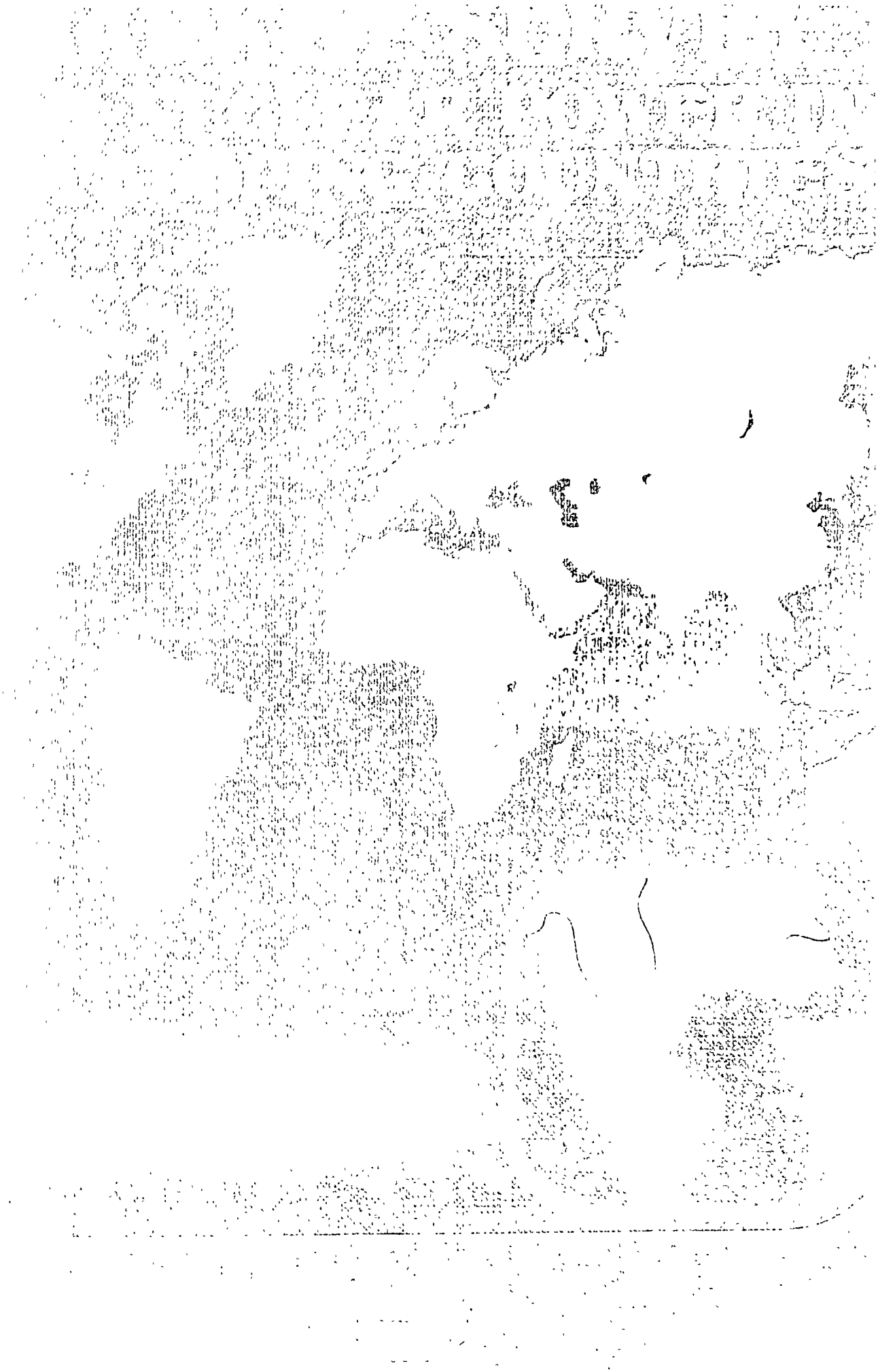


MARKET SURVEY
FOR
NUCLEAR POWER
IN
DEVELOPING COUNTRIES

GREECE

PRINTED BY THE
INTERNATIONAL ATOMIC ENERGY AGENCY
IN VIENNA
SEPTEMBER 1973

FOREWORD

It is generally recognized that within the coming decades nuclear power is likely to play an important role in many developing countries because many such countries have limited indigenous energy resources and in recent years have been adversely affected by increases in world oil prices. The International Atomic Energy Agency has been fully aware of this potential need for nuclear power and has actively pursued a program of assisting such countries with the development of their nuclear power programs. So far, inter alia, the Agency has:

(a) Sponsored power reactor survey and siting missions;
(b) Conducted feasibility studies;
(c) Organized technical meetings;
(d) Published reports on small and medium power reactors; and
(e) Awarded fellowships for training in nuclear power and technology.

At present only eight developing countries[1] have nuclear power plants in operation or under construction - Argentina, Brazil, Bulgaria, the Czechoslovak Socialist Republic, India, the Republic of Korea, Mexico and Pakistan. The total of their nuclear power commitments to date amounts to about 5200 MW as compared to an estimated installed electric generation capacity of about 56 000 MW. It is estimated that by 1980 only 8% of the installed electrical capacity of all developing countries of the world will be nuclear. In contrast, in the industrialized countries more than 16% of total electrical capacity will be nuclear by 1980.

In view of the possible greater need for nuclear power in developing countries it was recommended at the Fourth International Conference on the Peaceful Uses of Atomic Energy, held in Geneva in 1971, and at the fifteenth regular session of the General Conference[2], that efforts should be intensified to assist these countries in planning their nuclear power program. In response to these recommendations the Agency convened a Working Group on Nuclear Power Plants of Interest to Developing Countries on 11 - 15 October 1971 to review the then current status of the potential for nuclear power plants in these countries and advise on the desirability of carrying out a detailed market survey for such plants.

As a result of its deliberations, the Working Group recommended that a Market Survey be carried out to determine in a more definitive way the size and timing of demand for nuclear power plants in selected developing countries where they might play an economic role in complementing conventional energy sources. The Working Group also pointed out that, although the Survey would be performed in the interests of the countries concerned, the results should be directed toward the nuclear industry, including manufacturing, engineering, construction and financial institutions, who would be looked to ultimately for meeting the requirements for equipment, facilities and financing as identified in the Survey.

In response to these recommendations, the Director General decided that the Survey should be undertaken and steps were initiated in November 1971.

The objectives of the Survey as finally undertaken were as follows:

(a) Examine the potential role of nuclear power in interested developing countries over the next five to fifteen years as a means of defining the size and timing of the installation of nuclear plants in this period.
(b) Identify the specific market for small and medium power reactors in the countries participating in the Survey.
(c) Estimate the financial requirements for the selected power system expansion programs in each of the participating countries.

Thus, this Survey will define the size and timing of the likely market for nuclear plants to be commissioned in the participating developing countries and the domestic and foreign financial requirements for that market in the 1980-1989 period[3].

It should be emphasized that this report provides only an indication of the need for nuclear power and associated financial considerations for the countries involved. The

---

[1] As classified under the United Nations Development Program.
[2] See General Conference Resolution GC(XV)/RES/285.
[3] For convenience this will be called "study period" throughout the report.

scope of the data and information surveyed are not in such great detail as to allow the findings to be considered the equivalent of a rigorously determined feasibility study of any specific installation. The results, however, are as accurate as they could be made within the limits of data, time and manpower available. The methodology and analytical procedures used are believed to be accurate.

In case the countries may need more detailed plans, an in-depth analysis will be required. It is suggested that the matter of defining the steps which would be needed to implement the suggested nuclear power programs, by all parties concerned, be the subject of further study after the participating countries have had an opportunity to thoroughly analyse the results of the Survey.

In order to avoid biasing the results in favour of nuclear power, the approach and bases for analysis, including the technical and economic parameters, were subject to careful review by independent observers at the start of the study and prior to its completion. Comments by these observers were taken into consideration wherever possible. It is hoped that as a result of these reviews any bias however unintentional has been removed from the study.

SCOPE AND IMPLEMENTATION

In November 1971 letters were sent to 23 developing countries considered to be the most promising candidates for introduction of nuclear power in the time period of interest. Fourteen of these countries expressed an interest in participating and agreed to provide relevant basic data and counterpart staff to work with the visiting teams of experts. Seven Survey missions were undertaken as follows:

Turkey-Greece	3-21 July 1972
Argentina-Mexico	7 August - 1 September 1972
Jamaica-Chile	4-15 September 1972
Republic of Korea-Singapore-Philippines	23 October - 17 November 1972
Pakistan-Arab Republic of Egypt	13 November - 1 December 1972
Thailand-Bangladesh	20 November - 8 December 1972
Yugoslavia	4-5 and 15-17 January 1973

The team selected for each mission was assigned the responsibility of collecting the necessary information on the characteristics of the power supply system(s) concerned, the projected power demand, current plans for expansion of the system(s), the availability of indigenous energy resources, and related economic and technical factors. This information was subsequently analysed by each mission team, reviewed by the country involved and used as a basis for the final report.

Data gathered by the missions were also evaluated by the engineering staff of the Agency and by the experts assigned to the Survey. This evaluation included consideration of power flows in the basic interconnected system under normal operating conditions, the possible differences in transmission system requirements under varying generating capacity plans, an analysis of the transient stability and frequency stability of each system following an unplanned outage of one or more generating units, an analysis of alternative power system expansion plans involving nuclear and conventional plants and an estimation of the present worth of all costs for each plan. The results served as a basis for the selection of near-optimum power system expansion programs for each of the fourteen countries involved.

FINANCIAL AND MANPOWER SUPPORT OF SURVEY ACTIVITIES

Since the Market Survey was not foreseen at the time the Agency's 1972 budget was prepared, financial support was obtained from various countries and financial institutions. Furthermore, the work of the Market Survey could not have been completed within the time and manpower constraints but for the great efforts of the personnel in each country who participated in the preparation and review of data, the Agency professional and supporting staff, and the contributions of many other experts and organizations.

Support in cash funds was made available from:

Federal Republic of Germany	US $ 25 000
Inter-American Development Bank	25 000
International Bank for Reconstruction and Development	50 000
United States – Export-Import Bank	75 000
Agency for International Development	25 000
Atomic Energy Commission	9 950
Total	US $ 209 950

In addition, several countries provided experts on either a cost-free or partially cost-free basis:

	Approximate man-weeks
Canada	22
Federal Republic of Germany	48
France	4
India	3
Japan	17
Sweden	9
United Kingdom	14
United States of America	19
Total	136

The fourteen participating countries contributed counterpart personnel and bore part or all of the expenses of each Survey mission during the time spent in the country in addition to the cost of preparing the responses and data required for the analyses.

The Agency's contribution to the Survey included US $20 000 in cash plus approximately 260 man-weeks of professional staff, secretarial and administrative support, equivalent to about US $176 000. In addition, special consultants to the Agency provided about 170 man-weeks of support equivalent to about US $112 000.

Based on the above, the total cost of the Survey is estimated to amount to US $555 000, including more than US $100 000 for cost-free services provided by its sponsors.

ACKNOWLEDGEMENTS

Mr. O. B. Falls, Jr., USA, consultant to the Agency, was Project Manager for the Market Survey.

To list all of those who contributed in one way or another, even for one country, would be lengthy. Hence, specific recognition is limited to:

Associated Nuclear Services Ltd (ANS), London, England – who furnished, under a special contract, an electric utility system planning expert for each mission and co-ordinated the technical systems analysis work for the participating countries.

Bechtel Corporation, San Francisco, California, USA – who furnished complete heat rate data for the many sizes and types of fossil and nuclear power plants used in the Survey analyses.

Lahmeyer International GmbH, Frankfurt, FRG – who also furnished heat rate data, consulting service on costs and availability of smaller nuclear reactors, and an expert in mining of coal and lignite.

Tennessee Valley Authority, Chattanooga, Tennessee, and the Atomic Energy Commission, USA – who made available TVA's basic power system planning computer program, Mr. Taber Jenkins of TVA's staff and Dr. David Joy of Oak Ridge National Laboratory (USAEC) to develop the changes required to provide the computer program capabilities especially needed for the Market Survey.

Others who contributed materially to the work of the Survey were the many organizations and the liaison officers from each country as listed in the Appendixes and the outstanding staff of consultants and Agency personnel who participated in the several missions and in the work at headquarters.

It is hoped that the information contained in this report will be of value to each country in formulating appropriate plans in regard to the potential use of nuclear energy for electric power generation in the years ahead.

INTRODUCTION

Fourteen Country Reports, one for each of the developing countries that took part in the Survey, have been prepared. These fourteen Country Reports are summarized in the General Report.

Sections 1-8 of each Report contain data gathered during the visit of the team of experts and other data gathered for general accuracy. Sections 9-17 present the method of approach, the data used in the analyses, the analyses made and the results of the studies. General data and methodology common to the studies for all countries are given in the Appendixes.

Section 1 concerns general economics and contains data on population, gross national product, mineral resources and energy consumption.

Data on the national energy resources such as hydro potential, fossil fuel reserves, refinery capacity and production, and nuclear materials resources are given in Section 2.

The electricity supply system, its development, generating and transmission facilities, costs of existing plants and plants under construction, various system operating and economic criteria, and technical data on existing generating units are given in Section 3.

The historical growth of the electrical demand is described in Section 4, together with historical data on per-capita consumption, installed capacity, energy generated, load factor, and system load characteristics. Data are also given on system reliability, reliability criteria, and outage experience.

The future system requirements are described in Section 5 including projections of maximum demand, generated energy, load factor and future reserve capacity. Also included are data on generating units and transmission facilities planned, under construction or projected, and on future sites.

Section 6 contains data on local material and labour costs, labour practices, and the participation of local industry in the manufacture of power system components.

Economic and financial aspects such as the method of evaluating the economic merit of projects, sources of funds, import duties and restrictions are described in Section 7.

Section 8 contains a description of the administration and regulation practices of the Agencies responsible for nuclear power and information on nuclear legislation, licensing and safety.

Section 9 describes the analytical approach used in the study; the bases of analysis, the computer programs, and the economic and technical methodology and parameters. The approach taken to determine the sensitivity of the results to certain parametric changes is also described.

In Section 10 are described the bases of the load forecasts used in the study, the future load characteristics such as seasonal peak demand, the load duration data, and the load factor.

The results of the analysis of the factors limiting system development, made by Associated Nuclear Services, are given in Section 11, including data on system reliability, response of the system to loss-of-load, and recommendations on limits of generating unit sizes.

The existing and committed electrical power system technical data, such as unit capacity, heat rates, fuel costs, forced and scheduled outage rates, seasonal and energy factors relating to hydro, and data on emergency hydro and pumped storage are given in Section 12.

Capital cost data and the bases for their calculation are given in Section 13.

The technical characteristics of the alternative generating units considered for the expansion of the power system are given in Section 14.

The analyses of the alternative expansion programs are described in Section 15, including a discussion of the alternative plans considered, the method of determining the "optimum" expansion program and the consideration given to system reliability.

The results of the study for the reference conditions and the sensitivity of these results to various parameters are given in Section 16. These results include the overall thermal plant additions required during the study period, the nuclear units required, and the financial requirements of the reference case expansion plan.

The summary and conclusions of the study are presented in Section 17.

A number of Appendixes have been included to provide additional information on the computer programs, methods of forecasting load, methodology and parameters used, fossil and nuclear fuel costs, general technical and economic data on thermal and nuclear plants, and other appropriate data.

TABLE OF CONTENTS

1.	ECONOMIC BACKGROUND	1
2.	NATIONAL ENERGY RESOURCES	7
3.	ELECTRICITY SUPPLY SYSTEM	18
4.	HISTORICAL SYSTEM DATA	28
5.	PROJECTED SYSTEM DATA	35
6.	NATIONAL CAPABILITIES AND LOCAL COSTS	39
7.	ECONOMIC AND FINANCIAL ASPECTS	43
8.	ADMINISTRATIVE AND REGULATORY	45
9.	ANALYTICAL APPROACH	47
10.	FORECASTS OF SYSTEM LOADS AND LOAD DURATION CURVES	50
11.	LIMITING FACTORS IN SYSTEM DEVELOPMENT	53
12.	CHARACTERISTICS OF THE EXISTING AND COMMITTED ELECTRIC POWER SYSTEM	60
13.	CAPITAL COST DATA	65
14.	CHARACTERISTICS OF ALTERNATIVE GENERATING UNITS CONSIDERED FOR EXPANSION DURING THE STUDY PERIOD	70
15.	ANALYSIS OF ALTERNATIVE EXPANSION PROGRAMS	73
16.	RESULTS	76
17.	SUMMARY AND CONCLUSIONS	81
APPENDIXES A-N		85

1. ECONOMIC BACKGROUND

1.1. Geographic features

As shown in Fig. 1-1, Greece forms the south-eastern tip of Europe and is bounded on the north by Albania, Yugoslavia, Bulgaria and Turkey. Most of the country is surrounded by the Eastern Mediterranean resulting in 15 000 km of shoreline. The total area of the country amounts to 132 000 km^2, of which about 170 inhabited islands account for over 25 000 km^2. Only 30% of the area is low or flat country, 27% is hilly or semi-mountainous and the remainder consists of rugged mountains. Almost 30% of the total land area is under cultivation, 41% consists of grazing pastures, 22% is forest, and 7% comprises lakes, swamps, marshes and inhabited areas. There are 20 main rivers ranging between 247 and 70 km in length.

The climate in the north and in the central regions is continental and variable while in the southern regions and the islands it is Mediterranean. The average annual air temperature is about 17°C ranging from about 13°C in the north to 18°C in the capital area and 19°C on the southern islands. Rainfall diminishes from west to east and from north to south, ranging between 1800 and 400 mm and averaging almost 700 mm.

FIG. 1-1. MAP OF GREECE.

1.2. Population

The total population was about 8.8 million at mid 1971 (66.6 per km^2), nearly half of it living in urban areas. The three cities of Athens (including Piraeus), Thessaloniki and Patras alone account for more than 30% of the population. The rapid industrialization of Greece is changing the country from a predominantly rural to an urban one as shown in Table I-1. The population growth during the past decade is given in Table I-2.

TABLE I-1. POPULATION DISTRIBUTION

Census year	Percent distribution		
	Urban	Semi-urban	Rural
1940	32.8	14.8	52.4
1951	37.7	14.8	47.5
1961	43.3	12.9	43.8
1971 [a]	53.2	11.7	35.1

[a] Provisional figures.

TABLE I-2. HISTORICAL POPULATION GROWTH (Mid-year estimates)

Year	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971
Population (10^3)	8398	8448	8479	8510	8550	8614	8716	8741	8773	8793	8817 [a]

[a] Provisional figure.

The population growth rate has thus averaged about 0.4% since the 1961 census; however, during the years 1968-1971, the growth rate was only 0.3%/yr. This level is lower than in most countries as a result of a considerable net emigration which has averaged about 50 000 a year during the 1960's. Despite the relatively slow growth of total labour supply, there is a large surplus of labour in agriculture which since 1961 has been gradually moving into other employment in Greece or abroad. There is, however, a shortage of skilled labour. As a result of the economic, educational and social improvements (including subsidies to large families) the population is expected to grow at an average rate of about 0.7%/yr and reach 9.7 million in 1985.

1.3. National economics[1]

(a) Gross National Product

Rapid economic growth since the mid-1950's has been accompanied by significant changes in the structure of the economy. Economic policy has promoted private enterprise with the State providing social services and the basic economic and institutional infrastructure. The economic development was guided in the years 1968-72 by a Five-Year Development Plan with indicated targets for both the private and public sector. A second Five-Year Plan for 1973-77 is near completion.

[1] The Greek national currency is the Drachma (Dr). The exchange rate relative to the US$ used throughout this report is 30 Dr. = 1 US$.

The development of the Greek Gross National Product (GNP) since 1960 at constant 1958 prices is given in Table I-3. It is anticipated that the GNP will increase up to 1985 at an average annual rate of 7%.

In addition to the vigorous growth of the economy, the most important development is its structural change. The share of industry of the Gross Domestic Product has been increasing at the expense of agriculture. This trend is expected to continue up to 1985 as illustrated in Table I-4.

TABLE I-3. GROSS NATIONAL PRODUCT

Year	GNP at constant 1958 prices (10^6 Dr)	GNP per capita at constant 1958 prices (US$)
1960	102.0	408
1961	113.4	450
1962	117.5	464
1963	125.6	500
1964	137.1	543
1965	149.7	584
1966	159.4	622
1967	169.3	647
1968	181.8	684
1969	197.9	736
1970 [a]	218.0	825
1971 [a]	236.0	893

[a] Figures for 1970 and 1971 are provisional.

TABLE I-4. PAST AND PROJECTED INPUT TO GROSS DOMESTIC PRODUCT

Branches	Percent				
	1960	1965	1970	1977	1985
Agriculture	26.2	24.9	20.2	15.7	12.5
Manufacturing	14.4	15.3	16.5	20.2	23.3
Other industry	8.9	9.9	11.5	13.9	15.9
Services	50.5	49.9	51.8	50.2	48.3
Total	100.0	100.0	100.0	100.0	100.0

(b) Indigenous minerals

Greece is known to have a number of mineral resources, primarily bauxite, magnesite, nickel, manganese and chromite. In 1969, the production of bauxite amounted to almost 2 million tons, magnesite to 570 000 tons, and nickel ores to 500 000 tons. Barytes, chromite and manganese were produced in lesser quantities. It is evident that with the exception of aluminium production from bauxite, the availability of indigenous minerals will not have a significant influence on future power requirements.

TABLE I-5. INDUSTRIAL PRODUCTION INDICES, 1963-1970 (1959 = 100)

Branch of industry	1963	1964	1965	1966	1967	1968	1969	1970	1971 [a]
Chemical	171	197	220	268	312	356	407	449	503
Petrochemical	117	120	121	175	222	261	275	305	325
Basic metals	191	279	363	518	576	719	943	1075	1199
Rubber and plastics	216	253	308	401	437	490	632	765	870
Metal products	161	181	212	227	219	245	270	298	340
Machinery	88	86	86	85	81	75	75	74	73
Electrical	169	185	208	202	239	221	258	306	354
Transport equipment	178	192	199	204	199	202	218	268	285
Total	137	151	163	187	192	206	229	254	279

[a] Figures for 1971 are provisional.

TABLE I-6. ENERGY CONSUMPTION IN GREECE, 1960-1970 (10^3 TEC)

Year	Solids (lignite)	Liquids (oil)	Hydro	Gas	Total	Electricity portion of total
1960	819	3 558	190	52	4 619	900
1961	799	3 935	215	56	5 005	970
1962	768	4 839	246	33	5 886	1 100
1963	993	5 012	320	30	6 355	1 230
1964	1 268	5 351	294	28	6 941	1 460
1965	1 525	6 087	313	30	7 955	1 710
1966	1 535	6 399	688	50	8 672	2 190
1967	1 283	7 511	701	100	9 595	2 700
1968	1 385	7 706	550	104	9 745	2 820
1969	1 703	8 298	793	98	10 892	3 120
1970	2 033	8 801	1 067	108	12 009	3 640
Average annual growth rate (%)	9.5	9.5	18.8	7.5	10.0	15.0

(c) Industrial production capabilities and growth

Industrial production indices for selected branches of industry are given in Table I-5. High growth rates were experienced by the basic metal, rubber and plastics, petrochemical and chemical industries. The output of metal products and electrical machinery and appliances grew at a lesser rate while the manufacture of non-electrical machinery and appliances declined over the period.

1.4. Total energy consumption

(a) Distribution of energy consumption by source

Table I-6 shows the growth in energy consumption from 1960 to 1970 and the sources of this energy in terms of thousands of metric tons of coal equivalent (TEC)[2]. Over this

[2] Metric tons of coal equivalent (TEC) is equal to 28.5×10^6 Btu and to 7.25×10^6 kcal.

decade total energy consumption increased at an average rate of 10% per annum reaching 12 million TEC in 1970. The greatest rate of increase was in hydrogeneration at 18.8%. The consumption of oil and lignite increased at an average rate of 9.5%.

(b) Distribution of energy consumption by end use

Table I-7 shows the distribution of energy consumption by end use in terms of coal equivalent. The greatest increase in energy consumption occurred in the industrial sector

TABLE I-7. DISTRIBUTION OF TOTAL ENERGY CONSUMPTION[a], 1960-1970 (10^3 TEC)

Year	Losses during conversion	Industry	Land transport	Ship propulsion	Domestic and commercial	Others
1960	859	838	1 500	719	522	181
1961	999	808	1 461	1 029	503	205
1962	1 105	966	1 746	1 378	545	146
1963	1 209	1 151	1 873	1 330	667	125
1964	1 394	1 508	2 079	1 008	804	148
1965	1 564	1 846	2 228	1 316	839	162
1966	1 974	2 192	2 424	1 041	919	122
1967	2 300	2 254	2 746	1 102	1 085	108
1968	2 339	2 487	2 969	693	1 120	137
1969	2 530	2 911	3 274	691	1 334	152
1970	2 766	3 249	3 654	791	1 375	175
Average annual growth rate (%)		14.5	9.3	0	10.1	0

[a] Electrical energy is included in the figures.

TABLE I-8. ENERGY CONSUMPTION FOR THE PRODUCTION OF ELECTRICITY[a], 1960-1970 (10^3 TEC)

Year	Lignite	Liquid fuels	Hydro	Total
1960	480	230	190	900
1961	475	280	215	970
1962	475	379	246	1 100
1963	570	340	320	1 230
1964	750	416	294	1 460
1965	838	559	313	1 710
1966	837	665	688	2 190
1967	865	1 134	701	2 700
1968	940	1 330	550	2 820
1969	1 065	1 262	793	3 120
1970	1 303	1 270	1 067	3 640
Average annual growth rate (%)	10.5	18.6	18.8	15.0

[a] Derived from kWh and hydroelectric data. Hydroelectric output has been converted at a rate of 11 500 Btu/kWh. For the thermal stations no allowance has been made for the lower efficiency of the lignite compared with the oil-fuelled plants.

which grew at an average annual rate of 14.5%. This was followed by domestic and commercial consumption growth at 10.1% and land transportation at 9.3%.

(c) Electrical energy as share of total energy

Table I-8 shows the sources of energy used in the generation of electricity. During the last decade, generation from liquid fuels and hydro stations increased at an average annual rate of 18.6% and 18.8% respectively whilst that from lignite-fuelled plants increased at a rate of 15%. Table I-9 records the percentages of the total energy consumption which was consumed as electricity and in other forms. During the decade, electricity increased its share from 19.5% to 30.3% largely at the expense of oil; lignite and gas supplied a small but constant percentage.

TABLE I-9. SHARES OF ENERGY CONSUMPTION BY ELECTRICITY AND OTHER SOURCES

Year	Percentage share of total energy consumption			
	Electricity	Oil	Lignite	Gas
1960	19.5	72.1	7.3	1.1
1961	19.4	73.0	6.5	1.1
1962	18.7	75.7	5.0	0.6
1963	19.4	73.4	6.7	0.5
1964	21.0	71.1	7.5	0.4
1965	21.5	69.5	8.6	0.4
1966	25.3	66.1	8.0	0.6
1967	28.1	66.4	4.4	1.1
1968	28.8	63.5	4.6	1.1
1969	28.6	64.5	5.9	1.0
1970	30.3	62.7	6.1	0.9

1.5. Interest in nuclear power

The Public Power Corporation (PPC) and the Government made plans in 1968 to integrate a 450 MWe SGHWR nuclear unit into the electric supply system. This plan however was not implemented. Subsequently, PPC decided, with the agreement of the Government, to utilize all local energy resources before embarking on a nuclear power program.

A study of the introduction of nuclear power into the integrated Greek power supply system was prepared for the 1971 Geneva Conference (A/CONF.49/P/270) jointly by staff members of PPC and the Greek Atomic Energy Commission (GAEC). It reached the preliminary conclusion that the first nuclear plant should be a 600 MWe unit to be commissioned early in the 1980's. This study has been used as the starting point for further nuclear planning of which an outline has been published in the Greek and foreign press.

PPC has, as of 1 January 1971, established a Nuclear Power Stations Service within its organization. It has called for tenders from consulting firms to assist PPC on all aspects of issuing and evaluating bids from manufacturers of nuclear power stations up to the signing of the contract.

The performance of, and operating experience with, the various types of nuclear plant are being evaluated in order to determine the type or types most appropriate for consideration by PPC.

2. NATIONAL ENERGY RESOURCES

2.1. Hydroelectric potential

(a) Description of potential or undeveloped sites

At present PPC has 1400 MW of hydro capacity in operation or scheduled for construction and planned to be on line between 1972 and 1977. As a next stage, four stations are being designed for operation during the period 1978 to 1982. They are listed in Table II-1. About 19 projects are being investigated for operation beyond 1982. Their probable output and estimated capacity are listed in Table II-2. A summary of the present and future hydro potential as planned by PPC is given in Table II-3. The location of these sites is shown in Fig. 2-1.

TABLE II-1. HYDRO PROJECTS UNDER DESIGN FOR OPERATION 1978-1982

Project	River	Region	Capacity (MW)	Energy (GWh/yr)	Distance to load centre (km)
Pournari	Arachtos	W. Sterea	300	471	300
St. George	Acheloos	W. Sterea	360	546	300
Avlaki	Acheloos	W. Sterea	170	523	300
Sykia	Acheloos	W. Sterea	160	283	300
Total under design			990	1823	300[a]

[a] Average.

TABLE II-2. HYDRO PROJECTS UNDER INVESTIGATION FOR OPERATION 1983-2000

Project	River	Region	Capacity (MW)	Energy (GWh/yr)	Distance to load centre (km)
St. George[a]	Acheloos	W. Sterea	240	-	300
Stikia	Aliakmon	W. Macedonia	300	302	400
Assomata	Aliakmon	W. Macedonia	67	198	400
Thissavros	Nestos	W. Thrace	400	593	600
Platanovrissi	Nestos	W. Thrace	240	340	600
Temenos	Nestos	W. Thrace	48	110	600
Stratos	Acheloos	W. Sterea	170	426	300
Pigae	Aoos	Epirus	210	184	400
Famila	Evinos	W. Sterea	720	681	300
Steno-Kalaritico	Arachtos	W. Sterea	720	946	300
Palialona	Aliakmon	W. Macedonia	220	315	400
Glafkos	Glafkos	Peloponnese	100	114	200
St. Nicolas Pistiana	Arachtos	W. Sterea	280	345	300
Kalamas Project	Kalamas	Epirus	350	702	400
Rest of Aliakmon	Aliakmon	W. Macedonia	100	300	400
Rest of Aoos	Aoos	Epirus	600	800	400
E. Acheloos	Acheloos	W. Sterea	650	1450	300
Rest of Evinos	Evinos	W. Sterea	125	150	300
Messochora	Acheloos	W. Sterea	240	263	300
Total under investigation			5780	8219	380[b]

[a] Pumped storage.
[b] Average.

TABLE II-3. SUMMARY OF PRESENT AND PLANNED HYDRO POWER

By periods			Cumulative		
Period operating	Capacity (MW)	Output (GWh/yr)	Year operating	Total capacity (MW)	Output (GWh/yr)
to 1972	1040	3060	1972	1040	3060
1972-1977	360	584	1977	1400	3644
1978-1982	990	1823	1982	2390	5467
1983-2000	5780	8219	after 1982	8170	13686

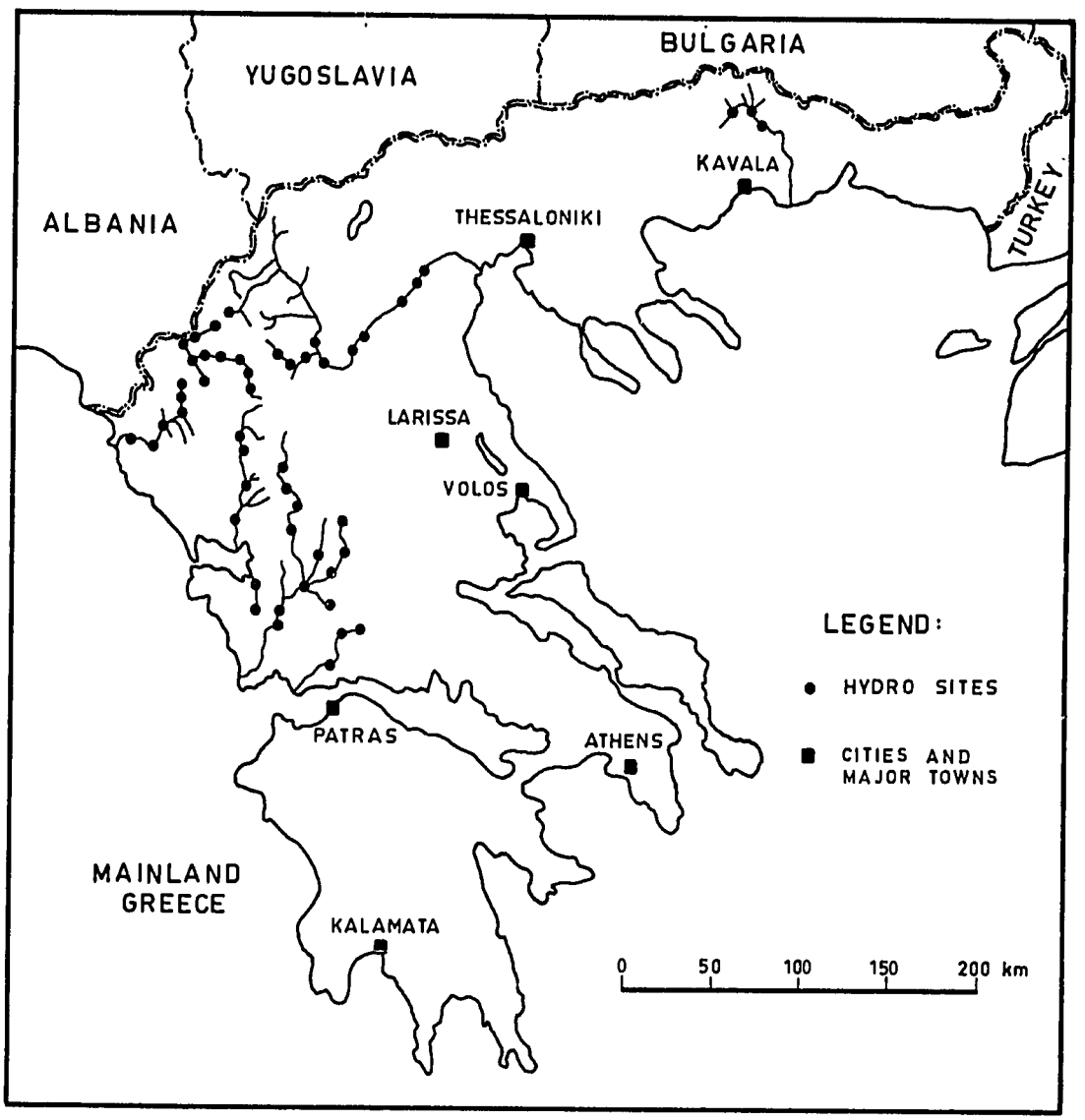


FIG. 2-1. LOCATION OF POTENTIAL HYDRO SITES CONSIDERED BY PPC.

This program covers only some of the regions with hydro possibilities, mainly in the west and north of the Greek mainland. Possible sites on the Peloponnese for example are not included.

The total theoretical gross energy potential was estimated from rainfall and runoff figures by A.D. Therianos, published in Water Power, February 1967. An extract from this paper is given in Table II-4 along with PPC's plans for hydro power expansion.

TABLE II-4. HYDRO POTENTIAL (GWh/yr)

	According to A.D. Therianos (Water Power, Feb.1967)				According to PPC (1972)				
	Gross potential (theoretical)	Known potential	Technically exploitable	Economically exploitable	Operating	Under construction	Under design	Under investigation	Total
1. W. Peloponnese	7 210	460	1 670	1 260	300	-	-	-	300
2. E. Peloponnese	4 300	32	570	417	-	-	-	-	-
3. N. Peloponnese	4 290	326	755	557	-	-	-	-	-
4. W. Sterea	14 880	3 860	5 500	4 200	2 670	1 823	1 712	2 620	8 825
5. Cen. Sterea	3 960	119	470	336	-	-	-	-	-
6. E. Sterea	282	21	7	3	-	-	-	-	-
7. Epirus	15 642	722	6 250	4 830	-	-	-	1 700	1 700
8. Thessaly	6 010	567	665	469	-	-	-	-	-
9. W. Macedonia	10 444	1 967	2 240	1 670	70	610	500	810	1 990
10. Cen. Macedonia	2 800	-	185	123	-	-	-	-	-
11. E. Macedonia	2 270	102	175	118	-	-	-	-	-
12. Thrace	6 212	691	1 470	1 100	-	-	1 003	-	1 003
13. Cen. Macedonia	571	4	19	10	-	-	-	-	-
14. Crete, Euboea and others	5 730	91	691	501	20	-	-	-	20
Total	84 601	8 962	20 667	15 594	3 060	2 433	3 215	5 130	13 838

For Greece as a whole, Therianos finds the following hydro possibilities:

Gross potential (theoretical)	84 601 GWh/yr
Known potential (in 1967)	8 962 GWh/yr
Technically exploitable	20 667 GWh/yr
Economically exploitable	15 594 GWh/yr

It would appear that in present day conditions, a greater proportion of the gross potential could become economically attractive. Table II-4 shows that in West Sterea, the total of 8825 GWh/yr according to PPC is more than twice the 4200 GWh/yr which is considered economically exploitable by Therianos. In West Macedonia, the potential of 1990 GWh/yr according to PPC is greater than the 1670 GWh/yr found to be economically exploitable by Therianos. Other river basins have not yet been considered at all in PPC investigations. Thus both the 13 838 GWh/yr total in existence or under consideration by PPC and the 15 594 GWh/yr considered economically exploitable by Therianos appear significantly to underestimate the technically exploitable hydroelectric potential.

(b) Distance from load centres

At present, Athens is the main consumer of electric power in Greece. In the future there will be an increasing demand in the Thessaloniki area and maybe also in the Larissa and Volos areas (see Fig. 2-1).

In the next decade the majority of the hydroelectric power will be produced in the western and northern mountain ridges of the mainland.

Distances from Athens to the hydro sites planned by PPC are listed in Tables II-1 and II-2. They range from 300 to 600 km and average about 365 km. This distance can be considered as the average transmission length for hydro power along the existing 150 kV and planned 400 kV transmission lines.

(c) Energy and capacity potential of future hydro sites

From Table II-3 it can be seen that the total energy potential of stations in existence, under construction or being considered by PPC is some 14 000 GWh and the corresponding potential capacity is some 8000 MW.

With such conditions the planned hydroelectric development is likely to be affected by the capacity balance of the system. More and more peaking capacity will be allocated to

TABLE II-5. OUTPUT DATA FOR HYDRO STATIONS OPERATING OR UNDER CONSTRUCTION

Station name and initial start-up	Kremasta 1966	Kastraki 1969	Kardamakis 1975	Poumari Future	St. George Future	Sykia Future	Avlaki Future	Total
Annual flow (m^3/sec)	160	196	65	85.4	47.5	67.0	72.2	
Storage (individual) (10^6 m^3)	4 270	50	1 939	350	580	6	670	
Regulation degree (%)	112	90	94		39	28	55	
Installed capacity (MW)	437	320	360	300	360	160	170	2 107
Firm capacity (MW)	235	306	300	300	360	160	170	1 831
Yearly output (GWh/yr)	1 430	705 + 225 [a]	584	471	546	283	523	4 542
Operation at inst. cap. (h)	3 280	2 200	1 620	1 600	1 500	1 800	3080	2 150

[a] Secondary power.

hydroelectric units whilst thermal (including nuclear) will take the base load. This leads to a declining utilisation time of the planned hydro capacity as follows:

in 1972	2990 hours continuous
in 1978	2400 hours continuous
in 1982	1950 hours continuous
after 1982	1760 hours continuous or less

(d) Costs of future hydro development

No cost data were obtained for the future hydro power projects under design or consideration by PPC. However, production, calculated benefits and annual costs for two major existing stations, Kremasta and Kastraki, as well as for five future projects are tabulated in Table II-5.

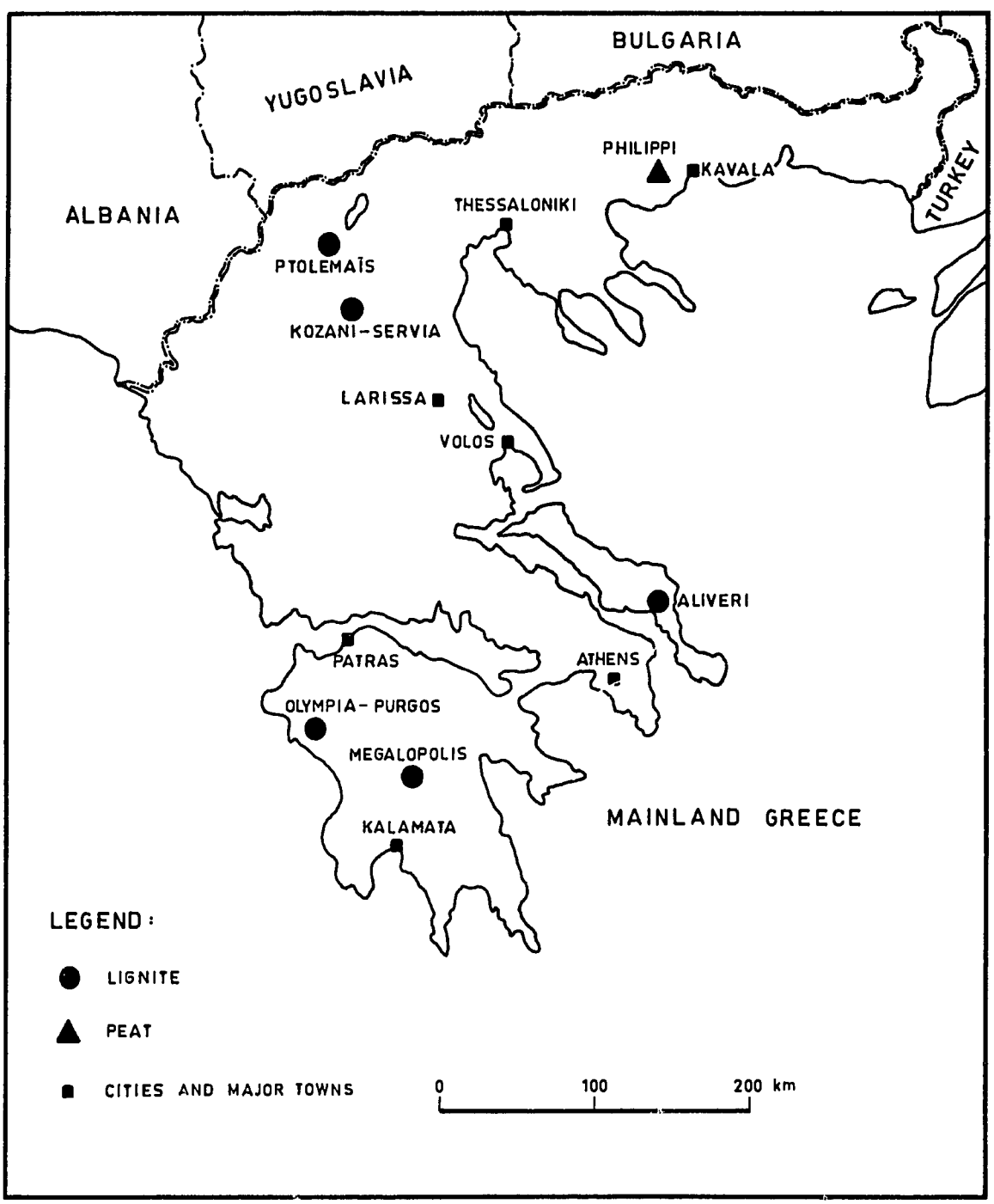


FIG. 2-2. LOCATION OF LIGNITE AND PEAT DEPOSITS.

2.2. Coal and lignite

(a) Amounts and location of reserves

There are no known coal deposits in Greece. However, there are two reasonably large lignite deposits in Megalopolis and Ptolemaïs respectively.

In addition there are old and small deposits in Aliveri as well as unexploited resources in the Kozani-Servia and Olympia-Purgos areas. The locations of these deposits are shown in Fig. 2-2. The estimated reserves at each site and the fuel characteristics are listed in Table II-6(a). It should be noted that at Aliveri the reserves of 3 million tons quoted are found at depths down to 150 m below sea level.

Besides those named above there are numerous other lignite deposits which are listed in Table II-6(b). They have mostly been ceded to private producers and are, in the main, small. They have, however, not been fully explored.

(b) Transportation facilities

Because of the high moisture and ash content, the production of electricity in lignite-fuelled power plants is most economically carried out in mine-mouth power plants. In such conditions the availability of transport becomes relatively unimportant.

TABLE II-6(a). MAJOR LIGNITE RESOURCES

Location	Resources (10^6 t)	Average moisture (%)	Average ash (%)	Average calorific value (kcal/kg)
Megalopolis	360	55	20	1040
Ptolemaïs	960	58	10	1300
Aliveri	3	31	22	2650
Kozani-Servia	120	-	-	2500
Olympia-Purgos	-	-	-	2500

TABLE II-6(b). OTHER KNOWN LIGNITE DEPOSITS

Peloponnese

(1) Palaiokhorion - Kalavryta
(2) Trypes - Elia

Mainland Greece

(1) Kalogreza - Attica
(2) Rafina - Attica
(3) Milesi - Attica
(4) Perivoli - Attica
(5) Anetope - Attica
(6) Mavrosouvala - Attica
(7) Katoune - Xeromeron
(8) Myloi - Phthiotis
(9) Zeli - Atalante

Thessaly

(1) Elasson - Larissa

Western Macedonia

(1) Amyndaion - Florina
(2) Veve - Florina
(3) Akhladha - Florina
(4) Katerini - Pieria

Eastern Macedonia

(1) Serrai
(2) Pangeon - Serrai
(3) Dhipotamos - Drama

Thrace

(1) Aemonion - Xanthi
(2) Iana - Evros
(3) Dhilophon - Evros
(4) Karydhia - Rodhope

Islands

(1) Kymi - Euboea
(2) Dhirphys - Euboea
(3) Apolakkia - Rhodes
(4) Kandanos - Crete

(c) Production capacity

The production of lignite at Megalopolis is carried out by open-pit mining with modern equipment of wheel excavators and rubber belt conveyors for removing the overburden and lignite seam. The thickness of the lignite is 10-20 m and there are 0.6 m^3 of overburden to each metric ton of deposit. The yearly product.on is now 4 million tons but from 1975 onwards it is expected to rise to 9 million tons.

Because of the difficulties experienced with burning this low calorific value fuel when the load is half or less of capacity a new technique has been adopted:

Crushed lignite of lower calorific value (LCV) 960 kcal/kg, 60% water content and of particle size 0 to 30 mm, together with hot gases, enters a mill where the lignite is dried and pulverized. 45% of the output of the mill, containing 65% pulverized lignite of 30% moisture content and LCV 1250 kcal/kg, is taken directly to the furnace. The remaining 55% which contains 35% pulverized lignite is taken to mechanical and electrostatic precipitators. The lignite recovered, which contains 15% moisture and has a LCV of 2500 kcal/kg, is blown by air to secondary burners in order to stabilize the flame conditions. The rest of the mixture is discharged to atmosphere.

At Ptolemaïs open-pit mining with wheel excavators and rubber belt conveyors is also used. The lignite is 20-35 m thick and there are 2.6 m^3 of overburden to each metric ton of deposit.

The annual production was 6 million tons in 1971 and is expected to rise to 26.3 million tons from 1982 onwards.

The deposits of lignite at Aliveri are in underground mines with difficult working conditions. Recovery is by the caving system with the use of explosives. The annual production is only 600 thousand tons. Because of high mining costs (US $13/t) this mine is not economic and will be shut down in four years.

The deposits of lignite in the Kozani-Servia area are similar to those at Aliveri in that the seam thickness is 10 m with an overburden of nearly 300 m. Some small underground mines are in operation. For the production of electrical power this basin would seem not to be economic because only underground exploitation is possible. In spite of this, the extent of the deposits will be explored.

In the basin at Olympia-Purgos the lignite seam is 1.5 m thick but lies only 3.5 m below the surface with an incline of 10°. Small mines are or have been in operation. The calorific value is given as 2500 kcal/kg. Other figures are not available. The area is rather extended between Olympia and the coast. The basin is under exploration and it seems that strip mining (such as is used in the USA) may be possible in the future.

(d) Current and projected costs

Lignite costs at Megalopolis amount to 43 Dr./t (US $1.43/t) made up as follows:

Wages	10 Dr./t
Depreciation + interest	27 Dr./t
Other costs	6 Dr./t
Total	43 Dr./t

This corresponds to an energy cost of 41.3 Dr./10^6 kcal (34.7 US¢/10^6 Btu), based on a calorific value of 1040 kcal/kg. Lignite costs at Ptolemaïs amount to 58 Dr./t(US $1.94/t). Because of the higher heating value of this lignite (1300 kcal/kg), the energy cost is only 44.5 Dr./10^6 kcal (37.5 US¢/10^6 Btu).

(e) The use of lignite for power production

The installed capacity of lignite-fuelled power plants in 1972 was 250 MW at Megalopolis, 320 MW at Ptolemaïs and 200 MW at Aliveri. 300 MW of new lignite-fuelled capacity are under construction at Megalopolis and there are plans to add an additional 1800 MW of lignite-fuelled capacity at Ptolemaïs by 1981. The total lignite-fuelled capacity at that time, therefore, will be 2670 MW. It is estimated that known deposits are sufficient to supply this capacity for about 30 years.

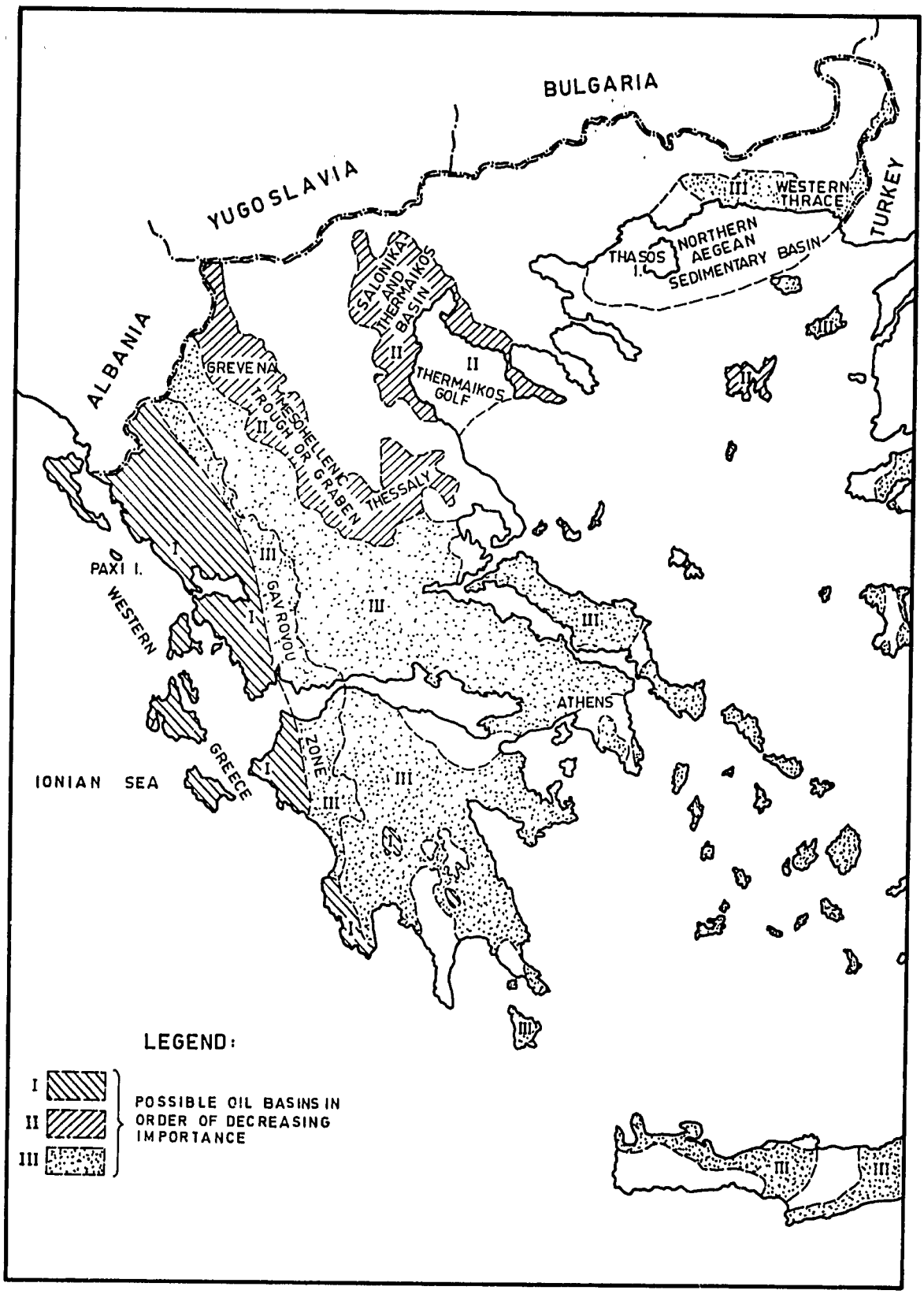


FIG. 2-3. POSSIBLE OIL BASINS IN GREECE.

(f) Other solid fuel resources

In addition to lignite resources, there is a peat deposit near Philippi as shown in Fig. 2-2. The deposit is not yet opened, but has been investigated. The peat is without overburden, the upper layer is 60 m deep and the amount is estimated to be $2 \times 10^9 m^3$. The analysis is:

Humidity	85%
Moisture in air-dried material	35%
Ash	19%
Calorific value	2000 kcal/kg

Burning tests will be made.

The installation of a peat-fuelled plant is being considered (see Section 3.7 and Table V-3).

2.3. Oil and natural gas

In connection with the preparation of the second Economic Development Plan for 1973 - 77, a subcommittee on energy supply was established. Its report was near completion in August 1972, but was not available and it was not clear whether it could be made available or would be published. It seems to contain factual information and considerations of great relevance to this section.

(a) Amount and location of reserves

Occurrences of crude oil and natural gas have been located. No usable reserves are known. Possible oil basins are shown in Fig. 2-3.

(b) Pipelines

No pipelines exist and none are planned.

(c) Consumption of crude oil and fuel oil

Consumption of crude oil is completely based on and equals imports. It is shown in Table II-7, which also shows production, import, export and consumption of fuel oil.

