

ENERGY MODELLING IN THE SOUTH AFRICAN  
ELECTRIC POWER INDUSTRY

BY

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ABSTRACT

The subject of this thesis is the development of a modelling system for the planning of the South African electricity supply industry. A power system planning process was developed with the object of establishing a long-range development plan that would enable the selection and timing of individual projects. This planning process is represented by several sub-models which include the prediction of future demands, the assessment of the generating capacity and the proportions of the different types of generating plant on the system (the plant "mix"), the analysis of the transmission network performances and the simulation of the financial processes.

One of the characteristics of the modelling system presented is its three-stage structure. The first stage is represented by the load model for the long-term prediction of power and energy demand. The second stage is represented by the two expansion models for generation and transmission. With the aid of these two models several expansion strategies are pre-selected, and then in the third stage, using the financial model, the total capital requirements are established.

The future system demand is predicted from the analysis of historical data and by the formulation of the electricity and economic growth relationship. Two major calculations, linear programming optimisation and loss of load probability analysis, are used in the computer models which aid the policy makers in selecting the optimum size and mix of the generating plants and scheduling the operation and maintenance of the generating units. Transmission system analysis programs have been developed in such a way that they use a common power system data base which enables the planning engineers to store and maintain their power system data. The calculation routines include load flow, fault analysis, stability studies, single and three phase travelling waves, and power and high

frequency transmission line parameters. The costing and financial models include the analysis of costs of all new expansion equipment, the costs of operation and maintenance of the generation units, transmission equipment and fuel, and the simulation of the financial environment and accounting processes.

On the basis of experience gained so far the author arrives at the conclusion that the modelling system presented is capable of providing a useful tool for planning the expansion of the South African electricity supply industry.

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CHAPTER 1

INTRODUCTION

A key factor in the development of industrialisation in South Africa as in many other countries is that of the energy supply. The cost and availability of energy affects the costs of many manufactured goods and living standards generally. Within the total energy sector, the role of electric energy is of growing importance and it is rapidly constituting a larger percentage of the country's total energy supply.

Planning may be defined as formulating, evaluating and choosing between the various courses of action being considered. In the electricity supply this process consists primarily of determining the sequence of expansion with regard to generating units, transmission lines, transformers, circuit breakers and other major plant components. It must be determined in such a way that the system is in a position to meet the future electricity demands with adequate security of supply combined with the lowest possible capital and operating costs and with existing financial options duly taken into account.

The planning of the electricity supply system raises special problems. Plant must continually be installed to meet the increasing demand for electricity and capital requirements for expansion are very large. The "lead-time" required between making the decision and the commissioning of plant is relatively long. The potential capacity available from the supply system must at all times exceed the simultaneous sum of the consumers' demands if restrictions are to be avoided. Abnormalities developing in one part of the system are felt to a greater or lesser extent immediately throughout the system.

In the planning of the expansion of the electricity supply system critical issues are encountered, of increasing capital

costs, financial and environmental restraints and increasing fuel costs. If these are compounded by the effects of changing technologies and the limited availability of resources, it becomes clear that a comprehensive analysis of the future outlook for electricity supply in South Africa is an enormously complex undertaking.

Modern facilities, especially the digital computer, enable many more alternative courses of action to be studied than in the past. A spectrum of "models" is needed stretching from those formulated for handling demand-type data, through those required for simulating future system operation, to a global type of model for doing project economic worth calculations and comparing the total (capital plus operating) costs of alternative mixes of new plant added to the existing plant.

A computer model has the additional advantage that it allows objective observation of problems and it simulates conceptual thinking. Additionally, experimentation with the aid of computer models provides a kind of consistency check on the assumptions going into the model and reveals the consequences of these assumptions. In many instances, the benefits of quantitative analysis of a complex system with computer models are derived as much from the insight and experience gained by the analyst and the user in the disciplined application of the methodology, that is required in computer modelling of engineering processes, as from the specific results specified in the model's output.

The expansion plans of the South African electricity supply system are concerned with the planning horizon which extends as far as 20 years ahead. This, however, does not mean that expansion decisions are made today for the next twenty years. Instead, the decisions are made today for the immediate future, but in these decisions the effect of expansion decisions in the more remote future is taken into account.

In the context of planning the term "optimum" plan is often used. It seems necessary to interpret this term as the best solution from the viewpoint of the electricity supply industry as a whole. In contrast with this, the best solution in respect of a sector of the electricity supply would correspond to the "sub-optimal" solution.

In the past decade numerous attempts have been made to apply mathematical optimisation and simulation methods in the development of models for planning the expansion of the electricity supply system. Nowadays, there is no electricity supply undertaking of any size which does not use mathematical models for carrying out transmission network calculations e.g. load flow, fault analysis and stability calculations. In many undertakings, models are also employed in generation planning, financial planning, etc. Most of these models are characteristically developed and used for solving specific planning tasks and the solutions obtained may correspond to sub-optimal solutions.

The modelling system presented here can be used as an instrument for finding an "optimum" plan from the point of view of the South African electricity supply industry as a whole. However, the solution of the integrated plans for generation expansion, transmission expansion and financing cannot be performed simultaneously by this model. A model which is capable of simultaneously coping with and representing all the relevant functions and inter-dependencies involved in the integrated planning of the South African electricity supply system in a sufficiently detailed and systematic manner is not realisable at the present time.

The system for the modelling of the South African electricity supply industry consists of various sub-models for the forecasting of the electricity demand, the planning of the generation system, the planning of the transmission network, and the evaluation of the effect of the various expansion and production projects on the total capital requirements.

With the aid of this system it is possible to simulate the effect of inter-dependencies and to use an iterative solution process to find near optimum solutions. One of the principal characteristics of the modelling system presented is its three-stage structure. The first stage is represented by the "load" model. The second stage is represented by the two "engineering" models for generation and transmission planning. With the aid of these models several practicable strategies are pre-selected, and in the third stage, using the "financial" model, the financial effects of the pre-selected strategies are further investigated.

More than 15 man-years were required for the development of the modelling system presented here. The author of this thesis, as the leader of the development team of three analysts, played a key part in the development of the modelling system. The author's part in the development was as follows:

- a) The definition of the objectives and the scope of the modelling system for the electricity supply industry in South Africa.
- b) The design of the modelling system in a three-stage structure, and the definition of the objectives and the scope of each sub-model.
- c) The definition of the scope of each program. Here it was also necessary for the author to consider the availability of input data and the relative importance of the results in making practical decisions.
- d) The development of mathematical models which represent the physical system. It was important to select the methods which are practical for machine computation and would produce the desired results in a reasonable amount of computer time.
- e) The coordination of the activities of the development team, which performed the design of the computer models and the programming and testing of the various routines.

It is difficult to foresee what benefit is likely to result

from the use of the modelling system in the planning of the South African electricity supply system. Details published in literature, with regard to the saving in capital and operating costs, relate to the use of sub-models for the planning of the expansion of the generation and transmission system and this amounts to approximately 2 - 3 per cent of the costs. Since the modelling system presented here enables the improved study of the individual aspects of the planning as well as the inter-dependent aspects, it follows that the use of this modelling system in the planning of the South African electricity supply industry ought, at the very least, to allow an equal saving in costs to be achieved.

This thesis includes nine chapters. Following the introduction, an overall view of the electricity supply in South Africa, the structural characteristics of the power system and the role of electricity as one of the main energy sources in South Africa is described. In chapter 3 the objectives and the technical stages involved in system planning are outlined and the use of computer models in system planning is described. Computer models for quantitative analysis in system planning include the prediction of future demand, the network analysis, loading simulation studies, the appraisal of the economic worth of alternative projects, reliability analysis, the evaluation of capital and operating costs, and the simulation of the accounting and financial procedures. The development of the modelling system of the electricity supply in South Africa, which is the subject of this thesis, is discussed in chapter 4. First the historical progress in the development of the models is described. This is followed by a discussion of the methodology of the development of scientific computing facilities and by a short description of the components making up the planning models. The various computer programs included in these four groups can be used separately or in combination with any of the other programs according to what is required by a given problem.

The prediction of the future demand for electricity in South

Africa is discussed in chapter 5, and two computer models have been developed to deal with this. One model deals with the analysis of the trend of growth of the maximum system demand and of the annual consumption of electrical energy by fitting mathematical functions to historical data and extrapolating the trends into the future. The second model enables demand estimates for various periods of the year to be made with reference to the maximum system demand of the year. This is done by the analysis of historical load diagrams for various periods of the year and for the various hourly periods in typical weeks or days of the year. In practice, the first model is no longer used in South Africa for the prediction of the long-term demand for electricity. Instead, this is carried out by formulating the relationship between the demand for total energy and the economic growth of the country, and determining the contribution of the electricity component to the total demand for energy. The author of this thesis did not participate in this analysis, but in order to present a complete picture of the modelling system, a description of the work done in South Africa concerning this long-term prediction of the demand for electricity is also included in chapter 5.

Having arrived at an estimate of the maximum system demand it is necessary to make decisions regarding the generating plant that needs to be installed in order to meet the increasing demand for electricity. This necessitates the evaluation of the total generating capacity required to supply the estimated load with specified reliability and the determination of the broad composition of the different types of new generating stations ("plant mix") and future fuel requirements. Linear programming optimisation techniques and the normal probability theory are used in the formulation of the generation planning models. These models make it possible to evaluate the various combinations of available power generation sources in order to arrive at an economic solution in which the projected load requirements are met and the system reliability criteria are satisfied. These topics are dealt with in chapter 6.

At this stage the network configuration, that is required to transmit power from the generating stations to the consumers, must be determined and this is dealt with in chapter 7. The basic mathematical element of the network analysis models is the solution of sets of simultaneous equations, linear or non-linear depending on the model used. The technique of solving triangular matrices by an ordered elimination process is used in the load flow and the fault analysis programs to calculate voltage distributions, power flows and fault currents. Three network analysis programs are used for analysing the transient stability of the system, for calculating the overvoltages in the line terminals due to switch and lightning surges and for determining the power and high frequency parameters of the transmission lines. The formulation and the development of these three programs were performed by the author's associates in Escom and the contribution of the author was to integrate the data and the results obtained from the programs with the design of the power system data base.

The purpose of the financial planning models, which are described in chapter 8, is primarily to establish a framework for investment decisions. These models make it possible to evaluate the effect of the various expansion and production projects on the total capital requirements and to provide predictions of the likely future revenue and additional capital resources that may be required.

Finally, in chapter 9, the summary, conclusions and recommendations for further developments are discussed.

CHAPTER 2

ELECTRICITY SUPPLY IN SOUTH AFRICA

2.1 HISTORICAL DEVELOPMENT

Electricity was first used on a commercial basis in South Africa in 1882 for street lighting in the town of Kimberley<sup>(1)</sup>. From this time until the turn of the century a large number of towns and other consumers began to generate electricity for their own use. It was only when the Victoria Falls and Transvaal Power Company (VFP) was formed in 1906 that the first important step was taken towards establishing a system in which one electricity authority supplied power to a number of consumers. One of the objects of the VFP was to generate power in a hydro-electric station on the Zambezi River at the Victoria Falls and to transmit it some 1000 km to the Witwatersrand, using low frequency alternating current. This scheme was eventually abandoned for economic reasons, but the VFP carried on to develop an extensive network supplied from thermal stations in the Witwatersrand area. By 1915 the VFP had already erected four power stations with a total capacity of 160 MW. These were at Brakpan, Simmerpan, Rosherville and Vereeniging.

The provision of an adequate electricity supply for the industrialisation of South Africa was technically and financially far too big a task for any private initiative. The need for a national electricity authority was recognised early in the 1920's and in terms of the Electricity Act of 1922, the Electricity Supply Commission (Escom) was formed by a notice in the Government Gazette of 6th March, 1923<sup>(2)</sup>. According to the Act, it was the responsibility of Escom "to stimulate the provision wherever required of a cheap and abundant supply of electricity" throughout South Africa. Escom was also granted the right to investigate and establish electricity undertakings and to take over existing undertakings after a prescribed period. The Electricity Act

defines the public utility status of Escom by stating: "It shall be a general principle of the Commission that its undertakings shall, as far as practicable, be carried on, neither at a profit nor at a loss" and its activities shall be financed by raising "moneys by way of loan" and by revenue obtained from consumers.

From the time it was formed, Escom worked in close cooperation with the VFP in connection with the planning and the design of power stations at Klip (1936) and Vaal (1945) and the continued expansion of the supply system. In 1948 Escom took over the VFP from which the present Rand and Orange Free State Undertaking developed.

The first undertaking created by Escom was in the Eastern Transvaal where supplies were originally provided from a temporary hydro-electric station at Malieveld Spruit (1925) and subsequently from a permanent hydro station at Sabie (1927). In Natal an undertaking was established in 1927 by taking over the Colenso Power Station and the 88kV transmission system which was being constructed for railway electrification between Glencoe and Pietermaritzburg. With the construction of the Umgeni Power Station in 1954 a 132kV link was provided between Colenso, Pietermaritzburg and Durban. When Ingagane Power Station was built in 1963, two 275kV lines were used to link this station to the Georgedale distribution station near the major load areas of Pietermaritzburg and Durban. In the same period what is now the Cape Western Undertaking was formed around power stations at Salt River (1928) and Hex River (1952). In this area transmission voltages started at 33kV and developed to 66kV and 132kV as supplies were given to areas as far apart as Saldanha Bay, Beaufort West, Swellendam and Hermanus. In 1947 the Border Undertaking was formed by taking over the West Bank Power Station at East London and in 1950 the Cape Northern Undertaking was established by taking over Kimberley Power Station.

Thus by 1950 Escom owned and operated six electricity undertakings, each having its own local generation. From 1950 to 1960, seven new power stations were built and the generating capacity increased from approximately 1500 megawatts in 1950 to 3500 megawatts in 1960.

In the early 1960's a start was made to connect the Rand and Orange Free State Undertaking with the other undertakings. Connections were made to the nearer undertakings with 132kV and 275kV lines, but the distances involved showed these voltages to be inadequate to connect the more remote undertakings. This led to the planning of a national grid consisting of 400 kV lines with which all the major load centres and power stations will be interconnected<sup>(3)</sup>.

The interconnection of the main load centres, as illustrated in figure 2.1, also led to changes in design, construction and operation of power stations. The three power stations, Camden, Grootvlei and Hendrina, all using 200 MW turbo-generator sets, were commissioned in the period 1966 - 1970. Grootvlei was the first station with a dry-cooling tower. Experience with the dry-cooling tower has already shown that water consumption can be reduced to about ten per cent of that of conventional wet towers. This cooling method offers material advantages in South Africa with its dearth of inland water resources. Another means of conserving water is to treat the water of normal cooling towers chemically in order to reduce the carbonate concentration. This method is already applied at the new power stations and reduces water consumption by about 20 per cent.

Between 1970 and 1976 two more stations were commissioned on the Eastern Transvaal coal fields. These were Arnot with 350 MW sets and Kriel with 500 MW sets. Arnot was the first power station in South Africa designed for steam reheating.

The national transmission system permitted greater freedom in the choice of power station types and in the siting of new

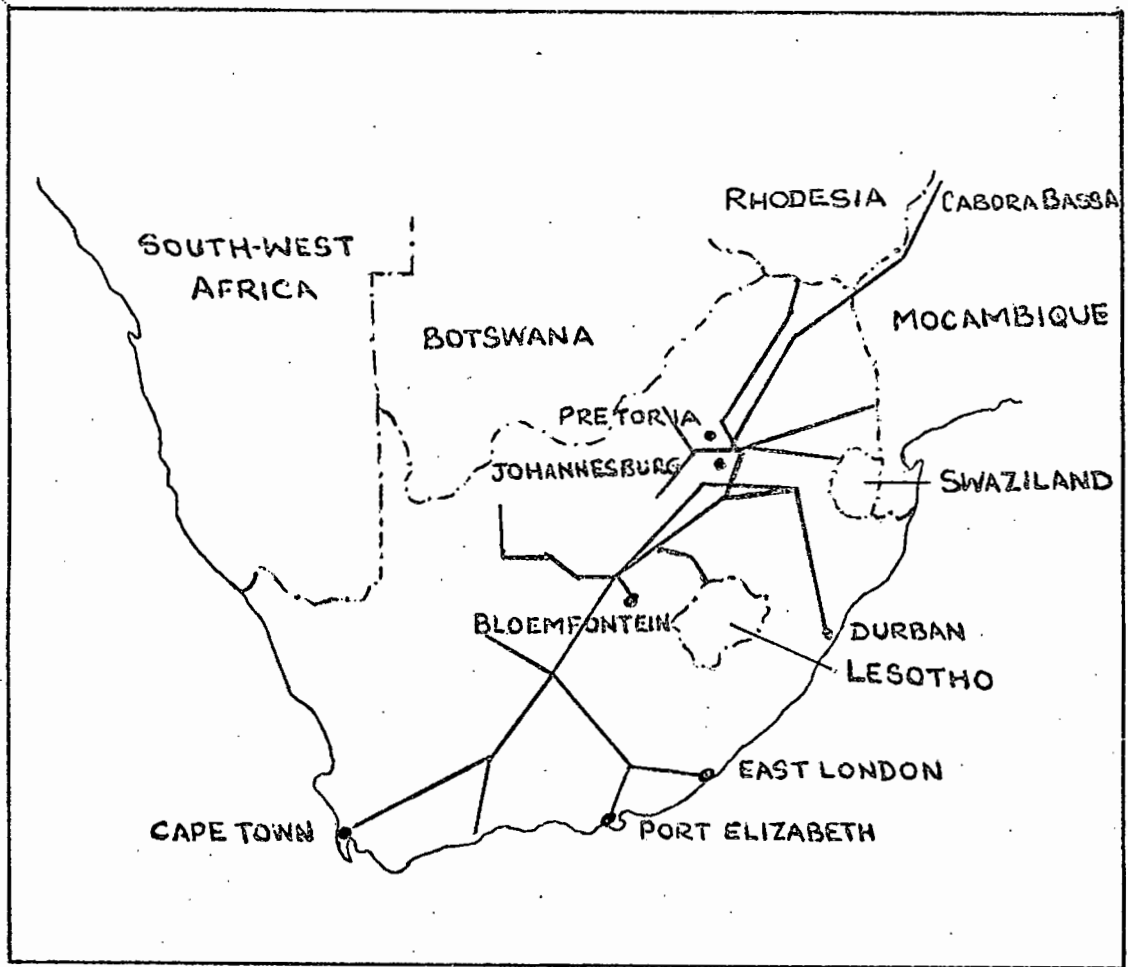


Figure 2.1: Map showing the main transmission lines in South Africa.

(Ben-Yaacov 1977)

stations. New power sources could be selected to meet the specific needs of the interconnected system. Thus, extensive studies were undertaken especially to probe the possibilities of choosing plant limited to peak load operation. These studies included an analysis of the hydro-electric potential of the Tugela River, the possibilities of pumped storage schemes and gas turbines.

Consideration was also given to the possibility of extending existing stations by the addition of one or more large generating sets to augment the base load capacity. The collieries serving these stations had coal reserves in excess of the needs of the existing stations, which could be exploited economically by these extensions.

The economic and technical benefits which this national grid offered could only be fully utilised by integrating the operation of all the power sources. The power stations are now operated in order of economic merit, so that the load factors of power station plant are no longer determined by regional power needs. Thus the smaller, older stations with high fuel costs and relatively low efficiency have been mostly relegated to peak load, reserve and emergency duties, while the new larger power stations on the Eastern Transvaal coal fields, with their low fuel costs and high efficiency, are supplying the bulk of the base load requirements. Large power stations housing large generating sets are now erected to meet the total needs of the national grid, instead of separate smaller stations to meet the needs of individual undertakings. The standby plant requirements for the interconnected power stations, operated as an integrated system, are lower than the aggregate of the reserves required for the regional undertakings operating independently. Owing to the diversity in demand of the various regions, the total demand on the integrated system is lower than the aggregate of the demands of the individual undertakings. Integration of the generating resources therefore permits a relative reduction in the overall capacity of these resources.

During the past ten years the electricity supply in South Africa has increased at a rate of 8 - 10 per cent per year. Details of the units generated in the Republic of South Africa and in the Escom system for the period 1935 - 1975 are shown in figure 2.2.

In 1975 about 72000 GWh were supplied, which is nearly 60 per cent of the total figure for the whole of Africa. In this year the Electricity Supply Commission supplied about 62000 GWh which amounted to about 86 per cent of the total figure for South Africa. The municipal undertakings at Johannesburg, Pretoria, Cape Town, Port Elizabeth and Bloemfontein supplied about 7000 GWh, and other municipal stations and industrial producers such as Sasol, supplied

about 2600 GWh. Many other municipalities like Durban, East London, Paarl, Pietermaritzburg, Kimberley etc. take all their power from Escom.

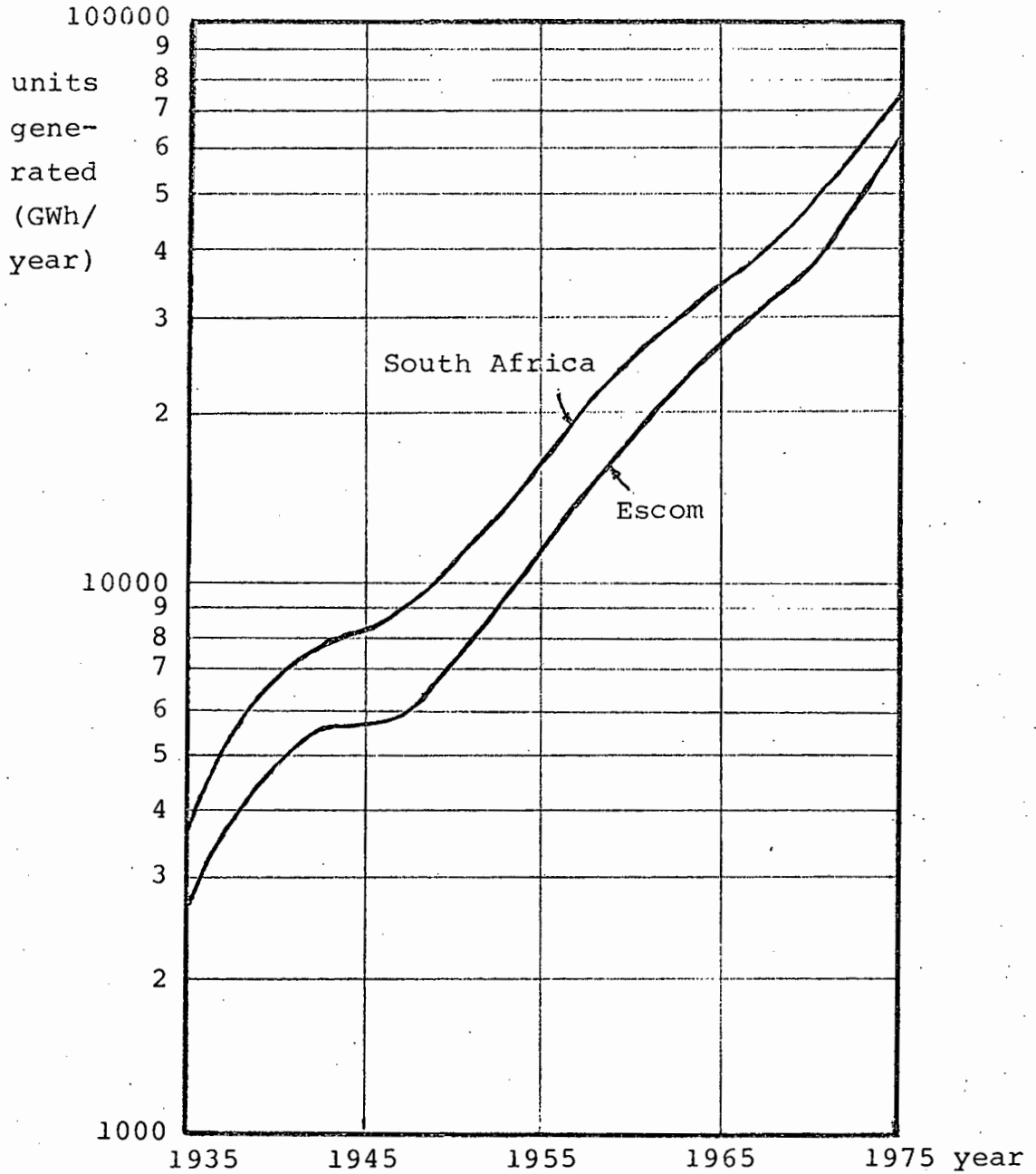


Figure 2.2: Units generated in the Republic of South Africa and in the Escom system for the period 1935 - 1975<sup>(2)</sup>.

In terms of the Electricity Act of 1958, the municipalities have the choice to:

- a) undertake their own generation and distribution,
- b) buy in bulk from Escom and undertake their own distribution, or
- c) let Escom undertake the supply and distribution of electricity within the municipal boundaries. Whereas Escom is obliged to sell at cost, the prices that municipalities may charge for the supply of electricity are limited largely by the acceptance of the rate-payers.

Until 1962 many large municipalities found it economically worthwhile to construct and operate their own power stations. With the construction of the national grid system, it became more economical for the municipalities to purchase their additional requirements in bulk from Escom, and in 1962 a State-appointed Commission (The Borckenhagen Commission) recommended that future policy should be for power generation to be undertaken as far as possible by Escom, leaving municipalities to undertake the retail distribution of electricity to users. However, municipalities may add to their own generating capacity by building more power stations if circumstances are such that this appears to be more economical than obtaining the extra supply from Escom. An example of such a case is to be found in Cape Town where the Steenbras pumped storage installation is being built.

The total installed capacity of all municipal power stations in 1973 was 2372 MW (Johannesburg 944 MW, Pretoria 567 MW, Cape Town 420 MW, Port Elizabeth 302 MW, etc.), which was about 20 per cent of the Republic's total installed generating capacity in the same year. The continuing growth of the demand requires an increasing dependence on Escom for bulk supplies of electricity. An example of the growth pattern for the Johannesburg municipal system is shown in figure 2.3. The present installed generating capacity of the Johannesburg system is 944 MW. The Orlando Power Station with 10 sets of 30 MW turbo-generators was commissioned in

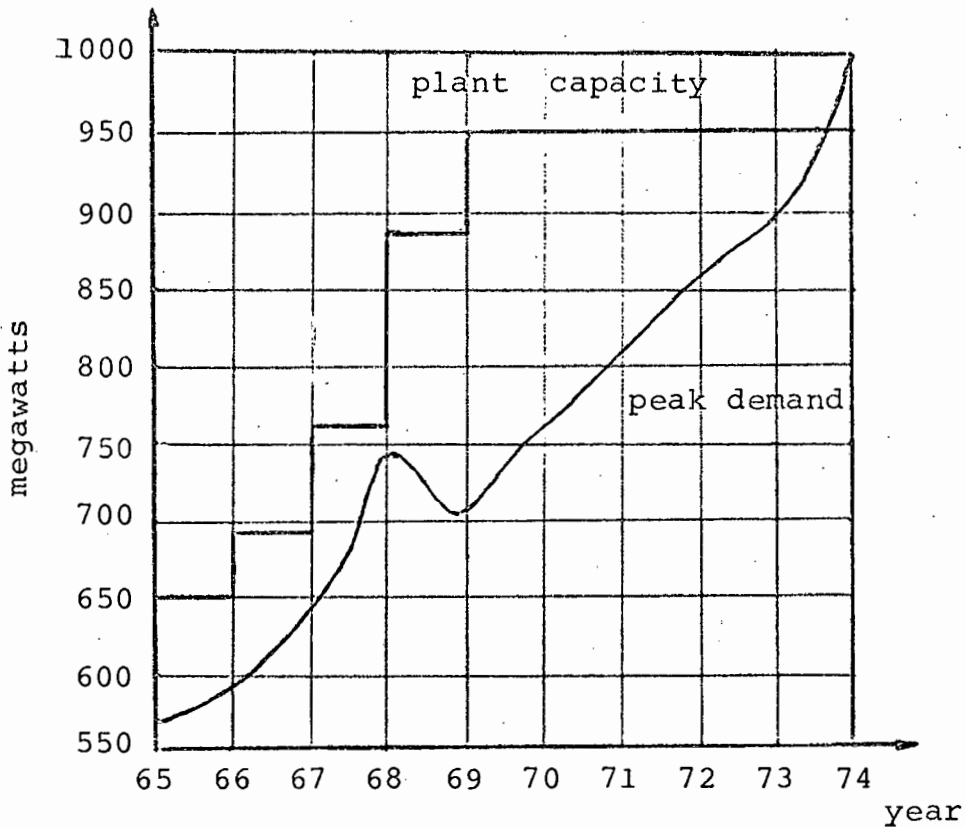


Figure 2.3: Installed capacity and peak demand for the Johannesburg municipal system.

1942. The Kelvin 'A' Power Station consisting of six 30 MW sets was commissioned in 1957. The Kelvin 'B' Power Station consisting of seven 60 MW sets came into operation with the commissioning of the first set in 1962, followed by further sets in 1964, 1965 and 1968. In 1969 two more sets were brought into operation, and the seventh and last set was commissioned in 1970. The peak demand for Johannesburg in 1974 was 1000 MW of which 957 MW were supplied from the Council's own power stations and 43 MW were imported from Escom. The average rate of growth of demand for the past 10 years was 7 per cent per annum and the total power demand of Johannesburg is forecast to reach 2000 MW by 1985 and 4000 MW before the year 2000<sup>(4)</sup>. Most of the future demand will have to be taken from Escom's national grid. Similar patterns exist in the other municipalities and therefore the generation of electricity in South Africa by resources outside Escom will decrease with time and become zero when the municipal and private power stations are decommissioned.

A breakdown of the load of the Escom system into various

categories over the period 1960 - 1975 is given in figure 2.4. It can be seen that in 1975 32 per cent of Escom's load was supplied to the mining industry, 30 per cent to other industry and 29 per cent to municipalities. Included in the last figure is the supply of about 3000 GWh to the municipalities

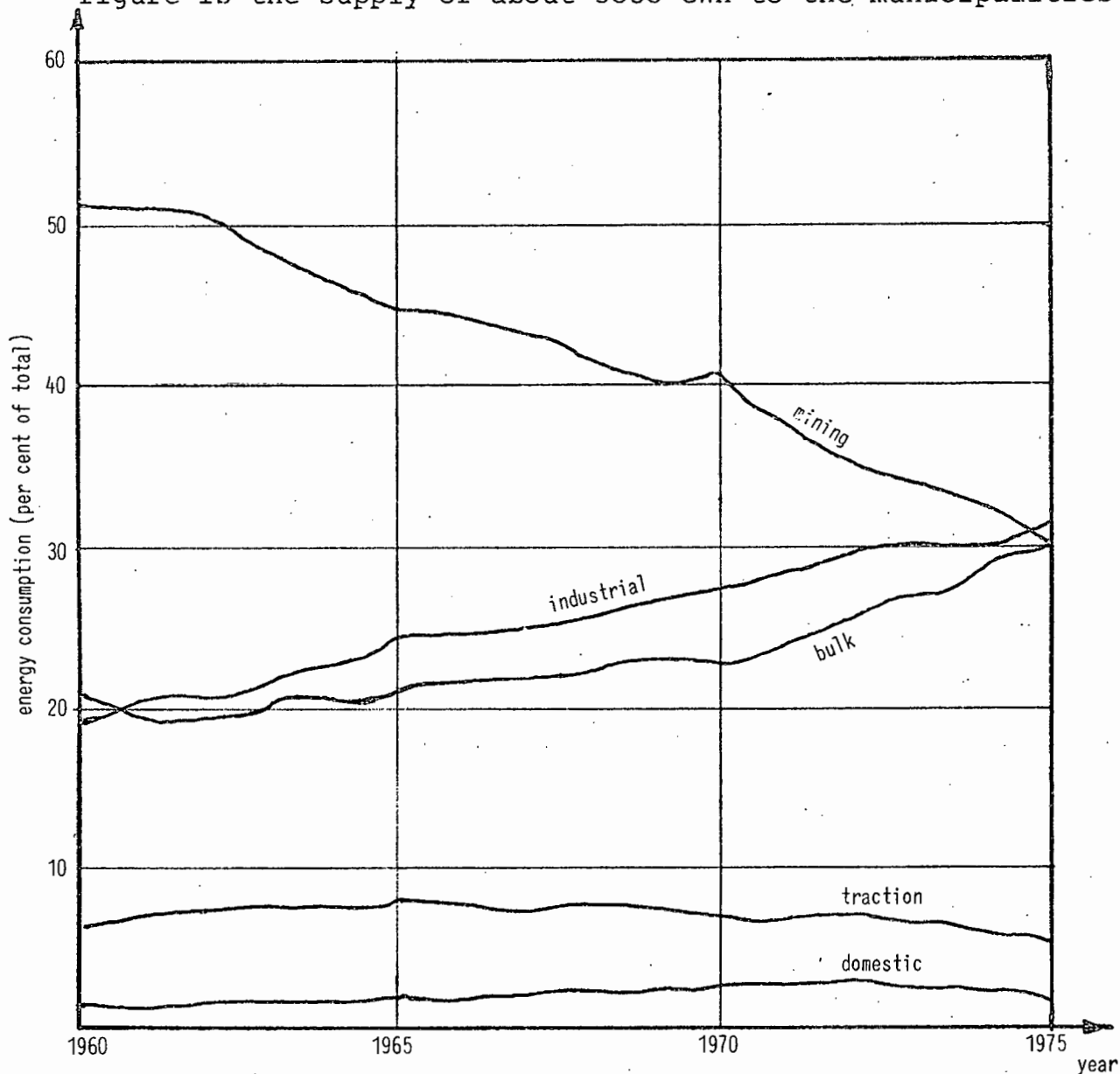


Figure 2.4: A breakdown of the load into various consumer categories (2).

of Pretoria, Johannesburg, Cape Town, Port Elizabeth and Bloemfontein. The other categories include traction (6 per cent), domestic and street lighting (2 per cent) and bulk supplies to neighbouring countries (0,5 per cent). In general, Escom supplies electricity in bulk at voltages

ranging from 6,6 to 132kV to towns and other large consumers who undertake the low voltage distribution to consumers. Escom does, however, supply some 100000 urban and rural consumers at 380/220 volts from supply lines generally operating at 11 or 22kV.

In 1975, the annual load factor of the Escom system was about 75 per cent. This high load factor arises in part from moderate climate conditions without extremes, but mainly because of the continuous operation of mining and primary industries which play a significant role in the electricity market. In the municipalities of Johannesburg, Pretoria, Cape Town, Port Elizabeth and Bloemfontein, the average annual load factor amounts to about 50 per cent. This figure is lower than that of Escom as a large proportion of the municipal load is supplied to domestic consumers.

The national policy towards the electricity supply industry in South Africa was formulated as early as 1922 and this policy has not changed in any significant way since. The statutory duties of the Electricity Supply Commission are broadly to meet the demand for electricity in the most efficient way and to conduct the finances so that over time they at least break even, having provided for interest and repayment of loans. In order to finance the steady expansion of the power system, Escom has traditionally raised funds by issuing loans on the domestic and foreign capital markets. However, because of the increasing cost of capital it was necessary to increase the internal financing capability of new expansion projects. Accordingly, the Electricity Act was amended in 1971 and provision was made for the allocation of limited proportions of the revenue to a capital development fund, sufficient to make some contribution towards the future capital development programme, and to the reserve fund which is to finance the replacement of obsolete machinery and plants.

Since electricity plays an important role in the total energy supply of South Africa, it is highly relevant to have a clear

idea of the objectives of the government as regards the energy sector as a whole and still further, an idea of government policy as regards the total economy in whose infrastructure the energy sector plays a vital role.

## 2.2 ELECTRICITY DEMAND AND THE NATIONAL ECONOMY

One of the consequences of the national energy policy is the fact that, at the present time, electricity accounts for approximately 18 per cent of the total net energy input to the South African economy. The nature of the South African inland coal deposits is such that the quality of the coal is relatively low and the mining costs are also low in comparison with those of other countries. By the conversion of coal to electrical energy it was possible to ensure a low energy cost structure for the economy.

The use of coal as the prime energy source in South Africa has led to a capital intensive energy supply industry as the total capital needs for the energy supply are increased by the conversion from primary energy to electricity and then from electricity to useful energy in the final user process.

The analysis of the demand for electricity cannot be viewed in isolation from the demand for other energy sources. Statistical analysis of energy used in South Africa has been carried out by Kotze<sup>(5)</sup>, for the various energy resources. The results of the analysis are in terms of "useful energy" which represents the last stage of the energy use, that is the part of the energy supplied to an end user which finds its way usefully into the product or process. It can be seen from table 2.1 that the percentage of useful energy consumption of electricity increased from 18,9 per cent in 1948 to 31,3 per cent in 1973, whereas the useful energy consumption of coal decreased from 47,3 per cent in 1948 to 22,2 per cent in 1973.

Kotze has forecasted that this trend of an increased proportion of electricity consumption will continue in future

and will reach 35 per cent in 1980 and 46 per cent by the turn of the century.

energy components	per cent of the total useful energy consumption	
	1948	1973
electricity	18,9	31,3
coal	47,3	22,2
oil	13,8	23,7
coal-gas	0,5	1,6
other gas	9,5	10,4
coke	9,6	10,6
gas coke	0,4	0,2

Table 2.1 : Consumption of useful energy in South Africa for 1948 and 1973<sup>(5)</sup>.

Although useful energy represents the final stage of the energy use, the demand for energy can be measured at other levels. The demand may be measured for primary sources as offered by nature (hard coal, crude oil, etc.,) or for secondary sources (coke, electricity, etc.,) which are derived in one or more conversion processes from the primary sources. The relationship between the demand for the net energy input to the economy and the useful energy, depends on the efficiencies of conversion in the consumers' apparatus.

The relationship between the growth in the demand for net energy and the corresponding growth of the national economy has been analysed by Stoffberg<sup>(6,7)</sup>. Stoffberg has shown that there is a linear relationship between the growth of the national economy and the net energy demand which is measured in units of equivalent electricity demand. In this analysis the net energy was divided into electricity and the sum of the other components. This relationship is expressed by an equation:  $z = ax + by$  where  $z$  is the real Gross Domestic Product (GDP) for a given year,  $x$  is the number of kWh of electricity included in the total national net energy input for the year concerned and  $y$  is the corresponding

energy content in kWh of the other components of the total net energy which is comprised of solid fuels, oil and gas. This equation implies that a net energy input of one kWh of electricity will contribute a/b times as much to the GDP as an input of one kWh of alternative energy. If the cost of one unit of electrical energy was less than a/b times the cost of one unit of alternative energy then there would be an incentive to use electricity instead of alternative fuels. An analysis of the statistics for 27 years indicates that the GDP in South Africa expressed in U.S. dollars at the level of the 1963 prices<sup>(7)</sup>, can be expressed by the equation:  $GDP = 0,317x + 0,026y$ . The ratio of a/b in South Africa is 5,07 as compared to 4,44 in the United Kingdom and 3,25 in the United States. Taking into consideration that the thermal efficiency of conversion of prime energy to electricity is in the order of 28 per cent in South Africa and 32 per cent in the U.K. and U.S.A., the corrected a/b ratio would be 1,42 for South Africa and the United Kingdom and 1,04 for the United States. In South Africa and the United Kingdom the contribution of one unit of prime energy to the GDP is larger if that unit is first converted into electricity rather than used directly whereas in the United States there is not much difference whether or not the prime energy is first converted to electricity. Clearly for South Africa and the United Kingdom the amount of prime energy used for a given GDP would be reduced if the proportion of net energy supplied by electricity was increased. This may partly explain why electricity accounts for a larger fraction of the total net energy input in South Africa than in most of the other developed countries.

The analysis by Stoffberg of the change in the electricity component of the net energy input as a percentage of the total net energy indicates that in 1948 electricity represented 7,4 per cent of the total, whereas in 1973 it represented 18 per cent of the total. Stoffberg has forecasted that electricity will continue to replace other energy sources and by the year 2000 the electricity component will reach

44,6 per cent of the total net energy.

### 2.3 A LOOK INTO THE FUTURE

During the past ten years electricity generation in South Africa has increased at an average rate of more than 8 per cent per year. It is estimated that this same growth rate will continue until the end of the century<sup>(8)</sup>. This means that the consumption of electricity which was about 70000 GWh in 1975 should increase to about 300000 GWh by the year 2000.

At present the generation of electricity is based almost entirely on the coal deposits in the northern provinces of Natal, the Orange Free State and Transvaal<sup>(9)</sup>. Of these areas, the Eastern Transvaal highveld has become the centre of power generation, because of the vast deposits of economically mineable coal and the availability of water for cooling purposes. As far as possible it has been the policy of Escom to build power stations on the coal fields and to feed the coal directly from the mines to coal staiths at the stations by means of conveyor belts. For about the next ten years, coal-fired power stations in the Eastern Transvaal coal fields will continue to provide the bulk of the South African power generation.

