Completion of design studies and preparation and issuing of bid documents for the Sinai coal station should therefore proceed with urgency since a program for commissioning in 1989 will be tight; and

(c) conversion of combustion turbines at Talkha and Damanhour is one of the few short lead time options remaining and technical and economic feasibility studies should be completed without delay.

2.42. A number of other investment decisions will need to be taken shortly for the period 1991/92 and beyond. There are major uncertainties about demand and natural gas supplies and economic costs for this period (para. 2.35) and the risks of alternative strategies need to be evaluated. It is strongly recommended that EEA carry out economic studies to evaluate a least cost program. Because of the long lead times involved, priority should be given to evaluating the following projects during the least cost program studies:

(a) the first nuclear station, using cost data contained in the bids recently received;

(b) The Sidi Kreir coal fired power station, particularly the timing of its development;

(c) the role of natural gas in future power generation given alternative gas reserve/economic cost scenarios and focussing on the Kuraimat project compared to combined cycle alternatives; and

(d) development of remaining Nile hydro options.

III. DEMAND MANAGEMENT

A. Tariff Policy

Historical Overview

3.01 Tariffs remained unchanged from 1975 until 1982 when changes were introduced for residential, small commercial, and government buildings.

Table 3.1

Trend of Average Electricity Prices

Year	Average Electricity Price (mills/kWh) /2	Average Electricity Price (1970=100)	General Price Indices (1970=100) Consumer	General Price Indices (1970=100) Wholesale	Real Price of Electricity (1970 mills/kWh)
1970	5.96	100	100	100	5.96
1972	6.70	112	105	101	6.63
1975	8.94	150	134	133	6.72
1978	8.40	141	184	180	4.67
1980	10.80	181	244	241	4.48
1980/81	10.52	177	258	252	4.17
1981/82	11.14	187	288	270	4.12
1982/83	12.30	206	332	300	4.10

Sources: EEA, IMF (IFS), mission estimates.

/1 Deflated by Wholesale Price Index.
/2 Exchange rates and currency equivalents.
LE 1.00 = 1,000 milliemes (mills)
LE 1.00 = US $1.00
US mils 1.0 = mills 1.0

In April 1982 tariffs for residences, and commercial and for agricultural pumping were increased by between 5% to 20% depending on the level of consumption. Tariffs for the lowest priced blocks of consumption remained unchanged. These increases were followed in November 1982 by an increase of about 60% for the Kima fertilizer plant and about 50% for the Nag Hamadi aluminum smelter. In April 1983 residential and commercial tariffs were again increased by between 5% to 20% for the higher consumption blocks, and agricultural tariffs by 5%. Later, the tariffs of the few VHV and EHV consumers and public sector establishments which had not increased since 1975, were raised by 15% in July 1983. The average price of electricity is distorted by the different growth rates for the large VHV consumers with low tariffs and the MV and LV tariffs with higher tariffs. Bearing in mind this limitation of average prices as an indicator of tariff levels, the consequence

of these changes was for the real level of electricity tariffs to fall between 1975 and 1980/81 and remain roughly constant in real terms thereafter (Table 3.1). On January 1, 1984, all tariffs were raised, with the exception of the lowest priced blocks for residential and commercial consumers. Increases were in the order of 20% apart from intermediate blocks of the residential and commercial tariffs. The overall increase in the average price of electricity is expected to be about 14.6%. This represents the largest increase in electricity prices for about 10 years.

Tariff Levels

3.02 Tariff levels for each category of consumer can be compared to the economic cost of supply in order to appraise their effectiveness as a means of resource allocation and to consider the extent to which cross-subsidization exists among consumer groups. The economic cost of supply is usually taken to be the long-run marginal cost (LRMC) of supply. This has two elements -- the cost of expanding system capacity to meet a sustained increment in demand and the energy (mainly fuel) cost of providing an extra kWh at different times of the day and year. EEA has recently completed a major tariff study, executed in conjunction with consultants supported under Bank Loans 1453-EGT and 1733-EGT. This study investigated the LRMC and proposed a new set of tariffs for EEA and the Distribution Companies. LRMCs were calculated for fuel priced at the heavily subsidized local prices, as well as at international prices which represent the economic cost of fuel to the national economy. The results of the consultants study have been updated to 1983 prices and to an exchange rate of LE 1.00 = US$1.00, which gives a better indication of the opportunity cost of foreign exchange than the Central Bank Pool rate of LE 1.00 = US$1.43, which applies to goods and services imported by the electricity supply industry. Table 3.2 shows that there is a significant time of day and seasonal variation in both capacity and energy costs. The variation in capacity costs is accounted for by the differing probabilities of supply shortage, which in turn are closely linked to the daily and seasonal fluctuation in demand. Energy costs vary by time of day and season because of the different plants (steam or combustion turbine) operating at the margin, caused by seasonal variations in demand and maintenance), and the different prices for gas oil used in some combustion turbines and fuel oil/natural gas used in steam plants. These estimates of LRMC should be interpreted carefully since they would change over time as the structure of system capacity changes and as relative fuel prices change.

3.03. The analysis of marginal costs at international prices was based on the assumptions that the economic price of natural gas is equivalent to thermal parity with fuel oil. The validity of this assumption is sensitive to the magnitude of gas reserves. The economic price of gas could fall if greater reserves are discovered (see Oil and Gas Sector Investment Review). It is important to note that under the extreme assumption of the economic price of gas falling from fuel oil parity of about $3.75/mcf, to LRMC plus depletion allowance of about $1.50/mcf, the summer off-peak energy cost at international prices would fall from about 59 mills/kWh at VHV to about 23 mills/kWh.

Table 3.2

Long-Run Marginal Costs of Electricity Supply
(1983 prices)

Voltage Level /1	Period /2: Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Capacity Element (LE/kW/a) /3				
VHV	65.9	25.8	13.2	2.1
HV	81.9	34.3	21.0	6.1
DC	105.6	42.5	31.0	9.6
MV	129.3	73.6	43.3	23.9
LV	194.8	146.2	72.4	56.2
Energy Element Calculated at International Prices (mills/kWh) /4				
VHV	95.1	87.0	89.1	58.5
HV	98.0	88.4	91.7	59.5
DC	98.5	88.7	92.2	59.6
MV	107.4	93.7	100.6	63.1
LV	117.9	102.0	111.4	68.5
Energy Element Calculated at Domestic Prices (mills/kWh) /5				
VHV	13.0	8.3	10.8	2.7
HV	[illegible]	8.4	11.2	2.8
DC	13.5	8.5	11.2	2.8
MV	14.7	8.9	12.2	2.9
LV	16.3	9.7	13.5	3.2

Soures: SOFRELEC Tariff Study (Dec. 1982) mission estimates.

/1 Voltage levels: VHV - very high voltage, HV - high voltage, DC - distribution companies, MV - medium voltage, and LV - low voltage.

/2 Period definitions: Winter (September - April), peak 1730-2300 h
Summer (May - August), peak 1830 - 2330 h
Off-peak is other times.

/3 SOFRELEC capacity costs adjusted for inflation to 1983 and for an excahnge rate of LE 1.00 = $1.00

/4 International Prices are: fuel oil: LE 160/ton, gas oil: LE 255/ton.

/5 Domestic fuel prices are: fuel oil LE 7.8/ton, gas oil LE 35/ton.

The marginal cost with the low economic cost of natural gas is still more than double the cost at domestic energy prices. Similarly, assuming that natural gas would displace all gas oil in combustion turbines would result in the VHV winter peak energy cost falling from about 95 mills/kWh to about 24 mills/kWh, which is still about twice the marginal energy cost calculated using domestic fuel prices. One can conclude that the availability of large supplies of natural gas for power generation would lower the economic cost of electricity substantially, particularly at VHV where the economic cost of supply at international prices is more than 90% fuel. However, even under these favorable assumptions, the LRMC would be greater than the LRMC calculated using domestic prices. To conclude, the discovery of large reserves of natural gas would reduce the magnitude of increases in real electricity tariffs to bring tariffs in line with LRMC, but would not eliminate the need for substantial increases.