TABLE II-7. CONSUMPTION OF CRUDE OIL AND FUEL OIL (10^6 t)

Year	Crude oil consumption	Fuel oil				
		Domestic production	Imports	Exports	Shipping	Domestic consumption
1960	1.66	1.33	0.61[a]	b	b	b
1961	1.60	1.29	0.76	b	0.66	1.39
1962	1.77	1.31	1.07	0.03	0.91	1.44
1963	1.84	1.31	1.41	0.02	1.05	1.65
1964	1.88	1.24	1.24	0.02	0.87	1.59
1965	1.83	1.30	2.01	b	0.95	2.35
1966	3.11	2.12	1.30	0.05	0.87	2.50
1967	3.99	2.79	1.05	0.12	0.94	2.78
1968	4.35	3.10	0.98	0.07	0.63	3.38
1969	4.60	3.15	1.26	0.12	0.60	3.68

[a] Net import.
[b] Not available.

TABLE II-8. OIL REFINERIES

Name	Location	Capacity (mid 1972)	
		10^6 t/yr	bbl/day
Aspropyrgos	Near Athens	1.9	380 000
Eleusis	Near Athens	1.0	200 000
Salonika (Esso Pappas)	Salonika	3.2	640 000
St. Theodore	Near Corinth	1.2	240 000
Total capacity		7.3	1460 000

(d) Refinery capacity

There are four refineries, shown in Table II-8 with capacities. The Aspropyrgos refinery is being enlarged and will have a capacity of 4.5 million tons (900 thousand bbl/day) and 6 million tons (1.2 million bbl/day) by the end of 1972 and 1976 respectively. In addition, it was decided in mid-1972 to build a new large refinery at Megara, west of Athens.

(e) Distribution of refinery production

Information on the distribution of refinery production as fuel oil and lighter petroleum products was not available.

(f) Projected imports of crude and fuel oil

Forecasts for the future total import of crude and fuel oil were not made available. However, in respect of fuel import for oil-fired power stations, it should be noted that PPC is not planning to install further oil-fired units. Furthermore it is expected that after 1980 both the capacity and operating hours of oil-fired units will be gradually reduced and that, by 2000, they will no longer be operated during periods with average hydraulic conditions. By that date PPC expect that a capacity of 700 MW will be kept as a cold reserve for operation when hydro power is inadequate. In consequence consumption of fuel oil for power stations is expected to increase only moderately up to 1980 and, thereafter, to decrease gradually.

(g) Current and projected cost of imported oil

The government-controlled fuel oil prices ex-refinery paid by PPC have remained unchanged over recent years until the end of 1971 in spite of increases in import prices of crude oil. Details of these prices were not available. Until the end of 1971, PPC was exempt from almost all taxes and duties on fuel oil. This exemption was removed with effect from the beginning of 1972 and the cost to PPC of fuel oil, ex-refinery, was then 781.2 Dr./t made up as follows:

Heavy oil 3 500"R	Dr./t.
Price ex-refinery	448.40
Stamp tax	8.96
Custom charges	1.50
Insurance	1.60
Port charges	1.60
Custom duties, consumption tax and other charges	319.14
Total	781.20

In addition, transportation charges from the refineries to the oil-fired power stations at St. George's Bay were:

From the Aspropyrgos refinery	10.00 Dr./t
From the Salonika refinery	20.00 Dr./t.

PPC does not normally import fuel oil directly but obtains it from Greek refineries at government-controlled prices. Therefore, PPC cannot define the relationship between international prices and the prices which it has to pay (refer also to 7.4 below).

(h) Exploration activities

Information supplied by the Institute for Subsoil Research indicates that limited mineral hydrocarbon explorations have been conducted in Greece since 1930. These have been extended and intensified since 1960, when potential oil bearing areas were located and relevant exploration objectives for each one of them were determined. However, possible oil and gas basins will be small, scattered, and at great depth. Any oil found is therefore likely to be expensive. The following areas shown in Fig. 2-3 have been investigated:

Western Greece (Zigos Gavrovou, Ionian Sea and Paxi Island Zone). More than 12 drillings have been made at varying depths down to 4000 m and below. No commercial quantities have been found. In the Aetolikon area, at 3400 m depth, a non-commercial quantity of oil of good quality was discovered. This drilling was advanced down to approximately 4500 m without further indications of oil. On Peloponnese nothing was found apart from a small quantity of natural gas.

Central Greece – Mesohellenic Ditch (Grevena – Thessaly Basin). This basin, a small area at Neapolis, and the Thessaly area have been investigated but nothing was found. In addition, it has been proved that natural gas jetting from the ground at various parts of the Thessaly Plains is contained in small pockets of limited importance.

Thessaloniki – North Aegean Sea – Western Thrace Basin. A total of 8 drillings of great and small depth have been carried out on-shore in the Thessaloniki Basin, but they yielded no results. Furthermore, two off-shore borings were carried out in the Thermaikos Gulf without results. In the Thasos area in the east, a borehole penetrated recently into a heavy oil deposit, which cannot be exploited as pumping of the oil is not feasible. On-shore drilling operations in the Western Thrace region account for ten borings, of which two boreholes in the Tavris area struck oil. However, the deposits found were not commercially exploitable.

Dodecanese area (Rhodes Island). Two borings in the area yielded no results. Further off-shore oil exploration operations are being conducted and their results are anticipated with great interest in view of the rising oil prices.

2.4. Uranium ores

No uranium deposits of economic importance have been found in Greece so far. Since there is an active interest in becoming independent of the uranium imports which would be necessary to support the nuclear power program, substantial prospecting activities are under way. The objective of this project, which is supported by UNDP special funds, is to locate and define areas with uranium potential. Various exploration methods are used, such as geology, geophysics and geochemistry.

As a result of the work to date using car-borne alpha scintillometry, numerous anomalies have been found in Central and Eastern Macedonia and Thrace. It is probable that there are substantial uranium deposits in these promising areas. To establish this as a fact, a great amount of detailed investigation will be required. This will involve ground radiometric surveys and different kinds of sampling (stream sediments, water, bed-rock, etc.). It is unlikely that all of this can be done within the planned budget; therefore, supplementary funds will be required.

Because the work to date has been in the nature of a reconnaissance, it is not clear whether there are important uranium ore deposits or only scattered occurrences. Such results will not be available until about 1973-75. It seems probable, however, that deposits will be found which can be exploited economically.

3. ELECTRICITY SUPPLY SYSTEM

3.1. Past history and development of industry up to the present

The Public Power Corporation (PPC) is a state-owned enterprise working according to the rules of private business practice, with the exception that rate changes, loans and investments must be approved by the Ministry of National Economy. The Corporation was established by law in 1951 with responsibility for the production and transmission of electricity throughout the country. In 1957 it was also entrusted with the distribution of electricity, to which end it acquired, between 1957 and 1961, the 400 previously existing utilities.

3.2. Present organization structure

The Corporation is governed by a Board of Directors which reports to the Representative Assembly. The Ministry of National Economy supervises the activities of the PPC on behalf of the Government.

The Corporation is requi. .d to secure its own sources of finance. The earned surplus is re-invested for construction of power plants, networks and related installations. The organization of PPC is shown in Fig. 3-1. The total staff of PPC is about 20 000.

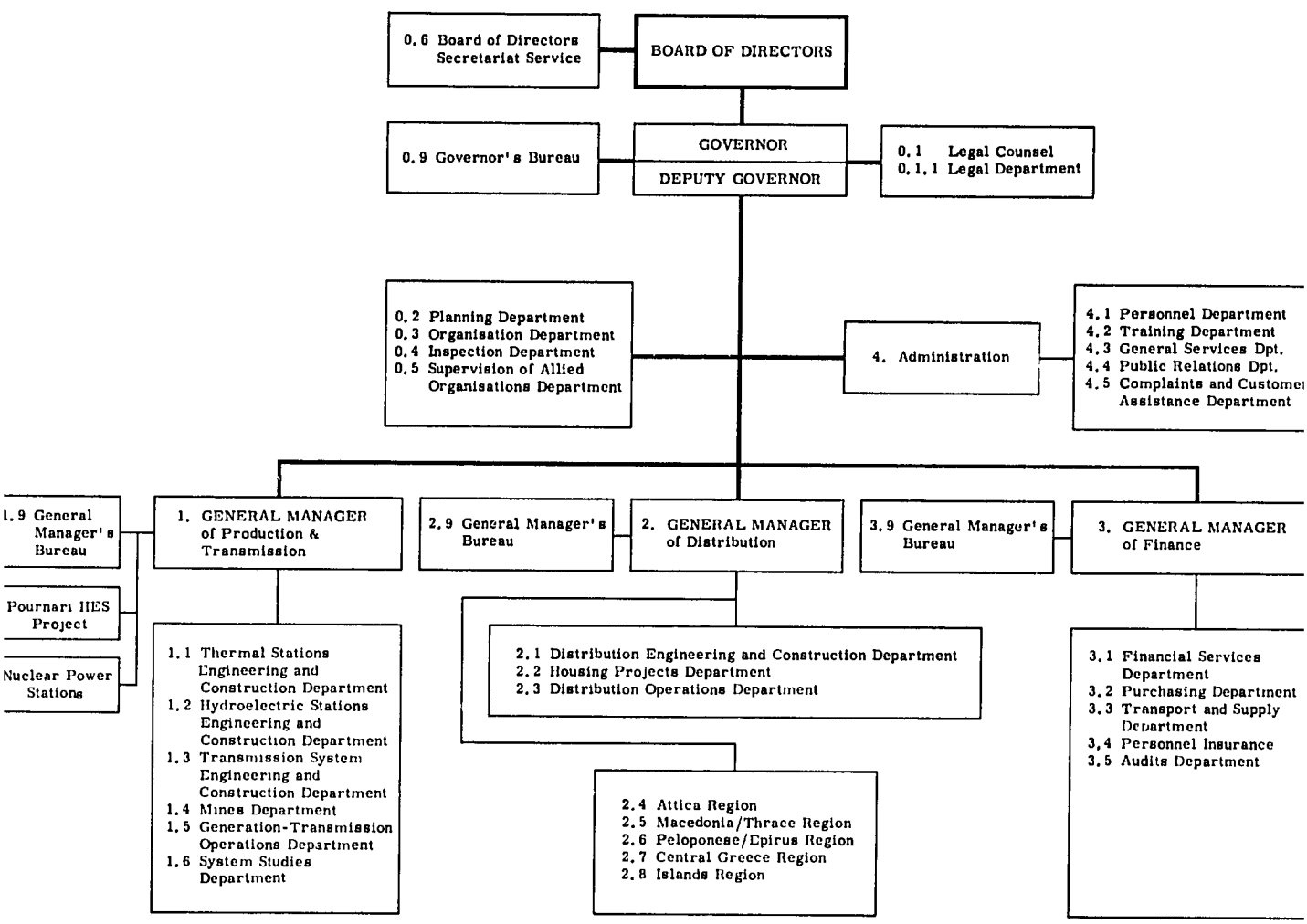


FIG. 3-1. PUBLIC POWER CORPORATION ORGANIZATION CHART (SEPTEMBER 1972).

3.3. Geographic areas of responsibility

PPC is responsible for the generation, transmission and distribution of electricity all over Greece. For the purpose of administrative control, the country is divided into five regions (Attica, Macedonia/Thrace, Peloponnese/Epirus, Central and Islands), each with a regional manager.

3.4. Generation and transmission facilities

(a) Location and rating

Table III-1 gives a list of the generating units in existence in 1972 together with their characteristics. The total installed net capacity in March 1972 amounted to about 2600 MW.

(b) Voltage and routing of transmission lines

The location of the generating stations and the 150 kV transmission system are shown in Fig. 3-2, including the present 76 km interconnection with Yugoslavia rated for 100 MVA interchange by the end of 1972.

TABLE III-1. GENERATING PLANTS IN MARCH 1972

Power station	Unit No.	Fuel	Year commissioned	Installed capacity (MW)		Energy generated in 1971 (GWh)
				Gross	Net	
Thermal						
St. George's Bay	2	Oil	1929	15	14	-
St. George's Bay	3	Oil	1929	15	14	-
St. George's Bay	6	Oil	1956	60	57.5	619
St. George's Bay	7	Oil	1965	60	57.5	
St. George's Bay	8	Oil	1968	160	155	851
St. George's Bay	9	Oil	1971	200	190	406
Aliveri	1	Lignite	1953	40	38	190
Aliveri	2	Lignite	1953	40	38	158
Aliveri	3	L + Oil	1968	150	144	974
Aliveri	4	Oil	1969	150	145	989
Lavrion	1	Oil	1972	150	145	-
Megalopolis	1	Lignite	1970	125	113	1583
Megalopolis	2	Lignite	1970	125	113	
Ptolemaïs	1	Lignite	1959	70	65	540
Ptolemaïs	2	Lignite	1962	125	117	964
Ptolemaïs	3	Lignite	1965	125	117	889
Markupoulon	1	Gas turbine	1964	12.5	12.5	-
Markupoulon	2	Gas turbine	1964	12.5	12.5	-
		Total thermal stations		1635	1548	8163
Hydro						
Agras	1, 2		1954	50	50	32
Edhesseos	1		1969	19	19	22
Kastraki	1, 2, 3, 4		1969	320	320	832
Kremasta	1, 2, 3, 4		1966	437	437	1191
Ladhou	1, 2, 3		1955	70	70	288
Louros	1, 2, 3		1954	10.3	8.6	57
Tavropos	1, 2, 3		1960	130	130	212
Verria	1, 2, 3		1929	1.8	1.8	9
Patrae	1		1927	1.6	1.6	8
		Total hydro stations		1040	1038	2651
		Total installed capacity		2675	2586	10814

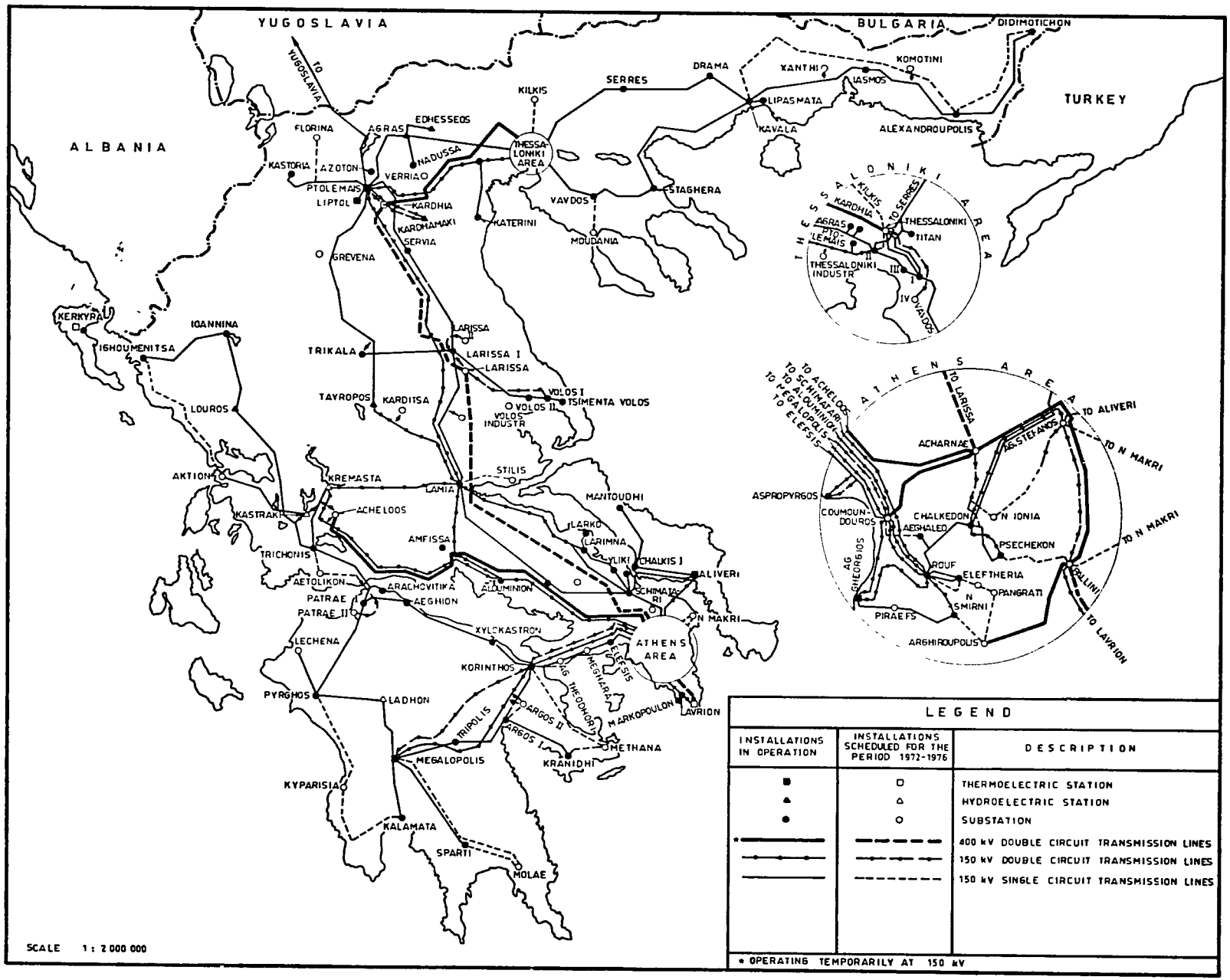


FIG. 3-2. GREEK ELECTRIC POWER SYSTEM 1971 (TRANSMISSION SCHEDULED 1972-1976).

This figure also shows the location of new stations and the 150 kV/400 kV transmission facilities scheduled for construction in the period 1972 to 1976.

Figure 3-3 shows the projected 400 kV transmission system up to 1980 and, tentatively, beyond that date. Each 400 kV line will be of double circuit construction with 2 × 954 MCM conductors per phase giving a per-circuit thermal rating of 1400 MVA for a planned per-circuit normal loading of up to 700/800 MVA. It is intended that a 2000 MVA (3 × 600 MW) generating station would be connected to the grid by two such double circuit lines.

Figure 3-4 shows a single line diagram of the main 400 kV system at a stage which has been taken to correspond to early in the 1980's and which remains virtually unchanged for more than another decade.

(c) Construction costs for thermal stations

Table III-2 gives typical installation costs of some recent stations. Detail figures for Lavrion I and II are given in Table III-3.

(d) Costs of recent transmission lines

Table III-4 gives installation costs of recent transmission lines.

3.5. System reserve capacities

Past and future system reserve capacities are based on the following criteria:

(i) A reserve margin to cover whichever is greater, the largest unit or 11% of the peak demand. Studies of reliability proved that if this margin were increased to 22%, the reliability index for 1975 would be one shortage in 214 years – an excessively conservative value.

(ii) A further allowance of 3% to 6% is made to allow for uncertainties in the forecast of demand.

(iii) The capacities of hydro plants are taken for critical hydrological conditions.

The general practice is to schedule spinning reserve equivalent to the output of the largest set operating. The greater part of this reserve is normally allocated to the hydro stations; notably to Kremasta (4 × 109 MW) or to Kastraki (4 × 80 MW) where, for example, load can be increased from 30% to 100 % of unit rating in about 10 sec. The availability of a computer-controlled load despatch centre, at the end of 1975, will further facilitate the load-frequency regulation of the system.

It is a normal requirement that full load must be met in the event of the loss of the most heavily loaded double circuit transmission line.

In the event of the loss of generation or transmission capacity beyond the level of the above defined first-order contingencies, selected loads of lesser importance are disconnected by means of under-frequency relays. The settings of these relays and the stages of load shed as a percentage of the 1971 system peak load are shown in Table III-5.

Table III-6 shows the results of a series of load rejection tests carried out in 1971 at various system load levels and indicates the relationship between change of load and the long-term change of frequency.

This is only a small part of the overall load-frequency regulation effect. The long-term change in frequency is a balance between the setting of the primary and secondary regulation and the loss of that portion of the system load which is frequency dependent (and which varies throughout the day). This data was used by PPC in assessing the validity of the model studies carried out to determine the response of system frequency to loss of generation for various system and generation configurations.

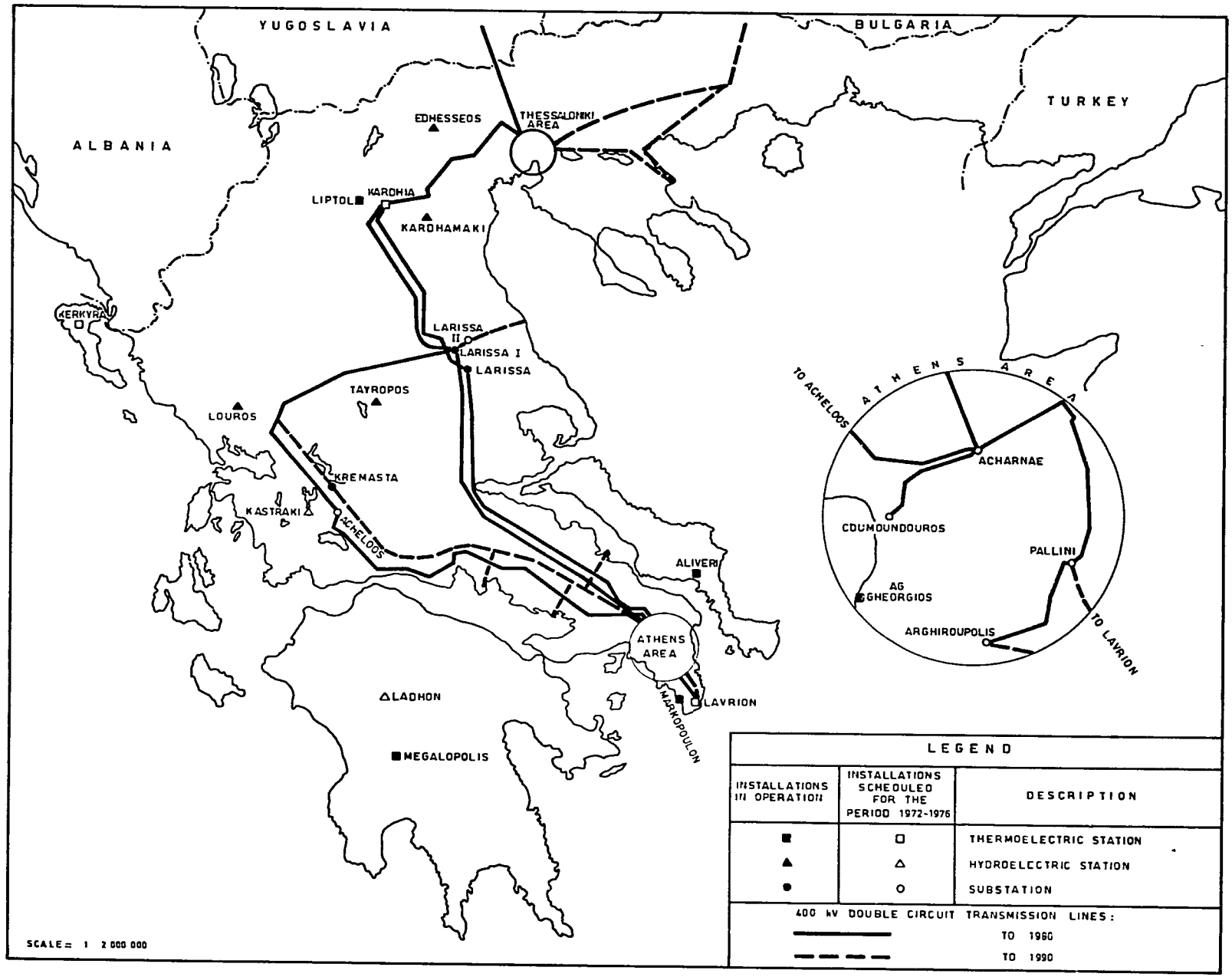


FIG. 3-3. GREEK ELECTRIC POWER SYSTEM. PROJECTED 400 kV DEVELOPMENT.

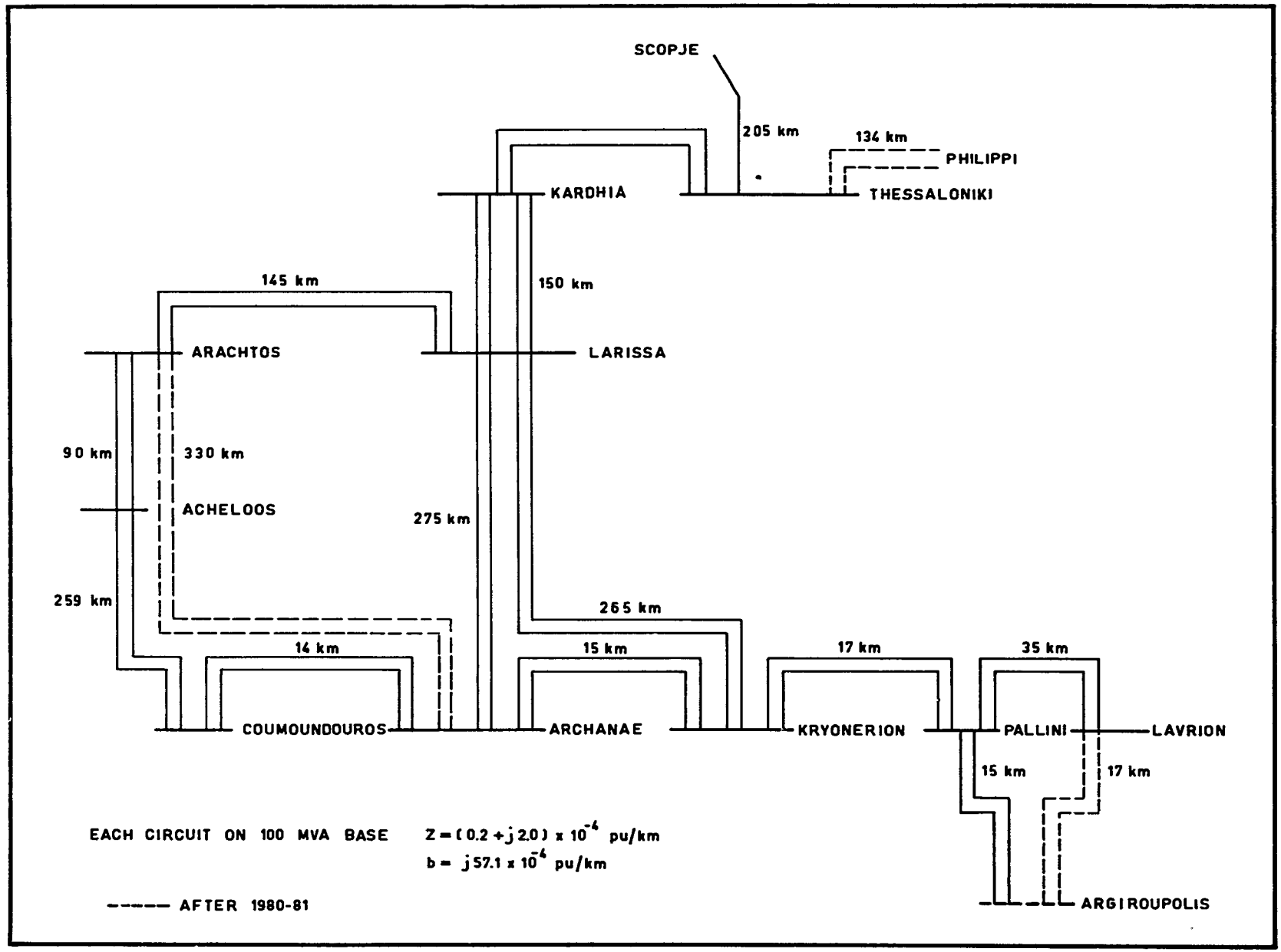


FIG. 3-4. ONE-LINE DIAGRAM OF MAIN 400 kV SYSTEM 1980/90.

TABLE III-2. COSTS OF RECENT GENERATING PLANTS

Power station	Unit No.	Capacity (MW)	Date of operation	Gross energy generated in 1971 (GWh)	Installation cost (US $ 10^6)	US$/kW
Thermal						
Aliveri	3	150	Jan. 1968	974	26.7	177
Aliveri	4	150	Dec. 1970	989	14.4	96
Ptolemaïs	1	70	Oct. 1959	540	18.1	258
Ptolemaïs	2	125	Nov. 1962	964	23.5	188
Ptolemaïs	3	125	Sept. 1965	889	23.1	185
Megalopolis	1, 2	2 x 125	Aug./Oct. 1970	1583	69.8	278
St. George's Bay	8	160	1968	851	16.8	105
St. George's Bay	9	200	Jul. 1971	406	23.1	115
Hydro						
Kremasta	1, 2, 3, 4	437	1966/67	1191	85.0	194
Kastraki	1, 2, 3, 4	320	1969	832	67.0	210
Tavropos	1, 2, 3	130	1960/62	212	38.0	293
Ladhou	1, 2, 3	70	1955	288	22.6	324
Agras	1, 2	50	1954	32	25.7	515
Louros	1, 2, 3	10	1954/64	57	5.0	500

TABLE III-3. COST BREAKDOWN FOR LAVRION I AND LAVRION II OIL-FIRED POWER PLANTS

	Lavrion I			Lavrion II		
General Information						
1. Installed capacity (MW)	150			300		
2. Net capacity (MW)	142			285		
3. Annual generation (GWh)	994			2000		
4. Date of commissioning	May 1972			March 1973		
	Foreign exchange	Local	Total	Foreign exchange	Local	Total
Direct cost, in 10^6 Dr.						
Site and property rights	-	26.6	26.6	-	-	-
Building improvements	-	201.7	201.7	-	94.0	94.0
Electromechanical equipment	358.2	60.0	418.2	646.2	118.7	764.9
Temporary works and job-site equipment		13.5	13.5	-	5.0	5.0
General contractor services	11.4	2.6	14.0	10.2	14.8	25.0
Turnover tax [a] + other expend.		27.8	27.8	-	51.7	51.7
Total	369.6	332.2	701.8	656.4	284.2	940.6
Indirect cost, in 10^6 Dr.						
Preliminary studies and research	-	3.7	3.7	-	0.5	0.5
Construction supervision by PPC	-	6.0	6.0	-	6.0	6.0
Construction overhead at 3%	-	21.1	21.1	-	28.2	28.2
Administrative expend. at 3%	-	21.1	21.1	-	28.2	28.2
Interest during construction at 6%	-	56.0	56.0	-	64.0	64.0
Total		107.9	107.9		126.9	126.9
Grand total	369.6	440.1	809.7	656.4	411.1	1067.5
Unit costs, in Dr./kW net	2603	3099	5702	2304	1442	3746
in US$/kW net			190.1			124.9

[a] 8% on equipment paid for in foreign exchange.

TABLE III-4. COSTS OF RECENT TRANSMISSION LINES

Voltage (kV)	No. of circuits	ACSR conductors/phase	US $/km	
			Mid 1970	1972
66	1	1 x 336 MCM	11500	13700
150	1	1 x 336 MCM	13500	15800
150	1	1 x 636 MCM	17650	20700
150	2	1 x 636 MCM	23850	28100
400	2	2 x 954 MCM	58000	73400

TABLE III-5. LOAD SHEDDING ARRANGEMENTS (1971)

Frequency (Hz)	% of peak load shed	Time delay of relay (sec)
48.2	3.6	1
48.2	2.2	4
47.6	1.4	0
47.6	5.0	2
Total	12.2	-

TABLE III-6. CHANGE OF FREQUENCY WITH LOAD SHED (1971)

Load shed δ P (MW)	Total system load P (MW)	Change in frequency δ f (Hz)	Load-frequency characteristic $\frac{\delta f}{50} \Big/ \frac{\delta P}{P}$
120	1300	1.0	0.22
150	1353	1.6	0.29
120	1633	1.7	0.23
116	955	1.5	0.25
150	1587	1.4	0.30
148	876	1.7	0.20
288	1437	2.6	0.27
150	1469	1.2	0.24
125	1226	1.3	0.26
100	1564	1.1	0.34
160	1247	1.6	0.25
190	1276	2.2	0.30
380	1560	3.0	0.25
210	1566	1.8	0.27
150	1420	1.7	0.32
250	1173	3.0	0.28
170	1700	1.4	0.28
70	1742	0.7	0.35

3.6. Operating and maintenance costs of recent thermal station

Table III-7 gives the number of personnel by types for existing thermal and hydroelectric plants. Table III-8 gives the associated manpower costs and other operating costs (i.e. maintenance, supplies, etc.).

3.7. Electricity generation costs

Characteristics of power plants in the interconnected system of PPC are given in Table III-9. Total electricity generation costs and the breakdown of these costs for these

TABLE III-7. NUMBER OF PERSONNEL BY TYPES

Power station	Scientific personnel (engineers, chemists)	Technical personnel	Other personnel	Total
Thermal [a]				
Ptolemaïs	10	292	113	415
Aliveri	10	277	79	366
Megalopolis	9	198	114	321
Lavrion	9	176	76	261
St. George's Bay	10	279	147	436
Total	48	1222	529	1799
Hydro				
Kremasta	4	33	59	96
Kastraki	3	36	24	63
Tavropos	3	17	39	59
Ladhou	2	17	33	52
Agras	3	42	27	72
Louros	1	15	15	31
Total	16	160	197	373

[a] See Table III-1 for fuel type

TABLE III-8. OPERATING AND MAINTENANCE COSTS (1971) [a]

Power station	Dr./kWh			US mill/kWh Total
	Salaries	Other	Total	
Thermal				
St. George	0.0291	0.0162	0.0453	1.51
Aliveri	0.0132	0.0107	0.0239	0.80
Ptolemaïs	0.0129	0.0105	0.0234	0.78
Megalopolis	0.0154	0.0115	0.0269	0.89
Hydro				
Ladhou	0.0149	0.0101	0.0250	0.83
Louros	0.0688	0.0329	0.1017	3.29
Tavropos	0.0257	0.0064	0.0321	1.07
Kremasta	0.0046	0.0055	0.0101	0.34
Kastraki	0.0078	0.0042	0.0120	0.40
Gas turbines	1.44	0.25	1.69	5.65

[a] Excluding fuel, overhead expenses.

plants are shown in Table III-10. Generating costs in thermal stations range from 7.4 to 9.5 US mill/kWh while those for hydro stations range from 6.4 to 14.7 US mill/kWh. The high generating costs for the Louros hydro station arise from its small capacity, while those of the Tavropos station result from the very low load factor of 18.7%.

Table III-11 details the estimated costs for the Lavrion I and Lavrion II oil-fired stations. Unit costs for the 150 MW unit I are 7.13 US mill/kWh, whilst for the 300 MW unit II they are only 5.47 US mill/kWh.

According to a study made by the Soviet organization Energomachexport the energy cost of a peat-fuelled plant at Philippi (see Table V-3) would be 5.829 US mill/kWh.

TABLE III-9. CHARACTERISTICS OF POWER PLANTS IN INTERCONNECTED SYSTEM (PPC)

Power station	Fuel type	Station capacity (MW)	1971 output (GWh net)	Load factor (%)
Thermal				
St. George	Oil	510	1780	46.0
Aliveri	Lignite/oil	380	2194	68.6
Ptolemaïs	Lignite	320	2216	84.3
Megalopolis	Lignite	250	1411	68.0
Lavrion I, II[a]	Oil	450	-	-
Hydro				
Ladhou		70	287	47.6
Louros		10.3	56	75.2
Tavropos		130	212	18.7
Kremasta		437	1189	30.8
Kastraki		320	829	32
Gas turbines		25	1.9	0.6

[a] To be commissioned in March 1973.

TABLE III-10. NET GENERATING COSTS (1971)

Power station	Dr./kWh			Total	
	Fuel	Operating and maintenance	Investment and overhead	Dr./kWh	US mill/kWh
Thermal					
St. George	0.123	0.0453	0.1022	0.271	9.05
Aliveri	0.185	0.0239	0.0765	0.285	9.50
Ptolemaïs	0.124	0.0234	0.0880	0.235	7.85
Megalopolis	0.051	0.0269	0.1438	0.222	7.40
Hydro					
Ladhou		0.0250	0.1815	0.207	6.97
Louros		0.1017	0.2180	0.320	10.65
Tavropos		0.0321	0.406	0.438	14.65
Kremasta		0.0101	0.1815	0.192	6.43
Kastraki		0.0120	0.182	0.194	6.47
Gas turbines	0.408	1.690	5.280	7.378	245.5

TABLE III-11. ESTIMATED GENERATING COSTS FOR LAVRION I AND II

	Lavrion I			Lavrion II		
	Foreign exchange	Local	Total	Foreign exchange	Local	Total
Annual costs, in Dr. x 10^6						
Fixed charges [a]	32.5	38.6	71.1	57.6	35.9	93.5
Salaries [b]	-	28.8	28.8	-	10.8	10.8
Operating materials	6.0	2.0	8.0	9.0	3.0	12.0
Fuel costs [c]	105.0	-	105.0	211.2	-	211.2
Total	143.5	69.4	212.9	277.8	49.7	327.5
Unit costs [d], in Dr./kWh	0.144	0.070	0.214	0.139	0.025	0.164
in US mill/kWh	4.80	2.33	7.13	4.64	0.83	5.47

[a] Includes depreciation (25 yr sinking fund), interest on net assets employed (7%) and insurance premium (0.2%). Total fixed charge rate = 0.08781.

[b] At 12 000 Dr./month for 200 staff at Lavrion I and 75 staff at Lavrion II.

[c] Specific fuel consumption = 0.22 kg/kWh at a fuel cost = 16 US$/t.

[d] Based on net capacity and 7000 h/yr operation.

4. HISTORICAL SYSTEM DATA

4.1. Historical load growth

(a) Distribution of electricity supply and demand

Table IV-1 shows the electrical energy balance between input and output (consumption) for Greece as a whole for the years 1970 and 1971. It is seen that total input, including private industrial generation and imports of electricity, amounted to 9440 GWh in 1970 and 11053 GWh in 1971. Of this total generation PPC contributed more than 95%. Consumption by the interconnected system amounted to 93.5% in 1970.

(b) Past energy and per-capita consumption

Table IV-2 shows the historical growth in total consumption of electricity (excluding losses and exports) along with the per-capita consumption. The growth of total consumption corresponds to an average increase of 16.2% per annum whilst the growth of the per-capita consumption averaged 15.6% per annum.

TABLE IV-1. ELECTRICAL ENERGY BALANCE (1970 and 1971)

	1970		1971	
	GWh	% of total	GWh	% of total
Input				
Interconnected system				
Hydro	2630	27.9	2645	23.9
Thermal	6048	64.1	7604	68.8
Subtotal	8678	92.0	10249	92.7
Net independent thermal (islands)	313	3.3	362	3.3
-total	8991	95.3	10611	96.0
Private industrial generation	408	4.3	432	3.9
Subtotal	9399	99.6	11043	99.9
Imports from Yugoslavia	41	0.4	10	0.1
Total	9440	100.0	11053	100.0
Output				
Sales				
Industrial	4886	51.8	5853	53.0
Domestic and commercial	2939	31.1	3366	30.4
Other	532	5.6	603	5.5
Subtotal	8357	88.5	9822	88.9
Losses and own consumption	840	8.9	975	8.8
Subtotal	9197	97.4	10797	97.7
Private industrial consumption	224	2.4	241	2.2
Export	19	0.2	15	0.1
Total	9440	100.0	11053	100.0
Consumption by interconnected system	9197 - 313 = 8884		10797 - 362 = 10435	
Consumption excluding losses and export	8357 + 224 = 8581		9822 + 241 = 10063	

TABLE IV-2. CONSUMPTION OF ELECTRICAL ENERGY[a]

Year	Total (GWh)	Per capita (kWh)
1960	1 933	232
1961	2 155	257
1962	2 426	287
1963	2 747	324
1964	3 281	386
1965	3 841	449
1966	5 106	593
1967	6 136	704
1968	6 658	762
1969	7 650	872
1970	8 581	976
1971	10 063	1 142

[a] Excluding losses and exports of electricity.

TABLE IV-3. ELECTRICAL ENERGY GENERATION BY SOURCE [a]

Year	GWh				
	Lignite	Liquid fuels	Total thermal	Hydro	Total generation
1960	1 173	566	1739	467	2 206
1961	1 223	725	1 948	552	2 500
1962	1 184	945	2 128	614	2 742
1963	1 445	861	2 306	806	3 112
1964	1 903	1 063	2 966	749	3 715
1965	2 029	1 357	3 385	759	4 144
1966	2 087	1 661	3 747	1 714	5 461
1967	2 021	2 645	4 666	1 643	6 309
1968	2 317	3 278	5 595	1 354	6 949
1969	2 730	3 249	5 979	2 031	8 010
1970	3 230	3 131	6 361	2 630	8 991
1971	4 361	3 604	7 965	2 646	10 611

[a] Excluding private industrial generation and imports

Table IV-3 shows the electrical energy generation by source for the period 1960 to 1971. Private industrial generation and imports are not included.

(c) Electricity consumption by category of use

The electricity consumption for various classes of customers plus losses is shown in the lower part of Table IV-1, including the private industrial consumption of electricity.

(d) Growth in peak demand (total system)

The historical growth in peak demand for the interconnected and total system is shown in Fig. 4-1 along with the interconnected and total system capacity. The distribution of capacity between hydro and thermal stations is also indicated, as well as the interconnected system reserve (shaded area).

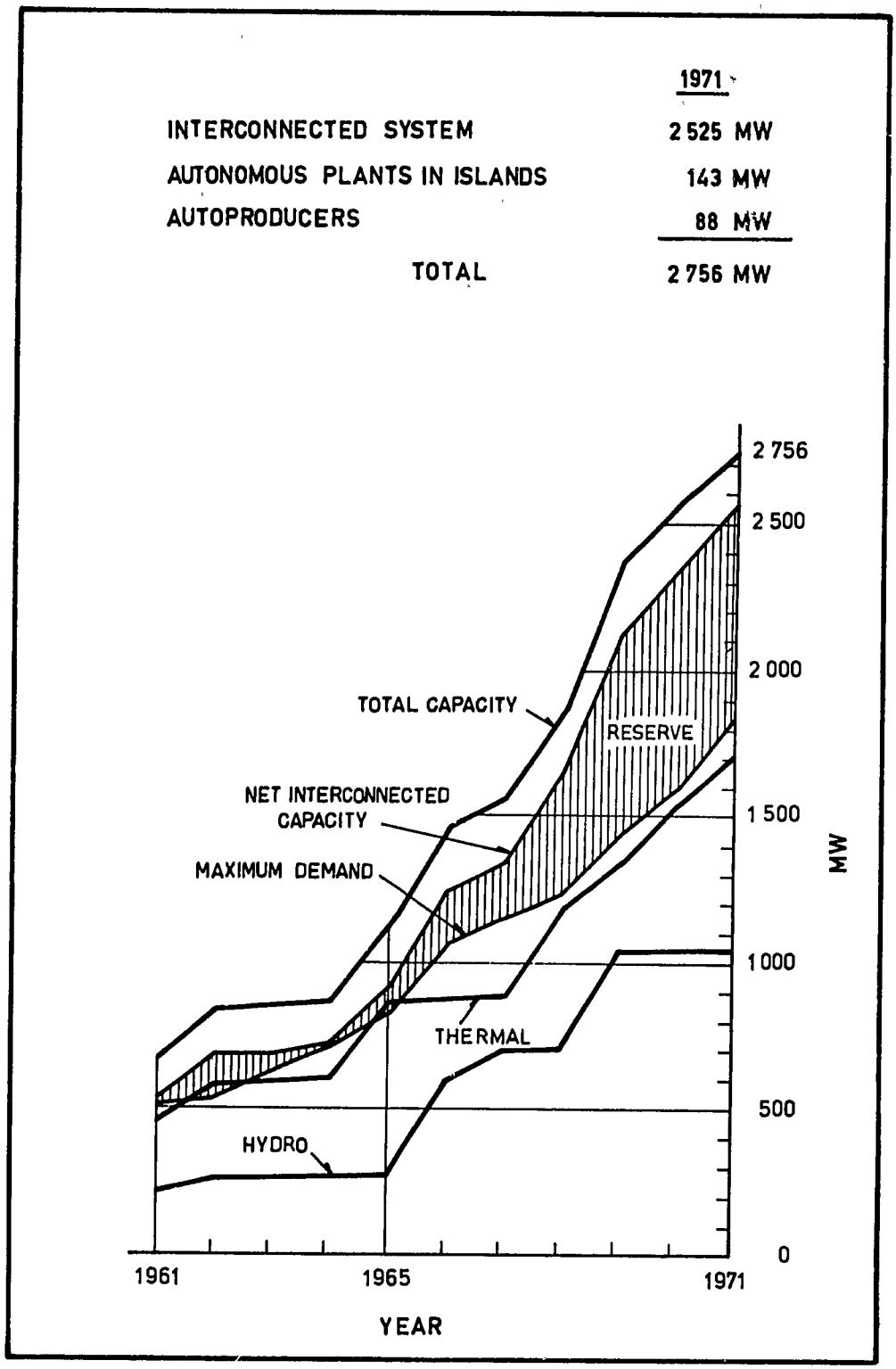


FIG. 4-1. INSTALLED CAPACITY (1961-1971).

(e) Energy and demand growth for the interconnected system

Figure 4-2 gives the interconnected system total energy demand (including losses) and system peak load during the past decade. The geographical distribution of low voltage customers is also indicated. Private industrial consumption of self-generated electricity and consumption by island customers are not included.

(f) System load characteristics

The load duration curve projected for 1972 is shown in Fig. 4-3 and the annual load factor during the years 1956 - 1971 is shown in Fig. 4-4.

4.2. Discussion of system reliability

(a) Reliability criteria

The Greek interconnected system is planned so that the probability of failing to meet 50 MW of peak load is not more than once in ten years. Accordingly the Five-Year Plan for the construction of new units is based on the following assumptions:

(i) Reserve margin sufficient to cover the biggest unit or 11% of the maximum demand, whichever is greater (see Section 3.5. above);

(ii) Additionally, the load demand must be met in the case of a critical hydrological year occurring in conjunction with energy consumption exceeding the forecast by a percentage increasing from 3% to 6% over the five-year period under consideration.

Furthermore a uniformly distributed reserve throughout the whole year is scheduled. In actual operation of the system a spinning reserve is always maintained to cover the outage of the biggest unit. In order to cope with an unforeseen contingency under-frequency relays have been installed for load-shedding in different frequency levels and durations.

(b) Outage records

The availability of thermal stations as a result of unscheduled outages during the period 1971 to March 1972 is shown in Table IV-4. It is seen that the lowest availabilities are those associated with the recent large thermal units at St. George.

During the seven-year period 1964-1970 the average annual forced outage duration of power transformers was 61 minutes per transformer and of transmission lines 7.5 hours per 100 km length.

The recorded average number of faults on the transmission lines during the same period was 1.5 faults per 100 km of line per year. Table IV-5 shows the recent annual outage rates per 100 km for 150 kV transmission lines. As yet there is no experience with transmission at 400 kV.

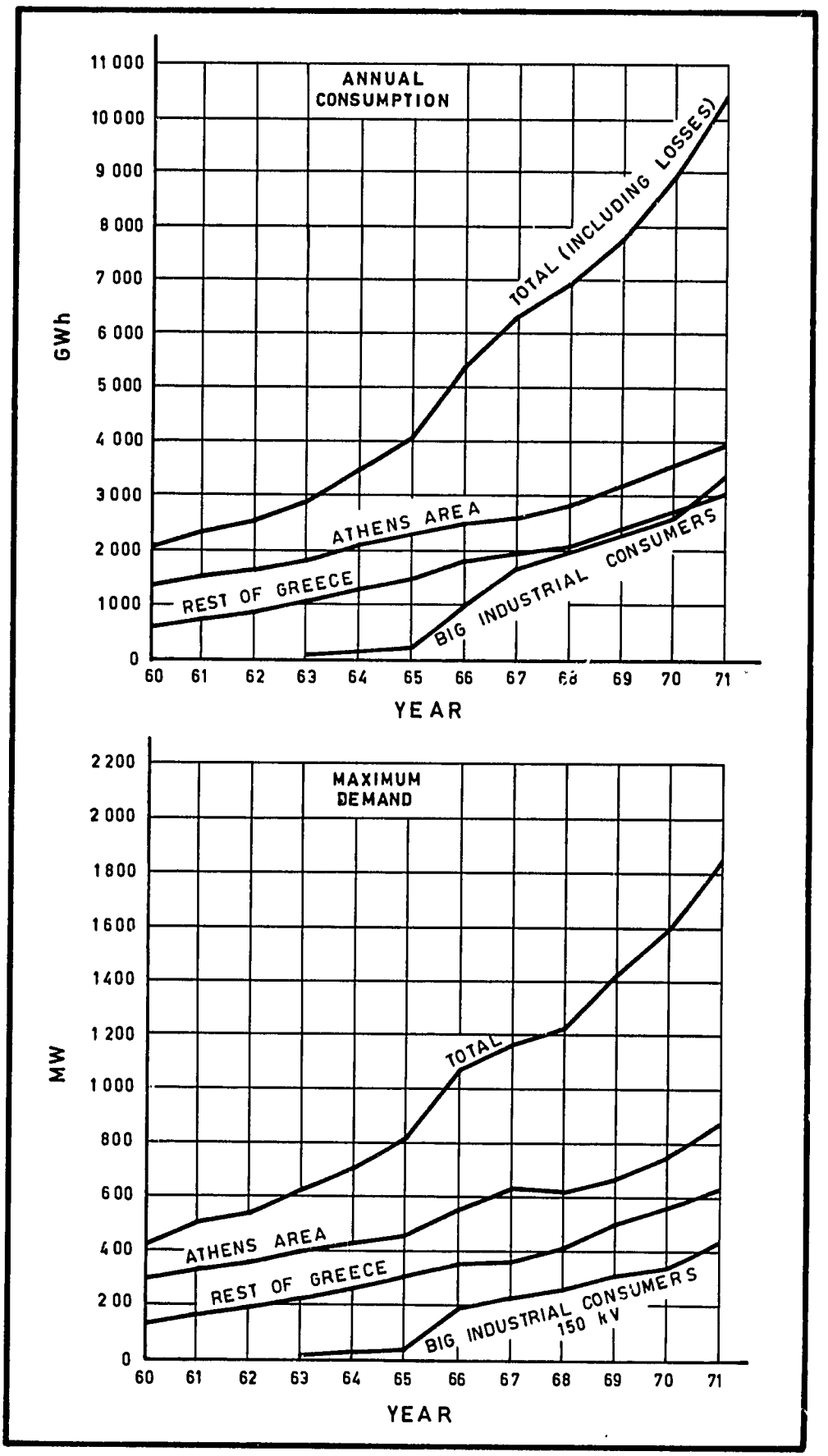


FIG. 4-2. ANNUAL MAXIMUM DEMAND AND CONSUMPTION IN THE INTERCONNECTED SYSTEM (1960-1971).

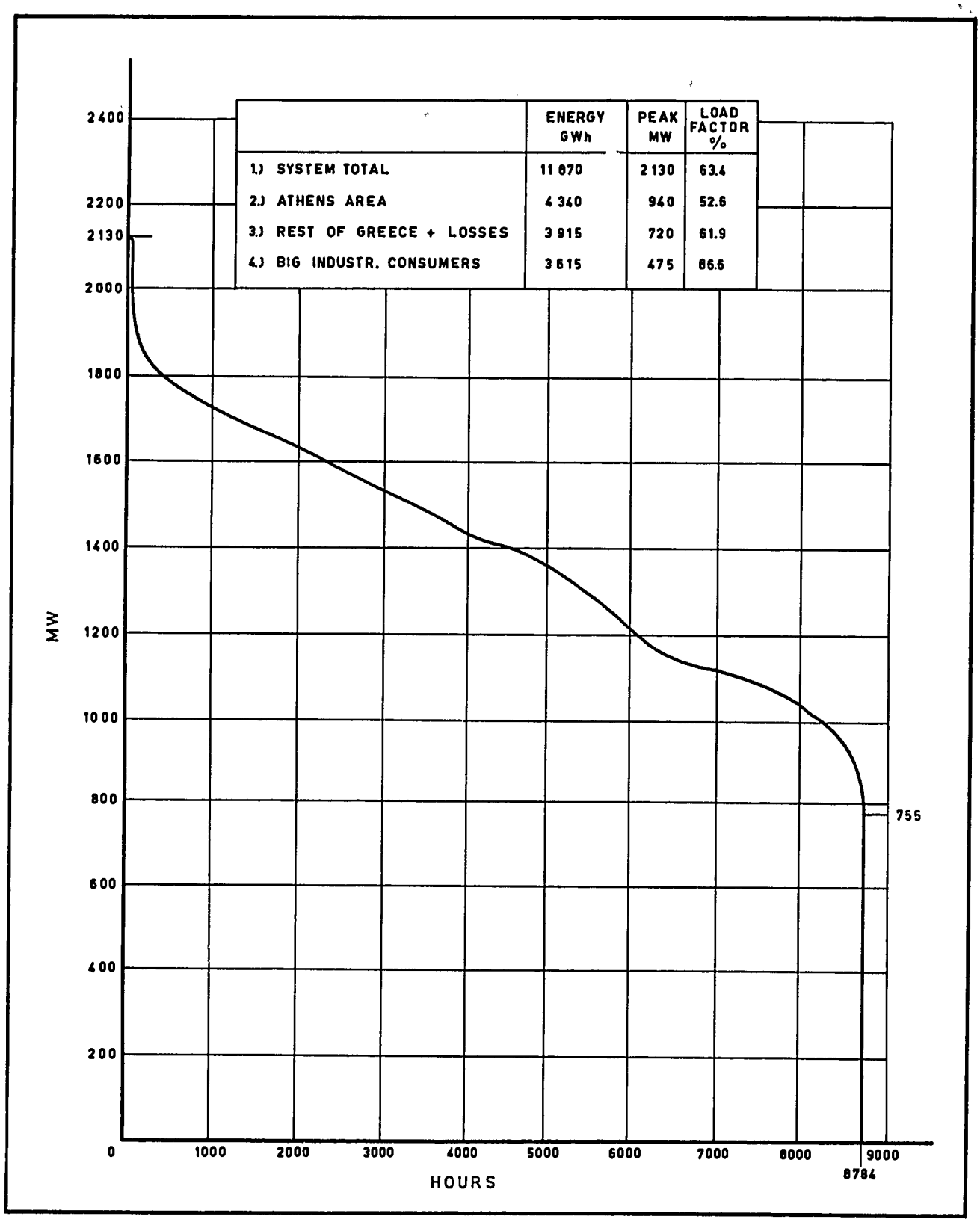


FIG. 4-3. PROJECTED LOAD DURATION CURVE FOR 1972.