Nuclear generation will be introduced in South Africa in 1982 with the construction of two units of nearly 1000 MW each at Koeberg in the Western Cape. It seems likely that at least part of the future load growth of the Western Cape and other coastal regions will be met by the installation of additional nuclear plants in these regions.

The seasonal fluctuations of flow in South African rivers is such that generation of hydro-electricity in reasonable quantities is not possible without water storage, and the size of the dams needed is such that hydro-electric power stations can only be justified with irrigation schemes. The value of hydro-electricity for peaking power has been

recognised in the construction of the Hendrik Verwoerd and Van der Kloof hydro stations. Another large potential source of hydro-electric power is the Tugela River which has an estimated capacity of some 2500 MW.

The electricity authorities in South Africa have had long experience in the construction and operation of fossil-fired generating plant. The commission of hydro-electric stations and the planned addition of a pumped storage scheme, gas turbines and the nuclear plants means that by the early eighties South Africa will have had experience with every commercial type of generation. It will then become possible to select the optimum combination of types of generation, taking into account the cost of electricity, the preservation of natural resources and the effects on the environment. Table 2.2 gives the possible percentage utilisation<sup>(8)</sup> of the various energy sources, assuming gas turbine to be negligible.

year	source of power generation (per cent)		
	coal	nuclear	hydro
1975	93	0	7
1985	78	8	14
1995	76	10	14
2005	45	46	9

Table 2.2: Utilisation of the various energy sources<sup>(8)</sup>.

A significant feature of electrical utilities is the large amount of capital needed to obtain expensive specialised equipment. It is estimated that in the period 1976 - 1981 about R600 million will be required annually to finance the expansion of the generation and transmission system<sup>(2)</sup>. Currently about 70 per cent of the capital requirements come from foreign and domestic loans and about 30 per cent is internally financed, but it is questionable whether the 70 per cent loan portion can also be maintained in future. Without a sufficient increase in tariffs to enable a greater

proportion of capital development to be financed internally, there is the danger that the development programme of Escom would have to be curtailed.

The existence of an interconnected national supply system in South Africa makes it feasible to consider a connection to neighbouring countries. The real advantage of an integrated network over the whole of Southern Africa lies in the variety of resources which the various countries have to offer<sup>(10)</sup>. While the countries to the north have tremendous hydro potential, those to the south have large coal and uranium deposits.

The Cabora Bassa hydro-electric power project on the Zambezi River in Mozambique was the first step towards establishing such a transcontinental network. The damming of the Zambezi at Cabora Bassa will create a power potential of 4000 MW, of which Escom will buy about 1500 MW by 1980. This power will be transmitted to the Apollo distribution station south of Pretoria as direct current at a voltage of  $\pm$  533 kV.

Four of the Republic's neighbours, Mozambique, Lesotho, Swaziland and Rhodesia, are already receiving electricity supplies from Escom. South Africa is also participating in the establishment of a power system for South-West Africa which will be based largely on the hydro-electric potential of the Kunene River.

CHAPTER 3

MODELLING TECHNIQUES AS AN AID IN POWER SYSTEM  
PLANNING.

3.1 OBJECTIVES AND STAGES IN POWER SYSTEM PLANNING

All planning procedures require objectives, and these must be expressed at least in general terms before any real progress can be made. An electricity supply authority needs to specify its objectives clearly, because electricity is both basic to all sectors of the economy and a major consumer of capital. In South Africa these objectives are defined in the Electricity Act as the provision of electricity to each type of consumer with the quality and quantity of supply which he requires, and the management of the finance in such a way that the total costs for the required standard of supply will be kept at a minimum.

Planning may be defined as formulating, evaluating and choosing between the various courses of action being considered in the light of the planning objectives. In electricity supply this process takes place within a framework of the following major considerations:

- a) In most countries there is no firm sign that the growth in the electricity demand is approaching saturation. It is still tending to grow at a relatively high and continuous rate.
- b) Generating plant is relatively expensive and the power supply industries are, therefore, highly capital intensive.
- c) The bulk of the demand for electricity at any instant must be met from current generation. Storage schemes connected with electricity production are usually indirect and expensive.
- d) It takes a long time to build generating stations and transmission lines. (In South Africa it takes about

five to seven years for generating stations and about three to five years for transmission lines from the time of executive decision to commissioning.) The planning must thus be done with "decision points" five to seven years in advance.

The planning process may require the exploration of a considerable number of courses of action; the implications of each course must be examined and costed. As the system being examined is that postulated for a future date, simulation techniques must frequently be resorted to as a means of evaluation of consequences.

In general, the aim of power system planning is to provide a pattern of expansion which will ensure that sufficient plant is available to supply the forecast load with an adequate level of reliability, and that this pattern of expansion is the lowest cost alternative of those available. The following definition of system planning was prepared early in 1953<sup>(11)</sup> and now appears to be generally acceptable: "System planning is the preparation of a rational programme for the development of an electric power system, so that it can evolve in an orderly and economical manner. It includes forecasting and analysing loads, rationalising standards of service, anticipating trends in equipment design and co-ordinating the various elements of the system into a well-designed whole; it is particularly concerned with plans for changes and additions to generation, transmission, substations, and distribution facilities. It is not concerned with the problems of day-to-day operation or design except to the extent that these problems affect future system development. Briefly, electric system planning is the process of determining when and where certain facilities should be provided in order to assure adequate electric service at minimum average annual cost to the community."

System planning studies may be divided into three stages<sup>(12,13)</sup>: policy study, analysis, and optimisation. Policy studies are made to establish the long-term major engineering and

financial development of the power system. These studies are often concerned with the pattern of energy sources, transmission voltages, standards of security or the tariff structure. In the analysis stage various alternative plans are analysed for their ability to meet reliability standards. In this stage the various alternatives are evaluated by the simulation of the system operation under steady-state and transient or fault conditions. In the optimisation stage economic evaluation studies are performed to identify minimum cost alternatives from those plans which meet the reliability criteria.

Before beginning an expansion study, a large amount of information must be available. This includes the history of peak demand and energy requirements, location and reserves of fuel sources, characteristics of existing generating units and transmission systems, and estimates of costs for all plants which are considered, including installation, production and maintenance costs. It is also necessary to set the standards for evaluating reserve requirements, for economic comparisons or for the security of operation. In table 3.1 some of the main parameters involved in system planning are outlined.

system component	data	study period (years ahead)	
		policy	detail
load forecast	historical demands economic growth	1-30	1-10
choice of generation plant (type, size and site)	power and energy estimates energy sources plant parameters site information cost of fuel and plant	5-30	2-10
choice of transmission network	estimates of demand supply areas and load factors generation pattern existing transmission system site and geographical information plant costs and parameters	2-20	1-10

Table 3.1: Outline of the components of system planning.

Modelling of a power system can be separated into consideration of long-range, mid-range, and short-range planning. Within each of these periods, the areas of emphasis and the complexity of the simulation model can differ considerably.

Long-term strategies usually cover a period of about 20 - 30 years, this being the longest period over which electric demand can reasonably be estimated for utility planning purposes. The objectives of this planning are:

- a) an economic assessment of the amount of electricity that should be generated by the various energy resources,
- b) an assessment of the structure and the voltage levels of the main transmission system, and
- c) the determination of the policy of financing the whole of the electricity supply industry.

Mid-range planning strategies usually cover a period of about 5 - 10 years. The purpose of this planning, according to which capital expenditure will be finally committed, is to explicitly define the generation and main transmission systems to be constructed. The tariff structure should also be considered in this type of planning.

In short-term planning, periods of up to 5 years are taken into consideration. It involves mainly operational consideration such as plant operation strategy and scheduling the maintenance of the various plants. The short-term planning also involves changes in the mid-range plant installation programme and the choice of sub-transmission and distribution networks.

The value of any power system planning strategy is measured in terms of expected reliability in meeting forecast loads and the total capital and operating costs incurred over the system. Usually, the prime objective is to minimise costs while maintaining a specified system reliability as a constant.

### 3.2 APPLICATION OF COMPUTERS TO POWER SYSTEM PLANNING

The power industry has long been one of the largest users of computers and ranks among the most sophisticated in its modelling and computational techniques. The modelling techniques date back to at least the late 1920's, long before the advent of digital computers. This is understandable when one considers the complexity of planning an electricity supply system. The capital intensive nature of individual projects, the severe operational and reliability requirements, and the complexity of the numerical solutions are the major problems encountered in electricity supply planning.

The need for computational aids in power system engineering, coupled with the solid mathematical base of electrical engineering, which originated with the work of Kelvin, Kirchhoff, Heaviside and Steinmetz, led in 1929 to the design of a special purpose analogue computer, called an AC network analyser. This device made possible the study of a large variety of system conditions for future system designs. It provided the means for determining power flows and system voltages during normal and fault conditions.

The earliest application of digital computers to power system problems dates back to the early 1950's where the availability and speed of these digital computers made it possible to meet the requirements of major power system problems. Improved formulation of various aspects of power system analysis continued through the 1950's and 1960's and the aims have been to increase the size of the system which could be solved and to reduce the time of solution. A definite turning-point in the application of computers to power system modelling probably occurred between 1965 and 1970, when Newton-Raphson techniques for the solution of non-linear simultaneous equations were introduced to solve power system network equations. At present these techniques, together with probability and optimisation methods associated with operation research, are applied to a broad range of problems. In the planning area these include establishing generation capacity requirements,

selecting new generation units and network equipment, analysing the steady-state technical and economical characteristics and evaluating the total finance requirements. The current trends in some of these applications are discussed below.

Load forecasting:

Load forecasting for planning includes expected peak demands and total energies with the associated uncertainties, and daily and seasonal variation of demand with time. Generation planning also requires models of the hour-by-hour characteristics of the demand while transmission planning requires the assignment of components of demand to various locations.

The use of mathematical forecasting models for the long-range prediction of power and energy demand is a subject of controversy. The reason is that it is questionable whether the complex factors affecting the forecast can be determined with sufficient accuracy and completeness. Frequently, several forecasting methods are used and judgment is made by providing an ultimate figure between the various estimates.

There are two basic methods for the long-range prediction of power requirements - mathematical analysis, and economic investigation of individual consumer sectors<sup>(14)</sup>.

All mathematical analysis methods can be reduced to two basic forms, extrapolation and correlation<sup>(15)</sup>. With extrapolation, past history is used to derive a trend line which is extrapolated to the future. Here the choice of equation for the trend line and the grouping of the historical data play an important part.

The main objection to trend extrapolation is its purely mathematical character. Changing patterns of energy use, technological development and gross national product may all bring about changes in the historic trend. With correlation methods, the historic demands are correlated with suitable indicators for the whole economy or sections of it, and from

the expected changes in these, the changes in the electricity demand are estimated.

The second method, economic investigation of individual consumer sectors, requires detailed investigation of the electricity consumption characteristics of a given consumer group. With information of past electricity consumption and possible replacement dates of existing equipment, the forecast of the future electricity consumption of the individual consumer sectors can be determined.

As compared with mathematical analysis methods, the economic investigation of individual consumer sectors method has the advantage of actually being able to explain the increase in electricity consumption and not, as in the case of mathematical functions, simply describe it as dependent on certain variables. An essential requirement for this method is the availability of the maximum possible amount of basic information, which has been lacking in most consumption sectors.

The above description has been mainly in terms of the annual consumption of electrical energy and the maximum system demand. Demand patterns for various periods of the year can be assessed by analysis of historic distribution and the adjustment can then be made for a known major development.

Generation and transmission expansion planning:

Power system expansion planning is usually divided into generation and network planning functions. The latter are further sub-divided into classical technical levels: transmission, sub-transmission and distribution. The succession of the planning steps are similar for both generation and network systems. Starting with an existing generating system, its steady-state technical and economical characteristics must first be analysed. Then, usually a security analysis leads to requirements for an additional generating capacity. This is followed by an economical analysis. The economics aspect of the generation expansion problem will be to select the plant with a balance between capital and operating costs that

is appropriate to the demand profile, and to the present and future mix of the plant. This new addition modifies the system and more steady-state analysis is needed. Similar steps are usually performed for the analysis of the transmission system.

Although interest is growing in techniques which allow combined examination of more than one step of the main system planning - for example, plant siting and transmission interconnection or security analysis and investment decisions, the generation margin, plant mix, network expansion and the steady-state and transient behaviour of the transmission system are usually considered separately.

In order to assess the required generation capacity which needs to be added to the existing system, probability methods and Monte Carlo sampling techniques are used. Many utilities use the loss of load probability method which makes it possible to calculate the number of days per year on which there may be insufficient generation to meet the demands<sup>(16)</sup>.

Other utilities use probability methods to calculate loss of energy probability which is given by the ratio of expected energy not supplied to total energy demand. It is also possible to use probability techniques to calculate the probable intervals between failures to meet the demand and the duration of such failures<sup>(17)</sup>. In the case of systems which possess a significant proportion of hydro-generation capacity, the probability studies may also need to consider the variability of the inflow of water<sup>(18)</sup>.

Another important factor may be the evaluation of the mutual assistance possible between different utilities in the country, or between the utilities of different countries<sup>(19)</sup>. In this case the loss of load probability is calculated separately for each area and then the combined effect is calculated.

In Monte Carlo methods the demand and generation availability

levels are randomly chosen to form a possible system state, which is checked for being able to supply the demand. By repeating these procedures many times, the expected failure rates can be obtained.

The system economic aspect of the generation expansion planning is to select the plant with an appropriate balance between capital and operating costs of the whole system over long periods of time. It is common practice<sup>(20,21)</sup> to adopt the minimum present worth of the future cost of system investment and operation as the economic objective of system planning. Two approaches are used to find optimum solutions - simulation models and global models. With simulation models a pre-defined alternative of system expansion is given as input data and only system operation is optimised by using the model. This is repeated for all possible alternatives. Simulation of a large number of feasible expansion alternatives requires a lengthy analysis by the planners and in many cases they need to use their own judgment in selecting the most promising alternatives for simulation. With global models the planner presents all the possible alternatives and the optimisation is done simultaneously for the capital and operating costs.

There are many methods of analysing the economic aspects of generation planning. These include graphical analysis, tabulation in ascending order of marginal operating costs (merit-order), Monte Carlo techniques, probability mathematics, linear, non-linear and dynamic programming.

In a linear programming model the objective function is the measurement of the best solution to the set of conditions (constraints) defined by the user. For selection of generation units on an economic basis, the objective function is the determination of the total present worth of the cost of building and operating all the plants for a specified period of time<sup>(21)</sup>. Mathematically, the constraints are used to define the region of feasibility of the model, and the solution

algorithm will select the optimum solution from the feasible region.

Planning the expansion of a high voltage transmission system involves deciding which new lines and other plant components will enable the system to satisfy forthcoming loads with the required degree of reliability. As in the planning of the expansion of the generating system, the expansion of the high voltage transmission system involves considerable investment and operating costs and the economic objective is to keep the present worth of all costs as low as possible. The difficulties entailed in doing this arise from the tremendous number of possible alternatives and the complexity of the reliability constraints. While generation planning has made use of both probability and optimisation methods to a large extent, transmission planning has generally made use only of optimisation methods. A linear programming model has been developed<sup>(22)</sup> to identify the major transmission circuits needed for a long period in the future. Dispatches of generation to serve the load are computed for several assumptions such as normal peak load, a lower load condition, and peak load with the two largest units out. After a network with sufficient capacity for the dispatches is planned, all single circuit outages are checked and further additions are made to the network. However, because of the large number of possible alternatives and the complexity of the reliability analysis, the use of mathematical programming techniques has successfully solved only limited problems in transmission planning.

The essence of power system analysis lies in the solution of large networks under various conditions and assumptions. The mathematical structure of load flow, fault study, and transient stability has been explained in the book by Stagg and El-Abiad<sup>(23)</sup>. The network and all its elements are usually taken to be linear, having the simple relation  $Y \cdot V = I$ , where  $Y$  is the complex nodal admittance matrix and  $V$  and  $I$  are vectors of nodal voltage and current phases. Load flow studies involve the solution of simultaneous non-linear algebraic equations whilst fault analysis involves the solution

of simultaneous linear algebraic equations. Transient stability calculations involve the solution of simultaneous non-linear differential and algebraic equations.

#### Financial Planning:

With the aid of the models described so far, partial investment plans with the associated capital and operating costs, may be developed for the expansion of the generation and transmission systems. The sum of the partial capital and operating costs gives the global costs which must be checked for their financial consequences. In order to establish a framework for investment decisions, such as development of capital intensive projects as against operation intensive projects, financial models, which are also called corporate models have been developed<sup>(19,24,25)</sup>. These models are used to make long-range forecasts of the economic performance of the utility, which are based upon projections of sales and costs and of certain efficiency ratios. Based upon this, a cash flow analysis is made to check what revenue can be expected and what additional external capital resources may be required. The financial models are used to simulate possible futures of the utility in total financial terms. For each year of the study period the cash flow statements, balance sheet, capital requirements, funds generated and other financial statistics are calculated.

In addition to their use in establishing a framework for investment decisions, financial models are also used for the projection of the effects of changes in economic conditions such as rising costs of labour and equipment, or increasing costs of external capital resources in view of the profitability and risks involved.

#### For the future:

A general conclusion which might be drawn is that at the present time adequate techniques exist for the solution of most of the power system problems. There is still much work to be done in making the best programs more generally

available and some improvements in basic formulation and solution methods can be expected. It is expected that the most important developments in the future will be in the field of data bases and interactive computation. Some comprehensive technical data bases already exist but these need to be extended to more users, and also need to be integrated with business-oriented data bases. There is also a need for greater information exchange between system control centres and an improvement in the availability and quality of data. A number of interactive load flow programs are already available. These need to be extended to the point where most engineers will have interactive facilities to handle most of their analysis work. Computer graphics should be used extensively to present results in a more easily understood form.

CHAPTER 4

MODELLING OF THE SOUTH AFRICAN ELECTRICITY  
SUPPLY SYSTEM

4.1 HISTORICAL BACKGROUND

In the early sixties, the demand for electricity in South Africa reached a level at which it became economically worthwhile to consider high voltage transmission from power stations in the Transvaal coal fields to the various load centres. In order to plan a 400kV transmission system, extensive investigations had to be undertaken. At that stage the electrical utilities in South Africa did not possess their own digital computer and the major part of the system investigations were carried out on an AC network analyser. However, certain problems associated with an extensive high voltage system, such as switching over-voltages that may arise from the high speed re-closing of circuit breakers, could only be analysed by a digital computer. Thus the various investigations concerning these problems were carried out for the South African electricity supply industry by a group of engineers in England who made use of sophisticated computer techniques.

The first digital computer was installed in Escom in 1967. Gradually, more and more computer programs have been developed and used for the planning and operation of the South African power system. With the installation of a large computer system (Control Data-6400) in 1971, it became possible to develop more highly complex computer programs to enable power system engineers to deal with the large scale problems encountered in generation and transmission planning.

During the period 1971 - 1973, various programs were developed for the analysis of the network under steady-state and fault conditions. These programs were developed together with an integrated system data base which made it possible to describe the system network in an organised manner and to make the

data and results of one program e.g. load flow, available to other calculation programs, such as fault analysis or stability studies.

During the same period, a computer program was developed for the simulation of the generation system by using the approach of marginal analysis where the generator units are arranged in ascending order of operating cost (called the "merit-order"). Other computer programs were developed for the analysis of the consumer's demand for electricity.

The increase in the capacity and speed of the computer system which resulted from the installation of CDC cyber-74 in 1975 and the purchase of an advanced linear programming optimisation system, made it possible to use mathematical optimisation techniques for planning the expansion of the generation system. Two complementary techniques, LP optimisation and probability analysis, were used to develop computer programs for the economic analysis of future plant mix, the optimum scheduling of the operation of the power system, the analysis of generation reserve margins and the scheduling of plant maintenance.

Finally, costing models have been developed which make it possible to carry out the financial analysis of the various possible alternatives of future system expansion plans.

#### 4.2 DEVELOPMENT STRATEGY

The development of computer programs to assist in power system planning is influenced profoundly by the advances taking place continuously in scientific data processing, in simulation techniques, and in the new mathematical approaches arising from theoretical developments in applying computers to solutions of engineering problems.

There are two complementary skills required for the development of computer programs in the field of power system planning, viz., the engineering know-how to specify the

problem and develop special techniques for its solution, and the skill to develop programs in which the objective is to optimise the application of the computer for solving the problems.

The development of a large modelling system, such as the one presented here, requires a certain amount of discipline in the thinking process leading from the definition of the objectives of a given problem to its implementation and operation. The process which was adopted in the development of this system involves a number of steps or stages:

- a) Problem definition. Initially, the problem and the objectives must be defined. Consideration must be given to the scope of the problem and its limitations, availability of input data and the relative importance of the results in making practical decisions.
- b) Mathematical formulation. After the problem has been defined, it is necessary to develop a mathematical model to represent the physical system. This requires specification of the characteristics of individual system components as well as the relations governing the interconnection of the elements. Different mathematical models may be used to represent the same system, and for many problems complementary formulations may be obtained.
- c) Selection of a solution technique. The formulation of most of the power system problems involves mathematical expressions such as sets of non-linear and differential equations, and optimisation of linear or non-linear equations. It is important, at this stage, to select a method which is practical for machine computation and will produce the desired results in a reasonable amount of computer time. Since numerical approaches involve a number of assumptions, consideration must be given to the degree of accuracy required.
- d) Program design. The sequence of logical steps by which a particular problem is to be solved, the allocation of memory and the access of data are important aspects of computer program design. The objectives are to develop

a procedure which eliminates unnecessary repetitive calculations and remains within the capability of the computer.

- e) Programming. The process of programming is the translation of the detailed steps to be performed in the solution of a problem into an organised list of computer instructions. A program can be written in a generalised programming language such as Fortran. There are many occasions on which errors could be introduced during the development of a computer program. Thus, a systematic series of checks must be performed to ensure the correctness of the problem formulation, the method of solution and the operation of the program.
- f) Application. Computer models can be used by power system engineers in three ways. The first and most common one is as an aid to analysis. A design is formulated by the engineer based on his experience and judgment, and the computer is used to analyse its probable performance. According to the results of this analysis the engineer changes his design and obtains a new analysis, and he repeats this process until he is satisfied. The second way of using computer models is to postulate a number of alternative designs as a series of "if-then" statements, and the computer is used to find the best solution, based on criteria that were previously decided upon. The third use of computer models is the overall optimisation solution. In this case the computer program is used to derive various solutions to the problem, to test the solutions for validity and to compare them until an optimum solution is obtained. The selection of any one of the three ways of using computer models depends largely on the complexity of the system, on the degree to which the model is a representation of reality, and on the practicality of the mathematical solutions.

#### 4.3 THE COMPONENTS OF THE MODELLING SYSTEM

The large amount of capital involved in the expansion plans

of the South African power system and also the significant differences in costs between different alternatives of expansion strategies justify the development of a modelling system for the integrated planning of the generation expansion, the transmission system expansion and the financing. Before describing the design of the modelling system for the South African electricity supply industry, it is necessary to consider the present planning procedures.

The planning process in Escom is triggered by the annual load forecast. This forecast, which extends over a period of twelve years, is prepared by correlating historical trends with the expected growth of various consumer sectors. Once every few years a long-term forecast which extends over a period of 20 - 30 years is prepared and is based on the relationship between the use of electricity and the growth of the national economy. In order to be able to supply the expected increase in the demand, the generation expansion plan is produced and is followed by the expansion plans for the transmission and associated facilities. All these plans are reconciled with each other to ensure that the operation and maintenance of the system will be provided for, and that the security of the system will be maintained. These plans, which cover a time span of at least twelve years, set out in very broad outlines the main events or major tasks to be completed during this period. Based on these plans the required investment and operation expenses are estimated. These expenses are financed by revenue and by raising money in the external capital markets. If the capital requirements cannot be met, the expansion plan or the tariff has to be reviewed.

In the development of the modelling system for the South African electricity supply industry the author's intent was to formulate the various technical and economic aspects which are involved in the planning of the power system. The design of the modelling system is based on the assumption that most of the economic and technical considerations involved in

power system planning can be formalised as computer applications.

The system for the modelling of the South African electricity supply industry consists of various sub-models for the forecasting of the electricity demand, the planning of the generation system, the planning of the transmission network and the evaluation of the effect of the various expansion and production projects on the total capital requirements. In order to obtain a better understanding of the different techniques and processes used in the modelling system, the various types of studies can be arranged in a sequence of conceptual models as shown in figure 4.1. The author's approach to the design of the system was to divide the complex planning process into a number of smaller sub-problems and corresponding sub-models and then to co-ordinate their solution. By using co-ordination rules for solving the individual sub-problems, which correspond to the long-term objectives of the electricity supply industry in South Africa, it became possible to obtain solutions which represent the entire scope of the planning procedures.

One of the main characteristics of the modelling system, shown in figure 4.1, is its three-stage structure. The first stage contains routines to forecast the peak loads and the characteristics of the loads for the whole system and for parts of the system. The second stage is represented by two models for the generation and transmission planning. The generation model includes routines for the determination of the reserve margin which is necessary to ensure a certain power system reliability, the additional generation capacity required to meet the loads, and the schedules for the operation of the generating plant. The transmission model consists of routines to calculate the load flow in the lines, the voltage levels at the busbars, the stability of the system and overvoltages in the network owing to switching and lightning surges. With the aid of the generation and transmission models several practical strategies are pre-selected,

and in the third stage, using the financial model, the financial effects of the pre-selected strategies are further investigated. The financial requirements are calculated in conjunction with the revenue and expenditure account and the balance sheet. The problem arising with classical methods of investment calculation, namely that on the one hand the expansion strategy depends on the financial requirements whilst on the other hand the financial requirements can only be determined after the formulation of the expansion strategy, prevents the simultaneous determination of the optimum expansion strategy. The optimum expansion strategy of the problem can be determined by an iterative process between the different components of the modelling system. The experience and judgment of the planning engineers will provide, in many cases, the links between the various models.

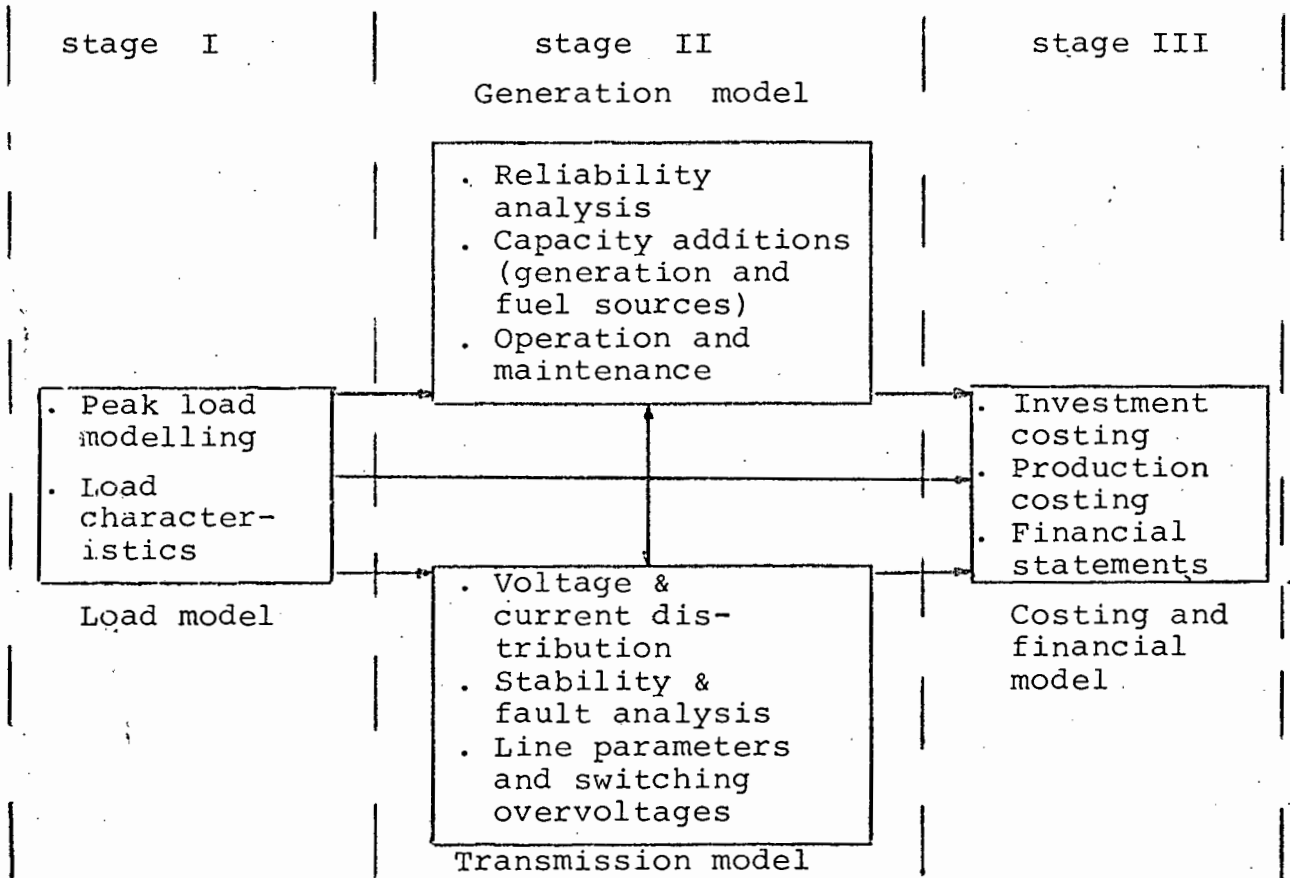


Figure 4.1: Schematic presentation of the components of the modelling system.

The various computer programs of the modelling system can

be used separately to solve specific problems or in combination with any of the other programs as required by a given problem. The sub-models and the computer programs, which were developed for expansion planning in the Electricity Supply Commission, are discussed below:

Load Model:

Load forecasting for planning requires the specification of peak demand and total energy for the years ahead. Generation planning also requires models of the hour-by-hour distribution pattern of the demand, while transmission planning requires the assignment of components of demand to various locations. Peak demand is commonly forecasted by multiple regression of historical load and correlation of the trends of the various consumer sectors such as mining, industry, etc. Demand patterns and characteristics are obtained by analysis of historical load distributions.

The analysis of future demand is carried out with the aid of a computer program, by trend extrapolation of historical loads. Various equations for the trend line and various ways of grouping the data of the historical years were used to derive an average trend line for the future load. However, because of the changing pattern of usage of electricity, the simple extrapolation of past growth is not sufficient and therefore this program is no longer used.

At present, in Escom, forecasting of peak loads for future years is not prepared with the aid of computer programs. Every year a forecast for the following twelve years is carried out. This forecast involves some extrapolation of past trends but relies heavily on the notifications by existing and prospective large consumers, of future load increases associated with specific future developments. In general it can be stated that the twelve year forecast relating to industrial, mining and traction sales is very largely determined by the present knowledge of expected specific developments in the near-term future. Every few

years a longer term forecast is also carried out in terms of a quantitative relationship between the use of electricity and the growth of the national economy.

The load patterns of the individual distribution undertakings and of the power system as a whole are analysed with the aid of a computer program. In the program mathematical techniques are used to analyse the historical load data for a single distribution undertaking in order to obtain the seasonal factors and standard deviation of the load distribution. These same statistics are calculated for any combination of distribution undertakings by summing up the individual loads for each hour in order to obtain the total coincident daily peaks and the period average daily peak, and the period standard deviations are developed together with an average load curve for each historical load period.

#### Generation model:

Generation expansion studies are carried out to examine various combinations of available power generation sources in order to arrive at an economic solution in which the projected load requirements are met and the system reliability criteria are satisfied.

Two major calculations are used for selecting the optimum size and mix of generating units. The first is the reserve requirement calculation, using the loss of load probability method, and the second is a linear programming optimisation model which is used to determine the installation schedule of new sets and the production scheduling of all generating plants.

For the calculation of reserve requirements two computer programs are used: the probability simulation model for generation reserve analysis and the loss of load probability model. A pre-requisite to the calculation of generation reserve requirements is the preparation of an adequate representation of the system load during the study period. In the first program a typical load distribution for every

month is represented by an average weekly load duration curve which includes the distribution of the load for any hour of the week, while in the second program only the daily peak demands are used to determine the daily loss of load probability. Both programs use probability analysis to calculate the ability of the generation system to supply the demand in the presence of forced outages.

Once the system reserve requirements are determined by probability study, the optimum size and mix of generating units in the proper location is determined by using the linear programming optimisation model. A list of possible generation additions is prepared together with the technical and cost parameters of the construction and operation of all power stations and fuel resources. The determination of the installation schedule of new sets is done in such a way that the present value of the total capital costs of new plants and operating costs of new and existing plants will be minimised.

After the generation unit selection is completed, it is necessary to schedule the maintenance of the various generation units. Here again the two probability models may be used. These programs compute the maintenance requirements while attempting to keep the yearly loss of load probability as low as possible. At the same time the reliability calculations are repeated for the proposed expanded system.

Once the expansion plan and the maintenance plan have been defined, a detailed economic production plan may be derived by again using the linear programming optimisation model. For these runs the system can be represented in detail with fuel sources and the power stations handled separately. Fuel transport channels can be postulated between the fuel sources and the power stations that they supply. These runs will reveal the bottlenecks due to fuel source capacity limits and power station availability.

#### Transmission Model:

Following the evaluation of different generation expansion

strategies it is necessary to consider the resulting changes in the system transmission network. This is done by proposing alternative routes and voltage levels for the added circuits. These alternatives should be checked for their economic and technical parameters. Significant progress has been made in the use of linear programming techniques for transmission planning. However, there is no tested optimization method that enables the determination of the optimum system with allowance being made for the various aspects of load flow and line outages at the different voltage levels.

Usually, power system planners specify the design and the operating conditions to be investigated, and the computer is then used to predict the performance of the engineer's choices. By way of a trial and error method it is possible to find strategies that approximate most closely to the optimum. The main power system analysis programs are load flow, fault analysis and transient stability. The load flow program is used to calculate the voltages at the busbars in the network, the current flowing in the transmission lines and the losses in the system. Once a satisfactory network configuration has been determined from load flow considerations, the behaviour under fault conditions must be examined. If the fault currents are too high, it may be necessary to redesign the network. If the fault occurs near a generator busbar, the power that flows out of the generator into the network will drop suddenly. However, as the response of the turbine which drives the generator is not so fast, power will still continue to be fed into the turbo-generator and the speed of the turbo-generator will exceed that of other generators in the system. The transient stability program is used to simulate one to ten seconds of elapsed time after a major disturbance is imposed upon the network. It calculates accelerating powers and changes in the power angle for the synchronous machines and thus determines the stability of the whole system. In some cases where it is impossible for circuit breakers to operate quickly enough to maintain stable operation, a change in the network design will be necessary, and perhaps also a change in the turbo-generator characteristics

or control equipment.

After the planning engineers have calculated the voltages and current distribution for the steady-state and fault conditions, they can use the single and three phase traveling wave programs to calculate the overvoltage conditions in the network due to switch and lightning surges. The results of these studies assist the planners in refining the insulation levels at the terminals of the transmission plant. The power frequency and the high frequency parameters of the transmission lines, which need to be used in the application of the various power system programs, can be calculated with the aid of the line parameter program.

All of the power system analysis programs have been developed in such a way that they use a common power system data base. This data base enables the planning engineers to store and maintain their power system data and perform the necessary calculations either directly via computer terminal, or indirectly, using the normal computer batch processing facilities.

#### Costing and financial model:

Expansion studies made for generation and transmission result in a number of specific plans for the rating and timing of major system additions. To complete the planning cycle it is now necessary to provide the total sum of the costs involved in a given expansion pattern and to assess the potential effects on the financial requirements of the utility. Three computer programs are used to simulate possible futures of the utility in total financial terms: the investment costs program, the production costs program, and the financial simulation program.

In the investment costs program a typical pattern of expenditure over the construction period is given together with other economic parameters such as escalation rates and interest rates. The total capital requirements for any period in the future are calculated together with the present

worth of the expenditure. In the production costs program the costs of operation and maintenance of the power system, which include fuel and manpower costs and the costs of materials, can be calculated for any future time period. Both programs allow the planners to evaluate the effect of various expansion and production plans and the effect of changes in economic factors, such as escalation and interest rates, on the total financial requirements of the utility.

The financial simulation program is used to calculate annual balance sheets, revenue and expenditure accounts and other financial statistics such as the total capital requirements needed to finance the expansion of the system, and what proportion of these requirements should be raised internally through revenue or externally by obtaining new loans.

Summary:

This review of the modelling system has dealt with the bulk power supply system consisting of the generating plant and the main transmission lines. The computer programs which are included in the modelling system are summarised in table 4.1.

sub-model	computer program
1. load model	1.1 trend extrapolation of historical data 1.2 load pattern analysis
2. generation model	2.1 linear programming optimisation model for generation planning 2.2 probability simulation model for generation reserve analysis 2.3 loss of load probability model
3. trans- mission model	3.1 load flow study 3.2 fault analysis 3.3 stability study 3.4 travelling waves 3.5 transmission line parameters 3.6 power system data base
4. financial model	4.1 investment costs program 4.2 production costs program 4.3 financial simulation program

Table 4.1: Computer programs in the modelling system.

The modelling system described here forms a framework for the discussion of the principles of planning in the South African electricity supply system. The formulation of the various computer programs which are used in load forecasting, generation planning, transmission planning and financial analysis are described in the following four chapters.

CHAPTER 5

THE PREDICTION OF FUTURE DEMAND

5.1 FORECASTING OF THE ELECTRICITY DEMAND

The electric utility industry is one that requires large capital investments for its installations, and these require a longer time to construct as compared with other industries of different categories. This means that the plans for the most economical expansion of the generation and transmission plants must be drawn up with considerations for the long-term future in mind. The estimates of future demand for electricity will to a large extent determine the timing and capacity of power plant additions.

For system planning purposes, the estimates of future demand for electricity must include estimates of the peak demands, of the total electrical energies and of the time characteristics of the load<sup>(31)</sup>. The forecast of the peak demands will usually influence the determination of the capacity of the generating plant additions. The estimates of the total energies and the load characteristics will influence the determination of the type of plant additions and the fuel requirements. Estimates of load demands for sections of the system, in conjunction with proposals for the generating plant additions, will determine the requirements for the expansion of the transmission system.

The prediction of peak demands and total energies is usually made by the application of some selected techniques which improve the accuracy and comprehensiveness of the forecasts. These techniques usually require some form of extrapolation, correlation and market research<sup>(14,32,33)</sup>. In extrapolation analysis, the procedure is to fit a suitable time function, called a trend curve, to past values of electricity demand and to make the forecast by extrapolating this trend curve forward to the desired time of the forecast. The consistency

of growth of demand over the years has led to the assumption, in many cases, that the regular trend will continue into the future. The choice of the suitable trend function is made with the aid of statistical tests which help to find the type of function that best describes the past development. When it is necessary to consider the changing patterns of energy use, the choice of suitable trend functions can be made by using correlation techniques which are in accordance with the long-term development of the energy demand. The historic demands are correlated with suitable indicators for the whole economy or sections of it, and from the expected changes in these the changes in the electricity demand are estimated<sup>(34)</sup>. As energy forecasts are concerned with the future it is essential that the load forecasting process will include a market research. This makes it possible to estimate the changing patterns of the electricity consumption of the individual consumer sectors.

In some electrical utilities, the various forecasting techniques are applied in order to estimate the peak demands directly, whereas in others the total annual energy demands are first estimated and these are converted to annual peak demands by multiplication by the annual load factor<sup>(35)</sup>. Both approaches seem to contain the same amount of accuracy. Although energy can be forecasted with greater accuracy than demand, as it is less sensitive to variation in the weather and to other seasonal factors, the annual load factor, which is necessary to convert energy to peak demand, is just as difficult to forecast as the annual peak demand.

In practice, the figures finally accepted for the forecasted peak and energy demands, will be an amalgamation of several estimates. For instance, in Escom, estimates of the total energy demands and load factors of individual distribution undertakings are obtained by the extrapolation of the trends of past growth and the correlation of these trends with specific known developments of large consumers. The estimates of the annual peak demands of these undertakings are obtained

by multiplying the forecasted annual energy demands by the annual load factors. The integrated maximum demand of Escom is estimated by applying a diversity factor to the sum of the maximum demands of each undertaking.

In general terms, Escom utilises three main forecasts: the long-term forecast of electrical energy demands, the medium-term estimates of the total units and the annual peak demands, and the short-term detailed estimates of the monthly characteristics of the loads. At present the long- and medium-term forecasts are made in Escom without the use of digital computers.