Comparison of Tariff Levels to LRMC

3.04. On average, tariff levels are about 12% of the LRMC calculated at international fuel prices and about 47% of the LRMC at domestic fuel prices (Table 3.3). However, the precise relation of tariffs to LRMC depends on the investment and operating assumptions assumed by the consultants in calculating LRMC and would change as the system evolves towards optimal balances of plant type and capacity and demand. Even though there is uncertainty about the precise level of LRMC, it is clear that it is several times above the level of existing tariffs. At domestic fuel prices LV consumers receive the greatest subsidy, since fuel accounts for a smaller proportion of their cost of supply. This pattern of cross-subsidization is reversed at international fuel prices. Large industries and government establishments supplied at VHV and HV pay only 5-8% of the economic cost of supply. Fuel accounts for most of their supply costs when priced at international prices. By contrast, LV residential and small shops pay 13% and 15% respectively of LRMC when fuel is valued at international prices. The economic cost of electricity to Egypt is the case with fuel valued at international prices, since these represent the opportunity cost of fuel. In economic terms, the pattern of cross-subsidization is from MV and LV consumers, households and small enterprises, to large industries such as Kima and Aluminum. There is little logic in this pattern of cross-subsidization since it does little or nothing to achieve any income distribution objectives and a major part of the subsidy goes to aluminum, most of which is exported.

3.05. The greater part of the difference between tariff levels and the economic cost of supply is accounted for by the domestic price of fuel being less than its economic cost. Fuel oil, which is the main fuel used in electricity generation, has been priced at LE 7.5/ton (US$7.5/ton) since the 1960s whereas the 1983 international price is about $155/ton ex-refinery. Of the difference between the average tariff of 13.5 mills/kWH and the economic cost of 109.4 mills/kWh, about 84% is accounted for by distortions to the fuel price and 16% by the tariffs not reflecting the long-run marginal costs at domestic prices. Nevertheless, on average tariffs would need to double to equal the LRMC at domestic fuel prices.

Table 3.3

Comparison of Tariff Levels to Long-Run Marginal Cost
(mills/kWh, 1983 prices)

Consumer Group	Weight	Long-Run Marginal Cost Calculated Using: Domestic Fuel Price	International Fuel Price	Average Price Sold	Price as Percent of: Domestic Fuel LRMC	International Fuel LRMC
VHV						
Kima	0.0708	10.6	83.3	5.354	51	6
Aluminum						
lines 1-4	0.1062	10.7	83.8	4.425	41	5
line 5	0.0266	10.7	83.8	7.000	65	8
Others	0.0133	11.9	85.0	5.833	49	7
HV						
Industry	0.0463	14.9	89.9	7.434	50	8
Agriculture /1	0.0337	6.5	78.6	7.126	110	9
Government	0.0015	17.1	92.1	6.464	38	7
MV						
Industry	0.2215	22.8	102.9	13.974	61	14
Agriculture /1	0.0164	6.9	83.3	15.670	227	19
Public Utilities	0.1233	23.4	103.7	17.634	75	17
Housing Co.s	0.0177	30.8	112.5	10.890	35	8
Commercial	0.0163	52.9	138.3	26.228	50	19
LV						
Residential	0.2337	49.7	139.0	18.060	36	13
Commercial	0.0318	81.9	175.4	26.228	32	15
Industrial	0.0409	35.6	123.0	13.974	39	11
Consumption Weighed Average	1.0000	28.4	109.4	13.5	47	12

Sources: Consultant's study, EEA, mission estimates.

/1 The consultants estimate of LRMC assumed all consumption was off-peak.

3.06. The Government has introduced special tariffs for joint venture companies in the Suez Canal Free Trade Zone to avoid subsidizing the price of electricity to foreign companies. These tariffs have a maximum demand charge and a formula to adjust the kWh rates which depend on the difference between the international price and the domestic price of fuel. For industrial consumers, these tariffs result in average prices about 4 to 9 times the level of the normal tariffs, depending on the voltage of supply. The tariffs for joint venture companies are about 60% of the LRMC calculated using international fuel prices compared to 7-14% for the normal tariffs. The tariffs for joint venture companies represent a substantial step in principle towards the economic pricing of electricity.

Tariff Structure

3.07. There is a need to change the electricity tariff structure to give consumers an incentive to use electricity efficiently and to make tariffs easier for the consumer to understand. With the exception of the new tariffs for the Suez Free Trade Zone, all tariffs for VHV and HV consumes consists of a flat kWh charge. As Table 3.2 shows, there are substantial variations in the costs of supply by time of day and season. For large consumers, it is economic to provide metering, so that tariffs can reflect these costs differentials, in order to give consumers an incentive to shift their consumption to periods where the costs of supply are lowest. EEA has prepared proposals based on the consultants' study to implement such tariffs, but awaits the approval of the Government to introduce them. This reform to the tariff structure is an integral part of a program of load management (para 3.20).

3.08. Tariffs for residential, commercial, and public sector consumers are of the increasing block type (Tables 3.4). For residential consumers this tariff structure meets the governments equity objectives since households obtain a tranche of electricity at a low price for their essential needs such as lighting. An additional advantage is that it is also possible to raise the price of marginal consumption so as to convey a limited message of LRMC of supply. As Table 3.4 shows recent tariff increases have been larger for the highest priced blocks, with the lowest priced block remaining unchanged.The difference beween the tariff rates for each block of the tariffs is small. The Government could consider implementing its policy of increasing the price of electricty for large areas at a greater pace by larger increases e.g. doubling, the prices for marginal consumption, which would probably have little effect on the cost of electricity to low and middle-income households and would be easier to justify politically than similar increases to all tariff rates.

Table 3.4

Residential, Commercial, and Government Tariffs
(mills/kWh)

Residential	March 1980	April 1982	April 1983	January 1984	Index Jan. 1984 (March 1980=100)
0-100 kWh/month	16.20	16.20	16.20	16.20	100
101-250 kWh/month	17.00	18.70	20.57	22.63	133
above 250 kWh/month	18.00	21.60	25.92	31.10	173
Commercial					
0-75 kWh/month	17.00	17.00	17.00	17.00	100
75-100 kWh/month	19.40	20.37	21.39	23.15	119
101-250 kWh/month	20.00	22.00	24.20	26.62	133
above 250 kWh/month	25.00	30.00	36.00	43.20	173
Government Buildings					
0-80 kWh/month	15.00	15.00	17.25	20.70	138
81-150 kWh/month	20.00	20.00	23.00	27.60	138
above 150 kWh/month	25.00	25.00	28.75	34.50	138

Source: EEA

Table 3.5

Tariffs for Motive Power
(Effective April 1983)

Contracted Demand Greater Than 500 kW

Supplied at medium voltage
Fixed Annual charge: LE 6.800 per kW of contracted demand

Energy rates:

First 1,000 kWh per kW of contracted power	12.225 mills/kWh
Next 500 kWh per kW of contracted power	11.499 mills/kWh
Next 1,000 kWh per kW of contracted power	10.047 mills/kWh
Next 1,000 kWh per kW of contracted power	8.595 mills/kWh
Next 1,500 kWh per kW of contracted power	6.538 mills/kWh
Remaining consumption of contracted power	5.570 mills/kWh

Contracted Demand Less Than 500 kW

Supplied at MV or LV

First 70,000 kWh per annum	24.620 mills/kWh
next 100,000 kWh per annum	20.143 mills/kWh
Remaining consumption kWh per annum	19.847 mills/kWh

Source: EEA

3.09. MV tariffs for motive power have a complicated structure that probably confuses all but the most sophisticated consumer (Table 3.5). In addition, the tariffs do not give these consumers a clear incentive to reduce their consumption at times when supply is expensive. MEE is aware of these limitations and is seeking Government approval to introduce a simpler tariff that provides a better representation of LRMC.

Reform of Electricity Pricing

3.10. Electricity tariffs in Egypt are among the lowest in the world. Tariff levels lie between only 5% to 19% of the economic cost of supply (Table 3.3). Furthermore, the structure of tariffs for large consumers does not give any incentive for them to modify their consumption so as to achieve savings in the cost of supply. These very severe distortions to electricity prices have several undesirable consequences:

(a) the growth in peak demand is stimulated resulting in the need for massive investment in electricity supply;

(b) self-financing is now zero, yet the electricity supply industry requires large amount to finance the investment needed to meet the rapid growth in demand;

(c) rapidly growing electricity production in turn requires expansion of the fuel supply industries, e.g., natural gas pipelines, oil refineries, port facilities. It also consumes depletable resources of oil and gas which reduces the exportable surplus of oil and brings forward the date of importation of replacement fuels at international prices; and

(d) the electricity supply industry requires subsidies from the Government to continue in operation and to service debt. This weakens the autonomy of the enterprises and the excessive reliance on the Government does not enable the industry's qualified and competent executives to take the actions they appreciate are needed to provide efficient and reliable electricity supply.

3.11 The present level and structure of tariffs are largely the result of historical circumstances that have now changed. For example, Egypt once had surplus cheap hydroelectric power from the Aswan dam. Now electricity is produced at the margin from combustion turbines using gas oil. Present tariffs do not meet the objectives of economic efficiency, financial viability or equity. Consumers are subsidized with little regard to the impact of subsidies on the distribution of income. Moreover, the Government has deferred taking major steps to reform energy policy because of the risk of adverse political reaction from the population. Yet large industries in remote locations are subsidized proportionally more than low income households living in cities.