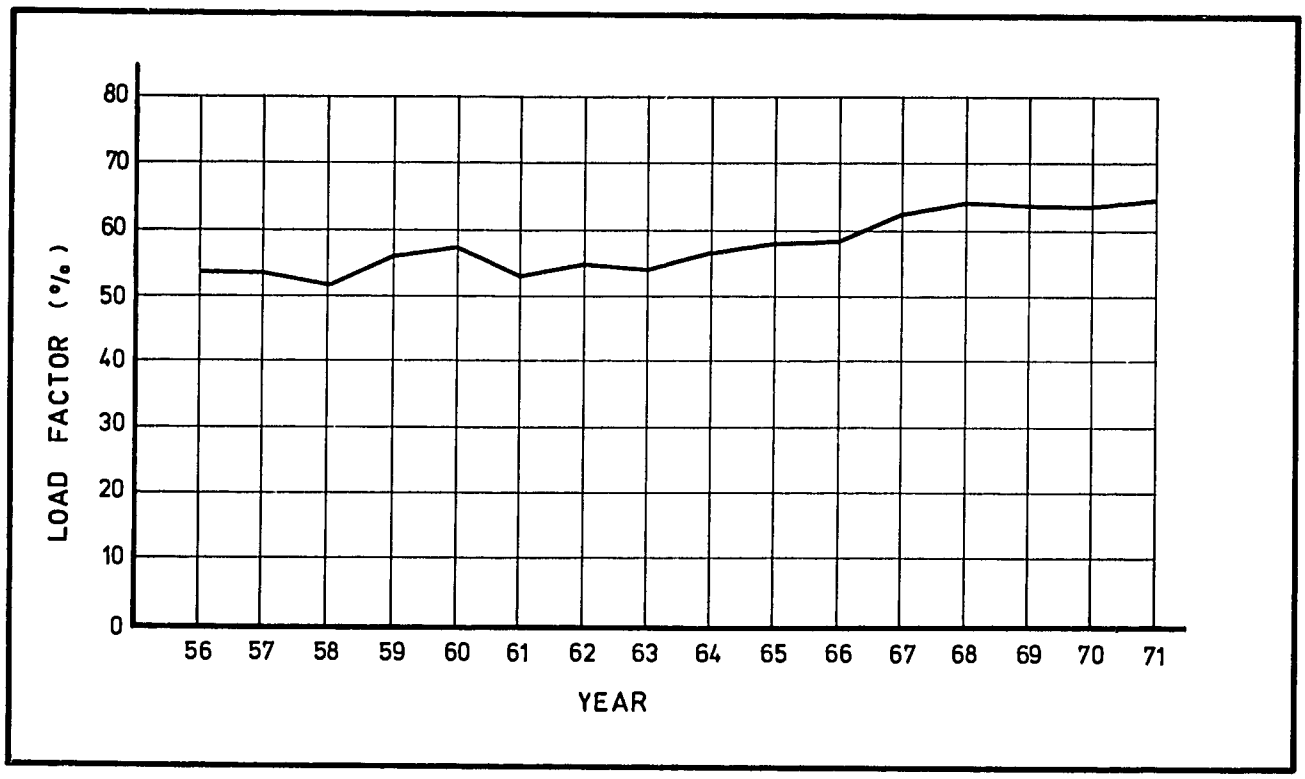


FIG. 4-4. ANNUAL SYSTEM LOAD FACTOR.

TABLE IV-4. THERMAL GENERATION PLANT AVAILABILITY

Station and fuel	Unit No.	Rating (MW)	Availability 1971 to March 1972 [a] (%)	Date of operation
St. George's Bay (oil)	6, 7	2 x 60	99.6	1956/65
	8	160	84.1	1968
	9	200	81.5	1971
Aliveri (lignite)	1, 2	2 x 40	99.3	1952
(lignite-oil)	3	150	90.8	1968
(oil)	4	150	99.4	1970
Megalopolis (lignite)	1	125	94.2	1970
	2	125	97.9	1970
Ptolemais (lignite)	1	70	98.3	1959
	2	125	99.1	1962
	3	125	95.9	1965

[a] Scheduled maintenance of 1 month/yr is not included.

TABLE IV-5. UNSCHEDULED TRANSMISSION OUTAGES [a]

Year	Number of faults	Faults per 100 km of line length/yr
1968	8	0.69
1969	39	2.71 [b]
1970	11	0.68
1971	24	1.47 [c]

[a] Number of faults on a 150 kV double circuit line that caused tripping of both circuits.
[b] Due to very bad weather and smog conditions as well as a lowering of earth resistivity.
[c] Average to adopt.

5. PROJECTED SYSTEM DATA

5.1. Projection of kWh requirements

A projection of total electrical energy demand up to 1990 made by PPC is given in Table V-1. No breakdown of electrical energy by class of consumer was available.

5.2. Projection of peak demand

Projection of peak demand up to 1991 made by PPC is shown in Table V-2.

TABLE V-1. FORECAST OF THE ELECTRICITY DEMAND

Year	Total electrical energy demand (GWh)	% increase over previous year
1972	11 170	–
1973	12 470	11.8
1974	13 870	11.3
1975	16 330	17.7
1976	18 420	12.8
1977	20 690	12.3
1978	22 360	8.1
1979	24 140	8.5
1980	26 020	7.8
1981	28 040	7.8
1982	30 220	7.8
1983	32 570	7.8
1984	35 110	7.8
1985	37 840	7.8
1986	40 710	7.0
1987	43 730	7.4
1988	46 870	7.2
1989	50 160	7.0
1990	53 670	7.0

TABLE V-2. PROJECTION OF PEAK DEMAND

Year	Peak demand (MW)
1982	5 000
1987	7 400
1991	10 000

5.3. Committed and planned generation program

The PPC is committed to a five-year forward rolling development plan. Beyond this period many alternative plans are studied. One such plan for development of generation up to the period of 1990-91 is shown in Table V-3 and this embodies the present committed development up to 1976. Particular features of this plan are the large hydro stations envisaged and the proposed nuclear capacity of 2400 MW (4 × 600 MW) by 1986-87 and 4200 MW (7 × 600 MW) by 1990-91.

TABLE V-3. GENERATION DEVELOPMENT PROGRAM UP TO 1990-91 (COMMITTED AND PLANNED BY PPC)

Station	Net capacity at end of period (MW)			
	78 - 79	82 - 83	86 - 87	90 - 91
Lignite				
Ptolemaïs	571	571	571	571
Kardia	828	1380	1380	1380
Megalopolis	496	496	496	496
Philippi (peat)	339	339	339	339
Lignite total	2234	2786	2786	2786
Oil				
Aliveri	355	355	355	355
St. George's Bay	452	452	452	452
Lavrion	427	427	427	427
Oil total	1234	1234	1234	1234
Hydro				
Kardamakis	360	360	360	360
Tavropos	130	130	130	130
Kremasta	437	437	437	437
Kastraki	320	320	320	320
Ladhon and others	73	73	73	73
Louros	8	8	8	8
Agras	50	50	50	50
Edessaios	19	19	19	19
Pournari	300	300	300	300
St. George	-	360	360	360
Avlaki	-	170	170	170
Sykia	-	160	160	160
St. George [a]	-	-	240	240
Sfikia	-	-	300	300
Assomata	-	-	67	67
Thissavros	-	-	400	400
Temenos	-	-	48	48
Platanovrissi	-	-	240	240
Stratos	-	-	-	170
Pigae	-	-	-	210
Famila	-	-	-	720
Hydro total	1697	2387	3682	4782
Nuclear				
Lavrion	-	600	1800	1800
Salonica	-	-	600	1200
Eypolion	-	-	-	1200
Nuclear total	-	600	2400	4200
Gas turbine	25	25	-	-
Total capacity	5190	7032	10102	13002

[a] Pumped storage.

TABLE V-4. 400 kV TRANSMISSION DEVELOPMENT PROGRAM UP TO 1985

Year	Double circuit lines	Function
End 1973	Connecting Pallini, Archanai and Koumoundourou and from the 300 MW No.2 unit at Lavrion to Pallini (80 km)	Existing lines to operate at 400 kV. To form an open ring around Athens.
Beg. 1975	Connecting Kardia (Ptolemais), Thessaly (Larissa) and Archanai (370 km)	To connect main thermal stations in the north to Athens.
End 1975	Kardia to Thessaloniki (110 km)	Existing lines to operate at 400 kV. To connect thermal stations and Kardamakis hydro station with load centres in Central and East Macedonia.
End 1975	Single circuit Thessaloniki to Skopje (Yugoslavia) via Kavadarci (205 km)	International interconnection
End 1976	Acheloos to Koumoundourou (250 km)	Existing lines to operate at 400 kV. To connect hydro stations in the West to Athens.
1977	Acheloos to new EHV Centre in West	New EHV Centre to collect output of West hydro stations
(later)	West EHV Centre to Archanai and/or Thessaly	
1979	Second North-South double circuit interconnecting Kardia, Thessaly and Kryonerion	To strengthen N-S connection
1980-85	(a) Third line between West EHV Centre and Archanai or Thessaly	Depending on further hydro stations in the West.
	(b) Nestos/Philippi to Thessaloniki	If hydro stations built at Nestos and Philippi
	(c) Lavrion to Argyroupolis	To connect first nuclear units to Athens.

5.4. Committed and planned transmission program

Table V-4 summarizes the projected 400 kV transmission program and should be referred to in conjunction with Fig. 3-3.

5.5. Planned future reserve capacity

It is understood that the philosophy described in Section 3.5 concerning spinning reserve and transmission reserve will continue for the future However, the planned 1975-76 interconnection at 400 kV with Yugoslavia, which will effectively be a single circuit line and which may import up to 300 MW (500 MW in emergency) and export up to 700 MW, will be disconnected in the event of conditions exceeding the criteria for a first-order contingency. This interconnection may thus be regarded as equivalent to an additional reserve capacity only at certain times and of an amount according to the power import. A further interconnection of similar capacity has been considered between Greece and Bulgaria, but this is too nebulous to include in the present study.

The future installed generation capacity will be determined so that the probability of failing to meet 50 MW of peak load is not more than once in ten years. This philosophy is consistent with the planning criteria given in Section 3.5.

These criteria are embodied in the generation reserve forecasts shown in Table V-5, but it is important to note that no provision has been made for the possible delayed commissioning of stations or for possible lower than average availability of new units. It is understood that after 1985 PPC intends to allocate all of its oil-fired generation to spinning reserve.

TABLE V-5. INTERCONNECTED SYSTEM PEAK LOAD, AVAILABLE CAPACITY AND RESERVES

Year	High projection of peak load (MW)	Critical hydrologic conditions		Low projection of peak load (MW)	Average hydrologic [a] conditions	
		Avail. capacity (MW)	Reserve (MW)		Avail. capacity (MW)	Reserve (MW)
1972	2245	2662	417	2180	2818	638
1973	2540	2944	404	2430	3100	670
1974	2920	3436	516	2770	3416	846
1975	3400	4096	696	3210	4288	1078
1976	3695	4096	401	3485	4288	803
1977	4030	4536	506	3800	4728	928
1978	4370	5200	830	4120	5392	1272

[a] For the years 1972 - 1976 inclusive the MW values are the same for the "high" as for the "average" hydrologic condition.

6. NATIONAL CAPABILITIES AND LOCAL COSTS

6.1. Contribution of Greek industry to power projects recently completed or now under construction

(a) Mechanical material and equipment

The following types of mechanical equipment and construction work were carried out by local labour:

Assembling of mechanical equipment
Metallic constructions according to general contractor's drawings, i.e. scaffolding, air ducts, flue gas ducts, tanks (non-stainless), piping except seamless steel piping
Metallic constructions of minor importance in accordance with the Greek constructor's drawings and specifications, i.e. fuel tanks, piping except seamless steel piping, cranes
Air conditioning, heating and pumping systems
Insulating materials and insulation work
Steel liners
Paints and painting

(b) Electrical equipment

The following types of electrical equipment are manufactured in the country:

Metallic scaffolding
Cables and conductors up to 150 kV
Low and medium voltage transformers up to 2 MVA
Low voltage motors up to 500 hp
Open air disconnect switches up to 150 kV
Low and medium voltage switchgear
Lead batteries

(c) Civil engineering works

All civil engineering works construction can be undertaken by Greek companies.
It is required by law that the maximum contribution be made by Greek industry. However, it is estimated by PPC that in the 1970's up to 75% of the expenditure on a large thermal plant would be in foreign exchange, and that at least this or a higher percentage would apply to the first nuclear unit.

6.2. Targets for future local industrial participation in power projects

No specific targets have been established. However, in connection with the vigorous industrialization now under way in Greece, efforts are being made to expand the capability of Greek industry, for example to manufacture transformers and motors of sizes larger than given in Section 6.1.

6.3. Local construction costs and practices

(a) Labour costs

Labour rates for various types of craft are shown in Table VI-1. In order to obtain an estimate of a weighted average man-hour cost for constructing an oil-fired plant, the distribution of labour was assumed to be the same as for construction in the USA. This approach probably overestimates the average man-hour cost in Greece because it is likely that the percentage of unskilled labour utilized would be higher in Greece than in the USA. Nevertheless, even on this assumption the average man-hour cost, including fringe benefits, comes to only US$ 1.90/h.

TABLE VI-1. LABOUR COSTS[a]

Type of labour	Drachmas[b] per day	Equivalent US $ per hour[c]
Building construction	320	1.35
Heavy construction	440	1.84
Brick layer	490	2.04
Carpenter	540	2.26
Structural iron worker	490	2.04
Electrician	490	2.04
Steamfitter	490	2.04
Hoisting engineer	380	1.58
Tractor operator (49 hp)	390	1.62
Tractor operator (100 hp)	390	1.62
Crane operator	440	1.84
Air compressor operator	390	1.62
Truck driver	390	1.62
Other	380	1.58

[a] 1972 costs in Lavrion area.
[b] 8 hr day including fringe benefits.
[c] 30 Dr. = 1 US $.

TABLE VI-2. COSTS OF CONSTRUCTION MATERIAL[a]

Type of material	Unit cost	Equivalent unit cost
Channel beams	12 000 Dr. /t	$18/cwt
I-beams	12 000 Dr. /t	$18/cwt
Wide flange beams	12 000 Dr. /t	$18/cwt
Re-inforcing bars	10 000 Dr. /t	$15/cwt
Ready-mix concrete	500 Dr. /t	$13/yd^3
3/4" plyform 8B	8 000 Dr. /m^3	$0.5/ft^2
2" × 4" × 8' fir/pine (imported)	2 700 Dr. /m^3	$212[b]

[a] 1972 costs in Lavrion.
[b] Per thousand board feet.

(b) Construction material costs

Costs of local construction materials are shown in Table VI-2. With the exception of ready-mix concrete materials, costs are higher in Greece than in the USA (based on costs in the Boston area).

(c) Construction practices

Greek construction practices are modern and a considerable amount of modern construction equipment is being used. However, since wages are lower than in North America and

Western Europe, the tendency is to employ somewhat more labour for construction than would be used for comparable work in North America or Western Europe.

(d) Labour productivity

Labour productivity in the Greek manufacturing industry, in terms of value added per person employed, has been increasing at an average annual rate of more than 5% over the last decade. The rate of increase in productivity has varied much among different groups of industries, but information was not available about the level of productivity in the construction industry. Nor was information available about how productivity in the construction of power plants in Greece compared with productivity in Western Europe or North America. Estimates by knowledgeable persons of the number of workers required in Greece for construction of thermal power plants averaged 1.5 times the number required for comparable work in the Federal Republic of Germany. This difference may diminish before the first nuclear power plant is constructed.

6.4. Problems and costs associated with possible nuclear power plant sites

Studies and reports on site selection for the first nuclear power plant were carried out in 1968 and 1969 (see Table VI-3). These studies recommended a site near the Lavrion oil-fired power station on the south-east coast of Attica. A 400 kV transmission line connects the Lavrion station with the Athens area. The site is about 50 km south of Athens by good road, but it is expected that a heavy pressure vessel would have to be brought to the site by barge. The seismic conditions are favourable. The site has already received tentative approval by the GAEC. It is expected that three nuclear units will eventually be installed at Lavrion.

PPC is in the process of locating about five to seven sites for nuclear power stations. Seismic conditions generally lead to locations in eastern Greece. Some sites have been

TABLE VI-3. STUDIES OF THE LAVRION SITE FOR A NUCLEAR POWER STATION

I. Reports prepared by consultants on site selection and investigation

(1) Preliminary site survey – May 1968.

(2) Site survey for nuclear plants – First conclusion – July 1968.

(3) Site selection and investigation program – September 1968.

(4) Specifications for research program on selected sites – October 1968.

(5) Site selection and investigation – Complementary survey – November 1968.

(6) Site selection for a nuclear power station – Final report – March 1969.

II. Site investigation studies

(1) Report on the seismic dangers of the Lavrion area (Ag. Marina) by A. Galanopoulos, Professor of the University of Athens – December 1968.

(2) Geotechnical report, soil profiles and laboratory tests of Ag. Marina – Lavrion – December 1968.

(3) Geological report of Ag. Marina – Lavrion site by C. Pisoni – January 1969.

(4) Geotechnical works at Ag. Ioannis – Lavrion 1969.

(5) Investigation borings at the area reserved for the construction of the station for foundation purpose – November 1969.

(6) Study of the bottom of the gulfs at Ag. Marina – Lavrion – December 1969.

Note: There are two main meteorological stations in the area, one started in July 1969, and the other in September 1971, and a secondary station also started in September 1971.

identified but none has been acquired. Preliminary studies are under way but feasibility studies have not yet been started. Some of the criteria for the initial selection of possible sites are:

(a) Proximity to present and future load centres;
(b) Coastal location for cooling water;
(c) Proximity of existing transmission lines;
(d) Seismic conditions;
(e) Possibility of bringing heavy equipment to site by road or sea;
(f) Population density; and
(g) Exclusion of scenic sites.

Because the Lavrion site appears to satisfy these criteria, it is considered to be one of the most likely sites for the first two nuclear units, whilst two other stations may be located one near Salonica and one in Thessaly.

6.5. Plans for staffing of future conventional and nuclear power plants

Plans for the staffing of nuclear power plants have not been made. Detailed plans for staffing of the two Lavrion oil-fired units (145 MW and 285 MW) to be put into operation in 1972 and 1973 were not received. The total number of personnel, shown by the categories of engineers, technical personnel and others, is given for a number of different stations in Table III-7.

7. ECONOMIC AND FINANCIAL ASPECTS

7.1. Economic ground rules

The economic ground rules used by PPC in preparing power system expansion studies and feasibility reports are as follows:

Interest rate: In comparing different investment projects PPC uses a rate of 7%. It is currently considering increasing this rate but no decision has yet been taken.

Construction period: Five years has been assumed for a nuclear plant.

Plant life: For feasibility studies the following plant lives are used:

Type of station		Plant life (yr)
Nuclear		25
Fossil:	Oil	
	Lignite	
	Peat	
Diesel		12
Hydro		50

Escalation: Feasibility studies are made on the basis of current prices and the question of escalation therefore does not arise. The actual annual increase in hourly earnings in industry during the period 1964-69 has been 10.8% according to information published by OECD. The present rate in PPC is estimated to be 6%.

Plant factor: In comparing the generating costs of nuclear and conventional stations, an 80% plant factor has been assumed for nuclear units, 84% for oil-fired units, and 95% for hydroelectric stations. At the same time, it is assumed that half of each type of those stations will be operated at 90% load in order to have sufficient spinning reserve available for frequency and load control. In addition, the continuous upward trend of the expected demand is assumed not to allow sufficiently large seasonal dips during which all required maintenance of units can take place. The consequences drawn for the estimates of generating costs for the different types of stations are described in Section 5 of the Geneva paper A/CONF. 49/P/270.

Customs duties: See Section 7.4.

Fuel oil cost: A price of US $ 16 per metric ton has been paid by PPC up to the end of 1971 and this value has been used in recent studies. However, the situation is now changed as described in Section 2.3 (g). If oil-fired stations were to be considered in the future, PPC could make its calculations using two oil prices, one including, and the other excluding, customs duties and taxes.

7.2. Current methods and sources of financing

PPC's initial funds were provided through the Greek Government. However, the law establishing PPC required that it be run as a private enterprise and be self-financing. PPC accordingly is now being financed from its own profits and reserves, as well as from loans on the local and foreign capital market. Its own funds represent more than 40% of total capital, the balance being domestic and foreign loans and suppliers' credits.

Domestic loans and credits consist of bond issues, the latest at $7\frac{1}{2}$%; loans from the Postal Savings Bank, the latest repayable in 20 years with a five-year grace, as well as medium-term and short-term bank loans and suppliers' credits.

Foreign loans and credits are mainly intended for the purchase of equipment and material which are not manufactured locally. When requesting bids for projects, PPC simultaneously requests bids on the terms of financing. Usually, 80 - 85% of the foreign currency value of equipment of foreign origin is financed by credits secured by the supplier.

Actual interest rates paid by PPC on loans vary from 1% on large Government-subsidized loans for rural electrification and for purchases of equipment and supplies from Eastern European countries, to over 9% on some smaller foreign loans. Most foreign loans are at a higher interest rate than domestic loans and vary between 5.5 and 9%. However, two very large foreign loans have been obtained at less than 4%. Foreign loans amount to about one

third of total loans. Domestic loans, with the exception of subsidized Government loans, vary between 5.5 and 7%. Latest domestic loans carry an interest rate of 7.5%. Loans to borrowers on the domestic market other than PPC are considerably more expensive. Banks charge 12% plus commission.

7.3. Foreign exchange and considerations in evaluating capital and fuel costs

The drachma is a convertible currency. However, there is a varying but persistent deficit on the current account of the balance of payments which in some years amounts to 4% of GDP. This deficit is to a large extent being financed by private capital inflows and by the Government borrowing abroad, which often entails a heavy short-run burden of debt services.

This development has made the Government conscious of the need to limit the deficit on the current account of the balance of payments. One result of this has been the policy decision to develop the national energy resources of Greece on a priority basis. For instance, this consideration, among others, has led to the selection of the Megalopolis lignite station in preference to an oil-fired station requiring imported oil. However, PPC continues to make feasibility studies on the basis of purely technical and economic criteria, including current rates of exchange, in order to determine the optimum solution resulting from application of these criteria. Deviation from them or the application of different or additional criteria are made only as a result of Government directives. Consideration has recently been given to using in feasibility studies the exchange rate of US $ 1.00 = 37 drachmas in preference to the current rate, US $ 1.00 = 30 drachmas. A decision to apply this new rate has, however, not been taken.

7.4. Import duties and taxes applicable to utilities

PPC was completely exempt from taxes and duties until 1965. From 1965, PPC became subject to a purchase tax but continued to be exempt from import duties until the end of 1971.

From the beginning of 1972, PPC has paid tax on fuel oil (see Section 2.3 (g)). PPC has been subject to import duties on equipment since January 1972 at the following rates:

on mechanical and electrical machinery and equipment	10%
on transmission and distribution line material	15%
plus 13% for other charges.	

8. ADMINISTRATIVE AND REGULATORY

8.1. Organization of the Greek Atomic Energy Commission

The Greek Atomic Energy Commission (GAEC) is a governmental organization reporting to the Ministry of Science. It was established by legislative decree No. 3891/1958, amended by legislative decree No. 4115/60 and superseded by legislative decree No. 451 of 18 June 1968. It has a Board of Governors which is the highest authority of the Commission and is composed of seven members. The Commission is advised on the scientific aspects of its activities by a Scientific Program Committee composed of 25 members.

The GAEC operates the Nuclear Research Centre at Democritos, which has eight scientific divisions, including the Reactor Division. This division has three groups, one of which is responsible for nuclear power, safety and licensing.

The main tasks of the Reactor Division are, besides safety and licensing and the execution of experiments at the reactor, the training of personnel needed for power reactors, development of the necessary infrastrucutre, and assistance to PPC and industry.

In the training of personnel for power reactors there are two main objectives; firstly to accumulate sufficient specific knowledge amongst the staff (of PPC mainly) to enable Greece to be an efficient buyer and user of nuclear power stations developed outside the country and secondly to enable GAEC staff to face all the safety, regulatory and licensing problems that will result from the installation of such stations. Post-graduate training of Greek personnel in the nuclear field is achieved either abroad or locally.

In view of the increased need for trained personnel which will result from the installation of the first nuclear unit, a detailed training program has been proposed. This program envisages training in two stages. In the first, training will take place in Athens where the facilities of the Democritos centre will be used and teachers from Greece, and occasionally from abroad, will contribute to the program. This will lead to the equivalent of a Master of Science degree with emphasis on the engineering aspects. In the second stage personnel with the basic training will be sent abroad, either to the design office of the supplier, or to a nuclear station similar to that which will be installed in Greece.

As part of the infrastructure, a regular licensing procedure needs an organization which can control quality of materials and constructions and certify that they are within existing specifications. Such an organization does not yet exist in Greece, but GAEC is aware of the need for it.

In respect of assistance to industry, there is close collaboration with PPC. However, no definition of policy concerning the introduction of interested industry into the nuclear field has yet been made. It is not expected that in the first years Greek industry will make any substantial contribution; in these years most of the nuclear installations will be imported.

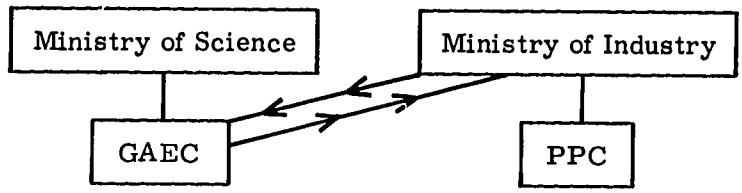
8.2. Relationship of the Greek Atomic Energy Commission to other interested organizations

The GAEC is in informal, but close, collaboration with all ministries and governmental organizations related to nuclear matters and national planning such as the Ministry of National Economy, the Ministry of Industry, PPC and the higher research and educational institutions, and provides scientific support wherever it is needed. Many of these ministries, organizations and institutions are represented on GAEC's Board of Governors or on the Scientific Program Committee.

8.3. Safety and licensing

The GAEC is the regulatory and licensing body for nuclear power plants and is responsible for safety assessments. This work is carried out by the nuclear power safety and licensing

group of the Reactor Division. The official licensing procedure is shown in the following diagram:



The Ministry of Industry gives the license on the basis of recommendations from GAEC. It is also responsible for the implementation of existing regulations.

8.4. Nuclear legislation

A law concerning the construction and operation of nuclear installation already exists, Law No. 854 of 15 March 1971. This law applies not only to nuclear power plants, but also to all installations intended for "the use, manufacture and exploitation of nuclear fuels or other radioactive products in large quantities and the storage thereof, and also the storage, processing and disposal of radioactive wastes." Nuclear installations run by GAEC, at universities, or concerned with National Defence are not affected by this law.

Several decrees dealing with the details of licensing are under preparation. A law on civil liability for nuclear damage is ready to be signed by the Government.

By legislative decree No. 336 of 16 December 1969, the Government of Greece ratified the Paris Convention of 29 July 1960 on Third Party Liability in the Field of Nuclear Energy and its Additional Protocol of 28 January 1964. The Convention entered into force on 1 April 1968.

9. ANALYTICAL APPROACH

9.1. Approach and bases of analysis

The major objective of this study is to determine the size and timing of nuclear power plants that could, on economic grounds, justifiably be built in Greece during the period 1980-1989, and to determine the sensitivity of the results to certain of the key parameters. The economic criterion, which is explained fully in Appendix D, is that the total operating and capital costs of the expansion plan for the generating system should be near to the minimum, when calculated in terms of present worth at 1 January 1973 and in terms of constant US dollars at that date. That is, normal price escalation is not treated explicitly. The implicit treatment of escalation is discussed in Appendix D. Any expansion plan must clearly be consistent with the forecast of load growth during the period of the study, and with other technical constraints of the system. The near-optimization approach consisted in studying a number of alternatives in which an all-nuclear installed capacity is assumed between every year of the decade under study and the year 1990. The objective functions of these alternatives present a minimum which corresponds to the year of introduction of a nuclear plant provided all the installed capacity for the following years and up to 1990 is nuclear.

One forecast of the growth in system demand has been used, and the method of deriving it is given in Section 10. A number of alternative expansion plans were then taken consistent with this forecast and the near-optimum plan determined by the use of a series of computer programs, the principal one being the Wien Automatic System Planning Package (WASP). This program evaluated the capital and operating costs of each alternative expansion plan over the period from the first study year (1977) to 2000. The reason for extending the evaluation for a decade beyond the study period proper is to take account of at least ten years of operation of all plants introduced during the study period.

The analysis was based partly upon data obtained during the visit of the Market Survey mission to Greece in July 1972 and partly on data developed to permit a consistent approach to the fourteen-country survey.

A summary of the computer programs used in the analysis is given below together with a summary of the data required for the evaluation. These data and the results obtained in the analysis are discussed in more detail in the sections that follow.

9.2. Description of computer programs

The basic tool used in the analysis of the alternative system expansion plans was the WASP program. Two subsidiary programs were used to provide specific data for the WASP program — the ORCOST program for calculating the capital costs of various fossil and nuclear units and the polynomial regression analysis program used to fit a polynomial equation to the load duration data.

(a) Wien Automatic System Planning Package (WASP)

The WASP program utilizes six blocks of input data as the basis for simulating the operation of the power stations on a seasonal (quarter-by-quarter) basis, evaluating the operating costs of each plant, present-worth discounting these operating costs and the capital costs associated with all additions beyond the start of the study and determining the total system costs to the year 2000.

The data required for this analysis are as follows:

(i) System load description — consisting of the year-by-year peak demands for the power system during the study period, quarterly load duration data expressed as the coefficient of a polynomial equation and factors relating the quarterly peak loads to the annual peak loads.

(ii) Fixed system description — consisting of a list of the generating units that will be in operation at the start of the first study year (1976), their maximum and minimum operating levels, their minimum-load and incremental heat rates, 1 January 1973 fuel costs, expected scheduled and forced outage rates, and expected operating and maintenance costs. The description also includes data on the retirement of existing plants, on specific firmly planned additions and on seasonal factors affecting the operation of the hydro units in the system.

(iii) Alternative generating units — consisting of technical data on the various sizes and types of generating units that may be considered for an alternative expansion plan during the study period. The data required are the same as those required for the fixed system.

(iv) A series of alternative expansion plans — each consisting of a year-by-year definition of the generating units to be added during the study period.

(v) Loading order — for both the plants in the fixed system and those considered as expansion alternatives.

(vi) Capital costs of the alternative generating units — broken down into foreign and domestic costs and the expected economic life of the units.

The output from the WASP program consists of a quarter-by-quarter, plant-by-plant tabulation of the energy generation and associated costs for the study period. The total of these costs, plus the capital costs of the additions minus their salvage value at the study horizon, all present-worthed to 1973, is the "objective function" used to measure the economic merit of the system being analysed. That is, the expansion plan with the smallest value for the objective function was considered to be the "best" or "near optimum".

A detailed description of the data input to the WASP program is included in the following sections and the results of the analysis are described in Section 16. For further information on the WASP program, see Appendix A.

(b) Capital cost program

The capital cost data required by the WASP program, were determined by utilizing the ORCOST computer program. This program, which was obtained from Oak Ridge National Laboratory of the US Atomic Energy Commission, had been prepared by them to provide estimates of power plant capital costs in the USA for PWR, BWR, HTGR, coal, oil and gas-fired plants. Provision had been made in the program to adjust equipment, materials and labour costs from region to region. This made it possible to adjust the costs to conditions prevailing in Greece by utilizing local labour, materials and equipment cost information. Section 13 describes how these cost data were developed. For a more detailed description of the ORCOST program, see Appendix B.

(c) Polynomial regression program

Load duration curves were obtained from the Public Power Corporation. The WASP program requires quarterly load duration curves expressed as the coefficients of a fifth order polynomial. The coefficients were calculated by a least-squares curve-fitting program that is described in more detail in Appendix C. The coefficients and the actual shapes of the quarterly load duration curves defined by the polynomial expressions are shown and discussed in Section 10.

9.3. Economic methodology and parameters

The economic merit of the various alternative expansion plans was determined and used as a basis for selecting the near-optimum case. External or social costs were disregarded, as were taxes and restraints on foreign capital. Definitions of the costs and other economic parameters are given in Appendix D.

The parameters for the reference case were assumed to be as follows:

	Study values	Equivalent real values (at 4% inflation)
Discount rate	8%	12%
Capital cost escalation rate	0%	4%
Oil price escalation rate	2%	6%
Lignite price escalation rate	0%	4%
Nuclear fuel price escalation rate	0%	4%
Depreciation	Linear	
Loss-of-load probability	Maximum – 0.010 Average – 0.005	

The fuel oil costs are those prevailing in the Persian Gulf at 1 January 1973, plus ocean and inland transport costs.

9.4. Technical methodology and parameters

In order to facilitate preparation of data for the WASP program, the characteristics of the alternative generating units which might be installed on the associated system were standardized as described in Appendix E. Since Greece has resources of lignite and also utilizes imported oil for power production, it was necessary to consider the range of plant types and sizes as shown in Table IX-1.

TABLE IX-1. PLANT SIZES AND TYPES CONSIDERED AS POSSIBLE SYSTEM ADDITIONS

Type of plant	Rated capacities (MW)
Lignite-fired	125, 300
Oil-fired	140, 300, 400, 600, 800
Nuclear	300, 400, 600, 800

All of the hydro projects planned by the PPC were considered for the expansion alternatives.

Characteristics of these alternative generating units are described in more detail in Section 14, and the supporting data on operating and maintenance costs, expected outage rates and plant life are described in Appendix E.

9.5. Sensitivity studies

In order to evaluate the sensitivity of the results obtained for the reference case to the various economic parameters used, studies were carried out for other values of these parameters. These are summarized as follows:

	Study values	Equivalent real values (at 4% inflation)
Discount rate	6% & 10%	10% & 14%
Oil price escalation rate	0% & 4%	4% & 8%
Nuclear price escalation rate	2%	6%
Shadow exchange rate	1.30	

Two sets of capital cost data were used. These were ORCOST-1 (lower differential capital costs between nuclear and conventional plants) and ORCOST-3 (reference capital costs as of 1 January 1973). For details of these costs see Appendix B.

In the sensitivity studies, all parameters listed above were kept constant except for the parameter being studied. The results of these studies are discussed in Section 16.

10. FORECASTS OF SYSTEM LOADS AND LOAD DURATION CURVES

10.1. Review of the load forecasts used in the study

Two energy forecasts were considered. One is based on a sectorial and regional projection method computed by PPC as described in Section 5. This energy forecast is given in Table V-1. The other forecast was based on the world-experience method computed by H. Aoki and described in Appendix F. Due to the fact that the two forecasts were less than 1% apart during the study period, the PPC energy data shown in Table V-1 were used for further calculations Using a constant load factor over the study period of 0.66, which appears to be about the average over the past two years (see Fig. 4-4), peak loads as shown in Table X-1 were obtained. It will be noted that the energy and load factor shown do not coincide precisely with the data of Section 5, as for practical computation reasons, related to the computer derivation of the seasonal load duration curve (see (d) below), the load factor actually used was 0.65. The use of this value and the peak load MW resulted in an energy forecast slightly lower than shown in Table V-1. For comparison the Aoki energy forecast values are also shown in Table X-1.

TABLE X-1. LOAD AND ENERGY FORECAST

Year	PPC forecast		Aoki forecast	
	Peak load (MW)	Energy (GWh)[a]	Peak load (MW)	Energy (GWh)
1977	3 749	21 250		
1978	3 955	22 420		
1979	4 175	23 660		
1980	4 500	25 500	4 390	25 400
1981	4 850	27 490		
1982	5 227	29 630		
1983	5 633	31 930		
1984	6 072	34 410		
1985	6 544	37 090	6 320	37 100
1986	7 041	39 910		
1987	7 563	42 860		
1988	8 107	45 950		
1989	8 676	49 170		
1990	9 280	52 600	8 780	52 300
1991	9 930	56 280		
1992	10 630	60 250		
1993	11 370	64 440		
1994	12 170	68 980		
1995	13 020	73 790	11 300	67 300
1996	13 930	78 950		
1997	14 905	84 480		
1998	15 950	90 400		
1999	17 065	96 720		
2000	18 260	103 500	14 300	85 100

[a] At 0.65 load factor

In evaluating the peak loads for 1990-2000, an annual growth rate of 7% and the same constant load factor were assumed.

10.2. Derivation of load description data required for WASP program (Module 1)

(a) Study increment

As indicated in Appendix A, the WASP program carries out its computation by considering the system demand requirements in discrete blocks of capacity called study increments. Practical computation reasons led us to select a study increment of 50 MW.

(b) Annual peak load demand

The annual peak load demands were derived as explained in Section 10.1.

(c) Quarterly peak loads

PPC provided data showing the ratio of typical monthly peak demands to the annual demand. These data were then converted to quarterly peak demand ratios as required in the input of the WASP program. The computed factors relating the quarterly peak demand to the annual peak demand were the following:

1st quarter	0.88
2nd quarter	0.84
3rd quarter	0.939
4th quarter	1.000

(d) Quarterly load duration curves

The quarterly load duration curves determined by the method described in Appendix C are shown in Fig. 10-1.

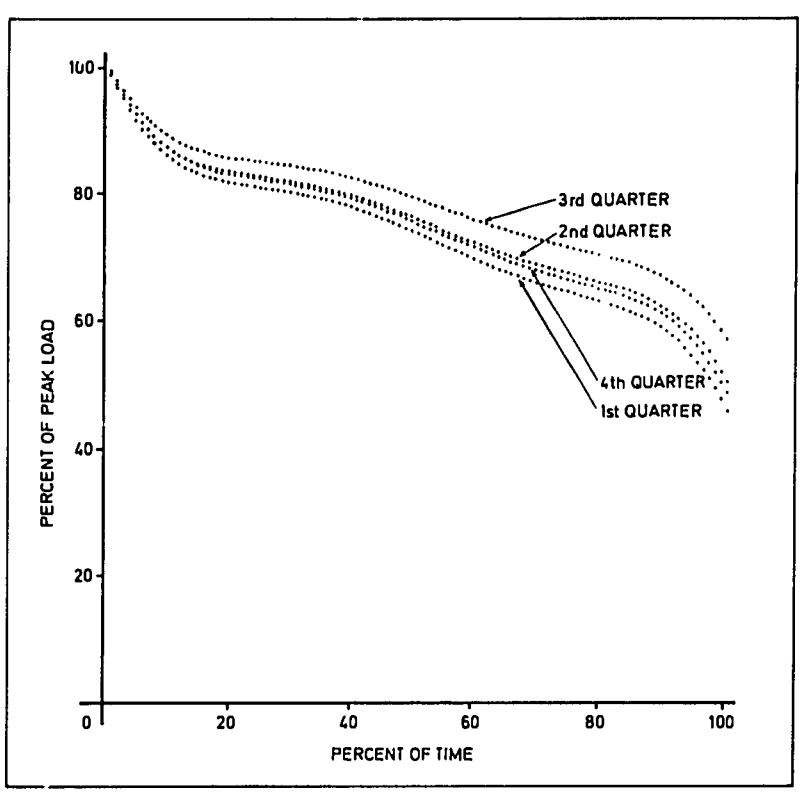


FIG. 10-1. QUARTERLY LOAD DURATION CURVES.

(e) Coefficients of polynomial describing load duration curve shapes

The quarterly load duration curves were analytically expressed by the fifth order polynomial equation:

$$\text{Fraction of quarterly peak demand} = b_0 + b_1 t + b_2 t^2 + b_3 t^3 + b_4 t^4 + b_5 t^5$$

where t = hours during the quarter at that demand or less. The coefficients for the load fact· used are indicated in Table X-2.

TABLE X-2. COEFFICIENTS OF POLYNOMIALS DESCRIBING LOAD DURATION CURVE SHAPES

Quarter	b_0	b_1	b_2	b_3	b_4	b_5
1st	1.000 000	-2.637 552	12.627 753	-29.453 415	30.525 085	-11.652 822
2nd	1.000 000	-2.467 387	11.813 061	-27.553 192	28.555 725	-10.901 028
3rd	1.000 000	-2.212 140	10.591 019	-24.702 866	25.601 685	-9.773 335
4th	1.000 000	-2.552 469	12.220 407	-28.503 311	29.540 405	-11.276 924

11. LIMITING FACTORS IN SYSTEM DEVELOPMENT

11.1. General philosophy

Appendix H sets out the philosophy which has been adopted in assessing the development of systems for which formal planning has not reached a definitive stage. For Greece, however, PPC had made long-term plans using data which are generally in agreement with those adopted for the Market Survey. The results of their studies are described in this Section and Appendix H should therefore be regarded as being of general comparative interest only.

The introduction in 1975 - 76 of a 400 kV transmission system with a per-circuit normal rating of 700/800 MW and a thermal rating of 1400 MW and the extension of this system as shown in Figs 3-2 and 3-3 ensures that virtually no limit is set by transmission to the expansion of alternative generation schemes. The rating and the timing of these circuits have been determined by optimum economic considerations of security and losses under steady-state load flow conditions. A next level of voltage, which might be 1100 - 1200 kV, could not be envisaged under normal circumstances before, say, an eight-fold growth in system load which, with a ten-year doubling time (7. 18% growth rate per year), would not occur until 2005 - 2010, i. e. well beyond the Survey period.

11.2. Load flow/transient stability

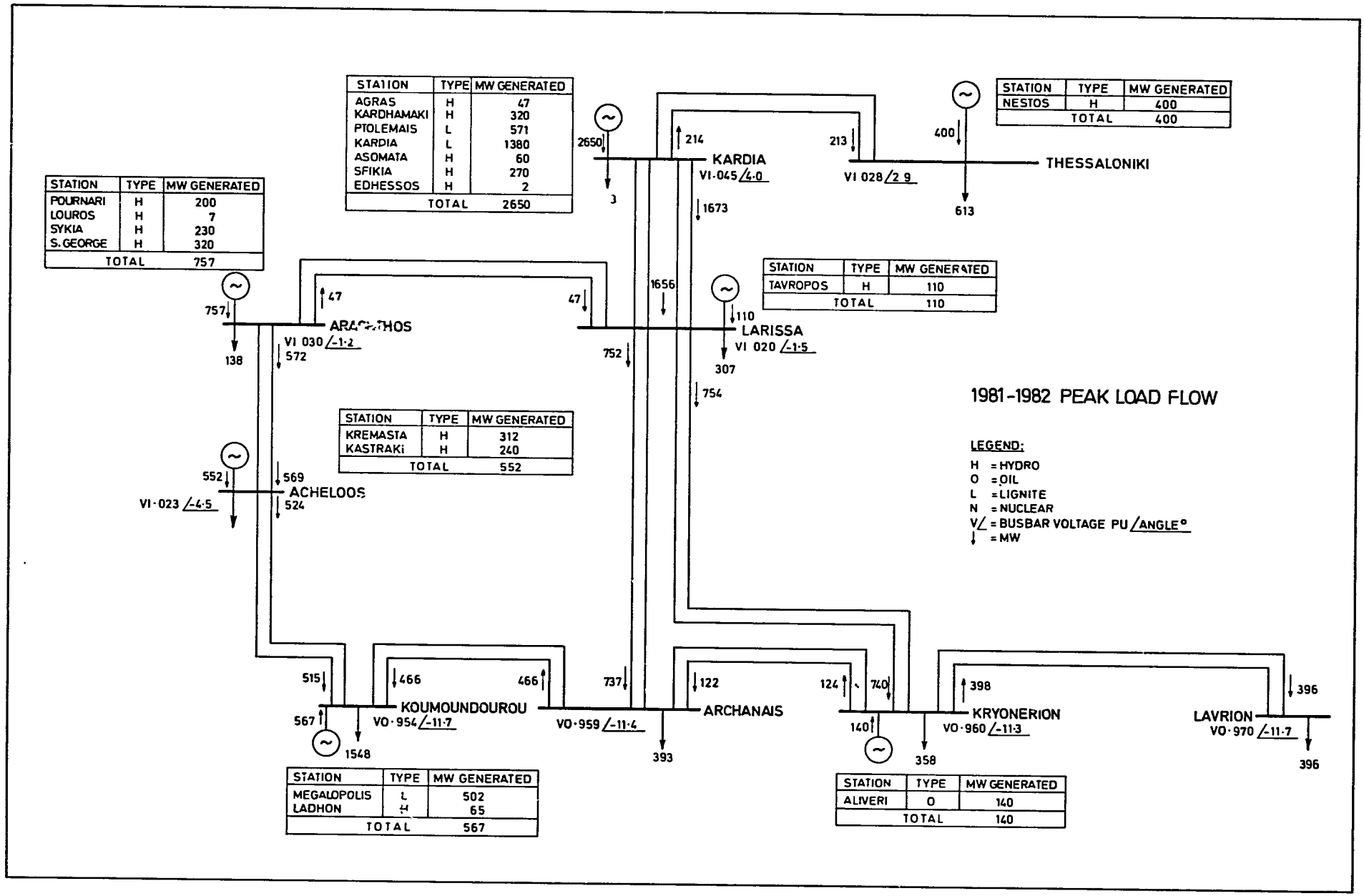
Figures 11-1, 11-2 and 11-3 show the main generation and 400 kV system information from detailed load flow studies carried out by PPC for system peak load conditions in 1981 - 82, 1986 - 87 and 1990 - 91, respectively. In these simplified diagrams, generation is shown at the nearest 400 kV busbar but with the actual net generated value; the local load shown at 400 kV has been adjusted to give the correct 400 kV circuit flows. The studies correspond to the generation development program shown in Table V-3, which is typical of several studies with minor variations in each and is very similar to the reference program discussed in Section 16. 1 and used in the Survey results. The total load considered in these studies is very similar to that shown in Table X-1 for the same year and the small differences will have a negligible effect on the interaction between system development and optimum size of generating unit.

It is seen from the studies that even in 1990-91 with a maximum loading of 1740 MW on the two double circuit lines south from Kardia, the transmission angle between that busbar and Archanai is only 16 electrical degrees. This is well within the 30° angle stability criterion described in Appendix H. Since there is an intermediate busbar at Larissa, this arrangement provides a very generous reserve against transient instability, especially since there remain to be explored by PPC measures to increase this reserve such as auto-reclosing, series capacitors etc. Therefore, a dynamic study of system transient stability is considered unnecessary for the purpose of the Survey since it will not be a limiting factor during the period of interest.

As system loads increase and if the proportion of power transmitted from north to south increases more rapidly than total load (i. e. if the majority of new generation is in the north), then the first technical problem to be encountered will be the provision of adequate "spinning reactive reserve" in the south. This may be provided by the most economic alternatives such as controllable shunt reactors or synchronous compensators etc.

11.3. Frequency stability

Thermal generation can provide fast spinning reserve power up to about 15% to 20% of the unit rating whereas hydro generation can provide up to 70% of the unit rating but over a period of 10 - 15 s in the case of the Greek plants. These times refer to the provision of "prime-mover" energy, the inertia effect causing slower overall response in both cases. However, due to the PPC method of system operation in which thermal plants are run mainly at base load and hydro plants provide most of the system spinning reserve, the effect of loss of a given proportion of generation is to cause a greater dip in frequency than in systems where the reverse is the case.



STATION	TYPE	MW GENERATED
AGRAS	H	47
KARDHAMAKI	H	320
PTOLEMAIS	L	571
KARDIA	L	1380
ASOMATA	H	60
SFIKIA	H	270
EDHESSOS	H	2
TOTAL		2650

STATION	TYPE	MW GENERATED
NESTOS	H	400
TOTAL		400

STATION	TYPE	MW GENERATED
POURNARI	H	200
LOUROS	H	7
SYKIA	H	230
S. GEORGE	H	320
TOTAL		757

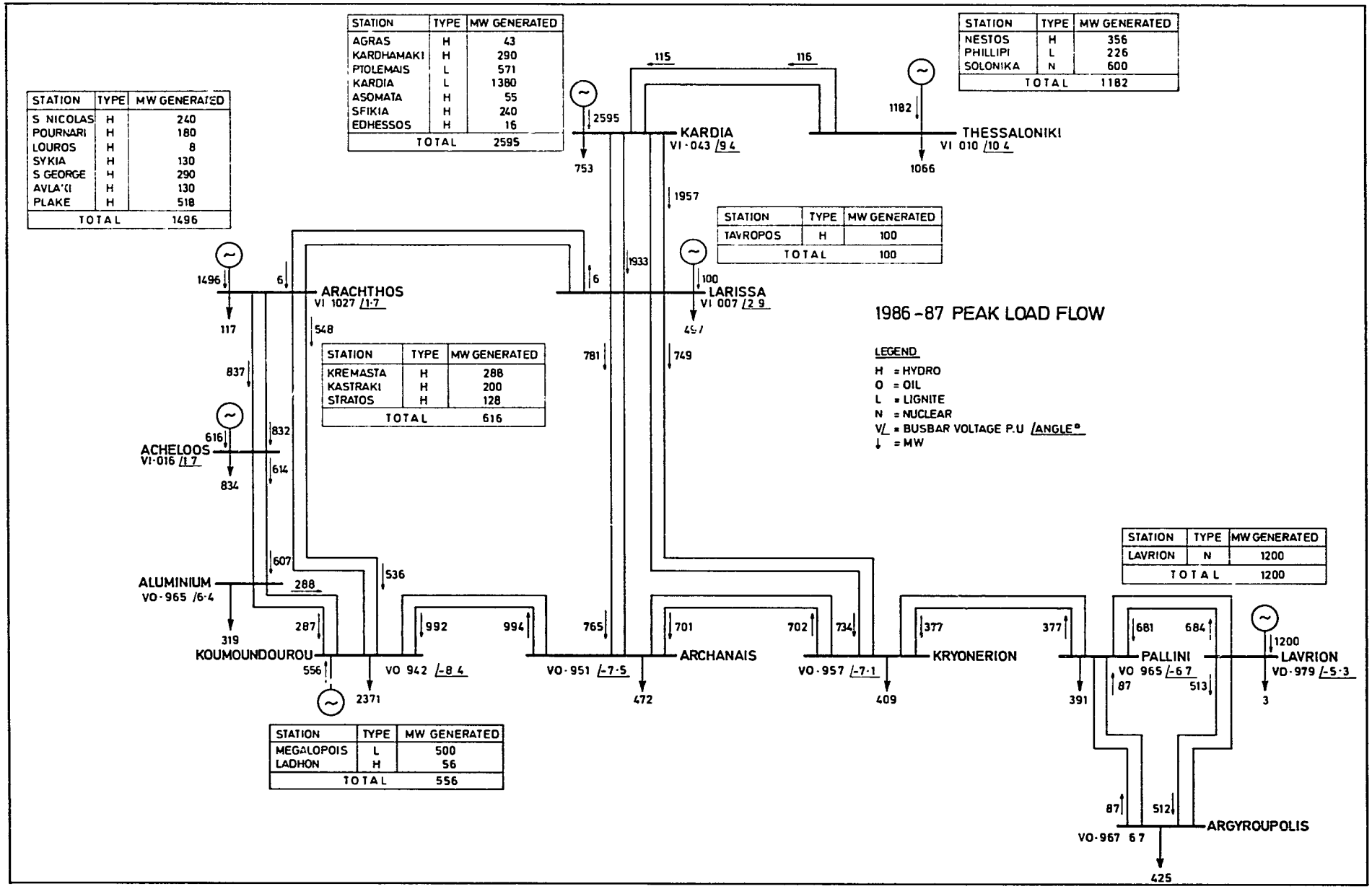
STATION	TYPE	MW GENERATED
TAVROPOS	H	110
TOTAL		110

STATION	TYPE	MW GENERATED
KREMASTA	H	312
KASTRAKI	H	240
TOTAL		552

STATION	TYPE	MW GENERATED
MEGALOPOLIS	L	502
LADHON	H	65
TOTAL		567

STATION	TYPE	MW GENERATED
ALIVERI	O	140
TOTAL		140

FIG. 11-1. LOAD FLOW IN 400 kV SYSTEM, 1981-82 PEAK LOAD.



STATION	TYPE	MW GENERATED
S NICOLAS	H	240
POURNARI	H	180
LOUROS	H	8
SYKIA	H	130
S GEORGE	H	290
AVLA'CI	H	130
PLAKE	H	518
TOTAL		1496

STATION	TYPE	MW GENERATED
AGRAS	H	43
KARDHAMAKI	H	290
PTOLEMAIS	L	571
KARDIA	L	1380
ASOMATA	H	55
SFIKIA	H	240
EDHESSOS	H	16
TOTAL		2595

STATION	TYPE	MW GENERATED
NESTOS	H	356
PHILLIPI	L	226
SOLONIKA	N	600
TOTAL		1182

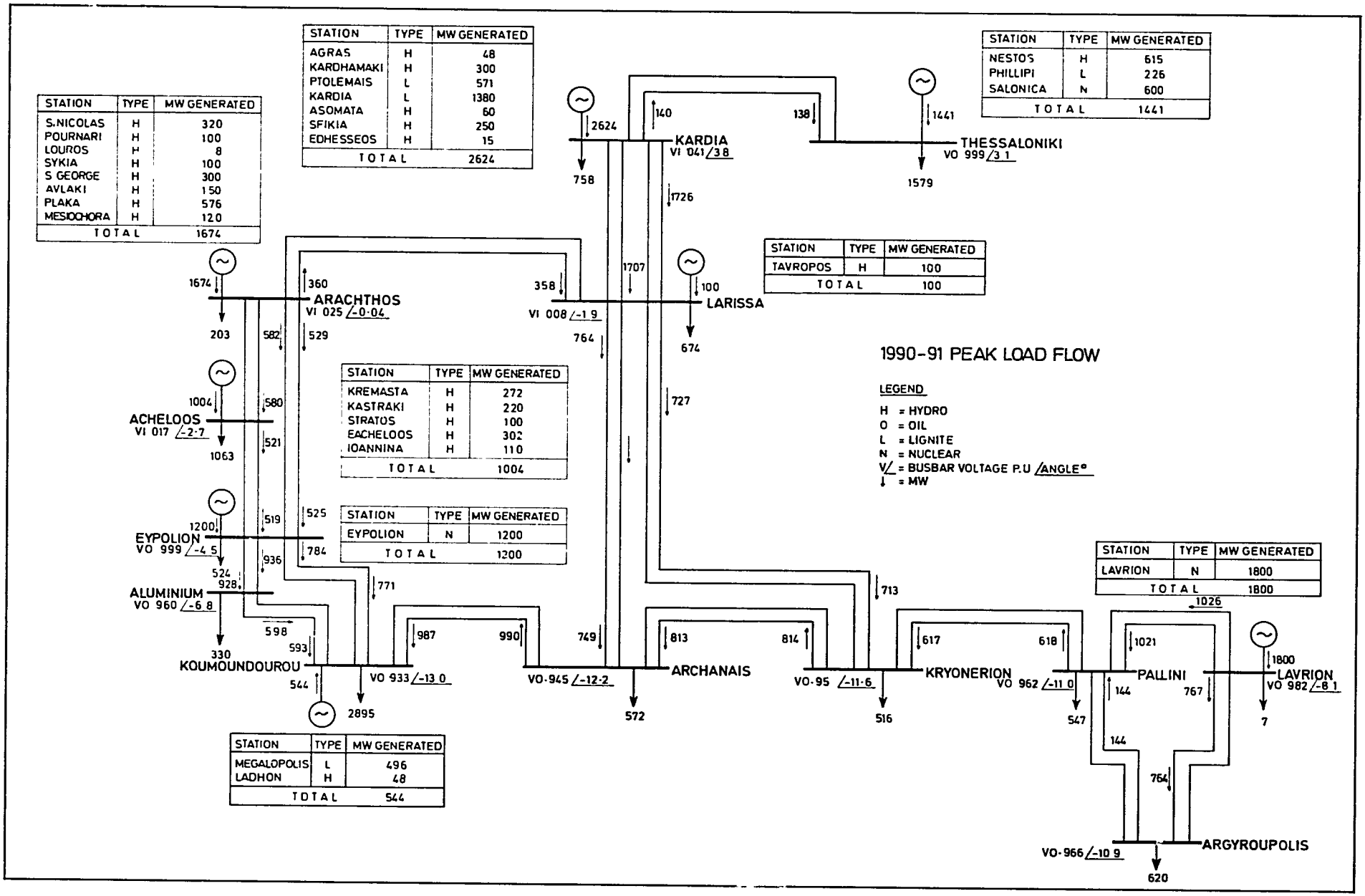
STATION	TYPE	MW GENERATED
TAVROPOS	H	100
TOTAL		100

STATION	TYPE	MW GENERATED
KREMASTA	H	288
KASTRAKI	H	200
STRATOS	H	128
TOTAL		616

STATION	TYPE	MW GENERATED
LAVRION	N	1200
TOTAL		1200

STATION	TYPE	MW GENERATED
MEGALOPOIS	L	500
LADHON	H	56
TOTAL		556

FIG. 11-2. LOAD FLOW IN 400 kV SYSTEM, 1986-87 PEAK LOAD.