The long-term forecast of the demand for electricity is usually prepared for periods of twenty to thirty years. These forecasts are used to determine a long-term strategy for the expansion of the generation and transmission plants and for the utilisation of the country's natural resources. The estimates of the long-term demand for electricity are made by the quantitative analysis of the relationship between the demand for the total energy and the growth of the country's economy, while taking into account the progressive replacement of other energy sources by electricity. This is discussed in section 5.2.

The medium-term estimates of the total units and the annual peak demands are prepared for the purpose of developing a programme for plant installation and for evaluating the capital requirements. This forecast is extended over a period of twelve years. For each of Escom's distribution undertakings, this forecast includes estimates of the load factors and the units to be sold to various consumer categories, which include bulk supplies to municipalities and to neighbouring territories and direct supplies to mining, industries, traction and domestic and street lighting. These estimates involve some extrapolation of past trends but they rely heavily on the notification, by existing and prospective large consumers, of future load increases associated with specific developments. The annual peak demand of the integrated system is obtained

by the summation of the individual peak demands and the application of a diversity factor.

The short-term forecasts include estimates of the monthly peak demands and the total units sold to consumers in each of the distribution undertakings. For operating scheduling purposes these forecasts also include the averages of week-day peaks, the averages of week-night minimums and the averages of the week-end minimum and maximum demands.

The analysis of future demands is carried out by trend extrapolation of historical loads. Various mathematical functions have been used, in the computer program discussed in section 5.3, to represent the trend growth of the electricity demands. This program has been used by Joubert<sup>(36)</sup> to study the growth trend in the demand for electricity in South Africa. Eleven different functions, which are included in the program, were used by Joubert to find the growth trend of the electricity consumption in South Africa. A weighted average of all the various forecasts was calculated according to:

$$W = \sum (y \cdot p^2) / \sum p^2$$

where W is the annual electricity consumption weighted average of the various methods, y is the number of GWh forecast by each one of the methods and p is the inverse of the standard error for each of the methods. The actual values for electricity consumption in South Africa for the period 1950 - 1970 and the forecast values up to the year 2000 are shown in figure 5.1. However, because of the changing pattern of usage of electricity it is unlikely that the pattern of growth in the past will automatically be the same as the pattern of growth in the future. This is the main reason that this program is no longer used in Escom for the forecasting of future demands. The contribution of the program has been towards the understanding of the changing characteristics of the historical loads.

The study of the load characteristics by the detailed examination of the shapes of the various daily and seasonal load diagrams is an essential part of the load forecasting process.

From this study the forecaster can obtain a comprehensive picture of the loading environment which could not otherwise be derived from the normal demand and energy statistics. With the aid of a computer program system planners can analyse the load characteristics of the South African system. This program enables the system planners to obtain, for various parts of the country, load diagrams, load period peaks, averages, standard deviations and seasonal factors from

GWh/year

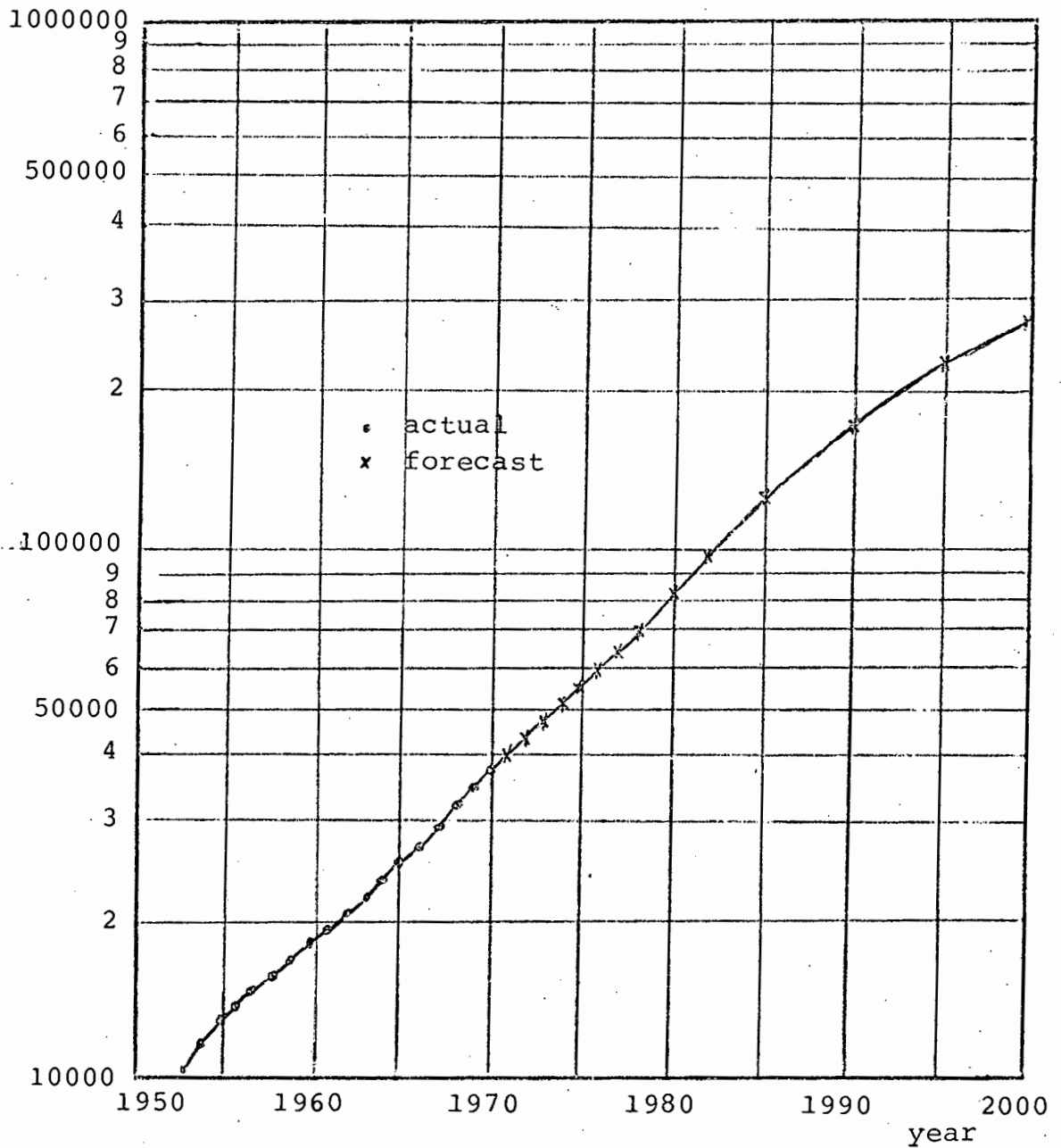


Figure 5.1: Growth of the electricity consumption in South Africa (Joubert<sup>(36)</sup>).

historical load data. The computer system consists of three main parts: the hourly load data collection and data manipulation, statistical reports, and load duration plots.

The system contains the historical hourly loads for each of Escom's distribution undertakings and the total hourly loads of the whole system. It also includes the generated and sent-out hourly loads from the generating plants, and the loads transferred from one undertaking to another. It is possible to manipulate the data in order to obtain any combination or fraction of the data for any required period. The statistical reports cover maximum demand curves for any period and any combination of distribution undertakings. Of specific importance are the weekly load duration curves for various seasons and the distribution of the weekly maximum demands over the year, which are often required in generation expansion, operation and maintenance studies.

## 5.2 MODEL OF THE ELECTRICITY AND ECONOMIC GROWTH RELATIONSHIP

The necessity exists for the careful analysis of the long-term prediction of power requirements owing to the important position that the power sector holds within the framework of the national economy. An adequate supply of electric power is one of the essential conditions for economic advancement. Further, because of the recent fuel price escalations, electricity has also become a factor of considerable strategic and political relevance. Since decisions concerning the type of new power plant to be built in the near future will affect the choice of later projects and since the capital expenditure is generally spread over a comparatively long period, the knowledge of the long-term future situation in the electricity market can have an important bearing on the policy of selecting future plant expansion patterns.

The growth of the demand for electricity is determined by such diverse factors as population growth, increase in the real purchasing power of individual consumers, development of new industries, expansion of existing industries and markets,

replacement of other energy forms by electricity and so on. Since the required information relating to the specific long-term future development is not available, the long-term forecast of future electricity demand is best handled by the analysis of the relationship between the demand for energy and the economic growth and the determination of the contribution of the electricity component to the total demand for energy. The gross national product, which is generally estimated for a long period into the future, can be taken to be the representative value for the economic development. However, such a global quantity has definite shortcomings. The economic growth is associated with considerable changes in the structure of its many components, and while some branches expand more than others, other branches are on the decline. Because of the difference in the relative consumption of electricity in the various sectors of the economy such changes in the structure of the economy can affect the growth in demand for electricity considerably.

The demand for energy can be measured at different levels. It may be measured for the primary sources of energy as found in nature, such as hard coal, crude oil, etc., or for secondary sources of energy such as coke or electricity which are derived in one or more conversion processes from primary sources. The demand for energy may also be measured at the stage of the net energy used by the final consuming sectors or as useful energy which includes only that part of the net energy supplied to the end user which finds its way usefully into the final product. The net energy and the useful energy thus comprise both primary and secondary sources in the proportions required by the final consuming sectors.

It seems, at first sight, that the electricity-economic growth model should be developed at the useful energy level, since the demand for power, heat, light and other energy forms originates from the economic activities of the consumers themselves. However, in many countries the analysis of the relationships between useful energy and economic growth has

often not advanced beyond rough estimates and approximate calculations. The main reason for this is that useful energy is produced almost entirely in the consumer's apparatus whereas the available historical statistics are generally extended only to the source of energy from which the consumer derives the useful energy.

At the stage of net energy demand there is still a close relationship with the economic activities of the final consumers, and sufficient historical data is available for a proper analysis of the net energy and economic growth relationship. For a known efficiency of transformation from primary energy sources to secondary sources and for a given structure of energy consumption, it is possible to calculate, with reasonable accuracy, the demand for primary energy sources from the net energy demand. Because of the continuous changes in the efficiencies of conversion in the consumer apparatus, which are due partly to technical progress and partly to changes in the structure of the final energy demand, it is only possible to calculate some rough estimates for the useful energy demand from the net demand for energy by the final consumers.

In South Africa, two different methods have been used for the analysis of the relationship between energy consumption and the national economic activities. Kotze<sup>(5)</sup> developed a mathematical model of the correlation between useful energy consumption and the economic activities of each of the major energy consumers (household, industry, mining and transport) while the Stoffberg model<sup>(6,7)</sup> is in terms of the correlation between the demand for net energy and the total gross national product. Kotze assumes in his model that there is a linear relationship between the total demand for useful energy and the economic indicators of each of the consuming sectors whereas in the Stoffberg model the linear relationship exists only if separate economic weights are assigned to the electricity component and the other remaining components of the total demand for net energy.

In the Kotze model, the relationship between the useful energy consumption for each of the major end user sectors and the economic activity within each of those end user sectors is expressed by the following equation:

$$Y = ax_1 + bx_2 + cx_3 + d$$

where Y is the useful energy consumption within an end user sector, the variables  $x_1$ ,  $x_2$ , and  $x_3$  are indicators of the economic activities of the end user sectors and the parameters a, b, c and d are constants which are derived from the regression analysis of historical data.

Different economic indicators have been used for the various end user sectors. In the case of the household sector one economic indicator, the real private consumption expenditure, has been used for the correlation analysis. For the industrial sector, in order to consider the overall economic growth as well as the manufacturing output, two economic indicators, the real gross domestic product (GDP) and the real value of gross manufacturing output, were employed in the correlation analysis. In the mining sector, energy consumption was correlated with a single indicator, the real value of mining production. Three indicators were considered representative of the transport sector; the real gross domestic product, railway ton-kilometres and the total motor vehicle population.

After establishing the demands for energy of each of the end user sectors it is necessary to estimate the relative contribution of the individual energy components to the total useful energy demand of each sector. In the Kotze model the energy components are classified into seven groups: electricity, coal, oil, coal-gas, other gas, coke and gas-coke. The relative contribution of each of the individual energy components was established by extrapolation of historical patterns into the future. In some cases, departures from the historical trends were made and the market shares of the individual energy components were rationalised from expected future developments.

The total demand for useful energy for the years 1973, 1980

and 2000, and the contribution of the electricity sector to the total demand, as given by Kotze<sup>(5)</sup>, are summarised in table 5.1. It can be seen that the useful energy contribution of the electricity component is expected to rise from 31,3 per cent in 1973 to 35,1 per cent in 1980 and to 46,0 per cent in the year 2000.

year	total useful energy consumption (10 <sup>6</sup> MJ)	contribution of the electricity component to the total useful energy(per cent of total)				
		household	mining	transport	industry	total
1973	512 389	41,7	88,1	11,4	22,7	31,3
1980	729 678	46,6	90,4	14,6	28,4	35,1
2000	1 822 102	60,8	92,0	16,9	40,9	46,0

Table 5.1: Estimates of useful energy consumption in South Africa and the contribution of electricity to the total demand (Kotze<sup>(5)</sup>).

Another model of the energy and economic growth relationship has been developed by Stoffberg<sup>(7)</sup>. Stoffberg used the net energy demand, which is the demand by the final consuming sectors for primary and secondary sources of energy, in the study of the energy-economic growth relationship. The electricity component of the net energy can be measured at different levels: as it is generated, as it is sent out to the transmission system, or as it is sold to the consumers. In South African conditions the ratio of the units sold to the units set out is 0,912. Stoffberg used the number of units sent out as the electricity component of the net energy.

Analysis of historical data has shown that the relationship between the percentage change in energy use and the corresponding percentage change in economic output has remained non-linear. Stoffberg has shown that there is a stable linear relationship between the total economy and the net energy input if the energy is measured as "the electricity equivalent of net energy". If separate economic weights are assigned to the electricity components and the remaining components of

the net energy, the energy-economic growth relationship can be represented by a linear equation in the form:

$$Z = a.x + b.y$$

where Z is the real gross domestic product for a given year measured in the national currency at fixed prices, x is the number of kWh of electricity included in the total national net energy input for the year concerned, y is the corresponding energy content in kWh of the other components of total net energy and a and b are the different economic weights which are attached to the two defined parts of the total net energy. The ratio b/a is the electricity equivalent of one unit of the other net energy input.

The parameters a and b, in the case of South Africa, have been determined by the regression analysis of past energy inputs and past economic achievements and the following equation has been obtained:

$$z = 0,080315.x + 0,021427.y$$

where z is measured in terms of the real gross domestic product at 1963 prices. The above equation can be expressed as

$$x = \frac{z}{0,05889 + \frac{2,1427}{s}}$$

where z and x have the same meaning as already defined and s is the electricity component of the net energy input as a percentage of the total net energy input for the year. This equation enables the national total kWh of electricity sent out (x) to be estimated for any year from the knowledge of the real gross domestic product for the year concerned in rands at 1963 prices (z) and the electricity component of the net energy input as a percentage of the total energy input for the year (s). For the regression analysis of historical data, of the growth pattern for the economy and the electricity percentage of the total net energy, Stoffberg implied in his assumptions that the future growth of the economy will be at the same average exponential growth rate as in the past, and the electricity percentage growth will follow a saturation curve which will eventually approach a saturation level of 75 per cent of the total net energy input. The values for

the contribution of the electricity component to the total net energy input and the estimated number of units of electricity sent out for the years 1973, 1980 and 2000 are summarised in table 5.2. The trend shown here, that electricity is progressively replacing other energy forms in the case of South Africa, is similar to the one shown previously by Kotze. However, before comparisons can be made between the results of Stoffberg and those of Kotze, it is necessary to convert both results into common units of the electricity component of the net energy input which is taken to be the number of units delivered to the consumers. The conversion ratio from units sent out to units sold is given in reference 7 as 0,912, and the conversion factors from useful energy to

year	electricity units sent out kWh.10 <sup>9</sup>	electricity units sent out as percentage of total net energy
1973	60,70	18,04
1980	99,10	24,38
2000	358,67	44,59

Table 5.2: Estimates of the units of electricity sent out as a percentage of the total net energy. (Stoffberg<sup>(6)</sup>).

net energy input are given in reference 5. The results of this comparison are summarised in table 5.3. The difference

year	electricity units delivered to consumers kWh.10 <sup>9</sup>		electricity units as percentage of total net energy	
	Kotze	Stoffberg	Kotze	Stoffberg
1973	55,61	55,36	16,86	16,45
1980	88,14	90,38	19,29	22,23
2000	290,95	327,11	27,56	40,67

Table 5.3: Comparison of the results of the Kotze and Stoffberg models.

in the results of the two estimates is mainly attributable to the assumptions made in the two models as the same source of historical data was used in both cases. In comparison, the

average share of the electricity component of the total net energy input in the European Community countries, was 12 per cent in 1973 and is estimated to increase to 15 per cent in 1980 and 40 per cent in the year 2000 (published in the "Outlines for the electricity sector in the community", Commission of the European communities, Brüssels, 27.11.1974).

### 5.3 TREND ANALYSIS OF HISTORICAL DATA

As described earlier, the various forecasting methods can broadly be classified into a study of historical load data and a study of the potential development of the markets. The fitting of curves to the historical load data and the extrapolation of the trends is the basic part of the computer model described here. Although straightforward extrapolation without a study of the potential changes in the future patterns can be misleading, it provides a valuable tool for the understanding of the particular characteristics of the local electricity demands.

The computer model described here enables the analysis of growth trends of annual peak demands and total energies by the fitting of mathematical functions to historical data and the extrapolation of these trends into the future.

In order to establish which particular function best represented the trend it was necessary to fit different mathematical functions to the data, and to use different periods of grouping of the data of historic years. A computer program was developed for fitting any of the main functions that are generally used in forecasting. The least squares technique has been chosen as the method of fitting and the standard errors method has been used to establish which particular function best represents the historical trends.

The mathematical functions which are used in the programs have the following groups of trend curves:

a) Polynomial functions. The general equation for the

polynomial of the (n - 1)th order is:

$$y = a_1 + a_2 \cdot t + a_3 \cdot t^2 + \dots + a_n \cdot t^{n-1}$$

where y is the dependent variable (electricity loads), a<sub>1</sub>, a<sub>2</sub> ... a<sub>n</sub> are constants and t is the independent variable (time). Linear and parabolic functions have been chosen to represent this group of trend curves.

Fitting a straight line to a set of points by the method of least squares results in the following equations:

$$y = a + b \cdot t$$

$$\begin{bmatrix} m & \Sigma t \\ \Sigma t & \Sigma t^2 \end{bmatrix} \cdot \begin{bmatrix} a \\ b \end{bmatrix} = \begin{bmatrix} \Sigma Y \\ \Sigma Y \cdot t \end{bmatrix}$$

and for the parabolic function:

$$y = a + b \cdot t + c \cdot t^2$$

$$\begin{bmatrix} m & \Sigma t & \Sigma t^2 \\ \Sigma t & \Sigma t^2 & \Sigma t^3 \\ \Sigma t^2 & \Sigma t^3 & \Sigma t^4 \end{bmatrix} \cdot \begin{bmatrix} a \\ b \\ c \end{bmatrix} = \begin{bmatrix} \Sigma Y \\ \Sigma Y \cdot t \\ \Sigma Y \cdot t^2 \end{bmatrix}$$

b) Exponential functions. The general equation for exponentials is of the form:

$$y = \exp (a_1 + a_2 \cdot t + \dots + a_n t^{n-1})$$

which can also be expressed as a polynomial by taking the logarithm. Three functions, the simple exponential, the logarithmic parabola, and the logarithmic-linear function, have been chosen to represent this group of trend curves.

The simple exponential is given by:

$$y = e^{a + bt}$$

which is fitted in the same way as the linear polynomial after taking the logarithm:

$$\ln (y) = a + bt$$

The logarithmic parabola is given by:

$$y = e^{a + bt + ct^2}$$

which is, again, fitted in a manner similar to the parabolic polynomial after taking the logarithm:

$$\ln (y) = a + bt + ct^2.$$

The logarithmic-linear function is given by:

$$y = a.t^b$$

where, according to the value of the parameter  $b$ , the trend of  $y$  may increase or decrease.

The logarithm:

$$\ln (y) = \ln (a) + b.\ln (t)$$

is fitted again in a similar manner by means of the method of least squares.

- c) Saturation function. The general equation for the saturation function is of the form

$$y = (a + b.c^t)^d$$

where the numeric value for  $c$  is less than one, and accordingly, the asymptotic value of  $y$  is  $a^d$ .

Three functions, the simple saturation function, the Gompertz or S function and the logistic function, have been chosen to represent this group of trend lines. The simple saturation curve is given by:

$$y = a - b.c^t$$

which is fitted with the least squares method, after taking the logarithm of the derivative of this function:

$$\ln (y') = \ln (-b.\ln(c)) + t.\ln (c)$$

The Gompertz function is given by:

$$y = 10^{a-b.c^t}$$

Before the fitting is performed the Gompertz curve is represented by:

$$\log_{10} (y) = a - b.c^t$$

$$\log_{10} (e.y'/y) = -b.c^t.\ln (c)$$

$$\ln (\log_{10} (e.y'/y)) = \ln (-b.\ln (c)) + t.\ln (c)$$

The logistic function is given by

$$y = \frac{1}{a + b.c^t}$$

The curve fitting is done after taking the logarithm of the derivative of  $1/y$ :

$$y'/y^2 = -b.c^t.\ln(c)$$

$$\ln (y'/y^2) = \ln (-b.\ln(c)) + t.\ln (c).$$

The various functions described above form only the working basis for the estimation of future loads. The types of functions and the results of projection must be checked for statistical reliability. For this reason it is advisable to always use a number of functions from which a choice can be made. If the results of statistical tests are satisfactory they can be regarded only as a formal check. Projection of future loads needs supplementation and confirmation by means of the available technical and economic information of the future requirement for electricity.

CHAPTER 6

GENERATION EXPANSION STUDIES

6.1 POWER SYSTEM GENERATION PLANNING

The power system in South Africa is composed of many generating stations which are linked together by a transmission grid system that also provides the means of taking power to the distributors and thus to the consumers. All over the world there is a relatively high growth in the demand for electricity. In South Africa the average compound rate of growth in the consumption of electricity in recent years was in the range of 8 - 10 per cent per annum and it is expected that this rate of growth will continue for the following ten years. This means that the demand for electricity is doubled every decade. In order to meet the increasing demand for electricity in the various regions of the country, it is necessary to plan continuous extensions to the national power system. These must provide the additional generating capacity and when necessary, must include additional transmission lines and ancillary equipment.

The general purpose of the power system generation planning is to provide a pattern of expansion which will ensure that sufficient plant is available to supply the forecast load with an adequate level of reliability. This pattern of expansion must be the lowest cost alternative of those available. The task of achieving this broad aim is a most complex one because the "lead-time", required between making the decision and the commissioning of the plant, necessitates that the plans be formulated some 5 - 8 years in advance of plant installation. Thus considerable uncertainty is involved in arriving at values for the estimates of the load, plant performance and costs, as all processes of estimating suffer a marked decrease in accuracy the further ahead of the event being planned the estimates are made.

Since all electricity supply systems are highly capital

intensive, it is important to ensure that the correct type of plant is chosen for installation and that, as far as can be ascertained, it constitutes the minimum total cost solution. The South African electricity supply authorities, similar to the electricity authorities in many other countries, usually plan on the basis of minimising the present value of the costs of providing the required electrical energy to their consumers. The selection and siting of a particular new generating plant is usually a compromise between economic, technical, political and amenity considerations. The object is to deploy plant of different fuel, capital and running cost characteristics in such a way as to meet the growth of demand for electricity at the minimum present worth of the sum of capital and operating costs for all equipment. (See Figure 6.1).

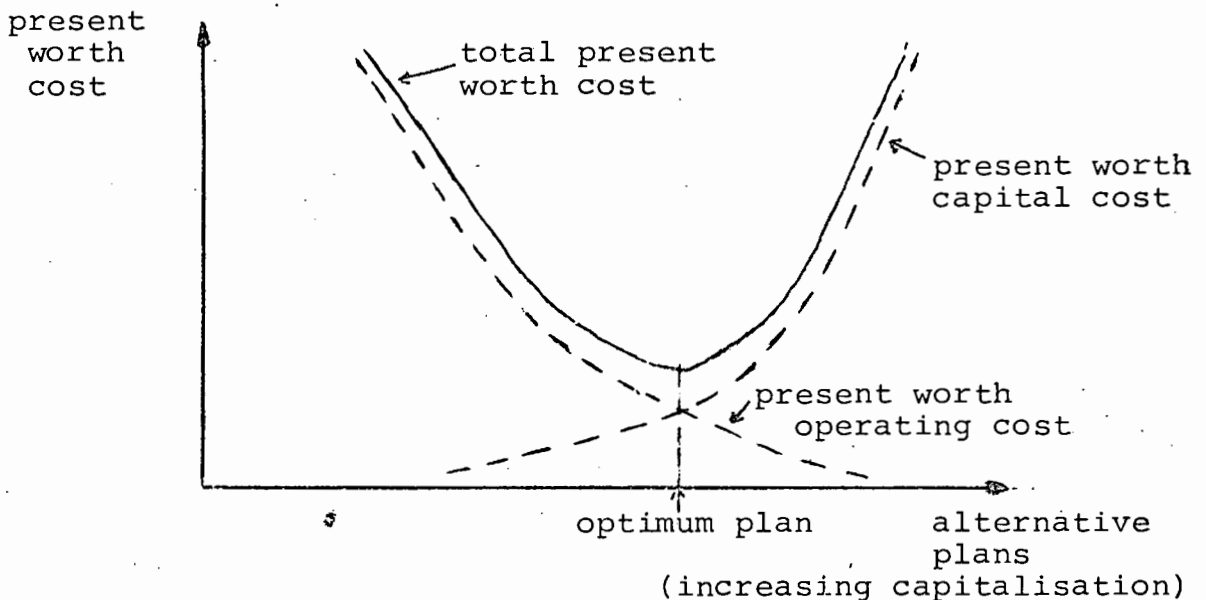


Figure 6.1: Determination of optimum expansion plan.

The pattern of demand for electricity varies continuously and therefore not all of the generating stations will be required to run at all times. In order to determine the total costs it is necessary to provide demand estimates for various months of the year and for various hourly periods in typical days of the year. When the hourly system loads are plotted as a function of time, the resulting curve gives a chronological representation of the generating power requirements of the system. Figure 6.2 shows such a normalised curve for a

typical week in February for the South African system. The area under the curve represents the total amount of energy required to be supplied by the system for the time period

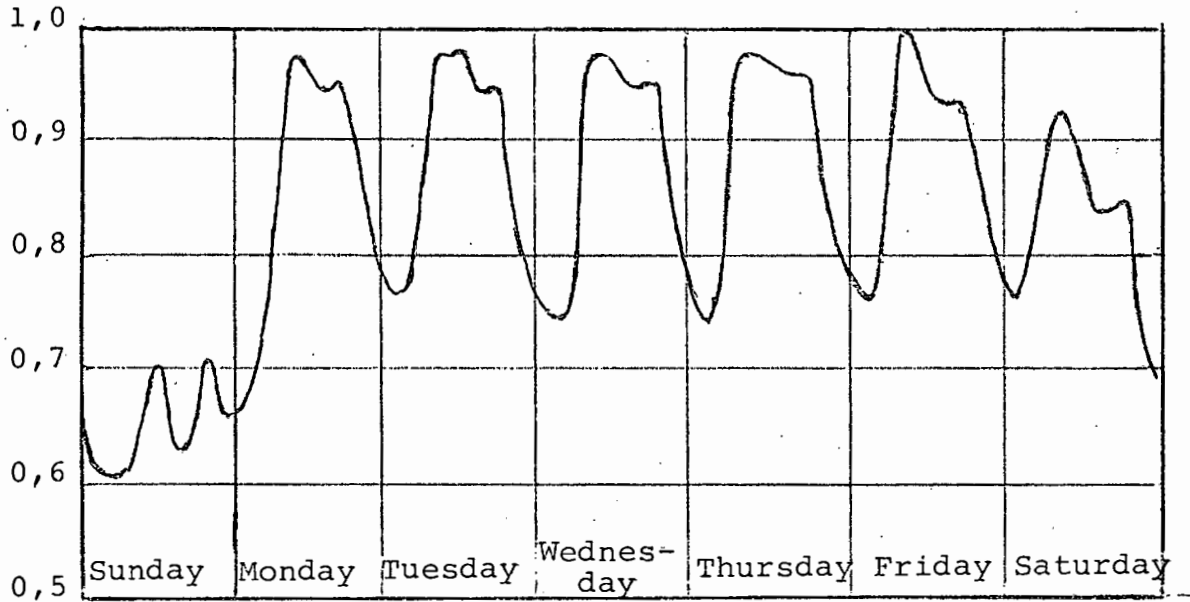


Figure 6.2: Typical hourly load representation of the South African system. (normalised)

being considered. If the same hourly loads are rearranged in decreasing order of magnitude, the resulting curve (figure 6.3) is called a load duration curve. Here too, the area beneath the curve represents the total amount of energy to

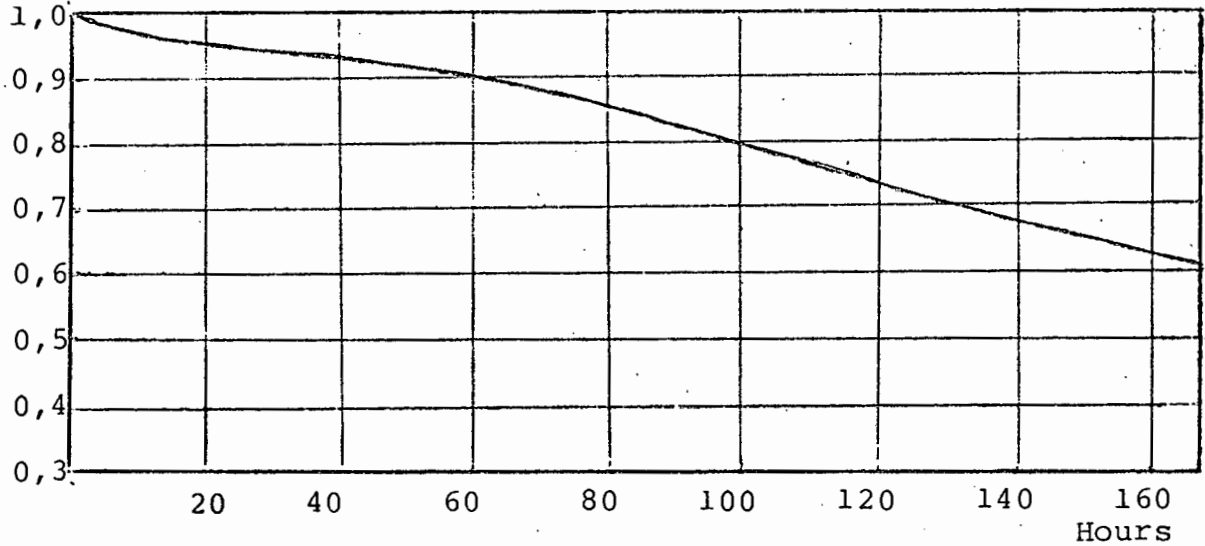


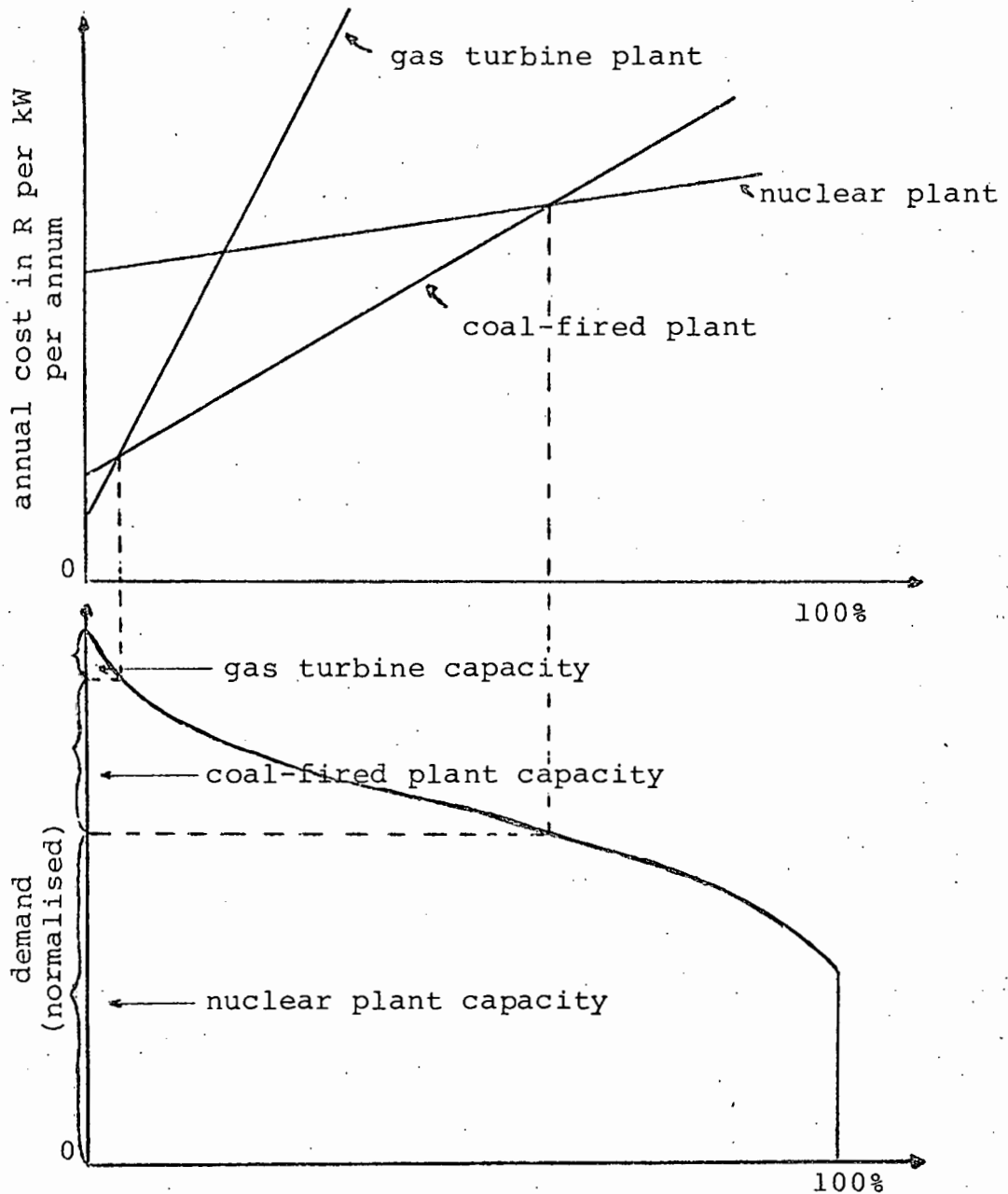
Figure 6.3: Typical weekly load duration curve for the South African system. (normalised)

be supplied for the time period under consideration, but the chronological sequence of the loads has been lost. For the load duration curve, the abscissa represents the number of hours during which the system load equals or exceeds the value of the associated power on the ordinate.

A simple graphical method, which enables the approximate determination of the optimum plant mix and illustrates the inter-relation between the load duration curve, the capital costs and the operating costs, will now be described. (The term "plant mix" may be used to describe the proportions of the different types of generating plant at any point in time. These are usually classified by fuel, i.e. nuclear, oil, coal, gas turbine, hydro or pumped storage).

The total cost for any year of installing and operating an increment of generating plant capacity is the sum of its annual capital charges and the product of its operating cost and its operating time. The operating time is determined by arranging the generator units in ascending order of operating cost (called the "merit order") and loading these successively according to the changing pattern of demand with time. The cost of each plant item can be represented by a straight line where the total annual cost for the increment of generating capacity is  $Y = gt + c$  where  $c$  is the annual capital charges of the increment of capacity,  $g$  is its operating cost per unit of time and  $t$  is its operating time in merit-order. The lines shown in the upper part of figure 6.4 illustrate the above equation for three types of plant: a nuclear plant, where the capital costs are high and the operating costs are low, a coal-fired plant where both the capital and operating costs are medium and a gas turbine with low capital costs but high operating costs. Proceeding in the direction of increasing duration of operation, gas turbine plant is seen to give the lowest total cost until its cost line intersects that of the coal-fired plant. Thereafter, the latter provides the lowest total costs until the nuclear plant line is encountered. This gives a rough measure of "plant mix" for, by referring the intersection points to the load duration curve in the

lower part of figure 6.4, the approximate optimum capacities of the increments of the new plant types can be determined.



Duration of the demand as a percentage of whole year.  
Figure 6.4: Graphical method of determining optimum plant mix.

The different types of generating plant are usually classified by fuel, i.e. nuclear, coal, oil, gas turbine, hydro and pumped storage plant. As shown in table 6.1, the different types of plant are grouped into base plant, intermediate plant and peaking plant. In figure 6.4, the nuclear

plant group	capital cost	operating cost	usual load factors %
base plant	high	low	60 - 90
intermediate plant	medium	medium	10 - 60
peaking plant	low	high	1 - 10

Table 6.1: Grouping of the different types of generating plant.

represents a base plant, the coal-fired unit represents an intermediate plant and the gas turbine represents a peaking plant. However, the simple graphical approach can only provide a general background for the development of the plant expansion plan. The assessment of the detailed comparative economic worth of the proposed generating stations is a dynamic process in which each decision depends on what has gone previously. The optimum plant mix depends on both the inherited and the expected structure of the power system. For example, if the inherited structure is dominated by the high fuel costs, then the present emphasis will be on the saving of fuel costs. Due attention must also be given to the expected non-availability of generating plant, network limitations and the margin of generating plant capacity above the maximum system demand etc.

In South Africa, another important aspect in the determination of the future expansion of the generation system is the dependence on coal as the major fuel source. The capital and operating costs of the collieries, the optimum allocation of the coal to the various utilities, and the cost of transporting the coal to the power stations are important considerations to be taken into account in the expansion planning.

A linear programming (LP) model has been developed to aid in the planning of the optimum expansion of the generation system in South Africa. The model is described in section 6.2. The design of the model is based on that described in a paper by Anderson<sup>(21)</sup> in which the electricity supply investment problem is formulated in cost minimisation form. Anderson pointed out that the investment problem is a statement of the

investor's objective to minimise the sum of the capital and operating costs over some future time period, given the existence of several important constraints. These constraints ensure that the system's instantaneous power demand is satisfied at all times, that no generating unit is allowed to operate above its peak available capacity, that the amount of fuel may be restricted to a maximum level and that the system operates with adequate reliability. In addition to the above constraints the LP model developed here includes further conditions which were required to simulate the South African system. These conditions are concerned mainly with the building of new collieries, the operation of existing and new collieries and the transportation of coal to the power stations. Thus the model of the generation system in South Africa is represented as a combination of generating units, energy sources and fuel transportation channels.

The detailed comparative economic worth of the individual generating units for the plant expansion plan can only be investigated after the basic philosophy of system planning has been defined with respect to planning standards for the security of supply. Following the estimates of the annual maximum system demand, it is necessary to decide on a margin of generating plant capacity that should be planned for over and above the maximum system demand. At the planning stage both the magnitude and the time of occurrence of the maximum system demand are unknown. In figure 6.5 a plot of the weekly peak demands for a typical year in the South African system is presented. The maximum system demand in South Africa may occur at any time in the three winter months of June, July or August. During that time all of the installed capacity will not be available because some of the generating units may be out of service owing to an unexpected breakdown. Planned overhaul is usually done in the low demand seasons of the year. However, in many cases, planned overhaul will also be performed during the period of the annual maximum system demand and this will contribute to the non-availability of the generating plant at the time of maximum system demand. Plant margin

allowances must also be made for errors that are introduced when the basic estimates are made. Estimates of the total plant capacity expected to be in commission can often be wrong. Similarly, the estimates of the maximum system demand and of the total plant capacity installed may also be wrong.