3.12 Because of the possibilities for generating electricity by enterprises and households, electricity tariffs should not be changed without reference to the prices of petroleum products and natural gas. If electricity

tariffs were to move out of line from the prices of other fuels, an uneconomic level of private electricity generation would result. 1/

3.13. The government accepts the principle that electricity tariffs and energy prices in general should be at their economic cost. The issue is to devise a strategy for achieving this that enables economic prices to be reached as quickly as possible, yet is not destroyed through political reaction during its implementation. Several possibilities exist for implementing tariff reform, some of which might apply only to limited groups of consumers In our view, a program of electricity pricing reform should consist of a substantial first step, followed by a gradual elimination of the difference between price and LRMC (at international fuel prices) over a period of ten years. Pricing reforms should proceed in parallel with other measures for demand management (see Sections B and C of this chapter). Below are some suggestions of measures the Government could consider as part of a strategy for electricity pricing reform:

(a) the magnitude of subsidies could be frozen in nominal terms, i.e. at their present levels. This would stop the level of subsidies growing in step with consumption and enable inflation to gradually erode it in real terms. This could be achieved in several ways:

(i) selling electricity to new consumers at VHV, HV, and MV only at prices that were substantially above the present tariffs. The tariffs for Suez Free Trade Zone joint venture companies is a precedent for this;

(ii) having steep increases, e.g., doubling of tariffs for large VHV, HV, and MV consumers, but enabling consumers to apply for a rebate each year of, say, 80% of their bill in the year before the reform, or their current years consumption valued at the old prices, whichever is lower. This rebate would be reduced to zero over, say, four years; and

(iii) concentrating tariff increases to LV consumers on the higher priced blocks so that the average price rises when the average consumption increases;

(b) pricing consumption at the margin close to economic cost, so as to give incentives for using electricity efficiently, but enabling low income consumers to afford a basic level of service. This could be achieved by increasing the prices more in the higher priced blocks of LV tariffs, which has already been done to some extent (para. 3.08), and by rebates to larger consumers as in (a);

1/ If tariffs are not raised sufficiently to ensure the financial viability of the electricity supply industry, the quality of supply could deteriorate because of insufficient investmant and some enterprises would invest in private generators in any case. Obviously, the best solution is to raise petroleum and gas prices as well as electricity tariffs.

(c) separating the issue of pricing electricity to households, which is politically sensitive, from tariffs for enterprises. It would then be possible to concentrate on raising producer prices of electricity relatively quickly, with slower progress on consumer prices that took account of the ability to pay. However, consumer prices too should eventually reach the level of economic costs;

(d) making subsidies explicit whereever possible. For example, tariffs could be set at much higher level for state enterprises, which account for 70% of industrial value added. The Government would then posess information on the viability of the enterprises and could either subsidize them directly, instead of the electricity supply industry, or restructure them; and

(e) reducing the decision-making burden on the Government by setting annual programs in advance for monthly or quarterly tariff increases that would then take place automatically. Regular, frequent tariff increases that were less than the nominal rate of inflation might also be more acceptable politically.

B. Load Management

Basis for Load Management

3.14. Even if tariffs are set equal to LRMC, complementary load management policies may still be necessary to achieve the maximum savings in the costs of supplying and using electricity, for the following reasons:

(a) consumers may not be aware of the possibilities they have for reducing their electricity bills;

(b) tariffs can be blunt instruments for achieving load savings at peak, since peak periods of tariffs are usually sufficiently broad to prevent the peak shifting. Some consumers might be willing to lower their consumption for shorter periods but would not be able to shed load for the entire peak period of the tariff. Similarly, from the utility's viewpoint, it is not necessary for these consumers to shed load every day; only at times when the system is under stress; and

(c) some consumers may lack incentives to achieve electricity savings. Typical examples are when enterprise performance is not measured by profit and where changes in electricity costs are translated into product price changes through government regulation or monopoly.

3.15. When electricity prices are severely distorted and can not be corrected quickly, as in the case in Egypt, load management has additional advantages. First, it can achieve some of the savings that would be achieved through proper pricing signals. Second, load management can minimize some of the costs of supply rationing that may occur when investment in electricity supply is constrained by lack of finance. Load management allows peak demand

to be shed by consumers who suffer little loss, instead of being spread indiscriminately through blackouts and restrictions to new connections.

Options for Load Management

3.16. Load management options range from the provision of information to consumers on their opportunities for saving expenditure on electricity to the control of consumer's loads by the utility. Loads that can be controlled are usually those with storage, e.g., water pumping and water heating, although some industrial processes can be deferred for short periods without significant effect on the output of the enterprise, e.g., melting of metals. Control of the consumer's load may be indirect, such as by the utility notifying the consumer in advance when consumption will be expensive, or direct, as when the utility can switch off consumers' loads, e.g. by remote control.

3.17. A further option for load management is combined heat and power production (CHP), where an enterprise has its own electricity generator from which it extracts process heat. Such arrangements offer high thermal efficiency which would offset the economies of scale and fuel flexibility in public electricity generation, if the project were justified economically. Surplus power could be sold to the public system. A more limited option is for enterprises to operate their standby plant when requested by the utility so as to reduce the peak demand on the system.

Status of Load Management in Egypt

3.18. Power subsector policies in Egypt have, to date, given little regard to load management. Priority has been given to expanding facilities to meet the rapidly growing demand without much consideration of whether consumers would be willing to pay for the expansion. Both the level and the structure of present tariffs give almost no incentive to reduce peak demand. Indeed, VHV and HV tariffs, which account for about 30% of the electricity sold, have no demand or time of use charges at all, although metering costs such tariffs would be negligible in relation to the other costs of supply. The shortage of finance for EEA's ambitious investment program argues for a re-direction of policy to achieve savings in peak demand and energy generated without having to resort to random load shedding.

3.19 Recently, the government has commissioned a demand management study, partly financed under Loan 1733-EGT. The consultants have completed the first phase of their work and their report is being finalized. This report will serve as the basis for establishing demand management policies. Unfortunately, there is a shortage of finance to complete the last two phases of the consultants' work and there is some doubt as to whether the work would be completed as originally planned.

3.20. Successful load management policies will be difficult to achieve without reforms to electricity tariffs and energy pricing. It would be hard to convince an enterprise to adopt load control if it could not make a saving in its electricity costs greater than the costs of control equipment and supervision that would be required. Furthermore, some changes in tariff

structure will be required since present tariffs give no incentive to reduce consumption at the time of the system peak and new tariffs would be required for, say, interruptible supply. In theory, managers of state enterprises could be offered special incentives e.g. bonuses, and credits to adopt load management techniques. However, to do this successfully would require a high degree of cooperation among ministries which might be difficult to achieve, but would be essential if load management measures were to be implemented without major reforms to electricity tariffs. Load management policies also need to take account of distortions to prices outside the power sector. In particular, distortions to petroleum and natural gas prices could lead to undesirable responses to load management policies, e.g., an uneconomic level of private generation. Ideally, load management is a complement to rational pricing policies, not a substitute for them. In the case of Egypt, load management will, of necessity, have to be a temporary substitute for economic pricing. Because of the lack of incentives for the adoption of load management and the possibility of uneconomic forms of load management arising from distortions in other prices, particularly oil and gas, it is recommended that the government ensures that the consultants' study provides a practical basis for a program for implementing a load management program.

C. Industrial Energy Rationalization

Conservation and Rationalization

3.21. Industrial energy rationalization has three aspects: (a) conserving energy use in existing processes; (b) substituting low value for high value fuels; and (c) restructuring the capital stock of industrial processes or industries. Each of these is essentially an adaptation to the present and expected economic costs of energy. Experience in other countries has shown that significant quantities of energy can be conserved through improved operating procedures which require little investment. Further savings often require relatively small investments, e.g., heat recovery devices, electric motors with greater efficiency, etc. The electric power load management study (para 3.19) proposes to examine the possibility of interfuel substitutes involving electricity. Potential candidates could be CHP and the substitution of solar energy for applications requiring low temperature heat, e.g., water heating, where the scope is probably limited. Introducing a package of energy conservation and rationalization measures, e.g., information, technical assistance, access to credits, in parallel with pricing reforms would take advantage of the psychological impact of increased energy prices and would give firms a legitimate opportunity to avoid them. The Government should prepare a package of energy conservation and rationalization measures ready for implementaton when a program of energy price increases begins.

Industrial Restructuring

3.22. The increases in world energy prices in the 1970's meant that some industrial processes have become uneconomic and that countries have lost comparative advantage in industries that were formerly viable. There are two

highly visible examples of this in Egypt, although there probably other smaller scale examples as well.