STATION	TYPE	MW GENERATED
S.NICOLAS	H	320
POURNARI	H	100
LOUROS	H	8
SYKIA	H	100
S GEORGE	H	300
AVLAKI	H	150
PLAKA	H	576
MESOCHORA	H	120
TOTAL		1674

STATION	TYPE	MW GENERATED
AGRAS	H	48
KARDHAMAKI	H	300
PTOLEMAIS	L	571
KARDIA	L	1380
ASOMATA	H	60
SFIKIA	H	250
EDHESSEOS	H	15
TOTAL		2624

STATION	TYPE	MW GENERATED
NESTOS	H	615
PHILLIPI	L	226
SALONICA	N	600
TOTAL		1441

STATION	TYPE	MW GENERATED
TAVROPOS	H	100
TOTAL		100

STATION	TYPE	MW GENERATED
KREMASTA	H	272
KASTRAKI	H	220
STRATOS	H	100
EACHELOOS	H	302
IOANNINA	H	110
TOTAL		1004

STATION	TYPE	MW GENERATED
EYPOLION	N	1200
TOTAL		1200

STATION	TYPE	MW GENERATED
LAVRION	N	1800
TOTAL		1800

STATION	TYPE	MW GENERATED
MEGALOPOLIS	L	496
LADHON	H	48
TOTAL		544

FIG. 11-3. LOAD FLOW IN 400 kV SYSTEM, 1990-91 PEAK LOAD.

It is this drop in frequency which provides the main limit to the size of generating units that could be lost without causing dips in frequency which would activate the underfrequency relays described in Section 3.5. PPC have studied this problem for the development period corresponding to about 1980 with the following conclusions:

(i) In order to prevent operation of load-shedding relays set according to the present policy, it was postulated that frequency dips should not exceed 1 Hz at times of peak load and 1.5 Hz at times of light load. (These levels provide some margin and, if critical, they may require a more detailed study.)

(ii) To meet the criterion of (i), the largest unit should not exceed 7% of system peak load, which corresponds to about 6.4% of connected generating capacity.

(iii) In the special case of the loss of a nuclear reactor feeding two generator units each of rating equivalent to 7% of system peak load, this could be tolerated, provided that the time between the tripping of the first and second unit was at least 15 s.

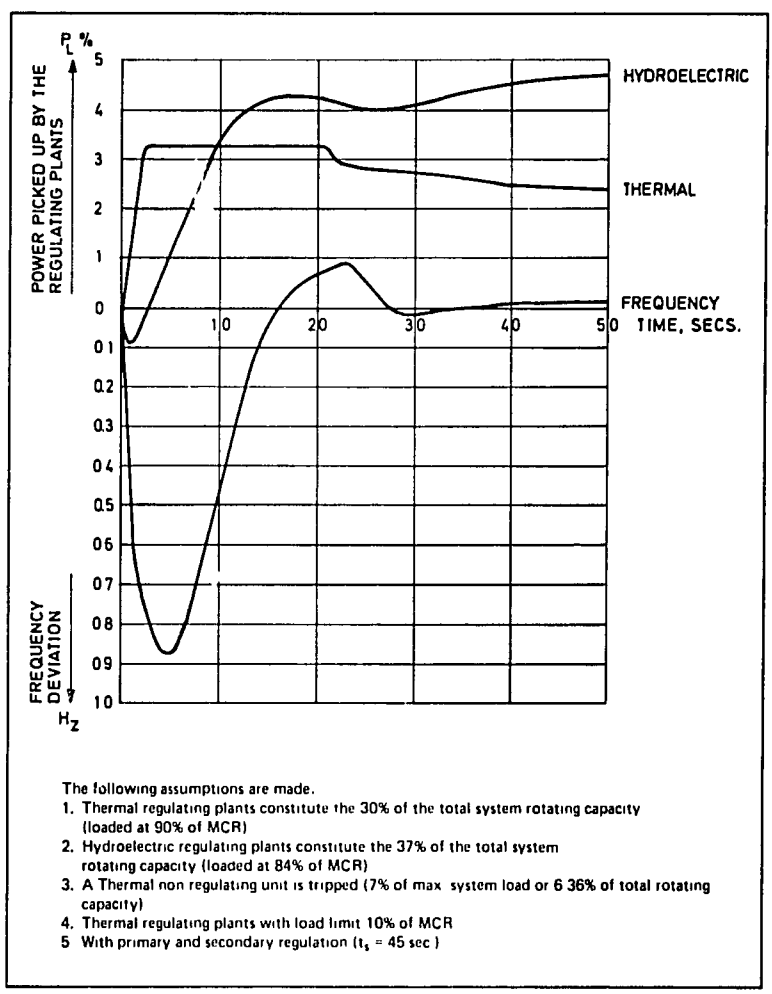


FIG. 11-4. LOAD FREQUENCY REGULATION FOR GENERATION LOSS OF 7% MAXIMUM LOAD

Curves illustrating these results for loss of generation at the time of system peak load are shown in Figs 11-4 and 11-5.

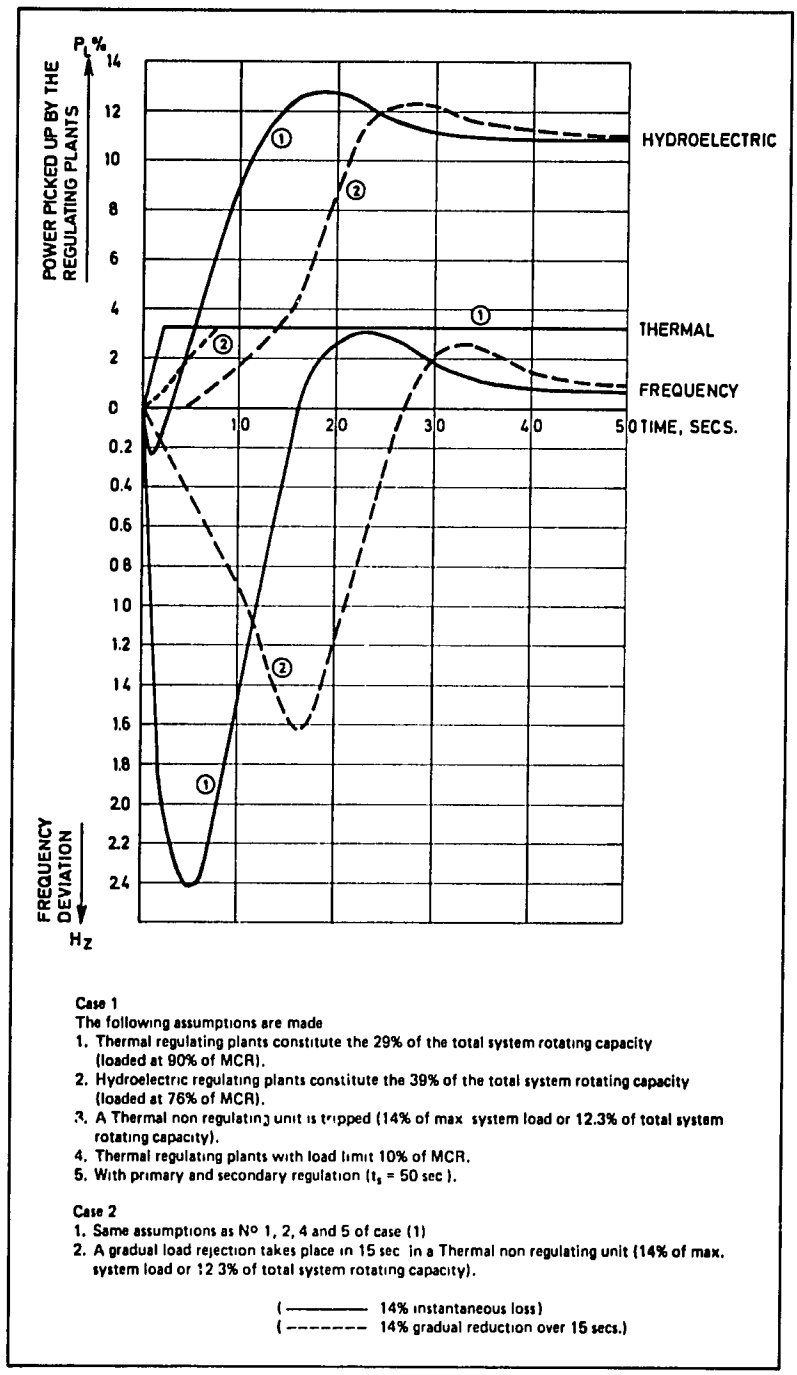


FIG. 11-5. LOAD FREQUENCY REGULATION FOR GENERATION LOSS OF 14% MAXIMUM LOAD.

11.4. Limits to the introduction of large units

It is apparent that the development of the PPC main transmission system sets no limit to generating unit size which is not above that determined by frequency stability in the period of interest.

The PPC analysis of frequency stability following loss of the largest generating unit is necessarily approximate both from the point of view of analytical technique and also because of the data employed. The actual maximum acceptable loss, for the same frequency change, will vary with connected load, generation mix, nature of spinning reserve etc.

Taking into account that higher standards of system security might need to be maintained in the future and the PPC analysis is based on conditions prevailing at the beginning

of the Survey period, it is considered that a limit to set size of 5% of maximum demand be adopted for the end of the study period (1990).

Table XI-1 summarizes the recommended limits to set size up to the end of the century.

TABLE XI-1. RECOMMENDED LIMITS OF GENERATOR SIZE[a]

Year	Peak demand (MW)	Max. unit (MW)
1980	4 715	350
1985	6 875	500
1990	9 725	600
1995	14 810	750
2000	20 950	1 000

[a] For the computer analysis slightly higher unit sizes were chosen; see Section 14.4.

11.5. System reliability

Due to the interconnected nature of the PPC system, as it develops, and the intended retention of the criterion whereby the loss of the most heavily loaded double circuit line is tolerated without loss of load, it is considered that reliability considerations of the main transmission system will in no way restrict the development of individual generating stations. The connection to the interconnected system of each new generating station should, of course, meet the same standards of security.

12. CHARACTERISTICS OF THE EXISTING AND COMMITTED ELECTRIC POWER SYSTEM

12.1. Existing power system and country's committed plans for expansion

The existing power system up to the year 1972 given by PPC is described in Section 4. The plant additions committed by PPC up to the end of 1976 were taken into consideration in assessing the power situation in 1977 which is the first year of our computation studies.

The following plant additions are committed for the system expansion between 1972 and 1975:

		Thermal	Hydro
1972	Laurion I	150 MW	
1973	Ptolemaïs	300 MW	
	Laurion II	300 MW	
1974-75	Khardamorkis		360 MW
1974	Khardia I	300 MW	
1975	Khardia II	300 MW	
	Megalopolis III	300 MW	
	Total 1972-75	1 650 MW	360 MW

The peak demand at the beginning of 1977, the first year of study, is 3749 MW (Table X-1) and the installed capacity is 4506 MW.

12.2. Derivation of thermal plant data required for fixed system (WASP Module 2)

The characteristics for the fixed system generating plants as required for the computer input are represented in Table XII-1. One integrated value is assumed for the total hydro capacity as the computer program requires all the hydro capacity to be lumped into one equivalent unit (HYD).

12.3. Derivation of hydro plant data required

(a) Distribution of hydro capacity into base and peak load components

The distribution of the hydro capacity additions into maximum and minimum (base load) capacity as well as the potential yearly energy generation are shown in Table XII-2. These values at 1977 are shown as one equivalent unit (HYD) of 1400 MW.

(b) Energy generation (by plant and total)

The energy that can be generated by the hydro system is a function of the water flow as described in Section 1. The monthly variations of flows and hence the available energy are substantial in most of the areas of Greece. The seasonal capacity and energy factors to apply to the base capacity, peak load capability and energy are shown in Table XII-3. These values were computed from the monthly data given to the mission and were maintained constant throughout the study.

It is important to note that no economic studies of relative costs of hydro power and other power sources were carried out. The hydro system is fixed at the beginning of the study and kept constant in all of the alternative programs considered. Any expansion alternatives or reconsiderations of some of the hydro factors adopted would not affect the comparative results of the various thermal expansion alternatives studied.

TABLE XII-1(a). WASP PRINTOUT SHOWING CHARACTERISTICS OF THE PLANTS IN THE FIXED SYSTEM AT 1977[a]

	NAME	NO. OF SETS	MIN. LOAD MW	CAP-CITY MW	BASE LOAD HEAT RATE	AVGE INCR HEAT RATE	FUEL COSTS CENTS/MILLION DMSTC	FORGN	TYPE	L C T N	FRCD OUT-AGE RATE	DAYS SCHL MAIN	MAIN CLAS	ENRGY GWH	O&M (FIX)	O&M (VAR)	FULL LOAD HEAT RATE
1	PTO	1	18	70	3340.	2470.	125.00	0.0	3	1	8.60	30	75	0.	0.390	0.0	2694.
2	PTL	2	32	125	3300.	2500.	125.00	0.0	3	1	7.50	30	100	0.	0.390	0.0	2705.
3	PTM	4	75	300	3120.	2340.	125.00	0.0	3	1	8.70	30	300	0.	0.390	0.0	2535.
4	MEG	2	31	125	3300.	2500.	187.00	0.0	3	1	7.50	30	100	0.	0.390	0.0	2698.
5	ALI	1	38	150	3270.	2450.	0.0	185.00	1	1	7.50	30	150	0.	0.390	0.0	2658.
6	ALV	2	40	40	3025.	3025.	160.00	0.0	3	1	8.60	30	75	0.	0.420	0.0	3025.
7	ALF	2	38	150	2970.	2230.	0.0	185.00	1	1	5.30	30	150	0.	0.440	0.0	2417.
8	STG	1	50	200	2920.	2195.	0.0	185.00	1	1	5.40	30	200	0.	0.440	0.0	2376.
9	STE	1	40	160	2970.	2230.	0.0	185.00	1	1	5.30	30	150	0.	0.440	0.0	2415.
10	STR	2	15	60	3020.	2265.	0.0	185.00	1	1	6.50	30	75	0.	0.440	0.0	2454.
11	STS	1	30	30	2640.	2640.	0.0	185.00	1	1	6.50	30	75	0.	0.440	0.0	2640.
12	LAR	1	75	300	2840.	2130.	0.0	185.00	1	1	6.50	30	300	0.	0.440	0.0	2308.
13	GAT	2	13	13	3450.	3450.	394.00	0.0	2	1	2.00	15	75	0.	0.860	0.0	3450.
14	HYD	1	300	1400	0.	0.	0.0	0.0	5	1	0.0	0	0	4522.	0.130	0.0	0.

[a] For nomenclature of column headings see Table XII-1(b).

TABLE XII-1 (b). NOMENCLATURE USED IN TABLE II-1(a)

NAME	WASP code for existing plants (see Table XII-1(c) for fossil plants), HYD = hydro.
NO. OF SETS	Number of units of a given size located at a given plant.
MIN. LOAD, MW	Minimum load at which units will be operated.
CAP-CITY, MW	Maximum load at which units will be operated.
BASE LOAD HEAT RATE	Unit heat rate at base load, in kcal/kWh.
AVGE INCR HEAT RATE	Unit heat rate for each kW above base load, in kcal/kWh.
FUEL COSTS, DOMESTIC	Fuel costs, in US¢/kcal × 10^6.
FUEL COSTS, FOREIGN	Same as above, except for imported fuel.
TYPE	A code where: -1 = emergency hydro 0 = nuclear 1 = oil fired 2 - 4 = optional 5 = hydro
LCTN	Not used. Defaulted to 1 in all cases.
FRCD OUTAGE RATE	Days lost due to forced outage.
DAYS SCHL MAIN	Days lost due to scheduled outage.
MAIN CLAS	An arbitrary assignment of unit size, for maintenance calculations.
ENRGY, GWh	Used only for hydro.
O & M (FIX)	Average O & M costs, in US $/kW -month (see 12.2(g)).
O & M (VAR)	Not used.
FULL LOAD HEAT RATE	Full load heat rate, as calculated by WASP based on the base load heat rate and average incremental heat rate data above.

TABLE XII-1 (c). NAMES OF PLANTS IN "FIXED SYSTEM"

WASP appreciation	Name of power stations	Unit No.
PTO	Ptolemaïs	1
PTL	Ptolemaïs	2, 3
PTM	Ptolemaïs	4, 5, 6, 7 [a]
MEG	Megalopolis	1, 2
ALI	Aliveri	3
ALV	Aliveri	1, 2
ALF	Aliveri	4, 5 [a]
STG	St. George's Bay	9
STE	St. George's Bay	8
STR	St. George's Bay	6, 7
STS	St. George's Bay	2, 3
LAR	Lavrion	1, 2 [a]
GAT	Markupoulon	1, 2
HYD	Combined hydro plants of Kardamakis [a], Tavropos, Kremasta, Kastraki, Ladhon, Louros, Agras, Edessos	

[a] To be commissioned in 1973-1976.

TABLE XII-2. ASSUMED HYDRO CAPACITY ADDITIONS

Year	Minimum capacity[a] (MW)	Maximum capacity (MW)	Energy (GWh)	Year	Minimum capacity[a] (MW)	Maximum capacity (MW)	Energy (GWh)
1977/79	40	160	283	1990	0	360	340
1980	0	170	523	1991	0	320	429
1981	0	360	546	1992	0	400	700
1982	0	0	0	1993	0	450	770
1983	0	300	302	1994	0	400	700
1984	0	307	198	1995	0	450	770
1985	0	288	450	1996	0	500	850
1986	0	400	593	1997	0	500	850
1987	0	170	426	1998	0	500	850
1988	0	210	184	1990	0	600	1 000
1989	0	360	341				
Totals 1980-89	40	2 565	3 846	Totals 1990-99	0	4 480	7 259

[a] From 1980 onwards no minimum (base load) capacity was defined, thus allowing the WASP program to divide the energy into base and peak portions as demanded by the system.

TABLE XII-3. SEASONAL DEMAND AND ENERGY FACTORS FOR HYDRO ENERGY

	1st quarter	2nd quarter	3rd quarter	4th quarter
Peak load factor	0.750	0.750	0.850	1.000
Base load factor	1.000	1.000	1.000	1.000
Energy factor	0.230	0.200	0.2800	0.2900

12.4. Computer printout showing characteristics of system at start of study year

Table XII-4 shows the various characteristics of the system as it was assumed to be in the first quarter of 1977 which is the first study year.

TABLE XII-4. CHARACTERISTICS OF THE GENERATING UNITS IN THE SYSTEM AT START OF STUDY (first quarter 1977)

Name[a]	No. of units	Unit capacity (MW)	Hours base	Hours peak	Energy base (GWh)	Energy peak (GWh)	Operating cost Local (K $)	Operating cost Foreign (K $)	Cap fact
PTO	1	70	2001.66	1577.00	36.03	80.13	479.73	0.0	75.77
PTL	2	125	1702.52	1230.20	108.96	192.35	1343.07	0.0	55.03
PTM	4	300	1740.25	1740.25	522.08	1461.66	7715.43	0.0	75.48
MEG	2	125	1702.52	19.61	105.56	2.48	955.48	0.0	19.73
ALI	1	150	2025.75	7.26	76.98	0.62	175.50	468.51	23.62
ALV	2	40	665.94	0.0	47.13	0.0	328.93	0.0	26.90
ALF	2	150	2073.93	302.64	157.62	46.22	396.00	1056.71	31.03
STG	1	200	2071.74	500.66	103.59	63.84	264.00	818.81	38.22
STE	1	160	2073.93	127.57	82.96	11.16	211.20	501.86	26.86
STR	2	60	2047.65	44.46	61.43	3.20	158.40	356.62	24.59
STS	0	30	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LAR	1	300	1782.18	885.94	133.66	161.05	396.00	1336.90	44.86
GAT	2	13	4.11	0.0	0.11	0.0	68.53	0.0	0.19
HYD	1	1400	2190.00	1173.29	657.00	383.06	546.00	0.0	33.92
ALIR	1	140	2071.74	57.75	145.02	3.73	184.80	682.77	48.52
PHIL	1	125	1693.31	9.87	110.07	0.39	766.78	0.0	40.35
KARD	0	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[a] See Table XII-1(c) for station/unit identification.

13. CAPITAL COST DATA

13.1. Basis for thermal plant cost estimates developed by ORCOST computer code

Appendix B describes in detail how capital cost estimates were developed using the ORCOST computer program. The required input data for this program are shown in Table 5 of Appendix B. Except for the equipment, materials and labour cost indices, which varied for each country, these input data were kept constant to provide consistency among results. The following describes how the input data were established.

(a) Interest rate

ORCOST-1 and ORCOST-3 capital cost estimates were based on an assumed 8% interest rate during construction. This was assumed to be constant for all study cases even though the present-worth discount rate was varied from 6% to 10%. The effects of this assumption on the results of the Survey are discussed in Section 16.3.

(b) Construction schedules

The construction schedules for each size and type of plant used in the studies are shown in Table XIII-1.

TABLE XIII-1. CONSTRUCTION SCHEDULES ASSUMED IN CAPITAL COST ESTIMATES (yr)

Plant size (MW)	Oil	Lignite	Nuclear
125	-	3.0	-
140	2.6	-	-
300	3.0	3.5	5.0
400	3.2	3.7	5.2
600	3.5	4.0	5.5
800	3.7	4.2	5.7

(c) Contingency and spare parts factors

As seen in Table 5 of Appendix B, contingency factors were taken as 5% on equipment and materials and 10% on construction labour. The spare parts factor was assumed to be 1% of equipment and material costs corresponding to US practic .

(d) Other considerations

The ORCOST program allows for the inclusion of unusual costs such as costs of special materials, the use of cooling towers instead of river or ocean water, the inclusion of SO_2 removal equipment and overtime pay; however, none of these costs was included in the capital cost estimates. Electrostatic precipitators are included in all fossil-fuelled plant costs.

13.2. Derivation of country indices

(a) Equipment and cost indices

A recent review of world market prices of conventional fossil plant equipment indicated that on a competitive bid basis these should be about 85% of the prices used in ORCOST. Allowing 5% additional for transportation costs of such equipment gave an equipment index for conventional thermal plants of 0.90. In the case of nuclear plant equipment, however, it was concluded that world market prices would be equal to those in the USA and, after allowing for transportation costs, this gave an equipment index of 1.05 for PWR plants.

(b) Materials cost indices

It was assumed that the cost of construction materials at the job site in Greece would be the same as in the USA after adjusting for possible lower base prices for local supplies and higher transportation costs for imported materials.

(c) Labour cost index

Based on data provided by PPC and evaluations of productivity and basic labour rates in other developing countries a labour cost index of 0.38 was established.

The above three factors are summarized in Table XIII-2.

(d) Indirect cost indices

These were taken to be the same as used in ORCOST (see Appendix B for details).

TABLE XIII-2. ASSUMED COST INDICES

	Type of plant		
	Nuclear	Oil	Lignite
Equipment cost	1.050	0.950	0.950
Materials cost	0.85	0.85	0.85
Labour cost	0.380	0.380	0.380

13.3. Summary of costs of generating units considered as expansion alternatives

(a) ORCOST printouts of capital cost data

Table XIII-3 summarizes the costs assumed for various types and sizes of plants. These costs are derived from the ORCOST program by modifying the base model costs with the indices referred to above and in Table XIII-2 to convert the costs to those expected to be prevailing in Greece.

Tables XIII-4 and XIII-5 show the detail breakdown of capital costs of 600 MW oil and nuclear plants respectively, as computed by ORCOST. Lignite plants are assumed to cost 1.3 times the cost of oil plants.

(b) Comparison of ORCOST calculations to reported costs of recent plants

Table XIII-6 gives a comparison of reported (see Table III-2) and computed costs for the Megalopolis No. 1 and St. George's Bay No. 9 units, respectively. It can be seen that the reported and computed costs are in the same range for the lignite-fired plant Megalopolis No. 1, whereas for the oil-fired St. George's Bay No. 9 unit the reported costs are much lower than the computed ones. This may be due to the fact that the St. George's Bay unit is an extension of an existing plant and the indirect costs will have been limited by this.

TABLE XIII-3. PLANT CAPITAL COSTS (US $/kW)

Gross capacity (MW)	Nuclear [a]	Oil	Lignite
125	-	-	370
140	-	270	-
300	478	222	290
400	418	205	-
500	-	195	-
600	351	182	237
800	312	-	-

[a] Does not include capital portion of nuclear fuel.

TABLE XIII-4. ORCOST-3, CAPITAL COST ESTIMATES FOR A 600 MW OIL PLANT (10^6 US $)[a]

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	1.2	11.6	9.2	22.0
22	REACTOR/BOILER PLANT EQUIPMENT	31.0	10.1	5.8	47.0
23	TURBINE PLANT EQUIPMENT	28.2	7.2	5.5	40.9
24	ELECTRIC PLANT EQUIPMENT	4.9	5.9	3.3	14.2
25	MISCELLANEOUS PLANT EQUIPMENT	1.9	0.2	1.0	3.1
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	UPGRADED RADWASTE SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	67.3	35.0	24.8	127.2
	CONTINGENCY ALLOWANCE				7.6
	SPARE PARTS ALLOWANCE				1.0
	SUBTOTAL (PHYSICAL PLANT)				135.8
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				135.8
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES				9.3
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES				23.9
93	OTHER COSTS				5.2
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 5.50 YRS)				36.0
	SUBTOTAL (TOTAL INDIRECT COSTS)				74.4
	SUBTOTAL (TOTAL PLANT COST)				210.3
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				210.3
	$ / KW(E)				351.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				210.3
	$ / KW(E)				351.

[a] Costs are in 1972 constant dollars.

TABLE XIII-5. ORCOST-3, CAPITAL COST ESTIMATES FOR A 600 MW PWR PLANT (10^6 US $)[a]

		EQU.	MAT.	LABOUR	TOTAL
	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT				
21	STRUCTURES AND SITE FACILITIES	0.5	5.9	4.1	10.4
22	REACTOR/BOILER PLANT EQUIPMENT	16.2	3.9	4.8	25.0
23	TURBINE PLANT EQUIPMENT	17.1	5.1	3.9	26.1
24	ELECTRIC PLANT EQUIPMENT	3.9	1.4	2.0	7.3
25	MISCELLANEOUS PLANT EQUIPMENT	0.9	0.6	0.7	2.2
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	38.7	16.9	15.4	71.0
	CONTINGENCY ALLOWANCE				4.3
	SPARE PARTS ALLOWANCE				0.6
	SUBTOTAL (PHYSICAL PLANT)				75.9
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				75.9
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES				6.7
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES				11.0
93	OTHER COSTS				3.1
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				12.2
	SUBTOTAL (TOTAL INDIRECT COSTS)				33.1
	SUBTOTAL (TOTAL PLANT COST)				109.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				109.1
	$ / KW(E)				182.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				109.1
	$ / KW(E)				182.

[a] Costs are in 1972 constant dollars.

TABLE XIII-6. COMPARISON OF REPORTED AND COMPUTED POWER PLANT COSTS

Name	Power plant description				Capital costs (US $/kW) [a]						Ratio of ORCOST costs to reported costs	
	Unit No.	Size (MW)	Type	Comm. date	Reported [b]		ORCOST-1		ORCOST-3		ORCOST-1	ORCOST-3
					Direct	Total	Direct	Total	Direct	Total	Total	Total
Megalopolis	1	125	Lignite	8/70		278	168	315	177	300	1.14	1.08
St. George's Bay	9	200	Oil	7/71		115	119	220	124	212	1.91	1.85

[a] At indicated commissioning date.
[b] Excluding taxes and duties.

(c) Breakdown into local and foreign components

The factors used for determining the amount of domestic and foreign currencies are indicated in Table XIII-7.

TABLE XIII-7. DIVISION OF CAPITAL COSTS BY DOMESTIC AND FOREIGN CURRENCIES

Plant type	Domestic % of total	Foreign % of total
Lignite	40	60
Fuel oil	40	60
Nuclear	30	70

13.4. Treatment of transmission costs

Costs of the transmission systems were not included in the economic analyses and comparisons, except in the case of certain remote hydro projects, since it was assumed that any transmission system would be the same whether the generating units were oil, coal, lignite or nuclear units. Due to the generally remote location of hydro projects average capital costs of transmission lines were added to the assumed hydro project capital costs and the hydro project's energy was discounted by a factor to take account of transmission losses to the load centre. The transmission costs were based on data provided by PPC for typical transmission voltages up to 380 kV, discussed in Section 3.4(d).

13.5. Costs of hydro plants added during study period

Average costs adopted for added hydro capacity were derived from recent hydro project costs as given in Table III-2. The values used in the analyses are shown in Table XIII-8. These costs include a transmission line cost factor as discussed in Section 13.4(d).

TABLE XIII-8. ASSUMED COSTS FOR ADDED HYDRO PLANTS

Plant size (MW)	Capital costs (US $/kW)
200	330
300	280
400	245
500	220
600	205
700	190
800	180
900	170
1000	160

As indicated earlier, the changes in these costs would not actually affect the final comparative results of thermal expansion alternatives as the hydro input is fixed and, therefore, its costs are constant for all the alternatives studied.

14. CHARACTERISTICS OF ALTERNATIVE GENERATING UNITS CONSIDERED FOR EXPANSION DURING STUDY PERIOD

14.1. Review of plans for system expansion

The plans established by PPC for the system expansion were described in Section 5. The electric system will be developed in two phases. In the first phase, which will last up to the mid-1980s, priority will be given to the use of the hydro and lignite resources of the country and in the second phase the use of nuclear energy will be adopted assuming no more larger lignite resources are discovered. Table V-3 shows the planned installed capacity through the period 1990-91.

14.2. Characteristics of hydro projects which might be added

Following the planning criteria of PPC, priority was given to the hydro project installations as listed in Section 2. Table XII-2 shows the installed capacity (MW) and energy (GWh) for the hydro projects assumed for the study.

14.3. Minimum and maximum thermal capacity additions required

After fixing the schedule of hydro projects which might be added to the system, it was possible to fix the schedule of total thermal capacity additions required for adequate system reliability. This was defined for Greece as being a loss-of-load probability of a maximum of 0.010 with an average of the annual values over the study period of 0.005. Trial computer studies indicated that to stay within this range of loss-of-load probability, the minimum reserve margin should be about 30% in the critical (hydro) quarter, but during some years, when large hydro installations were assumed to be added to the system, the reserve margins exceeded 40% The maximum reserve margins were held as close to the minima as possible within the limits set by the choice of unit capacities to be considered. The actual loss-of-load probability averaged about 0.0042.

14.4. Characteristics of thermal units for alternative generation system (WASP Module 3)

(a) Choice of unit sizes and types of plants

The WASP program for evaluating alternative generating units being considered as possible additions to the electric power system is limited to a total of 20 different types and sizes of which all hydro is considered as one. The types and sizes of thermal plants selected are shown in Table IX-1 and the characteristics of the selected plants are shown in detail in Table XIV-1.

It should be noted here that the maximum unit size given in Section 11.4 is 350 MW up to 1984 and 500 MW from 1985 to 1990. Since the unit sizes selected for these analyses did not include 350 MW or 500 MW units, the next larger sizes, namely 400 MW and 600 MW, were used. In using these unit sizes, it is recongized that the frequency stability may be slightly less than desired. Refer to Section 11.4 for further discussion of these possible effects.

(b) Minimum operating capacities

The minimum operating capacity for the steam generating units was assumed to be 50% of the (nameplate) rated capacity (as discussed in Appendix E).

(c) Heat rates

Half (base) load heat rates and incremental heat rates were taken from data given in Appendix G for all expansion alternative plants except for the plants described in the first three lines of Table XIV-1 which are designed to burn two fuels such as oil and lignite or peat. In those cases heat rate data were derived from information on plant designs and fuel data provided by PPC.

TABLE XIV-1. WASP PRINTOUT SHOWING EXPANSION ALTERNATIVE PLANTS AND THEIR CHARACTERISTICS[a]

	NAME	NO. OF SETS	MIN. LOAD MW	CAP-CITY MW	BASE LOAD HEAT RATE	AVGE INCR HEAT RATE	FUEL COSTS CENTS/MILLION DMSTC	FORGN	TYPE	L C T N	FRCD OUT-AGE RATE	DAYS SCHL MAIN	MAIN CLAS	ENRGY GWH	O&M (FIX)	O&M (VAR)	FULL LOAD HEAT RATE
1	ALIR	0	70	140	2487.	2249.	0.0	185.00	1	1	5.40	30	150	0.	0.440	0.0	2368.
2	PHIL	0	65	125	2810.	2499.	200.00	0.0	3	1	8.00	30	100	0.	0.390	0.0	2661.
3	KARD	0	150	300	2702.	2446.	125.00	0.0	3	1	8.70	30	300	0.	0.390	0.0	2574.
4	N800	0	400	800	2632.	2369.	0.0	53.20	0	1	12.20	35	800	0.	0.270	0.0	2500.
5	N600	0	300	600	2638.	2365.	0.0	55.10	0	1	12.00	28	600	0.	0.320	0.0	2501.
6	N400	0	200	400	2643.	2362.	0.0	57.00	0	1	9.80	28	400	0.	0.420	0.0	2502.
7	N300	0	150	300	2645.	2360.	0.0	57.90	0	1	6.50	28	300	0.	0.520	0.0	2503.
8	0800	0	400	800	2334.	2170.	0.0	185.00	1	1	12.20	35	800	0.	0.440	0.0	2252.
9	0600	0	300	600	2328.	2172.	0.0	185.00	1	1	12.00	28	600	0.	0.440	0.0	2250.
10	0500	0	250	500	2404.	2203.	0.0	185.00	1	1	11.00	30	600	0.	0.440	0.0	2304.
11	0400	0	200	400	2324.	2098.	0.0	185.00	1	1	9.80	28	400	0.	0.440	0.0	2211.
12	0300	0	150	300	2335.	2183.	0.0	185.00	1	1	6.50	28	300	0.	0.440	0.0	2259.

[a] For nomenclature see Table XII-1(b).

(d) Other data

Operating and maintenance costs, forced outage rates and scheduled maintenance times were taken from data given in Appendix E. Fuel oil costs were derived from the base cost of 168 US ¢/10^6 kcal plus 17 ¢10^6 kcal for inland transportation costs (see Appendix I). Nuclear fuel cycle costs were taken from data given in Appendix J.

15. ANALYSIS OF ALTERNATIVE EXPANSION PROGRAMS

15.1. Method of analysis

(a) Description of method used to determine "near-optimum" expansion program

The method adopted to determine a near-optimum program consisted of, first, studying different alternative expansion plans to establish the relationship between unit sizes, timing, the loss-of-load probability and cost. Table XV-1 shows the capacity additions which resulted from this analysis and the types and sizes of units assumed or selected. Then, using this expansion schedule, several computer runs were made in which the thermal capacity assumed between each year of the decade under study and the year 1990 is taken as nuclear with the earlier years remaining as oil-fired plants. The values of the objective functions in the year 2000 for the various expansion alternatives were adopted as the criterion to compare and select the best alternative. The expansion alternative presenting the minimum objective function in the year 2000 is considered the best alternative and the nuclear installed capacity between the year of introduction of the first nuclear plant and 1990 represents the market for nuclear power plants.

(b) Summary of cases considered

Ten alternative cases were studied. Some alternatives were studied in the initial approach based on the PPC program of expansion, with slight modifications, and replacement of one fossil plant by one nuclear plant at a time. The other expansion alternatives studied are those based on the forecast of Table X-1 and referred to in Section 9.1 and 9.5,

For each of the alternatives considered, a reference case was adopted, as described in Section 9.3, and additional sensitivity analyses conducted, as described in Section 9.5, with a shadow exchange rate of 1.30, discount rates of 6% and 10%, % and 4% fuel oil price escalation, 2% nuclear fuel escalation, and ORCOST-1 capital costs. For each sensitivity analysis only one parameter was modified at a time, all the other parameters being kept identical to the reference case.

15.2. Derivation of input data required for WASP Module 4-6

(a) Schedules of plant additions during study period

The schedules of plant additions assumed are shown in Table XV-1.

(b) Expansion configurations from end of study period to horizon

Table XV-2 shows the expansion configuration between the years 1990 and 2000 which was kept constant for all the alternatives studied.

(c) Minimum and maximum reserve range during critical period

The reserve margin was kept at a minimum of 30% in the critical quarter with exceptions for some years where it exceeded 40% due to the installation of large hydro projects.

(d) Loading order of all plants in the system

The loading of the plants under the load duration curve was carried out with due consideration to the order of the incremental fuel costs for the various plants. These were calculated from heat rates given in Appendix G and fuel costs as given in Appendixes I and J. This resulted in the following loading order starting with the base of the load duration curve, hydro base plants, nuclear plants, lignite and oil-fired plants according to their incremental fuel costs and gas turbines. In all cases smaller plants were loaded above the larger ones.

Plants in the system at the start of the study period were interspersed throughout the loading order depending on their incremental fuel costs. In the case of hydro peaking capacity, the WASP program calculates the position of this capacity under the load duration curve that makes use of all of the available energy from the hydro units. Thus, it is not necessary to specify a loading order for the peak hydro. More details of this procedure are given in Appendix A.

(e) Other input data

The various economic parameters used in the study are presented in detail in Appendixes B, D and K. The base for the present-worth calculations was 1 January 1973.

TABLE XV-1. SYSTEM CAPACITY EXPANSION SCHEDULE – REFERENCE CASE

Year	Capacity (MW)						% Reserve [a]	Annual loss-of-load probability
	Retirements	Nuclear	Conventional steam	Hydro	Gas turbines	Total		
Total system 1977	0	0	3 080	1 400	26	4 506		
Additions 1977-1979	0	0	955	160	0	1 115		
Total system 1979		0	4 035	1 560	26	5 621	35	0.0025
1980 [b]		0	0	170		170	29	0.0053
1981		0	300	360		660	34	0.0034
1982		400	0	0		400	30	0.0045
1983	-80	400	0	300		620	35	0.0055
1984		400	0	307		707	36	0.0047
1985		600	0	288		888	40	0.0035
1986	-126 -26	600	0	400		854	42	0.0044
1987		600	0	170		770	42	0.0032
1988		600	0	210		810	43	0.0034
1989	-70	600	0	360		890	44	0.0039
Total additions 1980-89	-296 [c]	4 200	300	2 565	0	6769 [c]	Average 37.5	Average 0.0042
Total system 1989	-	4 200	4 335 -270 4 065 [c]	4 125	26 -26 0 [c]	12 390 [c]	-	-
Additions 1990-2000	-	5 200	3 400	4 480	0	13 080	-	-
Total stem 2000	-	9 400	7 465	8 605	0	25 470	-	-

[a] Critical quarter.
[b] Additions and retirements each year.
[c] 270 MW thermal units and 26 MW of gas turbines netted out during period.

TABLE XV-2. ASSUMED PLANT ADDITIONS (MW)

Year	Nuclear	Oil	Hydro	Total
1990		600	360	960
1991	600		320	920
1992		600	400	1 000
1993	600		450	1 050
1994		600	400	1 000
1995	800		450	1 250
1996	800		500	1 300
1997		800	500	1 300
1998	800		500	1 300
1999	800		600	1 400
2000	800	800	-	1 600
Total	5200	3 400	4 480	13 080

16. RESULTS

16.1. Selection of the optimum expansion program in the reference case

Values of the objective functions for the cases considered are shown in Table XVI-1 for the reference case and for the sensitivity studies carried out. For each case studied (i.e. reference and sensitivity cases) a series of computer runs were made assuming that nuclear units were first installed (substituted for fossil-fired units of the same rating) in a given year and in all subsequent years of the study decade. The lowest value of the objective function indicates the near-optimum solution. For example, in the reference case of Table XVI-1, introduction of nuclear plants from 1982 onwards shows the lowest objective function; hence, it is considered to be the near-optimum solution. As the parameters are varied, each sensitivity study develops its own unique solution.

As may be seen from Table XVI-1, slight changes in the parameters selected for the reference conditions will change the objective function up or down, with the result that either nuclear or fossil-fired plants could be in the preferred position.

As can be seen, the use of a zero rate of oil price escalation or a 2% rate of nuclear fuel price escalation provides a near-optimum solution only if nuclear plants are introduced as late as 1985.

16.2. Market for nuclear plants during study period

Table XV-1 shows a near-optimum expansion schedule for the load forecast based on the reference conditions and sensitivity cases. Table XVI-2 shows the resulting nuclear units called for from these studies.

It can be seen that the total market could vary from 3000 MW to 4500 MW during the study period. These amount to about 34% of the total system capacity by the year 1990 in the reference case, although it corresponds to 62% of the added capacity during the decade under study. (See Table XV-1.)

16.3. Sensitivity analysis

The analysis carried out to evaluate the sensitivity of the reference case to the various key economic parameters, such as shadow rate of exchange, fuel escalation, discount rates and lower nuclear capital costs, are summarized in Table XVI-2.

It is important to stress that in all these alternatives all of the nuclear plant installations are assumed to be contained in the period between the year of introduction of the first nuclear plant and the year 1990. However, some sensitivity analyses have been carried out and more studies could be done where the nuclear plant additions are scattered over the ten years' period instead of being contained together over a contiguous sequence of years.

In the reference case, the salvage value of plants at the end of the year 2000 was based on linear depreciation which tends to penalize capital intensive alternatives. The use of sinking fund depreciation as a base for determining plant salvage values would improve even further the competitive position of nuclear plants.

16.4. Financial considerations associated with reference case expansion program

Capital costs of alternative generating units considered in the expansion plans were calculated by the ORCOST program described in Section 13 and in Appendix B. These capital costs were used by the WASP program in determining the objective functions of each expansion alternative.

As a supplement to the basic analyses described above, it was decided to determine the year-by-year domestic and foreign cash requirements of the reference case expansion plan, as a guide to planners and financial institutions. In order to accomplish this, a computer program was written (cash-flow program).

TABLE XVI-1. OBJECTIVE FUNCTIONS FOR CASES STUDIED (10^9 US $)

Year of first introduction of nuclear plants	Reference case [a]	Sensitivity studies						
		6% discount rate	10% discount rate	0% fuel oil escalation rate	4% fuel oil escalation rate	ORCOST-1	Shadow exchange rate 1.3	2% nuclear fuel escalation rate
1981	2.450	3.044	1.984	2.389	2.539	2.359	2.340	2.579
1982	2.442	3.041	1.972	2.378	2.533	2.360	2.819	2.555
1983	2.451	3.064	1.972	2.371	2.563	2.380	2.828	2.553
1984	2.450	3.086	1.975	2.364	2.593	2.398	2.837	2.551
1985	2.467	3.107	1.974	2.358	2.622	2.416	2.846	2.550
1986	2.491	3.152	1.986	2.361	2.676	2.450	2.874	2.561

[a] For reference case parameters refer to Section 9.3.

TABLE XVI-2. SUMMARY OF NUCLEAR UNITS FROM SENSITIVITY STUDIES (MW)

Year	Reference case	Sensitivity studies						
		6% discount rate	10% discount rate	0% fuel escalation rate	4% fuel escalation rate	ORCOST-1	Shadow exchange rate 1.3	2% nuclear fuel escalation rate
1981						300		
1982	400	400	400		400	400	400	
1983	400	400	400		400	400	400	
1984	400	400	400		400	400	400	
1985	600	600	600	600	600	600	600	600
1986	600	600	600	600	600	600	600	600
1987	600	600	600	600	600	600	600	600
1988	600	600	600	600	600	600	600	600
1989	600	600	600	600	600	600	600	600
Total additions 1980-89	4200	4200	4200	3000	4200	4500	4200	3000
Total system 1989	4200	4200	4200	3000	4200	4500	4200	3000
Nuclear % of total system capacity 1989	34	34	34	24	34	26	34	24

The input data required for the cash-flow program for each year of the study period and for each plant that became operational during that year are as follows. Plants were assumed to become operational on 1 January and capital costs were assumed to have been fully expended by the end of the preceding year. These assumptions are consistent with the WASP program.

(a) Plant construction schedule (the same schedule, in years, that was used in the ORCOST calculations). The ORCOST-3 total plant capital costs (including interest during construction) are distributed over the construction period according to the expenditure-time schedules (S-curve) assumed in ORCOST.

(b) Per cent of expenditure that was domestic (the foreign being 100 minus this value).

(c) Capital costs, in US $/kW (same value as used in the WASP program; this value includes interest during construction).

(d) Unit capacity, in MW.

The cash-flow program, using a fourth order polynomial approximation of the S-curve used in the ORCOST program, developed the year-by-year domestic and foreign expenditures associated with each plant. These values were printed in tabular form, together with the annual totals.

It should be noted that nuclear plants were entered in two parts, (i) the cash requirements of the plant excluding the first (fuel) core, and (ii) the cash requirements of the first core. These first core requirements were calculated on the basis of 90% cash required during the year preceding operation, and 10% being required one year earlier.

Table XVI-3 displays the domestic and foreign cash flows associated with capital investments for the near-optimum solution, based on reference conditions, i.e. that of

TABLE XVI-3. CASH FLOW FOR THERMAL PLANTS COMMISSIONED IN 1980-1989 (10^6 US $)

DOMESTIC CASH FLOW

YEAR	PLANT	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
1980	No Plants Added																
1981	L300	.0	.0	.0	.3	6.8	17.4	10.1	.0	.0	.0	.0	.0	.0	.0	.0	34.7
1982	N400	.0	.0	.2	1.5	8.2	16.0	17.6	6.4	.0	.0	.0	.0	.0	.0	.0	50.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1983	N400	.0	.0	.0	.2	1.5	8.2	16.0	17.6	6.4	.0	.0	.0	.0	.0	.0	50.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1984	N400	.0	.0	.0	.0	.2	1.5	8.2	16.0	17.6	6.4	.0	.0	.0	.0	.0	50.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1985	N600	.0	.0	.0	.0	.0	.3	3.1	11.7	20.0	20.7	7.1	.0	.0	.0	.0	63.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1986	N600	.0	.0	.0	.0	.0	.0	.3	3.1	11.7	20.0	20.7	7.1	.0	.0	.0	63.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1987	N600	.0	.0	.0	.0	.0	.0	.0	.3	3.1	11.7	20.0	20.7	7.1	.0	.0	63.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1988	N600	.0	.0	.0	.0	.0	.0	.0	.0	.3	3.1	11.7	20.0	20.7	7.1	.0	63.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1989	N600	.0	.0	.0	.0	.0	.0	.0	.0	.0	.3	3.1	11.7	20.0	20.7	7.1	63.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Domestic total		.0	.0	.2	2.1	16.8	43.6	55.6	55.4	59.4	62.4	62.7	59.6	47.8	27.8	7.1	501.1

FOREIGN CASH FLOW

YEAR	PLANT	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
1980	No Plants Added																
1981	L300	.0	.0	.0	.5	10.2	26.2	15.1	.0	.0	.0	.0	.0	.0	.0	.0	52.1
1982	N400	.0	.0	.5	3.5	19.2	37.3	41.2	15.0	.0	.0	.0	.0	.0	.0	.0	117.0
	Fuel	.0	.0	.0	.0	.0	.0	1.2	11.5	.0	.0	.0	.0	.0	.0	.0	12.7
1983	N400	.0	.0	.0	.5	3.5	19.2	37.3	41.2	15.0	.0	.0	.0	.0	.0	.0	117.0
	Fuel	.0	.0	.0	.0	.0	.0	.0	1.2	11.5	.0	.0	.0	.0	.0	.0	12.7
1984	N400	.0	.0	.0	.0	.5	3.5	19.2	37.3	41.2	15.0	.0	.0	.0	.0	.0	117.0
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	1.2	11.5	.0	.0	.0	.0	.0	12.7
1985	N600	.0	.0	.0	.0	.0	.9	7.3	27.4	46.6	48.3	16.6	.0	.0	.0	.0	147.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	.0	16.8
1986	N600	.0	.0	.0	.0	.0	.0	.9	7.3	27.4	46.6	48.3	16.6	.0	.0	.0	147.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	16.8
1987	N600	.0	.0	.0	.0	.0	.0	.0	.9	7.3	27.4	46.6	48.3	16.6	.0	.0	147.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	16.7
1988	N600	.0	.0	.0	.0	.0	.0	.0	.0	.9	7.3	27.4	46.6	48.3	16.6	.0	147.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	16.8
1989	N600	.0	.0	.0	.0	.0	.0	.0	.0	.0	.9	7.3	27.4	46.6	48.3	16.6	147.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	16.8
Foreign total		.0	.0	.5	4.6	33.5	87.3	122.6	142.2	151.5	159.0	163.3	155.9	128.3	81.7	31.7	1262.8
Total - nuclear fuel only		.0	.0	.0	.0	.0	.0	1.2	12.7	12.7	13.2	16.7	16.7	16.7	16.7	15.0	121.6

Table XV-1. The cash flows are given for each plant and for the total program. Only thermal plants (fossil and nuclear) commissioned during the 1980s are included. The cash flows begin in 1976 and peak in 1984. However, in fact, they will continue to increase after the peak years because of expenditures on plants to be commissioned during the 1990s.

For the nuclear plants the fuel cycle working capital requirements are also shown. Although individual fuel purchases are normally financed over short terms, e.g. three to five years, there is in fact a substantial investment outstanding in fuel over the life of the plant. Also, the fuel capital investments used in the WASP economic evaluation are the present-worth levelized average investment over plant life; thus they may be used as an approximation to the cost of the first core and in Table XVI-3 they have been distributed over the two years preceding commissioning more or less according to the payment schedule for the first core (Appendix J). The total requirements are about US $1764 million, about US $1263 million being in foreign currency. (Note: These are 1973 costs with no allowance for escalation.) The nuclear fuel costs are shown separately by years and in total, at the lower part of Table XVI-3. The total is about US $1[illegible] million, all of which requires foreign exchange.

17. SUMMARY AND CONCLUSIONS

17.1. Basic conditions

Table XVII-1 summarizes the conditions used in the analyses of various alternative expansion plans for the electric generation system in Greece during the period 1980 to 1989. From the figures given in this table it is seen that during the study period there is a total addition of 4200 MW of thermal capacity.

In carrying out the analyses, it was assumed that the schedules of hydro capacity additions would be fixed and were therefore held constant for all cases considered. The hydro schedules are referred to in Section 14.2, and the selected schedules are given in Table XII-2. These additions represent appropriate selections from the hydro projects being considered for construction by PPC.

TABLE XVII-1. SUMMARY OF CONDITIONS USED IN THE ANALYSES

	1979	1989
Population (10^6)	9.2	9.8
GNP/capita (US $/yr) [a]	1315	2110
Energy consumption (GWh/yr)	23660	49170
Peak demand (MW)	4175	8676
Total installed capacity (MW)	5621	12390
Installed capacity, critical period (MW)	5621 [b]	11770 [c]
Total thermal capacity (MW)	4061	8265
Average reserve margins (%)	37.5	
Average loss-of-load probability	0.0042	

[a] 1964 US $.
[b] Fourth quarter (hydro capacity = total hydro capacity).
[c] Third quarter (hydro capacity = 85% of total hydro capacity).

17.2. Economic basis

The economic merit of the various alternatives was determined from an objective function representing the present worth of all costs associated with the construction and operation of the generating units being considered. External or social costs were disregarded, as were taxes and restraints on foreign capital. Although the study period was extended to a horizon ending in the year 2000, the capacity additons during the 1990-2000 period were held constant and assumed to contribute a constant amount to the objective function. Thus, changes in the objective function are essentially caused by changes in the types and sizes of units added during the study period.

The economic data used as a basis for present-worth calculations are summarized in Table XVII-2. The capital costs were derived for construction conditions in Greece as described in Section 13. The heat rates given are based on data in Appendix G and other unit costs are given in Section 14.4(d).

17.3. Summary of cases considered

A number of trial computer runs were made to establish the sizes of capacity additions required to give the desired loss-of-load probability for each year of the study period.

TABLE XVII-2. ECONOMIC DATA ASSUMED IN THE ANALYSES

Plant types and sizes	Capital costs (US $/kW)			Full load heat rate (kcal/kWh)	Half load heat rate (kcal/kWh)	Fuel costs (US ¢/10^6 kcal)	O & M costs (US $/kW-month)	Annual availability (%)
	Local	Foreign	Total					
L125	148	222	370	2661	2810	200.0	0.39	84
O140	108	162	270	2368	2487	185.0	0.44	87
O300	89	133	222	2259	2335	185.0	0.44	86
O400	82	123	205	2211	2324	185.0	0.44	83
O500	78	117	195	2304	2404	185.0	0.44	81
O600	73	109	182	2250	2328	185.0	0.44	80
O800	67	99	166	2252	2334	185.0	0.44	78
C300	116	174	290	2574	2702	160.0	0.39	83
N300	143	335	478	2503	2645	57.9	0.52	86
N400	125	293	418	2502	2643	57.0	0.42	83
N600	105	246	351	2501	2638	55.1	0.32	80
N800	94	218	312	2500	2632	53.2	0.27	78

These runs also served to indicate which of the various fossil fuels resulted in minimum costs with the reference economic parameters. The results showed that the addition of 400 MW nuclear units in the 1982-84 period and 600 MW nuclear units starting in 1985 (see Table XVI-2) would give near-optimum programs and that lignite would be the most economic fossil fuel.