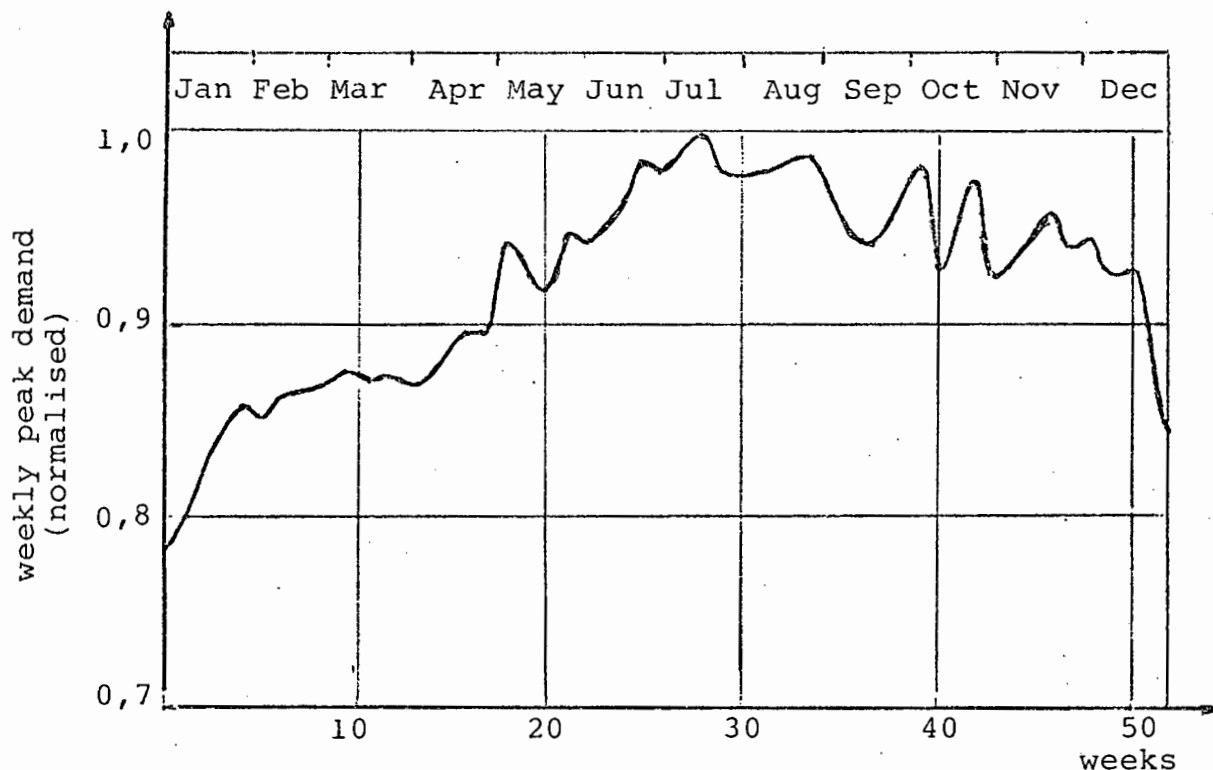


Figure 6.5: Distribution of the weekly peaks for a typical year in the South African system.

There must always be a finite risk of failure to meet the maximum system demand for electricity, unless a system of infinite capacity is envisaged. The greater the capacity of plant the smaller the risk of failure to meet the demand. The standard of risk being planned is often expressed in the form of the number of days in ten years in which at least some consumers can be expected to be disconnected because of shortage of generating plant capacity. Since it is normally possible to shed some load by voltage reduction before resorting to disconnection, the standard is perhaps better expressed by the number of days in ten years when at least some voltage reduction will be necessary.

When considering the overall planning margin it must be

recognised that the variances of the various estimates are unrelated and do not necessarily deviate in one direction at the same time. The normal probability theory can be of assistance in dealing with the determination of the plant margin<sup>(37)</sup>. The formulation of the probability distribution of the non-availability of generating plant is given in section 6.3.

Based on probability mathematics two models have been developed here which are used in the analysis of the reliability of the electricity supply in South Africa.

The basis of the "equivalent load" model, which is described in section 6.4, is the use of probability distributions to describe the system loads and the generating unit forced outage performance, and the combination of these distributions to obtain the mathematical expectation of the energy generated by each unit in the system. With the aid of this model it is possible to quantify the probability of a failure to meet the consumers' power demands during any month in the future. This is determined by comparing the distribution of the available capacity (installed capacity minus the capacity on planned maintenance) with the cumulative probability distribution of the equivalent load (the system load plus the generating capacity on forced outage) for that month. The method of simulation based on probability distributions of the equivalent load was first used by Booth<sup>(18)</sup> for the solution of a variety of problems concerning the optimum operation of the Australian power system. The formulation described by Booth has been used here for solving problems concerning the reliability of the generation system and the optimum schedules for the maintenance of the generating units.

The second model, which is the "loss of load probability" model, is described in section 6.5. The loss of load probability is defined as the quantity which indicates the length of time for which possible combinations of generating plant outages and excessive load requirements will result in the load being bigger than the capacity available to meet it.

In this model the probabilities of not having sufficient available plant capacity to supply the peak demand in every day of the study period is calculated. The probabilities for all the days of a given year are summed up to give a yearly loss of load probability.

In order to determine the absolute standard of the risk of failure to meet the maximum system demand for electricity it is necessary to consider the capital cost of the additional capacity and the costs arising to the consumer because of a shortage of generating plant capacity. As shown in figure 6.6, the greater the capacity of plant the smaller the risk of failure to meet the demand but the larger the capital cost that will be required. By far the most difficult costs to assess are those that arise to the community at large if the standard of electricity supply is changed.

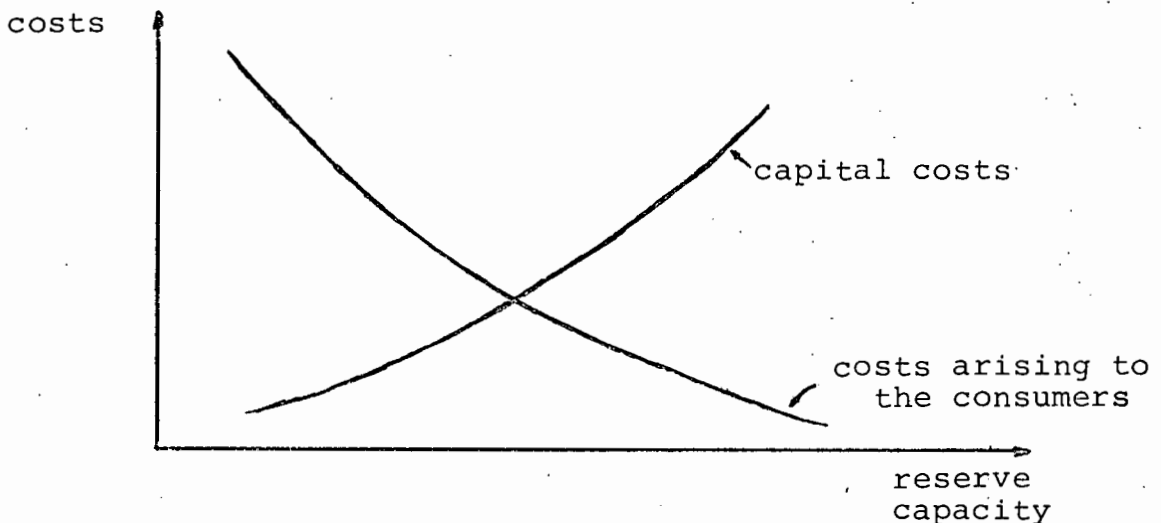


Figure 6.6: The economics of reserve capacity.

In practice the decisions on increasing or decreasing the generating plant planning margin are based on differentials rather than absolutes. For this reason it is necessary to know what standard of reliability of supply has actually been achieved over a reasonable period of time. If this does not appear to be satisfactory then thought must be given to increasing the planning margin.

## 6.2 LINEAR PROGRAMMING MODEL FOR GENERATION EXPANSION ANALYSIS

The electricity generating system exists to meet the demand for electricity. This demand varies in time, fluctuating from hour to hour, and grows over the years. The short-term variations in demand are met by having sufficient capacity in the system to meet the peak demand. In order to meet increases in demand for electricity on a long-term basis, additional power station capacity must be built. There is a choice of the type of station which can be built at any point in time and a choice of the type of fuel that can be used.

The long-range planning of generating facilities in South Africa is becoming an increasingly complex problem. The growing number of different types of generating plants having different economic and operating characteristics substantially complicates the decision as to when, what type and what size of generating units should be installed. A few years ago the planner was faced with the options of only coal-fired plant. However, the completion of the South African national grid, mentioned in previous chapters, made it feasible to install different types of plant in various parts of the country. The commissioning of hydro-electric stations and gas turbine plants and the planned addition of a pumped storage scheme and nuclear plants means that by the early eighties South Africa will have in operation every commercial type of generation.

Until the turn of the century the total installed capacity is expected to rise to more than 60000 MW. A very high percentage of this will still be coal-fired but nuclear, hydro, pumped storage and gas turbine plant is likely to amount to about 40 per cent of the total installed capacity by the end of this period<sup>(8)</sup>.

It is more than a decade since the computer was first applied to generation planning analysis. Computer programs were written to simulate generation expansion plans. With the aid of a simulation program a planner could postulate an expansion

plan or strategy. From the simulation he would obtain an estimate of the costs associated with that strategy, along with other information such as system reliability and plant operating schedule. By postulating many different strategies the planner could obtain a feel for the best plan according to which different types and sizes of units could be installed at various times. As it was impossible to simulate all the feasible expansion strategies, much reliance was placed upon the judgment of the planner to select the most promising alternatives for simulation. This left substantial doubts as to the optimality of the plan finally selected.

One of the questions that has existed in the minds of utility planners since the introduction of the computer simulation programs is why it should be necessary to postulate a plan and then simulate it when the computer could arrive directly at the optimum expansion strategy. The reason that such a computer program was not immediately implemented was that to retain reasonable accuracy the problem turned out to be too large for existing computational techniques and capabilities.

Recently the increase in the capacity and speed of computers and advances in mathematical optimisation techniques have joined to make the formulation and solution of a problem of this nature and size feasible. Specifically, advances in the implementation of linear programming optimisation techniques on computers allow the reasonable solution of problems with a few thousand variables and conditions.

Linear programming (LP) is a mathematical process which seeks to minimise (or maximise) a linear function, called the objective function. Linear programming requires that all relationships between variables and constraints placed upon them be expressed in a linear algebraic form. One of the characteristics of basic linear programming that prevented it from providing a realistic optimum solution is that the answers are generally non-integer. Thus the answer to the number of units of particular plant to be installed would be

a fraction or a mixed number. For example, the results may indicate that 0,452 of a 600 MW coal-fired unit is to be installed. To avoid this type of unacceptable solution, mixed-integer programming is employed. Mixed-integer programming is based upon linear programming, but designated variables are forced to their optimum integer values while still keeping within the problem's constraints. In the solution process a continuous optimum solution is first found using the revised simplex method. Then a technique known as "branch and bound" is used, beginning with the continuous solution to find the optimum solution respecting the integer requirements of specified variables. The integer variables in the generation expansion problem are the number of installations and the size of the generating units and the energy sources. The variables associated with the operating of the plant are continuous since fractional loading of units is meaningful.

The mathematical form of the model presented here is a mixed-integer program which minimises the total discounted system cost over the period studied. This model represents the principal investment decisions that have been taken by the South African electricity supply authorities, namely the choice of plant mix to be built to meet the growing demands for electricity. For each new station there are variables in the model representing:

- a) the capacity of the station,
- b) the use made of the station (operating schedule),
- c) the fuel used by the station,
- d) the capacity of the energy source (colliery), and
- e) the transportation of the fuel from the energy source to the station.

Given data about the capital cost of the capacity, the running cost of the station in generating electricity, and the cost of the fuel used, the total cost of adding any new capacity to the system is evaluated. From among all the possible combinations of plant which could be used, the plant mix is

chosen for which the total cost of meeting the demands made on the system is minimised.

The costs of alternatives are compared in the model on the basis of their present value. The process of determining the present value is known as discounting, from which the term "discounted cash flow" (d.c.f.) is derived. It is obvious that one rand is worth more now than one rand will be worth at some future date. Firstly, there is a risk that one rand in the future may not materialise, secondly, the effect of inflation may make one rand in the future worth less than one rand now and the third reason is that one rand received now could be invested and amount to more than one rand in the future.

The concept of present value considers only the ability of money to earn interest. Thus one rand invested now would amount to  $1 \cdot (1 + d)$  in one year's time, where  $d$  is the annual rate of interest that can be earned. Conversely, the present value of one rand in  $n$  years' time is  $1 \cdot (1 + d)^{-n}$ . With the aid of the present value method one series of annual payments can be compared with any other series of payments. In table 6.2, which assumes an interest rate of 10% per year, the cash flows A and B are identical in arithmetic sum but the present value is quite different. The difference in the present values arises from the difference in the time incidence of the cash flows. Present valuing thus converts all cash amounts to equivalent amounts at a common date.

year	cash flows		present-value factor at 10% per year	present value of cash flows	
	scheme A	scheme B		scheme A	scheme B
1	10	50	0,909	9,1	45,4
2	20	40	0,826	16,5	33,1
3	30	30	0,751	22,5	22,5
4	40	20	0,683	27,3	13,7
5	50	10	0,621	31,0	6,2
total	150	150	-	106,4	120,9

Table 6.2: Present value comparisons.

Often more importance is attached to extra costs in the near

future than to saving in the distant future. This is achieved by the normal process of present valuing at the interest rate payable on capital. However, because of the risk attached to materialisation of distant future savings, it is usually thought that a greater bias is required. The two ways of achieving this bias are by increasing the present-valuing rate above the rate payable on capital and by reducing the study period.

Inflation should also be considered in the comparison of various schemes. Inflation usually benefits high capital and low operating cost schemes. If such a scheme can be justified without inflation, the justification will be even greater with inflation. The effect of inflation will be to increase the present value of costs in  $n$  years by  $(1 + e)^n / (1 + d)^n$  where  $e$  is the rate of inflation and  $d$  is the minimum required return or the annual rate of interest.

A number of considerations were incorporated into the design of the linear programming model described here. These include the following:

- a) Ability to handle the various types of power station such as coal-fired stations, nuclear stations, hydro schemes, pumped storage hydro schemes and gas turbines.
- b) Evaluation of present worth of actual payments.
- c) Inclusion of the capital and production costs of power stations, energy sources and fuel transport channels.
- d) Automatic selection of units for installation from an input shopping list of available types and sizes of units.
- e) The allowance of separate inflation rates for each type of generating plant and for each type of fuel.
- f) Maintenance of specific system reliability.
- g) Performing an economic dispatch to determine the production cost.
- h) Allowance for any combination of power stations and collieries.
- i) Consideration of capacity limits in the transportation

- of the fuel from the energy sources to the power stations.
- j) Ability of one energy source (colliery) to supply more than one power station and one station to be fed by several fuel sources.

The object of the analysis, which is performed with the aid of this model, is to decide, for a given planning period, which power station or individual generating units should be constructed in any specific time within the planning period, and how all existing and new plants should be operated such that the total present worth of capital costs and fixed and variable operating costs becomes a minimum, under the conditions that given system power and energy demand, as well as given operational constraints are satisfied.

If the power capacity of any plant  $i$  in the system is defined by  $X_{iv}$  where  $v$  is the time period of commission, and if the power output of this plant at any time instant  $t$  is given by  $U_i(t)$  where  $0 \leq U_i(t) \leq X_{iv}$  then the operating costs of the plant over the interval  $0$  to  $T$  are given by:

$$\int_{t=0}^{t=T} F_i(t) \cdot U_i(t) \cdot dt \quad (6.1)$$

where  $F_i(t)$  is the discounted operating cost per unit of energy output.

At any instant  $t$ , the generating system is comprised of  $i$  different plants where  $i = 1, 2, \dots, I$ . These plants include those which have been installed prior to the beginning of the planning period as well as those which are installed at discrete intervals between  $0$  and  $T$ . Over the planning period the total discounted capital cost of a new plant  $j$  is given by

$$\int_{t=0}^{t=T} C_j(t) \cdot X_{jv} \cdot Y_{jv} \cdot dt \quad (6.2)$$

where  $C_j(t)$  is the discounted capital cost per unit of capacity of new plant  $j$ , which is payable at time instant  $t$ , and  $Y_{jv}$  is the decision parameter of whether plant  $j$  should

be constructed or not. ( $Y_{jv} = 0$  indicates no.  $Y_{jv} = 1$  indicates yes).

In cost minimisation form the investment problem can be represented by:

$$\text{minimise } F(X, Y, U, G, D, E) \quad (6.3)$$

where the parameters  $X, Y$  and  $U$  are the decision variables ( $X =$  capacity,  $Y =$  installation decision variables and  $U =$  operating levels), the parameter  $G$  represents the data related to a given plant (costs, capacity, availability, lead-time, etc.), the parameter  $D$  represents the demand data (maximum system demand, demand patterns, etc.) and the parameter  $E$  represents the economic data for the study period (interest rates, escalation rates, etc.).

An explanation of the time relation in the model is essential as an aid to understanding the equations. Each year in the study is sub-divided into a number of time periods. A period is defined as the number of weeks during which the electricity demand remains constant on the weekly maximum curve. This latter has been approximated by a histogram as shown in figure 6.7.

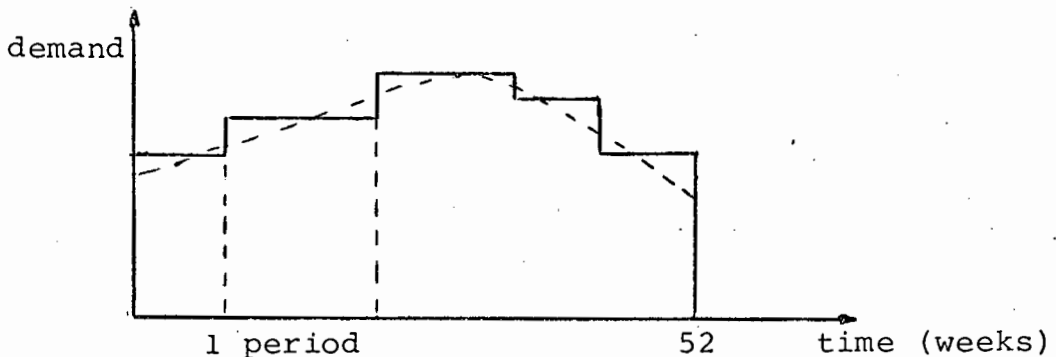


Figure 6.7: A weekly maximum curve

The generation requirements for each time period are related to the corresponding predicted system load by means of load duration curves. Each load duration curve is approximated by a histogram as shown in figure 6.8. The curve is divided into  $p$  time slices (where  $p = 1, 2 \dots P$ ), each of width

$\theta_p$ . A slice is the time interval in which the electricity demand remains constant on the weekly load curve.

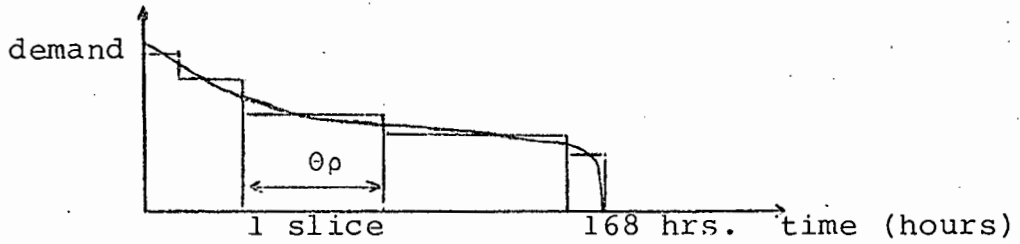


Figure 6.8: A load duration curve.

In linear programming form, the cost minimisation function (objective function), along with the various constraints regarding the system load, unit capacity and operational requirements, specifies the goal of system planning which is to ensure that, in the future, the load will be supplied with adequate reliability and the electrical energy will be provided at a minimum cost.

In generation planning the objective is to minimise the sum of capital and operating costs over some future time period 0 to T. Using the operation cost terms of equation 6.1 and the capital cost terms of equation 6.2, the cost minimisation problem can be expressed by

$$\text{minimise } \int_{t=0}^{t=T} \sum_{i=1}^I F_i(t) \cdot U_i(t) \cdot dt + \int_{t=0}^{t=T} \sum_{j=1}^J C_j(t) \cdot X_{jv} \cdot Y_{jv} \cdot dt \quad (6.4)$$

The cost minimisation function (objective function) in linear programming form can be obtained by the discrete approximation of equation 6.4. The objective function thus becomes:

$$\text{minimise } \sum_{j=1}^J C_j \cdot X_{jv} + \sum_{i=1}^I \sum_{t=1}^T \sum_{p=1}^P F_{itp} \cdot U_{itp} \cdot \theta_p \dots \quad (6.5)$$

The first term expresses the capital cost of future plants and the second expresses the operating costs of all plants whether future or existing, where:

- $C_j$  (R/kW) = Capital cost per unit of capacity of new plant  $j$ .  
 $X_{jv}$  (kW) = Maximum capacity of new plant  $j$  for time period of commissioning  $v$ .  
 $F_{itp}$  (R/kWh) = Discounted operating cost per unit of energy of plant  $i$  at time period  $t$  and time slice  $p$ .  
 $U_{itp}$  (kW) = Power output of plant  $i$ , period  $t$  and time slice  $p$ .  
 $\theta_p$  (hours) = Duration of time slice.  
 and,

- $j$  - new plant number  $j = 1, \dots, J$   
 $i$  - plant number (existing and planned)  $i = 1, \dots, I$   
 $t$  - time period  $t = 1, \dots, T$ .  
 $p$  - time slice  $p = 1, \dots, P$ .  
 $v$  - time period of commissioning.

In addition to the capital and operating cost terms of the generating plant, as expressed in equation 6.5, there is an option in the model to include in the cost minimisation function the capital and operating costs associated with the utilisation of the energy sources and the fuel transport channels. Thus the objective function becomes the minimising of the sum of the capital and operation costs of the power stations, the energy sources and the transport channels.

The variables must satisfy various constraints and equality relationships which define the essential characteristics of the power system. These include the following:

- a) Demand Constraints: This states that the demand for electricity must be met at each instant of time in each year.

$$\sum_{i=1}^I U_{itp} - \sum_{s=1}^S P_{itp} = Q_{tp} \quad \text{for all } t = 1, \dots, T \quad (6.6)$$

$$p = 1, \dots, P$$

- where  $Q_{tp}$  - power demand at period  $t$ , slice  $p$ .  
 $P_{itp}$  - pumping loads for pumped storage schemes  
 $S$  - total number of pumped storage schemes in the system.

The electricity demand  $Q_{tp}$  for the time slice  $p$  within the period  $t$  is calculated in the model by using the three types of curves which represent the load. These curves include the annual maximum demands expressed in megawatts, the weekly maximum curve over one year (normalised), and the weekly load duration curve (normalised) (figure 6.9). The electricity demand in megawatts at any point in time is the product of the values corresponding to these three curves.

$$Q_{tp} = Q_y \cdot (\text{weekly max})_t \cdot (\text{slice of load curve})_p \quad (6.7)$$

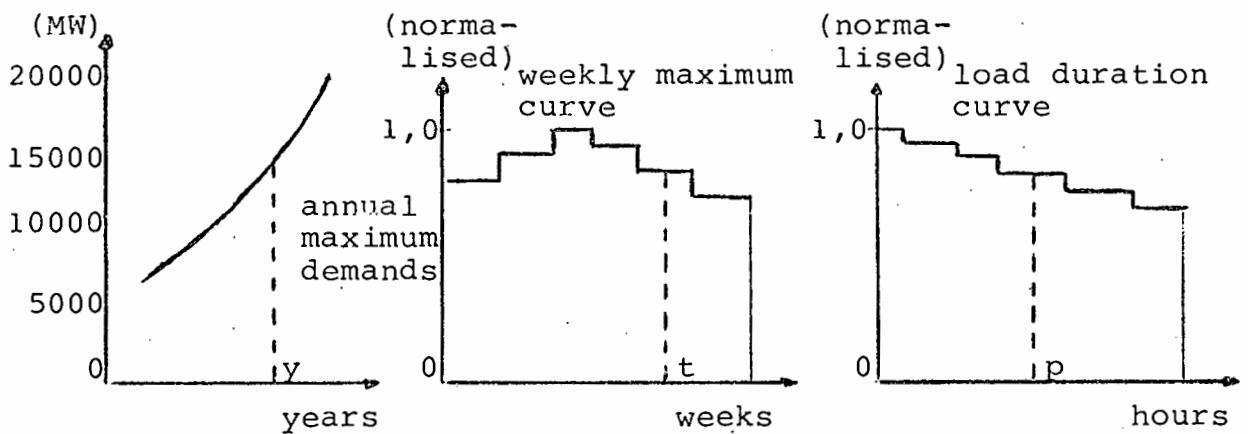


Figure 6.9: Representation of the load.

b) Capacity Constraints: The output of any plant at any time must be less than or equal to the available capacity at that time.

$$U_{itp} \leq a_{it} \cdot X_i \quad \text{for all } i = 1, \dots, I \\ t = 1, \dots, T \\ p = 1, \dots, P \quad (6.8)$$

Where  $a_{it}$  - availability of plant  $i$  in period  $t$ .

c) Inflexibility of Operation: The plant may be meant to operate above some minimum level. The purpose of this is to allow for the inflexibility of some type of plant or to include some limitation of the transmission system.

$$U_{itp} \geq b_{it} \cdot X_i \quad \text{for all } i = 1, \dots, I \\ t = 1, \dots, T \\ p = 1, \dots, P \quad (6.9)$$

Where  $b_{it}$  - minimum capacity of plant  $i$  in period  $t$ .

d) Security of Supply: Sufficient total capacity must be planned to ensure that the peak demand can be met with the desired level of risk. This requirement can be

expressed by stating that total capacity must be greater than or equal to a fixed margin above the expected peak demand.

$$\sum_{i=1}^I X_i \geq Q_t (1 + m) \quad \text{for all } t = 1, \dots, T \quad (6.10)$$

Where  $m$  - reserve capacity

$Q_t$  - maximum demand for period  $t$ .

- e) Energy Balance: The energy output of all stations must meet the demand.

$$\sum_{i=1}^I U_{itp} \cdot \theta_p \geq Q_{tp} \quad \text{for all } t = 1, \dots, T$$

$$p = 1, \dots, P \quad (6.11)$$

- f) Transfer Function of Plant: Energy input to the plant multiplied by the efficiency of the plant is equal to the energy output of the plant plus the energy consumption by the auxiliaries.

i.e.

$$E_{it} \cdot \text{EFF}_i = \sum_{p=1}^P U_{itp} \cdot \theta_p = \text{AUX}_i \quad (6.12)$$

Where  $E_{it}$  - Energy input (kWh) to plant  $i$   
for time period  $t$ .

$\text{EFF}_i$  - Efficiency of plant  $i$ .

$\text{AUX}_i$  - Fixed energy consumption by auxiliaries over the period  $t$ .

- g) Pumped Storage Equation: The transfer function of pumped storage can be expressed by equating the energy output plus auxiliaries to the pumped energy input multiplied by the efficiency of the pumping cycle.

$$\text{EFF}_i \cdot \sum_{p=1}^P P_{ipt} \cdot \theta_p = \sum_{p=1}^P U_{ipt} \cdot \theta_p + \text{AUX}_i \quad (6.13)$$

for all  $i = 1, \dots, I$

$t = 1, \dots, T$

Where  $P_{ipt}$  = pumping energy input for station  $i$  at period  $t$ , time slice  $p$ .

- h) Fuel Balance: The amount of fuel supplied to the system must be equal to the amount of fuel consumed by the system.

$$\sum_{k=1}^K \text{SCOAL}_{kit} = E_{it} \quad \text{for all } i = 1, \dots, I$$

$$t = 1, \dots, T \quad (6.14)$$

Where  $SCOAL_{kit}$  - coal shipped from colliery  $k$  to station  $i$  in period  $t$ .

Total output from colliery  $k$  is equal to the sum of all the shipments from colliery.

$$TCOAL_{kt} = \sum_{i=1}^I SCOAL_{kit} \quad (6.15)$$

$TCOAL_{kt}$  - total coal output from colliery  $k$ .

- i) Fuel Supply Limitation: The total amount of fuel supplied by a colliery  $k$  to various power stations is less than or equal to the maximum amount of fuel which can be mined in that colliery.

$$TCOAL_{kt} \leq HCOAL_{kt} \quad (6.16)$$

Where  $HCOAL_{kt}$  - the maximum amount of coal that can be mined in colliery  $k$  in period  $t$ .

The total amount of fuel supplied by a colliery  $k$  to power stations must exceed or equal some specified minimum.

$$TCOAL_{kt} \geq LCOAL_{kt} \quad (6.17)$$

Where  $LCOAL_{kt}$  - the minimum amount of coal mined in colliery  $k$  in period  $t$ .

In the case where there is a lower limit in transport volume owing to specific coal contracts or a higher limit due to transport restrictions, the minimum and maximum limits in equations (6.16) and (6.17) can represent these limits.

- j) Water Supply Limitation for Dams: The water input to hydro station  $i$  in period  $t$  summed up for a period of one year is less than or equal to the total water available in one year for that hydro station. It is possible to use the prime energy and the average energy as input data and to observe the effect of both on the production costs.

$$E_{it} \leq HWAT_{it} \quad (6.18)$$

Where  $HWAT_{it}$  - maximum amount of water available per year for hydro station  $i$ .

- k) Building Constraints: There is a limitation as to the amount of new plant that can be installed within a pre-defined period. This constraint is represented by the minimum time between the installation of two sets in the

same station.

$$(\text{MIN TIM}) = T \text{ min} \quad (6.19)$$

In the linear programming application three stages have to be followed, namely:

- i) The problem must be given in the form of an objective function and the constraints matrix.
- ii) The optimisation study is executed using general linear programming system.
- iii) The results are presented in an easily understandable form.

The computer model consists of three main sections as indicated in figure 6.10. The first section is a data processor which takes the input data, checks it for any input errors and produces a file in linear programming standard notation, called MPS format. This section includes a Cobol program developed in Escom and a matrix generator package, named

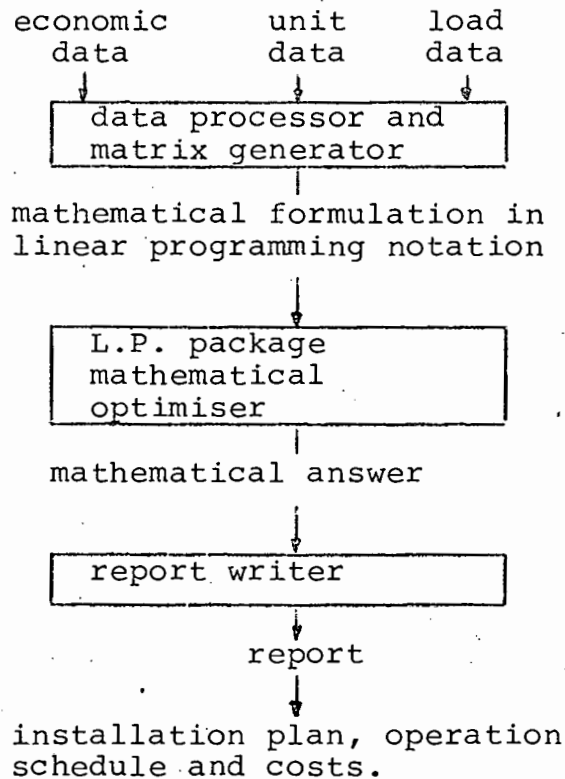


Figure 6.10: The structure of the linear programming model.

Ophelie, supplied by Control Data. In the second section the linear programming equations are solved by using a

mixed-integer linear programming package, named Apex-III which was also supplied by Control Data. The solution is passed to the third section where the answers are printed. This section also includes a Cobol program which was developed in Escom.

The inputs to the program are essentially the same as for many other generation planning procedures. The load data includes the anticipated annual peaks, weekly peaks within each year and weekly load duration curves. A description of all existing and committed generating plants should be given. This includes unit capacities, availability, thermal efficiency and operating costs characteristic of each plant. If energy sources and transport channels are also included in the study then their capacity and operating costs should also be included in the input data.

For units which are being investigated for possible future installation the same data as for existing units must be supplied plus details of installation characteristics such as the first year in which the new plant of a specific type and size can be installed, the minimum time between the installation of two sets in the same power station and the capital and operating costs of each set. The same information may be specified for new collieries which are being investigated. The output capacity of the collieries must meet the energy requirements of the power stations and all possible ways of transportation of coal from the collieries to the power station must be specified.

Economic input data includes discount rates, interest rates and escalation rates for the various types of plant and fuel. The minimum acceptable reliability of the system may be presented in the input data in terms of the margin of spare available capacity required to meet demands above the anticipated peak demand.

The output reports of the model provide the installation

scheduling and costs of the new plants, the generation scheduling and costs of the existing and new plants and the quantity and cost of the fuel supplied to the power station. For the detailed analysis of the optimisation process it is possible to obtain reports of all equations used and the state and sensitivity of all the parameters.

To illustrate the use of the model, an example of a small hypothetical power system is presented. The generating system is represented by a large coal-fired generating plant (GEN-1), fed with coal from a colliery CL-1 through a transport channel TR-1. The costs at the reference date of the existing generating system are given in tables 6.3 and 6.4. In table 6.3 the operating costs of the plant GEN-1 do not include the cost of the coal which is given in table 6.4.

station	capacity (MW)	availability	efficiency	fixed operating costs (R/week)	variable operating costs (R/MWh)
GEN-1	10000	0,95	0,333	1000000	0,2

Table 6.3: Input data for the existing power station.

plant	maximum output capacity (10 <sup>3</sup> ton/week)	minimum output capacity (10 <sup>3</sup> ton/week)	operating costs (R/week)	calorific value (MWh/ton)
colliery CL-1	600	100	2,0	6,0
transport TR-1	600	50	0,2	-

Table 6.4: Input data for the existing colliery and transport channel.

In the four-year study period considered here, from 1976 - 1979, all the cost data are given for the reference date which is the beginning of 1976. The estimated annual peak demands and the required reserve margins are given in table 6.5. One weekly load duration curve represents each week of the study period and consists of three steps as shown in

table 6.6.

The weekly maximum curve within a year is considered to be identical for the four years and for the sake of simplicity is represented by two steps as shown in table 6.7.

year	annual maximum demand (MW)	reserve margin (per cent)	no. of hours	demand (normalised values)	no. of weeks	demand (normalised values)
1976	10000	20	18	1.00	10	0,80
1977	11000	20	75	0,75	42	1,00
1978	12000	20	75	0,50		
1979	13000	20				

Table 6.5: Input data for the annual maximum demand and reserve margins.

Table 6.6: Input data of the weekly load duration curve.

Table 6.7: Input data of the weekly maximum curve for a year.

To meet the expected load demand with an adequate reserve capacity it is possible to add new generation capacity with any combination of three new power stations, coal-fired station (GC), pumped storage (PS), and hydro station (HP). The economic criteria for the selection is the minimum present worth of the sum of the capital costs for the duration of the economic life period of the stations and the operating costs for the duration of the study period. The input data for the new alternatives is given in table 6.8. For the coal-fired station, the costs of the coal production and transportation are included in the variable operation costs of the station.

station	set capacity (MW)	no. of sets	avail-ability	estab-lishment costs (R/kW)	set cost (R/kW)	operating costs		plant economic life (years)
						fixed (R/week)	variable (R/MWh)	
GC*	1500	4	0,90	50	200	50000	1,0	10
PS**	1000	2	1,00	100	50	10000	0,01	10
HD***	1000	2	1,00	150	100	5000	0,3	20

\* GC- there is a minimum period of 1 year between commissioning of 2 sets.  
 \*\* PS- pumping capacity of 1265 MW/set; pump efficiency of 0,79.  
 \*\*\* HD- maximum capacity of the dam is 3000 GWh/year; also the escalation rates of the fixed operating costs are 10 per cent above the standard escalation rates.

Table 6.8: Input data for the new alternatives of power stations.

The economic conditions are represented by the escalation and discount rates and these are given in table 6.9. The economic conditions beyond 1979 are considered to be identical to those in 1979. All the costs which were given at the reference date are assumed to escalate at the standard escalation rates as shown in table 6.9, except for the fixed operating costs of the hydro station which are assumed to escalate at a rate of 10 per cent above the standard escalation rates.

year	standard discount rates (per cent)	standard escalation rates (per cent)
1976	12,0	10,0
1977	13,0	12,0
1978	14,0	11,0
1979	13,0	11,0

Table 6.9: Input data for the expected economic conditions during the study period.

The results of the study include the installation dates for the new sets and the operation scheduling of the power stations. To satisfy the demand constraints, two new stations, the coal-fired station GC, and the pumped storage station PS, were required to be commissioned during the study period. The installation schedule of the new sets is shown schematically in figure 6.11 and the numerical values are given in table 6.10. The operating schedule of these generating plants for the two year period 1976 - 1977 is shown in table 6.11.

The application of the model to the planning of the South African generation system has been described by Rubbers<sup>(38)</sup>. He described the generation planning process in South Africa and the problems associated with the expansion of Escom's generation system. Four cost items were considered to be the most influential in the planning of the South African generation system. These were the costs associated with the construction of the new generating plant, the costs of fuel production, the costs involved in the transportation of fuel and the operation and maintenance costs of the power stations. Rubbers described the input data required by the linear programming model and the method of obtaining the actual values for Escom's system.

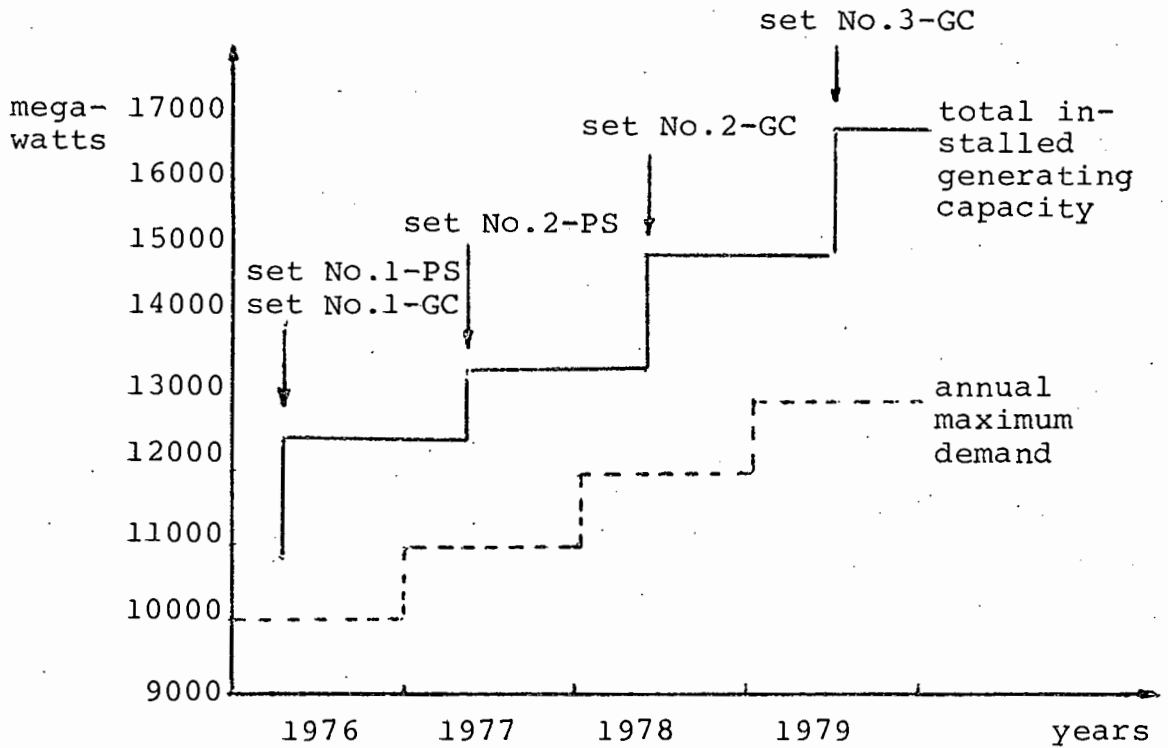


Figure 6.11: Schematic representation of the generation capacity installed for the duration of the study period.

station	set	installation date	set capacity (MW)	present worth of costs ( $10^6$ Rand)
PS	Establishment	week 10,1976		197,9
PS	1	week 10,1976	1000	49,5
PS	2	week 10,1977	1000	50,0
GC	Establishment	week 10,1976		296,9
GC	1	week 10,1976	1500	296,9
GC	2	week 10,1978	1500	288,3
GC	3	week 10,1979	1500	283,2

Table 6.10: Study results of installation schedule of new generating sets.

time periods (weeks, year)		time slice	power station	generation level (MW)
0-10	1976	1 (18 hrs)	GEN-1	8000
		2 (75 hrs)	GEN-1	6000
		3 (75 hrs)	GEN-1	4000
10-52	1976	1 (18 hrs)	GEN-1	8650
			GC	1350
		2 (75 hrs)	GEN-1	6150
		GC	1350	
		3 (75 hrs)	GEN-1	3650
			GC	1350
0-10	1977	1 (18 hrs)	GEN-1	7450
			GC	1350
		2 (75 hrs)	GEN-1	5250
		GC	1350	
		3 (75 hrs)	GEN-1	3050
			GC	1350
10-52	1977	1 (18 hrs)	GEN-1	9500
			GC	1350
			PS	150
		2 (75 hrs)	GEN-1	6946
			GC	1350
			PS	0
		3 (75 hrs)	GEN-1	4150
			GC	1350
			PS	0

Table 6.11: Study results of the operating scheduling of the power stations for 1976 - 1977.