3.23 The Kima fertilizer plan uses an electrolytic process to produce ammonia. This process may have been viable when there was surplus hydroelectric power at Aswan. At current energy prices the process is economically obsolete. Using the LRMC of US8.3 cents/kWh (Table 3.3) the cost of electricity is $1040 per ton of ammonia, or about 7 times the cost of ammonia plants elsewhere. Several options exist for restructuring Kima. One is to close the plant completely and invest in a new natural gas based plant near Suez, which is located near both the gas field and main fertilizer market. Another is to construct a natural gas pipeline to Kima construct a gas based ammonia plant and rehabilitate other plant in the 33 year old plant. The government has commissioned a consultants' study to investigate these and other options. Whichever, option is chosen, the closure of the ammonia plant will result in a savings of about 200 MW in maximum demand on the power system, about 2.4% of the demand in 1991/92. This would result in a one off saving in power generation investment of roughly $250 million and recurring fuel and other operating savings of about $70 million p.a. at international prices. The magnititude of these savings is so large that the Government should give priority to restructuring or closing the Kima plant once the consultants findings are available.

3.24 The second large industry where substantial savings could be made in the power subsector is the Nag Hamadi aluminum smelter. The original smelter was completed around 1976 and was intended to utilize surplus hydroelectric power from the Aswan High Dam. A fifth potline was completed in 1983. Although aluminum smelting in Egypt may have been economic when the plant was envisaged, this is clearly no longer the case. The rapid growth in electricity consumption and shortages in capacity in the 1970s have resulted in all hydro energy being used. Marginal generation at present is from combustion turbines burning gas oil or naphtha. If the smelter were to cease operation today, the electricity saved would be that generated in combustion turbines, since the output of hydro stations would remain unchanged. The smelter is also energy inefficient, consuming about 15 MWh of electricity per ton of product compared to 12-14 MWh/ton for modern smelters. Taking the LRMC of US8.38 cents/kWh as the best estimate of the total cost of electricity supply (Table 3.3), the electricity cost per ton of aluminum would amount to about $1,260/ton compared to a world price of aluminum about $1,100/ton. The economic cost of electricity used to produce aluminum is greater than the value of the product. In addition to its disadvantage in terms of electricity cost, the smelter also suffers from locational disadvantages. Alumina has to be shipped from Australia and then transported to Upper Egypt. Aluminum ingots produced at the smelter have to be transported to the coast for shipping to export markets. Moreover, the comparison above assumes that Egyptian aluminum can be sold at the world spot price. It is not unusual for aluminum producers to have long-term contracts with prices fixed below the current level of spot prices. It is unlikely that the fifth potline would have been built or that the remaining four potlines would continue in service if energy were priced at its economic cost. The Nag Hamadi smelter , although an efficiently run enterprise which is financially viable because of the low electricity tariff, is an example of the economic waste which current energy prices encourage.

3.25 Closing the smelter and restructuring or closing the Kima plant would lower system maximum demand about 608 MW, equivalent to the output of two 300 MW generating units. The reduction in maximum demand would be equivalent to the increase in maximum demand over about 18 months during the first half of the 1990's. Reducing the demand of these plants would thus have a substantial impact on the power investment program. Two possible adverse consequences exist. The first is the effect on employment in upper Egypt. The savings from closing down the electricity intensive processes are so large that it would probably be possible to compensate the workers generously for their loss of earnings. Since neither industry is viable in the long run, the long term employment prospects for the workers are not good. Moreover, the drain of resources caused by the two industries reduces investment in economically viable industry in Upper Egypt or elsewhere and thus lowers the overall level of employment. The second adverse impact is that the decline in power consumption in Upper Egypt might require extra transmission facilities to the North in order to be able to transmit power from Aswan to meet the growth in demand in lower Egypt. The need for this and an examination of the costs should be carried out as part of studies to investigate the future of the two industries.

IV. INSTITUTIONS AND MANPOWER

A. Energy Sector Institution

Sector Institution

4.01 The two main ministries in the energy sector are the Ministry of Energy and Electricity (MEE), and the Ministry of Petroleum (MOP) and which are responsible respectively for electricity supply, petroleum production and distribution. In addition the Ministry of Irrigation (MOI) has a subsidiary role though its responsibility for the management of water resources used for hydroelectric generation. In the future the Ministry of Industry would be responsible for coal production and would be involved in energy conservation, if such projects proceed, MEE and MOP supervise enterprises involved in energy production, investment and distribution, such as EEA and EGPC.

Co-ordination of the Power Subsector with Other Subsectors

4.02 The main external reltionships are with the MOP with regard to fuel supplies for thermal power stations, and with MOI on new hydropower projects and the operation of existing hydro stations. There is considerable room for improvement in coordination between the power subsector and other subsectors. The 1979 Joint Egypt/US Energy Assessment 1/ commented that MOP and MEE operated from different viewpoints, and their objectives sometimes appeared to be at cross-purposes. There have been problems in coordination between agencies under these ministries, e.g. between EGPC and EEA with regard to the gas pipelines required to supply power stations. Problems have also arisen about the respective roles and responsibilities of MOI and the Qattara Projets Authority (QPA) in relation to the Aswan II hydropower project.

4.03 Furthermore, planning in the subsectors is not adequately co-ordinated with national economic development planning. For example, the enterprises do not receive information or guidance on the economic background for demand forecasting. Different discount rates are used in project appraisal by various institutions, although recently there has been some moves towards establishing common criteria, e.g. valuing fuels at international prices in feasibility studies.

4.04 It is too soon to judge whether the creation of the Supreme Council of Energy (SCE), an ad hoc commitee composed of the Ministers of the major energy producing, consuming and planning sectors, will have an impact on improving the problems of interministerial coordination. The new Organization of Energy Planning (OEP), a permanent secretariat to the SCE, should, at the working level, improve coordination. OEP is being strengthened by a $12.7 million technical assistance program financed substantially by USAID. This

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1/ "Joint Egypt/United States Reports on the Egypt/United States Cooperative Energy Assessment," US Department of Energy, April 1979.

will establish OEP's role in policy, planning and analysis; engineering support, especially for energy conservation; and information services. OEP's fields of activity initially are likely to be in energy demand, especially conservation, demand analysis and pricing.

4.05 OEP is the best hope for improving co-ordination among the energy subsectors and between the energy sector and other sectors and institutions. However, OEP is in its infancy and there is a long history of inter-ministerial rivalry and mistrust. The economic consequences of unco-ordinated investment and pricing decisions are sufficiently great for Government to ensure the OEP develops into a viable and independent institution.

B. Power Subsector Institutions

Organization of the Power Subsector

4.06 The public sector predominates in the power subsector, accounting for over 95% of total installed generating capacity. Autogeneration has played and will continue to play only a marginal role in the subsector. MEE retains jurisdiction over all the agencies in the subsector, with responsibility for general policy and co-ordination, including co-ordination of the plans of the various agencies and submission of a consolidated plan for the subsector to the Ministry of Planning. MEE is assisted in the regulation of the subsector and co-ordination of its plans with those of other Government departments by the High Council for the Electricity Sector, which includes the Ministers of Agriculture and Irrigation, Industry and Petroleum, under the chairmanship of the Minister of Electricity and Energy. However, it is not clear to what extent the High Council plays a major role in policy formulation and co-ordination in the subsector and how this body relates to the Supreme Council of Energy. Figure 4.1 shows the relationships of the various agencies in the subsector.

4.07 Despite the allocation of some of its functions to other agencies, the EEA remains the dominant agency in the subsector, responsible for the operation and expansion of the interconnected power system to meet the electricity needs of the country. Although it shares the responsibility for the construction of power stations with the Qattara Hydropower and Renewable Resources Project Authority (QPA) (hydropower) and the Nuclear Power Plants Authority (NPPA), these agencies have had to hand the stations over to EEA for operation on completion.