However, since lignite reserves are indicated only to meet the demand of about 2800 MW of lignite-fired power plants for 30 years (see Section 2.2(e)), no lignite-fired plant additions beyond a total of 2800 MW were considered.

Having established the desired schedule of capacity additions, additional computer runs were carried out to evaluate the competition between nuclear plants and lignite plants. In all of these runs, the sensitivity of the results to variations in economic parameters such as discount rate, fuel escalation rates, capital costs of generating units and method of depreciation was considered. The results of these studies are given in detail in Section 16.

The result was that 400 MW and 600 MW nuclear units seemed to give the optimum results. The use of 0% fossil fuel escalation rate or 2% nuclear fuel escalation rate resulted in a reduction of 1200 MW in the market. The use of ORCOST-1 capital costs, giving a closer relationship between the nuclear and fossil plant capital costs, resulted in an increase of 300 MW of nuclear capacity.

17.4. Potential 1980-1989 nuclear power market

The potential market for nuclear plants in Greece under varying economic conditions is shown in Table XVI-2. It is seen that the potential nuclear market varies from 3000 MW to 4500 MW.

17.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980-1989 period is nearly 6800 MW. Because of the abundance of economically exploitable hydroelectric power, however, the market for nuclear thermal plants will only be in the range of maximum 4000 to 4500 MW.

(b) An evaluation of the conventional fuels available in Greece indicates that lignite is the fuel which will be most competitive with respect to nuclear power. The reasons for this conclusion are as follows:

(i) There are no known coal deposits, but there are reasonably large lignite deposits which could supply 2800 MW of lignite-fired power plants for about 30 years.

(ii) Only occurrences of natural gas and oil have been found.

(iii) The present price of fuel oil at the refineries is fixed by the Government. Early 1972 prices were set at 781.2 Dr./t compared to the f.o.b. Persian Gulf posted heavy crude oil prices of about 690 Dr./t. Even if the price of fuel oil drops to a level equal to that prevailing on the world market, such a level will probably be subject to an annual escalation rate of 2% to 4% in excess of the general inflation rate. Under such conditions, lignite would be the preferred fuel.

(c) An evaluation of the competitiveness of nuclear versus lignite plants indicates that under the reference conditions (8% discount rate, 0% escalation on fuel prices) both types of plants are essentially equally competitive at a rated capacity of 400 MW; however, the nuclear plants are more competitive at capacities of 600 MW and above.

(d) The nuclear markets described above are based entirely on economic factors and do not take into consideration other factors, such as the possible scarcity of the required investment capital, local manufacturing and construction capabilities, or the desire for greater diversification of fuel supply, all of which might limit the rate at which nuclear plants can be built. Thus the given nuclear plant market statistics probably represent an upper limit to what will actually be achieved.

BIBLIOGRAPHY

Development Program, 1972-1976, Public Power Corporation (PPC) (1971).

Report on System Development, PPC (Bonnard & Gardel, Consulting Engineers Ltd, Lausanne, and Electro-Watt Engineering Services Ltd, Zurich) (1966).

Current Economic Position and Prospects of Greece, IBRD Rep. No. EMA-36a (1971).

DARRAS, D., CASSAPOGLOU, C., ANDREADIS, C., MARGARITIDIS, P., CHRYSOCHOIDES, N., "Nuclear power in Greece – Evaluation procedure", Nuclear Energy Costs and Economic Development (Proc. Symp. Istanbul, 1969) IAEA, Vienna (1970) 197.

CASSAPOGLOU, C.B., A Method for the Economic Scheduling for Integrating Pumped-Storage Hydroelectric Plants into a Power System, PPC.

SAMARAS, A., Reliability Calculation for Power System Generation and Capacity Reserve using the Probability, Frequency and Duration Method, PPC (presented at UNIPEDE Data Processing Conference, Lisbon, 21-24 June 1971) (1971).

BRELLAS, N., CASSAPOGLOU, C.B., MARGARITIDIS, P., CHRYSOCHOIDES, N.G., PAPADATOS, G., PERRICOS, D.C., "The problem of introducing nuclear power into a fast-growing electrical energy system", 4th Int. Conf. peaceful Uses atom. Energy (Proc. Conf. Geneva, 1971) 4, IAEA, Vienna (1972) 35.

Map of Hellenic Electric Power System, PPC (1971).

Information concerning Studies of Hydro Power Potential in Co-operation with UN, Energy Generation Forecasts and Maximum Demand for 1973-2000, Studies of Geothermal Power Potential, Load Duration and Peak Day Curves for 1970, PPC (1970).

Information on a uranium exploration project in Greece, IAEA/UNDP exploration project (1972).

Statistical Yearbook of Greece, National Statistical Service of Greece (1971).

Economic Development Plan for Greece, 1968-1972, Ministry of Coordination (Central Committee for the Elaboration of the Economic Development Plan) (1968).

Greece Investment Guide, Hellenic Industrial Development Bank (1969).

Activities Report and Balance Sheet for the Year 1970, PPC (1971).

Kastraki Project, Acheloos River; Kremasta Project, Acheloos River, PPC, Administration for Engineering and Construction of Hydroelectric Stations (1971).

Electric Power for Greece, April 1967 - April 1972, PPC (1972).

Thermoelectric Power Station of Megalopolis, PPC (1971).

Map of Hydroelectric Development in Greece.

APPENDIXES

A. WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

B. GENERATING PLANT CAPITAL COSTS (ORCOST)

C. LOAD DESCRIPTION DATA FOR WASP PROGRAM

D. ECONOMIC METHODOLOGY AND PARAMETERS

E. STANDARDIZED DATA FOR GENERATING UNITS CONSIDERED AS EXPANSION ALTERNATIVES

F. LONG-RANGE FORECASTING OF THE DEMAND FOR ELECTRICAL ENERGY

G. BASIS FOR HEAT RATE DETERMINATION

H. GENERALIZED POWER SYSTEM ANALYSIS APPROACH TO DETERMINE SYSTEM LIMITATIONS

I. FUTURE FOSSIL FUEL PRICES

J. NUCLEAR FUEL CYCLE COST TREATMENT

K. SENSITIVITY STUDIES

L. IAEA SERVICES AND ASSISTANCE IN CONNECTION WITH NUCLEAR POWER

M. ABBREVIATIONS USED IN THE MARKET SURVEY REPORTS

N. COOPERATING ORGANIZATIONS AND PARTICIPANTS IN THE MARKET SURVEY MISSION

APPENDIX A

WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

R. Taber Jenkins*

INTRODUCTION

The WASP package is a series of six computer codes which include capabilities especially developed for the needs of the IAEA Market Survey. At the same time, it is a second generation of an earlier power system planning program developed by and for the Tennessee Valley Authority in the United States of America. The package is designed to find the "optimum" power system expansion plan within established constraints. By optimum is meant that the discounted cash flow (capital and operating expense) is minimized over the study period with provision made to reduce effects of uncertainties beyond that period.

Until recent years the choice of generating equipment available to an electric utility was fairly limited. In many cases only one fuel could be considered and it was only necessary to determine the appropriate unit size. The major questions to be resolved were, firstly, the extent to which it was sensible to increase the unit size in order to benefit from the economy of scale at the expense of early investment and of possible system operating problems and, secondly, how much should be spent to reduce heat rates. The traditional method of solution was for the system planner to assume two or three possible expansion plans and to determine their present-worth values either by hand calculations, or, more recently, with computer assistance, but with the planner intervening at various stages of the calculation. Such solutions required many hours of engineer's time in spite of the fact that the range of cases studied was extremely limited.

The choice of generating equipment is now much wider and includes nuclear units, gas turbines, combined cycle, quick start intermediate fossil fuel units and pumped storage stations. Dynamic programming, in its most general sense, is an ideal method for solving the system planning problem. However, even with a limited range of possible expansion plans this method of solution was impractical without the aid of a computer. With the additional range of units now available the number of possible expansion plans is so large that even with the aid of computers general linear programming is impractical.

The WASP package attempts to tread the ground between the two extremes. The system planner is given the facility to direct the area of study to configurations which he believes most economic, but the program will tell him if his restrictions were a constraint on the solution. The WASP program then permits him to modify his constraints and, without repeating all the previous computational effort, to determine the effect of the modification. This process can be repeated until an optimum path conforming with the user-imposed constraints is determined.

The WASP package consists of six modular programs which may be operated sequentially in a single run, or may be operated individually. The six modules are:

(1) a program to describe the forecast peak loads and load duration curves for the system;
(2) a program to describe the existing power system and all future additions which are firmly scheduled;
(3) a program to describe the alternative plants which could be used to expand the power system;
(4) a program to generate alternative expansion configurations;
(5) a program to determine if a particular configuration has been simulated and, if not, to simulate operation with that configuration; and
(6) a program to determine the optimum schedule for adding new units to the system over the time period of interest.

* Tennessee Valley Authority, United States of America.

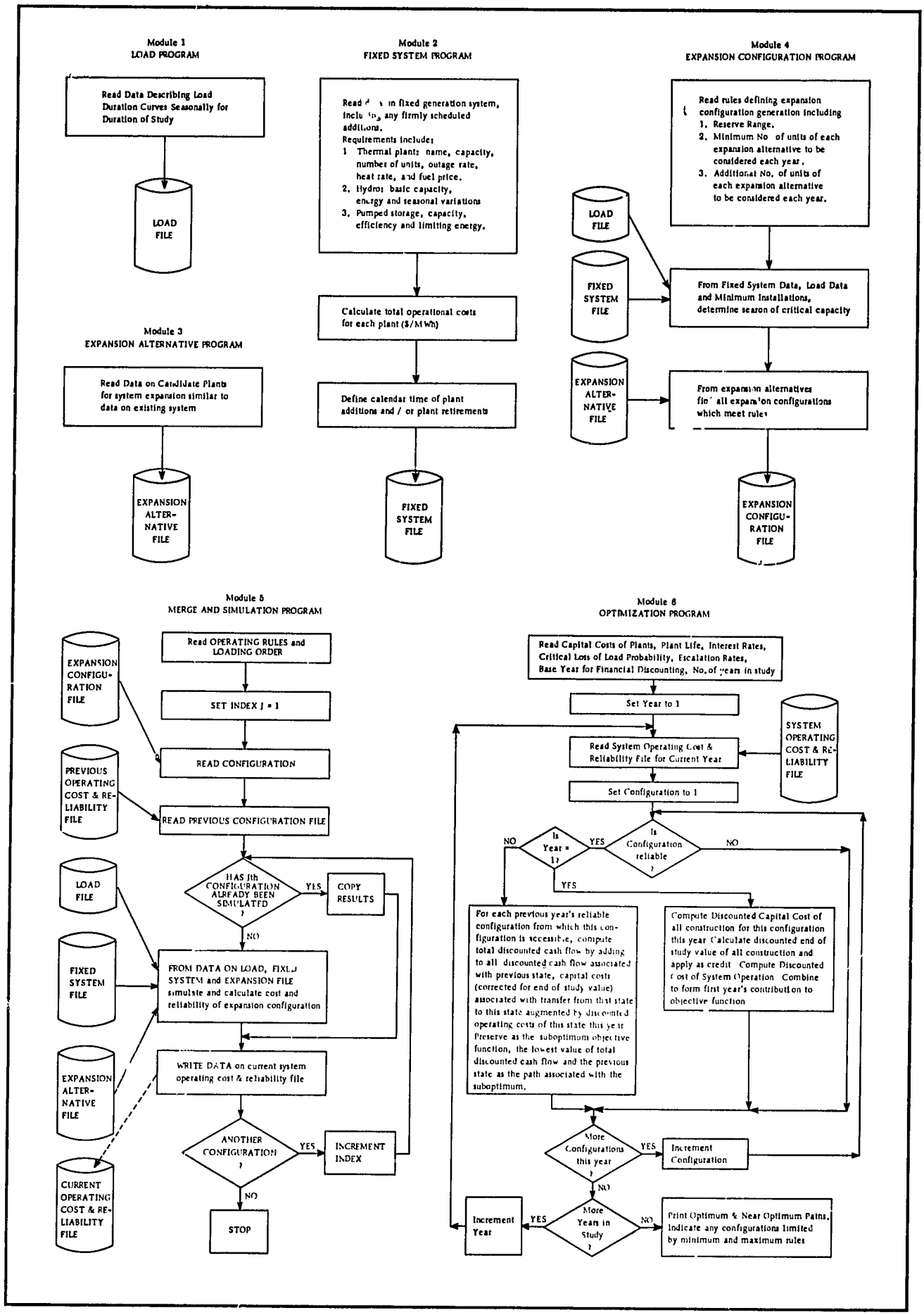


FIG. A-1. WASP PROGRAM FLOW SHEET.

Each of the first three programs creates data files which are used in the remaining programs. Additional files are created by the fourth and fifth program and are used in the sixth. Each program produces a printed summary. Figure A-1 shows a flow chart of this program.

An immediate advantage of the modular program approach is that the first three programs (loads, existing system, expansion alternatives) can be run separately and in parallel to eliminate the bulk of the data errors. These programs are very fast to run, thus avoiding extensive long runs with incorrect data. The separation of the expansion configuration generator from the simulation produces further savings in computer time by permitting elimination of a large number of expansion configurations from being simulated when data errors are made in defining configurations to be considered. The ability to save simulation results on a data file is the major time-saving feature of the program. While searching through successive re-runs of the last three programs for the unconstrained optimum, only those simulations which have not been performed are executed. Since simulation is the most time-consuming part of examining an expansion configuration, the computation time saved can be very large.

The program permits consideration of up to 20 alternative generating units (size, fuel, heat rate etc.). In addition to thermal units, hydro and pumped-storage units can be included in the list of alternatives. If a series of hydro or pumped-storage projects are to be considered by the program, projects of each type must be identified in the chronological order in which they would be installed in the system. Up to 20 such projects may be included in the list. When hydro or pumped-storage units are added to the system, they are merged with existing hydro or pumped-storage units. Therefore, all of the hydro projects count as only one alternative and all of the pumped-storage projects count as an additional alternative.

The expansion configurations to be chosen for simulation in any year are controlled by three factors:

(i) The configuration must satisfy the specified minimum and maximum reserve margin.
(ii) The choices must lie within minimum and maximum constraints (tunnels) specified by the user.
(iii) They must be accessible from at least one of the previous years' alternatives.

The logic of modules 5 and 6 is broken into three general areas: firstly, the simulation of the power system operation which makes use of a probabilistic simulation method which has generated much interest in recent years; secondly, the handling of financial cash flows and their effects on the function to be minimized; thirdly, the actual optimization procedure utilizing a dynamic programming algorithm. These three aspects and their handling in the program are described briefly below. More complete information is available from the references and textbooks.

Simulation

The purpose of the simulation is to provide an estimate of production costs associated with a given system configuration. This is the most time-consuming part of the program.

The program permits the years to be broken into as many as 12 periods each of which may have its own peak load, load shape, hydro operating characteristics and maintenance schedule. The running time of the simulation is directly proportional to the number of periods chosen. Consequently, for the purposes of the Survey, the year was divided into four periods or seasons. On the basis of seasonal peak loads and seasonal capacity variations caused by hydro conditions, a heuristic method is used to develop a "reasonable" distribution of maintenance among the seasons. By 'reasonable' is meant that maintenance on the largest units will be in that season which has the greatest difference between installed capacity and peak load, while maintenance on smaller units is distributed in those seasons having less excess capacity. Having decided in which season maintenance on a particular unit will occur, the actual maintenance within the season is randomly distributed.

The heart of the simulation is the algorithm which distributes the energy among the units on the system. It is an extension of the old load duration curve method which rigorously accounts for random outages of thermal units and has the effect of causing units higher on the loading order to supply more energy at a higher unit price than would otherwise be

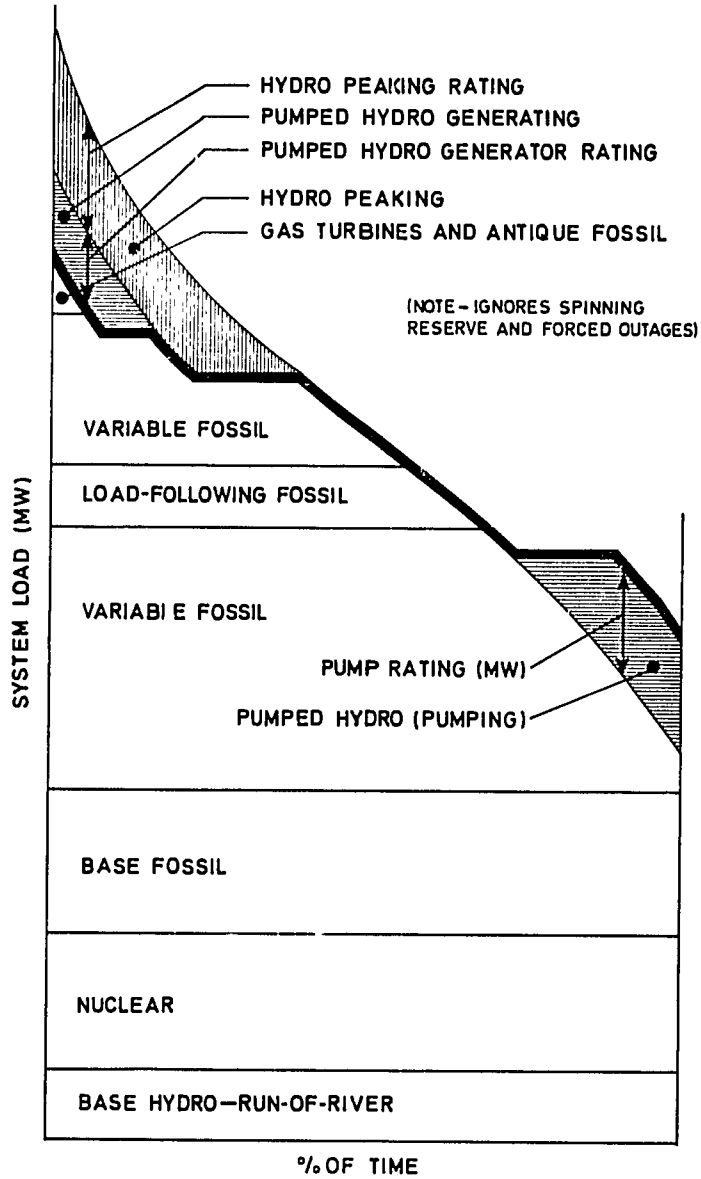


FIG. A-2. IDEALIZED PLACING OF VARIOUS TYPES OF STATION UNDER THE LOAD DURATION CURVE.

experienced. Figure A-2 illustrates the idealized placement of various capacity types under a typical load duration curve. The above procedure is illustrated by the simple diagrams shown in Fig. A-3.

Figure A-3(a) shows a load duration curve with ten thermal units "stacked" under the load curve. As long as all units are running, units 1-4 run 100% of the time; units 5-9 run part of the time; and unit 10 does not run at all. However, if a unit fails, for example unit 1, unit 2 assumes the position of unit 1; 3 the position of 2; and so on. The same effect can be achieved by raising the load curve by the capacity of unit 1, as shown in Fig. A-3(b), in which case units 5 to 9 inclusive have their energy requirements increased and unit 10, which formerly did not generate at all, is carrying significant load. If it is assumed that outages of unit 1 are random, and occur x% of the time, then (100 - x)% of the time the system operates like Fig. A-3(a) and x% of the time like Fig. A-3(b). Therefore, a resultant "expected" load curve (called the equivalent load) which is shown as the solid line in Fig. A-3(c) can be computed. An algorithm computes the resultant equivalent load curve recursively as one considers all of the units in the merit order of their loading. Figure A-4 shows the resultant equivalent load curve after all the plants have been considered. If the total system generating capacity is plotted on the ordinate, the corresponding value on the abscissa, p^*, represents the per cent of time the equivalent load exceeds the system generating capacity. In other words, the value p^* represents the per cent of time that the system cannot meet the expected load. The probability of not meeting the load is simply p^* 100.

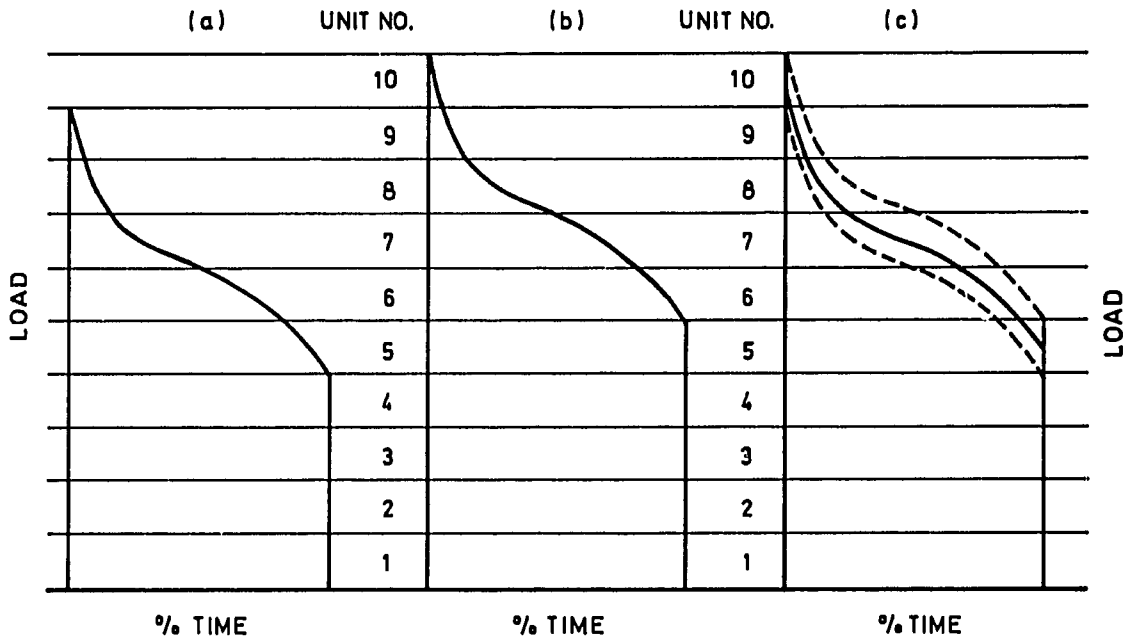


FIG. A-3. ILLUSTRATION OF THE METHOD OF STACKING THERMAL UNITS UNDER THE LOAD CURVE.

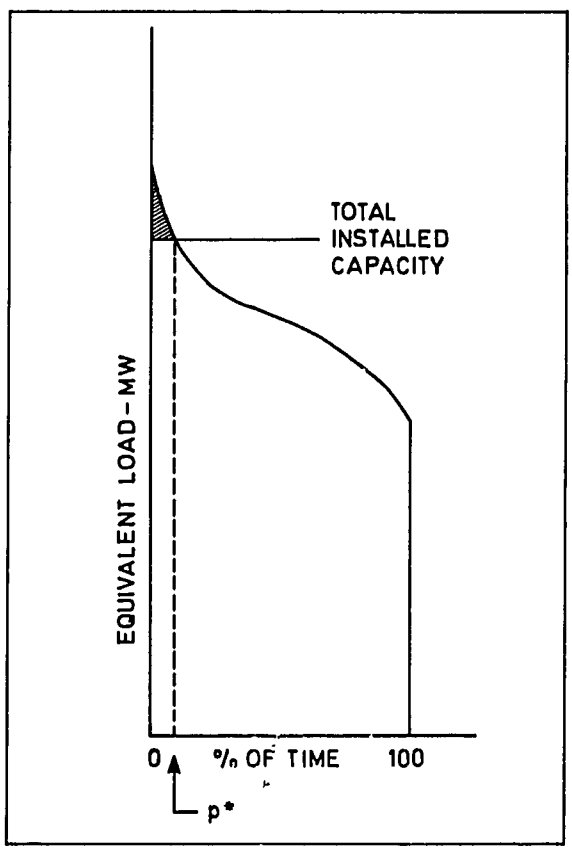


FIG. A-4. EQUIVALENT LOAD CURVE FOR AN ENTIRE SYSTEM.

The loss-of-load probability calculated in this model only considers the generating system. To get a true measure of system reliability, the transmission and distribution systems must also be considered, but consideration of the system aspects is beyond the scope of the model. The true system loss-of-load probability can never be less than the loss-of-load probability calculated by the model since the model assumes a perfect transmission system. The area

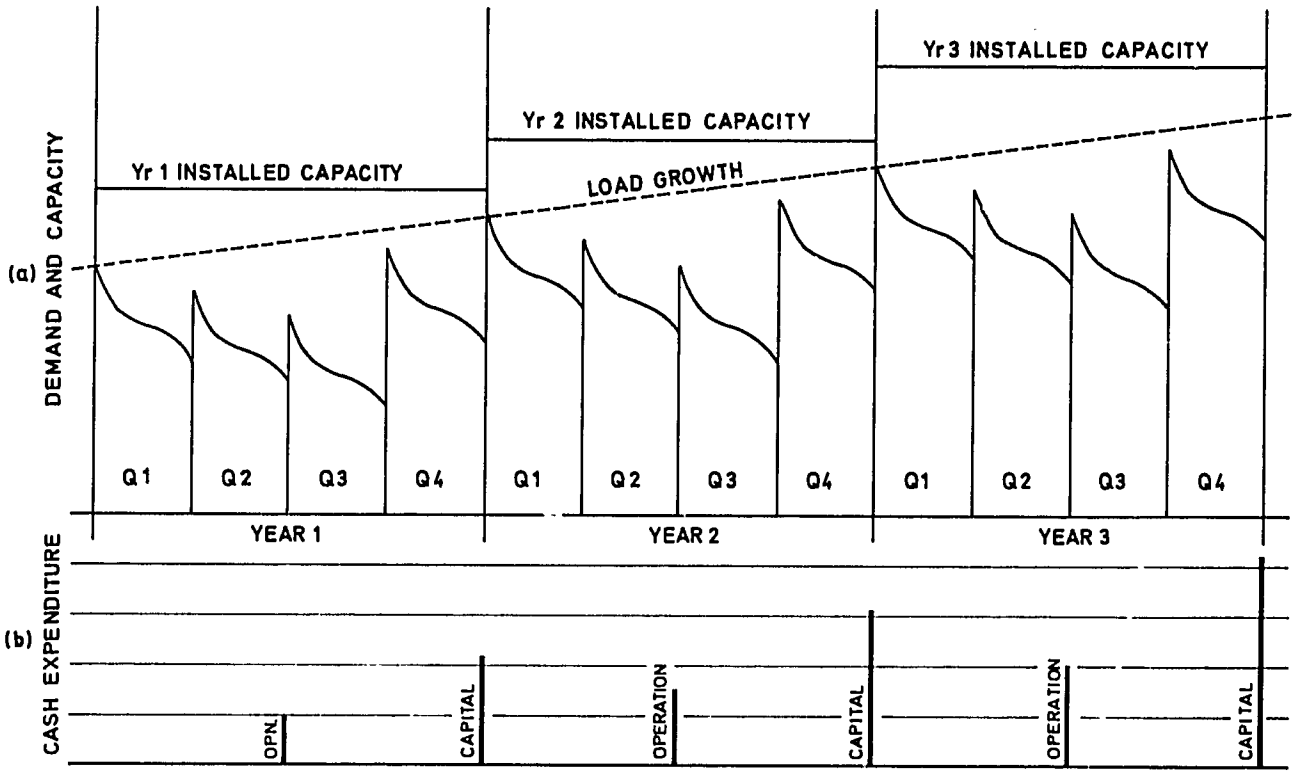


FIG. A-5. SCHEMATIC DIAGRAM OF LOAD GROWTH AND CORRESPONDING CASH FLOWS.

between the equivalent load curve and the ordinate above the total installed capacity is a measure of the probable value of energy demand not served. The simulation code calculates loss-of-load probability and the amount of energy not served for each time period of the study (usually quarterly).

The more complicated aspects of the probabilistic simulation are beyond the scope of this simplified description. These aspects include the simulation of pumped storage and hydro units and the use of multiple capacity blocks for thermal units to better represent actual unit loading.

Treatment of economics

Consider the situation illustrated in Fig. A-5(a). This shows, in diagrammatic form, three years in the history of a power system experiencing load growth. It is seen that at the beginning of year 2 and year 3 an increase in system capacity is required by the growth in load. The capital expenditure which is equivalent to all of the construction costs of these plants is considered to be concentrated at a single point in time when the plant becomes operative. The operating expense to serve the given load duration curves is assumed for simplicity to be concentrated at the middle of each year. The corresponding cash flow diagram is shown in Fig. A-5(b). The present worth, to some reference year, of such a cash flow (ignoring the effects of the study horizon) is a measure of the cost of that particular expansion scheme.

The method chosen to deal with the end effects caused by a finite study horizon is to assume that the salvage value of any piece of equipment installed during the study is proportional to the unused portion of its plant life. Therefore, the present worth of the cash flow calculated in the previous paragraph should be reduced by the present worth, measured from the horizon, of a credit for each plant's salvage value. The function (present worth) to be minimized then may be stated symbolically as

$$F = \sum_{k=0}^{NYRS-1} \left[\sum_{\ell=1}^{NINST_k} \left[P_{k,\ell}\left(C_\ell\right) - P_{NYRS,\ell}\left(C_\ell \cdot \frac{L_\ell - NYRS + k}{L_\ell}\right)\right] + \sum_{m=1}^{NFUELS} P_{(k+\frac{1}{2}),m}\left(PC\emptyset ST_{(k+1)}\right)\right]$$

where F — objective function
NYRS — number of years in the study
$NINST_k$ — number of installations in the kth year
$P_{k,\ell}$ — present-worth factor for the kth year and ℓth plant
C_ℓ — capital cost of the ℓth plant
$P_{NYRS,\ell}$ — present-worth factor for the horizon and the ℓth plant
$P_{(k+\frac{1}{2}),m}$ — present-worth factor for the mth fuel in the kth year
L_ℓ — plant life of the ℓth plant
$PCØST_{(k+1)}$ — operating cost of the mth fuel system for the (k+1) year
NFUELS — number of different fuel types considered

Dynamic programming

In optimization terminology, the above function is known as an objective function or performance criterion. The value of the objective function denotes the relative benefit of a particular expansion schedule. The purpose of the optimization package is to determine which one of the selected alternative expansion schedules minimizes the value of the objective function. Dynamic programming is a powerful optimization tool and requires the definition of three types of variables: the stage variable, the state variable, and the control variable. The stage variable defines the sequence of events and, in the WASP program is defined as the year being considered. The state variable describes the state of the system under study and is defined as the configuration of installed units in any given year. Once the values of the state variable are defined for all stages, any question concerning the system can be answered. The change between the states that might occur from stage to stage is determined by the value of the control variable between stages. Hence the control variable determines the capital investment and operating costs from year to year. In simple terminology, the control variable is the independent variable and the state variable is the dependent variable.

In operation a number of configurations are generated for each stage (year) of the study. These configurations must satisfy the constraints of reserve margin and capacity-mix specified by the user. The production cost and reliability of each of these configurations is determined in the simulations for the appropriate year (stage). All of these calculations are performed before going to the dynamic program. In Fig. A-6 a number of states are represented, by dots, for two successive stages, k and (k+1).

It should be kept in mind that the value of the objective function associated with each state in the kth stage is the minimum cost path from the beginning of the study to that state. In calculating the cost of the paths from state B to state A, the capital cost corresponding to the transfer from state B to A and the operating costs for state A are added to the value of the objective function of state B. This represents the present-worth cost of expanding the system to state A and passing through state B. The costs for the other paths from states C, D, E and F converging at state A are calculated in a similar manner. The path which yields the lowest value of the objective function at state A is retained by storing the objective

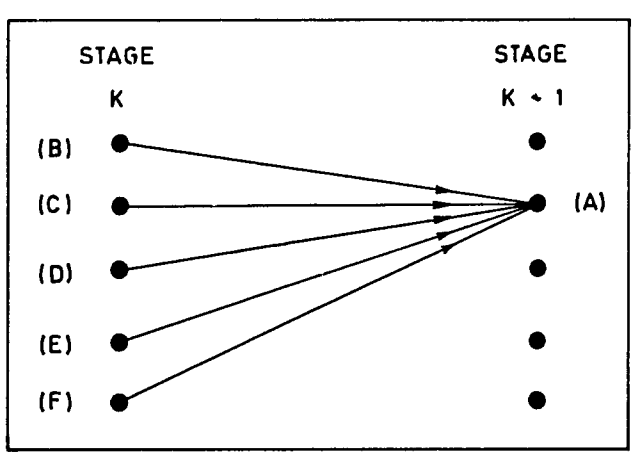


FIG. A-6. ILLUSTRATION OF A DYNAMIC PROGRAM STEP.

function and sufficient information for determining the state in the previous stage. The other paths are discarded as they cannot possibly be part of the optimal trajectory. This procedure is repeated for all of the states in stage (k+1). Then the next stage (k+2) is considered, with the calculations proceeding until the study horizon is reached. Then the lowest value of the accumulated objective function in the final stage is traced back from that state through the various stages to determine the optimal expansion strategy.

In order to provide flexibility in representing real system situations, many features have been included in the WASP package. All cash flow is separated into domestic and foreign exchange in computing total expenditure. Total operating costs and cost of the fuel used in the plant are separately stated. Thus discounting and escalation may be applied separately to the domestic and foreign costs of operating plants consuming different fuels. In the same manner, the capital cost of each expansion alternative is separated into foreign and domestic components. Different discount rates and escalation rates on capital costs (foreign and domestic) are permitted on each alternative. Consequently, many sensitivity studies can be carried out with a minimum of computational effort after a basic optimum has been reached. Studies of the effects of plant capital cost, capital cost interest rates and escalation, exchange ratio (foreign/domestic), plant life, interest rate on operating cost, and critical loss-of-load probability require only reruns of the sixth (dynamic programming) step. If the operating policy does not change and if there are no pumped-storage installations, the escalation of operating costs may also be included in sensitivity studies.

LIMITATIONS OF THE PACKAGE

The program suffers mainly from approximations in the simulation. When the year is divided into large time blocks, the maintenance schedule is only approximate. Since the simulation uses a load duration curve technique, the chronological sequence of events during the individual periods is lost. The hydro representation includes two approximations. All hydro is lumped into a single pseudo-plant with an "always-run" and a "peak-shaving" component. The peak-shaving component is removed from the load duration curve prior to thermal plant simulation. This is not rigorous since hydro is also normally used to cover forced outages of thermal units. All pumped-storage units are also lumped into a single pseudo unit and will not exactly simulate multiple plants with widely varying weekly capacity factors.

ACKNOWLEDGEMENTS

Dr. R.R. Booth of the State Electricity Commission of Victoria (Australia) introduced the probabilistic simulation method and provided the Tennessee Valley Authority with early versions of his simulation and dynamic programming system expansion model. Dr. David Joy of Oak Ridge National Laboratories (USA) provided extensive consultation and development work on the simulation and generous advice and instruction on the dynamic programming method. At TVA Mr. Roger Babb (formerly with TVA) did extensive work to speed the simulation, Miss Katherine McQueen of the Power Research Staff coded and debugged and extensively modified the first generation TVA program and T.R. Jackson of TVA's Power Supply Planning Branch struggled with the difficulties of TVA's first generation program to produce useful results. The improvements in this program are largely a result of his experience. Finally, Mr. Peter Heinrich of IAEA's Computing Centre Staff has carried much of the burden of debugging and implementation on the IAEA computer.

REFERENCES

[1] BALERIAUX, H., SAMOULLE, E., LINARD De GUERTECHIN, Fr., "Establishment of a Mathematical Model Simulating Operation of Thermal Electricity – Generating Units Combined with Pumped-Storage Plant," Review E (edition SRBE), S.A. EBES, Brussels, Belgium 5 7, pp. 1-24.

[2] BOOTH, R.R., "Power system simulation model based on probability analysis", Proceedings of the 1971 IEEE PICA Conf., 71-C26-PWR, pp. 285-291.

[3] SAGER, M.A., RINGLEE, R.J., WOOD, A.J., A New Generation Production Cost Program to Recognize Forced Outages, IEEE paper T72 159-7, pp. 2114-2124.

[4] JOY, D.S., JENKINS, R.T., A Probabilistic Model for Estimating the Operating Cost of an Electric Power Generating System, ORNL-TM-3549 (1971).

APPENDIX B

GENERATING PLANT CAPITAL COSTS (ORCOST)

STEAM-ELECTRIC POWER PLANTS

In order to carry out the very large number of capital cost estimates for the thermal generating units being considered as expansion alternatives, it was necessary to make use of a digital computer program, ORCOST. This program was prepared specifically to provide estimates of the capital costs of steam-electric power plant in the United States of America for use in studies conducted by the Oak Ridge National Laboratory for the USAEC Division of Reactor Development and Technology. The code includes cost models for PWR, BWR, HTGR nuclear plants and coal, oil, and gas-fired plants which were developed from ORCOST's "big brother" CONCEPT II [1-7]. In developing both CONCEPT II and ORCOST the assumption was made that, for a given type and size of power plant and irrespective of its geographical location, the sizes of individual items of equipment, the amounts of construction materials, and the number of man-hours of construction labour remain the same for each of the nine major direct plant cost accounts shown in Table B-1. (Accounts 21-26/91-93 of the USAEC uniform system of accounting.) Such an assumption permits one to start with a base model in which costs for each of the major direct plant cost accounts are identified and to adjust these costs to conditions prevailing at different site locations by applying appropriate indices for equipment, material and labour cost. These indices reflect the unit costs of these items relative to the unit costs used in the base model. In the case of plant equipment costs the index to be used includes both cost escalation factors and cost factors specific to the site.

In CONCEPT II these indices are calculated within the program from input data on the actual unit costs of equipment, materials and labour, whereas in ORCOST the indices are calculated separately.

After applying the specific indices, the computer program sums up the adjusted total direct cost of the physical plant.

In order to estimate these direct plant costs as a function of plant size, a second assumption is made, namely that the exponential scaling laws developed for the base model (to reflect the variation in costs of each of the major accounts with plant size) are independent of the indices used for equipment, materials, and labour costs.

TABLE B-1. 2-DIGIT ACCOUNTS USED IN THE USAEC SYSTEM OF ACCOUNTING

Account No.	Item
Direct costs	
21	Structures and site facilities
22	Reactor/boiler plant equipment
23	Turbine plant equipment
24	Electric plant equipment
25	Miscellaneous plant equipment
26	Special materials
Indirect costs	
91	Construction facilities, equipment and services
92	Engineering and construction management services
93	Other costs

Having found the direct physical cost of the plant for a given size and site location, the program adds allowances for contingencies and spare parts and then computes the indirect costs by applying appropriate percentages to the physical plant costs.

The technique of separating the plant cost into individual components, applying appropriate cost indices, and summing the adjusted components is the basic tool used in ORCOST. The procedure is illustrated schematically in Fig. B-1.

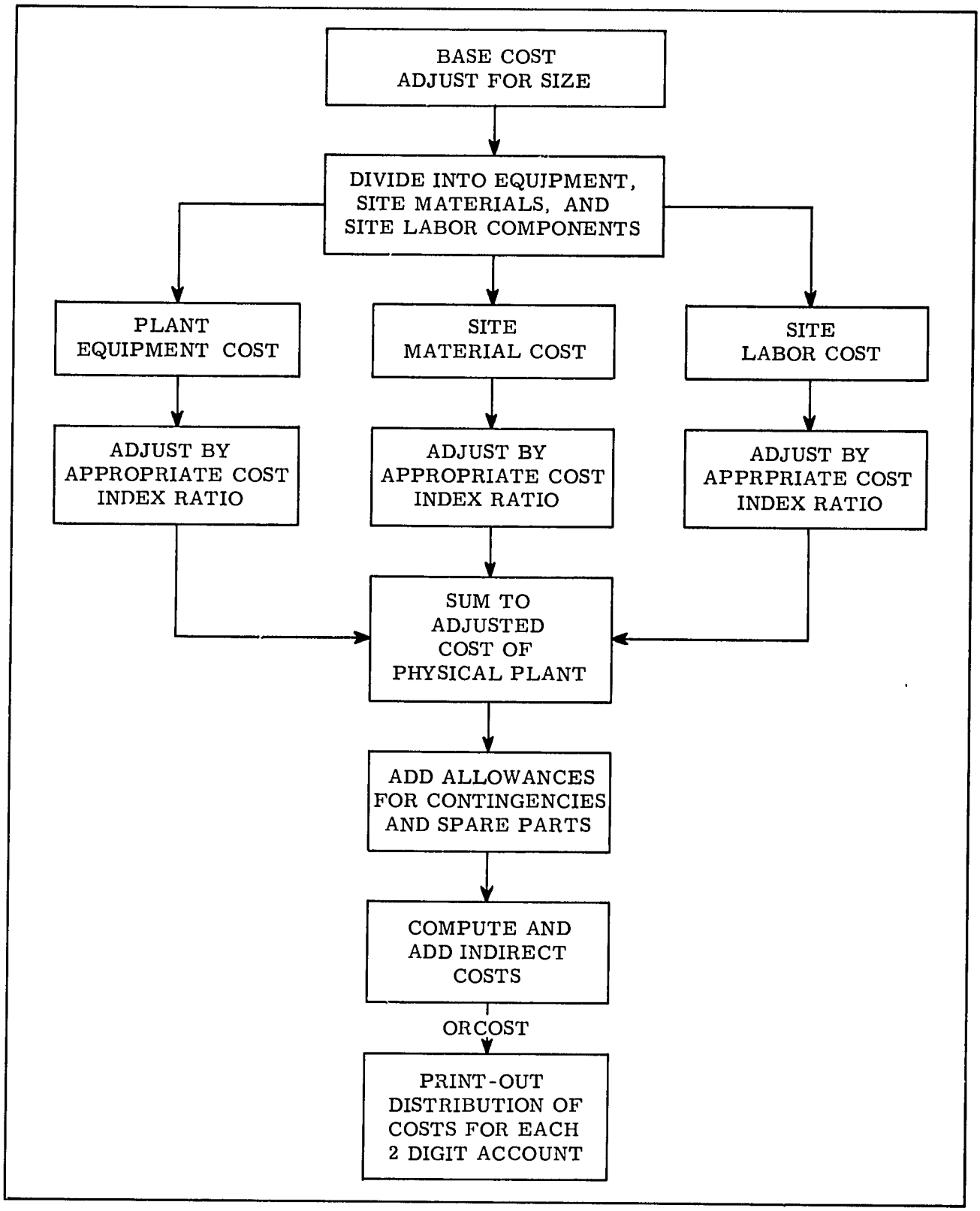


FIG. B-1. SCHEMATIC ILLUSTRATION OF ORCOST (AND CONCEPT II) PROCEDURE.

Selection of nuclear reactor type

It should be noted here that in view of the diversity of reactor types now available commercially and because of the limited scope of the Survey, it was decided to base the evaluation of nuclear versus conventional power plants on a single reactor type, the PWR. Such a selection is not intended to imply a preference for this particular type of nuclear plant, but merely to provide an illustration which is believed to be representative of nuclear power in general.

Other types of power reactors which have already been constructed and could be considered for developing countries in their future plans include AGR, BWR, HTGR, PHWR, and SGHWR.

It is believed that breeder reactors will not be developed to the point of being useful in planning systems in developing countries within the study decade.

To date, the following reactor types have been purchased or committed by the countries listed:

	Type	Gross electricity output (MW)
Argentina	PHWR	340
	CANDU-PHWR	600
Brazil	PWR	657
Bulgaria	PWR	2 x 440
Czechoslovakia	HWGCR	144
	PWR	2 x 440
India	BWR	2 x 210
	CANDU-PHWR	1 x 220
	CANDU-PHWR	3 x 220
Korea	PWR	595
Pakistan	CANDU-PHWR	137

The base cost model

The base cost model for each type of plant was established from a detailed cost estimate for a reference 1000 MW plant assumed to be located at "Middletown", USA, the standard hypothetical site described in Ref. [3].

Since the base cost models in the original ORCOST program were developed in 1971, these were updated to the end of 1972 by applying appropriate escalation rates on equipment, materials and labour. These costs are referred to in the Survey as ORCOST-1. However, recent construction experience in the USA indicated that some adjustments should be made in the scope of work, particularly as it affects the construction costs of nuclear power plants. These adjustments were made and the resulting costs are referred to in the Survey work as ORCOST-3.[1] The ORCOST-3 data are used as the reference case data in the Survey analyses. Table B-2 shows the ORCOST-3 total plant base cost models used for the Survey. Table B-3 shows a comparison of ORCOST-1 and ORCOST-3 total plant costs for 300, 600 and 1000 MW PWR and oil-fired plants. It also shows the modified costs (see below for discussion of country cost indices) for the participating country having the maximum cost levels and the one having the minimum cost levels. It is to be noted here that the adjustments made to obtain ORCOST-3 costs (from the ORCOST-1 values) resulted in essentially no change in the oil-fired (or other fossil-fired) plants, but there were substantial increases in the costs of nuclear plants of the order of 21-22% on all sizes. This resulted in the ratio of nuclear to oil-fired plant costs increasing from values of about 1.5 - 1.8 for ORCOST-1 to about 1.9 - 2.2 for ORCOST-3. ORCOST-1 costs were used to make a few sensitivity studies in selected countries in order to indicate the possible effect on Survey results if the ratio of nuclear to fossil-plant costs reverted to their pre-1972 levels.

[1] ORCOST-2 referred to data not used for Survey analyses.

TABLF B-2. ORCOST-3 BASE COST MODELS USED IN THE MARKET SURVEY (all 1000 MW capacity)

Account No.	PWR		Coal-fired		Oil-fired		Gas-fired	
	10^6 US $	Scaling exponent	10^6 US $	Scaling exponent	10^6 US $	Scaling exponent	10^6 US $	Scaling exponent
21	52.03[a]	0.80[a]	29.18	0.75	26.67	0.75	26.67	0.75
22	77.20	0.60	67.91	0.90	56.00	0.90	36.50	0.90
23	74.95	0.80	53.21	0.80	53.00	0.80	53.00	0.80
24	27.84	0.60	18.52	0.45	14.15	0.45	13.40	0.45
25	5.39	0.30	4.35	0.30	4.08	0.30	4.08	0.30
26	0	0	0	0	0	0	0	0
Total	237.41		173.17		153.9		133.65	

[a] For plant sizes below 800 MW, these figures become US $ 47.75 x 10^6 and 0.40 respectively.

TABLE B-3. COMPARISON OF CAPITAL COSTS FOR NUCLEAR AND OIL-FIRED PLANTS

Size (MW)	Type		ORCOST-1			ORCOST-3		
			Maximum country	Minimum country	USA	Maximum country	Minimum country	USA
300	PWR	Capital costs (US $/kW)	490	378	517	593	442	624
	Oil		272	210	316	268	206	315
		Cost difference (US $/kW)	218	168	201	325	236	309
		Cost ratio PWR/Oil	1.8	1.8	1.63	2.21	2.15	1.98
600	PWR	Capital costs (US $/kW)	358	275	377	439	322	460
	Oil		216	171	249	216	170	253
		Cost difference (US $/kW)	142	104	128	223	152	207
		Cost ratio PWR/Oil	1.64	1.61	1.51	2.03	1.89	1.82
1000	PWR	Capital costs (US $/kW)	296	225	312	365	266	382
	Oil		187	145	218	189	146	223
		Cost difference (US $/kW)	109	80	94	176	120	159
		Cost ratio PWR/Oil	1.58	1.55	1.43	1.93	1.82	1.71

The base model plant costs include, in all oil and coal-fired plants, electrostatic precipitators. However, these costs do not include any of the other so-called environmental control equipment such as SO_2 removal systems, cooling towers/lakes or near-zero radiation release systems. It was felt that environmental considerations which have caused designs of almost all future plants in industrialized countries to include such equipment, or provision to add it at later dates, would not generally apply during the study period in the developing countries included in the Survey. It is recognized, however, that in certain countries these considerations might possibly have to be faced and coped with during the study decade. Therefore, the following should be noted when considering the capital costs of future plants.

(a) High-efficiency (99.5 + %) electrostatic precipitators to remove particulate matter from stacks of oil or coal/lignite-fired plants cost of the order of US $8-10/kW of installed capacity. Thus, if precipitators are not required in any given instance, this amount may be omitted from the appropriate costs in Tables B-2 and B-3.

(b) Although there is no known proven process for the effective economic removal of SO_2 from the stack gases of fossil-fired plants, it is at present estimated that such equipment, when commercially applicable, could involve an additional equivalent investment cost of the order of US $50/kW for a 1000 MW plant burning coal containing 3.0% sulphur. This would include both the initial investment (about US $35-40/kW) and the capitalized operating cost and capacity penalty (about US $10-15/kW). The actual final costs would, of course, depend on the original sulphur content of the fuel being used, the size of plant, the ability to dispose of the recovered sulphur etc.

(c) Cooling towers, of various designs, are presently in use in many power plants and they can be considered fully developed technically. Their costs are reasonably well known for installations under a wide variety of conditions. The initial investment for a 1000 MW plant would be of the order of US $5-10/kW for fossil-fired plants depending on whether a mechanical draft or natural draft design is used. For nuclear plants, these values should be increased by about 50%. The costs of cooling lakes, ponds or equivalent methods of disposing of thermal discharges will vary quite widely, but they can be generally considered as less expensive overall than cooling towers if the amount of land required is available at a reasonable price. An upper limit of their cost can be considered as the cost of equivalent cooling towers.

(d) The addition of equipment to light-water nuclear plants to accomplish near-zero radiation release will be likely to cost about US $5-10/kW for larger sizes of plants, depending on the type of reactor plant involved.

It is quite possible, therefore, that costs for future fossil-fired plants could increase substantially more than for nuclear plants if precipitators, SO_2 removal systems and cooling towers or the equivalent were required for the fossil-fired plants and cooling towers or the equivalent and near-zero radiation release systems were required for nuclear plants. On a comparable basis, therefore, for large plants of the order of 1000 MW, the possible future incremental penalty against fossil-fired plants would appear to be of the order of US $40/kW when precipitators are not required and US $50/kW if precipitators are required for the coal-fired plants. These US $/kW values could increase by as much as 50% for the smaller sizes of units considered in the study.

It should be noted that, in addition to the increases in capital cost for environmental control equipment, the operating and maintenance costs of the plants, as discussed in Appendix E, will be increased.

Modifications of indirect costs

Indirect costs in the base model (construction facilities, equipment and services, engineering and construction management services, taxes, insurance and owner's general and administrative expenses) are estimated as percentages of the direct physical plant cost based on experience in the USA. It was recognized that this experience would not be directly

applicable to conditions prevailing in the countries being studied; therefore, the indirect cost percentages in the base model were adjusted to reflect such conditions. Such adjustments to the base model are easily made by changing the indirect cost indices applicable to Accounts No. 91, 92 and 93. The indices actually used are shown in Table B-4. These indirect cost indices were derived for the Survey as follows:

Firstly, it was assumed that the plants being considered would be two-unit plants; therefore, the costs of temporary facilities which would be common to both units were divided by two. Secondly, it was assumed that the costs of local labour and materials associated with account 91 would be about 75% of the costs used in the base model. These assumptions decreased account 91 from 6.6% of the physical plant costs to 5.3%, resulting in an index of 0.8 for account 91.

For account 92, engineering services were taken to be the same as for the USA based on the assumption that all design and engineering for the nuclear plant would be done by an architect-engineering firm from outside the country being studied. Costs of construction management services, moreover, were increased by US $ 5 million in the base model for overseas support of personnel supervising the construction. This increased the percentage of physical plant costs from 11.6% in the base model to 13.6% resulting in an index of 1.17 for account 92.

Account 93 was adjusted to remove the local taxes assumed for the base model resulting in an index of 0.71 for account 93.

Indirect cost indices for conventional plants were derived in a similar manner, to give the values: account 91 = 0.72, account 92 = 1.06, account 93 = 0.65.

In the cost model, indirect costs are calculated using a hyperbolic function. This results in abnormally high indirect costs for unit sizes below 300 MW both in terms of total dollar costs and the ratio of the indirect costs to total plant costs. Therefore, the calcula-

TABLE B-4. ADJUSTMENT OF THE INDIRECT COSTS OF THE BASE MODEL (1000 MW PWR) TO MARKET SURVEY CONDITIONS

Account No.		Percentage of physical plant cost		
		Base model		Market survey
91	Construction facilities, equipment and services			
	911 Temporary facilities	2.0		1.5
	912 Construction equipment	3.3		3.0
	913 Construction services	1.3		0.8
	Total for account 91	6.6		5.3
	Ratio – Market survey/base model		0.80	
92	Engineering and construction management services			
	921 Engineering services	5.8		5.8
	922 Construction management services	5.8		7.8
	Total for account 92	11.6		13.6
	Ratio – Market survey/base model		1.17	
93	Other costs			
	931 Taxes and insurance	2.7		1.5
	932 Staff training and plant start-up	0.3		0.3
	933 Owner's general and administrative expenses	1.2		1.2
	Total for account 93	4.2		3.0
	Ratio – Market survey/base model		0.71	

tion of indirect costs for the smaller sizes of plants was made by taking a linear approximation.

It should be noted that although the percentages applied to the physical plant costs to obtain the indirect costs vary with size of plant, the indirect cost indices remain constant for all sizes of plants.

Derivation of country cost indices

Specific cost indices for equipment, materials and labour were used for each participating country. These cost indices are stated as a ratio of the effective foreign costs to the US-based costs and thus allow the determination of total construction costs of the various types and sizes of plants in each country based on equipment, materials and labour cost indices and interest rates unique to each country. The following paragraphs explain how the cost indices were obtained and used to modify the US-based costs:

(a) Equipment cost index

The equipment cost indices were determined after giving consideration to international sources for the items of equipment, the location of the country relative to those sources, the transport costs from likely sources to the country, the competitive nature of the international market, known country preferences for equipment types and sources and the likely location of the power plants within the country, i.e. inland or on the seashore. On balance, the equipment cost index, for an "ideal" plant site in an "average" country, was established as 1.0 for nuclear plants and 0.9 for fossil plants relative to the US values in the ORCOST models. A specific index was then established for each country relative to these values, considering the above factors as they were known to apply or as best they could be approximated.