### 6.3 THE USE OF PROBABILITY MATHEMATICS FOR THE ANALYSIS OF GENERATION RESERVE MARGINS

The electric power system is planned in such a way that the generating capacity will be in excess of the anticipated annual peak load. This excess capacity provides a reserve margin to ensure against the probability of the load exceeding the available generating capacity.

Generating plant may become unavailable owing to unexpected breakdown or planned maintenance. Unit failure or forced outage is the main factor to be considered when establishing the required reserve margin. Scheduled maintenance will ordinarily be performed in the low load seasons of the year. However, forced outages are just as likely to occur on the

peak load day of the year as on any other day. Thus, if large seasonal load variations exist in a system, the effect of scheduled generation maintenance on required reserve will be small. The converse would be true for a system with relatively small seasonal load variations.

Most of the electric utilities use one or more of the following methods in determining the size of their generation reserve: the standard per cent reserve, the loss of the largest generator and the loss of load probability method.

In the standard per cent reserve method, some fixed percentage of the forecasted system peak load is used as the required reserve. This fixed percentage is usually determined from the past history of the utility's own reliability records.

With the loss of the largest generator method, the reserve will be equal to the size of the largest generator plus some percentage of the peak to allow for load uncertainty. In this method the reserve is automatically increased as larger units are added to the system.

Methods based on the loss of load probability analysis are at present widely used in many electrical utilities. These methods permit a desired probability level of the confidence of satisfying the consumer's demand to be designed. With the reliability fixed, the installed generation reserve becomes variable and changes with the load characteristics and the size and availability of the units. The loss of load probability method requires that the reserve be a function of the probability of the loss of capacity needed to meet the load.

One of the primary elements in the loss of load probability calculation is the probability distribution of the system's available capacity which is determined from the forced outage statistics and capacity rating of each individual unit. Several aspects of forced outages deserve particular attention. Forced outage rates have historically increased with increasing unit size. The unit type also will affect forced outage

rates. For example, a 600 MW nuclear unit will typically have a higher forced outage rate than a coal-fired 600 MW unit. Also, unit immaturity is another factor to consider. The increased outage rates during the first few years after installation will definitely affect the required reserves during an expansion study.

All generating units are subject to random outages caused by various types of equipment malfunction. The occurrence and duration of these forced outages are unpredictable. The simplest stochastic method for treating unit reliability is to define two possible states for each unit. The unit is either available and capable of full power generation, or the unit is not available and is unable to deliver any power. Associated with each state is the probability of a unit being in that state. The probability of a unit being available is  $q$ , while the probability of the unit not being available is  $p$ . Since the unit must be in one of the two states,  $p + q = 1$ . The probability  $p$  is normally called the expected forced outage rate.

The probability of having various amounts of capacity out of service due to forced outages can be determined for any set of generating units once the availabilities are defined. By assuming that the units are totally independent of one another, a forced outage distribution function can be calculated using a recursive relationship similar to that used for the binomial distribution.

The random variable  $x$  is defined as the amount of capacity available from the unit. This random variable can have only two values, 0 or  $c$  where  $c$  is the unit capacity. Thus, the probability that the random variable,  $x$ , has a value 0 is  $p$  as defined above, since this occurs when the unit is in forced outage and the probability that the random variable has the value  $c$  is  $q$  (where  $q = 1 - p$ ) since this occurs when the unit is available or not in forced outage.

The probability distribution or density function of  $x$ ,  $P(x)$ ,

can be mathematically defined by:

$$P(x) = p \left( \frac{c-x}{c} \right) \cdot q \left( \frac{x}{c} \right) \quad \begin{array}{l} \text{for } x = 0, c \\ \text{and } 0 \leq p \leq 1 \end{array} \quad (6.20)$$

Thus  $P(0) = p$ , and  $P(c) = q$ .

This function mathematically describes the probability characteristics of a generating unit.

With more than one unit in the system the joint probability density can be generalised by using the multiplicative law for independent events.

$$P(x_1, x_2, \dots, x_n) = P_1(x_1) \cdot P_2(x_2) \dots P_n(x_n) \quad (6.21)$$

$$\left( \frac{c_i - x_i}{c_i} \right) \left( \frac{x_i}{c_i} \right)$$

where  $P_i(x_i) = p_i \cdot q_i$

$x_1 = 0, c_1, x_2 = 0, c_2$ , etc.,  $c_1 c_2 \dots$  are the capacities of the generating unit,  $p_1 p_2 \dots$  are the forced outage rates of the generating unit and  $q_1 = 1 - p_1, q_2 = 1 - p_2 \dots$  are the unit availability rates.

For example, for two units the probability distribution becomes:

$$P(c_1, c_2) = \left[ p_1 \left( \frac{c_1 - c_1}{c_1} \right) \cdot q_1 \left( \frac{c_1}{c_1} \right) \right] \cdot \left[ p_2 \left( \frac{c_2 - c_2}{c_2} \right) \cdot q_2 \left( \frac{c_2}{c_2} \right) \right]$$

Probability when both units are available

$$= q_1 \cdot q_2$$

$$P(0, c_2) = \left[ p_1 \left( \frac{c_1 - 0}{c_1} \right) \cdot q_1 \left( \frac{0}{c_1} \right) \right] \cdot \left[ p_2 \left( \frac{c_2 - c_2}{c_2} \right) \cdot q_2 \left( \frac{c_2}{c_2} \right) \right]$$

Probability unit no.1 is forced out and unit no.2 is available

$$= p_1 \cdot q_2$$

$P(c_1, 0)$  = probability unit no.1 is available =  $q_1 \cdot p_2$   
and unit no.2 is in forced outage.

$P(0,0)$  = probability of both units being in forced outage.  $= P_1 \cdot P_2$

A new random variable,  $Y$ , may be defined which is the sum of the random variables associated with the individual units. This new random variable,  $Y = \sum x_i$ , is the system available capacity since  $x_i$  is the available capacity associated with the  $i$ th unit. The probabilities associated with the random variable  $Y$ , that is, the probability of system available capacity, is a function of the joint forced outage events. The probabilities of  $P(Y = \sum x_i)$  can be determined directly from the joint probabilities. For example, in the case where the two units each have the same capacity ( $c_1 = c_2 = c$ ), it can be seen that there are two ways in which the event  $Y = c$  megawatts of available capacity can occur in the system. The first is when unit no.1 is available and unit no.2 is in forced outage,  $P(c,0)$ , and the second is when unit no.1 is in forced outage and unit no.2 is available,  $P(0,c)$ . The probability  $P(Y = c)$  is the sum of these mutually exclusive events and thus  $P(Y = c) = P(c,0) + P(0,c) = P_2q_1 + P_1q_2$ . In general the additive law of probabilities of mutually exclusive events applies and the probability of the event  $Y$  is the sum of the mutually exclusive ways it can occur.

The process of obtaining the probability density of a random variable which is the sum of two other independent random variables is called convolution. That is, for  $n$  units on the system, the probability of each possible available capacity situation can be obtained from the joint probability.

The probability density of system available capacity,

$Y = \sum_{i=1}^n x_i$ , is the sum of these joint probabilities for all  $i=1$

common values of  $Y$ . The probability density function of system available capacity is mathematically given for  $n$  units on the system by:

$$P(Y = \sum_{i=1}^n x_i) = P_1(x_1) * P_2(x_2) * \dots * P_n(x_n) \quad (6.22)$$

where \* denotes convolution and the expression indicates successive convolution of the density functions of the individual units.

To illustrate the application of the convolution expansion, a system consisting of 3 units is considered. The forced outage rates and the unit capacities are given in table 6.12.

unit no.	forced outage rate p	capacity c (MW)
1	0,01	10
2	0,05	20
3	0,10	30

Table 6.12: Forced outage probabilities and unit capacities for the example system.

The development of the probability distribution is as follows:

$$P(0 \text{ MW available}) = P(x_1 = 0, x_2 = 0, x_3 = 0) = p_1 p_2 p_3 = 0,0005$$

$$P(10 \text{ MW available}) = P(x_1 = 10, x_2 = 0, x_3 = 0) = q_1 p_2 p_3 = 0,00495$$

$$P(20 \text{ MW available}) = P(x_1 = 0, x_2 = 20, x_3 = 0) = p_1 q_2 p_3 = 0,00095$$

$$P(30 \text{ MW available}) = P(x_1 = 0, x_2 = 0, x_3 = 30) + \\ + P(x_1 = 10, x_2 = 20, x_3 = 0) = p_1 p_2 q_3 + q_1 q_2 p_3 = 0,0945$$

$$P(40 \text{ MW available}) = P(x_1 = 10, x_2 = 0, x_3 = 30) = q_1 p_2 q_3 = 0,04455$$

$$P(50 \text{ MW available}) = P(x_1 = 0, x_2 = 20, x_3 = 30) = p_1 q_2 q_3 = 0,00855$$

$$P(60 \text{ MW available}) = P(x_1 = 10, x_2 = 20, x_3 = 30) = q_1 q_2 q_3 = 0,84645$$

The resulting probability distribution is shown in table 6.13.

available capacity - Y	outage capacity	P(Y) probability	cumulative probability
0	60	0,00005	0,00005
10	50	0,00495	0,00500
20	40	0,00095	0,00595
30	30	0,09450	0,10045
40	20	0,04455	0,14500
50	10	0,00855	0,15355
60	0	0,84645	1,00000

Table 6.13: Probability distribution results for the example system.

If there are  $n$  identical units in the system, and  $c$  is the capacity and  $p$  is the forced outage probability of each of the  $n$  identical units, the joint probability becomes:

$$P(x_1, x_2, \dots, x_n) = p^{(n-r)} \cdot q^r \quad (6.23)$$

where  $n$  is the number of units available.

The probability density function of the system's available capacity  $P(Y = \sum_{i=1}^n x_i)$  is formed by summing up all combinations of probabilities from above which yield the same  $Y$  megawatts of available capacity. Since for  $Y$  megawatts there must be  $r$  units available, the combinations or numbers of ways  $r$  units out of  $n$  total units can be available is given by:

$\binom{n}{r} \frac{n!}{r!(n-r)!}$  Combinations of  $Y = c \cdot r$  megawatts where  
 $!$  denotes factorial;  $n! = (n) \cdot (n-1) \cdot (n-2) \dots 1$

$$\text{Thus: } P(Y) = \frac{n!}{r!(n-r)!} \cdot p^{(n-r)} \cdot q^r \frac{n!}{(\frac{Y}{c})!(n-\frac{Y}{c})!} \cdot p^{(n-\frac{Y}{c})} \cdot q^{(\frac{Y}{c})} \quad (6.24)$$

This is the general term of the binomial expansion of  $(p + q)$  and all possible values of  $Y$  megawatts of available capacity are generated by:

$$(p + q)^n = p^n + np^{(n-1)}q + n(n-1)p^{(n-2)}q^2 + \dots + \frac{n!}{r!(n-r)!} p^{(n-r)} \cdot q^r + \dots + npq^{(n-1)} + q^n \quad (6.25)$$

The following example will illustrate the meaning of the terms presented in the above equations. A station has three sets of 30 megawatts each. The station probability distribution function may be written as:

$$p^3 + 3p^2q + 3pq^2 + q^3 = 1.$$

The probability of all units available is given by  $q^3$ . The probability of having two sets not available and one set available is given by  $pq^2$  and there are three ways that this can occur. The terms of the equation can be placed in table form, as shown in table 6.14. The entries in table 6.14 give

the discrete probability of an event occurring in the station. Since the station must exist in one of the states the sum of the terms must equal 1,0.

megawatts available	megawatts not available	probability	table entry
0	90	$p^3$	1
30	60	$3p^2q$	2
60	30	$3pq^2$	3
90	0	$q^3$	4

Table 6.14: Station probability distribution list.

When a power system with a few stations is considered the task of finding the probability of having or not having a given number of megawatts available to supply the load becomes more difficult. To find all states of the system the technique of convolution is used. To understand the way the technique is applied an example is used. A system with two stations is considered. Station number 1 is defined in table 6.14 and station number 2, with two sets of 60 megawatts each, is defined in table 6.15. The total installed capacity is

megawatts available	megawatts not available	probability	table entry
0	120	$p^2$	1
60	60	$2pq$	2
120	0	$q^2$	3

Table 6.15: Probability distribution for station No. 2.

90 + 120 = 210 megawatts. The common multiple of all the sets in the system is 30 megawatts, thus  $\Delta MW = 30$ . Table 6.16 summarises the results of the convolution of table 6.14 and table 6.15.

For a system where there are many generating units having various capacities and different forced-outage rates, the forced-outage distribution is built up sequentially by

megawatts available	megawatts not available	probability	table entry
0	210	$p_1^3 \cdot p_2^2$	1
30	180	$3p_1^2 q_1 \cdot p_2^2$	2
60	150	$3p_1 q_1^2 \cdot p_2^2 + p_1^3 \cdot 2p_2 q_2$	3
90	120	$q_1^3 \cdot p_2^2 + 3p_1^2 q_1 \cdot 2p_2 q_2$	4
120	90	$3p_1 q_1^2 \cdot 2p_2 q_2 + p_1^3 \cdot q_2^2$	5
150	60	$q_1^3 \cdot 2p_2 q_2 + 3p_1^2 q_1 \cdot q_2^2$	6
180	30	$3p_1 q_1^2 \cdot q_2^2$	7
210	0	$q_1^3 \cdot q_2^2$	8

Table 6.16: Probability distribution of the two stations.

considering one unit at a time. The following example will illustrate how the forced-outage distribution function is generated. The three generating units described in table 6.17 are considered. For a system consisting of only the first unit, the distribution function of forced-outages can be written by inspection and is shown in column 2 of table 6.18. When the second unit is added, it is necessary to calculate the probabilities of having various amounts of capacity out of service. This is done by using the previously calculated distribution function and the availability of unit no.2. When both unit no.1 and unit no.2 are available the outage,  $x$  (in MW), would be zero; and, by multiplying the probabilities of these events, one obtains:

$$\begin{aligned}
 P_2(0) &= P_1(0) \cdot q_2 \\
 &= (0,80)(0,80) = 0,64
 \end{aligned}$$

where

$P_2(x)$  = the probability of having  $x$  MW out of service in a two-plant system,

$P_1(x)$  = the probability of having  $x$  MW out of service in a one-plant system,

$q_2$  = the availability of unit 2.

The following two possible events would result in 200 MW being out of service: unit no.1 down, with unit no.2 available; and unit no.1 available, with unit no.2 down. The probability of this event is:

$$P_2(200) = P_1(200) \cdot q_2 + P_1(0) \cdot p_2$$

$$= (0,2)(0,8) + (0,8)(0,2) = 0,32.$$

The probability of both unit no.1 and unit no.2, being out of service simultaneously (a total of 400 MW out of service) is:

$$P_2(400) = P_1(200) \cdot p_2$$

$$= (0,2)(0,2) = 0,04.$$

The forced-outage distribution for the two units is shown in column 3 of table 6.18. The third unit is added to the distribution in a manner similar to that just described, and the results of this calculation are summarised in column 4 of table 6.18.

The general form of the recursion equation for adding any number of units is:

$$P_n(y) = P_{(n-1)}(y) \cdot q_n + P_{(n-1)}(z) \cdot p_n \quad \text{for } z \geq 0,$$

$$P_n(y) = P_{(n-1)}(y) \cdot q_n \quad \text{for } z < 0, (6,26)$$

where

x = capacity of nth unit,

y = MW out of service,

z = y - x.

and y is assumed to take on all possible values of the power outages.

unit no.	capacity (MW)	unit probability	
		available	not available
1	200	0,80	0,20
2	200	0,80	0,20
3	100	0,90	0,10

Table 6.17: Sample generating units.

power outage, x (MW)	probability of occurrence		
	$P_1(x)$	$P_2(x)$	$P_3(x)$
0	0,80	0,64	0,576
100	0,0	0,0	0,064
200	0,20	0,32	0,288
300	0,0	0,0	0,032
400	0,0	0,04	0,036
500	0,0	0,0	0,004

Table 6.18: Distribution of forced outages.

#### 6.4 PROBABILITY SIMULATION MODEL FOR GENERATION RESERVE ANALYSIS

The capital requirements of any electrical utility are largely influenced by the decisions made in regard to the additional generating plant to be installed. When estimating the amount of additional generating plant required, a plant reserve margin above the anticipated annual peak demand must be provided. This safety margin is necessary to provide for the day-to-day variations in the operating conditions of the installed generating plant, and for the likelihood that the system demand will deviate from the predicted value.

The yearly peak demand is affected by the two basic variations; the national economy and the weather. Since the "lead-time" required between making the decision and the commissioning of the generating plant is in the order of five to seven years, the desired generating plant reserve must be determined five to seven years in advance. Thus the yearly peak demand prediction must be based on relatively long-range assumptions regarding business activity and weather conditions. Since assumptions in both of these areas are subject to potential errors, a component of generating reserve capacity is required to allow for the fact that the actual yearly peak demand will deviate somewhat from that forecasted.

Plant margin allowances of a somewhat different kind must be made for the fact that at the time of the peak demand not

all the installed generating plant capacity will be available. Generating plant may become unavailable either as the result of being in forced outage owing to breakdown, or because of being scheduled out for planned maintenance.

For the purpose of establishing plant reserve requirements for some future period, the probability simulation model can be used to quantify the probability of failure to meet the consumers' power demand in any month during the period considered. With the aid of the probability simulation model it is possible to evaluate "what the chances are" that the total system demand can be met. This is done in the model on a monthly basis after subtracting the generating plant which is scheduled for planned maintenance, and using a "sample week" as an indication of the system's demand pattern for the month concerned. The expression of "what the chances are" in quantitative terms is done in the program by considering, on the one hand, the probability distribution of generating plant breakdowns (after planned maintenance), and, on the other hand, the probability distribution of the total system demand.

The probability of failure to meet the consumer's demand is determined by comparing the available generating capacity during a particular month (which is calculated by subtracting the capacity in planned maintenance from the total installed capacity) with the cumulative probability distribution of the "equivalent load" in that month.

Equivalent load is defined<sup>(18)</sup> as:

$$P_e = P_d + P_o \quad (6.27)$$

where  $P_e$  is the equivalent load during any hour,  $P_d$  is the system demand during any hour and  $P_o$  is the generating capacity in forced outage during any hour. The system demand  $P_d$  and the generating capacity in forced outage  $P_o$  are expressed as probability distributions. The probability distribution of the equivalent load  $P_e$  is obtained by the convolution of the two distributions  $P_d$  and  $P_o$ .

If the hourly system loads are plotted as a function of time, the resulting curve gives a chronological representation of the load requirements of the utility's system. If these same hourly loads are rearranged in decreasing order of magnitude, the resulting curve is called a load duration curve. For the load duration curve, the abscissa represents the number of hours during which the system load equals or exceeds the value of the associated power on the ordinate. By normalising the time variable, the value at any point on the abscissa becomes the fraction of the entire period for which the load equals or exceeds the associated power. Carrying this logic a step further, the abscissa can be considered to represent the probability that a particular value of the system load will be equalled or exceeded. By reversing the ordinate and abscissa, the load duration curve, as shown in figure 6.12, can be considered to represent the cumulative probability distribution.

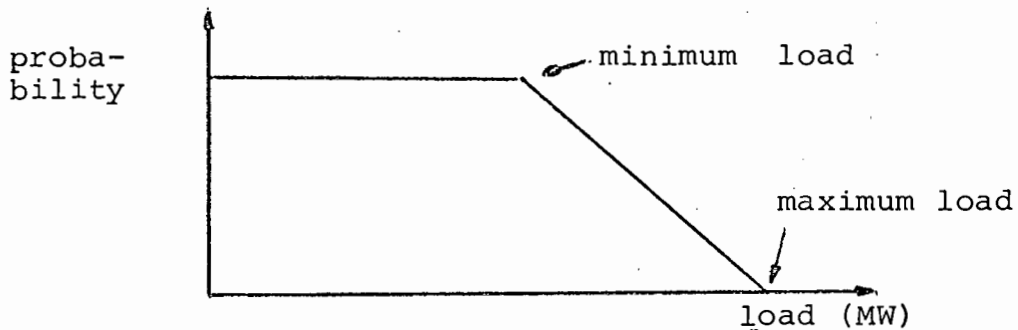


Figure 6.12: Probability distribution of the load duration curve.

To simulate the hourly system demand fluctuation in each month, a sample weekly load duration curve is used. The sample weekly load duration curve for each month is expressed in the program by a polynomial:

$$y = \sum_{i=0}^n c_n x^n \quad (6.28)$$

where  $y$  is the probability distribution of the system demand,  $x$  is the system demand and  $c_1 c_2 \dots c_n$  are constants which are obtained by using the method of minimum least square fitting to historical data. For instance, in Escom the seventh order polynomial was found to best represent the

historical data.

In addition to the sample weekly load duration curve, the probability distribution of the weekly peak demand about the expected average figure for each month is calculated in the program. This is done by using the probability density function of a normal distribution as illustrated in figure 6.13. The ordinate represents the probability density:

$$f(x) = \frac{1}{\sqrt{2\pi} \sigma} \cdot e^{-\frac{1}{2} \left(\frac{x-\mu}{\sigma}\right)^2} \quad (6.29)$$

where  $x$  is the system weekly peak demand,  $\mu$  is the average system weekly peak demand and  $\sigma$  is the standard deviation of the system weekly peak demand for a specific month.

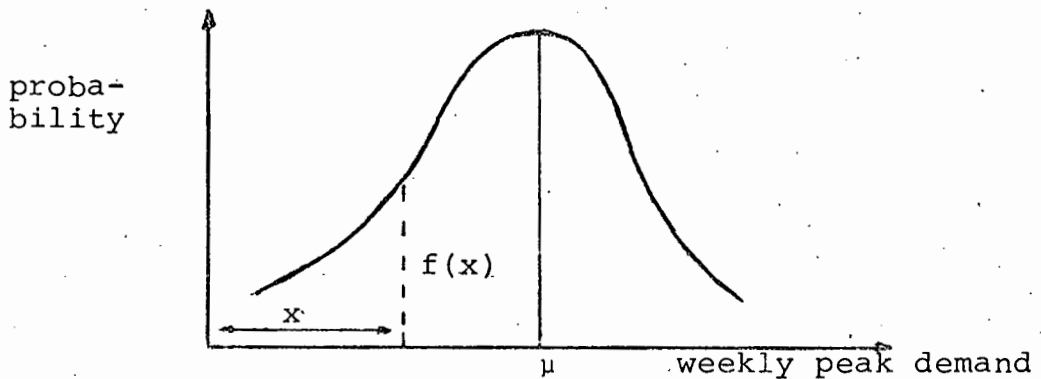


Figure 6.13: Normal distribution of the weekly peak demands for a specific month.

The convolution of the probability distributions of the weekly peak demands and the hourly demands below the peak is performed for each month of the study period. This gives the probability distribution of the system demand  $P_d$  for each month.

In section 6.3 it was explained that the probability distribution of the generating capacity in forced outage  $P_o$  is obtained by the convolution of the binomial distributions of the individual power stations. Obtaining the individual power station distributions is simplified by recognising three types of coal-fired power stations. The older power stations have many interconnected boilers supplying a

relatively smaller number of turbo-generators and in these stations, boiler outages can be ignored. The intermediate power stations have interconnected turbines. Thirdly, the new power stations have separate boiler-turbo units with no interconnection. By appropriate substitution of the forced outage rate  $p$  of individual boilers and turbo-generators, the binomial theorem is used to calculate the probability distribution of the generating capacity in each power station.

The equivalent load  $P_e$  is derived by the convolution of the probability distributions of  $P_d$  and  $P_o$ , as explained in section 6.3. The resulting probability distribution can be expressed in cumulative form. The cumulative distribution function is a convenient way of representing the equivalent load data, and the curve obtained by using these data will be called the equivalent load curve. As shown in fig. 6.14, the equivalent load curve has the same general shape as the load duration curve. As mentioned earlier, the area under the load duration curve equals the total energy requirement for the system over the time period being considered. As a result of the contribution of unit outages to the equivalent load, the area under the equivalent load curve is greater than the area under the load duration curve and represents the equivalent energy.

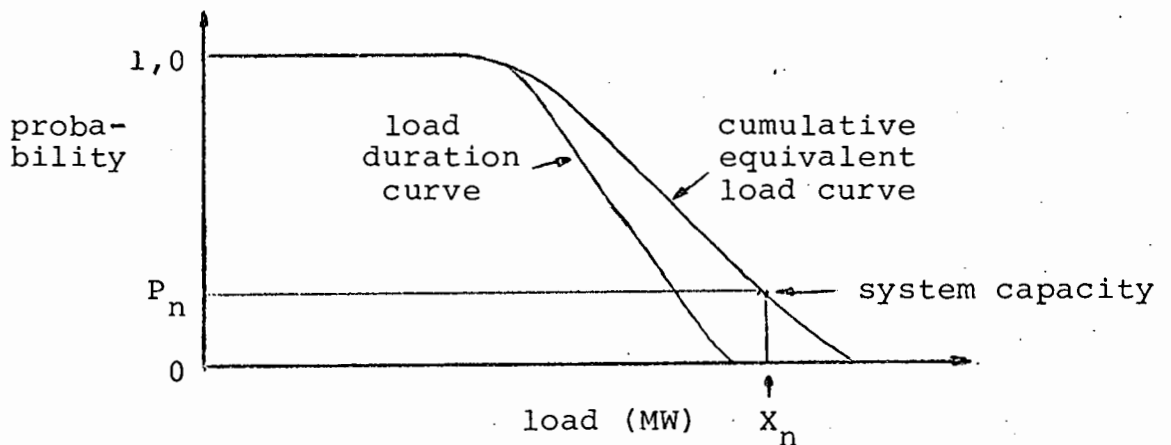


Figure 6.14: Comparison of Load Duration Curve and Cumulative Equivalent Load curve.

Referring to the definition of the equivalent load curve it is evident that the cumulative equivalent load curve is the probability of having an equivalent load equal to or greater than the system capacity. As shown in figure 6.14, the generating system would not be able to supply loads greater than the system capacity  $X_n$ , therefore the corresponding probability  $P_n$  is the probability of the loss of load.

The following example illustrates how the system reliability is calculated in the program. The power station A has 4 turbo-generators, each having a sent-out capacity of 55 megawatts, an average forced outage rate of  $p = 0,00644$  and an average availability of  $q = 1 - p = 0,99356$ . Using the binomial expansion, the probability that zero, one, two, three and four turbo-generators will be forced cut due to breakdown is given by the first, second, third, fourth and fifth term of the expression.

$$(q + p)^4 = q^4 + 4q^3p + \frac{4.3}{1.2} q^2p^2 + \frac{4.3.2}{1.2.3} qp^3 + p^4$$

Power station A therefore has a probability distribution of generating capacity forced outages of

FO	( 0)	0,974496
FO	( 55)	0,025258
FO	(110)	0,000245
FO	(165)	0,000001
FO	(220)	0,000000
		<hr/>
		1,000000

The meaning of this probability distribution is that a probability of 0,974496 is assigned to the chance event that no breakdowns are experienced during a particular hour taken at random. Likewise, the chance of a breakdown of one turbo-generator, or an outage of 55 megawatts is assigned a probability of 0,025258. The total of all the probabilities of the distribution is 1,0. This total expresses the probability that one of the various possible events must occur during the random hour.

A second power station, B, with 4 units each of 93 megawatts

is considered. This power station contains an equal number of boilers and turbines with pipe cross-connection. The outage rates of the boiler and the turbo-generators are 0,0078 and 0,0035 respectively. The probability distribution of the generation capacity in forced outage of station B becomes:

FO	( 0)	0,944860
FO	( 93)	0,054419
FO	(186)	0,000716
FO	(279)	0,000005
FO	(372)	0,000000
		<hr/>
		1,000000

The probability distribution of the generating capacity in forced outage at both stations is obtained by the convolution of the two individual probability distributions. The probability distributions become:

FO	( 0)	0,920762
FO	( 55)	0,023865
FO	( 93)	0,053032
FO	(110)	0,000231
FO	(148)	0,001375
FO	(165)	0,000001
FO	(186)	0,000698
FO	(203)	0,000013
FO	(241)	0,000018
FO	(279)	0,000005
FO	(372)	0,000000
		<hr/>
		1,000000

The convolution process can be continued by including one power station distribution at a time in order to establish the probability distribution for the total generating capacity.

The analysis of the weekly demands experienced in a specific month, for example January, over several years of the immediate past, enables the forecasting of the probability distribution of weekly demand for any future January. For January 1976, a forecast average weekly peak demand of say 8750 megawatts will result in the following probability distribution: (simplified form with 1000 megawatt intervals)

D	(4351 - 5350)	0,136808
D	(5351 - 6350)	0,124166
D	(6351 - 7350)	0,288413
D	(7351 - 8350)	0,347340
D	(8351 - 9350)	0,103273
		<hr/>
		1,000000

The probability distribution of the equivalent load is calculated by convolving the probability distribution of the capacity in forced outage with the probability distribution of the total demand. The equivalent load probability distribution for January 1976 becomes: (simplified form with 1000 megawatt intervals).

EL	(6000)	0,131497
EL	(7000)	0,124654
EL	(8000)	0,282039
EL	(9000)	0,345050
EL	(10000)	0,112745
EL	(11000)	0,004013
EL	(12000)	0,000002
		<hr/>
		1,000000

The probability distribution states that, during a random hour in January 1976, there is a probability of 0,131497 that the equivalent load (system demand plus generating capacity in forced outage) will reach a level of 6000 megawatts, etc. This probability distribution, when written in cumulative form, is a useful indicator of the probability of the failure to meet the consumer's demand during a random hour in January 1976.

ELC	( 6000)	1,000000
ELC	( 7000)	0,868503
ELC	( 8000)	0,743849
ELC	( 9000)	0,461810
ELC	(10000)	0,116760
ELC	(11000)	0,004015
ELC	(12000)	0,000002

For the purpose of illustration it can be assumed that the total capacity of the system is 10000 megawatts in January 1976 (excluding all plant shut down for planned maintenance). The cumulative probability distribution ELC for 10000 MW is 0,116760 and this is the probability of the failure to meet the demand in any random hour in January 1976 or that the equivalent load will equal or exceed the available generating capacity.

As mentioned earlier the probability of failure to meet the consumer's demand is determined by comparing the available

generating capacity during a particular month with the cumulative probability distribution of the equivalent load in that month. The available generating capacity is calculated by subtracting the capacity in planned maintenance from the total installed capacity. To enable the scheduling of the planned maintenance shutdowns the input data to the program must include "planned maintenance requests" for each year of the study period. The planned maintenance requests are stated in terms of boiler months and/or turbine months of shutdown for planned maintenance. Before commencing the scheduling of planned maintenance, the surplus generating capacity is calculated on the basis of zero planned maintenance. The surplus generating capacity is the difference between the installed capacity and the equivalent load corresponding to a pre-defined probability of failure to supply the consumer's demand. The selection of the periods for the boiler and/or turbine shutdown is performed in such a way that the reserve margin is maximised and kept as uniform as possible throughout the year.

The input data to the program consists of forecast load data, power station data, planned maintenance requests and the annual system reliability. The load data consists of the annual peak demand, the monthly peak demand over the year and the coefficients of the polynomial which describes the weekly load duration curve for each month. The power station data includes the capacity and the type of station, the forced outage rate, the number of boilers and turbines, the installation dates for new sets and the retirement of old sets. The planned maintenance data includes the number of boilers and turbines of any power station that needs to be maintained in a specific year and the duration, in months, of each maintenance request.

There are five different output reports: the monthly report, the yearly report, the planned maintenance scheduling, the initial distribution of the equivalent load, and the distribution of the equivalent load after the monthly maintenance.

The monthly report gives a summary of the monthly input data and includes the peak demand, the coefficients of the load duration curve, a list of the installations of new sets, the capacity of the generators and the outage rates of the boilers and the turbines.

The yearly report includes information for each month of the year before the scheduling of the maintenance is performed. It consists of the installed capacity, the peak demands and the monthly reserve margins for the specified annual probability of failure to meet the demand.

The maintenance scheduling report, includes the date, duration and the capacity of the units which must be maintained during the year. This report also repeats the summary of the yearly information compiled in the previous report.

The equivalent load distribution, before and after the planned maintenance are given for any load step which is required. For each load the probability is given that the equivalent load will equal or exceed the available generating capacity.

To illustrate the use of the model, an example of a small hypothetical system is presented. The duration of the study period is one year and the system at the beginning of the year consists of four power stations. The first station, with a total sent-out capacity of 384 megawatts, is of the first type where there are many interconnected boilers supplying a relatively smaller number of turbo-generators. The second station, with a total capacity of 760 megawatts, is of the second type where the interconnected boilers supply an equal number of interconnected turbines. In this case the forced outage rates for the boilers and the turbines are given in the input data as two separate figures. The other two stations, with capacities of 1980 megawatts and 475 megawatts, are of the third type with separate boiler-turbo units having no interconnection. During the study period a new set of 475 megawatt sent-out capacity is added to the fourth station. The input data of the power stations is summarised in table 6.19.

power station	no. of sets	set size (MW)	station type	availability (boiler)	availability (turbine)	maintenance requests and duration
A	12	32	1	-	0,976	-
B	4	190	2	0,9597	0,895	two boilers: boiler (a) - 1 month boiler (b) - 2 months one turbine- 4 months
C	6	330	3	-	0,874	2 sets: set (a) - 2 months set (b) - 1 month
D*	2	475	3	-	0,874	-

\* set no.2 of station D was added in October 1976 to the system.

Table 6.19: Power station input data to the probability simulation model.

The maximum annual peak in the study period from August 1976 to July 1977, was expected to reach the level of 3300 megawatts. The average weekly peak of each month is calculated in the program from the annual peaks of two successive years and the seasonal factor of each month which is obtained from past history. The input data for the seasonal factors is given in table 6.20.

month	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.
factor	0,98	0,95	0,93	0,92	0,87	0,89	0,90	0,91	0,92	0,96	0,99	1,0
annual peak of the study period = 3300 megawatts												
annual peak of previous year = 2988 megawatts												

Table 6.20: Input data of the monthly seasonal demand factors.

For the study period, the probability of failure to meet the demand was chosen to be 0,05.

The results of the study include a maintenance plan and the analysis of the system capacity. The maintenance schedule of the sets, which were required to be maintained during the year, is performed in such a way that the reserve margin is

kept as uniform as possible throughout the year. The results of the maintenance schedule are given in table 6.21. A summary of the analysis of the monthly capacity is shown in table 6.22.

station	megawatts out of service	duration (months)	start at	complete at
B	190	4	November	February
C	330	2	December	January
C	330	1	October	

Table 6.21: Study results of the maintenance schedule.

### 6.5 LOSS OF LOAD PROBABILITY MODEL

The purpose of the loss of load probability (LOLP) model is to compute the probability of the loss of load to the generation system, taking into consideration the unit capacity, forced outage rates, maintenance requirements and system daily peak loads. The program also computes a maintenance schedule from the general maintenance requirements while attempting to keep the yearly LOLP as low as possible.

As discussed in paragraph 6.3 the probability distribution of the system capacity is developed from the individual unit capacity and outage rates. Changes in the system capacity resulting from planned maintenance, new generation installation and the retirement of old generation units and changes in the forced outage rates are represented by adjustments to the probability distribution of the system capacity. For each day of the year the peak demand is combined together with the probability distribution of the generation capacity and the resulting loss of load probability for the day calculated. The daily LOLP values are summed up to give the expected number of days of load loss for the year.

The computer system was designed to take into account the following aspects relating to the model.

- Ability to calculate the loss of load probability for a period up to 20 years.

	August	September	October	November	December	January	February	March	April	May	June	July
installed capacity (MW)	3599,0	3599,0	4074,0	4074,0	4074,0	4074,0	4074,0	4074,0	4074,0	4074,0	4074,0	4074,0
monthly peak (MW)	2965,8	2881,3	2845,2	2844,3	2709,2	2794,7	2850,8	2902,3	2966,2	3125,9	3272,4	3300,0
capacity in planned maintenance (MW)	0,0	0,0	330,0	190,0	520,0	520,0	190,0	0,0	0,0	0,0	0,0	0,0
surplus reserve for failure probability of 0,05 (MW)	-89,0	-22,0	206,3	295,1	213,2	99,1	315,7	404,0	382,3	234,9	109,0	85,8
<u>Plant reserve margins:</u>												
for planned maintenance (per cent)	0,0	0,0	11,6	6,7	19,2	18,6	6,7	0,0	0,0	0,0	0,0	0,0
for forced outages (per cent)	27,4	25,7	24,3	26,2	23,3	23,6	25,2	26,5	24,5	22,8	21,1	20,9
surplus (per cent)	-3,0	-0,8	7,3	10,4	7,9	3,5	11,1	13,9	12,9	7,5	3,4	2,6
total (per cent)	21,4	24,9	43,2	43,2	50,4	45,8	42,9	40,4	37,3	30,3	24,5	23,5

Table 6.22: Summary of the results of the probability simulation model.

- Separate daily maximum curves of the week for different periods of the year or from one year to another.
- Separate weekly maximum curve of the year for different years.
- Each set may have more than one forced outage rate during the study period.
- The number of sets in a power station may be changed during the study period. This change may result from the addition of new sets or the de-commissioning of old sets.
- A power station may have sets of different sizes or different forced outage rates.
- Maintenance may be requested for a pre-defined time of the year or it may only be requested to be done during the year and the program will find the optimum time in such a way that the loss of load probability will be as low as possible.

The computer model consists of several sub-models. Each one performs a specific function as illustrated in figure 6.15.

#### Load sub-model:

The load sub-model is constructed from the daily maximum and weekly maximum curves and the annual peak loads. The daily maximum curve of a week is described by a number of steps with each step representing a number of days. The weekly maximum curve of a year is also described by a number of steps. At each step a value of the weekly peak load will be given per-unit of the yearly peak. The peak load, in megawatts, of a specific day may be calculated from the following algorithm:

$$L_k = A_s \cdot W_m \cdot D_n \quad (6.30)$$

where  $A_s$  is the annual peak of the year  $s$ ,  $W_m$  is the weekly per-unit value of step  $m$  in the weekly maximum curve and  $D_n$  is the daily per-unit value of step  $n$  in the daily maximum curve.

#### Maintenance scheduling sub-model:

After the daily load has been calculated, the system reserve

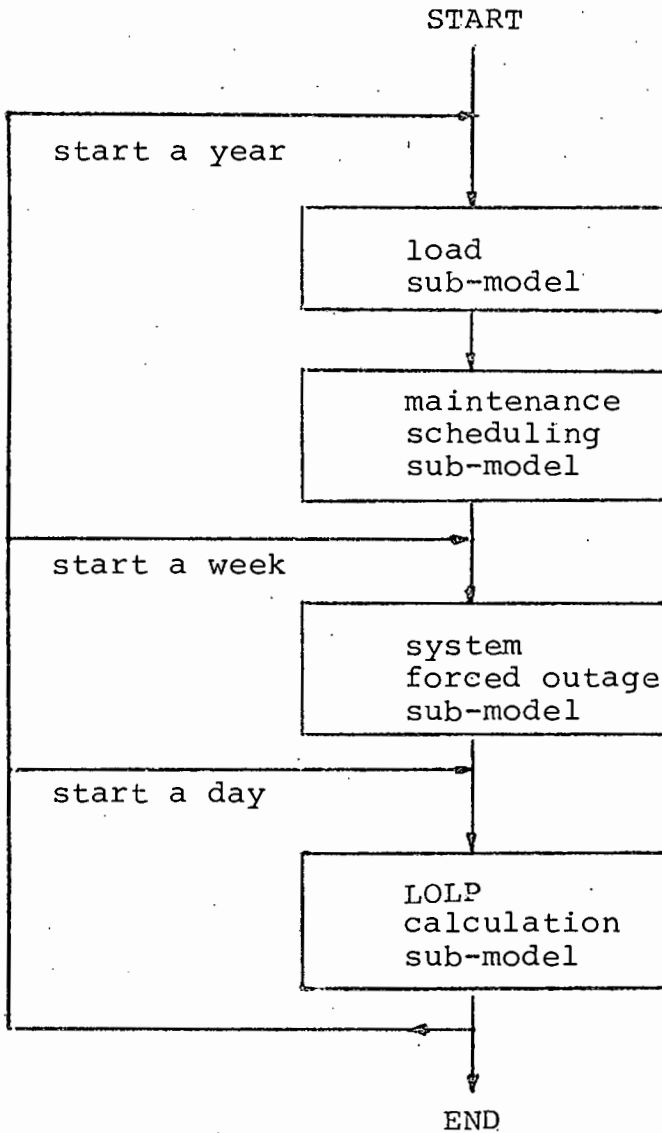


Figure 6.15: Structure of the probability calculation model.

is calculated from the following:

$$R_k = T_s - C_{s,k} - L_k + B_{s,k} \quad (6.31)$$

where  $R_k$  is the system reserve for the day  $k$ ,  $T_s$  is the total installed capacity at the beginning of the year  $s$ ,  $C_{s,k}$  is the amount of capacity out of service owing to planned maintenance in the year  $s$  and day  $k$ ,  $L_k$  is the peak load of the day  $k$  as calculated in the load sub-model and  $B_{s,k}$  is the increase or decrease in capacity to be installed or de-commissioned during the year.