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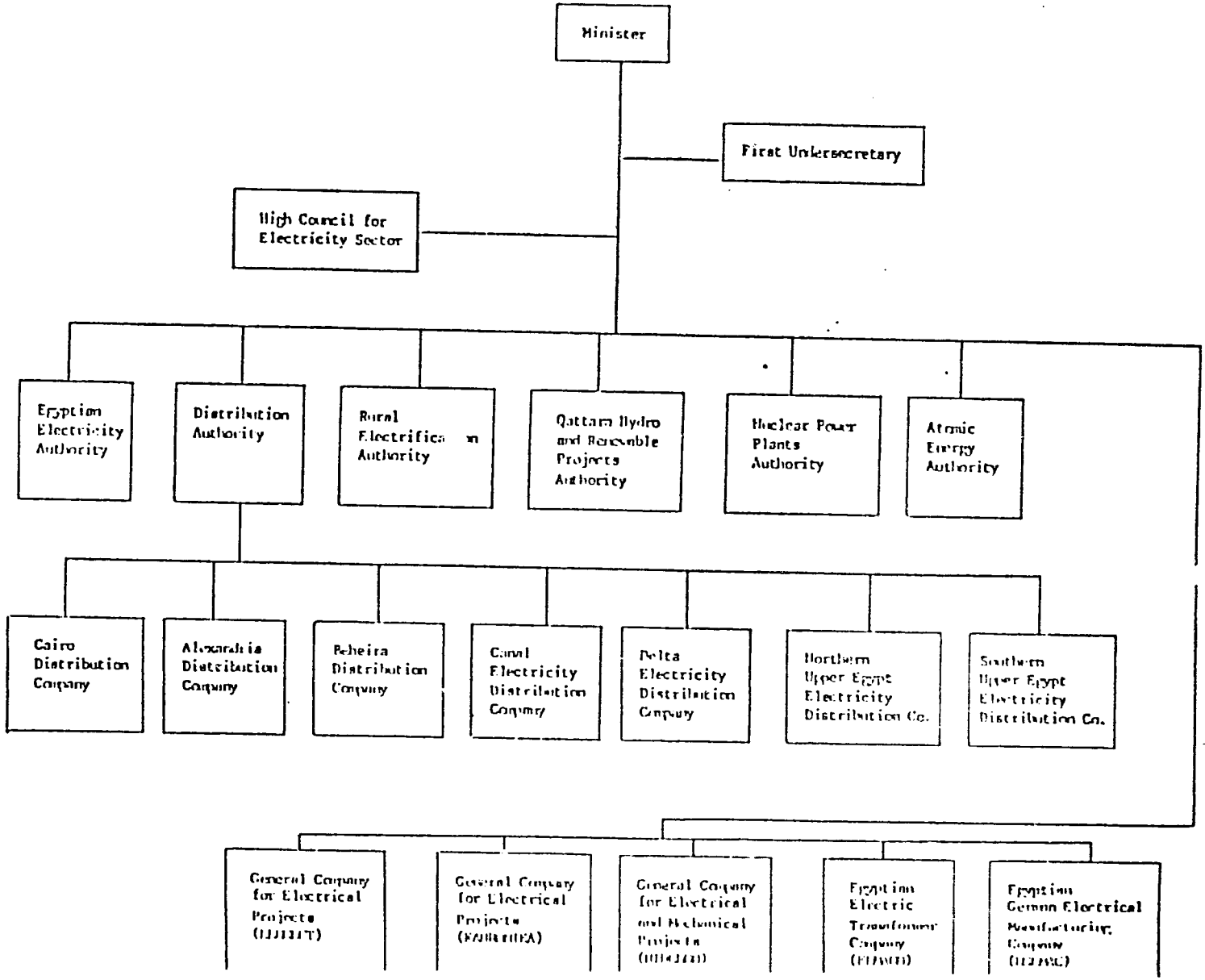
[illegible]

MINISTRY OF ELECTRICITY AND ENERGY

ORGANIZATION CHART



4.08 The Rural Electrification Authority's (REA) main function is the planning and execution of the rural electrification program but it is also responsible for upgrading the existing distribution networks up to and including 66 kV (except in Cairo and Alexandria, for which the respective municipalities under the broad guidance of EEA have been responsible). Its title is somewhat of a misnomer, since its activities are not confined to the electrification of villages and rural areas, but also embrace a large number of towns.

4.09 QPA retains the responsibility for the Qattara Depression project but its mandate has been extended to cover the development of all the country's geothermal and biomass. The responsibility for nuclear energy is divided between NPPA and the Atomic Energy Authority (AEA). NPPA was created specifically to plan and construct nuclear power stations. AEA is responsible for scientific research on the application of nuclear energy for peaceful purposes, particularly electricity generation and the use of radiation sources and isotopes.

4.10 Co-ordination within the subsector has been made more difficult by the proliferation of separate agencies in the last decade. In 1971 there was only a single agency 1/ the Egyptian General Power Corporation (EGPC), responsible for all aspects of public electricity supply. Now there are twelve, including the seven distribution companies, and it is not clear that there has been any commensurate gain in efficiency, except in the area of distribution. The tendency has been to create a new agency whenever a new activity has emerged, or increased in importance, such as the nuclear power program (NPPA), or even for a single large project (QPA). Apart from complicating coordination within the subsector, this continuous creation of new agencies aggravates the problem of staffing the existing agencies, in view of the scarcity of competent and experienced management talent in the public sector. The alternative of absorbing the new activity within an existing agency appears to be given insufficient weight in the decision process. The Nuclear Power Plants Authority and Atomic Energy Authority, for example, could constitute respectively the construction and research groups of a single atomic energy organization. Co-ordination within the Ministry is relatively weak and does not seem to be accorded any priority. This causes problems related to investment planning, staffing and operations.

4.11 The establishment of the distribution companies as individual enterprises appears to have been beneficial. Revenues from electricity sales are being collected more rapidly, theft of electricity is being reduced (at least in some areas) and the quality of service is improving, although much remains to be done. In November 1983 an authority for distribution was created within MEE. All of the seven distribution companies now report to this authority which is headed by a chairman and will have a small secretariate. Previously, the Cairo and Alexandria distribution companies reported to EEA and the other distribution companies to REA. The mission

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1/ Excluding the Atomic Energy Authority, a small research organization at the time.

understands that REA will now be responsible only for project planning and execution and its Chairman will continue to report to the Minister. This new organization is more logical since all distribution functions are linked together and the Ministry has a better chance of devolving day to day matters and policy preparation to chairmen responsible for generation and transmission (EEA) and distribution (the new authority). However, there is further scope for streamlining the Ministry, such as forming a holding company for the construction and manufacturing enterprises, that would establish an arms length relationship between the enterprises and the Ministry, and combining the nuclear agencies.

4.12. A major institutional shortcoming in the subsector is the lack of any effective provision for the regular collection and collation of data covering all aspects of the subsectors activities, technical, financial, commercial and economic, and their publication in a comprehensive, consistent and useable form. There is a mass of data within the subsector, but it is scattered about amongst various agencies and departments, making information retrieval a slow and laborious process. A central statistical unit is needed to pull all this information together as a basis for planning within the subsector and the analysis of subsector problems. The statistical department should also be given the mandate for the co-ordination, at least in matters of guidance on the planning, of the various subsectoral agencies. UNDP is considering financing a technical assistance project that would create such a database and this deserves and will require the full support and co-operation of all the power subsector institutions. Since EEA provides most of the technical support to MEE it is logical to locate the statistical unit within EEA. However, once it is established consideration could be given to transferring it to the Ministry. In order to improve, energy sector planning it will be necessary to assure the free flow of information between the MEE power subsector database and the SCE database for the energy sector being established in OEP.

C. Power Subsector Manpower Policies

4.13 The power subsector employs more than 56,000 staff, although the exact number is unknown. Of these, EEA employs about 23,200, the distribution companies about 25,000 and remaining agencies more than 8,000. REA employs 6,000 of these and NPPA 1,050.

Public sector agencies have been required to employ graduating students and discharged servicemen. About 38% of EEA's employees are skilled or semi-skilled, a high proportion compared to other national power utilities. A review of EEA's current manpower structure indicated that in almost all manpower categories except engineers the actual number of employees exceeded the budgeted level of employees. This results in overcrowding and also has a deleterious impact on staff morale. EEA has by its own estimate roughly twice as many employees as it really needs. Assessing institutional efficiency in terms of employees per consumer connected or per GWh generated suggests that, at least in terms of a cross country comparison, there is room for improvement.

4.14. The financial attractions of the oil exporting countries and the wide salary differentials between the private and public sectors have covered a major problem in recruiting and retaining qualified and experienced staff. There has been a large and continuing drain of staff from the subsector, especially engineers and technicians. This is not wholly discouraged by the agencies, since employees in the sector with more than five years service may be given leave of absence to work abroad for up to five years, and many have taken advantage of this. Although such staff may gain useful experience abroad, the drain of staff to foreign countries and the private sector reduce the effectiveness of the sector's training programs to meet its manpower needs. Moreover, uncompetitive civil service salaries make it increasingly difficult to recruit and retain qualified engineers. The salary structure should be reviewed with a view to making power subsector salaries at least equal to those in EGPC, a broadly comparable revenue earning agency in the energy sector which is able to pay salaries above the civil service rates.