(b) Materials cost index

The materials cost indices were determined either from detailed costs of completed power plants provided by the countries or from specific prices in the country for construction materials such as structural steel, re-inforcing steel, concrete (ready-mix), ply-form and lumber.

In some cases where such data were not available the indices were estimated based on a comparison with known data for a neighbouring country or for the general area.

(c) Labour cost index

The labour cost indices were calculated from the wages for different types of craft usually available in the country, such as common labour, bricklayer, carpenter, ironworker, electrician, steam-fitter, operating engineer, and other classifications as available.

These wages were weighted by the amount of man-hours to be spent in the construction of a power plant. For this purpose a labour efficiency was estimated. Where no detailed information about wages was available, the labour cost indices were calculated from detailed costs of constructed power plants, or it was estimated by comparison with other countries.

ORCOST input and output

With the above modifications to the basic ORCOST program the actual input data required for each country include plant size and type, labour cost index, materials cost index, equipment cost index, cost escalation rates (if any), interest rates, construction period, length of working week (if different from 40 hours).

From these input data total capital costs are obtained as the output, with the cost adjusted to the specific country's cost levels. Table B-5 shows a printout sheet from the ORCOST-3 program summarizing input data for a 600 MW PWR with equipment, materials and cost indices set at 1.0. Tables B-6 to B-9 show output data from ORCOST-3 for various fossil-fuelled 600 MW plants, again with the cost indices set at 1.0. It should be pointed out

TABLE B-5. ORCOST-3 PRINTOUT OF INPUT DATA FOR 600 MW PWR

```
PLANT SIZE, MW(E).                                  S   =  600.0
PLANT TYPE.                                         T   = PWR
YEAR CONSTRUCTION STARTED.                          YS  = 1973.00
YEAR OF COMMERCIAL OPERATION.                       YO  = 1978.50
BASE YEAR FOR ESCALATION                            YBX = 1971.50
LENGTH OF WORKWEEK, HRS.                            HW  =   40.0
ANNUAL INTEREST RATE, PERCENT.                      XIR =    8.0
INITIAL EQUIP. ESCAL. RATE, ANNUAL PERCENT          EREB=    0.0
INITIAL MATLS. ESCAL. RATE, ANNUAL PERCENT          ERMB=    0.0
INITIAL LABOR ESCAL. RATE, ANNUAL PERCENT           ERLB=    0.0
EQUIPMENT ESCALATION RATE, ANNUAL PERCENT.          ERE =    0.0
MATERIALS ESCALATION RATE, ANNUAL PERCENT.          ERM =    0.0
LABOR ESCALATION RATE, ANNUAL PERCENT.              ERL =    0.0
PROVEN DESIGN                                         IFLAG =  0
SUBROUTINE NAMELIST OPTION NOT SELECTED               JFLAG =  0
HEAT REMOVAL - RUN OF RIVER                             ICT =  0
UPGRADED RADWASTE SYSTEM NOT SPECIFIED                  IEC =  0

CONTINGENCY AND SPARE PARTS FACTORS, PERCENT DIVIDED BY 100
          CONTINGENCY FACTORS                  SPARE PARTS FACTORS
    ---------------------------------  ---------------------
    EQUIPMENT & MATERIALS      LABOR      EQUIPMENT & MATERIALS
       F21CEM= 0.050        F21CL= 0.100       F21SEM= 0.010
       F22CEM= 0.050        F22CL= 0.100       F22SEM= 0.010
       F23CEM= 0.050        F23CL= 0.100       F23SEM= 0.010
       F24CEM= 0.050        F24CL= 0.100       F24SEM= 0.010
       F25CEM= 0.050        F25CL= 0.100       F25SEM= 0.010
       F26CEM= 0.050        F26CL= 0.100       F26SEM= 0.010
       FSOCEM= 0.050        FSOCL= 0.100       FSOSEM= 0.010
       FHRCEM= 0.050        FHRCL= 0.100       FHRSEM= 0.010

EQUIPMENT COST INDEX.                           A(IN,1) =  1.000
MATERIALS COST INDEX.                           A(IN,2) =  1.000
LABOR COST INDEX.                               A(IN,3) =  1.000

BASE COST MODEL
            COST                        COST BREAKDOWN FACTORS
          $MILLION   EXPONENT    EQUIPMENT MATERIALS LABOR
ACCT 21 C(1)= 47.75 N(1)=0.40 EF(1)=0.03 MF(1)=0.35 LF(1)=0.62
ACCT 22 C(2)= 77.20 N(2)=0.60 EF(2)=0.52 MF(2)=0.21 LF(2)=0.27
ACCT 23 C(3)= 74.95 N(3)=0.80 EF(3)=0.54 MF(3)=0.17 LF(3)=0.29
ACCT 24 C(4)= 27.84 N(4)=0.60 EF(4)=0.23 MF(4)=0.34 LF(4)=0.43
ACCT 25 C(5)=  5.39 N(5)=0.30 EF(5)=0.39 MF(5)=0.04 LF(5)=0.57
ACCT 26 C(6)=  0.0  N(6)=0.0  EF(6)=0.0  MF(6)=0.0  LF(6)=0.0
RAD. W. C(7)=  0.0  N(7)=0.60 EF(7)=0.69 MF(7)=0.13 LF(7)=0.18
C. TOW. C(8)=  0.0  N(8)=0.80 EF(8)=0.47 MF(8)=0.04 LF(8)=0.49
INDIRECT COSTS  F91= 0.80 F92= 1.17 F93= 0.71
```

TABLE B-6. ORCOST-3 PRINTOUT OF OUTPUT DATA ON THE CAPITAL COST OF A 600 MW PWR

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 Mw(E) PWR
1973.00 - 1978.50

DIRECT COSTS

20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	1.2	13.6	24.1	38.9
22	REACTOR/BOILER PLANT EQUIPMENT	29.5	11.9	15.3	56.8
23	TURBINE PLANT EQUIPMENT	26.9	8.5	14.4	49.8
24	ELECTRIC PLANT EQUIPMENT	4.7	7.0	8.8	20.5
25	MISCELLANEOUS PLANT EQUIPMENT	1.8	0.2	2.6	4.6
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	UPGRADED RADWASTE SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	64.1	41.2	65.4	170.7
	CONTINGENCY ALLOWANCE				11.8
	SPARE PARTS ALLOWANCE				1.1
	SUBTOTAL (PHYSICAL PLANT)				183.5
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				183.5

INDIRECT COSTS

91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -	10.9
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -	28.1
93	OTHER COSTS	6.1
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 5.50 YRS)	47.3
	SUBTOTAL (TOTAL INDIRECT COSTS)	92.5
	SUBTOTAL (TOTAL PLANT COST)	276.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))	0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)	276.1
	$ / KW(E)	460.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)	0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)	276.1
	$ / KW(E)	460.

TABLE B-7. ORCOST-3 PRINTOUT OF OUTPUT DATA ON A 600 MW COAL-FIRED PLANT

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 MW(E) COAL
1973.00 - 1977.00

		EQU.	MAT.	LABOUR	TOTAL
	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT				
21	STRUCTURES AND SITE FACILITIES	0.6	7.8	11.5	19.9
22	REACTOR/BOILER PLANT EQUIPMENT	22.7	5.1	15.0	42.9
23	TURBINE PLANT EQUIPMENT	19.1	6.0	10.3	35.4
24	ELECTRIC PLANT EQUIPMENT	4.9	2.4	7.5	14.7
25	MISCELLANEOUS PLANT EQUIPMENT	1.0	0.7	2.0	3.7
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	48.3	22.0	46.3	116.6
	CONTINGENCY ALLOWANCE				8.1
	SPARE PARTS ALLOWANCE				0.7
	SUBTOTAL (PHYSICAL PLANT)				125.4
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				125.4
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				8.0
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				13.1
93	OTHER COSTS				3.6
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 4.00 YRS)				21.9
	SUBTOTAL (TOTAL INDIRECT COSTS)				46.6
	SUBTOTAL (TOTAL PLANT COST)				172.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				172.1
	$ / KW(E)				287.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				172.1
	$ / KW(E)				287.

TABLE B-8. ORCOST-3 PRINTOUT OF OUTPUT DATA ON A 600 MW OIL-FIRED PLANT

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 MW(E) OIL
1973.00 - 1976.50

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.5	6.9	10.7	18.2
22	REACTOR/BOILER PLANT EQUIPMENT	18.0	4.6	12.7	35.4
23	TURBINE PLANT EQUIPMENT	19.0	6.0	10.2	35.2
24	ELECTRIC PLANT EQUIPMENT	4.4	1.7	5.2	11.2
25	MISCELLANEOUS PLANT EQUIPMENT	1.0	0.7	1.8	3.5
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	43.0	19.9	40.6	103.5
	CONTINGENCY ALLOWANCE				7.2
	SPARE PARTS ALLOWANCE				0.6
	SUBTOTAL (PHYSICAL PLANT)				111.3
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				111.3
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				7.6
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				12.3
93	OTHER COSTS				3.4
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				17.0
	SUBTOTAL (TOTAL INDIRECT COSTS)				40.3
	SUBTOTAL (TOTAL PLANT COST)				151.8
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				151.8
	$ / KW(E)				253.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				151.8
	$ / KW(E)				253.

TABLE B-9. ORCOST-3 PRINTOUT OF OUTPUT DATA ON A 600 MW GAS-FIRED PLANT

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 MW(E) GAS
1973.00 - 1976.50

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.7	7.1	10.4	18.2
22	REACTOR/BOILER PLANT EQUIPMENT	12.7	2.3	8.1	23.0
23	TURBINE PLANT EQUIPMENT	19.0	6.0	10.2	35.2
24	ELECTRIC PLANT EQUIPMENT	4.6	1.1	5.0	10.6
25	MISCELLANEOUS PLANT EQUIPMENT	0.9	0.8	1.8	3.5
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	37.9	17.2	35.4	90.6
	CONTINGENCY ALLOWANCE				6.3
	SPARE PARTS ALLOWANCE				0.6
	SUBTOTAL (PHYSICAL PLANT)				97.5
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				97.5
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				7.2
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				11.6
93	OTHER COSTS				3.2
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				15.1
	SUBTOTAL (TOTAL INDIRECT COSTS)				37.1
	SUBTOTAL (TOTAL PLANT COST)				134.6
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				134.6
	$ / KW(E)				224.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				134.6
	$ / KW(E)				224.

that these costs do not represent costs of plants built in the USA, but costs of plants in a hypothetical developing country with equipment costs, materials costs and labour rates equal to those in the north-east of the USA.

Land costs

Land costs are treated as a separate item in both ORCOST programs. To reflect the lower cost of land in the Survey countries relative to the USA, land costs were assumed to amount to US $100 000 instead of US $1 million assumed in the original program.

GAS TURBINE PLANTS

Only 50 MW gas turbine plants were considered in the studies. Their installed cost was assumed to be US $125/kW at 1 January 1973 price levels. The costs were assumed to escalate at the same general inflation rate used for the other types of plants and equipment. Where more than 50 MW of capacity of this type was required, multiples of this 50 MW unit size were assumed with installed costs constant at US $125/kW.

HYDROELECTRIC PLANTS

As explained in Appendix A, all hydro or pumped-storage capacity, at any point in time, is merged in the WASP program with the then existing hydro or pumped storage into one equivalent hydro or pumped-storage plant. The costs of each hydro or pumped storage plant added to the system during the study period was taken as given by the country. In a few cases where costs of individual hydro projects were given, but no schedule was provided as to the order in which the projects would be constructed, average costs in US $/kW were determined for all projects in the group for which costs were given, and these average costs then used to obtain the installed costs of the required hydro capacity. Where known hydro potential was identified, but no costs were available, estimates were made of the installed costs based on known costs of existing projects in the same area or based on average conditions.

REFERENCES

[1] De LOZIER, R.C., REYNOLDS, L.D., BOWERS, H.I., CONCEPT – Computerized Conceptual Cost Estimates for Steam-Electric Power Plants – Phase 1 User's Manual, ORNL-TM-3276 (1971).

[2] De LOZIER, R.C., SRITE, B.E., REYNOLDS, L.D., BOWERS, H.I., CONCEPT II – Computerized Conceptual Cost Estimates for Steam-Electric Power Plants – Phase II User's Manual, ORNL-4809 (1972).

[3] USAEC Guide for Economic Evaluation of Nuclear Reactor Plant Designs, NUS-531 (1969).

[4] United Engineers and Constructors Inc., 1000 MW Central Station Power Plants Investment Cost Study, UEC-AEC-720630 (1972).

[5] BOWERS, N.I., MYERS, M.L., Estimated Capital Costs of Nuclear and Fossil Power Plants, ORNL-TM-3243 (1971).

[6] United Engineers and Constructors Inc. (Jackson and Moreland Division), Cost of Large Fossil Fuel-Fired Power Plants, J+M No.636 (1966).

[7] USAEC, CONCEPT – A Computer Code for Conceptual Cost Estimates of Steam-Electric Power Plants, WASH-1180 (1971).

APPENDIX C

LOAD DESCRIPTION DATA FOR WASP PROGRAM

REQUIRED DATA

The load description data required for the WASP program are as follows:

(1) Study increment, in MW.
(2) Peak load demand for each year of study period, in MW.
(3) Seasonal (quarterly) peak load demands expressed as a percentage of the annual peak load.
(4) Coefficients of a polynomial describing the shape of the load duration curves for each of the four seasons of the year.

The program will thus calculate the corresponding annual load factor for each year of the study.

The following describes how these data were obtained.

Study increment

In carrying out the computations associated with the load duration curves, these are divided into blocks of capacity (MW) equal to a selected study increment. To avoid on the one hand a too rough approximation of the load curve and on the other hand a waste of computer time, the study increment was selected in accordance with the following rules:

(a) It must be greater than the largest value of system installed capacity, during the entire study period, divided by 590.
(b) It should be less than 2% of the smallest value of system installed capacity during the entire study period.
(c) It should be less than approximately three times the capacity of the smallest generating unit in the system.

Peak load demands for each year of study

Peak load demands for each year of the study were derived from data provided by the country or by mathematical or graphical interpolation of the five-year interval forecasts developed by the method described in Appendix F.

Seasonal peak load demands

The seasonal variation of peak load demand in each case was obtained from historical data for representative years provided by the country. To simplify preparation of input data, the seasonal peak loads measured as a percentage of the annual peak load were assumed to remain constant throughout the study period.

Coefficients of a polynomial describing shape of load duration curves

Coefficients of a fifth order polynomial were used to represent the shape of the load duration curves. This fifth order polynomial gave a satisfactory fit in virtually all cases. The curve fitting was done by a standard polynomial regression program (No. 1001G/ST3 in the WANG 700 series program library) on a WANG Model 700 computer with plotter.

This program calculates the coefficients b_i in the expression

$$L = b_0 + b_1X + b_2X^2 + \ldots\ldots\ldots\ldots + b_5X^5$$

where L = fraction of peak load,
X = fraction of total time.

The computer then plots the fitting curve as shown in Fig. C-1. Examples of the coefficients b_0 to b_5 are shown in Table C-1 under the heading "Load coefficients in force this year".

In addition, a special program calculates both the slope of the curve at the point X=1 and also the load factor which is given by

$$LF = \int_0^1 L\,dX = b_0 + \frac{b_1}{2} + \frac{b_2}{3} + \ldots\ldots\ldots + \frac{b_5}{6}$$

It is important that the polynomial should not have a negative slope at any point. It follows therefore that

$$L = b_1 + 2b_2 + 3b_3 + \ldots\ldots\ldots + 5b_5$$

has to be less than 0 for $0 \leq X \leq 1$.

The value of b_0 is forced near to unity by entering the point (0, 1) a number of times. An additional program on the WANG forces it exactly to 1.

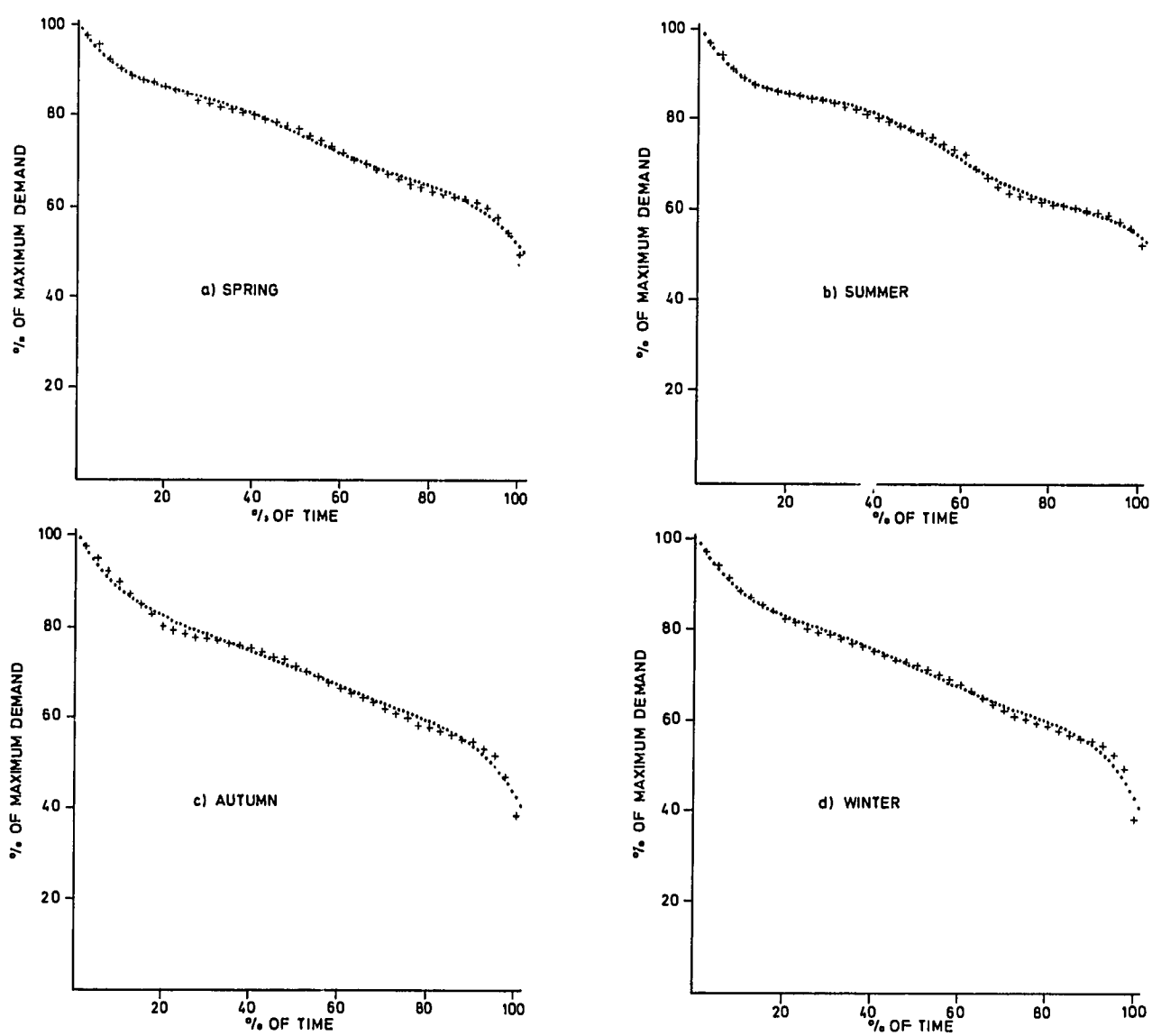


FIG. C-1. EXAMPLES OF THE FITTING OF A FIFTH ORDER POLYNOMIAL TO LOAD DURATION CURVES.

TABLE C-1. SAMPLE OUTPUT OF COMPUTER CALCULATIONS OF LOAD DURATION DATA.

```
PERIOD PEAK LOADS IN PU OF ANNUAL PEAK
  0.867000  0.989000  1.000000  0.971000

PERIOD PEAK LOADS IN MW
   25143.0   28681.0   29000.0   28159.0

LOAD COEFFICINTS IN FORCE THIS YEAR ARE
  1.000000 -2.958504 11.891810-23.599838 20.824448 -6.759686
  1.000000 -3.193929 12.838108-25.477798 22.481552 -7.297591
  1.000000 -3.131148 12.585763-24.977005 22.039658 -7.154149
  1.000000 -2.974198 11.954898-23.725037 20.934921 -6.795546

PERIOD   1 PEAK LOAD 25143.0 MW MIN LOAD   10012 MW
ENERGY UNDER LOAD DURATION CURVE     34304.1 GWH
PERIOD LOAD FACTOR(%) 62.30

PERIOD   2 PEAK LOAD 28681.0 MW MIN LOAD   10048 MW
ENERGY UNDER LOAD DURATION CURVE     37246.9 GWH
PERIOD LOAD FACTOR(%) 59.30

PERIOD   3 PEAK LOAD 29000.0 MW MIN LOAD   10530 MW
ENERGY UNDER LOAD DURATION CURVE     38169.4 GWH
PERIOD LOAD FACTOR(%) 60.10

PERIOD   4 PEAK LOAD 28159.0 MW MIN LOAD   11123 MW
ENERGY UNDER LOAD DURATION CURVE     38295.7 GWH
PERIOD LOAD FACTOR(%) 62.10
ANNUAL LOAD FACTOR(%) 58.26 ENERGY    148016.1 GWH

END OF DATA FOR YEAR 2000 * * * * * * * * * * * *
```

ANNUAL LOAD FACTORS

The following equations must hold:

$$AE = \sum_{1}^{4} PE_n = 2190 \sum_{1}^{4} (PLF_n)\,(PP_n)$$

$$AE = 8760\,(AP)\,(ALF) = 2190\,AP \sum_{1}^{4} (PPF_n)\,(PLF_n)$$

where AE = annual energy forecast,
AP = annual peak load,
ALF = annual load factor,
PLF = period load factor,
PP = period peak load,
PPF = period peak as a fraction of annual peak,
PE = period energy forecast.

From PLF, AP and PPF the WASP program will calculate an annual load factor (see Table C-1). If this calculated annual load factor (ALF_{ca}) is not equal to the projected annual load factor (ALF_{pr}) the values of PLF are modified by the quotient ALF_{pr}/ALF_{ca}. A code is available for the WANG 700 calculator which modifies the coefficients corresponding to a given PLF to give new coefficients corresponding to the projected PLF. This is done by calculating and applying a factor, a, as follows:

$$L = b_0 + a\,(b_1X + b_2X^2 \ldots\ldots b_5X^5) = 1 + \ldots\ldots \;.$$

Thus the shape of the curve is conserved.

This program was also used when the load factor varied during the time of the study. Figure C-2 shows an example of varying the load factor while conserving the shape of the load duration curve.

In some cases, seasonal load curves and load factors were not available but only one annual load curve and the seasonal minima and maxima. In these cases the following approximation for the load curve was used:

$$L = 1 - (1-LF^2)\, X^{LF}$$

From this expression the load factor LF can be shown to be

$$LF = \sqrt{L_{X=1}} = \sqrt{\frac{\text{minimum load}}{\text{maximum load}}}$$

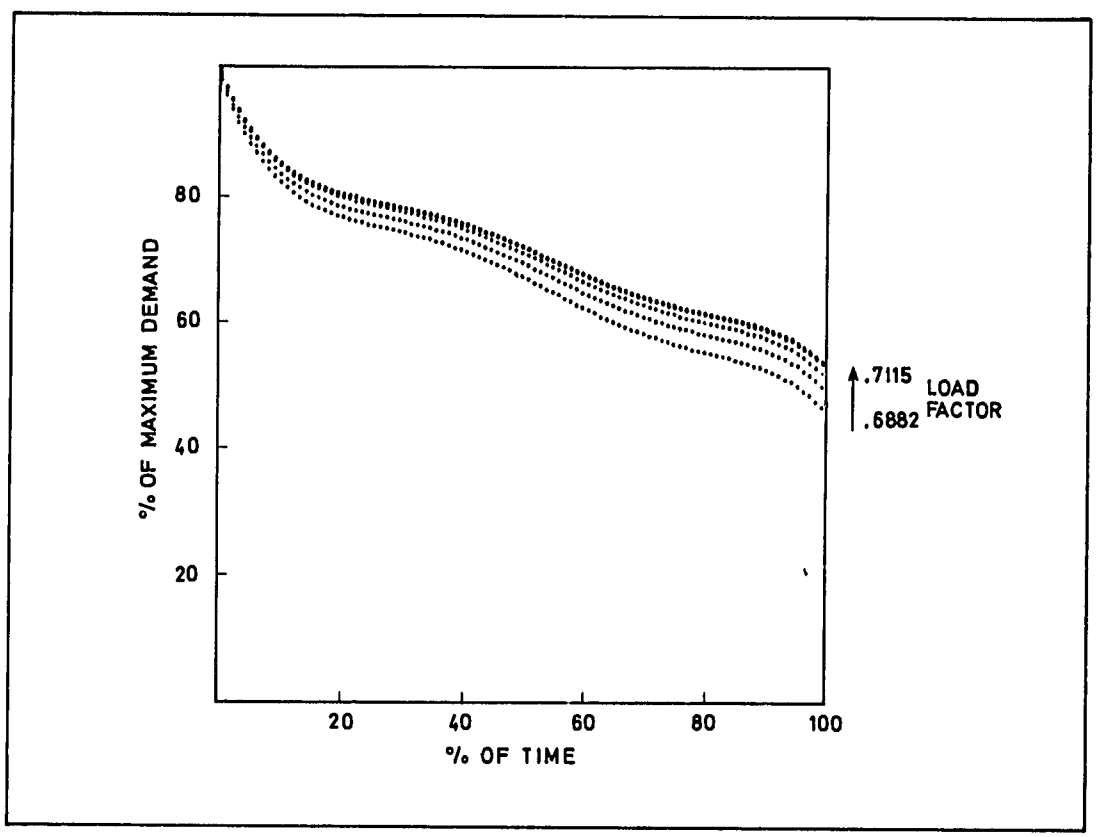


FIG. C-2. ILLUSTRATION OF THE EFFECT OF LOAD FACTOR ON A LOAD DURATION CURVE.

APPENDIX D

ECONOMIC METHODOLOGY AND PARAMETERS

The purpose of the Survey was to estimate the possible role of nuclear power in meeting the electric energy requirements of the countries over ten years from 1980 to 1989. Ideally the performance of this task would require estimating and comparing benefits and costs, both direct and indirect, arising from alternative development patterns, in order to determine in each case the power expansion plan yielding maximum total net benefits.

The above requirement has seldom been met in full even in analyses of a single project in one country. To fulfil it for the comparison of chains of projects extending over ten years and covering 14 countries would have been theoretically questionable and practically impossible.

A series of simplifying assumptions affecting both input data and the procedures for their aggregation, treatment and comparison was therefore unavoidable. The methodology described in the following sections represents an attempt at achieving a compromise between practical constraints and theoretical consistency.

The main components of this methodology involved:

(1) A definition of costs and benefits to be considered and the development of methods for estimating their quantitative values.

(2) A selection of criteria for comparing benefits and cost streams extending over time and containing domestic and foreign currency components in variable proportions.

(3) A choice of an optimization procedure and of a time horizon.

These three major components are reviewed in the following paragraphs.

DEFINITION AND ESTIMATES OF COSTS AND BENEFITS

It was assumed that costs rather than net benefits would be the only yardstick. This is tantamount to assuming that all programs of electric power expansion meeting projected demand with the imposed constraints on reliability offer the same total benefits and that the least cost program consequently yields maximum benefits to the ultimate consumers. In the case of comparing alternative ways of producing the same commodity, in this case electric power, this is a less questionable alternative than it would be in the general case of comparing alternative projects with different outputs. It does, however, ignore such indirect effects as, for instance, different employment levels arising from different power programs and their consequent effects on savings and investment or the future value of acquiring a pool of labour skilled in constructing and operating nuclear stations. Furthermore, it can lead to serious distortions where multi-purpose hydro plants are involved in the comparisons. Consequently in the latter case the share of costs assignable to power production was estimated.

Only costs directly connected with electricity production through a particular type of plant were taken into account. In particular such external or social costs as those arising from increasing environmental pollution in the case of fossil-fuelled stations or from the relatively larger thermal pollution by nuclear stations were disregarded in the basic analysis. The imposition of strict environmental controls by industrial countries leading to higher capital and fuel costs for thermal power stations shows that "external" costs may easily become "internal" over time. For the purpose of a basic analysis, however, and in spite of the recognition that the major industrial urban areas of some developing countries may well enact quantitative pollution controls, the effect of this assumption for the period under review does not appear to be decisive.

In all basic cases costs were defined as costs to the economy rather than costs to the electricity producers. A major consequence of this criterion was to eliminate taxes on all types of fuel and equipment from all cost inputs. This was a particularly critical assumption in the case of countries imposing a heavy fiscal burden on some types of fuel and in particular on fuel oil. It was felt, however, that the basic purpose of the Market Survey was

to advise countries on the total costs of alternative power programs estimated at the national level and that in this approach taxes represented internal transfers whose impact might distort the selection of power equipment which is most economic for the country as a whole. However, since the countries concerned are best judges of their tax policies which may involve items of social benefits disregarded by the Survey, since the electric utilities certainly view taxes on fuel and equipment as elements of costs, and since the Market Survey is addressed not only to the countries, but also to the potential equipment suppliers, alternative computations treating taxes as elements of costs were carried out for the cases which were expected to show critical differences in the results.

Finally, the actual data used as bases for capital and fuel costs of power stations and their extrapolation to varying local conditions are discussed in the relevant sections of the report.

SELECTION OF CRITERIA

The aggregation of domestic and foreign currency costs was carried out on the basis of the official rates of exchange prevailing on 1 January 1973. It is recognized that in many of the countries surveyed, the official rates do not reflect the relative values of foreign and domestic capital resources to the economy. Nor do they always represent values which achieve equilibrium between the supply of and the demand for foreign capital as evidenced by foreign exchange rationing and control, as well as by the existence of parallel markets.

The only defence of this approach which may substantially underestimate the true value of the ratio of foreign to domestic costs rests on its comparison with possible alternatives. The procedure of estimating "shadow" foreign exchange rates from 1980 till 1990 is dependent on political and economic forecasting and involves such a degree of uncertainty as to make its use unrealistic and its results highly doubtful. An estimate based on prevailing parallel rates would on the other hand rely on figures based on transitory trends and subject to large and rapid fluctuations.

The theoretical inaccuracies of using official rates of foreign exchange were somewhat reduced by the practices followed by some of the countries where the problem of instability was most acute. In some of these all domestic cost items of future projects were converted into hard currency equivalents on the basis of experience on past similar projects completed during periods when foreign exchange rates were more stable and more representative of the relative values of domestic and foreign capital resources.

As to the selection of the hard currency serving as common denominator, the US dollar was chosen for purposes of convenience and not because of any expectations of particular stability.

Increases of costs over time were assumed to take place at a rate identical for all countries and remaining constant over time. This rule involves three assumptions:

(a) The recognition of inflation as a permanent feature of the future economic development of both industrial and developing countries, an assumption which can hardly be questioned in the light of past experience.
(b) The assumption of an identical rate of inflation for all countries, which is admittedly wrong both on theoretical and empirical grounds but practically justifiable in view of the impossibility of realistic individual forecasts. The difficulty was, however, partially met by the combination of a single inflation rate with a series of alternative present-worth discount rates, a procedure more fully explained in the next section, thus giving each country the opportunity of basing its decisions on the values which it considers most relevant to its own case.
(c) The assumption of a rate constant over time is also based on considerations of practical expediency.

Finally the selection of 4% as the numerical value of expected annual price growth is a compromise between the much higher values recorded by most countries in the past and the somewhat lower targets set by their governments for the future.[1]

[1] The major exception was the rate of escalation for fuel oil which was taken at 6% for reasons explained at length in Appendix I.

The aggregation and comparison of time flows of costs was done through a discounting of their present-worth values and in all basic cases at a rate identical for all countries and assumed to remain constant in time. As in the previous case, this principle implies three decisions:

(a) The selection of present worth as a criterion. This decision must again be assessed against its possible alternative, which would have been to rank different patterns by their internal rate of return. The latter was, however, clearly ruled out since, apart from its theoretical flaws in the comparison of mutually exclusive projects, it requires estimates of benefits which the Survey deliberately refrained from making.
(b) The choice of an identical rate for all countries although the time value of money and resources is likely to be different for each of them. An objection to this choice is entirely valid and it was therefore decided to use a range of discount rates, computing for each country the corresponding present-worth values and consequent rankings of alternative expansion patterns and leaving to its discretion the decision which rate appears most suitable to its own conditions.
(c) The decision to assume that the rate of discount would remain constant in time may be open to theoretical objections since its value should in principle slowly decrease with higher levels of economic development and larger stocks of capital equipment. It was felt, however, that in the countries surveyed the practical difficulties involved in estimating, and in using, variable rates of discount far outweighed the possible advantages.

Finally the rates of discount and of inflation were combined into a single rate of discount equal to their difference. This considerably simplified the computational work since it was then possible to proceed on the basis of constant prices.[2]

For the basic case the rate of present-worth discount was chosen as 12% annual compound which was felt to be a representative average of the cost of money in most countries surveyed. Since, as was noted above, the rate of inflation was chosen as 4% annual compound, the corresponding constant price discount rate was 8%. For sensitivity studies constant price discount rates of 6% and 10% were used. The time origin for discounting was taken to be 1 January 1973.

METHODS OF OPTIMIZATION AND TIME HORIZON

In theory the selection of a lowest costs pattern of development for an electric power system requires:

(a) The choice of a method for a simultaneous optimization of the construction and operation of power plants expected to be available.
(b) The choice of a time horizon or cut-off date beyond which the differences of future costs arising from alternative decisions taken during the period under review may be considered negligible when reduced to their present-worth values at the date of origin for discounting.

Among the several methods of optimization, linear, non-linear and dynamic programming, the last was originally selected as offering the best combination of theoretical consistency and realistic system description. It became apparent, however, that the amount of computer time and man-power which the systematic application of this method would require were exceeding the limited resources of the IAEA computer made available for the Market Survey. Furthermore, the margins of uncertainty affecting some of the major input data did not always warrant the costs of applying a procedure based on such a comprehensive, detailed and exhaustive approach.

It was therefore decided, except for a few cases, to proceed along more empirical lines, thus achieving a substantial saving in time and man-power without an undue sacrifice

[2] This procedure of using a rate of constant costs discount $r' = r - i$, where r is the real rate and i the rate of inflation, is strictly valid only in continuous discounting, but the errors involved in discreet discounting are negligible.

of accuracy. For each country numerous plausible patterns of power system expansion of generating capacity for the 1980 to 1989 period were developed, their operation simulated under imposed constraints and the corresponding values of total present-worth costs computed for each pattern to find the minimum cost configuration. In each system, special attention was paid to determine in advance the system configurations which past trends and future constraints made particularly plausible. The theoretical flaws inherent in this empirical search were felt to be of relatively minor importance provided sound judgement was exercised in the selection of the alternative patterns used for simulation.

The selection of a time horizon was also based on compromise between theoretical accuracy and practical possibilities with the final decision substantially constrained by the latter factor. Consequently, while recognizing that a full analysis of the costs of power expansion patterns during the 1980 - 1989 period should theoretically extend up to a point in time when the economic consequences of alternative decisions lead to insignificant differences in present-worth values, it was also felt that detailed forecasts of development beyond the year 2000, and even beyond 1990, would not in most cases be realistic. Consequently, it was decided to take some, but not full account of future consequences by establishing for each system a single expansion plan for the 1990 - 2000 period which was then attached to each alternative plan for the 1980 - 1989 decade in the simulation and present-worth computation procedures. Furthermore, salvage values based on linear depreciation were factored in for all plants at the end of the Survey period.

The use of salvage values based on straight line depreciation, a practice current in most electric utilities accounting, involves a slight departure from strict economic accounting which should be based on sinking fund depreciation. It should be noted, however, that this procedure errs on the conservative side with regard to nuclear power stations since it leads to the use of higher present-worth coefficients than those of the sinking fund method.

As an example, for a power plant with a capital cost C commissioned j years before the cut-off date of the study and which is expected to have a useful life of ℓ years, the present-worth values of the capital cost of the plant net of salvage value discounted at the interest rate i would be given by

$$V_1 = C\left[1 - (1 - \frac{j}{\ell})(1+i)^{-j}\right]$$

according to the straight line method used in the survey, and

$$V_2 = C\,\frac{1 - (1+i)^{-j}}{1 - (1+i)^{-\ell}}$$

according to strict sinking fund depreciation.

For a plant built in 1985 or 15 years before the cut-off date set at year 2000, these formulae would yield the following capital cost charges to the objective function:

$$V_1 = 0.84\ C \text{ and } V_2 = 0.76\ C$$

Appendix A gives a comprehensive presentation of the WASP program used for simulating system operation and, in some selected cases, for dynamic optimization.

APPENDIX E

STANDARDIZED DATA FOR GENERATING UNITS CONSIDERED AS EXPANSION ALTERNATIVES

In order to facilitate preparation of input data for the WASP program, it was decided to standardize the characteristics of the various alternative types of thermal plants which might be used to expand the power system of each of the countries being studied. It was recognized that in some countries these standardized data might not be representative of units which would actually be considered as expansion alternatives and in such cases provision was made for modifying the data as necessary.

The following paragraphs describe the methodology used to develop the characteristics of the standardized alternative generating plants and the actual data used in the studies.

CHOICE OF UNIT SIZES, TYPES OF PLANTS AND NOMENCLATURE

Table E-1 shows the unit sizes, types of plants and standard nomenclature used for expansion alternatives. These choices were fixed in order to achieve comparable computer outputs.

TABLE E-1. SIZES, TYPES AND STANDARD NOMENCLATURE FOR EXPANSION ALTERNATIVES

Size (MW)	Type of plant					
	Nuclear	Lignite	Oil	Coal	Gas	Gas turbine
50						GT50
100	N100	L100	O100	C100	G100	
150		L150	O150	C150	G150	
200	N200	L200	O200	C200	G200	
300	N300	L300	O300	C300	G300	
400	N400	L400	O400	C400	G400	
600	N600	L600	O600	C600	G600	
800	N800	L800	O800	C800	G800	
1000	N1T0	L1T0	O1T0	C1T0	G1T0	

MINIMUM OPERATING CAPACITIES

It was recognized that thermal power plants can be designed to operate at as low as 25% of their rated capacity; for the purpose of the Survey, however, the minimum operating capacity of the standard plants was set at 50% of full load. Gas turbines were assumed to be operated at full load or not at all. Units in the fixed system (i. e. plants in the system at the start of the study period) with capacities below 50 MW were also assumed to operate only at full load and, for units of 50 MW and larger, the minimum operating capacity was taken to be that stated by the country.

HEAT RATES

Full load and half load heat rates for the standard alternative generating plants were derived from data provided by Bechtel Corporation and Lahmeyer International GmbH (see Appendix G for details of these).

OPERATING AND MAINTENANCE COSTS

Operating and maintenance costs of PWR and oil-fired plants were taken from data in the open literature [1, 2] adjusted to "end of 1972 dollars" by escalating at 4%/yr. Assuming that power stations would on an average have two units per station, operating costs for single unit plants were reduced by 15% to allow for the second unit. Property damage insurance was added to these costs. In the case of nuclear plants, this was assumed to amount to 0.25% of the capital cost and in the case of oil-fired plants to 0.1% of the capital cost. Tables E-2 and E-3 show the breakdown of operating and maintenance costs for PWRs and oil-fired plants. Gas-fired plants were assumed to have the same operating and maintenance costs as oil-fired plants, coal-fired plants were assumed to be 7% higher and lignite-fired plants 10% higher. These costs were adjusted to local conditions (i.e. lower staffing costs etc.) when warranted.

TABLE E-2. BREAKDOWN OF UNADJUSTED OPERATING AND MAINTENANCE COSTS FOR PWRs (10^3 US $/yr)[a]

Item	Capacity (MW)						
	100	200	300	400	600	800	1 000
Staffing	750	800	850	860	910	960	970
Maintenance supplies and services	260	330	410	465	580	680	760
Insurance[b]	500	570	610	690	810	940	1 070
Total	1 510	1 700	1 870	2 015	2 300	2 580	2 800
US $/kW per month	1.26	0.71	0.52	0.42	0.32	0.27	0.23

[a] Based on US conditions.
[b] Includes property damage and third party liability insurance.

TABLE E-3. BREAKDOWN OF UNADJUSTED OPERATING AND MAINTENANCE COSTS FOR OIL-FIRED PLANTS (10^3 US $/yr)[a]

Item	Capacity (MW)							
	100	150	200	300	400	600	800	1 000
Staffing	500	[illegible]	540	580	630	700	780	870
Maintenance supplies and services	170	200	240	300	360	500	620	760
Insurance	60	80	95	120	150	180	240	290
Total	730	800	875	1 000	1 140	1 380	1 640	1 920
US $/kW per month	0.61	0.45	0.36	0.28	0.24	0.19	0.17	0.16

[a] Based on US conditions.

SCHEDULED MAINTENANCE TIMES AND FORCED OUTAGE RATES

The scheduled maintenance times and forced outage rates assumed for the alternative generating plants are shown in Table E-4. These data result in the unavailability percentages given in Table E-5. They are essentially the same as the unavailabilities experienced on plants in the USA. These figures were also used for existing plants when actual data were unavailable. It is recognized that at the present time plant availabilities in some of the developing countries are substantially lower than these values. In addition, as nuclear units and much larger sizes of conventional plant are introduced, it is likely that total (forced and

TABLE E-4. SCHEDULED MAINTENANCE TIMES AND FORCED OUTAGE RATES OF ALTERNATIVE GENERATING PLANTS

Unit size (MW)	Scheduled maintenance (days/yr)		Forced outage rate (%)	
	Conventional	Nuclear	Oil/Gas, Nuclear	Coal, Lignite
50	21	-	7.5	9.6
100	21	28	6.5	8.6
150	21	-	5.3	7.5
200	21	28	5.4	7.5
300	28	28	6.5	8.7
400	28	28	9.8	12.0
600	28	28	12.0	14.1
800	35	35	12.2	14.5
1 000	35	35	12.2	14.5

TABLE E-5. PERCENTAGE UNAVAILABILITY OF ALTERNATIVE GENERATING PLANTS

Unit size (MW)	Unavailability (%)			
	Nuclear	Oil/Gas	Coal/Lignite	Electrical World[a]
50	-	13	15	13+
100	14	12	14	10 - 13
150	-	11	13	10 - 11
200	13	11	13	11
300	14	14	16	11 - 17
400	17	17	19	17
600	19	19	21	21
800	21	21	23	21
1 000	21	21	23	21

[a] Average for US plants as reported in Ref [3].

maintenance) outage times will be greater. This, however, is considered to be a transitory situation and it is expected that plant availabilities in the developing countries will improve with time as experience is gained with more sophisticated units until they approach those of the industrialized countries. This improvement is expected to occur within the study period of the Survey.

PLANT LIFETIME

Plant lifetimes were assumed to be 30 years for both nuclear and conventional plants. Linear depreciation of the plant investment cost was taken over this period. Since the levelized working capital component of the nuclear fuel cycle cost is treated as an addition to the plant investment cost, two years were added to the nuclear plant lifetime to correct for the fact that this working capital does not depreciate.

STUDY HORIZON

Although the time period of interest to the Survey is 1980 to 1989, the study horizon was extended to the year 2000 to allow for the influence of plants built in the second decade on the load factor of those introduced up to the end of 1989. Extension of the study horizon also results in a better approximation of the effect of escalation on the generating costs of oil-fired plants introduced in the 1980-1989 period (see also Appendix D).

TRANSMISSION COSTS

Transmission costs were not treated explicitly in the study, based on the assumption that they would be essentially the same for the alternative generating units being considered. In cases where extra transmission costs were required for the installation of a specific plant, such as a remote hydro plant, these were added to the capital costs of the plant and the available energy of the hydro plants was discounted by appropriate amounts to correct for transmission line losses.

REFERENCES

[1] KHAN, M.A., ROBERTS, J.T., "Small and medium power reactors – technical and economic status", 4th Int. Conf. peaceful Uses atom. Energy (Proc. Conf. Geneva, 1971) 6, IAEA, Vienna (1971) 57.

[2] NUS Corporation, Guide for Economic Evaluation of Nuclear Reactor Plant Designs, USAEC Rep. NUS-531 (1969).

[3] Electrical World (1 Nov. 1971) 47.

APPENDIX F

LONG RANGE FORECASTING OF THE DEMAND FOR ELECTRICAL ENERGY

H. Aoki

The basic objective of an electric power program is to provide sufficient power to meet the demand and to do so as economically as possible. In view of the time required for planning and constructing power plants, a plan for installing new power generation, transmission and distribution facilities should be established at least ten years in advance of the actual required date. The formulation of a reasonably reliable method for long range forecasting of the likely demand for electrical energy is therefore of vital importance.

A number of methods have been used and these are briefly reviewed below. The particular method used for providing forecasts for the countries covered by the Market Survey is described in detail.

VARIOUS METHODS

The methods used fall into two groups. In the first the country is considered in isolation, and the forecast is based upon past trends in that country.

(a) Simple extrapolation

The average growth rate of the demand for electrical energy over the past years is determined.

A factor, usually less than or equal to 1, is applied to the historical growth rate, and this modified growth rate is assumed for the future. Clearly the difficulty with this method lies in the determination of the modifying factor to be used for a particular country, particularly if it is a developing country.

(b) Correlation between the national economy and the energy demand

This involves taking some measure of the national economy, such as GNP or GDP, and comparing its historical growth with that for the demand for electrical energy. The past relationship between the two is then extrapolated into the future. Again this method is not particularly useful in the case of developing countries which are usually in a transitional stage of development in respect of their national economies and of their electrical energy demand.

Both methods can be useful for comparatively short range forecasts.

(c) Accumulative method

In this method various sectors of the country's economy and specific industries in the country are studied and estimates made of the likely individual future demands for electrical energy. These separate estimates are then added in order to give a complete forecast for the country. Again, this method is useful for short range forecasting but for long range it involves the making of sweeping assumptions about the long term development of particular industries and, whilst giving the appearance of accuracy, is in the end no more reliable than the first two methods.

The next three methods depend upon comparisons with one or more other countries.

(d) Sentiment method

This involves basing the forecast for a particular country upon either the forecast for what is believed to be a closely comparable country, or upon the recent experience of a country believed to be similar but rather more developed. Clearly the accuracy of this

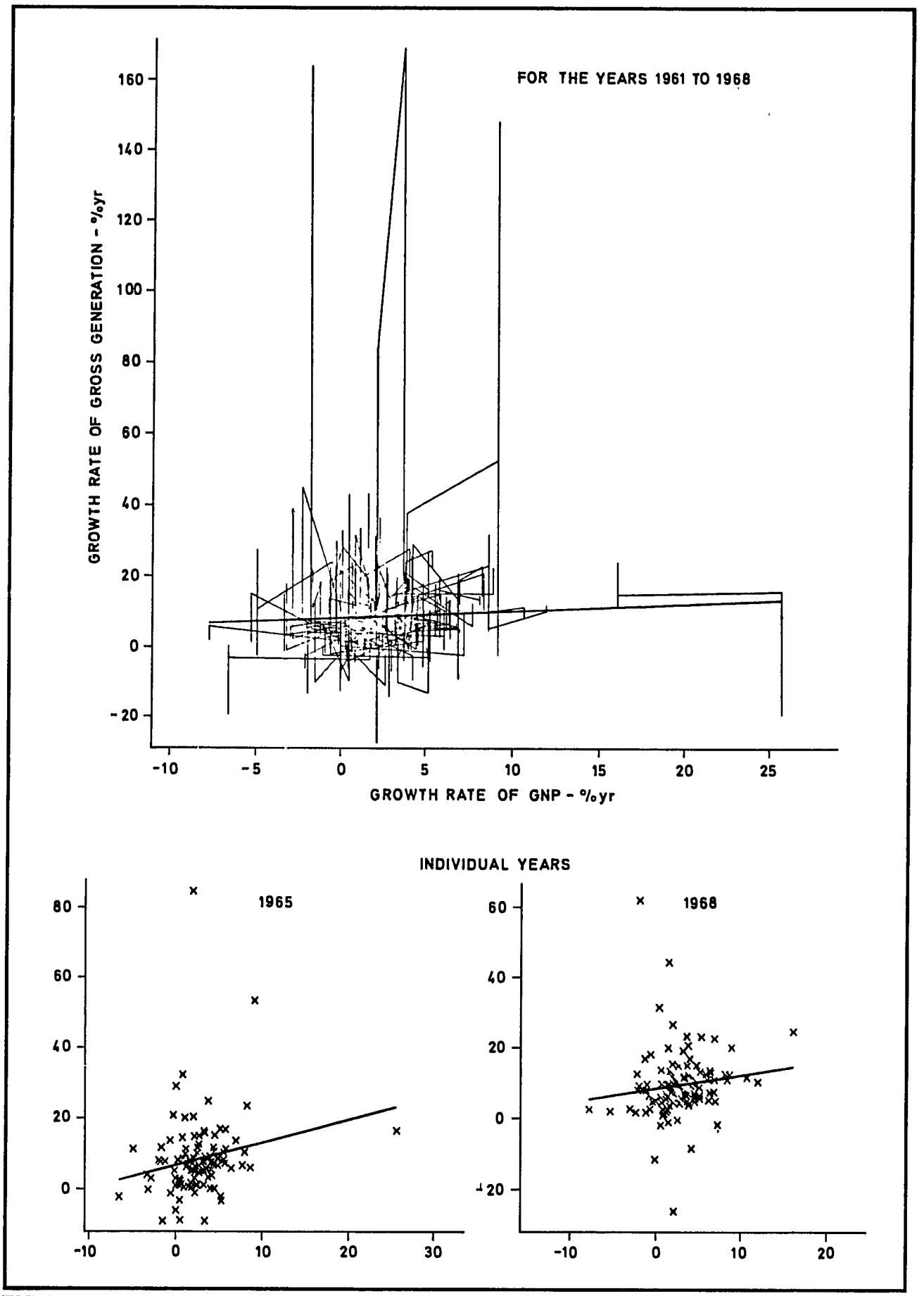


FIG. F-1. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GNP.

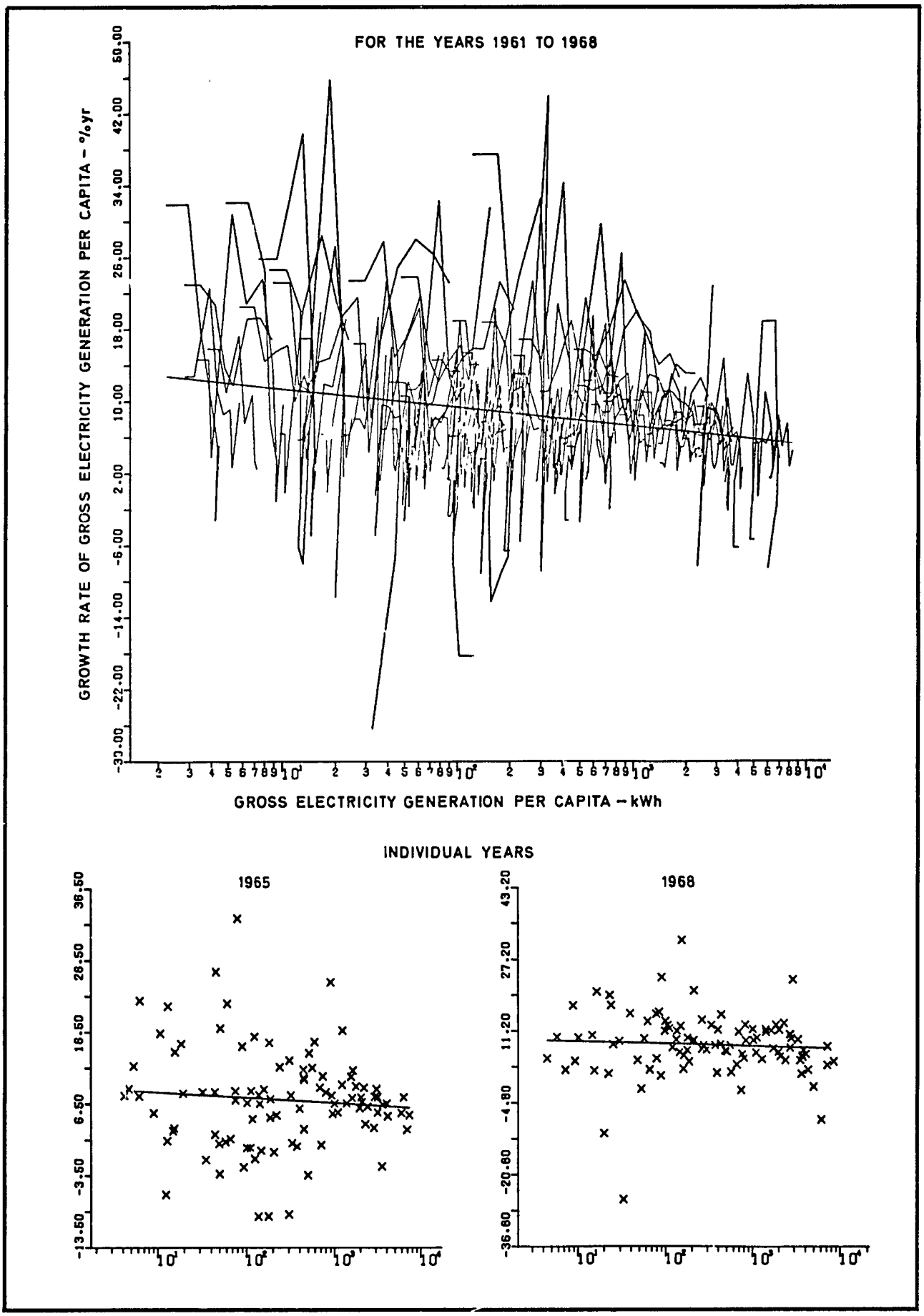


FIG. F-2. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GROSS GENERATION PER CAPITA.

method is completely dependent upon how comparable the reference country (or countries) really is. In this comparison it is necessary to take into account, for instance, the kind of energy resources available in the two countries since they might be similar in all respects except that one has a great deal of potential hydroelectric power which can be developed cheaply and the other has little potential or potential that would be costly to develop. The method is superficially attractive, but for the reasons stated cannot be recommended.

(e) World-wide correlation between growth rate of GNP and of energy generation

In this method the growth rate of GNP is plotted against the growth rate of electrical energy generation for as many countries as possible. If a correlation is seen to exist, and given that a reliable forecast of the future GNP can be made for the country being studied, this correlation can be used to forecast the future energy demand. Such data are plotted in Fig. F-1 for 111 countries, for the years 1961 to 1968 and for the two individual years 1965 and 1968. It will be seen from this figure that the correlation is very poor and this fact is confirmed by statistical analysis of the data. As a result this method cannot give reliable forecasts of electrical energy demand.