There are two types of maintenance requests; the request for special maintenance where the user specifies the exact time of the maintenance and the request for general maintenance where the user specifies only the year in which the maintenance must be done and the program calculates the period of the maintenance. In the requests for general maintenance the largest unit will be scheduled first. The rule for scheduling is that the unit is scheduled in a time slot in such a way that the time frame selected must be the one in which maximum reserve is available. This method when applied to all sets requiring general maintenance, will have the effect of keeping the reserve at a uniform level and giving a low loss of load probability.

System forced outage sub-model:

The probability of having various amounts of installed capacity out of service owing to forced outages can be determined from the forced outage rates of the individual units. First, during the simulated time a list of the status of each set is stored in the program. The available capacity may be changed because of planned maintenance, the addition and retirement of sets and changes in the forced outage rates. Since the outage rates of individual units are independent of those of other units, the station capacity outage distribution function can be constructed from the binomial expansion (as explained in section 6.3). If the capacity of each set in the station is  $c$  megawatts, and  $N_s$  is the number of sets in service in the station, then the probability of having  $x$  megawatts in forced outage is:

$$P_s(x) = \binom{N_s}{i} p^{(N_s-i)} \cdot q^i \quad (6.32)$$

where  $p$  is the forced outage rate,  $q = (1-p)$  is the availability of the set, the binomial coefficients  $\binom{N_s}{i}$  are the possible combinations of events which result in having exactly  $x$  megawatts of capacity in forced outage, and  $x = i \cdot c_s$  megawatts.

For different power stations, the units do not have the same

capacity or the same forced outage rates, therefore the system outage distribution function is developed from a series of successive convolutions.

LOLP calculation:

For each day of the year the system peak load can be determined from the load sub-model. To allow for representation of changes in the system capacity resulting from planned maintenance, new generation installations and the retirement of old units the system capacity distribution is developed for each day of the year. The system loss of load probability for the day is then calculated as shown in equation (6.33) by combining the peak load for the day with the corresponding distribution of the generation capacity.

$$LOLP_k = \sum_{x=0}^{x=L_k} P(x) \quad (6.33)$$

where  $L_k$  is the peak demand of day  $k$ ,  $P(x)$  is the probability of having  $x$  megawatts of capacity available and LOLP is the loss of load probability for day  $k$  and represents the probability of having  $L_k$  megawatts of capacity or less available to supply the load. The loss of load probability for the year is the sum of the daily LOLP's.

In the input data the information regarding the expected load is given by the annual peak load, the weekly maximum distribution of the year and the daily peak distribution in a week. A maximum of 5 weekly maximum curves and 5 daily peak curves are allowed. Each of the weekly peak curves and the daily peak curves is represented by a number of steps. For each step on the daily maximum curve the number of days and the value of the daily peak load, expressed per unit of the weekly maximum are given. For each step on the weekly maximum curve the number of weeks and the value for the weekly peak loads per unit of the yearly peak are given. From this information the daily peak, in megawatts, may be calculated for any day of the simulated period.

The input data for the power stations includes information

regarding the capacity of the stations, the number of sets and the forced outage rate. Each station may have one or more forced outage rates during the simulated period. For each power station there are two ways of specifying maintenance requirements. Fixed maintenance requests are used when the date of commencement of the maintenance is known in advance. General maintenance requests are used when the scheduling of the maintenance is done in the program. For general maintenance requests the year and the duration of the maintenance is given and for fixed maintenance requests the week in which the maintenance is scheduled to start is also given. The output reports include a list of the input data, the individual power station outage distribution, the schedule of maintenance, the daily system reserve and the LOLP of the total system.

To illustrate the use of the model an example of a small hypothetical system is presented. The generation system consists of 3 power stations with a total capacity of 3030 megawatts. The capacity of the individual sets, the forced outage rates and the maintenance requirements are summarised in table 6.23.

power station	no. of sets	set size (MW)	forced outage rate	maintenance requirements
A	6	60	0,03	2 sets, each for 12 weeks
B	6	330	0,04	2 sets, one for 9 weeks and the other for 11 weeks
C	3	230	0,02	-

Table 6.23: Power station input data.

The expected peak load for the year 1977, which is the study period, is 2500 megawatts. The weekly maximum data for the year is represented by a 12-step curve as shown in figure 6.16. The numerical values are given in table 6.24.

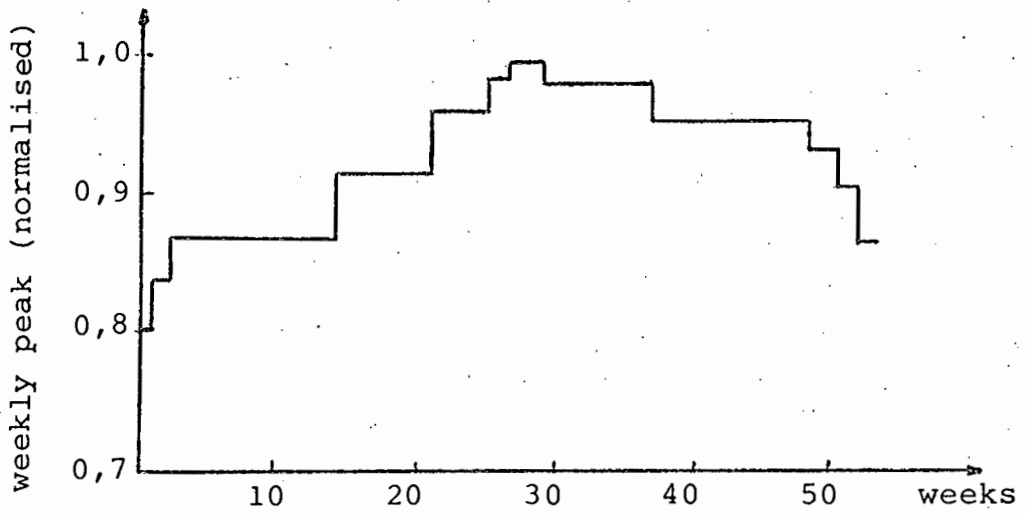


Figure 6.16: Weekly maximum curve.

no. of weeks	1	1	13	6	4	2	2	6	13	2	1	1
per cent value	0,80	0,84	0,87	0,92	0,96	0,99	1,00	0,99	0,96	0,94	0,90	0,86

Table 6.24: Input data for the weekly maximum curve.

Each week in 1977 is represented by the same daily peak maximum curve as shown in figure 6.17.

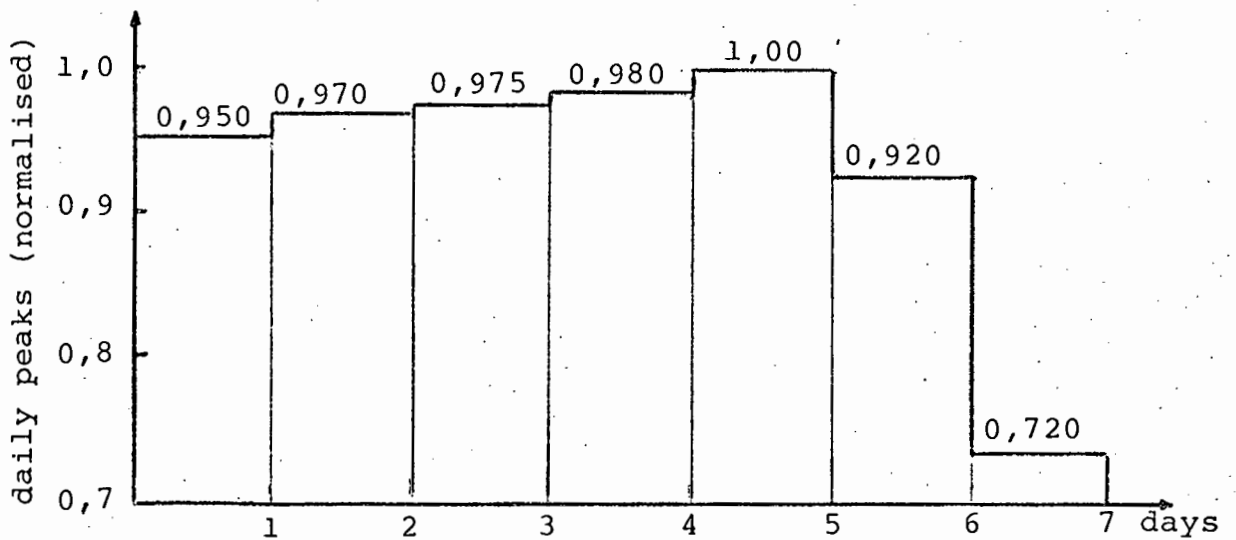


Figure 6.17: Input data of the daily peaks of a week.

The results of the study include the probability distribution of the generating capacity of each power station, as illustrated for one power station in table 6.25, the maintenance plan for the year as illustrated in table 6.26, and the daily values of the peak demand, the reserve margin and the loss of load probability. Typical results for one week are shown in table 6.27. The individual daily LOLP values are summated to give the total annual loss of load probability of 5,5 days in one year which is equivalent to a probability of  $5,5/364 = 0,0151$ .

megawatts in	discrete distribution	megawatts out	integrated distribution
0	$0,78276 \cdot 10^0$	1980	0,782758
330	$0,19569 \cdot 10^0$	1650	0,978447
660	$0,20384 \cdot 10^{-1}$	1320	0,998832
990	$0,11325 \cdot 10^{-2}$	990	0,999964
1320	$0,35389 \cdot 10^{-4}$	660	0,999999
1650	$0,58982 \cdot 10^{-6}$	330	1,000000
1980	$0,40960 \cdot 10^{-8}$	0	1,000000

Table 6.25: Study results of the probability distribution of power station B (6 sets each of 330 megawatts).

station	megawatts out of service	start at	complete at	no. of weeks out of service
A	60	week 36, 1977	week 47, 1977	12
A	60	week 36, 1977	week 47, 1977	12
B	330	week 1, 1977	week 9, 1977	9
B	330	week 10, 1977	week 20, 1977	11

Table 6.26: Model results of the maintenance plan.

day no.	week no.	load (MW)	re-serve (MW)	reserve per cent	LOLP	accumulated LOLP for the year
120	18	2185	515	19,07	$0,24995 \cdot 10^{-1}$	1,78049
121	18	2231	469	17,37	$0,25794 \cdot 10^{-1}$	1,80629
122	18	2243	458	16,94	$0,27705 \cdot 10^{-1}$	1,83399
123	18	2254	446	16,52	$0,27705 \cdot 10^{-1}$	1,86170
124	18	2300	400	14,82	$0,52441 \cdot 10^{-1}$	1,91414
125	18	2116	584	21,63	$0,16613 \cdot 10^{-1}$	1,93075
126	18	1656	1044	38,67	$0,15720 \cdot 10^{-3}$	1,93091
installed capacity : 3030 MW in service : 2070 MW on maintenance : 330 MW						

Table 6.27: Model results for a typical week of the study period.

CHAPTER 7

TRANSMISSION NETWORK ANALYSIS

7.1 POWER SYSTEM ANALYSIS

Previous chapters have indicated how the total demand can be estimated and how guidance on the corresponding plant capacity, mix and size can be obtained. It is now necessary to determine the network configuration required to connect the proposed new generation plant and to reinforce the transmission and distribution networks.

Transmission networks have several functions:

- a) the bulk transmission of power by high voltage links from the generating stations to large demand centres,
- b) the distribution of power to substations which, in turn, supply lower voltage networks over the whole area of supply, and
- c) the pooling of the available generation and the demand so that the whole system can operate in the most economic manner.

The term transmission is normally applied to the bulk transfer of power by high voltage links between the main load centres, and the term distribution usually implies the conveyance of this power by means of lower voltage networks.

Designing an electric network system has many similarities to the designing of any other transportation system, for example a road system. Many constraints must be taken into account, of which the more important are:

- a) the existing system,
- b) the geographical location of present and projected future load centres, and
- c) the location of the power stations.

Just as the geographical structure and the traffic handling capacity of the road system must be determined by present and future traffic flow patterns and volume, so must the design of an electric transmission system be governed by present and future

load flow patterns and load volume. A properly designed network system should meet the following requirements:

1. It must supply energy wherever it is required by the customer in such a way as to meet the customer's demands.
2. The load demands for real and reactive power vary with time. The system must be able to supply this ever changing demand.
3. The delivered energy must meet certain minimum requirements in regard to "quality". These include:
  - a) low variation in frequency,
  - b) low variation in voltage, and
  - c) high reliability.

An important consideration in planning a transmission system is how best to achieve the reduction of the voltage and current values in the main transmission system to the values needed by the consumers. As shown in figure 7.1, the power system is made up of networks which operate at various voltage levels and are separated by transformers. The voltage at the generator terminals, which is usually in the range of 11 - 20 kV, is increased by transformers to the voltage level of the main transmission system. The functions of the main transmission system are to transmit a large amount of power from the generating stations to the load centres and to interconnect all the power stations and all the major loading points in the system. The energy can generally be routed in any desired direction on the various links of the transmission system in such a way that ensures the optimum economic and technical operating conditions. In South Africa the main transmission network consists of 275 and 400 kV lines linking the Transvaal, the Western and Eastern Cape, Border and Natal. Most of the large and efficient stations feed through transformers directly into this network.

The second network level consists of high voltage transmission lines (88 and 132 kV in South Africa), which distribute the energy to a number of distribution substations in a certain

geographical area. Some of the older and less efficient stations feed into this system which also serves directly some of the large consumers. The role of this network level is basically the same as that of the main transmission network, except that it serves a smaller geographical area and distributes less energy at lower voltage levels. An increase in the demand makes it necessary and economical to superimpose a new and higher voltage grid on the existing one.

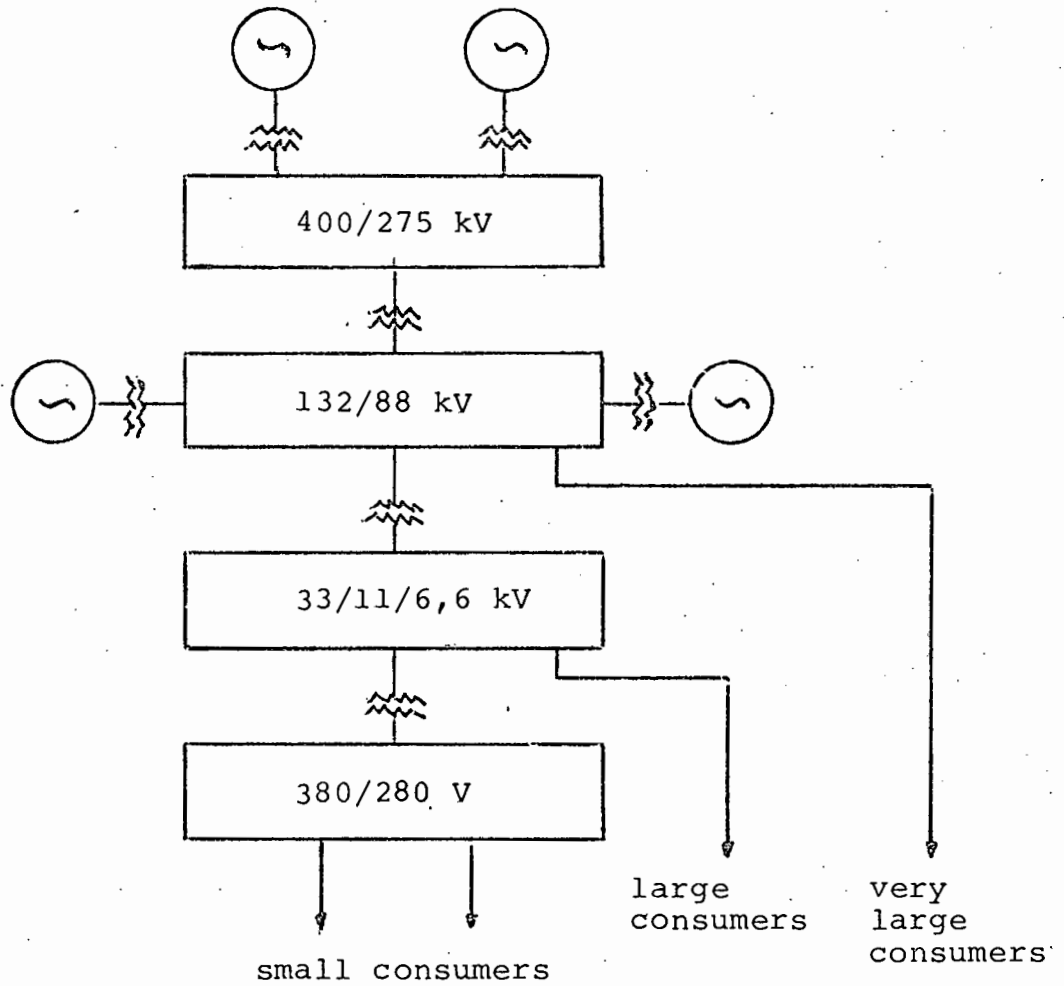


Figure 7.1: Schematic representation of the voltage levels in the South African system.

The distribution circuits constitute the finest meshes in the overall network. Usually two distribution voltage levels are used; the primary level which is concerned with the distribution to consumers in a given area and the secondary level which supplies the final consumer feeders. In South Africa the primary distribution networks operate at 6,6, 11 and 33 kV

and the secondary distribution networks operate at 380 V three-phase giving 220 V per phase.

There is a fundamental difference between the structure of the transmission networks and the structure of the distribution networks. The distribution networks generally have a radial structure whereas the transmission networks tend to have a loop structure (figure 7.2). A radial type of network is the obvious solution where the energy flow has a predominant direction. The loop structure gives more path combinations, and therefore better suits the purpose of the transmission level.

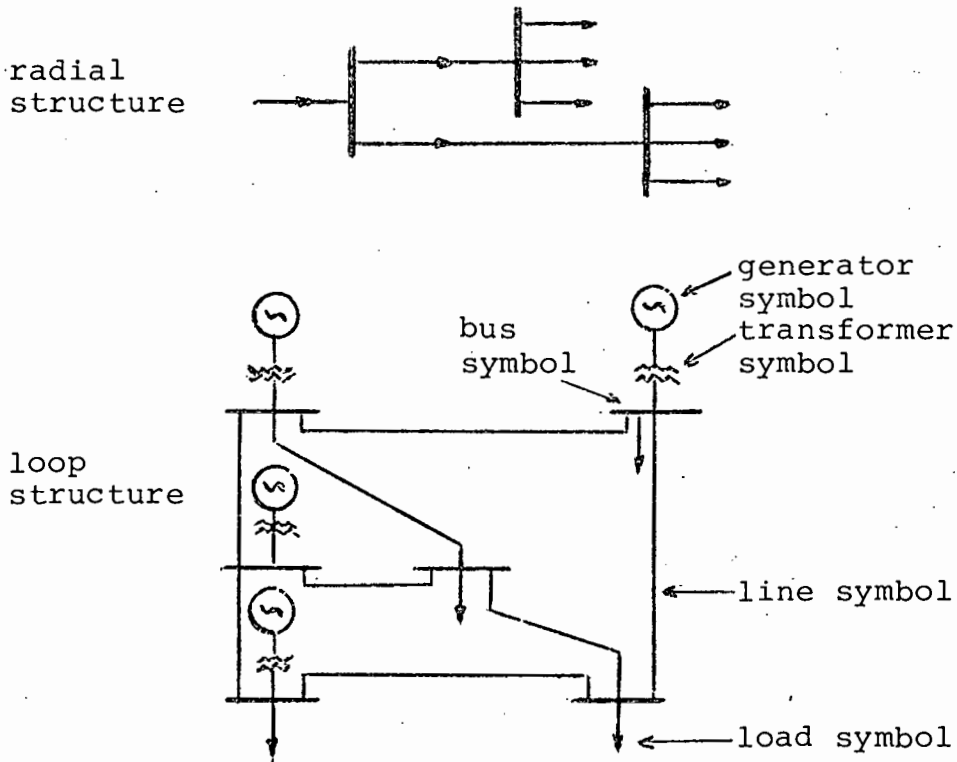


Figure 7.2: Radial and loop structured systems.

The basic differences in the methods and models required for planning the higher and the lower voltage system are to be found in the criteria for reliability and in the electrical simulation of the network. For example, the expansion of the lower voltage system is influenced most strongly by the criterion of the single outage of a line and less by the requirement for voltage stability. In the majority of cases the electrical properties of meshed low voltage systems can

be simulated with adequate accuracy by simplified flow methods complying with Kirchhoff's First Law. However, simulation of the high voltage system is more complex for the following reasons:

- a) The interaction existing between the planning of generation expansion and of system expansion and the difference between the availability of generating units and lines mean that the single outage as the sole reliability criterion does not ensure equal security of supply at the individual nodes.
- b) For the expansion planning of the high voltage system it is not only the load flows which are relevant, but also the fault levels and the stability limits.

Although the design and operation of the distribution networks entail the solution of many important and interesting technical problems, the most sophisticated engineering problems are encountered at the high voltage transmission level. The analysis techniques described here are applied mainly in the planning of the high voltage transmission networks.

The planning, design, and operation of a transmission system require a continuous and comprehensive analysis in order to evaluate the current system performance and to ascertain the effectiveness of alternative plans for system expansion. These studies play an important role in providing a high standard of power system reliability and ensuring the maximum utilisation of capital investment.

When engineers first began to use computers in power system analysis, a thirty to fifty busbar problem was very large. Today it is not uncommon for a 200 to 500 busbar problem to be solved. This requires the assembly of some 2000 network data items for the calculation of power flow or fault levels. Detailed transient stability studies, unbalanced fault level analysis, and other special purpose studies require a much wider range of data. A data base system, which enables the planning engineers to store and maintain the network data, is described in section 7.2.

The starting point for the analysis of the effectiveness of alternative plans for transmission system expansion is the calculation of power flows and voltages for a specified power system. This analysis requires the calculation of numerous load flows for both normal and emergency operation conditions. The voltage distributions are analysed to establish the needs for reactive or capacitative compensation so as to ensure that the variation of the voltages of all busbars is kept within limits.

Various contingency conditions with lines and equipment out of operation are simulated in order to determine the loading of the transmission circuits and to find out whether the required amount of energy can be transported from the appropriate generators to the loads, and whether the flow of reactive power in the network is acceptable. The formulation and the method of solution of the load flow problem is presented in section 7.3.

Information gained from a load flow study gives the engineer the voltages at the busbars in the network, the current flowing in the transmission lines and hence the line loading and the losses in the system. By varying the location and size of the generators and the size and number of transmission lines, he can design an optimum economical power system which will meet the load. He can also examine abnormal operating conditions, such as a transmission line outage condition.

In order to ensure a reliable supply, most power systems are designed to operate with some equipment out of service, and it is sometimes acceptable for certain power system equipment to be overloaded for short periods of time. These abnormal conditions must be carefully analysed to ensure that equipment is not stressed beyond acceptable limits, and also from a safety point of view.

Once a satisfactory power system configuration has been determined from load flow considerations, the behaviour under fault conditions must be examined. There is always the

unseen contingency of a system short circuit which must be cleared in the shortest possible time in order to minimise damage to equipment, while maintaining the ability of the system to satisfy the load demand. These short circuit currents must be known so that -

- a) the current interrupting capacity of the circuit breaker can be determined, and
- b) the relay settings can be fixed to cause the circuit breaker to operate when the current flowing through it exceeds the maximum allowable current, which is usually in excess of the full load current, but less than the short circuit current.

Short circuit calculations provide the currents and voltages in a power system for various types of fault conditions. The application of network matrices to the calculation of the fault currents is described in section 7.4. A typical computer program is described to illustrate a practical application of this technique.

The load flow and fault calculations require the solutions of simultaneous linear or non-linear equations. The network and all its elements are usually considered to be linear, giving the relation:

$$Y.V=I$$

where  $Y$  is the complex nodal admittance matrix and  $V$  and  $I$  are vectors of nodal voltages and current phases. A typical power system network has about 1,5 as many branches as busbars, and therefore the nodal admittance matrix which describes the coefficients of the network equations is usually sparse. In order to take advantage of the sparsity of the nodal admittance matrix, the triangular factorisation technique<sup>(39-42)</sup> was used in the solution of the network equations. As compared with the usual inverse of the coefficients matrix analysis, with this method large problems of several hundreds of busbars can be solved with reduced computer storage as only the non-zero terms are stored<sup>(43)</sup>.

The following algorithm shows how the network admittance

matrix can be reduced to triangular form. In figure 7.3 an example of a network is shown. The non-zero elements of the admittance matrix  $Y$  of this network are shown in equation 7.1.

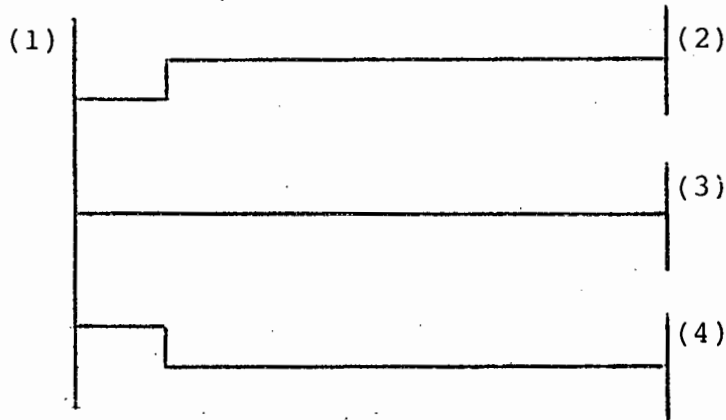


Figure 7.3: Example network.

The processing of the first row is accomplished by multiplying the first row by the reciprocal of its leading element, multiplying the new first row by the negative of the leading element of the second row and adding the product to the second row. The previous step is repeated for the third and the fourth rows. Equation 7.2 shows the pattern after processing the first row and equation 7.3 shows the form of the resultant upper triangle matrix  $U$  after processing the second- and the third rows.

$$Y = \begin{vmatrix} X & X & X & X \\ X & X & & \\ X & & X & \\ X & & & X \end{vmatrix}$$

(7.1)

$$Y' = \begin{vmatrix} 1 & X & X & X \\ X & X & X & \\ X & X & X & \\ X & X & X & \end{vmatrix}$$

(7.2)

$$U = \begin{vmatrix} 1 & X & X & X \\ & 1 & X & X \\ & & 1 & X \\ & & & 1 \end{vmatrix}$$

(7.3)

It is possible to get different solutions by varying the row and column sequence of the reduction process. If, for example, the numbering of rows and columns are interchanged in equation 7.1, the equivalent of equation 7.1 will be as shown in equation 7.4, and the pattern after processing the first row will be as shown in equation 7.5. The final upper

triangle matrix U will acquire the form shown in equation 7.6.

$$Y = \begin{vmatrix} X & & & \\ & X & & \\ & & X & \\ X & X & X & X \end{vmatrix} \quad (7.4)$$

$$Y' = \begin{vmatrix} 1 & & & \\ & X & & \\ & & X & \\ & X & X & X \end{vmatrix} \quad (7.5)$$

$$U = \begin{vmatrix} 1 & & & \\ & 1 & & \\ & & 1 & \\ & & & 1 \end{vmatrix} \quad (7.6)$$

The matrices of equations 7.3 and 7.6 are equivalent but the number of operations and the number of non-zero terms are different in the two cases. In order to reduce the computer storage requirements and the computation time, the individual busbar equations in the admittance matrix must be arranged in an order which will minimise the accumulation of non-zero terms in the upper triangular matrix during the elimination process. In the formulation of the load flow and the fault analysis problems the equations are sorted into the ascending order of the number of branches connected to each busbar. Although this arrangement is not the optimum, it greatly reduces the computing and memory requirements.

The solution of the admittance equation:

$$Y.V = I$$

is done in two steps with the aid of the following two equations:

$$\begin{aligned} L.W &= I \\ U.V &= W \end{aligned} \quad (7.7)$$

where L is the lower triangular matrix, U is the upper unit triangular matrix and  $l.U = Y$ . The lower triangular equation is first solved for the vector W by forward substitution. Then the vector V is found by backward substitution in the upper triangular equation.

Whenever a fault or disturbance occurs in a power system network, significant changes usually occur in the current that is flowing in the network and hence in the power transfer through the network. For example, if a short circuit occurs near a generator busbar, the power which can flow out of the generator into the network will drop suddenly. However, as

the power delivered from the boiler to the turbine driving the generator cannot drop as quickly, a net amount of power will be fed into the turbo-generator. Since there is no outlet for this power, it will accelerate the turbo-generator causing the speed to exceed that of other generators in the power network. Unless the fault condition is cleared quickly by rapid circuit breaker operation, the generators will get out of step with one another, large currents will flow in the network, power will be transferred from one generator to another in an oscillating manner, and the power system will become unstable. Under these conditions, relays will detect these excessive currents and cause circuit breakers all over the network to operate and this can result in a complete loss of supply.

Transient stability studies provide information with regard to the capability of a power system to remain in synchronism during major disturbances in the power system. Following a disturbance in the power system, these studies provide for each machine, the changes in the voltage, the real power output, the rotor slip and the angular position of the generator rotor relative to the rotating reference axis.

The starting point for a stability study is the determination of the steady-state conditions immediately before the occurrence of the system disturbance to be investigated. This is done with the aid of the load flow program. In this calculation the network is represented by busbars, transmission lines, RLC elements and loads. The network representation for the transient stability studies includes, in addition to these components, the characteristics of the generators and the motors in the system.

The operating characteristics of the synchronous machines are described by sets of differential equations. The number of the differential equations required to represent the system depends on the details needed to accurately represent the performance of the system. The solution of the transient stability study is therefore a combination of a solution of

the algebraic equations describing the network and a numerical solution of the differential equations.

In the stability study program<sup>(44)</sup> the impedance matrix method is used for the solution of the network equations, and the Range-Kutta methods are applied in the solution of the differential equations<sup>(45-48)</sup>. Also, in the program, there are various ways of representing the generators and the loads in the system. With the simple synchronous machine representation it is assumed that the voltage behind the transient reactance is constant and this gives a reasonable result for the first second or so after the disturbance. For stability analysis of longer periods it is necessary to use the full representation of the synchronous machines, which includes differential equations which are functions of the transient direct and quadrature axes time constants and reactance. The full machine representation may also include representation of the action of the automatic voltage regulator and the maximum and minimum limits and the time delay in the excitor of the two time constants of the governor, the steady-state and transient machine saturation conditions, and the machine damping factor which is due to damper windings and braking. In the full machine representation the loads can also be represented in a non-linear form.

The full representation gives a more accurate answer than the simple representation, especially when the fault is close to the generator or when the transient period lasts for a fairly long time, say 5 to 10 seconds. The full representation is also sufficient for doing dynamic stability studies when the disturbance is small and the stability limit of the system is of interest.

In many cases it is difficult to obtain the correct information for the full representation of the synchronous machines, as a large number of machine parameters are required. The main parameters such as reactance values and time constants are generally available but information about voltage

regulators and governors is sometimes difficult to obtain. In such cases it is possible to use a range of typical values in order to determine the importance of the various parameters.

So far, the solution of the network equation:

$$Y.V = I$$

for the steady-state and fault conditions has been achieved with the aid of three studies: load flow, which requires the solution of simultaneous non-linear algebraic equations, fault analysis, which requires the solution of simultaneous linear algebraic equations and transient stability, which requires the solution of simultaneous non-linear differential plus non-linear algebraic equations. These calculations are followed by the switching overvoltage studies. As the voltages of the transmission network are continually rising, the necessity for more highly refined insulation levels of the terminal equipment leads to further studies of overvoltage conditions. The single and three phase travelling wave studies are used for the calculation of the overvoltages in the power system network, owing to switching and lightning surges<sup>(49)</sup>. The object of the studies is to calculate transient overvoltages due to the energising and re-energising of the transmission line, switching operations, circuit breaker operations, and lightning phenomena.

For the purpose of calculating switching transients the elements of the power system are divided into those whose parameters are essentially lumped together, such as RLC components, generators, transformers and arrestors, and into overhead lines and underground cables whose parameters are of a distributive nature.

The program for solving the travelling wave equations<sup>(50)</sup> is based on the lattice diagram method. This method considers the voltage wave increments which travel up and down the line instead of the actual busbar voltages and line currents. Lines and cables are specified by their surge impedances and

surge travel times. The reflected and refracted voltages and currents at junctions and terminations are calculated by the use of reflection and refraction coefficients. For a single phase system these are:

$$K_r = \frac{Re - Zc}{Re + Zc} \quad \text{and} \quad K_t = \frac{2Re}{Re + Zc}$$

where  $Zc$  is the single impedance of the line or cable on which the wave is travelling and  $Re$  is the effective surge impedance encountered by the wave when it reaches the termination or junction. When a three phase system is considered the individual surge impedances are replaced by surge impedance matrices and it is necessary to solve three interconnected differential equations. The solution technique adopted is the transformation from the real domain of the three phase to ground voltages, to the modal domain where the resulting three differential equations are not coupled<sup>(51)</sup>. The solution of the transformed travelling wave equations provides three modes which are transferred back to the real domain to give the actual phase to ground voltage. Various additional facilities are available in the travelling wave program including representation of lumped inductive and capacitive elements and simulation of the arrestors with non-linear resistors and spark-gaps in series. Current sources may be used to inject current at a busbar or a node to simulate switching and lightning strokes. The current may be sinusoidal, exponential or rectangular. The output of the program includes a tabular listing or graphical output of the busbar phase voltages for every time-step used in the calculation.

A knowledge of the parameters of multi-conductor transmission lines is necessary in the application of load flow, fault analysis, stability analysis and travelling wave studies. Parameters may generally be divided into two groups, namely, those of power frequency which are required in order to study load flow, system stability and fault levels, and those of higher frequencies which are needed for studying the effects of switching and lightning surges on the overvoltages of the power system. Basic to the calculation of power and high

frequency parameters is the determination of the shunt admittance matrix  $Y$  and the series impedance matrix  $Z$ , and the calculation of the eigenvectors and eigenvalues of the product of these two matrices<sup>(52)</sup>. The power and high frequency parameters are calculated by a single program, namely, the transmission line parameters program<sup>(53)</sup>.

For the calculation of power frequency parameters the series and shunt parameters are calculated separately. From the conductor resistance and the geometric configuration of the conductors of the transmission line, the series impedance and shunt admittance matrices are calculated by using Carson's formula which includes the earth correction term<sup>(54)</sup>. From these matrices the positive and zero sequence impedances and susceptances, and the impedance, susceptance and capacitive distribution are calculated for each phase. The surge impedance matrix is computed from the eigenvectors and eigenvalues of the product of the matrices. In the case of a double circuit line, the zero-sequence mutual impedance and susceptance are also calculated.

At high frequency, as line lengths approach and exceed one quarter wave length, it is not possible to separate series and shunt parameters and the problem must be solved in terms of wave-propagation parameters. From the configuration, strand diameter and resistivity of the conductors, the conductor resistances and reactances are calculated, and from these values and the geometric configuration of the transmission line the series impedance and shunt admittance matrices are also determined. Earth effects are also considered here by using Carson's formula. The eigenvectors and eigenvalues of the product of these two matrices are computed and from the eigenvectors the real to model and model to real transformation matrices are found, and from the eigenvalues the velocity and attenuation of each mode is calculated.

## 7.2 POWER SYSTEM DATA BASE

In the past, the data necessary for power system calculations

was stored manually or on an ad-hoc basis. The difficulties of updating such records led to the tendency of individuals to keep personal files of particular data which was necessary for specific problems and functions. Inevitably, such data records tended to lack consistency and much time was wasted in verifying data which may have been obtained at second or third hand.

In order to enable the planning engineers to store and maintain their data efficiently, a computer program is used to handle the power system data. The program contains the following features:

- a) Simple data preparation, without complicated format requirements for data input. Where possible the input data is checked and incorrect data is rejected.
- b) Modification of the data is simple and quick, and this enables the engineers to study the effects of data changes on the results.
- c) Data base facilities which enable the sharing of input data between various studies. Also the results of one study can be used as input for another study.
- d) The power system data and results of calculations are stored permanently and in an organised fashion in the computer.
- e) The structure of the data base is flexible and new types of data can be added.
- f) The simple command language and free format data preparation are suitable for both interactive terminal use and batch processing.
- g) Flexible reporting facilities. The network and load flow results can be drawn from information on the data file.

The data describing a particular power system network is stored in a data base, or data file. The concept "data base" is used when the data is accessible to more than one user or to a number of programs, whereas a "data file" generally refers to data used by one person for a particular purpose. The data base is organised into a logical four-level structure as illustrated in figure 7.4.

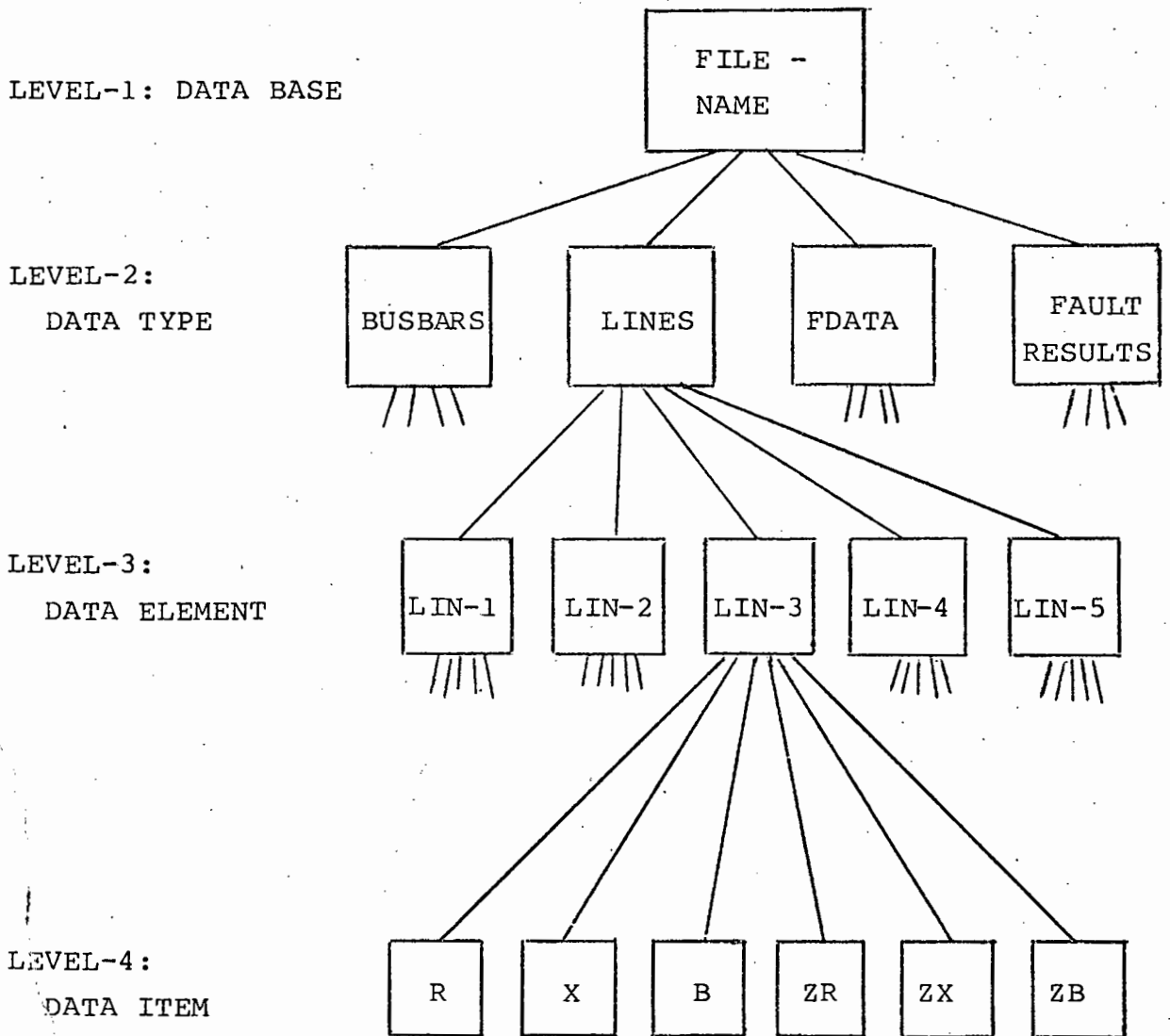


Figure 7.4: Structure of power system data base.