4.15 The investment required to meet the growing demand for electricity will require an increase in professional staff for operation and maintenance, especially in generation and transmission. Consultants financed in part under the Bank's Credit 1453-EGT have estimated current and projected shortfalls of engineers and technicians to EEA (Table 4.1). The shortage of technical staff is projected to double over the five year period 1982 to 1987. It is important to note that this projected shortage does not include the shortages in manpower for REA and the distribution companies.

Table 4.1

Current Shortfall and Additional Requirements of Operational and Maintenance Staff, EEA 1982-1987

	1982	1987
Engineers*		
Power Stations	185	555
Transmission	295	610
Total	480	1,165
Technicians/Semi-Skilled		
Power Stations	1,105	2,500
Transmission	1,080	2,785
Total	2,095	5,285

Source: British Council, "EEA Manpower and Training Plan 1984 to 1987.

4.16. Resolving the manpower problems in the subsector will be a long and complicated task. Simple expedients such as massive retrenchment or matching salaries to the private sector, either domestically or abroad, however desirable, are likely to be politically unacceptable. However, a major effort must be made in implementing an effective and realistic manpower planning and staffing policy. An excellent start has been made by the consultants who prepared the manpower and training development masterplan. EEA should now follow up on the implementation of the recommendations contained in the report, especially on the development of a comprehensive training program, the redeployment of surplus non-technical staff to other labor intensive activities such as safety and security, the distribution of electricity and the improvement of the environment, the development of a systematic recruitment campaign, and the initiation of a career development and promotion policy. In addition, a freeze on recruitment of all lower level staff should be implemented and all reasonable avenues for reducing the staff to a more appropriate level should be explored. This could include early retirement, redeployment, transfers, retraining, etc.

V. INTER-LINKAGES WITH OTHER SECTORS

Natural Gas

5.01. The main natural gas issue in power subsector planning concerns the magnitude of the supplies available and their economic cost (para. 2.31-2.33). Electricity generation accounts for about 45% of total gas consumption and the mission projects this to increase to more than 50% by the end of the decade. 1/ The economic cost of gas is not independent of projected demand since part of the economic cost, the "depletion allowance" or value of gas in the ground depends on demand and substitution possibilities. The planning of gas utilization in power supply therefore needs close collaboration between EEA and EGPC. Gas use by existing or committed power plant, i.e. over a 5 year horizon, is a straightforward technical issue. Given electricity demand projections and plant commissioning dates, the new EEA dispatch center has sufficient computing power to make accurate projections, providing there is co-operation between EGPC and EEA. The present method of projecting consumption by a committee lacks technical support. Moreover, the projects are for maximum consumption and do not show the year by year variation in fuel consumption caused by new plant with higher thermal efficiency or lower fuel cost, e.g. coal, affecting the overall operation of the system.

5.02. For longer term planning of power generating capacity EGPC needs to have better estimates of gas reserves if more gas consuming plant is to be considered an option. EPGC needs to know projected consumption of natural gas by EEA and EEA needs to know what quantities will be available and at what cost. Effective analysis of these issues, which is at the core of future gas utilization policy in Egypt, requires not only technical co-operation at the working level between EGPC and EEA, but overall policy guidance to ensure that rational gas depletion policies are adopted. This latter policy guidance could be provided by the Supreme Council for Energy.

5.03. By its nature electricity demand has daily, weekly and seasonal variations. As ntural gas becomes the major fuel in power generation the consumption of gas by EEA would tend to exhibit similar, but smaller, variations. 2/ EGPC would thus be faced with investments in production and transmission that would not be fully utilized. This may not be a real problem. The electricity supply industry has always had to adapt to changing demand. Economic pricing of gas could give EEA the correct signals as to when it would be more economic from the national viewpoint to substitute other fuels for gas. Gas tariffs which had time of use or maximum demand charges could assist in this. In addition an amount of gas could be supplied on interruptible agreements. The EEA dispatch center would be notified a day or so in advance how much gas under such agreements would be available and would

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1/ Egypt Public Sector Investment Program Review. The Oil and Gas Sector (Page____).

2/ Since hydro plant in Egypt meets most of the variation in demand during the day, variations in gas demand during the day would probably be small.

schedule plant to consume this amount. Gas supplied under interruptible contracts would be priced at short run marginal cost, i.e. excluding any fixed capacity costs such as gas transmission. These arrangements would have other advantages to EGPC, such as allowing gas to be diverted to power generation when other gas consumers temporarily reduce their gas consumption, e.g. during maintenance and giving flexibility to adjust demand to technical fluctuations in supply.

5.04. Other operational issues are likely to arise when EEA commissions plant with a cost less than for natural gas, e.g. Aswan II, Sinai coal and nuclear. The plant will lead to gas fired plant moving down the merit order and generating less. Unless gas becomes cheaper than fuel oil, the consumption of gas for power generation could slowly decline in the 1990's, although some increase in consumption is likely up to 1991/92 (Table 2.11). EGPC therefore needs much improved estimates of gas consumption so as to optimize investments in gas production and transmission for the power generation .

Oil Refining

5.05. Power generation currently accounts for about 60% of the national consumption of fuel oil and about 10% of the consumption of gas oil. The consumption of fuel oil by power stations will decline drastically during the 1980's, since all new oil fired steam stations will be also capable of burning natural gas (Table 2.11). Towards the end of the decade, EEA plans that new stations will burn coal or be nuclear. These new stations will be used for base load generation and will only burn fuel oil when gas is unavailable. Moreover, the steam stations for which no plans exist for conversion, e.g. Cairo North, Cairo South, Karmouz and Assuit, will be reaching the end of their economic lives in the late 1980's. The fuel oil consumption of these stations will decrease as they are displaced down the merit order and will cease in the early 1990's. Taking these factors into account, fuel oil consumption in 1991/92 could be only 420 thousand tons, compared to 2,948 thousand tons in 1982/83.

5.06. Since the consumption of middle distillates and light products used in transport will continue to increase, the decline in fuel oil consumption in power generation would lead to a marked shift in the relative demand for petroleum products. With the existing and planned refinery configuration, this would lead to a growing surplus of fuel oil that would need to be exported. Because of the surplus of fuel oil in the region, the net return to Egypt after deducting transport costs would probably be about $150-155/ton, compared to Mediterranean ex-refinery prices of about $160-170/ton. A potential solution to the fuel oil surplus would be to crack the fuel oil to produce lighter products and the Government should investigate this option.

Coal

5.07. Coal reserves are located in the Sinai Peninsula at Maghara, Ayun Musa and Wadi Thora, as well as in the Western Desert. Only the Maghara deposits, of which 35.6 million tons is recoverable, is considered to be

economic for mining at present. 1/ The Maghara deposit is 150 km northeast of Ismailia and 70 km southwest of El Arish. A mine at Safa was being opened at the time of the 1967 war. Present plans are to re-open this mine to produce 500,000 t/a. Of this 300,000 t/a would be washed and 200,000 t/a would be transported to the coke ovens at Helwan, south of Cairo, where it would be blended with imported coking coal. The remaining 100,000 t/a of middlings from the washery, plus 200,000 t/a of unwashed coal would be transported by road to the proposed Sinai power station, a distance of about 270 km. This local coal would be a small proportion of the coal consumed in the power station. About 1.2 million t/a would be imported from Asian coal producers, e.g. Australia.

5.08. Coal exploitation is the responsibility of the Ministry of Industry. The Ministry commissioned a consultants study of the development and utilization of Maghara coal. To the mission's knowledge, only a summary of the report was made available to EEA. Even though Maghara coal is of high quality (HHV 7,215 kcal/kg, ash 6.5%, moisture 4.9%, sulphur 3.0%) the remote location of the deposits and small scale of mining operations suggest that the economics of exploiting the deposits need to be proven. The consultants estimated that coal would cost LE 25.5/t at the mine-mouth and LE 38/t at the Sinai power station, which would make Maghara coal competitive with imports, although the basis of these figures was not available to the mission. Even though a power station burning imported coal would probably be justified on its own, there are a number of alternatives for using Sinai coal for power generation that have apparently been investigated by the Ministry of Industry's consultants. These include a mine-mouth power station and a power station at Al Arish on the Mediterranean coast, but to the missions knowledge, they were not evaluated in conjunction with EEA. There is a need to improve co-operation between the Ministry of Industry and EEA to ensure that coal reserves are developed in the most economic manner and that the location of any power station burning local coal has been based on rigorous economic analysis.