(f) World-wide correlation between the per-capita generation of electrical energy and the rate of growth of per-capita generation

This method would be used in a similar fashion to (e). The data for 111 countries are plotted in Fig. F-2. Clearly the correlation is a little better than that obtained for (e), but it is still inadequate for obtaining accurate forecasts of electricity demand.

THE AOKI METHOD USED FOR THE MARKET SURVEY

This method is similar to the last two described in that it is based upon data from a large number of countries. It is similar to method (e) in that it assumes that there must be a connection between generation of electrical energy and the state of the national economy. But it introduces the concept that the per-capita values of these variables, rather than the absolute values should be correlated. Figure F-3 shows a plot of electricity generation per capita against GNP per capita for 111 countries. The historical GNP data used in this plot were obtained from the IBRD World Table, January 1971, and are expressed in terms of constant prices (1964 US $).

The correlation between these two quantities is clearly much better than the one achieved in either method (e) or (f) and the correlation coefficient of the straight line fit shown in Fig. F-3 is remarkably high. Since the data at the upper and lower end of the figure tend to fall below this line, it is obvious that a better fit could be obtained by using a polynomial. This has been done in effect by determining the best straight line fit over a series of intervals of per-capita GNP as shown by Fig. F-4 for the 1968 data. It is important to note that both the single correlation lines and the curves obtained from the series of straight lines are virtually the same whether determined for any single year in the period 1961 to 1968 or determined from the data for all eight years grouped together (see Fig. F-5). Thus there is evidence that the relationship is stable and can be accepted as "universal".

The consequent recommended relationship is plotted in Fig. F-6. Close examination of the individual country lines in Fig. F-3 shows that, in general, if the initial point representing a particular country falls above or below the line, subsequent points at higher values of GNP per capita approach more closely to the trend line.

It is therefore possible to draw a number of "indicative" lines on each side of the main trend line which will indicate the likely path that will be followed by countries whose present state does not lie exactly on the line. Such indicative lines are drawn in Fig. F-6.

The use of the Aoki method has essentially been indicated above. A copy of the master trend curve is taken. The available historical data for the country being studied are plotted

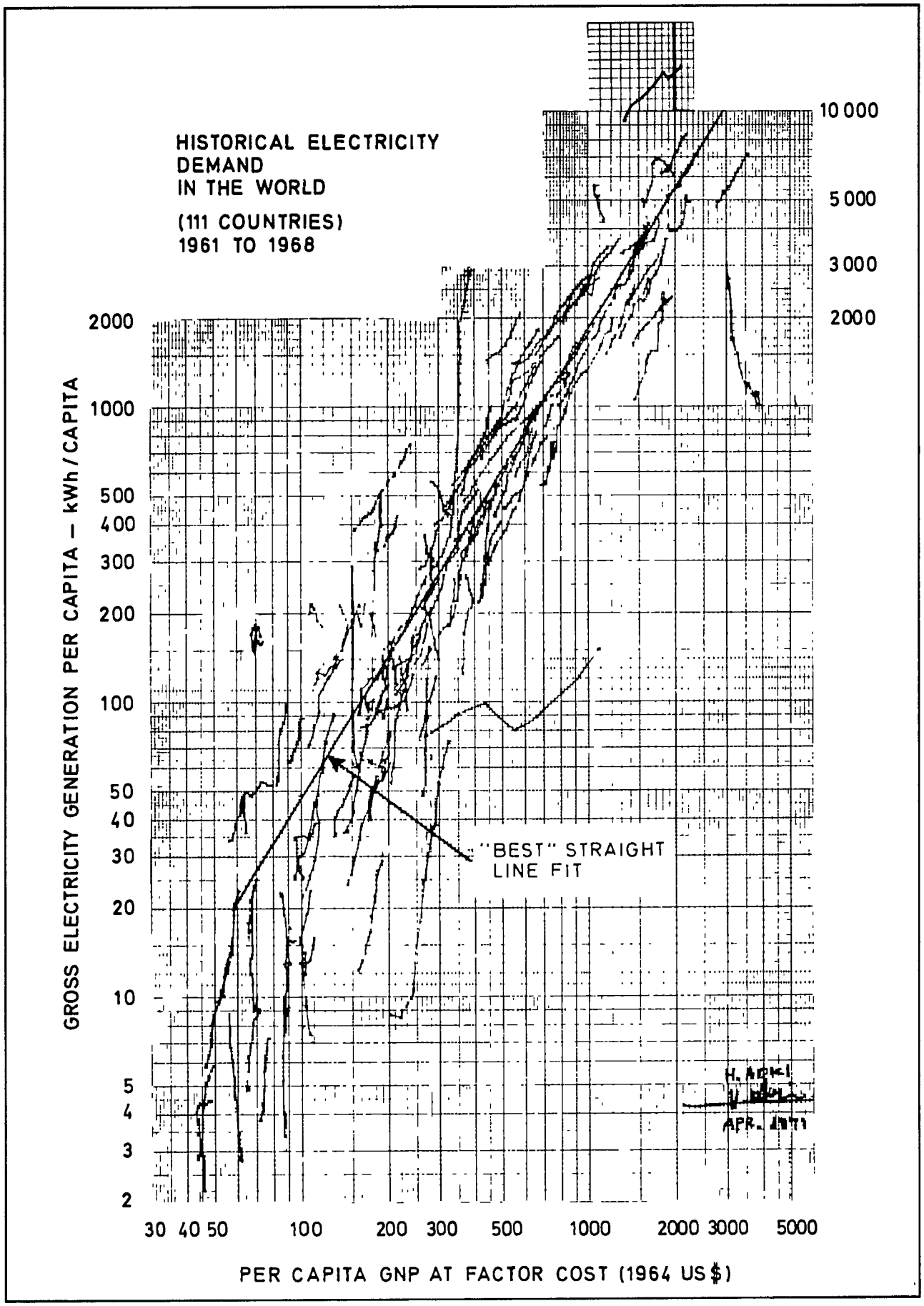


FIG. F-3. CORRELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA FOR 111 COUNTRIES FOR 1961 - 1968.

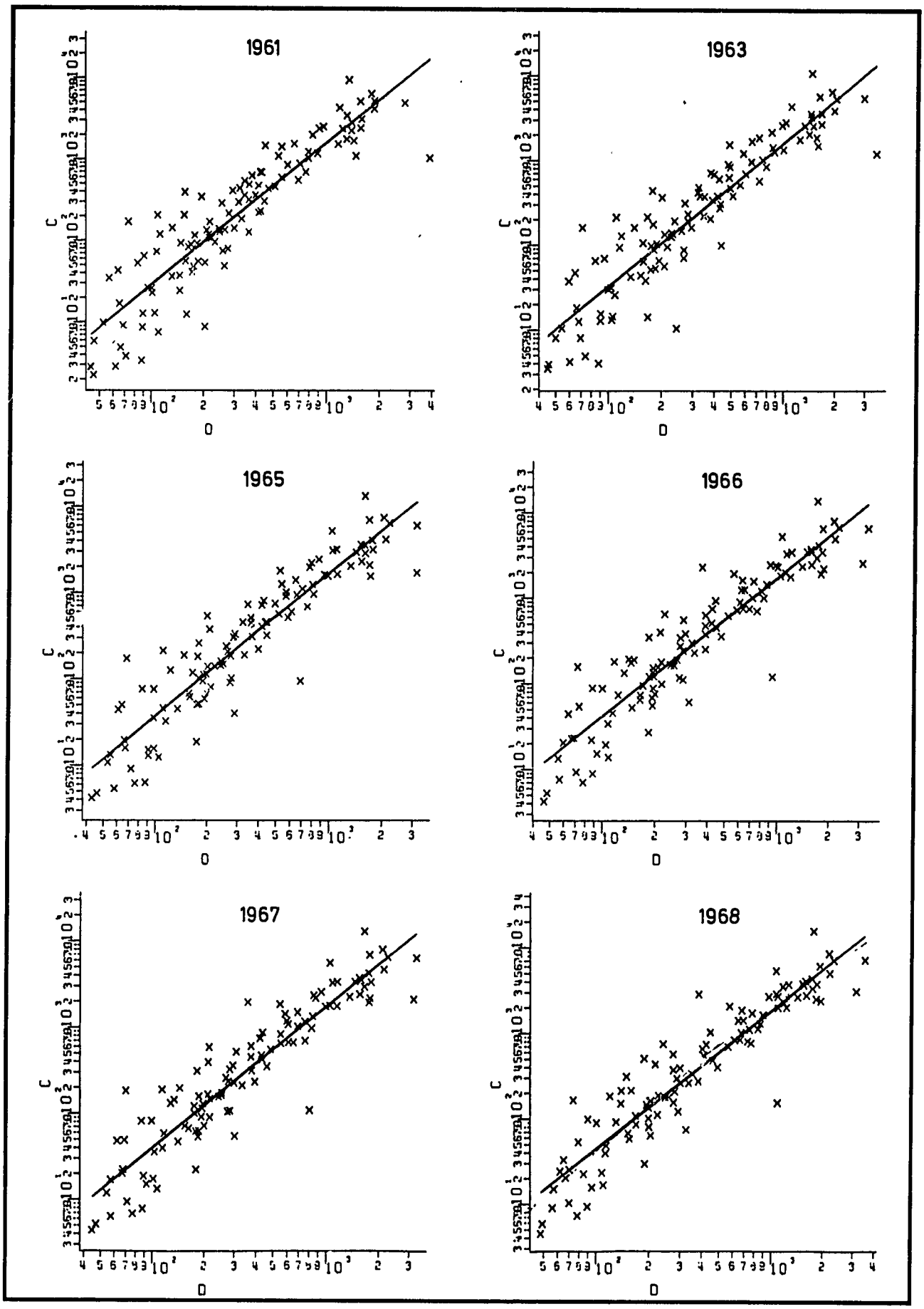


FIG. F-4. REGRESSION ANALYSIS OF THE PLOT OF GROSS GENERATION PER CAPITA VERSUS GNP PER CAPITA FOR 1968.

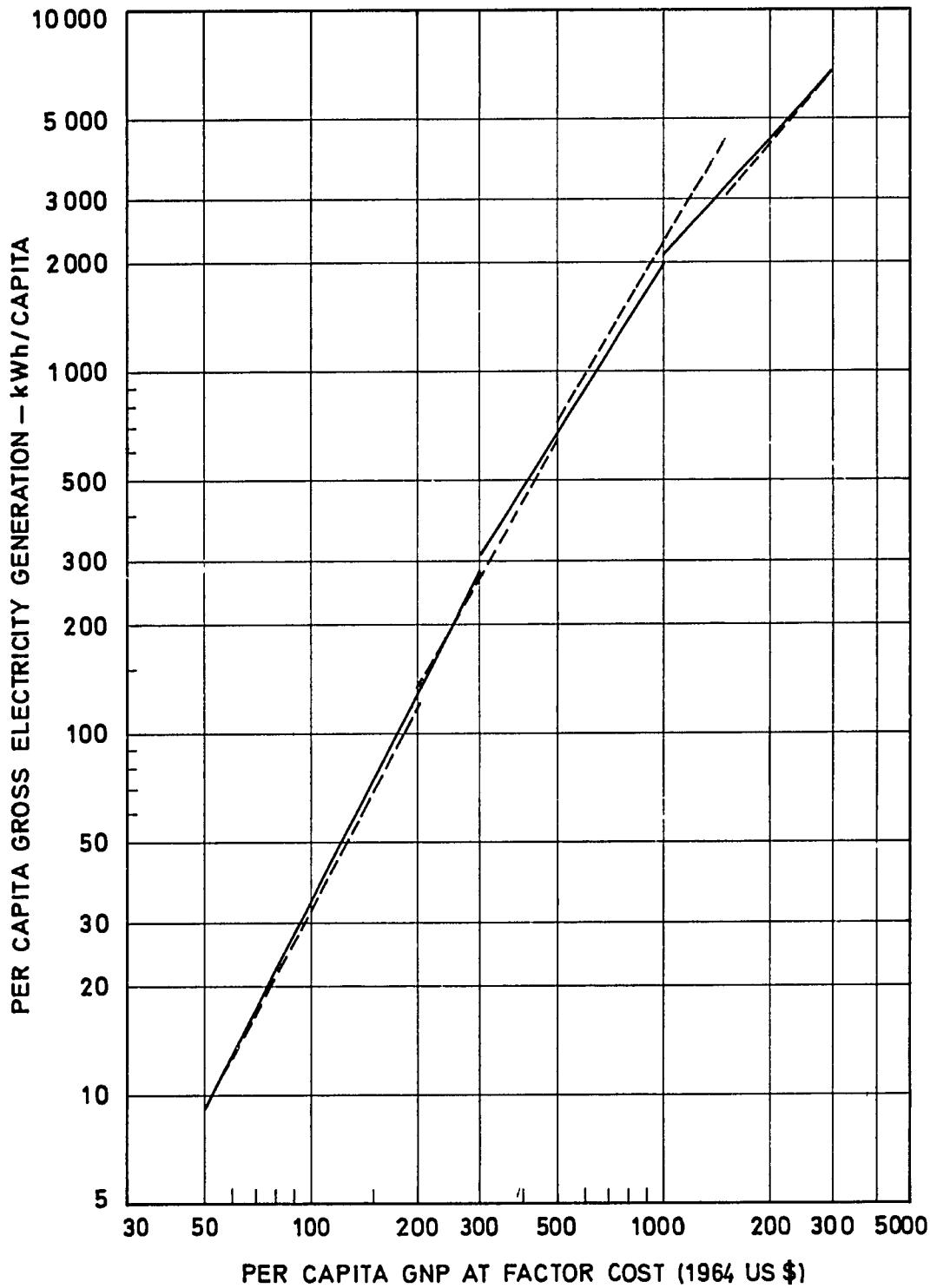


FIG. F-5. CORRELATION FOR INDIVIDUAL YEARS.

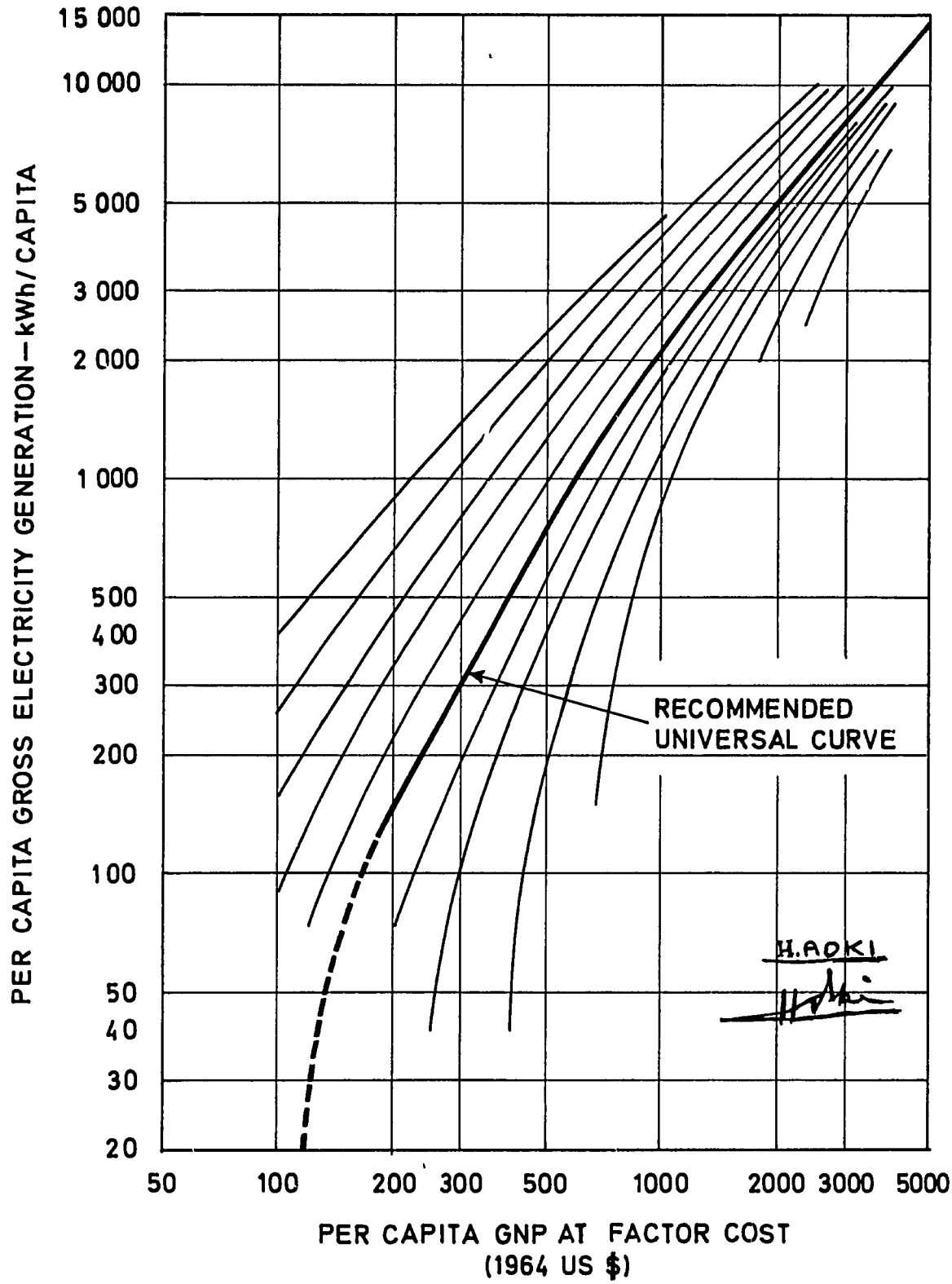


FIG. F-6. RECOMMENDED RELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA.

on the diagram. The future is then forecast by extrapolating this line following the main trend line or one of the indicative lines as appropriate. Given that a forecast of the future growth of GNP per capita is available, the future demand for electrical energy is then calculated from this extrapolation. This is done for the Survey countries in Figs F-7 and F-8.

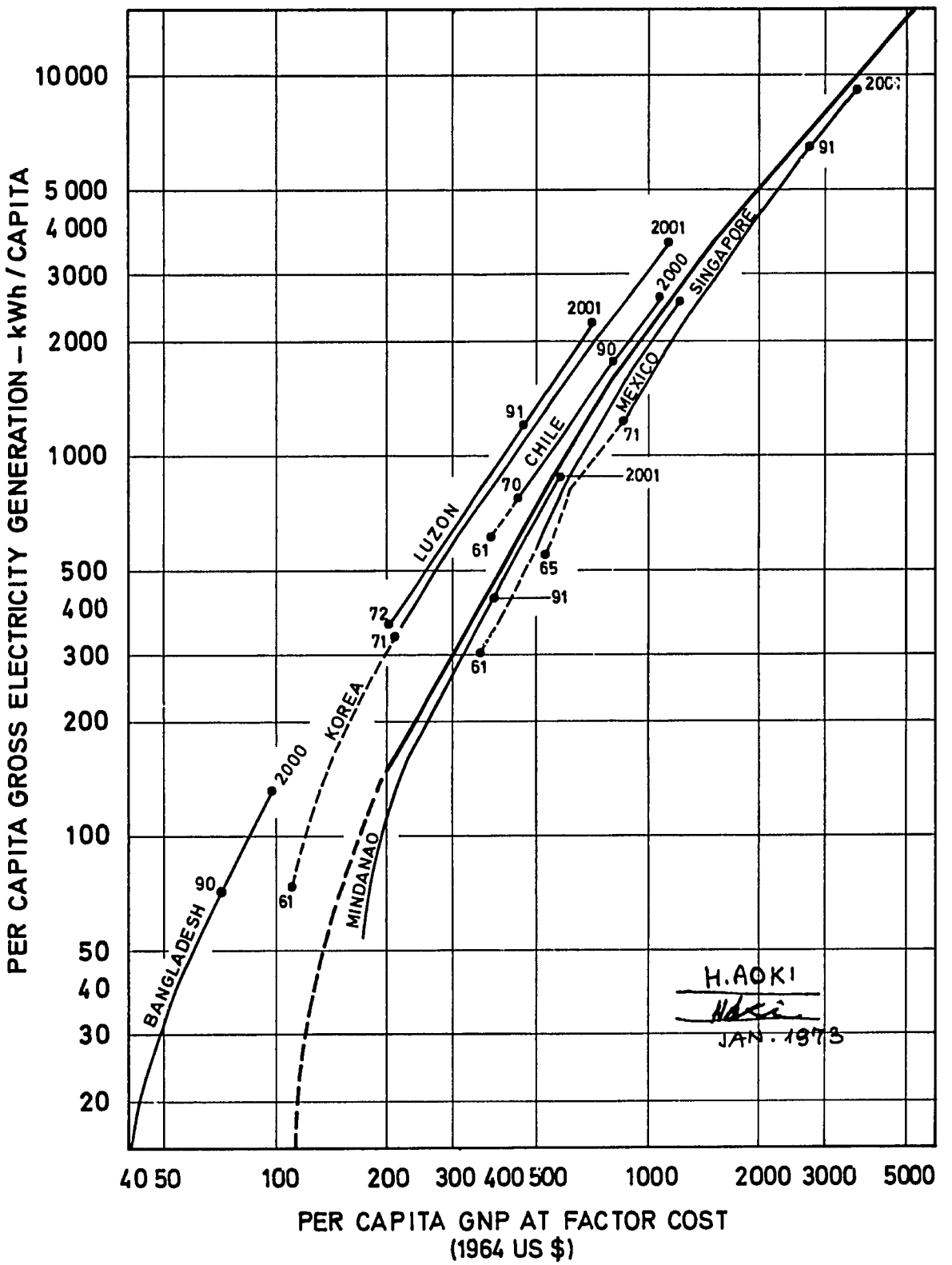


FIG. F-7. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

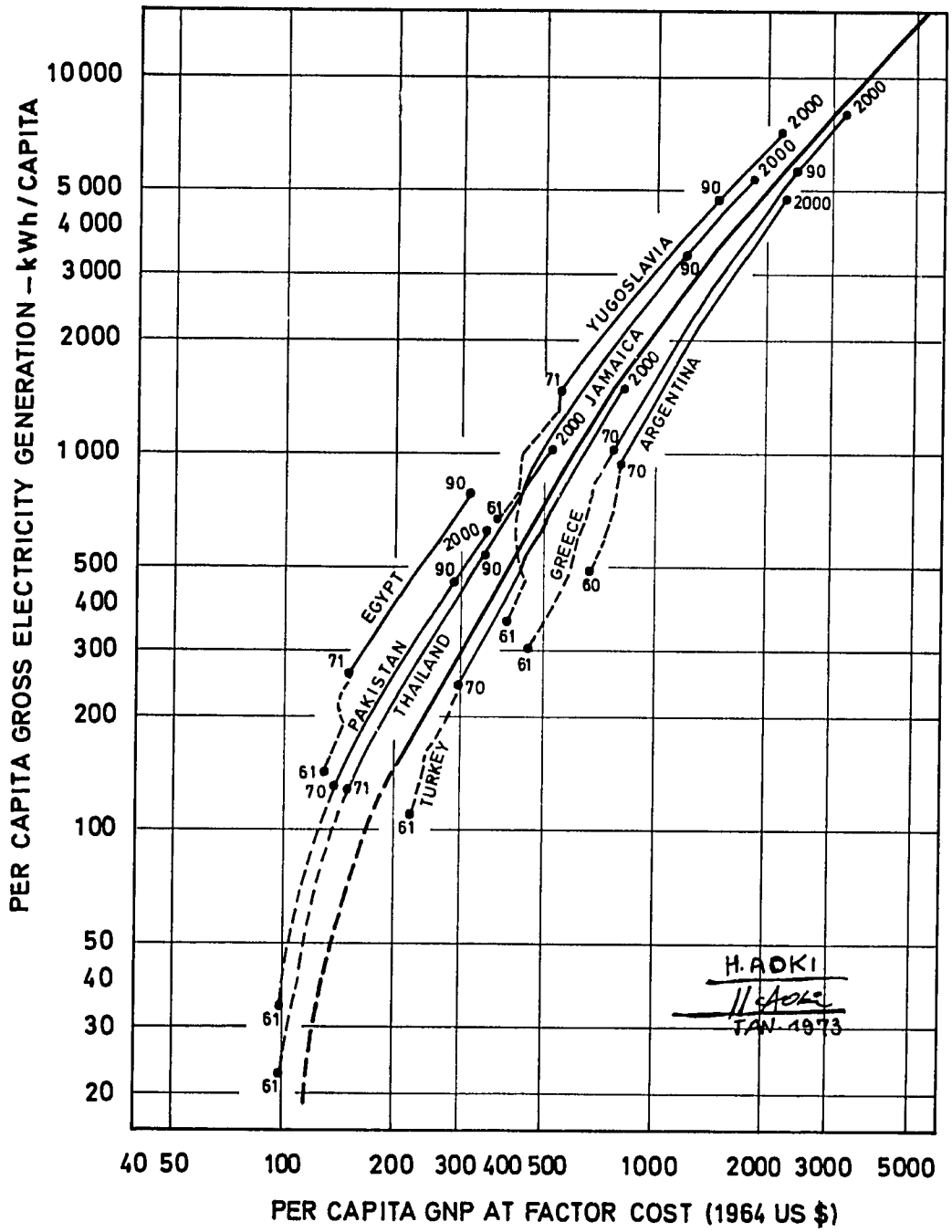


FIG. F-8. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

BASIS FOR HEAT RATE DETERMINATION

To permit an evaluation of the performance of various types of thermal power plants, the heat rates for energy conversion are required. Experienced power plant designers were requested to supply heat rates for modern plants of the type and size used in the expansion program for the various systems studied. The most detailed response was received from the Bechtel Corporation and the heat rates used in the study are based on the Bechtel data. These data were confirmed by information received from Lahmeyer International and also by data on existing plants collected in the participating countries.

The net and gross heat rates for pressurized water reactors (PWR) of capacity from 100 to 1500 MW and for coal, lignite, gas and oil stations from 100 to 1000 MW are listed in Tables G-1 to G-4. To be consistent with the country data on the fixed systems and on load forecasts, the gross heat rates were used in the study. The net heat rates are given to permit people familiar with design data to appreciate to more easily the values used.

The net heat rates for light water PWRs are calculated on the following bases:

(1) The use of a seven-heater cycle utilizing a two-reheat turbine is assumed. There are two high pressure heaters whose cascaded drains, combined with those of the third heater, are pumped into the reactor feed pump suction. Reactor feed pumps are driven in all cases by auxiliary turbines. All data on nuclear steam supply systems (NSSS) are based on information obtained from the Combustion Engineering Company (CE). This NSSS generates saturated steam at 70 kg/cm^2 (a 1.5 kg/cm^2 pressure drop to the turbine stop valve was assumed in all cases). Final feed-water temperature is 230°C.

(2) Auxiliary power requirements for reactor sizes of 800 MW and above are based on information obtained from CE. Auxiliary power requirements for reactor sizes below 800 MW are assumed to be 1.75% of output at the generator terminals at rated power and condenser pressure of 3.0 in Hg abs. In all cases, auxiliary power for the balance of plant is broken down in the following fashion:

	Rated load	50% load
Main transformer losses	0.40%	0.70%
Circulating water system (once through) auxiliary power	0.30%	0.60%
Balance of plant exclusive of main transformer & circulating pumps	0.95%	1.65%
Total balance of plant auxiliary power	1.65%	2.95%

(3) It should be noted that all heat rates assume that steam is generated at 70 kg/cm^2. Historically, the smaller units in the range 400 to 800 MW generated steam at 55 kg/cm^2 (770 lb/in^2 abs.); later steam pressures for larger units were increased to 58 kg/cm^2 (815 lb/in^2 abs.), and then to 63 kg/cm^2 (900 lb/in^2 abs.). Thus the heat rates in this study would appear better in comparison. However, CE states that were they to offer any of these smaller units today, they would quote them all on the basis of steam generated at 70 kg/cm^2 (1000 lb/in^2 abs.).

Heat rates were computed on the basis of using in all cases the smallest turbine exhaust consistent with turbine exhaust loading limits as specified by the two US turbine manufacturers.

TABLE G-1. NET HEAT RATES FOR FOSSIL-FUELLED PLANT [a]

Type	Full load		Half load		Incremental energy rate[b] (kcal/kWh)
	Power (MW)	Heat rate (kcal/kWh)	Power (MW)	Heat rate (kcal/kWh)	
Coal	100	2 443	50	2 592	2 294
	150	2 421	75	2 551	2 291
	200	2 378	100	2 501	2 255
	300	2 360	150	2 474	2 246
	400	2 358	200	2 463	2 253
	600	2 350	300	2 467	2 233
	800	2 352	400	2 472	2 232
	1 000	2 348	500	2 483	2 213
Lignite	100	2 666	50	2 832	2 500
	150	2 642	75	2 787	2 497
	200	2 595	100	2 732	2 458
	300	2 574	150	2 702	2 446
	400	2 573	200	2 690	2 456
	600	2 565	300	2 694	2 436
	800	2 567	400	2 701	2 433
	1 000	2 561	500	2 712	2 410
Gas	100	2 529	50	2 671	2 388
	150	2 506	75	2 629	2 383
	200	2 461	100	2 577	2 345
	300	2 443	150	2 551	2 335
	400	2 441	200	2 539	2 343
	600	2 433	300	2 593	2 323
	800	2 435	400	2 549	2 321
	1 000	2 431	500	2 560	2 342
Oil	100	2 390	50	2 528	2 252
	150	2 368	75	2 487	2 249
	200	2 327	100	2 438	2 216
	300	2 309	150	2 413	2 205
	400	2 307	200	2 403	2 211
	600	2 300	300	2 406	2 194
	800	2 302	400	2 412	2 192
	1 000	2 297	500	2 422	2 172

[a] Based on information received from Bechtel Corporation.

[b] Incremental energy rate = $\frac{\text{(Full load heat rate) (Full load power) - (Half load heat rate) (Half load power)}}{\text{(Full load power - Half load power)}}$

TABLE G-2. GROSS HEAT RATES FOR FOSSIL-FUELLED PLANTS[a]

Type	Size (MW)	Full load heat rate (kcal/kWh)	Half load heat rate (kcal/kWh)	Incremental energy rate (kcal/kWh)
Coal	100	2 311	2 411	2 211
	150	2 290	2 374	2 206
	200	2 233	2 306	2 160
	300	2 280	2 361	2 199
	400	2 233	2 351	2 115
	600	2 270	2 354	2 186
	800	2 272	2 360	2 184
	1 000	2 268	2 370	2 166
Lignite	100	2 512	2 615	2 409
	150	2 490	2 574	2 406
	200	2 427	2 500	2 354
	300	2 478	2 560	2 396
	400	2 427	2 549	2 305
	600	2 468	2 553	2 383
	800	2 470	2 559	2 381
	1 000	2 465	2 570	2 360
Gas	100	2 420	2 526	2 314
	150	2 404	2 486	2 322
	200	2 344	2 415	2 273
	300	2 393	2 473	2 213
	400	2 344	2 461	2 227
	600	2 383	2 465	2 301
	800	2 385	2 471	2 299
	1 000	2 381	2 482	2 280
Oil	100	2 290	2 388	2 192
	150	2 270	2 347	2 193
	200	2 213	2 280	2 146
	300	2 259	2 335	2 183
	400	2 213	2 324	2 098
	600	2 250	2 328	2 172
	800	2 252	2 334	2 170
	1 000	2 248	2 344	2 152

[a] Based on information received from Bechtel Corporation.

The net station heat rates for fossil-fired units are based on the following assumptions:

(1) Steam generator efficiencies are based on 144°C exit gas temperature at full load, and on the following fuels:
   (a) bituminous coal at 5544 kcal/kg (10 000 Btu/lb),
   (b) lignite at 3465 kcal/kg (6250 Btu/lb),
   (c) low sulphur or "bunker C" fuel oil,
   (d) natural gas.

TABLE G-3. PWR NET HEAT RATES[a]

Full load		Half load		
Net generator output (MW)	Heat rate (kcal/kWh)	Net generator output (MW)	Heat rate (kcal/kWh)	Incremental energy rate (kcal/kWh)
100	2 591	50	2 840	2 342
200	2 590	100	2 834	2 346
300	2 589	150	2 828	2 350
400	2 589	200	2 822	2 355
600	2 587	300	2 811	2 363
800	2 585	400	2 799	2 371
1 000	2 583	500	2 786	2 380

[a] Based on information received from Bechtel Corporation.

TABLE G-4. PWR GROSS HEAT RATES[a]

Size (MW)	Full load heat rate (kcal/kWh)	Size (MW)	Half load heat rate (kcal/kWh)	Incremental energy rate (kcal/kWh)
100	2 504	50	2 651	2 357
200	2 503	100	2 648	2 359
300	2 502	150	2 645	2 361
400	2 502	200	2 643	2 362
600	2 501	300	2 637	2 365
800	2 500	400	2 632	2 368
1 000	2 499	500	2 627	2 372

[a] Based on information received from Bechtel Corporation.

(2) All steam generators are balanced draft, with both forced and induced draft fans.
(3) Flue gas electrostatic precipitators are included for coal and lignite steam generators only. Precipitator power requirements are assumed to be 0.20% of rated generator load at full load, and 0.40% of generator load at half load. Flue gas SO_2 scrubbers and associated auxiliary power have not been included.
(4) Turbine throttle conditions are assumed to be 125 kg/cm^2 and 537°C with reheat to 537°C for the 100 and 150 MW units; and 168 kg/cm^2 and 537°C with reheat to 537°C for the 200 MW to 1000 MW units.
(5) All turbines are tandem compound, with the low-pressure turbine frame-size chosen for the closest possible approach to maximum allowable exhaust-steam flow loading, to obtain the required unit generator load rating.
(6) Boiler feed pumps are motor driven for the 100 to 200 MW units and steam turbine driven for the 300 to 1000 MW units.
(7) A once-through condenser cooling water system has been assumed (no cooling towers), with the circulating water pumping power assumed to be 0.25% of the rated generator load at full load, and 0.50% of the generator load at half load.
(8) The main transformer loss has been assumed to be 0.40% of rated generator load at full load, and 0.70% of generator load at half load. The net station heat rates are at the high voltage side of the main transformer.
(9) All full load heat rates are 3.0 in Hg abs. condenser pressure and all half load heat rates are at 2.0 in Hg abs. condenser pressure.

Note: Assumptions 8 and 9 apply also to the PWR units.

APPENDIX H

GENERALIZED POWER SYSTEM ANALYSIS APPROACH TO DETERMINE SYSTEM LIMITATIONS

Associated Nuclear Services Ltd (ANS)*

Power system anaysis plays an important role in determining the technical constraints to be taken into account in system design and planning studies and powerful and sophisticated techniques are available for evaluating such aspects as power flows, short-circuit levels, transient stability and frequency stability. However, the limited extent and wide tolerances associated with system data normally available for long-term planning studies of the present nature often contrast considerably with the sophistication and accuracy of these analysis techniques. Fortunately, in a study involving the comparison of a number of expansion plans, the optimization process is relatively insensitive to system data over the typical range encountered on present-day networks.

A simplified approach to system analysis is thus sufficient for the Market Survey purposes, provided this is applied consistently. The technical constraints of major interest to the Survey are transmission limitations and limits to generator unit size. This appendix describes the generalized methods adopted for the assessment of these constraints in the majority of countries. In one or two countries either or both aspects had been studied in sufficient depth by the supply authority or their consultants over the study period (1980 to 1989) and only a comparative check is necessary. Details of the application of the methods (where necessary) and results are given in Section 11 of the Country Reports.

TRANSMISSION LIMITATIONS

The main functions of transmission may be categorized as follows:

(i) Bulk distribution/collection within a load/generation region.
(ii) Point-to-point bulk transmission from a 'remote' power station to a load centre (may be long or short distance).
(iii) Inter-regional bulk transmission (i.e. an extension of (ii) to a group of remote power stations).
(iv) Inter-regional interconnection.
(v) International interconnection.

The normal transmission limitations encountered are excessive short-circuit levels, thermal ratings and transient stability limits. The varying importance and generalized approach to the assessment of these limits with reference to the above categories is discussed below.

Short-circuit levels

Where possible the short-cricuit rating(s) of grid switchgear for the various categories above are generally chosen with sufficient margin to cover system development into the foreseeable future taking into account average transmission distances, load density and the relative expected proportion of local and remote power generation. Excessive short-circuit levels are most commonly encountered in very high load density areas (category (i)) particularly where the grid system is predominantly cabled (small transmission impedances) and it has been found necessary to employ switchgear of the maximum commercially available short-circuit rating. Also, increasing the proportion of load fed from generation connected at local grid voltage level will aggravate the grid short-circuit problem.

* London, United Kingdom.

The normal eventuality of excessive short-circuit levels is the introduction of a higher voltage grid, other measures such as system segregation merely introducing a time delay which will be approximately equal for all plans. Hence the timing of a higher grid voltage in a particular system as dictated by short-circuit ratings will tend to be a common factor in all practical plant programs and will generally have little influence on the economic comparison of programs. Thus it was only necessary to check grid switchgear ratings against normal practice and where applicable to identify any special limitations or requirements.

Load flow transient stability

To achieve a reasonable standard of supply security the transmission grid should be capable of meeting the normal and 1st contingency power flow requirements throughout each plan without exceeding cricuit thermal ratings, loss of system stability (system splitting) or recourse to load shedding.

Information on standard grid circuit thermal ratings was generally available from each country. Transient stability limits were estimated using the 30° transmission angle criterion. This is a guiding criterion which, for the typical fault types and fault clearance times encountered on present-day systems, will ensure the retention of transient stability in the majority of cases. In the few cases where unforeseen difficulties arise, it is usually possible to retrieve the situation by introducing or increasing shunt and/or series compensation. With transmission costs of typically 15% to 20% of total plant costs and compensation costs at 10% to 15% maximum of transmission costs, the rare maximum error thus involved in this approach is of the order of 2% of total plant costs. This is regarded as being well within the accuracy of the capital cost data available to the Survey and there is no justification for a more elaborate approach to transient stability assessment, barring perhaps some well recognized exceptions.

The most common restriction to power flows in category (i, transmission are the thermal capabilities of circuits. However, this will tend to be a common factor in all generating plant programs considered for a particular country and detailed load flow studies within major load or generation regions were not necessary for the Market Survey.

For category (ii) transmission, the power flow requirement was simply estimated from the capacity of the power station less any local load to be supplied. Inter-regional power flow requirements (categories (ii) and (iii)) were determined by a simple regional plant/load balance tabulation taking into account generating set size and outage criteria and varying hydrological conditions. The number of transmission circuits at grid voltage to meet the power flow requirements so determined for categories (ii), (iii) or (iv) was then estimated to sufficient accuracy, taking into account thermal ratings, transient stability limits and transmission security criteria. If the number of circuits was excessive, then a higher voltage was considered and first establishment costs and also step-down transformer capacity were taken into account.

A further consideration in determining the capacity of category (iv) transmission is the integrity of the interconnected system following faults or a sudden loss of load or generation. Experience of interconnected systems in particular in the USA and the Scandinavian countries [1, 2] indicates that for a reasonable stability performance the capacity of system interconnectors should be at least 10% of the installed generating capacity of the smallest of the two systems interconnected. This was used as a guiding criterion for analysis purposes.

Details of any existing or proposed international interconnections (category (v)) were obtained from the Survey countries. In all cases these were found to be of insufficient capacity to have any noticeable influence on the Survey results.

LIMITS TO SET SIZE

The economics of scale play a major role in reducing the specific cost of installed generation and this is particularly so for nuclear power generation. On the other hand, increased unit size has associated penalties in system requirements such as generation and transmission reserve capacity. Thus there exists an optimum size for overall minimum cost of power delivered to the consumer [1].

The effects of increased unit size on the transmission system are taken into account in the network analysis described in this appendix. Any special transmission requirements can be allowed for by adjusting plant input data to the WASP computer program as described in Appendix E. The effect of increased unit size on non-availability rates and generation reserves can be directly allowed for in the corresponding input data items of the WASP computer program as required by the loss-of-load probability routine described in Appendix A. In this manner the 'economic optimum' set size can be determined. However, in addition to the economic optimum set size there is what may be termed a 'technical limit' set size (or reactor size in the case of nuclear stations) dictated by the permissible disturbance effects following the sudden loss of the largest generating unit. In cases where this technical limit is less than the economic optimum (which is highly probable in smaller systems) this can have a dominant influence on the economics of introducing large units into such systems.

The system frequency transient following sudden loss of a large generation unit has been found of prime interest in the assessment of this technical limit. The complete representation of this transient, termed 'frequency stability', is very complex, but a simplified analysis method and computer program was developed by ANS for the sudy of typical system response to sudden loss of generation. Although approximate, the analysis technique is regarded as adequate for the Market Survey purposes, bearing in mind the relatively large tolerances in data inherent in a forecasting exercise. The technique and computer program are described in the following paragraphs.

The average system frequency model

The dynamic response of a power system to a sudden loss of generation is generally characterized by two distinct components of power variation in the period of 10 to 20 seconds immediately following the disturbance. These are the faster transient oscillations in synchronizing power (time period typically 1 - 2 s) which arise due to angular disturbances from the steady state and the slower variation in prime mover power (time period typically 10 - 20 s) due to the primary regulation effects of the governor/turbine response to frequency change. The ability of a system to remain in synchronism following a given angular disturbance is mainly dependent on the transfer impedances between sources, i.e. on the transmission network. System faults will usually give rise to much larger angular deviations than loss of generation and will thus dictate the requirements of the transmission network for retention of transient stability. Thus, provided the transmission network has been designed with due regard to transient fault studies and the emergency redistribution of power flow resulting from plant outages, it is reasonable to assume that synchronous stability will be retained following a sudden loss of generation. (A possible exception to this premise is the case of a sudden loss of generation immediately following a severe system fault. However, such second contingency events are not considered here.)

Assuming that the system remains in synchronism then, neglecting losses (which may be assumed constant throughout the disturbance), the rate of change of stored kinetic energy (i.e. frequency) at any instant is equal to the difference between power input to the system (i.e. prime mover power) and power output (i.e. load),

$$(2H_T)(f_a)\left[\frac{df_a}{dt}\right] = \Sigma P_{mk} - P_L \qquad (1)$$

where H_T is the total inertia constant of connected machines including rotating loads (typically 3.0 to 5.0),

ΣP_{mk} is the sum of prime mover input power of connected generators,

P_L is the total connected load,

f_a is the average system frequency.

All quantities are in p.u. on the base of nominal system frequency and total nominal power of connected generation.

Since the system is assumed to remain in synchronism the transmission network may be neglected and Eq. (1) may be modelled by a number of prime movers and their generating units feeding a single block load as indicated in Fig. 1 and referred to as 'the average system frequency model' [3]. Simplified equations modelling the variation of prime mover power and load are described in the next section.

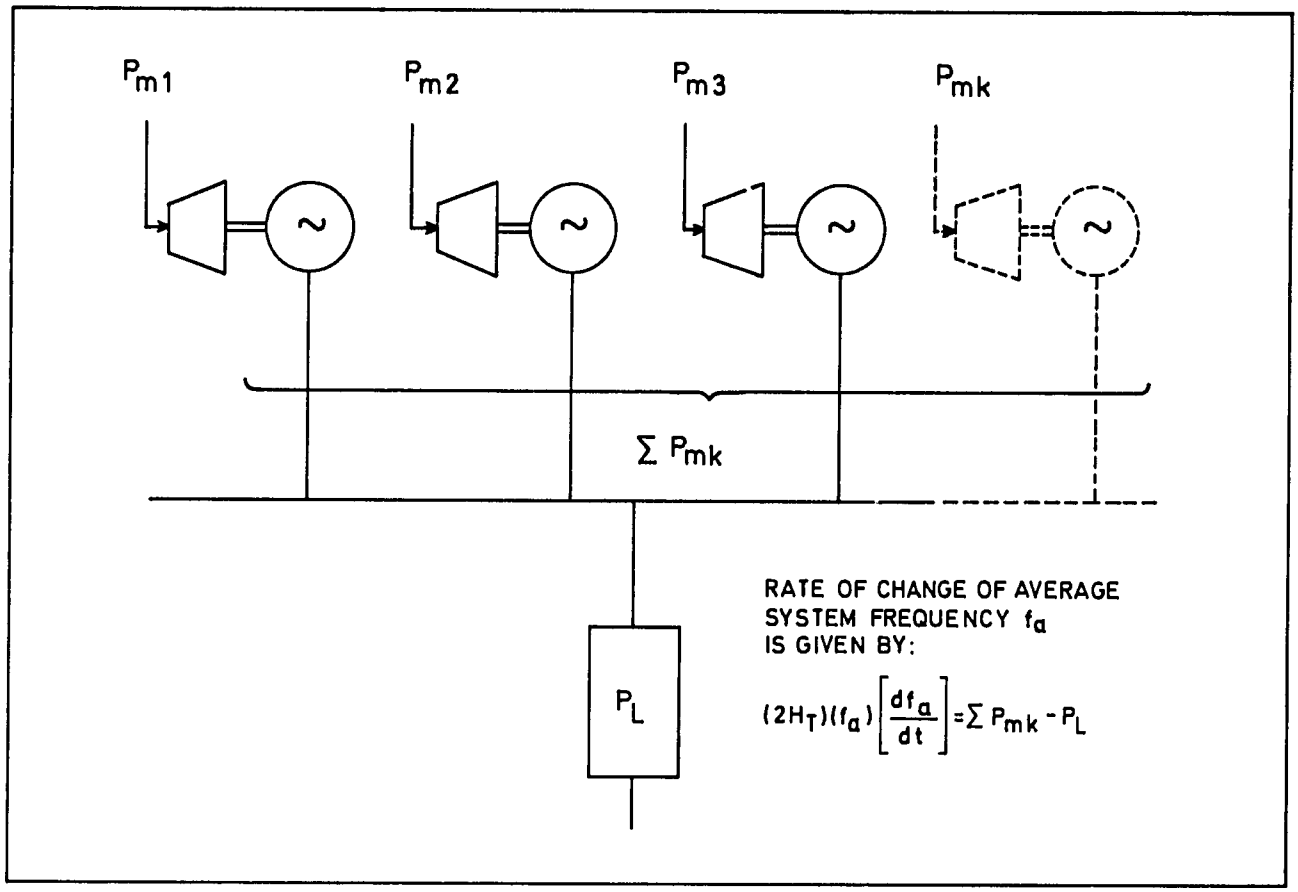


FIG. H-1. AVERAGE SYSTEM FREQUENCY MODEL.

Prime mover and load regulation

Maximum frequency dip before recovery (if it occurs), the time of maximum dip and the amount of load shed (if load shedding is permitted) are the main items of interest and thus the following assumptions can be made:

(i) Non-regulating base load units are assumed to have constant power output.
(ii) Only the governor/turbine response of regulating units is considered. Boiler response is neglected in thermal plants.
(iii) Secondary regulation is neglected.
(iv) Governor response is based on average system frequency. (The oscillating component due to synchronizing swings is generally at a much shorter time period than the governor/turbine response time and does not appreciably affect the prime mover output.)
(v) The total load P_L is assumed to depend only on average system frequency. Variations due to the oscillating component arising from synchronizing swings are neglected. Load variation with voltage, if desired, can be sufficiently represented by conversion to an equivalent variation with frequency.

Three types of regulating units are modelled:

(a) Thermal – non-reheat
(b) Thermal – reheat
(c) Hydro including pumped storage

For the time period of interest (about 10 s) thermal units will generally permit faster power change rates than hydro units, but with a limit on sustained change (typically up to 15%

of nominal power). Hydro units on the other hand can give much larger sustained variations in output approaching their nominal rating with total response times of typically 10 to 20 seconds.

(a) Thermal – Non-reheat model

It is assumed that the disturbance is of sufficient magnitude to drive the steam valve to its limiting position at constant rate. The time constant of a non-reheat turbine may be neglected and thus the change in power output of this type of unit may be represented to a first approximation by the equation

$$P_1 = \left[\frac{P_{1c}}{T_1}\right] (t) \text{ with limit of } P_{1c} \tag{2}$$

where P_{1c} is the maximum permissible power change,
T_1 is the time for the valve to move to its limiting position,
t is the time from loss of generator

(b) Thermal – Reheat model

As for the previous type the movement of the steam valve may be approximated by the equation

$$V_2 = \left[\frac{P_{2c}}{T_2}\right] (t) \text{ with limit of } P_{2c} \tag{3}$$

where P_{2c} is the maximum permissible power change,
T_2 is the time for the valve to move to its limiting position.

The change in power output of this type of regulating unit may thus be represented by

$$P_2 = \frac{1 + (m)(T_h)(p)}{1 + (T_h)(p)} (V_2) \tag{4}$$

where m is the proportion of power developed by the high pressure turbine
T_h is the reheat time constant
p is the Laplace operator

The maximum permissible power change for both reheat and non-reheat type generation will depend on the allocation of spinning reserve but will be typically about 10% of the nominal power of the generation block and may lie in the range 5% to 20%. The valve motion time is typically one second and may vary between 0.5 and 1.5 seconds. The factor m is typically 0.3 and the reheat time constant T_h may lie in the range 5 to 12 seconds.

(c) Hydro model

In Ref. [4] a simplified transfer function is derived which gives a very good approximation to the response of a hydro governor with dashpot. From this the change in gate opening may be represented by the equation

$$G = \frac{1 + (T_d\, p)}{1 + (T_3\, p)} \left[\frac{\sigma_a}{\delta}\right] (P_{n3}) \text{ with limit } P_{3c} \tag{5}$$

where $T_3 = \dfrac{T_g + T_d\,(\delta + \delta_t)}{\delta}$

T_d is the dashpot time constant (typically 5 s, range 2.5 - 25 s),
T_g is the governor response time or the inverse of governor open loop gain (typically 0.2 s, range 0.2 - 0.4 s),
δ is the permanent droop (typically 0.04 p.u., range 0.03 - 0.06 p.u.),
δ_t is the temporary droop (typically 0.31 p.u., range 0.2 - 1.0 p.u.),
σ_a is the average frequency deviation ($= f_a - f_0$),
P_{n3} is the nominal rated power output of regulating hydro generation,
P_{3c} is the maximum available change in power output (hydro spinning reserve).

Thus the change in power output for this type of regulating unit is given by

$$P_3 = \frac{1 - (T_w)(p)}{1 + 0.5(T_w)(p)} (G) \tag{6}$$

where T_w is water starting time and is inversely proportional to water head and directly proportional to penstock length. Typical values of T_w lie in the range 0.5 to 5.0 seconds.

The above model was also used to represent pumped storage plant operating in the generating mode.

Load regulation model

The variation of load with frequency may be represented by an equation of the type

$$P_L = (1 + (\alpha)(\sigma_a))\,(P_{L0} - P_s) \tag{7}$$

where P_{L0} is the total connected load at $t = 0$ and $f_a = f_0$,
P_s is the load shed as function of frequency and time,,
α is the load frequency regulation coefficient.

In those countries where load shed schemes are in existence, frequency settings and the amount of load shed for each stage were based accordingly. In other cases typical values were assumed. The determination of whether or not load shedding occurs is generally the prime factor of interest and thus the first stage frequency setting is the major item of load shed data. This is typically 48.5 to 49.0 Hz for 50 Hz systems and 58.5 to 59.0 Hz for 60 Hz systems.

The special case of pumping load being shed by under-frequency detection can be included in the load shedding scheme.

In Ref. [5] a range of values for the load/frequency regulation coefficient from 0 to 2.5 is given. The effects of load/voltage regulation can generally be adequately represented by increasing α. Thus a typical value for α of 2.0 was used except where more accurate information was available from the country studied.

Total regulation

The total prime mover power of connected units at instant t is given by

$$\Sigma P_{mk} = \Sigma P_{mk0} + P_m \tag{8}$$

where ΣP_{mk0} is the pre-disturbance power output of connected generating units excluding the lost generator, and

$P_m = P_1 + P_2 + P_3$ is the total change in prime mover outputs of connected regulating units.

Let the loss of generation be ΔP $(= P_{L0} - \Sigma P_{mk0})$ and since $\frac{d\sigma_a}{dt} = \frac{df_a}{dt}$, Eq. (1) becomes

$$(2H_T)(f_a)\ \frac{d\sigma_a}{dt} = P_m - \Delta P - (\alpha)(\sigma_a)(P_{L0} - P_s) + P_s \tag{9}$$

The effect of variations in f_a on the solution of Eq. (9) is small and may be neglected, hence

$$\sigma_a = \frac{1}{\alpha(P_{L0} - P_s) + (2H_T)(p)}\ (P_m - \Delta P + P_s) \tag{10}$$

The computer program

The computer program AVSYF (Average system frequency) for the step-by-step solution of Eq. (10) has been obtained by appropriately "patching" an existing digital program representation of an analogue simulator. Transfer functions of the type of Eqs (4-6), integral functions and limit functions exist as standard routines. Integration is performed by a simple three-step method, but provided a small enough time step is used, accuracy is sufficient. The program also includes a plot routine which permits an immediate plot of the frequency variation to be obtained as output.

REFERENCES

[1] CASAZZA, C.A., HOFFMAN, Ch., "Relationship Between Pool Size, Unit Size and Transmission Requirements", CIGRE (1968) Paper 32 - 09.

[2] OLWEGARD, A., "Improvement of System Stability in Interconnected Power Systems", CIGRE (1970) Paper 32 - 17.

[3] CHAN, M.L., DUNLOP, R.D., SCHWEPPE, F., "Dynamic Equivalent for Average System Frequency Behaviour Following Major Disturbances", IEEE Winter Meeting, New York (1972) 1637.

[4] RAMEY, D.G., SKOOGLUND, J.W., "Detailed Hydro Governor Representation for System Stability Studies", IEEE PAS-89 No.1, (1970) 106.

[5] ASHMOLE, P.H., FARMER, E.D., MYERSCOUGH, C.J., "The Dynamic Response of the Load to Changes in System Frequency", SUPEC (1972) 30.

APPENDIX I

FUTURE FOSSIL FUEL PRICES

R. Krymm

INTRODUCTION

Although practically all countries covered by the Market Survey possess and exploit domestic fossil fuel resources, fuel oil either imported or derived from imported crude remains in most cases the main competitor of nuclear fuels for future electric power production.

This fact alone suggests the use of fuel oil as the "reference fuel" and the validity of this assumption is further strengthened by the tight supply and demand relationship which is expected to prevail for oil products in the foreseeable future. The latter consideration suggests that the few Market Survey countries which are domestic producers of oil and gas in substantial quantities would be perfectly justified in pricing these resources on the basis of opportunity uses; that is, on the basis of thermal costs parity with imported fuel oil with due correction for transportation expenses.