The data in each data base is divided into a number of groups, each containing elements of a particular type, such as transmission lines or transformers. The data items describe the elements in each group. These items are identified by sequential numbers, and therefore the same method is used for referring to data items within any group. For example figure 7.5 defines some of the data items in the transmission line group.

data item number	description
1	line code
2	busbar name, side A
3	busbar name, side B
4	resistance
5	reactance
6	susceptance
.	.
.	.

Figure 7.5: Some of the data items in the transmission line group.

The information stored in the data base includes, as illustrated in figure 7.6, the network data (busbars, lines.....), the calculation instructions (fault conditions for fault study, disturbance time for stability study .....), and the calculation results (load flow, fault levels ....).

data type	data element	Bus-1	1100...	Busbars
		Bus-2	6600...	
data file		Lin-1, Bus-1, Bus-2, 0,1 0,3		Lines
			data item	Fault conditions
				Flow re-sults

Figure 7.6: Information contained in the data base.

The user can investigate and update the data in the data base until it meets with his satisfaction. The calculation routines assess this data and write the results back into the data base. The user seldom supplies data directly to the calculation routines - the data communication is usually done via the data file as illustrated in figure 7.7.

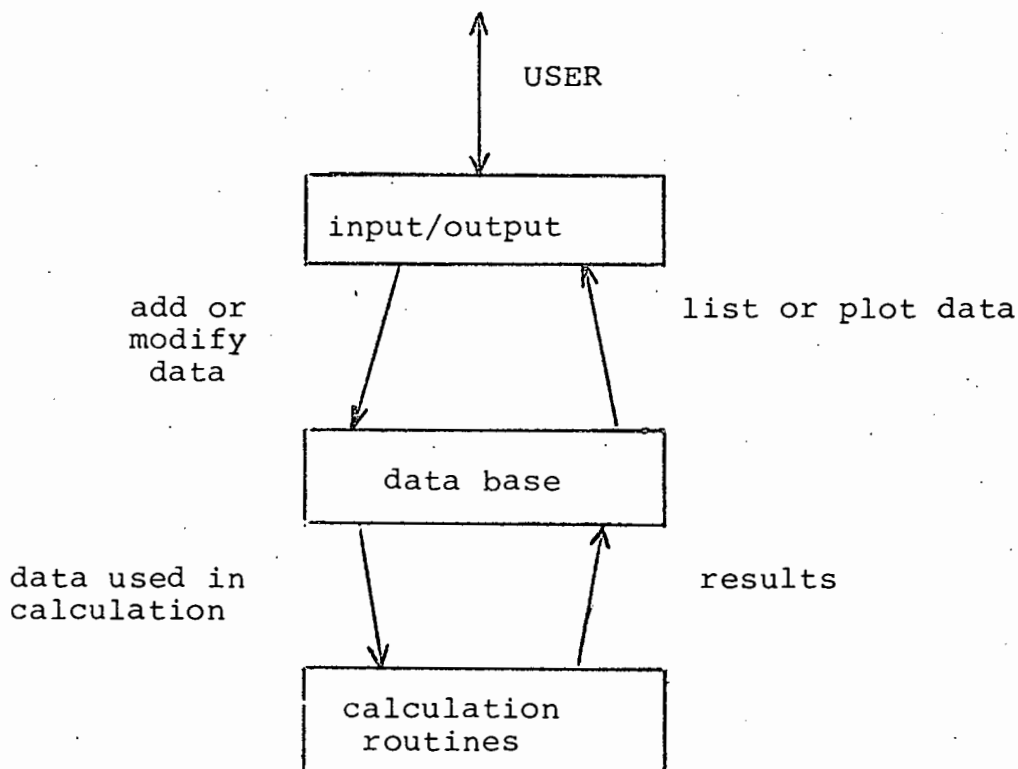


Figure 7.7: Communication with the data base.

In order to obtain a mimic diagram of the electrical networks together with the load flow results (voltage and power flow) on the plotter, the user needs to supply the coordinates of where each power network element is to be placed on the drawing. The plotting program has two modes of operation. Firstly, if the user is presented with a network which has not been plotted before, he makes a rough sketch of the network and assigns tentative coordinates to the element and then requests a set-up plot. As its name implies, this mode assists the user in setting up a new diagram. It plots the element symbols and the busbar names and it shows by means of red box outlines where the equipment and the data results will be plotted. The user can revise his original guesses of the coordinates so that the annotation and symbols do not overlap. The second mode of operation is used once the user has placed all his elements in suitable positions on the diagram. In this mode, as illustrated in figure 7.8, the electrical circuit network together with the numerical values of the load flow results are plotted.

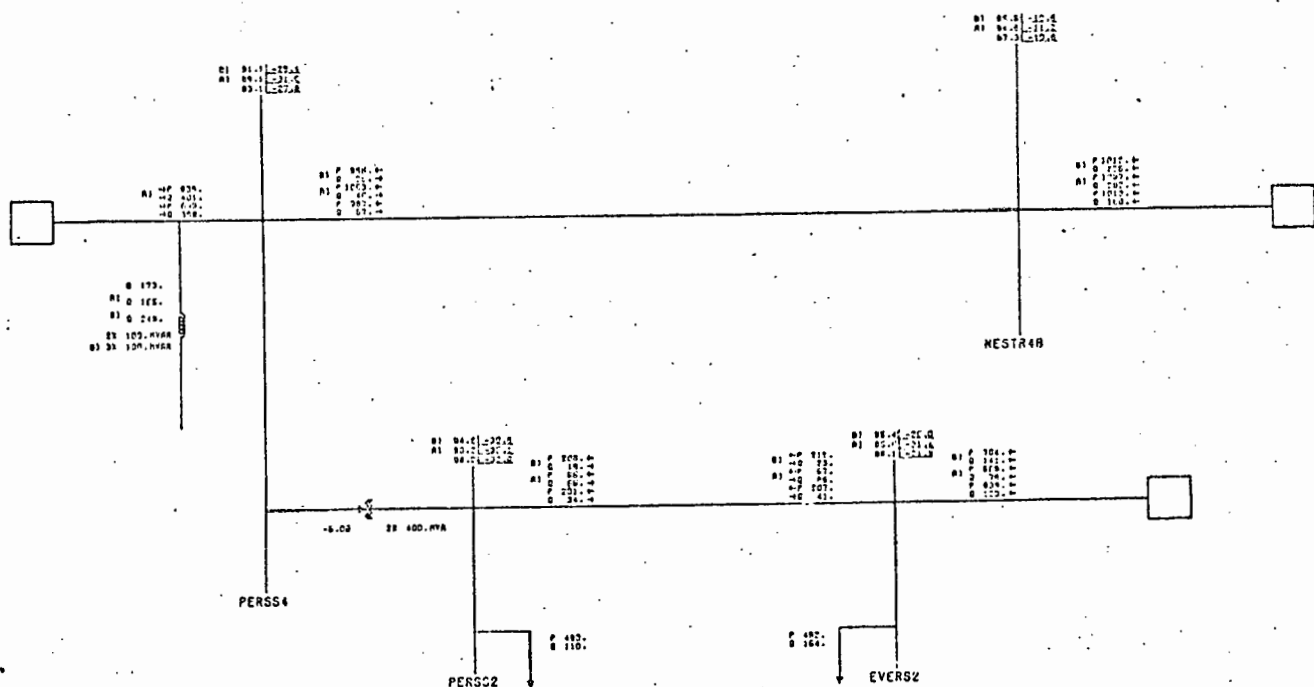


Figure 7.8: Electrical network plot.

### 7.3 LOAD FLOW STUDIES

Load flow studies are used for analysing the static operating conditions of an electric power transmission system, and they are the most frequently performed calculations among the power system analysis studies. Load flow calculations are performed in the planning of new networks, in the extension of existing networks, in operational planning and operation control.

In the last 20 years an enormous amount of effort has been expended in the development of various techniques for obtaining the numerical solution of the load flow equations<sup>(55)</sup>. Algorithmic improvements in load flow calculations over the years tended to be measured by the speed of their solution on the computer, rather than by other criteria such as simplicity in coding, maintaining and enhancing the algorithm of the computer program, or their ability to handle special features which were required by the planning engineers. However, for the traditional off-line solution, algorithmic

speed has ceased to be the most important parameter and input/output facilities are given much more attention in the design and coding of load flow programs.

The purpose of the load flow study is to find the power flow in each line and the busbar voltages for specified system conditions which include the real power output of the generators, the generator bus voltages, the generator var limits and the real and reactive load powers. The following features are available for the study:

- a) automatic tap changing transformers to maintain specified terminal voltage conditions,
- b) specified var limits for any or all of the generators including the swing machine,
- c) bus voltage controlled by a generator at a remote bus, and
- d) consecutive cases with specified line changes that are selected automatically.

For the solution of the load flow for a power system such as that shown in figure 7.9, a balanced three phase power system

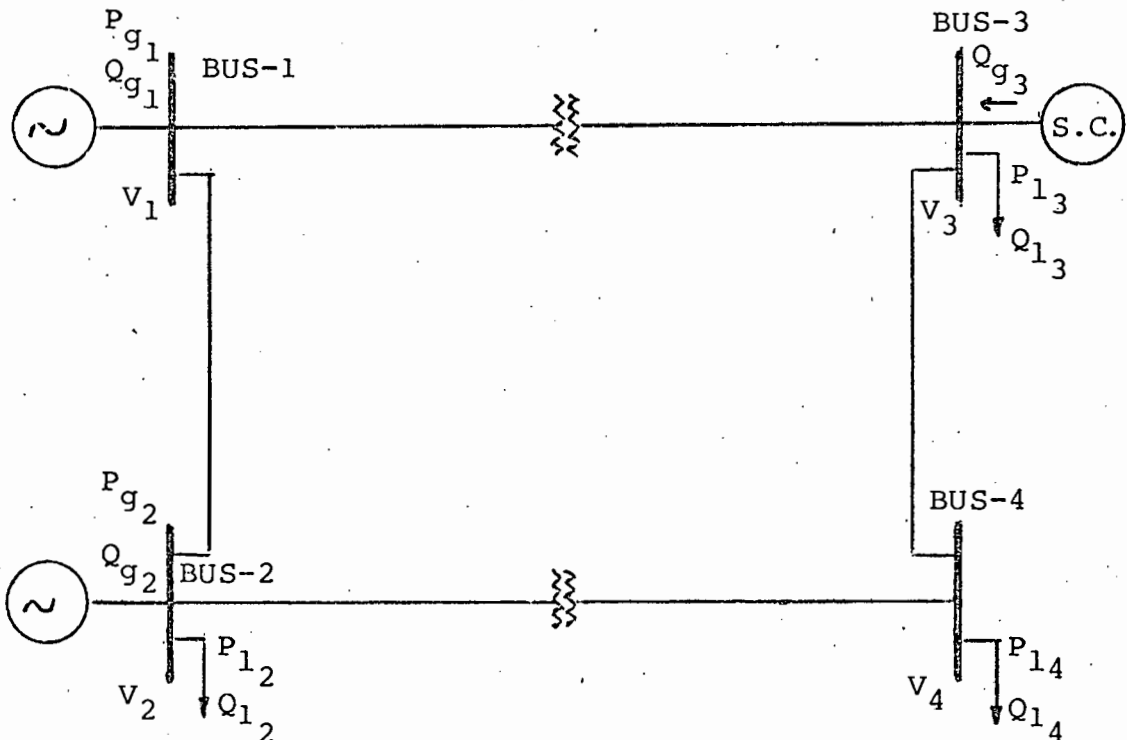


Figure 7.9: A typical system for load flow analysis.

is assumed, and the transmission system is represented by its positive phase sequence network of linear lumped series and shunt branches.

The solution to the problem of determining the voltage distribution in the power system, under specified loading and generating conditions, can be obtained from the system's nodal voltage equations:

$$[Y] \cdot [E] = [I] \quad (7.8)$$

where matrix Y is a square, sparse and symmetrical matrix (in the absence of phase shifters or mutual coupling), matrix E is a column matrix of the voltages and matrix I represents a column matrix of the equivalent nodal injected currents and it is calculated from the equation:

$$[I] = \left[ \frac{S^*}{E^*} \right] \quad (7.9)$$

where S is the net generation at a busbar, i.e.

$$S = (P_g - P_l) + j \cdot (Q_g - Q_l) \quad (7.10)$$

The operating state of the system is specified by the constraints on the power or voltage at the network busbars. Busbars are categorised into three types, PQ busbars, PV busbars and slack busbars.

A PQ busbar is one at which the total injected power (P and Q) is specified, and the voltage magnitude V and the voltage angle  $\theta$  are calculated.

$$S_i^{\text{specified}} = (P_{g_i}^{\text{specified}} - P_{l_i}^{\text{specified}}) + j \cdot (Q_{g_i}^{\text{specified}} - Q_{l_i}^{\text{specified}}) = E_i \cdot I_i^* \quad (7.11)$$

A PV busbar is one at which the total injected active power P is specified, and the voltage magnitude V is maintained at a specified value by the reactive power injected. The reactive power injected Q and the voltage angle  $\theta$  are calculated.

$$P_i^{\text{specified}} = P_{g_i}^{\text{specified}} - P_{l_i}^{\text{specified}} = \text{Re}(E_i \cdot I_i^*) \quad (7.12)$$

$$V_i^{\text{specified}} = |E_i| \quad (7.13)$$

The system slack busbar is a fictitious concept, created by the load flow analyst. It arises because the system losses of the load flow calculation are not known in advance. Therefore, the total injected active power cannot be specified at every single busbar. It is necessary to choose one or more of the available voltage controlled busbars as slack, and to regard the active power as unknown. The difference between its expected and solved megawatt output then represents the error in the prior estimates of the system losses. The slack busbar voltage  $E$  is usually used as a reference for the system phase angle, and its complex voltage (magnitude and angle) is therefore known. The total injected power, consisting of the active power  $P$  and the reactive power  $Q$ , is calculated.

It is possible to solve the linear equation  $Y.E = I$  directly for  $E$  in terms of  $I$  using the inverse of  $Y$ , but before inverting  $Y$  the equation for the slack busbar is eliminated. This leads to the  $(n - 1)$ th order equation.

$$E = Z.I + C.E_s \quad (7.14)$$

where matrices  $E$  and  $I$  do not contain the slack voltage  $E_s$  and current  $I_s$ , and  $C$  is a constant vector.

The voltage for the different busbars in the network is determined by the interactive solution of equation (7.9) above, after substituting for each busbar current  $I$  ( $i \neq s$ ) from:

$$I_i = \frac{(P_i^{\text{specified}} - j.Q_i)}{E_i^*} \quad (7.15)$$

where  $Q_i = Q_i^{\text{specified}}$  for a PQ busbar and  $Q_i = Q_i^{\text{calculated}}$  for a PV busbar. The busbar voltages are re-evaluated by the iterative application of equations (7.14) and (7.15). These equations are solved by using a triangular factorisation

technique which exploits the sparseness of the admittance matrix. Instead of using a matrix inversion method, which requires large in-core computer storage of more than the square of the number of nodes, the triangular factorisation technique reduces the computer storage as only the non-zero elements are stored.

The load flow solution converges when the busbar constraints, as expressed in equations (7.11), (7.12) and (7.13), are satisfied within a given tolerance. In order to speed up the convergence, it is found that by strengthening the diagonal elements of the admittance matrix and sorting out the equations into an ascending order of the number of branches connected to each busbar, the number of iterations is considerably reduced.

The formulation of the load flow solution has been adjusted to include more facilities which simulate the real life power system. These facilities are incorporated into the process of finding the load flow solution by the adjustment of the relevant parameters from iteration to iteration.

In some networks the voltages at some busbars will be too low and will therefore give meaningless results. It is possible to specify a minimum voltage for the PQ busbars. If the calculated voltage drops below the minimum, megawatts are injected into the busbar and this busbar is changed into a PV type. In most cases it has been found to be practical to use a minimum voltage of 85%. This minimum voltage may be modified for specific load flow studies.

When the reactive power source at a PV busbar reaches its upper or lower limit of output, and its ability to maintain the scheduled voltage  $V_i^{\text{specified}}$  is lost, the busbar is converted to a PQ type with  $Q_{g_i}^{\text{specified}}$  set to the given limit.

An important aspect in the electrical network study is an acceptable voltage distribution. The voltages of some busbars

are usually controlled by the adjustment of the taps of the transformers, which are directly or indirectly connected with the busbars. With an automatic tap changing transformer facility it is possible to calculate the optimum adjustment of the transformer taps and thus to achieve the desired voltages of the busbars.

Many power system calculations involve the repeated solution of the load flow problem, with modifications to the network in each case. The load flow change facility provides a means of automatically effecting data changes in the calculation of a series of load flow cases. The starting values for the iterative solution of the load flow equations are usually taken from the load data. For each case there is an option of choosing starting values from the results of the first case or from the results of the previous case.

In order to illustrate a load flow study, a typical system network, as shown in figure 7.10, is used.

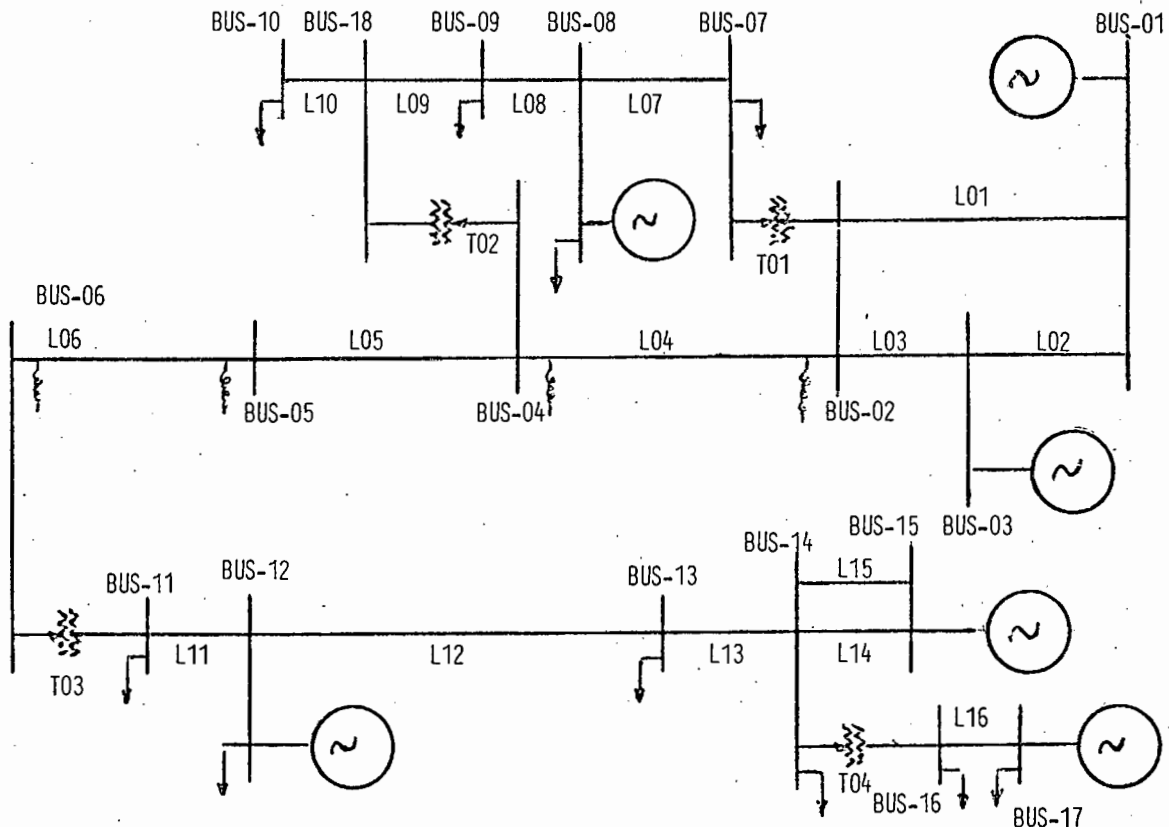


Figure 7.10: A typical system network.

The system includes 18 busbars, 16 lines, 4 transformers and 4 RLC elements. The busbars, given the code name of BUS-01 to BUS-18, all have maximum voltage limits of 107,5 per cent and minimum voltage limits of 92,5 per cent, except for busbar BUS-06, which has a minimum voltage limit of 99 per cent, and busbar BUS-16 which has a maximum voltage limit of 101 per cent. The input parameters for the network branches are given in table 7.1, and the input values for the busbar loads and generations are given in table 7.2. Three of the standard optional output reports, the busbar voltages and loads, the branch currents and the exception report of the exceeding limits are given in tables 7.3, 7.4 and 7.5 as representing the results of the study.

branch code	bus-A	bus-B	R (per unit)	X (per unit)	B(lines)or tap(trans- formers)	maximum limit level 1 (MVA)	maximum limit level 2 (MVA)
<u>LINES</u>							
L01	BUS-01	BUS-02	0,0032	0,0398	1,1600	100	
L02	BUS-01	BUS-03	0,0013	0,0164	0,9450		
L03	BUS-03	BUS-02	0,0004	0,0040	0,4700	300	500
L04	BUS-02	BUS-04	0,0053	0,0658	1,9200		
L05	BUS-04	BUS-05	0,0045	0,0556	1,6300		
L06	BUS-05	BUS-06	0,0041	0,0512	1,4900		
L07	BUS-07	BUS-08	0,0010	0,0065	0,1680		
L08	BUS-08	BUS-09	0,0050	0,0324	0,8820		
L09	BUS-09	BUS-18	0,0100	0,0559	0,3340		
L10	BUS-18	BUS-10	0,0087	0,0482	0,2970		
L11	BUS-11	BUS-12	0,1930	0,4060	0,3340		
L12	BUS-12	BUS-13	0,0478	0,2122	0,0412		
L13	BUS-13	BUS-14	0,0084	0,0376	0,0284		
L14	BUS-14	BUS-15	0,0040	0,0052	0,1275		
L15	BUS-14	BUS-15	0,0043	0,0097	0,0939		
L16	BUS-16	BUS-17	0,0064	0,1395	0,0962		
<u>TRANSFORMERS</u>							
T01	BUS-07	BUS-02		0,0060		400	600
T02	BUS-04	BUS-18		0,0120			
T03	BUS-06	BUS-11		0,0333	-5,0		
T04	BUS-14	BUS-16		0,0360	-4,0		
<u>RLC ELEMENTS</u>							
R01	BUS-02			1,0			
R02	BUS-04			1,0			
R03	BUS-05			0,5			
R04	BUS-06			1,0			

Table 7.1: The input parameters for the network branches.

Load code	bus	PL load (MW)	QL load (MVAR)	PG generation (MW)	type of busbar
S01	BUS-07	373,50	157,50		PQ
S02	BUS-08	135,00	67,50		PQ
S03	BUS-09	234,00	54,00		PQ
S04	BUS-10	49,50	22,50		PQ
S05	BUS-11	4,33	1,53		PQ
S06	BUS-12	28,81	11,71		PQ
S07	BUS-13	51,80	5,80		PQ
S08	BUS-14	2,66	1,00		PQ
S09	BUS-16	5,33	1,53		PQ
S10	BUS-17	27,97	8,99		PQ
S11	BUS-01			560,0	PV
S12	BUS-08			160,0	PV
S13	BUS-15			40,0	PV
S14	BUS-17			38,0	PV
S15	BUS-12			43,7	PV
S16	BUS-03				S

All values for QG are 0,0 MVAR  
 All values for VOLTAGE are 100,0 per cent  
 All values for ANGLE are 0,0 degrees

Table 7.2: The input values for the busbar loads and generations.

bus-code	angle	V(per cent)	PL	QL	PG	QG	type
BUS-01	3,45	100,00			560,00	-127,46	PV
BUS-02	-1,02	99,85					PQ
BUS-03	0,00	100,00			78,67	- 33,67	S
BUS-04	-4,83	100,81					PQ
BUS-05	-4,67	97,53					PQ
BUS-06	-4,62	96,71					PQ
BUS-07	-2,87	99,50	373,50	157,50			PQ
BUS-08	-3,53	100,00	135,00	67,50	160,00	107,70	PV
BUS-09	-7,02	99,57	234,00	54,00			PQ
BUS-10	-6,82	100,08	49,50	22,50			PQ
BUS-11	-4,61	102,07	4,33	1,53			PQ
BUS-12	-2,72	100,00	28,81	11,71	43,70	- 13,77	PV
BUS-13	-3,93	99,43	51,80	5,80			PQ
BUS-14	-3,03	99,87	2,66	1,00			PQ
BUS-15	-2,97	100,00			40,00	1,67	PV
BUS-16	-2,95	103,29	5,33	1,53			PQ
BUS-17	-2,08	100,00	27,97	8,99	38,00	- 19,77	PV
BUS-18	-5,51	100,90					PQ

Table 7.3: The output results for the busbar voltages and loads.

branch code	bus-A	bus-B	sending MW	sending MVAR	receiving MW	receiving MVAR
L01	BUS-01	BUS-02	194,84	- 62,29	193,62	38,42
L02	BUS-01	BUS-03	365,16	- 65,17	363,42	7,41
L03	BUS-03	BUS-02	442,09	- 26,26	441,31	12,85
L04	BUS-02	BUS-04	100,29	-115,02	99,74	71,38
L05	BUS-04	BUS-05	- 0,21	- 23,32	- 0,36	135,10
L06	BUS-05	BUS-06	- 0,36	- 55,16	- 0,37	85,26
L07	BUS-07	BUS-08	161,14	-108,38	160,78	- 94,03
L08	BUS-08	BUS-09	185,78	- 53,82	184,05	22,79
L09	BUS-09	BUS-18	- 49,95	- 31,21	- 50,23	1,83
L10	BUS-18	BUS-10	49,72	- 6,29	49,50	22,50
L11	BUS-11	BUS-12	- 4,70	9,82	- 4,85	23,97
L12	BUS-12	BUS-13	10,04	- 1,51	9,99	2,37
L13	BUS-13	BUS-14	- 41,81	- 3,43	- 41,96	- 1,28
L14	BUS-14	BUS-15	- 25,47	- 11,96	- 25,50	0,74
L15	BUS-14	BUS-15	- 14,49	- 11,77	- 14,50	- 2,41
L16	BUS-16	BUS-17	- 9,99	19,75	- 10,03	28,76
R01	BUS-02		0,00	99,70	0,00	0,00
R02	BUS-04		0,00	101,63	0,00	0,00
R03	BUS-05		0,00	190,25	0,00	0,00
R04	BUS-06		0,00	93,53	0,00	0,00
T01	BUS-07	BUS-02	-534,64	- 49,12	-534,64	- 66,59
T02	BUS-04	BUS-18	99,94	6,93	99,94	- 8,12
T03	BUS-06	BUS-11	- 0,37	- 8,27	- 0,37	- 8,29
T04	BUS-14	BUS-16	- 4,66	21,45	- 4,66	21,28

Table 7.4: The output results for the branch currents.

<u>Base case</u>			
23 iterations			
system generation		920,50	MW
system generation		- 85,38	MVAR
system losses		7,47	MW
system losses		-417,35	MVAR
<u>bus-code</u>	<u>voltage</u>	<u>limit</u>	
BUS-06	96,71	VMIN	- 2,3
BUS-16	103,29	VMAX	2,3
<u>branch-code</u>	<u>MVA</u>	<u>limit</u>	
L01	194,88	Lim 1	94,9
L03	442,10	Lim 1	47,4
T01	539,58	Lim 1	34,9

Table 7.5: The output results for the exceptional report of the exceeding limits.

A further load flow study is performed for a change case where three branches LO1, LO4 and RO1 are deleted from the system. The resulting exceptional report of the exceeding limits is given in table 7.6.

<u>Change case</u> - case 1		3 branches deleted LO1, LO4, RO1	
26 iterations			
system generation	925,16	MW	
system generation	167,85	MVAR	
system losses	12,13	MW	
system losses	-164,13	MVAR	
<u>bus-code</u>	<u>voltage</u>	<u>limit</u>	
BUS-05	91,07	VMIN	- 1,4
BUS-06	91,00	VMIN	- 8,0
BUS-16	103,29	VMAX	2,3
<u>branch-code</u>	<u>MVA</u>	<u>limit</u>	
LO3	640,47	Lim 2	28,1
TO1	641,74	Lim 2	7,0

Table 7.6: Output exceptional report for the change case.

#### 7.4 FAULT ANALYSIS

When a fault occurs in a power network, the current flowing is determined by the internal EMF's of the machines, their impedances, and the impedances in the system between the machines and the fault. These fault currents differ considerably from the steady - state values. The selection of circuit breakers for a power system and the calculation of relay operating time settings do not depend solely on the current that the breaker must carry under normal operating conditions but also on the maximum fault current that it may have to carry momentarily and on the current that it may have to interrupt.

On the basis of the symmetrical component theory, the fault analysis program is used for the analysis of a large number of common fault conditions. The symmetrical and unsymmetrical fault conditions include three phase faults, single phase to earth faults, two phase to earth faults, phase to phase faults and single series faults. The study confines itself to a bus type of fault or a branch element fault. From the results of

the study the branch currents and busbar voltages are obtained for any required number of busbars away from the fault.

For a balanced system, which is considered here, the network impedances are specified in terms of the zero, positive and negative values of the symmetrical component. It is assumed that the impedances are the same for the positive and the negative components.

Transmission lines are represented by a  $\pi$  type of equivalent circuit as shown in figure 7.11. Mutual coupling impedances between the lines may be considered only for the zero sequence network component.

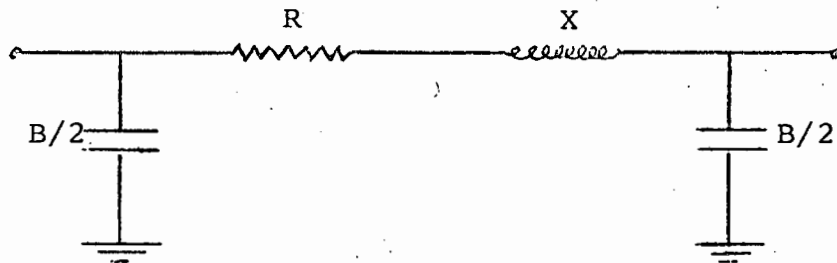


Figure 7.11: Representation of transmission lines.

The equivalent positive sequence network for a transformer with a tap is shown in figure 7.12.

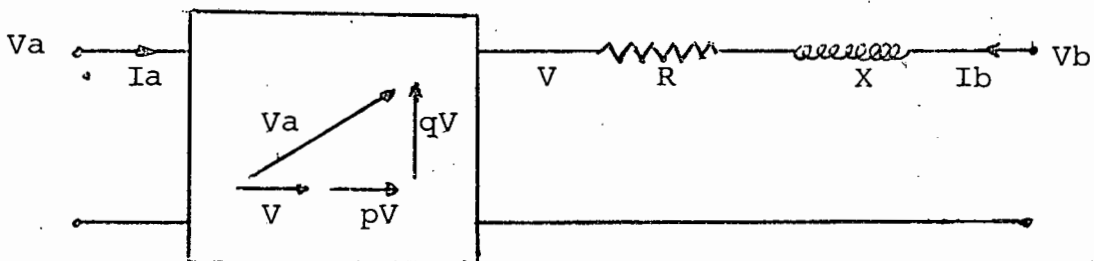


Figure 7.12: Representation of positive sequence of transformers.

The positive sequence of the transformer is represented mathematically by the following equations.

$$\begin{aligned}
 V_a &= (1 + p + jq) V \\
 I_a &= \frac{-I_b}{(1 + p - jq)} \\
 V_b &= V + Z \cdot I_b
 \end{aligned}
 \tag{7.16}$$

where  $Z = R + jX$ ,  $p$  is the tap setting and  $q = (1 + p) \cdot \tan(D)$ , where  $D$  is the phase shift in degrees.

The equivalent zero sequence network for a transformer depends on the type of winding connection. Three types of winding connections may be considered in the fault analysis program, the unearthed star connection (Y), the earthed star connection (E), and the delta connection (D). The equivalent zero sequence representation of these transformer connections is shown in figure 7.13.

Transformer Winding

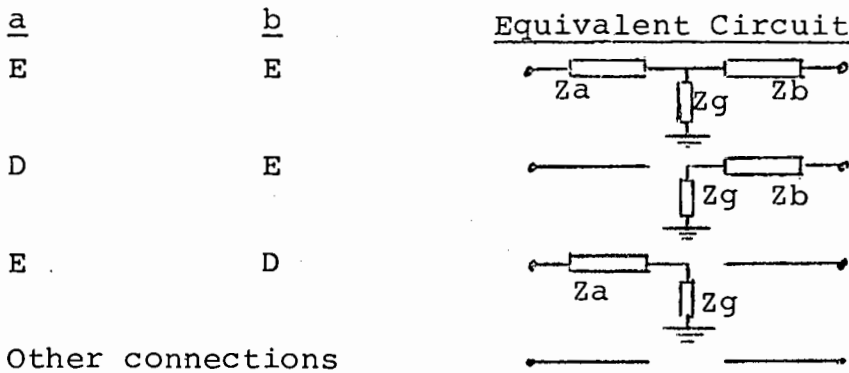


Figure 7.13: Equivalent zero sequence representation of transformers.

The negative sequence components are assumed to be equal to the positive sequence components. In the case of the transformers this gives the wrong secondary-to-primary phase current transformation. For example, for the DY1 transformer the positive sequence secondary phase currents lag behind the positive sequence primary phase currents by  $30^\circ$ . However, the negative sequence secondary phase currents lead those on the primary side by  $30^\circ$ .

The generator is represented by a voltage behind a fault

impedance which is usually the sub-transient reactance, as shown in figure 7.14. The voltage behind the fault impedance can be determined in three ways, depending on the data available.

- a) No loads or generation are specified, and the voltages are assumed to be one per unit. The effect of load current is ignored.
- b) The loads and generation are specified in the load data. The network voltages are calculated from the admittance matrix describing the network and the generator currents feeding into the network.
- c) Load flow results are available. Here the voltages behind the generator fault impedance can be determined directly from the load flow results.

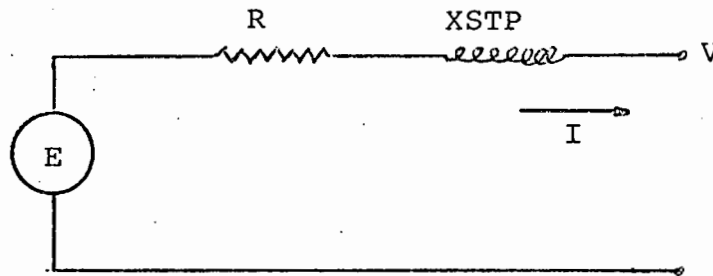


Figure 7.14: Generator representation.

The calculations of the fault currents are based on the pre-fault conditions in the network, which are determined from the loads, the generators and the voltages of the network busbars. The basic equation for a three phase symmetrical system is:

$$[Y] \cdot [V] = [Y_g \cdot V_g] \quad (7.17)$$

The matrix  $Y$  is obtained from the admittance data of the network branches. The internal admittance of the generators and the equivalent load admittances are added to the appropriate diagonal terms. Thus  $Y$  is the nodal admittance matrix of the network with all the generators short-circuited through their internal admittances. From equation 7.17, if  $Y$  is inverted, the solution becomes:

$$\begin{bmatrix} \mathbf{v} \end{bmatrix} = \begin{bmatrix} \mathbf{Z} \end{bmatrix} \cdot \begin{bmatrix} \mathbf{Y}_g \cdot \mathbf{V}_g \end{bmatrix} \quad (7.18)$$

Equation (7.18) enables the pre-fault voltage distribution to be determined. If a fault study follows a load flow study, the pre-fault voltages will already be available from the load flow results, which are stored in the data base. If load flow results and load data are not available the voltages on the generating busbars are assumed by the program to be one per unit.

In equation (7.18) the diagonal terms of the matrix  $Z$  represent the Thevenin impedances of the network viewed from any busbar. The Thevenin's equivalent circuit for a three phase fault is represented in figure 7.15.

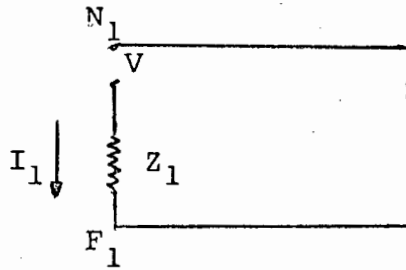


Figure 7.15: Equivalent circuit for a three phase fault.

The voltage  $V$  is the line to neutral voltage,  $N_1$  is the neutral terminal,  $F_1$  is the fault terminal,  $I_1$  is the fault level, and  $Z_1$  is the positive phase sequence diagonal term of the matrix  $Z$  corresponding to the fault busbar. In this case the positive, negative and zero sequence current components of the phase "a", are represented by  $I_{a_1}$ ,  $I_{a_2}$  and  $I_{a_0}$ , where

$$\begin{aligned} I_{a_1} &= \frac{V}{Z_1} \\ I_{a_2} &= 0 \\ I_{a_0} &= 0 \end{aligned} \quad (7.19)$$

and the fault level  $I_f$  in this case is equal to  $I_{a_1}$ .

It is usually assumed that the impedance of the fault-arc itself is very small, and is negligible in comparison with other impedances in the circuit. However, in many cases the contact resistance between the fallen conductors and the earth is not negligible. Any known fault impedance  $Z_f$  can be taken into account by including it in the sequence network and in this case equation (7.19) will be modified to become

$$I_f = \frac{V}{Z_1 + Z_f} \quad (7.20)$$

The various voltages are calculated from the fault level current  $I_f$  using a superposition method. The value of the voltage at any busbar  $s$ , with a fault on a busbar  $r$ , is the difference between the pre-fault voltage and the voltage produced by the injection of current  $I_f$  at the busbar  $s$  as shown in equation (7.21),

$$V_s \text{ (fault)} = V_s \text{ (pre-fault)} - I_f \cdot Z_{sr} \quad (7.21)$$

where  $Z_{sr}$  is an off-diagonal term of the matrix  $Z$  and represents the transfer impedances between the two busbars. It represents the voltage produced at busbar  $s$  by the injection of a current of one per unit at busbar  $r$ . The current flowing in any branch can be calculated directly from the voltage distribution.

For unsymmetrical faults a separate zero sequence impedance matrix is derived for the zero sequence network. For a single phase to earth fault the Thevenin's equivalent circuit is represented in figure 7.16 and the positive, negative and zero sequence current components of phase "a" are as shown in equation (7.22), and the fault level is equal to  $3 \cdot I_{a_0}$ .

$$I_{a_1} = I_{a_2} = I_{a_0} = \frac{V}{Z_0 + Z_1 + Z_2} \quad (7.22)$$

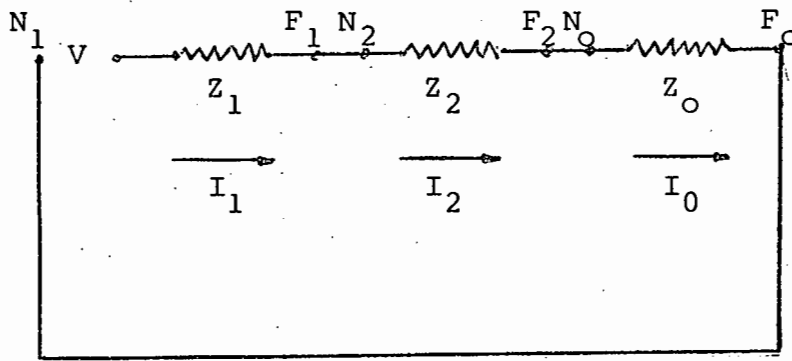


Figure 7.16: Sequence impedance network for the three phase to earth fault.

The sequence impedance network for the phase to phase fault is shown in figure 7.17.