Water Resources

5.09. Water resources are the responsibility of the Ministry of Irrigation (MOI). Water releases from the High Dam are intended primarily to meet agricultural requirements. The dominance of irrigation requirements over power is not unusual elsewhere and reflects a water management policy to maximize the benefits from the seasonal storage of water. Most of the hydroelectric resources of the Nile have been exploited, although a few remaining opportunities for adding power turbines to existing or re-constructed barrages remain (para. 2.34). Development of the remaining hydro sites requires a high degree of co-operation between MEE and MOI, which has not always been achieved in the past. The flow of information between the two Ministries has been much less than perfect. Disputes have arisen over the allocation of joint costs, e.g. for the Esna project where the exploitation of the hydroelectric potential would necessitate bringing forward the re-construction of the barrage. The Supreme Council to Energy is a possible institution for improving co-ordination between MEE and MOI.

1/ U.S. Department of Energy "Joint Egypt United States Energy Assessment (April 1979).

VI. POWER SUBSECTOR INVESTMENT AND FINANCE

Investment Requirements

6.01. Based on the missions revisions to the power generation investment program (Table 2.10), the mission estimates that power subsector investment during the 8th 5-year Plan 1982/83-1986/87 will amount to LE 3,756 million, at current prices. This is LE 1,286 million greater than the LE 2,470 shown in the Plan documents (Table 6.1). Reasons for this are:

(a) insufficient allowance in the Plan for expenditure during the first stages of construction on projects scheduled for completion beyond the Plan horizon, e.g. Sinai Coal, Sidi Kreir and the first nuclear power stations;

(b) increased investment in gas turbines because of delays to steam stations; and

(c) increased costs for some projects, e.g. Aswan II hydro.

The mission' estimate of the additional investment represents 52% of the Plan amount. Without this investment, or a major shift in Government policies regarding demand management, there would be a high risk of substantial deterioration in the quality of electricity supply towards the end of the decade. Attachment 1 shows a detailed breakdown of the investment program by major project and year.

Table 6.1

Power Subsector Investment
Fifth 5-Year Plan 1982/83 - 1986/87
(LE million, current prices)

	MEE Proposal for 5-Year Plan	Official 5-Year Plan	Mission Revision to Plan
EEA			
Generation			
- On-going projects	755	924	984
- New projects	2,537	216	1,300
- Rehabilitation	293	100	100
	3,585	1,240	2,384
Transmission	607	425	380
Training	8	5	20
Total EEA	4,200	1,670	2,784
Distribution Companies	416	192	192
Rural Electrification Authority	633	400	400
Qattara Project Authority	1,140	130	158
Nuclear Power Plants Authority	2,886	33	177
Atomic Energy Authority	26	18	18
Construction and Manufacturing Enterprises	24	24	24
Other	3	3	3
Total Power Subsector	9,328	2,470	3,756

Sources: Electric Power Subsector Study (Report 4165-EGT), Ministry of Planning, "The Detailed Frame of the Fifth Five Year Plan for Economic and Social Development" (December 1982) MEE, EEA, REA, QPA, Mission estimates.

6.02. Even though the mission's estimate of Plan expenditure is substantially above the amount shown in the Plan documents, both amounts are much less than the LE 9,328 million originally proposed by the subsector for the Plan 1/ (Table 6.1). Major cuts were made in the amounts allocated for

1/ See "Electric Power Subsector Study" (Report 4165-EGT) Annex 6.

nuclear power stations, conventional power stations and the Qattara project. The general direction of there cuts was, in our opinion, correct but the magnitudes were too great for conventional generations and, to a lesser extent, nuclear generation.

Balance of Investment Program

6.03 Generation accounts for 72% of the revised investment program, transmission 10% and distribution 16% (Table 6.2). Even after allowing for the highly concentrated population in Egypt and the high level of electrification, the proportion allocated to generation appears high. Given the need to reduce

Table 6.2

Distribution of Investment 1982/83 - 1988/87
(LE million, current prices)

	Proposed Plan		Offical Plan		Revised Plan	
	(LE x 10^6)	(%)	(LE x 10^6)	(%)	(LE x 10^6)	(%)
Generation	7,611	82	1,403	57	2,729	72
Transmission	607	6	425	17	380	10
Distribution	1,049	11	592	24	592	16
Other	61	1	50	2	65	2
Total	9,328	100	2,470	100	3,756	100

Source: Table 6.1

losses from their present level of about 22%, it is suggested that MEE investigates whether the balance between generation and transmission/ distribution investment is appropriate, with a view to increasing the amounts allocated to transmission and distribution during the Sixth 5-Year Plan.

Finance

6.04 The Plan documents show that the total investment would be financed as follows: local currency LE 914 million (37%), foreign credit facilities LE 1,257 million (51%) and other foreign currency LE 299 million (12%). The mission was unable to obtain either a more detailed financing plan for the investment plan or information on how much foreign finance had been secured. However, it seems likely that a foreign currency financing gap of at least LE 1 billion remains.

6.05 Because of the low level of electricity tariffs, EEA and the distribution companies has been unable to generate sufficient cash to meet its debt service in 1980/81, 1981/82 and 1982/83, even after local loans of LE 529 million were converted to equity. At existing fuel prices and with present tariffs cash flow would roughly balance debt service in 1983/84 and 1984, and there would be no internal cash generation in these years. The revenue earning institutions in the subsector are therefore unable to make any contribution to financing investment. This will not improve significantly unless tariffs are increased. Moreover, increases in tariffs would be needed to pass on any increases in fuel costs.

Options for Financing Investment

6.06 There appears to be a substantial (at least LE 1 billion) gap between available finance and investment needs of the power subsector. Since the precise magnitude of this gap is unknown, it is strongly recommended that MEE prepare rolling financing plans for the subsector covering the next 5 years. Unless the financial gap is resolved an imbalance will result between electricity supply and the demand of consumers. The Government has four options for addressing the financial issue:

(a) establish the financing of a reasonable portion of expansion requirements from net internal cash generation as an objective of subsector investment financing. The level of self-financing should increase from year to year until reaching a level of at least 25%-30% in due course. After establishing yearly objectives for self-financing, tariffs should be adjusted and expenses and losses controlled so as to assure such financing in each year;

(b) aquire more funds from bilateral, multilaterial and commercial sources. This has been the policy to date. However, sufficient funds have not been committed. Without changes to sector policies, i.e. energy prices, additional funds are extremely unlikely from several sources. Existing donors are unlikely to have the resources to supplement the sources where lending is in abeyance or to bridge the overall financial gap;

(c) ration demand. If sufficient finance can not be mobilized the investment program will slip. Shortages of electricity will result leading to outages, restrictions to new connections, etc. While in theory rationing can be carried out to minimize the costs of outages, in practice it tends to be random, and if severe, leads to economic disruption; and

(d) demand management, the implementation of tariff increases, energy conservation, industrial restructuring and load management (Chapter III). Such policies would reduce the need for investment substantially (Chapter II) and in addition would improve the self financing of the sector and attract additional official and commercial funds.

6.07 While the Government's efforts to secure additional foreign funds are to be encouraged, it is unlikely that sufficient finance could be obtained

unless a new donor could be found who was willing to commit more than a billion dollars for disbursement during the next 3 to 4 years. If rationing is ruled out the Government has no option other than to implement demand management policies. We recommend that such policies be implemented without delay.

February 10, 1984
(1633P)

EGYPT

INVESTMENT REVIEW

Power Subsector Investment Program 1982/83 - 1986/87
(LE '000, current prices)