Also, prices of coal and lignite are dependent on local conditions and must be considered separately in each specific case.

It is, therefore, not surprising that the bulk of this section is devoted to the problem of costs and prices of crude and fuel oils entering international trade.

It was, however, clear from the beginning that the fuel oil picture in developing countries could not be seriously studied without reviewing the world-wide structure of the oil industry and its rapidly changing trends.

It was, therefore, decided to consider in turn:

(1) The present and expected demand and supply structure of crude oil and the major producing and consuming areas.
(2) The changing cost and price structure of crude oil and its future trends.
(3) The cost of transport of oil by tanker and pipelines.
(4) The relationship between crude and oil product prices.
(5) The treatment of domestically produced fossil fuels.

DEMAND AND SUPPLY OF CRUDE OIL

Table I-1 shows the actual 1970 and estimated 1980 demands for oil in major areas of the world. The forecast is based on conservative rates of growth and the average annual rate of 5.4% for the world should be viewed against the 7.8% rate which prevailed during the 1950-1970 period.

TABLE I-1. PAST AND ESTIMATED DEMAND FOR CRUDE OIL (10^6 t)

	1970 (10^6 t)	1980 (10^6 t)	Rate of growth of demand (%)
USA	750	1 160	4.5
Western Europe	600	980	5
USSR and Eastern Europe	390	700	6
Japan	200	400	7
China	20	80	15
Rest of world	300	500	5
Total world	2 260	3 820	5.4

TABLE I-2. WORLD ESTIMATED CRUDE OIL PRODUCTION[a]

Countries	1970	1971	1972	% Change 1971/72	1972: % of Total
		10^3 t			
NORTH AMERICA[b]					
USA	533 677	530 385	532 000	+12.3	
Canada	69 954	75 025	87 500	+16.6	
	603 631	603 410	619 500	+2.7	23.9
CARIBBEAN AREA					
Venezuela	193 209	184 921	167 400	-9.5	
Colombia	11 071	11 127	10 400		
Trinidad	7 225	6 690	7 400		
	211 505	202 738	185 200	-8.7	7.9
OTHER LATIN AMERICA					
Mexico	21 877	21 920	22 600	+3.0	
Argentina	19 969	21 494	22 150	+3.0	
Brazil	8 009	8 376	8 400		
Ecuador	191	174	3 500		
Peru	3 450	3 048	3 300		
Bolivia	1 124	1 714	1 900		
Chile	1 620	1 652	1 700		
	56 240	58 378	63 550	+8.9	2.4
MIDDLE EAST					
Saudi Arabia	176 851	223 515	285 500	+27.7	
Iran	191 663	227 346	254 000	+11.7	
Kuwait	137 398	146 787	152 000	+3.6	
Iraq	76 550	84 000	67 000	-20.2	
Abu Dhabi	33 288	44 797	50 000	+11.6	
Kuwait/SA "Neutral Zone" ..	26 724	29 118	30 300	+3.9	
Qatar	17 257	20 201	23 300	+15.3	
Oman	17 169	14 106	13 600	-3.6	
Egypt	16 404	14 706	11 000		
Dubai	4 306	6 252	7 500		
Sinai[c]	4 500	6 000	6 000		
Syria	4 353	5 254	5 300		
Bahrain	3 834	3 728	3 500		
Turkey	3 461	3 253	3 350		
Israel	77	62	50		
	713 835	829 125	912 400	+10.0	35.0
AFRICA (excluding Egypt)					
Libya	159 201	132 250	105 000	-20.5	
Nigeria	53 420	75 306	89 500	+18.8	
Algeria	47 253	36 346	52 000	+42.1	
Angola	5 065	5 830	7 200		
Gabon/Congo	5 442	5 794	6 600		
Tunisia	4 151	4 097	4 100		
Morocco	46	22	30		
	274 578	259 645	264 430	+1.8	10.2

TABLE I-2. (cont.)

Countries	1970	1971	1972	% Change 1971/72	1972: % of Total
		10^3 t			
WESTERN EUROPE					
West Germany	7 535	7 420	7 100		
Austria	2 798	2 516	2 500		
Norway	-	301	1 700		
Netherlands	1 919	1 715	1 630		
France	2 309	1 858	1 500		
Italy	1 408	1 294	1 200		
Spain	156	120	250		
Denmark	-	-	100		
UK	83	84	84		
	16 208	15 308	16 064	+4.9	0.6
FAR EAST					
Indonesia	42 102	44 521	54 000	+21.3	
Australia	8 292	14 373	15 150		
Brunei	6 916	6 528	9 200		
India	6 809	7 191	7 500		
Malaysia	859	3 275	4 450		
Burma	750	840	900		
Japan	750	751	730		
Pakistan	486	487	450		
Taiwan	90	112	100		
	67 054	78 078	92 480	+18.4	3.6
Western Hemisphere.. ..	871 376	866 526	868 250	+0.2	33.4
Eastern Hemisphere	1 071 675	1 182 156	1 285 374	+8.8	49.4
	1 943 051	2 048 682	2 153 624	+5.0	82.8
EASTERN EUROPE AND CHINA					
USSR	352 574	376 992	394 000	+4.5	
Romania	13 377	13 794	14 000		
Yugoslavia	2 854	2 953	3 100		
Hungary	1 937	1 955	1 950		
Albania	1 199	1 350	1 575		
Poland	424	395	370		
Bulgaria	334	304	250		
East Germany	200	200	250		
Czechoslovakia	203	193	195		
China[d]	20 000	25 500	29 600	+16.0	
	393 102	423 636	445 300	+5.1	17.2
World totals	2 336 153	2 472 319	2 598 924	+5.1	100.0

[a] Excluding small-scale production in Cuba, Thailand, New Zealand, Mongolia and Afghanistan.
[b] Including natural gas liquids, in Canada also synthetic oils.
[c] Under Israeli occupation.
[d] Including oil from shale and coal.

Even under these modest assumptions, Tables I-1, I-2, I-3 and I-4 demonstrate some striking developments, the most important being:

(a) A growing dependence of the USA on imported oil and, in particular, on Middle Eastern oil even though allowance has been made for Alaskan production at the end of the decade.

(b) A growing Western European dependence on imported and Middle Eastern oil even though allowance has been made for maximum North Sea production and the percentage share of imports is expected to decrease.

(c) A continuation of Japan's total dependence on oil imports.

(d) A sharp rise in Middle Eastern production which is expected to double over the 1970-80 decade from 700 to 1500 million tons per year when it will represent close to 40% of total world production and more than 50% of that of the non-socialist countries while bringing to the countries of the region annual revenues of the order of 30×10^9 US $/yr.

TABLE I-3. NATIONAL PRODUCTION AND IMPORTS IN THREE MAIN CONSUMING AREAS (10^6 t)

	National production		Total imports		Imports from Middle East	
	1970	1980	1970	1980	1970	1980
USA	534	660	214	500	30	300
(% of consumption)	(71)	(57)	(29)	(43)	(6)	(26)
Western Europe	16	160	584	820	300	600
(% of consumption)	(2.6)	(24)	(97.4)	(76)	(50)	(61)
Japan	1	2	199	398	170	300
(% of consumption)	(0.5)	(0.5)	(99.5)	(99.5)	(85)	(75)
Total	551	822	987	1 718	500	1 200

TABLE I-4. PAST AND ESTIMATED PRODUCTION IN MAJOR EXPORTING AREAS[a] (10^6 t)

	1970	Share of world consumption (%)	1980	Share of world consumption (%)
Middle East	714	31.6	1 500	39.3
Africa	274	12	330	8.6
Caribbean	212	9.3	220	6
Total	1 190	52.6	2 050	54

[a] For exact definition of the geographical areas, see Table I-2.

No mention is made at this stage of estimated world oil reserves, not because the subject is not important, but because the figures usually advanced are highly questionable and cover an extremely wide range. Thus, for instance, figures of the order of 60×10^9 tons are often advanced for proven oil reserves while ultimate potential reserves which were estimated at around 90×10^9 as late as 1960 are now quoted as exceeding 900×10^9 tons if account is taken of probable off-shore oil fields, secondary recovery methods, oil-bearing shales and tar sands. It thus appears that the question for the next few decades is not one of exhaustion, but of costs.

It should, however, be noted that if demand continues to expand indefinitely at the 5.4% rate forecast for the next seven years, even the 900×10^9 tons of presently estimated ultimate reserves would only last 55 years instead of the 15 years assured by 50×10^9 of proven fields. Consequently, the 15 to 1 ratio between the two reserve figures should not be construed too optimistically.

COST AND PRICE STRUCTURE OF OIL AND ITS FUTURE TRENDS

The question of cost and prices of oil is fraught with difficulties unparallelled in any other industry:

(a) Technical difficulties in accurately defining a particular type of crude. Oils of different characteristics have, of course, historically sold at different prices, but the problem has become particularly acute recently because of environmental consideration which could restrict drastically the sulphur emissions from oil-fired stations in most industrial countries. Without going into the intricate problem of costs of desulphurization it should be noted that differentials of 50% and more can exist between prices of crudes in the same producing area depending on their sulphur content.

(b) Accounting difficulties in ascertaining the real price of crude rooted in the structure of the international oil industry which has, up to now, controlled the production, distribution and marketing of petroleum through vertically integrated operations. As a result, most of the oil entering international trade was moved from producing to refining and marketing subsidiaries at accounting prices fixed internally by the integrated companies essentially in the light of fiscal considerations, while only small amounts of crude were sold to outsiders at what might have been considered market prices.

(c) Political difficulties arising from the relatively small share of production costs in the total selling price. As Table I-5 shows, the cost of production represents less than 10% of the price of crude in the Middle East, the remaining 90% being divided between revenues to host countries and profits to producing companies. Historically, the split between two groups has been the result of a constant power struggle which has recently turned in favour of the countries which now collect more than three-fourths of the f.o.b. price of crude. The latest steps of the struggle were marked by the Teheran Agreement which sharply increased the share of the host nations and provided for automatic increases every year until January 1975. A no less important step was taken at the beginning of 1973 with the Participation Agreement entered into by several of the Arab countries and, in particular, by Saudi-Arabia and Kuwait, providing for a 25% ownership of production by the countries with a final objective of 51% participation by 1981. While Iran and Libya may follow different approaches, there is an unmistakable trend towards control of production by the countries of origin. For the time being, the participating countries plan to re-sell their share of production to the international oil companies which control the necessary distribution and marketing channels, but the situation may well change over the present decade.

(d) Economic difficulties arising from the theoretical impossibility of allocating costs of crude oil to the variety of oil products obtained as a result of refining. Gasoline, kerosene, naphtha, light fuel oil, and heavy fuel oil obtained from a single input of crude are priced separately by private companies according to market conditions in order to maximize total profits. There is no way in which the cost of producing, transporting and refining one ton of crude oil can actually be allocated to the different products derived from it.

TABLE I-5. ILLUSTRATIVE BREAKDOWN OF PRICE OF HEAVY KUWAIT CRUDE IN PERSIAN GULF AND WESTERN EUROPEAN HARBOURS[a] (US $/t)

Production cost	1
Producing country royalties and taxes	10
Company profit	2
Total	13
Transport cost to Rotterdam by 130 000 t tanker	6
Delivered cost at harbour refinery	19

[a] Needless to say, this table and Table I-6 are presented as illustrations rather than precise cost breakdowns which would require an analysis of the refining, distribution, marketing and fiscal situation in a specific country.

To this should be added another important consideration affecting the whole price structure of oil products. Table I-6 illustrates two important and connected points: the heavy impact of indirect and direct taxes levied by oil importing countries on the total costs of oil products to the ultimate consumers and the wide gap between these total final costs paid by the users and the "technical production costs", however widely these may be defined. Although the values given in this table are approximate averages and although Western Europe is one of the areas with the heaviest burden of taxation on oil products, the conclusions are nevertheless generally valid.

TABLE I-6. ILLUSTRATIVE AVERAGE COST STRUCTURE OF OIL PRODUCTS OBTAINED FROM ONE TON OF CRUDE IN WESTERN EUROPEAN COUNTRIES (US $/t)

Cost of crude at harbour	19
Cost of refining	3.50
Storage, inland transit, distribution and marketing	20
Profits of distributing companies	2.50
Taxes levied by consuming countries (excise taxes on products and corporate income taxes)	40
Total	85

With regard to the incidence of taxation by industrial countries, it will be seen that it represents close to 50% of the costs of the ultimate products, and about 4 times the amount of taxes levied by producing countries. True, these taxes fall mainly on gasoline (although several Western European and some developing countries also tax heavy fuel oil) and the fiscal revenues are used for highway maintenance, traffic control etc.; in other words, for tasks which actually make the use of oil products possible. Nevertheless, the fact remains that the impact on final costs is extremely heavy.

This leads to the second point, i.e. the almost total divorce of costs of production from ultimate revenues derived from a given quantity of crude oil, a situation radically different from that of for instance coal for which the relationship is much more rigid.

Production costs in the Middle East are less than 2% of the ultimate total (1.2% of US $85/t in the example given). If company profits, transportation and refining costs are added, the combined cost would still remain less than 20%. Finally, even if distributing and marketing costs are counted, the percentage would only increase to 41%, so that close to 60% of final outlay go to taxes levied by governments of either the producing or consuming countries. This cost structure has several consequences, one of the most important being the relative insensitivity of final product costs to variations in the costs of production at the oil field. In the example given, an increase of the cost of production of crude oil in the Middle East by a factor of 10, from US $1 to 10 per ton, would only lead to a 12% rise in the ultimate product costs to the consumers. This goes a long way towards explaining the wide disparity of actual oil production costs throughout the world. It also points to the probability that higher costs connected with off-shore production, shale oil recovery and other potential reserves will prove no serious obstacle to their future exploitation.

Finally, it should be pointed out that taxes on heavy fuel oil may seriously affect its competitive position and lead to major distortions in the selection of power plants with a resultant economic loss for the country concerned.

Taking these difficulties in turn, the following assumptions are made for the purpose of estimating prices of fuel oil for the Market Survey:

(a) Since none of the Survey countries had expressed special reservations on environmental constraints, one of the cheaper types of crude oil with no limitation on sulphur content was selected as the basis. This was Kuwait crude of 31° API.

(b) Its price was based on data available for transactions between producing companies and independent third parties to which this type of crude was sold in the Persian Gulf in 1972 and escalated to 1 January 1973[1]. Transport costs to the major harbours of the countries concerned were estimated on the basis of data summarized in Table VII.

(c) It was assumed that the strong position of the producing countries will permit them to maintain and probably increase the growing revenues already provided for by the Teheran and Participation Agreements. Consequently, an annual rate of growth of oil prices of 5% was considered minimal while 6% was viewed as probable.

(d) The relationship between the prices of crude and heavy fuel oil was assumed on a basis explained at greater length in Section 4 of this Appendix.

COST OF TRANSPORT OF OIL BY TANKER AND BY PIPELINES

These costs are given in detail in Tables I-7 and I-8. The sensitivity of unit transport cost to size of tanker and pipeline must be stressed. Consequently, future transport costs will depend critically on the existence of harbour facilities capable of handling the largest type of tanker size compatible with the demand of the country.

RELATIONSHIP BETWEEN CRUDE AND OIL PRODUCT PRICES

As has already been pointed out, there is no generally valid relationship between the two products and the price of fuel oil is entirely dependent on supply and demand. There are, however, lower and upper limits imposed by the availability of substitutes.

Regarding fuel oil for power plants, an immediate substitute is available in the form of crude oil itself which, subject to certain precautions, can and has been used as a fuel. Consequently, and except for short-lived special cases, the price of a given quality of crude in a specific location sets an upper limit to the price of heavy fuel oil of comparative sulphur content.

With regard to a lower limit, the situation is much more complex since it depends on the availability of alternative fuels as well as on the possibility of altering the proportion of different refinery products, both in the short and long term. A historical study of the relationship between long term prices of fuel and crude oils of similar characteristics shows that the differential between them has seldom exceeded 10% (except in the special case of the US Eastern Seaboard and the Caribbean area).

It was, therefore, decided to use as reference prices for heavy fuel oil landed in the major harbours of the countries covered by the Survey the price of landed crude as a maximum and 90% of the price of crude as a minimum. In fact, 95% of the price of crude was chosen as a representative single value.

CONCLUSIONS

The procedure finally selected for estimating fuel oil prices for the countries of the Market Survey was based on four main assumptions each one being open to some objections:

(a) The price of crude in the Persian Gulf was used as the basis even though some of the countries covered, particularly in Latin America, are not importing crude from this

---

[1] At the time these estimates were made, the impact of the 1973 devaluation of the US $ on the amount of taxes paid to the producing countries was still not officially agreed. It seems, however, that an increase of 10% in the payments to the countries would be a minimum expectation. Such an increase would result in the assumed price of Kuwait crude being more than US $14 per ton rather than the value of US $13 per ton f.o.b. Persian Gulf used in the Survey analyses. While further discontinuous increases of this nature are obviously difficult to forecast, their possibility emphasizes the advisability of assuming for oil prices a rate of escalation substantially exceeding that of general inflation.

TABLE I-7. COMPARATIVE TRANSPORTATION COSTS FROM PERSIAN GULF TO ROTTERDAM[a] IN VARIOUS SIZES OF TANKERS

Year of delivery	Size of tanker (dwt)	50 000	70 000	90 000	130 000	250 000	500 000
	Days at sea	58.2	58.2	56.4	58.2	58.2	58.2
	Days in port	3.2	3.2	3.3	3.3	3.5	3.5
	Trips per annum[b]	5.7	5.7	5.9	5.7	5.7	5.7
	Cargo (tons per trip)	47 200	66 300	85 000	123 400	240 000	480 700
	Voyage costs (US $ x 10^3)						
1971	Fixed direct costs	132.8	150.0	164.2	204.9	317.0	-
	Capital costs	121.0	154.7	175.0	246.7	396.7	-
	Bunkers[c]	50.5	70.7	98.2	126.6	163.1	-
	Port charges	13.0	17.2	19.5	24.8	43.6	-
	Total	317.3	392.6	456.9	603.0	920.4	-
1973	Fixed direct costs	171.4	192.1	209.8	260.9	405.6	18.2
	Capital costs	142.1	184.2	211.9	301.5	476.0	914.0
	Bunkers[c]	45.5	63.7	88.4	114.0	146.8	276.8
	Port charges	18.6	23.7	29.4	35.2	66.3	136.5
	Total	377.6	463.7	539.5	711.6	1 094.7	2 045.5
1975	Fixed direct costs	195.1	218.0	237.4	294.3	441.1	748.5
	Capital costs	173.7	228.4	276.3	397.5	740.4	1 269.2
	Bunkers[c]	51.4	71.9	99.9	128.8	165.9	312.7
	Port charges	20.5	26.1	32.4	38.8	73.0	150.7
	Total	440.7	544.4	646.0	859.4	1 420.4	2 481.1
	Costs (US $/t of cargo)						
1971	Direct costs	4.16	3.59	3.32	2.89	2.18	-
	Capital costs	2.56	2.33	2.06	2.00	1.65	-
	Total costs	6.72	5.92	5.38	4.89	3.83	-
1973	Direct costs	4.99	4.22	3.85	3.32	2.58	2.35
	Capital costs	3.01	2.78	2.49	2.44	1.98	1.90
	Total costs	8.00	7.00	6.34	5.76	4.56	4.25
1975	Direct costs	5.66	4.77	4.35	3.74	2.83	2.52
	Capital costs	3.68	3.44	3.25	3.22	3.09	2.64
	Total costs	9.34	8.21	7.60	6.96	5.92	5.16
	Costs (1972 world-scale equivalent)						
1971		68	60	55	50	39	-
1973		81	71	64	59	46	43
1975		95	83	77	71	60	53

[a] Distance for round trip 22 338 miles.

[b] All vessels in operation for 350 days each year.

[c] Bunker prices (US $/t) 1971 Persian Gulf 13.50, North Europe 21.00
1973 Persian Gulf 13.00, North Europe 18.00
1975 Persian Gulf 15.00, North Europe 20.00

TABLE I-8. ILLUSTRATIVE COSTS OF INLAND TRANSPORT BY PIPELINE

	Throughput	
	2×10^6 t/yr (10-in diam. pipeline)	5×10^6 t/yr (16-in diam. pipeline)
Costs (US cents/t per 100 miles)		
Capital	60	39
Other fixed	18	10
Variable	4	8
Total	82	57
Total cost (US cents/10^6 kcal per 100 mile)	8.1	5.6

Note: The table is restricted to pipeline sizes most likely to be encountered in oil-importing developing countries. The cost per ton of oil transported is, however, quite sensitive to size up to very large throughputs. Thus, for a pipeline with a transport capacity of 50×10^6 t/yr it would drop to less than 20 US cents/t per 100 miles, or to about 1/3 of the 5×10^6 t/yr figure.

[a] Assumes: flat country, no major river crossing; capital cost of pipeline US $9000/in diameter per mile; fixed charge rate 13.38%/yr based on an interest rate of 12%/yr and on 20-yr sinking fund depreciation.

[b] Sufficient for supplying 1200 MW of oil-fired plants at 80% load factor.

[c] Sufficient for supplying 3000 MW of oil-fired plants at 80% load factor.

source. This is not as serious a flaw as it may seem since the policy of pricing oil from various sources on the basis of equality of delivered cost, with the main producing region serving as a reference point, has been a recurring feature of past price policies.

(b) An annual escalation rate of 6% was proposed for the 1973-1980 period, which is higher than the approximately 4% which the Teheran Agreement alone would imply, but takes into account the progressive impact of participation of the Arab countries in production and the sharp rise in oil demand.

(c) A fixed relationship was assumed between the prices of crude and of heavy fuel oil while the actual connection is flexible and complex. As has been explained this is a simplification but its impact on actual results is unlikely to involve errors of more than 5%.

(d) Taxes levied on fuel oil by consuming countries were ignored since they are internal revenues to the governments and should not affect the economic selection of power plants. There is no question that even though from the standpoint of the electric utilities taxes levied by their own country on a particular type of fuel are an element of total costs, the same taxes appear as a revenue item in national accounting. Since the purpose of the Market Survey is to estimate national costs of alternative power programs, domestic taxes on fuel should be excluded, at least in the basic reference cases.

(e) Estimated base prices, resulting from the above, for crude and heavy fuel oil in major harbours of the countries participating in the Market Survey are given in Table I-9.

(f) Gas turbine fuels were arbitrarily priced at 175% of fuel oil on the basis of an averaging of existing data.

(g) Domestically produced oil and gas was priced on the basis of parity of thermal costs with imported fuel oil or fuel oil refined from imported crude.

(h) Prices of domestically produced lignite and coal were estimated independently on the basis of the data supplied by the countries and escalated at the general rate of 4%/yr except in cases where there were convincing arguments to depart from this general procedure.

TABLE I-9. ESTIMATED BASE PRICES FOR CRUDE AND HEAVY FUEL OIL IN MAJOR HARBOURS OF MARKET SURVEY COUNTRIES[a], 1 January 1973

Harbour	Sea transport cost[b] (US $/t)	CIF Price of crude in harbour (US $/t)	Corresponding prices of fuel oil (US $/t)	US cents/10^6 kcal
Egypt				
Alexandria	3	16	15.2	150
Greece				
Piraeus	5	18	17.1	168
Turkey				
Izmet	5	18	17.1	168
Yugoslavia				
Trieste	6	19	18	177
Argentina				
Buenos Aires	6.5	19.5	18.5	182
La Plata				
Chile				
Valparaiso	7	20	19	187
Quintero				
Jamaica				
Kingston	6	19	18	177
Mexico				
Tampico	7	20	19	187
Vera Cruz				
Pakistan				
Karachi	1	14	13.3	131
Bangladesh				
Chittagong	2.5	15.5	14.7	145
Singapore	2	15	14.3	140
Thailand				
Bangkok	3	16	15.2	150
Philippines				
Bantangas	3	16	15.2	150
Korea				
Pusan-Ulsan	4	17	16.1	159

[a] Kuwait heavy crude 31° API with no sulphur restriction estimated at US $1.80/bbl or US $13/t f.o.b. in the Persian Gulf.
1 t crude = 7.2 bbl
1 t heavy fuel oil = 6.8 bbl
1 t heavy fuel oil = 40.3×10^6 Btu.
= 10.15×10^6 kcal.

[b] Transport costs by sea estimated on the basis of journey by tankers of size suitable for country harbours except for Mediterranean countries where special allowances were made for possible transport by pipeline or canal through Suez in the future.

APPENDIX J

NUCLEAR FUEL CYCLE COST TREATMENT

James A. Lane

INTRODUCTION

Fuel cycle costs in a nuclear power plant depend on a wide variety of economic parameters, such as the costs of uranium, of separative work and of industrial operations which vary with time. It is likely that some of these costs, such as those for natural U_3O_8 and separative work will increase with time, while other cost components such as fuel fabrication and fuel recovery will decrease. To complicate the situation even more, the value of fissile plutonium recovered from spent fuel can go up or down depending on its marketability as recycle fuel.

In addition to dependence on the above economic factors nuclear fuel costs also depend on engineering parameters such as the fuel burn-up per cycle, the fuel management scheme employed etc., which the reactor designer or plant operator can vary to optimize overall generating costs. Because of this balancing of economic and engineering factors, total nuclear fuel cycle costs tend to remain relatively constant with time. In the case of light-water reactors, fuel costs lie within the rather narrow range 20 ± 5 US cents/10^6 Btu (80 ± 20 US cents/10^6 kcal) regardless of size or plant design. Unlike oil costs, moreover, nuclear fuel costs are not sensitive to where the plant is located in the world. In view of this situation, it was decided that it would be sufficient for the purpose of the Market Survey to base the economic evaluation on current nuclear fuel costs taken from studies published in the open literature. For the reference case, these fuel costs were assumed to follow the general inflation rate of 4%/yr, the same as all other capital costs (see Appendix D). Sensitivity studies were also carried out using a 6% escalation rate, the same as that used in the reference case for oil and gas.

FUEL CYCLE COSTS FOR A 400 MW PWR

In a paper by J. T. Roberts and R. Krymm [1], a variety of numerical examples of nuclear fuel cost calculations for a hypothetical 400 MW pressurized water reactor are presented and discussed in detail. Figure J-I shows a generalized schematic diagram of the LWR fuel cycle used as a basis for the calculations and Table J-1 shows the assumed economic and engineering parameters. The data in Table J-1 were used in a present-worth calculation to determine the levelized fuel cycle cost under steady state (equilibrium) conditions with one-third of the core being replaced each year. For this simplified equilibrium case, total fuel cycle costs and corresponding direct and indirect components are calculated by following a single batch of fuel throughout its three-year lifetime. Table J-2 shows the results of this calculation.

Since the cost calculation for the equilibrium fuel does not take into consideration the higher unit costs associated with the first core, calculations were also carried out to find the first core cost and also the levelized 30-year average fuel cost for the first core plus the 29 equilibrium refuelling batches. Table J-3 compares the costs for the three cases considered. The levelized 30-year average fuel costs shown in the last column were taken as the reference case for the Survey; however, two adjustments were made for this purpose. Firstly costs were adjusted to reflect the increase in separative work costs to the US $36/kg announced by the USAEC on 14 February 1973, and secondly, indirect costs were based on the 8% interest rate taken as the reference case in the Survey. These two changes tended to balance one another with the result that levelized 30-year average fuel cycle costs amount to 1.78 US mill/kWh for a 400 MW PWR.

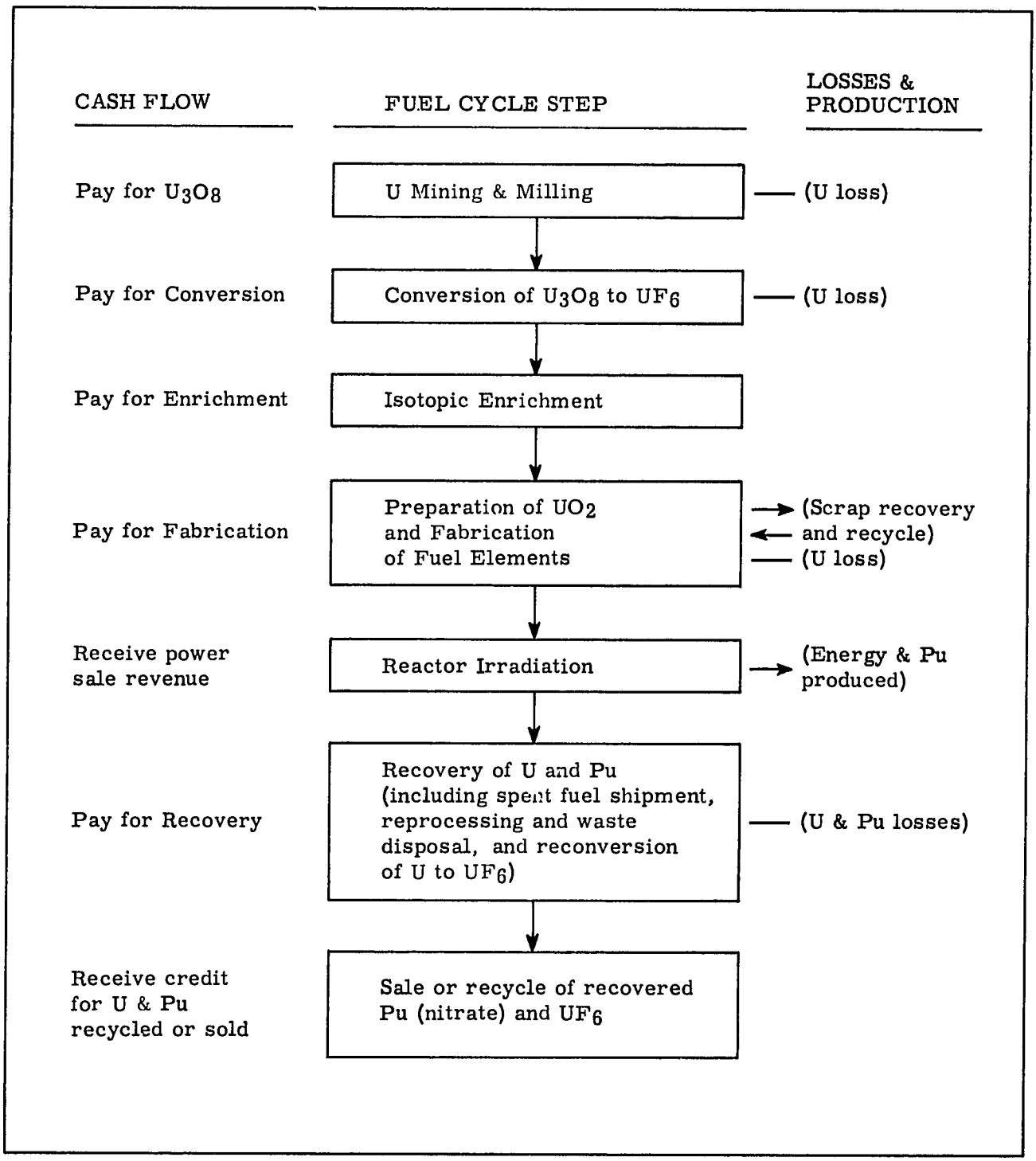


FIG. J-1. GENERALIZED SCHEMATIC DIAGRAM OF LWR FUEL CYCLE.

TABLE J-1. BASIS FOR FUEL CYCLE COST CALCULATIONS CARRIED OUT IN REF. [1]

1. Cost of natural uranium ore concentrate: US $7.00/lb U_3O_8

2. Losses (not economically recoverable) in processing:

Conversion	- 0.5%
Enrichment	- 0.0%
Fabrication	- 1.0%
Reprocessing (U and Pu)	- 1.0%
Reconversion, U nitrate to UF_6	- 0.3%

3. Uranium enrichment: Tails assay: 0.25% U-235
   Cost of separative work: US $32.00/SWU (kg)

4. Cost of converting U_3O_8 to UF_6: US $2.60/kg U (product)

5. Fabrication cost (including cost of scrap recovery):

First core	- US $110/kg U (product)
Equilibrium core	- US $ 80/kg U (product)

6. Recovery cost (including spent fuel shipment, reprocessing, reconversion of recovered uranium to UF_6):

First core	- US $44/kg U (feed)
Equilibrium core	- US $40/kg U (feed)

7. Plutonium credit: US $10.00/g (fissile)

8. Times at which pre-irradiation payments are made:

	First core	Equilibrium core
U_3O_8	15 months	12 months
Conversion	12 months	9 months
Enrichment	9 months	6 months
Fabrication	6 months	3 months

Times at which post-irradiation payments or credits are made:

Recovery + 6 months U and Pu credits + 9 months

9. Reactor power: 1222.5 MW(th) gross
   400 MW(e) net
   Plant capacity factor: 80%

10. Irradiation history:

First core	Batch "A"	Batch "B"	Batch "C"
Burn-up (MWd/t)	13 176	23 912	31 531
Initial enrichment (% U-235)	2.41	3.04	3.48
Final enrichment	1.24	1.17	1.08
Final fissile Pu (%) (based on U)	0.46	0.61	0.72
kg U charged to reactor	11 321	11 321	11 321
kg U discharged from reactor	11 100	10 949	10 846
In-core life at 80% load factor (yr)	1.00	2.00	3.00

Equilibrium Batch: Same as Batch "C" above.

Power production (% of total):		
	Outer region	24.16
	Intermediate region	34.05
	Inner region	41.79
		100.00

TABLE J-2. FUEL COST ESTIMATE FOR THE EQUILIBRIUM CORE LIGHT WATER REACTORS [1]

Cost category and components	Unit fuel cost (US mill/kWh)		
	Direct	Indirect	Total
I. Fertile and fissile materials			
(a) U_3O_8 purchase, gross	0.523	0.158	0.681
(b) Credit for equivalent U_3O_8 in recovered U	-0.126	0.022	-0.104
(c) Credit for recovered plutonium	-0.276	0.048	-0.228
Subtotal I	0.121	0.228	0.349
II. Industrial operations			
(a) Conversion, gross	0.074	0.020	0.094
(b) Credit for conversion equivalent in recovered U	-0.018	0.003	-0.015
(c) Enrichment, gross	0.623	0.150	0.773
(d) Credit for enrichment equivalent in recovered U	-0.052	0.009	-0.043
(e) Fabrication	0.323	0.069	0.392
(f) Recovery	0.155	-0.024	0.131
Subtotal II	1.105	0.227	1.332
Total	1.226	0.455	1.681

TABLE J-3. LEVELIZED FUEL CYCLE COSTS FOR 400 MW PWR (US mill/kWh) [1]

	First core	Equilibrium core	30-year average
Direct	1.59	1.23	1.32
Indirect	0.51	0.45	0.46
Total	2.10	1.68	1.78

FUEL COSTS FOR SMALL AND MEDIUM POWER REACTORS

A paper by M. A. Khan and J. T. Roberts [2] presents information on fuel cycle costs for light water nuclear plants in the size range 100 to 600 MW. These costs adjusted to the conditions described above (8% interest rate, US $36/kg separative work) are summarized in Table J-4. Note that, due to different assumptions which are explained in the references, the fuel cycle costs for the two 400 MW cases (Tables J-3 and J-4) are slightly different.

TABLE J-4. FUEL COSTS IN SMALL AND MEDIUM POWER REACTORS [2]

Reactor size (MW)	Levelized total fuel cycle costs (US mill/kWh)
100	2.10
200	1.85
300	1.75
400	1.65
500	1.60
600	1.60

FUEL COSTS FOR OTHER PWR SIZES

Total fuel cycle costs for other sizes of PWRs taken from Refs [3-5] are plotted in Fig. J-2 along with the costs from the IAEA studies previously described. All costs were adjusted to an 8% interest rate, 80% plant factor and US $36/kg separative work. A linear relationship between nuclear plant capacity and total fuel cycle costs was adopted for the Survey as shown in Fig. J-2.

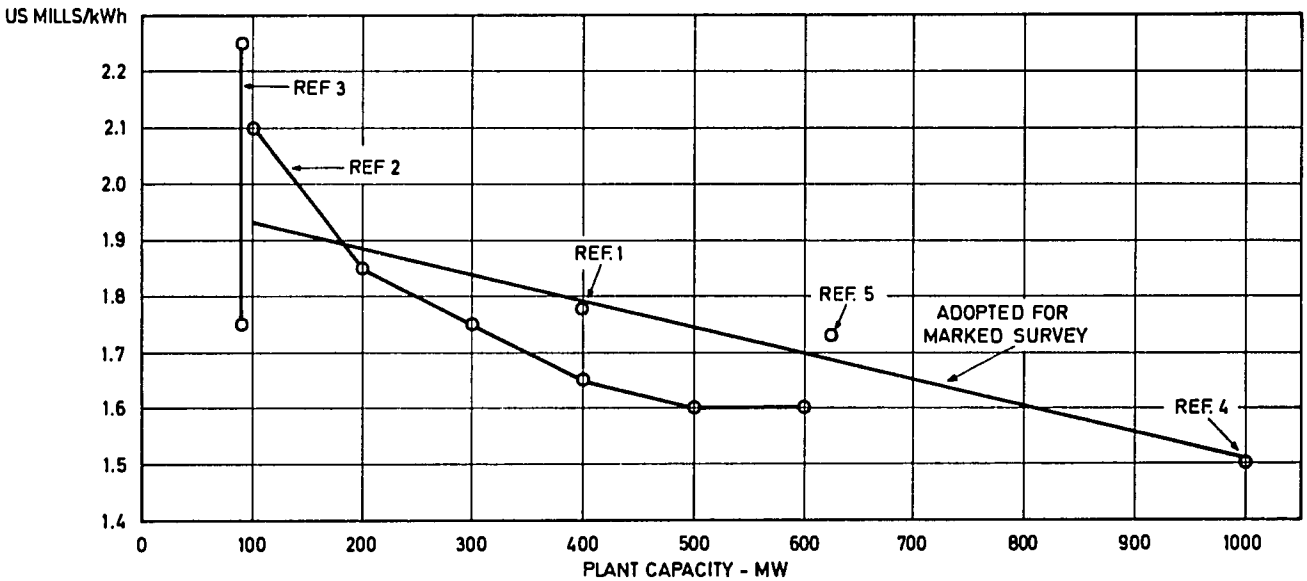


FIG. J-2. TOTAL FUEL CYCLE COSTS.

FUEL CYCLE WORKING CAPITAL COSTS

For the purpose of the WASP computer program, it was necessary to separate total fuel cycle costs into a "fixed" component which varies with the assumed interest rate and a "variable" component which varies with the amount of energy generated. The "fixed" component of nuclear fuel costs represents the levelized value of all outstanding investments associated with the fuel cycle over the life of the plant. Figure J-3 shows values of this fixed component taken from the previously mentioned references. As in the case of the total fuel cycle costs, a linear relationship between fixed costs and plant capacity was assumed as shown in Fig. J-3. It should be noted that the fixed component of nuclear fuel costs varies by only US $18/kW over the entire range of plant capacities, which is equivalent to about 2 US cents/10^6 Btu.

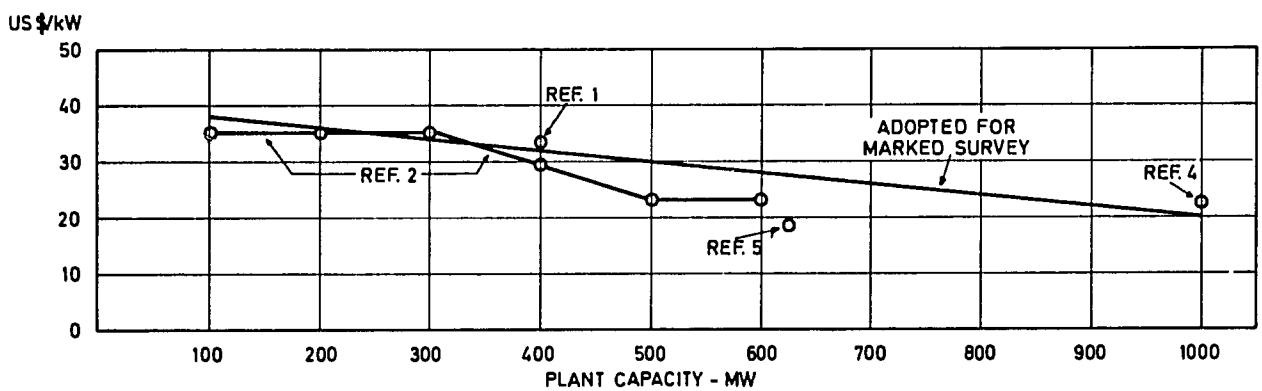


FIG. J-3. LEVELIZED FUEL CYCLE CAPITAL COSTS.

VARIABLE FUEL CYCLE COSTS

The difference between the total fuel cycle costs and the fixed component gives the variable fuel cycle costs. For the purpose of the WASP program, it was necessary to express the variable component in terms of US cents/10^6 kcal. For this purpose the full load gross heat rates estimated by the Bechtel Corporation (see Appendix E) were used. The resulting variable nuclear fuel costs are shown in Table J-5 along with total fuel cycle costs and the fixed component (calculated at 80% plant factor and 8% interest).

TABLE J-5. FUEL CYCLE COSTS ADOPTED FOR MARKET SURVEY

Plant capacity	Levelized fuel cycle costs (US mill/kWh)			Fuel load gross heat rate[a]	Variable fuel cycle costs
(MW)	Total	Fixed	Variable	(kcal/kWh)	(US cents/10^6 kcal)
100	1.93	0.43	1.50	2 504	59.8
200	1.89	0.41	1.48	2 503	58.9
300	1.84	0.39	1.45	2 503	57.9
400	1.79	0.37	1.43	2 502	57.0
600	1.70	0.32	1.38	2 501	55.1
800	1.60	0.27	1.33	2 500	53.2
1 000	1.51	0.23	1.28	2 499	51.3

[a] Gross heat rates were used to be consistent with the use of such heat rates in calculating conventional fuel costs.

REFERENCES

[1] ROBERTS, J.T., KRYMM, R., IAEA, "Fuel cost evaluation for light water reactors", Regional Training Course on Bid Evaluation and Implementation of Nuclear Power Projects, Tokyo, 29 November - 10 December 1971, IAEA-151, unpublished document, p.191.

[2] KHAN, M.A., ROBERTS, J.T., "Small and medium power reactors: Technical and economic status, potential demand and financing requirements", 4th Int. Conf. peaceful Uses atom. Energy (Proc. Conf. Geneva, 1971) 6, IAEA, Vienna (1972) 57.

[3] STORRER, J., GALLOIS, G., KAFKA, P., "Belgonucléaire and Siemens PWRs for small and medium power reactors", Small and Medium Power Reactors 1970 (Proc. Symp. Oslo, 1970), IAEA, Vienna (1971) 131.

[4] USAEC, Current Status and Future Technical and Economic Potential of Light Water Reactors, WASH 1082, March 1968.

[5] Electrowatt Engineering Services and Sargent and Lundy, Feasibility Study for a Nuclear Power Plant in Luzon, Philippines, February 1973.

APPENDIX K

SENSITIVITY STUDIES

In order that the results of the analyses of the participating countries could be compared and summarized, it was deemed desirable to analyse each country using the same basic values of the parameters and then to perform other analyses using different values of these parameters in order to determine the sensitivity of the results of the base case to such variations. This was done so that each country would have results available using parameter values which might more nearly represent its unique values. Also, since the base values are forecasts determined from historical information and a consideration of present and future trends, it was considered important to check the sensitivity of the selected system expansion plans to possible variations in these parameters.

The technique of using the WASP program to analyse predetermined system expansion plans allowed the addition of a number of sensitivity alternatives to each analysis at the expense of very little additional computer time.

The parameters selected for sensitivity studies and the values used are:

(a) Economic parameters

	Base case		Other cases	
	Study values[a]	Approximate equivalent "real" values	Study values[a]	Approximate equivalent "real" values
Discount rate (%)	8	12	6 & 10	10 & 14
Oil & gas price escalation (%)	2	6	0 & 2	4 & 8
Nuclear fuel price escalation (%)	0	4	2[b]	6
Capital cost of plants [c]	ORCOST-3		ORCOST-1	

[a] General inflation rate was assumed constant at 4%/yr.
[b] This value was used for sensitivity studies in only a few selected cases.
[c] ORCOST-3 values are as of 1 January 1973 and show a ratio of PWR to oil-fired plant costs ranging from about 1.8 to 2.2 (depending on MW rating) whereas ORCOST-1 values show a corresponding range from about 1.6 to 1.8. For a complete discussion of these costs refer to Appendix B.

(b) Load forecasts

The basic load forecast for each country was prepared on a common basis by Aoki as described in Appendix F. For several countries his forecast compared closely with that provided by the country itself; in those cases only one forecast was used. For most countries, however, the country forecast was appreciably higher than the Aoki forecast and in these cases both were used as the basis for analysis.

(c) Loss-of-load probability

An additional sensitivity study was carried out, in effect, on the variation in the loss-of-load probability. For a definition and further discussion of loss-of-load probability refer to Appendix A. The value of the loss-of-load probability for any given system is related to the amount of system reserve generating capacity and to the number, sizes and types of plants and this is also related to the degree of load shedding to be permitted at times of forced outage of generating capacity. Obviously, reducing the loss-of-load probability will increase the system cost to supply a given load and increasing it decreases system costs. Thus specific values, or a range of acceptable values, needed to be established for purposes of the

studies, since any specific system expansion plan is optimum only for a specific loss-of-load probability. Therefore, it was decided to use an average of the yearly values over the study period, as close as possible to 0.005 with a maximum of 0.010. It is considered that these values are representative of the values acceptable to developing countries, although they are substantially higher than the acceptable values for the industrialized countries. The actual loss-of-load probability value can be expected to vary from year to year depending on the amount and timing of generating capacity additions.

In a number of cases the loss-of-load probability value for a country's existing system was substantially higher than the maximum quoted above. The technique used in these cases was to bring the loss-of-load probability gradually down to the levels indicated above by adding more generating capacity. To achieve this generally required a number of attempts to determine the exact size of unit and the point in time when it should be added. A study of the results of these numerous analyses, involving varying values of loss-of-load probability, shows that although the value of the objective function (present worth) could vary considerably, the size and number of nuclear power units called for in the optimum (lowest present-worth value) case would vary only slightly. In this connection it should be pointed out that the probabilistic model used in deriving the loss-of-load probability values is limited in its handling of hydro power plants and, for systems with large proportions of hydro power, it tends to show unrealistically low loss-of-load probability values.

(d) Foreign exchange rates (shadow exchange)

In a few instances, studies were carried out to determine the sensitivity of the optimum case to variations in the rates of exchange between local and foreign currencies. This is intended to show the effect on capital-intensive projects of scarcity of foreign capital to finance such projects.

(e) Salvage values based on sinking fund depreciation

In the reference case, salvage values based on linear depreciation were factored in for all plants at the end of the study period (i.e. 2000). Although this practice is current in most electric utilities accounting, it involves a slight departure from strict economic accounting which should be based on sinking fund depreciation. Since the use of straight line depreciation gives a higher value of the objective function than sinking fund depreciation, its use tends to penalize capital intensive projects, i.e. nuclear plants. For this reason, the effect of using salvage values based on sinking fund depreciation was considered in some instances.

(f) Duties and taxes

Duties and taxes were not considered in the reference case; however, in some countries they might have an important influence on the market for nuclear power by increasing oil prices, on the one hand, and nuclear plant capital costs on the other. Sensitivity studies to evaluate the influence of duties and taxes were carried out for countries where their effect might be important.

(g) Environmental effects

It is not clear whether environmental considerations will play an important role in the participating countries; therefore, no allowance was made for these in the reference cases. If future environmental considerations require the use of fuels of low sulphur content or equipment to alleviate deleterious effects, capital and/or operating costs would increase and thereby influence the competition between fossil and nuclear plants. This factor was not treated in a finite quantitative manner in these studies; however, a qualitative and approximate quantitative discussion can be found in Appendix B.

APPENDIX L

IAEA SERVICES AND ASSISTANCE IN CONNECTION WITH NUCLEAR POWER

The International Atomic Energy Agency provides services and assistance to its Member States and to non-Member States under the United Nations Development Program (UNDP) in any technical field involving the peaceful application of nuclear energy permitted by its Statute. Information about the services and assistance available from and through the Agency is given in the publication "IAEA Services and Assistance"[1]. This booklet also explains who is eligible to receive services and assistance from the Agency and how these may be obtained.

In general, four stages can be identified in the initial introduction of nuclear power in a given country:

Stage 1. Preliminary survey
Stage 2. Preliminary study
Stage 3. Feasibility study
Stage 4. Construction and commissioning of power reactors.

Stages 1 and 2 are the most likely suitable subjects for technical assistance and during Stage 3 assistance could be requested from UNDP.

The activities in respect of which the Agency can assist or provide services related to nuclear power and the kinds of assistance possible are briefly summarized below. Neither this summary nor the "IAEA Services and Assistance" booklet can be exhaustive in coverage; therefore, if further information is required, it should be sought directly from the Agency's headquarters.

FIELDS OF ACTIVITY

(a) Activities connected with the development of nuclear power

Applications: Use of nuclear energy for the generation of electricity and possible other associated processes.

Economics of nuclear power: Comparison with other sources of power; economics of various fuel cycles; feasibility studies.

Nuclear power program: Planning of a nuclear power program; integration into a system; choice of reactor type; siting of reactors; training of staff; auxiliary services.

Fuels and fuel cycles: Fabrication, testing and inspection of reactor fuel elements and related processes; technical problems of fuel cycles.

Nuclear materials management: Establishment of methods.

Raw materials: Prospecting, mining, processing.

(b) Activities related to safety in atomic energy

Safety standards, regulations and procedures: Standards, regulations, codes of practice and recommendations and their application to specific operations and related procedures.

Radiological protection: Design of installations and laboratories; shielding; protective devices; personnel, area and environmental monitoring; instrumentation; decontamination; medical examinations; diagnosis and treatment of radiation injury and internal contamination.

[1] This publication is presently being revised.

Safety of reactors and nuclear materials: Safety aspects in the siting, design, construction and operation of power reactors and related facilities; management of radioactive wastes.

Safety evaluations: Safety evaluations of nuclear installations in respect of their design and siting, operational procedures, associated environmental monitoring and emergency planning.

(c) Activities related to legal aspects of atomic energy

Framing legislation in establishing national atomic energy authorities; legislation on third-party liability and on the licensing of nuclear facilities; provisions for insurance and other adequate financial protection of nuclear installations; legal problems in connection with the production, transport, use and storage of radioactive materials.

KINDS OF SERVICES AND ASSISTANCE

(a) Technical cooperation programs

Resources made available so that the Agency can provide technical and pre-investment assistance are used to implement projects under the Agency's regular program of technical assistance and under UNDP. Under these programs assistance may include one or more of the following elements:

Expert services: Experts can be sent individually or in teams to advise on or assist in general or specific fields of activity within the Agency's competence.

Equipment and supplies: These are usually provided in association with an internationally recruited expert.

Fellowships: Fellowships can be awarded as part of a comprehensive project or on an individual basis as a direct contribution to projects in the country's atomic energy program. These fellowships are available to qualified applicants at all educational levels and are not restricted to university graduates.

Intercountry projects: The Agency organizes a number of regional and interregional training courses and study tours every year in cooperation with its Member States and other United Nations organizations. Some of them deal with nuclear power. Large-scale projects of significant economic importance to countries in a region can be accommodated under the UNDP.

(b) Advisory and field services

The Agency provides, on request, information and advice on a number of subjects relating, among others, to nuclear power, as outlined above. If requested, missions may also be organized.

(c) Information services

The Agency also assists its Member States by means of a program of information services, including the International Nuclear Information System (INIS). Many of these activities relate to nuclear power.

(d) Supply of nuclear materials

Nuclear materials, such as uranium enriched in uranium-235 and plutonium, may be supplied to Member States by or through the Agency in accordance with Article XI of the Agency's Statute. The materials can also be supplied as fuel for power reactors.

ABBREVATIONS USED IN THE MARKET SURVEY REPORTS

ampere	A
approximately	approx.
barrels	bbl
billion	10^9
board feet	bd. ft.
British thermal unit	Btu
calorie	cal
centimetre	cm
cubic foot	ft^3
cubic metre	m^3
cubic yard	yd^3
cycles per second	Hz
degree centigrade	°C
degree Fahrenheit	°F
direct current	DC
feet	ft
figure(s)	Fig., Figs.
foot	ft
Gigawatt	GW
Gigawatt-hour	GWh
Hertz (cycles per second)	Hz
horse-power	hp
hour	h
hundredweight	cwt
kilocalorie	kcal
kilogram	kg
kilometre	km
kilovolt	kV
kilovolt-ampere	kVA
kilowatt	kW
kilowatt-hour	kWh
litre	l
maximum	max.
megawatt	MW
megawatt-hour	MWh
metre	m
normal cubic metre	Nm^3
million	10^6
number	No.
per annum	p.a.
per cent	%
pound (weight)	lb
pounds per square inch	lb/in^2
square foot/feet	ft^2
square metre	m^2
thousand	10^3
ton	t (always metric, unless specified otherwise as ton (UK) – long ton or ton (USA) – short ton.
tons of coal equivalent	TEC
volt	V
volt-ampere	VA
watt	W
yard	yd

APPENDIX N

COOPERATING ORGANIZATIONS AND PARTICIPANTS IN THE MARKET SURVEY MISSION

3-11 July 1972

Public Power Corporation (PPC)
(Nuclear Power Department, Planning Division, System Planning Division, Lignite Mines Department, Hydro Station Engineering, Construction Department, Geology Department)
Greek Atomic Energy Commission (GAEC)

Liaison officers: Mr. D. Christophilopoulos, PPC
Mr. N. G. Chrysochoides, GAEC

	Country	Status[a]
R. Alami, Engineer, IAEA	France	1
E. de Bellmond, Hydro Project and Systems Planning expert, State Power Board, Vällingby	Sweden	2
A. Böttcher, Nuclear expert, Nuclear Research Centre, Jülich	FRG	3
O. B. Falls, Jr., Project Manager, IAEA	USA	1
M. N. John, Electric Utility Systems Planning expert, Associated Nuclear Services, London	UK	4
O. Pedersen, Economist, IAEA	Denmark	1
R. Wawersik, Coal/lignite expert, Lahmeyer International GmbH, Frankfurt	FRG	4

[a] Status 1 = IAEA staff member

Status 2 = Expert provided salary-free with Agency paying travel and per diem

Status 3 = Cost-free expert with salary, travel and per diem paid by sponsoring country

Status 4 = Expert provided by contract with Engineering Consulting firm, the firm having the status of an independent contractor