Item	1982/83		1983/84		1984/85		1985/86		1986/87		Total 1982/83 - 1986/87		
	L	F	L	F	L	F	L	F	L	F	L	F	T
A. Distribution Companies													
Distribution Cos.													
Giza	9,900	10,100	8,500	10,500	12,000	8,000	13,000	8,000	15,874	4,176	59,274	40,776	100,00[illegible]
[illegible]	4,000	3,200	4,500	2,700	3,000	3,200	3,305	2,950	3,115	2,950	18,000	15,000	33,00[illegible]
[illegible]al	2,000	3,000	3,500	2,000	5,000	1,000	5,000	1,000	6,000	1,500	21,500	8,500	30,00[illegible]
[illegible]ta	640	210	1,200	200	1,110	1,400	770	1,830	830	1,360	4,500	5,000	9,50[illegible]
[illegible]era	700	500	1,100	100	1,100	300	1,090	350	1,0[illegible]	400	5,040	1,650	6,69[illegible]
[illegible]rth Upper Egypt	739	630	820	229	903	229	729	175	739	229	3,940	1,490	5,43[illegible]
[illegible]th Upper Egypt	1,000	500	1,000	500	1,010	490	1,000	500	990	510	5,000	2,500	7,50[illegible]
Total Distr. Companies	18,979	18,140	20,620	16,229	24,203	14,619	24,854	14,803	28,548	11,125	117,204	74,916	192,12[illegible]
B. EEA													
[illegible]ation													
[illegible] Projects													
[illegible] Oil (4[illegible]0 MW)	9,000	14,000	5,450	4,000	4,090	1,920	-	-	-	-	18,540	19,920	38,46[illegible]
[illegible] Suez (Ismailia) (2x[illegible] MW)	4,000	16,000	2,000	16,000	1,840	23,600	-	-	-	-	7,840	57,600	65,4[illegible]
[illegible] El Tawfik (2x[illegible] MW)	4,000	10,000	2,000	6,000	18,570	30,950	-	-	-	-	24,570	46,950	71,52[illegible]
[illegible] Suez (Ismailia) (1x[illegible] MW)	1,905	21,845	1,200	11,550	500	1,720	-	-	-	-	3,605	35,115	38,72[illegible]
[illegible]ga (Suez) (2x[illegible] MW+2x[illegible] MW)	9,000	10,000	3,500	12,500	16,217	20,750	25,500	67,500	12,783	46,250	67,000	157,000	224,00[illegible]
[illegible]abra El Khaima (2x[illegible] MW)	9,915	19,005	21,700	26,500	17,075	49,825	7,282	86,793	1,053	156,757	57,025	337,975	395,00[illegible]
[illegible]duction Turbines [illegible]d diesel engines	4,950	65,500	6,850	67,420	1,500	5,050	-	-	-	-	13,300	138,070	151,3[illegible]
Subtotal	42,770	156,510	42,700	143,970	59,792	132,815	32,782	154,298	13,836	203,017	191,880	797,610	954,49[illegible]
[illegible] Projects													
[illegible]ghan Coal Conv.	-	-	1,800	16,200	2,100	7,280	1,100	3,020	-	-	5,000	26,500	31,50[illegible]
[illegible]ensive of Damanhour [illegible] (1200 MW)	-	-	2,000	13,200	4,928	15,545	16,544	33,660	17,128	27,595	40,600	90,000	130,60[illegible]
[illegible]	-	-	984	3,280	6,478	42,558	14,934	95,940	23,206	145,058	45,592	286,836	332,42[illegible]
[illegible] Kureir P.S (1200 MW)	-	-	-	-	1,200	4,000	17,900	51,900	18,200	117,000	27,300	172,900	200,20[illegible]
[illegible]ait (300 MW)	-	-	590	1,970	3,890	25,530	8,950	57,560	12,950	87,020	27,350	172,090	199,4[illegible]
[illegible]al Coal P.S (1200 MW)	-	-	1,200	4,000	7,900	51,900	18,200	117,000	25,300	176,900	55,600	349,800	405,40[illegible]
Subtotal	-	-	6,574	38,650	26,496	146,813	67,618	359,080	100,754	553,583	201,442	1,098,126	1,29[illegible],56[illegible]
Rehabilitation of existing power stations	6,400	15,308	2,400	17,600	4,800	15,164	4,571	14,603	6,182	12,766	24,353	75,441	99,7[illegible]
Total Generation	49,170	173,818	51,674	200,220	91,088	294,792	104,971	527,981	120,772	769,366	417,675	1,966,177	2,383,8[illegible]

EGYPT

INVESTMENT REVIEW

Power Subsector Investment Program 1982/83 - 1986/87
(LE '000, current prices)

Year	1982/83		1983/84		1984/85		1985/86		1986/87		Total 1982/83 - 1986/87		
	L	F	L	F	L	F	L	F	L	F	L	F	T
B. EEA (cont'd)													
Transmission													
Lower distribution and 500/220 kV network	10,500	23,500	5,000	17,000	28,475	36,400	31,934	54,824	36,431	41,576	112,450	173,300	285,75[illegible]
66/33 kV network	3,700	11,000	3,000	3,000	7,875	2,500	10,178	9,910	3,697	14,590	28,450	41,000	69,45[illegible]
Stabilization	1,600	3,827	600	4,400	1,200	3,791	1,143	3,651	1,545	3,191	6,088	18,860	24,9[illegible]
Total Transmission	15,800	38,327	8,600	24,400	37,550	42,691	43,315	68,385	41,723	59,357	146,988	233,160	380,1[illegible]
Training & Studies	675	1,480	2,935	3,415	1,590	3,410	923	2,807	477	2,168	6,700	13,300	20,00[illegible]
Total EEA	65,645	213,625	63,209	228,035	130,328	340,893	149,209	599,173	162,972	830,911	571,363	2,212,637	2,784,00[illegible]
C. FEA													
High voltage network	11,518	13,592	12,670	14,951	13,937	16,446	15,331	18,091	16,864	19,900	70,320	82,980	153,3[illegible]
Urban electr. network	5,878	6,955	6,467	7,650	7,114	8,415	7,824	9,257	8,607	10,182	35,890	42,460	78,3[illegible]
Substation civil works	5,561	-	6,117	-	6,729	-	7,401	-	8,142	-	33,950	-	33,95
Rural electrification	13,579	10,150	11,747	8,781	12,923	9,658	14,215	10,624	15,636	11,687	68,100	50,900	11[illegible]
Training	1,182	89	1,218	125	957	68	974	90	1,169	103	5,500	500	6,00
Substation civil works	1,880	-	1,880	-	1,880	-	1,880	-	1,880	-	9,400	-	9,[illegible]
Total FEA	39,598	30,786	40,099	31,507	43,540	34,607	47,625	38,062	52,295	41,878	223,160	176,840	400,0[illegible]
D. GPA													
Aswan II Power Station	10,000	20,000	11,000	22,000	10,000	20,000	5,000	10,000	5,000	10,000	41,000	82,000	123,0[illegible]
Renewable Energy Project	1,500	130	2,695	240	3,001	260	2,500	217	1,804	153	11,500	1,000	12,5[illegible]
Studies	1,504	1,440	3,172	751	3,172	751	3,256	2,629	3,256	2,629	14,360	8,200	22,5[illegible]
Total GPA	13,004	21,570	16,867	22,991	16,173	21,011	10,756	12,846	10,060	12,782	66,860	91,200	158,0[illegible]
E. NPA													
Site studies	1,635	7,600	3,635	5,600	2,897	4,800	1,309	1,000	1,309	1,000	10,785	20,000	30,[illegible]
Head office building	250	-	500	-	750	-	625	-	375	-	2,500	-	2,5[illegible]
Nuclear power station (900 MW)	-	-	-	-	3,600	14,400	3,600	14,400	21,600	86,400	28,800	115,200	144,0[illegible]
Total NPA	1,885	7,600	4,135	5,600	7,247	19,200	5,534	15,400	23,284	87,400	42,085	135,200	177,2[illegible]

(1632P)

EGYPT

INVESTMENT PROFILE

Power Subsector Investment Program 1982/83 - 1986/87
(LE '000, current prices)

Item	1982/83		1983/84		1984/85		1985/86		1986/87		Total 1982/83 - 1986/87		
	L	F	L	F	L	F	L	F	L	F	L	F	T
F. Atomic Power Authority													
Nuclear Research Center	596	1,060	964	904	450	1,346	450	1,345	450	1,345	3,000	6,000	9,000
Pilot Laboratory	371	298	628	108	367	68	367	68	367	68	2,100	610	2,710
National Center for Radiation Research	511	367	538	437	364	176	359	205	358	185	2,130	1,370	3,500
Nuclear Security & Miscellaneous	408	172	408	172	408	172	408	172	408	172	2,040	860	2,900
Total	1,886	1,897	2,538	1,621	1,619	1,762	1,614	1,790	1,613	1,770	9,270	8,840	18,110
SUMMARY													
Distribution Cos.	18,979	18,140	20,620	16,229	24,203	14,619	24,854	14,803	29,553	11,125	117,204	74,916	192,120
EEA	65,645	212,625	63,209	228,035	130,215	340,893	149,209	509,173	142,972	830,911	571,360	2,212,637	2,784,000
REA	39,598	30,786	40,099	31,507	43,540	34,607	47,625	39,062	52,238	41,876	223,160	176,840	400,000
GPA	13,004	21,570	16,867	22,991	16,173	21,011	10,756	12,846	10,060	12,782	66,860	91,200	158,060
NPA	1,885	7,600	4,135	5,600	7,247	19,200	5,534	15,400	23,254	87,400	42,055	135,200	177,255
APA	1,886	1,897	2,538	1,621	1,619	1,762	1,614	1,790	1,613	1,770	9,270	8,840	18,110
Total	140,997	293,618	147,468	305,983	223,110	432,092	239,592	682,074	278,775	985,866	1,029,942	2,699,633	3,729,575

Sources: EEA, REA, GPA, Electric Power Subsector Study (Report 4165-EGT), Mission estimates.

February 1984
(1633P)