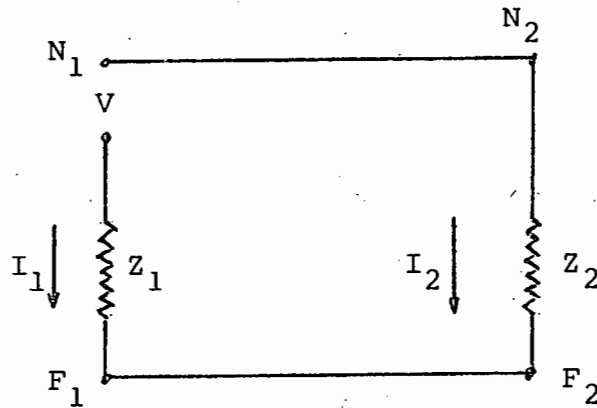


Figure 7.17: Sequence impedance network for phase to phase fault.

The current equations for phase "a" are:

$$I_{a1} = \frac{V}{Z_1 + Z_2}$$

$$I_{a2} = -I_{a1} \tag{7.23}$$

$$I_{a0} = 0$$

and the fault level is equal to  $\sqrt{3} \cdot I_{a1}$

The sequence impedance network for the two phase to earth fault is shown in figure 7.18.

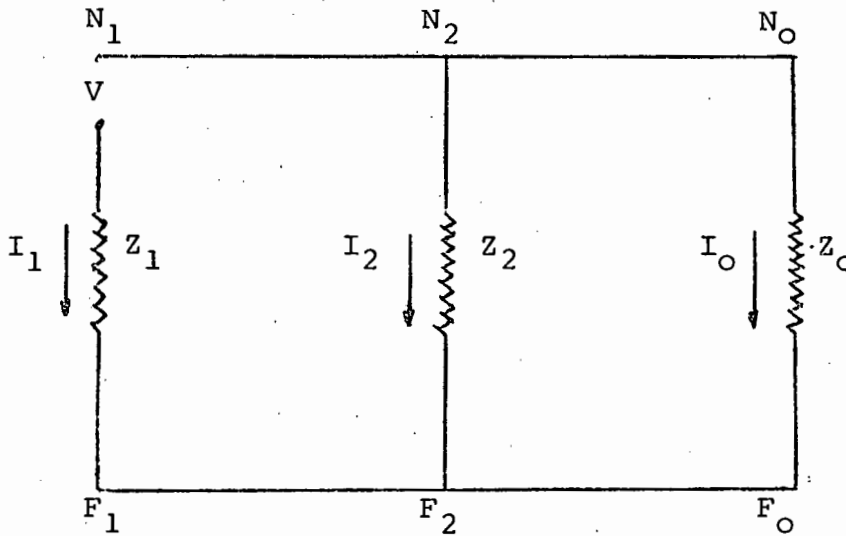


Figure 7.18: Sequence impedance network for the two phase to earth fault.

In this case the current equations are:

$$I_{a_1} = \frac{V}{Z_1 + \frac{Z_2 \cdot Z_0}{Z_2 + Z_0}} \quad (7.24)$$

$$I_{a_2} = -I_{a_1} \cdot \frac{Z_0}{Z_2 + Z_0}$$

$$I_{a_0} = -I_{a_1} \cdot \frac{Z_2}{Z_2 + Z_0}$$

and the fault level is equal to  $3 \cdot I_{a_0}$ .

The single series fault is conceptually different from the other types of faults. Whereas the other faults are called shunt faults, this one is called a series fault. A single series fault can occur only in a line when one phase in either end of the line is disconnected. This single phase opening is represented in the sequence networks by introducing a fault busbar at the point where the opening takes place, removing the link between the sending busbar and the fault busbar and connecting the sequence networks. The sequence impedance network and the corresponding current equations, in this case, will be similar to those of the two phase to earth fault.

The line currents  $I_a$ ,  $I_b$  and  $I_c$  are calculated from the sequence current components,  $I_{a_0}$ ,  $I_{a_1}$ , and  $I_{a_2}$ , as shown in the equations below,

$$\begin{aligned} I_a &= I_{a_0} + I_{a_1} + I_{a_2} \\ I_b &= I_{a_0} + \alpha^2 \cdot I_{a_1} + \alpha \cdot I_{a_2} \\ I_c &= I_{a_0} + \alpha \cdot I_{a_1} + \alpha^2 \cdot I_{a_2} \end{aligned} \quad (7.25)$$

where the operator  $\alpha$  is:

$$\alpha = 1 \cdot e^{j120^\circ} = -0,5 + j \cdot 0,866$$

Alternative expressions for the line currents are:

$$\begin{aligned} I_a &= I_{a_0} + I_{a_1} + I_{a_2} \\ I_b &= I_{a_0} - 0,5 (I_{a_1} + I_{a_2}) - j \cdot 0,866 (I_{a_1} - I_{a_2}) \\ I_c &= I_{a_0} - 0,5 (I_{a_1} + I_{a_2}) + j \cdot 0,866 (I_{a_1} - I_{a_2}) \end{aligned} \quad (7.26)$$

In fault studies the situation frequently arises where a basic case is first studied and then the effects of several outages in the network configuration need to be assessed. A common requirement is to evaluate the fault currents under conditions of sequential clearing of a feeder fault by the opening of a circuit breaker at one end of the feeder before that at the other end. In such cases the different types of fault conditions for various network outage conditions can be specified and the various cases will be considered automatically in the same study.

A variety of output reports of the system currents and voltages can be selected for printing. For example, the user can select to be printed

- a) only the currents for those branches which are connected to the fault bus, or
- b) the currents for those branches connected to the fault bus as well as the branches which are connected to every adjoining bus, or
- c) the currents for any number of busbars away from the fault bus, or

d) the currents for all the branches or any specific branches.

A similar variety of voltages can also be selected to be printed.

An example of a small network is illustrated in figure 7.19. The input data for this network is given in table 7.7. Two fault cases have been analysed. In the first case a single phase to earth fault on the busbar BUS-5 is considered. The line L8 has been deleted from the network. The output requested includes the currents at all branches and the voltages for the busbars BUS-1 and BUS-3. The output results are shown in table 7.8. In the second case a three phase fault is considered. The fault occurs on the line L5 at a distance of 40 per cent from the busbar BUS-6. Also in this case the line L8 has been deleted from the network. The output requested includes the currents at all branches and the voltages for the busbars BUS-1, BUS-5, and BUS-6. The results for the second case are given in table 7.9.

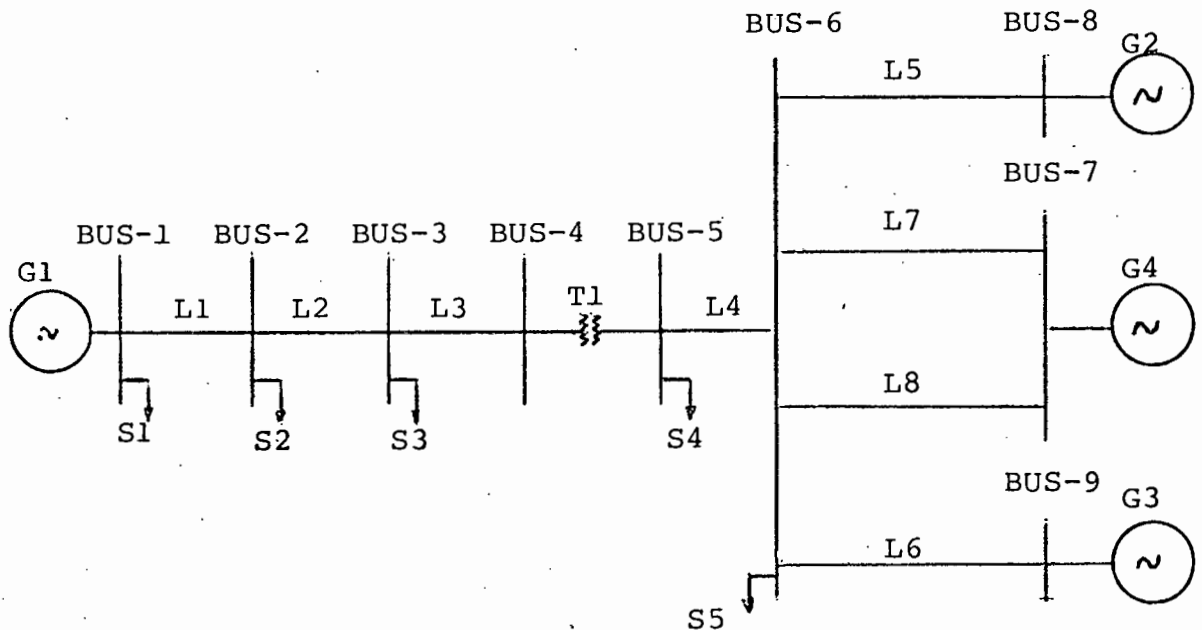


Figure 7.19: One line network diagram for fault study example.

branch code	bus-A	bus-B	R	X	B(lines) or tap (transformer)	ZX
<u>LINES</u>						
L1	BUS-1	BUS-2	0,0016	0,0107	0,2780	0,01
L2	BUS-2	BUS-3	0,0027	0,0178	0,4600	0,01
L3	BUS-3	BUS-4	0,0161	0,0892	0,5500	0,01
L4	BUS-5	BUS-6	0,0187	0,2820		0,01
L5	BUS-6	BUS-9		0,3860		0,01
L6	BUS-6	BUS-8		0,6300		0,10
L7	BUS-6	BUS-7		0,5000		0,10
L8	BUS-6	BUS-7		0,5000		0,10
<u>TRANSFORMER</u>						
T1	BUS-4	BUS-5		0,2160	-5,0	
load code	bus	PL	QL	PG	VG	type of busbar
S1	BUS-1	150,0	80,0		109,0	S
S2	BUS-2	25,0	14,0		100,0	PQ
S3	BUS-3	160,0	80,0		100,0	PQ
S4	BUS-5	40,0	32,0		100,0	PQ
S5	BUS-6	30,0	24,0		100,0	PQ
S6	BUS-7	20,0	12,5		100,0	PQ
S7	BUS-8			15,0	100,0	PV
S8	BUS-9			10,0	100,0	PV
S9	BUS-7			35,0	100,0	PV
generator code	bus		MVA		STP	
G1	BUS-1		390,0		0,40	
G2	BUS-8		21,9		0,17	
G3	BUS-9		20,0		0,18	
G4	BUS-7		40,0		0,18	

Table 7.7: Input data for fault analysis example.

Fault identification : case 1

fault type: single phase to earth

branch deleted is : L8

fault level on BUS-5 is 540,6449 MVA, angle -95,8

bus-A	bus-B	branch	units	3lo		phase A		phase B		phase C	
				value	angle	value	angle	value	angle	value	angle
BUS-1			volt (%)	0,000	0,0	77,993	- 12,6	94,292	-130,3	90,207	99,6
BUS-3			volt	0,000	174,2	70,513	- 14,6	91,519	-131,1	87,110	95,3
BUS-5	BUS-6	L4	curr(MVA)	540,645	84,2	315,038	88,8	149,635	80,0	78,768	73,5
BUS-4	BUS-5	T1	curr	0,000	0,0	241,044	-101,9	132,692	93,5	118,508	60,8
BUS-5	BUS-4	T1	curr	0,000	0,0	228,991	78,1	126,058	- 86,5	112,583	-119,2
BUS-3	BUS-4	L3	curr	0,000	- 95,8	227,248	-101,9	119,321	84,4	109,452	71,2
BUS-6	BUS-8	L5	curr	447,424	84,2	198,495	88,4	146,610	78,3	103,623	84,3
BUS-6	BUS-9	L6	curr	46,553	84,2	53,609	94,3	15,607	41,3	17,698	- 99,6
BUS-6	BUS-7	L7	curr	46,669	84,2	73,393	95,9	15,259	31,2	34,496	- 91,2
BUS-2	BUS-3	L2	curr	0,000	- 95,8	276,853	- 78,1	108,224	166,0	249,414	78,9
BUS-8		G2	curr	447,424	84,2	198,495	88,4	146,610	78,3	103,623	84,3
BUS-9		G3	curr	46,553	84,2	53,609	94,3	15,607	41,3	17,698	- 99,6
BUS-7		G4	curr	46,669	84,2	83,847	105,4	36,437	32,2	53,941	- 94,0
BUS-1	BUS-2	L1	curr	0,000	- 95,8	270,421	- 72,9	104,182	-177,0	265,153	84,7
BUS-1		G1	curr	0,000	84,2	361,272	117,4	228,526	16,2	388,007	- 97,9

Table 7.8: Fault study results for case 1.

Fault identification : case 2      fault type : three phase  
 fault position is 40,0 per cent from BUS-6 on line L5.  
 branch deleted is : L8  
 fault level on FAULTBUS is 293,0781 MVA, angle -93,0.

bus-A	bus-B	branch	units	value	$3I_o$	angle
BUS-1			volt(%)	89,237		- 14,9
BUS-5			volt	56,088		- 18,2
BUS-6			volt	30,154		- 7,9
FAULTBUS			volt	0,000		0,0
BUS-6	FAULTBUS	L5	curr(MVA)	195,201		- 97,9
FAULTBUS	BUS-8	L5	curr	99,891		96,6
BUS-5	BUS-6	L4	curr	95,451		-166,0
BUS-6	BUS-9	L6	curr	46,632		100,6
BUS-6	BUS-7	L7	curr	71,266		101,7
BUS-8		G2	curr	99,891		96,6
BUS-4	BUS-5	T1	curr	118,855		-103,4
BUS-5	BUS-4	T1	curr	112,912		76,6
BUS-9		G3	curr	46,632		100,0
BUS-7		G4	curr	82,642		109,8
BUS-3	BUS-4	L3	curr	97,890		-102,7
BUS-2	BUS-3	L2	curr	189,709		- 57,8
BUS-1	BUS-2	L1	curr	194,709		- 59,0
BUS-1		G1	curr	315,630		135,3

Table 7.9: Fault study results for case 2.

CHAPTER 8

FINANCIAL PLANNING

8.1 FINANCIAL MODELS IN THE SOUTH AFRICAN ELECTRICITY  
SUPPLY INDUSTRY

There is an increasing interest in the development of power utility financial models throughout the world. System expansion plans can no longer be viewed in isolation but must be studied with the realisation that these plans will affect the entire company with regard to its financial needs and future structure.

The purpose of financial planning in the South African electricity supply industry is to establish a framework for making investment decisions. The South African electricity supply industry is subject to price and profit regulations, and the operating expenses and a portion of the annual expenditure are financed from revenue. The remaining expenditure is financed by the issuing of long-term bonds.

While the demand for electricity continues to increase it is not at all meaningful to consider whether generating stations and transmission plants should be built, because these are non-optional investments. Thus the utility planners will normally choose, within internally and externally imposed limits, the projects which offer the lowest present value of the costs of the total system. The key financial considerations are therefore to evaluate the effect of the expansion, production and distribution projects on the utility's capital requirements and to provide predictions of the likely future revenue and the additional external capital resources that may be required.

A financial planning model is a mathematical representation of the financial aspects of the utility. Models, constructed by manual methods or with the aid of computer programs, can

provide projections of the financial statements for the various stages of planning for different departments as well as consolidated corporate financial statements. The process of constructing a financial model is illustrated in figure 8.1.

All financial models have certain characteristics in common:

- 1) They provide a framework for the utility planners in which they can specify the relevant assumptions regarding the utility's operation, the logic of the analysis and the format in which the results are to be presented.
- 2) They allow the utility planners to re-use the basic model for various sets of assumptions and to obtain the corresponding results in the form of financial reports, which show the impact of the assumptions on the balance sheet, revenue and expenditure account, and other aspects of financial planning.

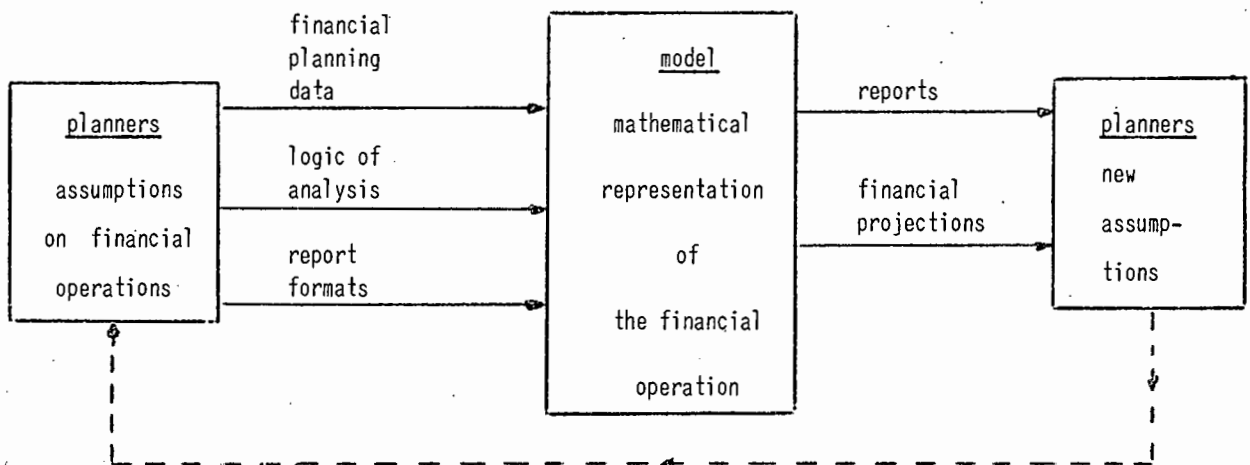


Figure 8.1: A typical model cycle.

Figure 8.2 shows the main components of the financial modelling system. This modelling system is designed to produce standard financial statements for yearly time intervals. The model may be used for providing financial measures for evaluating a specific expansion plan or for the calculation of the financial needs and the revenue required for different levels of self-financing. (The level of self-financing is defined as the proportion of the construction expenditure which is financed from revenue).

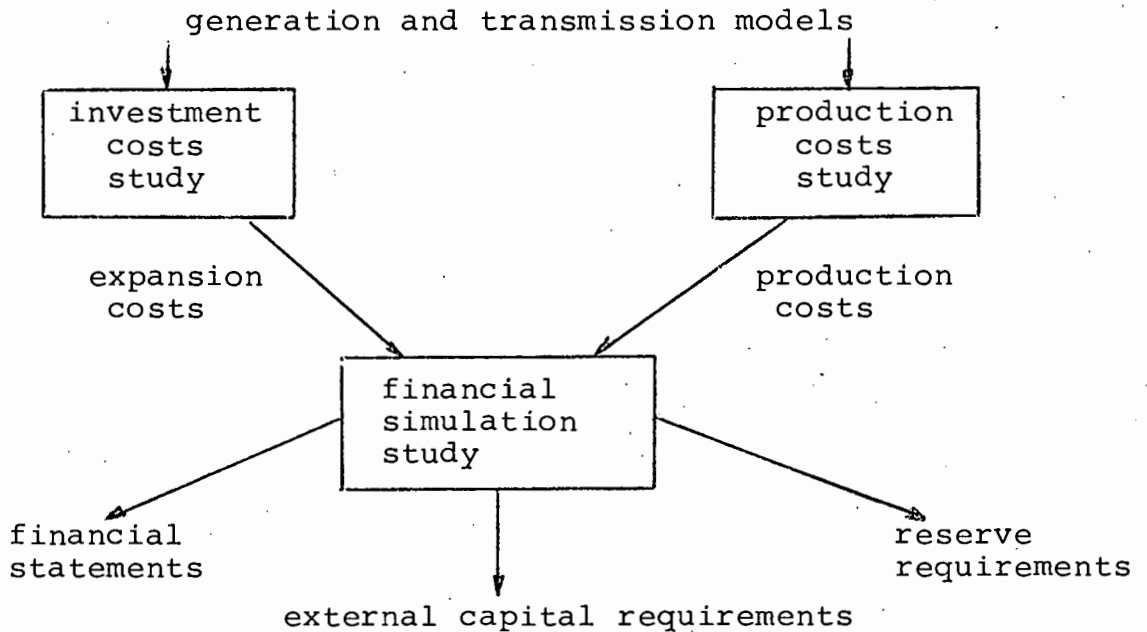


Figure 8.2: The financial modelling system.

With the aid of the financial modelling system it is possible to obtain a deeper understanding of the utility's economic and financial processes. Section 8.2 describes how this model is applied in the financial planning process in the South African Electricity Supply Commission.

As shown in figure 8.2, the financial modelling system comprises the investment costs study, the production costs study and the financial simulation study. Expansion studies made for generation and transmission result in a number of specific plans for the rating and timing of major system additions.

Investment cost studies provide the total annual investment costs by summing up the costs of the various expansion projects. In the investment cost studies three types of costs are considered: the construction costs, the interest charges on money paid prior to the completion of the projects (interest during construction), and the costs of the designing of the project and the supervision of construction (engineering services).

Each of the expansion projects is represented by a construction

pattern in which the total construction period is divided into several time intervals of varying lengths. The construction pattern also includes the fraction of the total costs to be spent during each time interval. From this pattern, and from the total cost of the project and the annual escalation rates, the total annual construction costs for the project are calculated. The costs of the engineering services are assumed to be a fixed percentage of the construction costs and they are added to the annual construction costs of each project. The interest charges during the construction period are computed on the basis of the average work-in-progress balance and are added to the construction costs and the engineering services costs to give the total annual costs for a given project. The annual costs of the various expansion projects are summed up to provide the total annual investment costs.

Production costing studies simulate the operation and maintenance of the power system in order to determine the total annual costs incurred in the operation of the power system. The production costs are divided into three categories: labour, fuel and materials. These costs are given for the operation and maintenance of the generation, transmission, distribution, workshops and distribution depots, etc. They are then summated for the various utility departments and are summarised for the utility as a whole.

Financial simulation studies are made to evaluate the effect of the expansion and production plans on the total annual capital requirements and to analyse the revenue and external borrowing requirements for several levels of self-financing. The final financial performances are expressed by the annual balance sheet and the revenue and expenditure account.

## 8.2 FINANCIAL SIMULATION STUDIES

The purpose of a financial simulation study is to simulate the financial aspects of the utility over a period of time and to provide projections of the financial statements for the various

departments of the utility. An illustration of how the financial simulation model is applied to the projection of the revenue and expenditure account and the balance sheet of the Electricity Supply Commission is given below.

In this study most of the calculations and reports are given for Escom as a whole. However, the expenditure items in the revenue and expenditure account and the asset items in the balance sheet are reported separately for various departments as well as for Escom as a whole. The departments included in this study are the various distribution undertakings, which are referred to as CWU, CNU, CEU, ORU, BOR, NAT, ETU and RND, the Central Generation Undertaking (CGU) and the Corporate Services (CCS).

The processing flow is illustrated in figure 8.3. The input data includes the annual costs of expansion and production, which are obtained from the investment and production cost

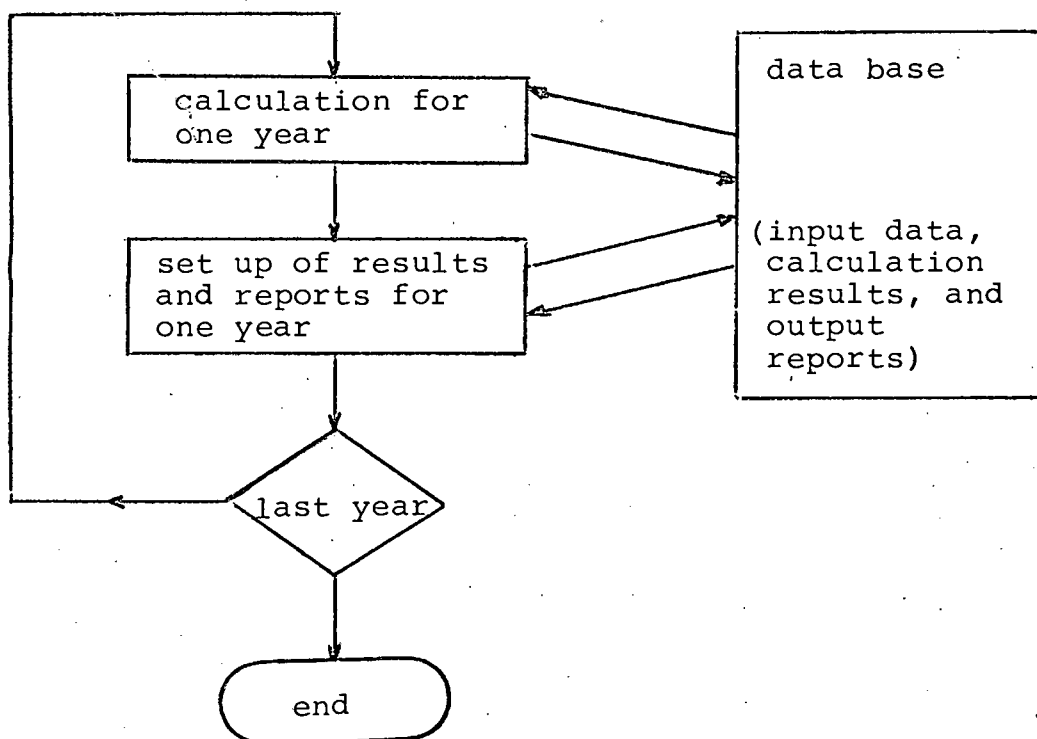


Figure 8.3: Processing flow of the financial simulation study.

studies, and the economic parameters for the duration of the study period, which include interest rates, escalation rates, depreciation factors and self-financing levels which are expressed by the "cash borrowed to cash generated ratio". These input values are stored in the data base together with the results of the calculations, and the simulation is performed for yearly time intervals.

In order to represent the data for the various undertakings each variable in the data base is held as a separate vector for each year of the modelling period. This vector consists of twelve parameters. The first parameter is the variable name which is also called an "account". The other parameters include the account values for the various departments and for Escom as a whole. As an example, the account of "total stores" is presented in table 8.1.

ac- count name	ESC	CCS	CGU	CWU	CNU	CEU	ORU	BOR	NAT	ETU	RND
total stores	90	7	26	7	2	6	3	3	9	7	20

Table 8.1: Vector presentation of an account on the data base.

For each year of the study period, the account value of the previous year is modified, as a result of the year's processing, to give a new value which is carried forward into the following year. The account of each year in the study period is usually represented by two vectors. One vector represents the change in the value (movement) and the other vector represents the total value for that year.

Thus:

$$\text{account value (year } n-1) + \text{movement (year } n) = \text{account value (year } n)$$

As an example, the 1976 processing of the account of "total stores" for Escom is shown in table 8.2.

year	value of "ESC" at the start of the year	movement in the year	value at the end of the year
1976	90	7	97

Table 8.2: Processing of an account in a specific year.

As shown in figure 8.4, there are six processing steps in the financial simulation study. An output report is produced at the end of the processing of each step. The final results are expressed in a revenue and expenditure account and in a balance sheet. The revenue and expenditure account summarises the detailed expenses of the utility. When all the expenses have been totalled, their sum total may be deducted from the actual revenue allocated for the financial year to give the net surplus or deficit of revenue over expenditure. The balance sheet is a statement of the assets, liabilities and reserves of the company.

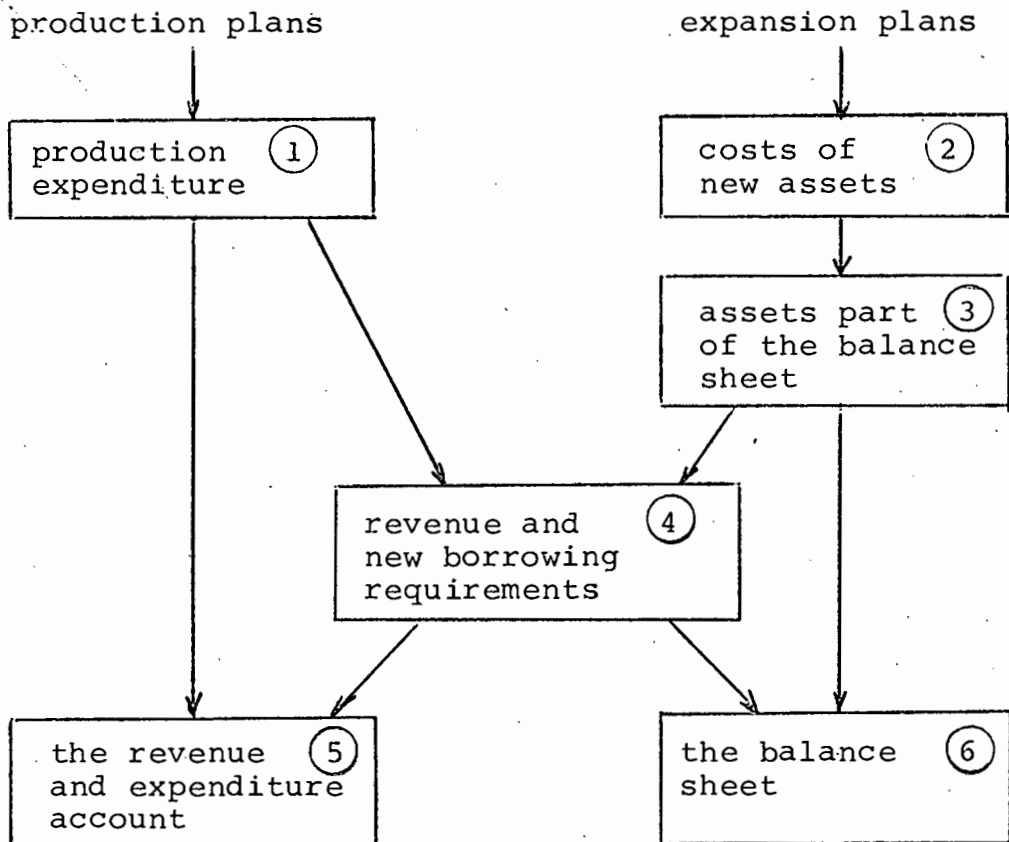


Figure 8.4: Processing steps in the financial simulation program.

In the first processing step the projected production expenditure for the revenue and expenditure account is determined. The expenditure items are calculated for each of Escom's undertakings and are summed up to give the Escom total. As illustrated in table 8.3, the production expenditure consists of four items: power system operation, power system maintenance, external electricity purchases and general expenses.

In the second processing step, as shown in figure 8.4, the projected changes in the value of assets in commission and assets under construction for a given year (movements) are calculated. These movements are shown in table 8.4. The assets in commission are subdivided into various asset types which include land, rights, production plants, buildings and facilities and production equipment. The depreciation values are calculated separately for each of the five categories of assets, using the formula (8.1) of straight line depreciation.

$$\text{depreciation for year (x)} = \frac{\text{cost} - \text{scrap value}}{\text{depreciation period}} \quad (8.1)$$

Following the calculations of the movements of assets in commission and assets under construction for Escom's individual undertakings, the assets part of the balance sheet is concluded in step 3. As shown in table 8.5, the assets part of the balance sheet consists of assets in commission, assets under construction and the stores. The stores include the various types of fuel and the strategic and consumable stores.

In the fourth step of the financial simulation program the annual revenue and the new borrowing requirements are calculated for a given input value of the cash ratio (CR).

$$CR = CB/CG = \frac{\text{cash borrowed}}{\text{cash generated}}$$

The total money required for a given year consists of the following items:

- a) costs of new assets

account	total Escom	CCS	CGU	CWU	CNU	CEU	ORU	BOR	NAT	ETU	RND
power system operation	185297	314	183742	191	72	11	16	22	236	219	474
power system maintenance	50837	72	28633	5099	1062	110	440	1068	3142	2660	8551
external electricity purchase	25438		25340			98					
general expenses	142716	64288	43257	5764	2950	96	1133	2112	7105	4574	11437
<b>total expenditure</b>	<b>404288</b>	<b>64674</b>	<b>280972</b>	<b>11054</b>	<b>4084</b>	<b>315</b>	<b>1589</b>	<b>3202</b>	<b>10463</b>	<b>7453</b>	<b>20462</b>

Table 8.3: Expenses on the revenue and expenditure account for Escom's undertakings (in thousands of rands for 1976).

account	total Escom	CCS	CGU	CWU	CNU	CEU	ORU	BOR	NAT	ETU	RND
land	1631	2	478	105	185	2	72	42	76	274	395
rights	1631	2	478	105	185	2	72	42	76	274	395
production plants	295369		191767	9683	17180	71	4802	3908	7078	25534	35346
buildings and facilities	15382	124	9810	509	904	3	252	205	372	1343	1860
production equipment	18198	2548	3905	3087	693	39	879	478	1361	1971	3287
<b>total assets in commission</b>	<b>332211</b>	<b>2676</b>	<b>206438</b>	<b>13489</b>	<b>19147</b>	<b>117</b>	<b>6077</b>	<b>4675</b>	<b>8963</b>	<b>29396</b>	<b>41183</b>
depreciation	77869	1117	46683	3658	1954	74	1026	850	4974	4452	13081
<b>book value assets in commission</b>	<b>254342</b>	<b>1559</b>	<b>159755</b>	<b>9831</b>	<b>17193</b>	<b>43</b>	<b>5051</b>	<b>3825</b>	<b>3989</b>	<b>4944</b>	<b>28102</b>
assets under construction	571029	27434	335175	27296	45366	789	3560	5320	14371	40311	71407
assets transferred to assets in commission	314013	128	202533	10402	18454	78	5198	4197	7602	27425	37886
<b>net assets under construction</b>	<b>257016</b>	<b>27306</b>	<b>132642</b>	<b>16894</b>	<b>26912</b>	<b>711</b>	<b>1638</b>	<b>1123</b>	<b>6769</b>	<b>12886</b>	<b>33521</b>

Table 8.4: Movements of assets for a period of one year for Escom's undertakings (in thousands of rands for 1976).

account	opening balance	movements	closing balance
land	14433	1631	16064
rights	14431	1631	16062
production plants	1994478	295369	2289842
buildings & facilities	121077	15382	136459
production equipment	45037	18198	63235
-----			
total assets in commission	2189456	332211	2521667
depreciation	617803	77869	695672
-----			
book value assets in commission	1571653	254342	1825995
-----			
assets under construction	355400	257016	612416
-----			
strategic and consumable stores	85278	22629	107907
coal fuel	7113	-967	6146
gas fuel		79	79
-----			
total stores	92391	21741	114132
-----			
total assets	2019444	533099	2552543

Table 8.5: Assets part of the balance sheet (in thousands of rands for 1976).

- b) repayment of existing loans
- c) interest payable on loans
- d) production expenses
- e) other expenses such as loans to employees for home ownership or external investments.

The basic forms of the equations used to calculate the revenue and the new borrowing requirements are shown in equations (8.2) and (8.3). Some modifications were made to these equations in order that they include the effects of the difference in the actual time of expenditure and the receipt of payments. For instance, consumer accounts are paid about a month after the expenditure has occurred.

$$\begin{aligned} \text{revenue} = & \text{production expenses} + \text{interest on loans} + \\ & \text{repayment of loans} + \frac{\text{CG}}{\text{CG} + \text{CB}} \cdot (\text{new assets} \\ & \text{and other expenses}) \end{aligned} \quad (8.2)$$

$$\begin{aligned} \text{new borrowing} = & \text{total money requirements} - \text{revenue} \\ & \text{requirements} \end{aligned} \quad (8.3)$$

In the fifth step, as shown in figure 8.4, the revenue and expenditure account is finalised. It is followed, in step six, by the final balance sheet statement. In tables 8.6 and 8.7 examples of the revenue and expenditure account and the balance sheet statement are shown.

account	Escom total	account	Escom total
power system operation	185297	electricity revenue	667879
power system maintenance	50837		
external electricity purchases	25438	GWh sold in the year	65317
general expenses	142716	average price per unit (R/kWh)	0,0102
		increase in price of previous year (per cent)	34,5
total expenditure	404288		
assumptions: interest rate = 13 per cent			
cash borrowed to cash generated ratio = 5,97			

Table 8.6: Revenue and expenditure account (in thousands of rands for 1976).

The same calculation steps are repeated for all the years in the study period. If various values for the cash ratio and the interest rates are supplied in the input data, it

is possible to study the effects on the resulting financial statements and thus to evaluate the financial consequences of the expansion and production plans.

account	opening balance	movements for the year	closing balance
<u>assets</u>			
total assets in commission depreciation	2189456 617803	332211 77869	2521667 695672
-----			
book value assets in commission	1571653	254342	1825995
assets under construction	355400	257016	612416
stores	92391	21741	114132
-----			
total assets	2019444	533099	2552543
-----			
<u>financed by</u>			
net loans debt	1656638	-85831	1570807
new money requirements		605843	605843
-----			
total borrowing	1656638	520012	2176650
general fund	61337	-9109	-15566
-----			
total debt	1717975	510903	2228878
general reserves	-15566		-15566
retained earnings	317035	22197	339232
-----			
total accumulated reserves	301469	22197	323666
-----			
total fund sources	2019444	533099	2552543

Table 8.7: Balance sheet statements (in thousands of rands for 1976).

CHAPTER 9

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

A primary aim in the development of the modelling system was to provide the means whereby more timely, accurate and economical planning information could be obtained. As a result of this accomplishment, planners are now able to consider a far greater number of alternatives in greater detail and with more confidence than was previously possible using traditional planning methods.

The system presented in this thesis is a specialised, computer-based, power supply planning system which enables the extensive analysis of a wide variety of problems to be carried out. The modelling process is initiated with the forecasting of the electricity demand on the planning horizon. After this, the principal system components, namely generation, transmission and distribution are analysed from the point of view of economy and security of supply, and alternative plans are usually studied. At this stage, various studies such as linear programming optimisation, loss of load probability, load flow analysis, etc., are extensively carried out. These analyses enable the planners to propose a set of expansion projects for the generation, transmission and distribution. In the last step, an analysis must be carried out to verify that the proposed projects are feasible from the point of view of corporate financing.

The modelling system has been divided into four components, namely, prediction of future demand, generation expansion studies, transmission network analysis and financial planning. The interface between these components appears at the security level, the investment level and the financial level.

At the security level both steady-state and transient breaches

of security are considered. Steady-state breaches of security include steady-state voltages outside the limits of given tolerances, steady-state overloads of transmission lines or other equipment, and insufficient generation and transmission capacity (real and reactive). Transient breaches of security include instability following a disturbance to the system, and tripping of lines due to the excessive transient flow following an outage.

At the investment level there are certain principles which are applied to the economic assessment of all alternatives of the plans for the generation and network expansion. These principles include the concepts of total system costs, real operation conditions, optimum system operation and present worth of actual payments. As future plants will affect the operating regime of all existing plants, it is necessary to estimate the total system costs for each alternative. The investment and the operating costs of the alternatives are based on those obtained from the simulation of the real operation conditions. The actual timing of all cash outflows, particularly construction costs, is important, and therefore the principle of present value or discounted cash flow is used for comparing the costs of various alternatives.

At the financial level, the sum of the partial costs given in the investment and production plans gives the total sum of the costs. Financial modelling constitutes a simulation of the potential effects of the total costs on the financial requirements of the utility.

The discussion in this thesis is based on the experience of the author in developing computational aids in power system engineering. Linear programming, simulation methods, system analysis and probability techniques are applied in the models to a broad range of power system problems. The overall conclusions of the developments were as follows:

- a) The establishment of the objectives presented a difficult task because many factors which had to be taken into

consideration during the planning process could not be formulated into a set of formal objectives and relationships. This weighted heavily against the development of a large, generalised, computer-based, corporate planning package, which would fit all the utility planning requirements.

- b) It is difficult to foresee the data needs of comprehensive models, because the problems that can be treated by such models have not been considered previously in such detail. Also, it is impossible to construct a comprehensive data base before the development of the models and their application to real planning problems.
- c) The three important areas of power system planning that would be amenable to computer system application were identified as investment planning, power system analysis and financial planning. Problems in investment planning were largely concerned with the timing, size and location of the new generation and transmission plants and also with the selection of alternative proposals. In power system analysis, the behaviour of the power system under steady-state and fault conditions was considered to be of prime importance. In financial planning, the system planners were keen on the development of techniques which would enable them to improve their ability to forecast future financial performances.
- d) The problem of communication between the management, the system planners, and the development analysts was identified as probably the most important single factor providing a setback to the modelling approach. The attitudes towards the use of computers in power system planning varied from great enthusiasm to vigorous rejection. However, only after the results obtained by using various models were shown to be useful in the decision making process, the attitudes were weighted towards the acceptance side.
- e) The application of computer models had a dramatic impact on the organisational structure because they transcended normal organisational boundaries. This fact was not initially anticipated by the development team.

- f) It is important that the features which promote the dialogue between the planner and the model should be prominent. Thus terminal-based systems using conversational routines were found to be desirable. Ease of use and flexibility of reporting, including graphic output which could be easily assimilated were also considered to be important features.
- g) Although many improvements could be made to the models, adequate techniques do exist for the solution of most of the power system problems. The author is of the opinion that the limiting factors in the use of the various analysis techniques for solving more complicated systems, lie in the ability of the user to understand and analyse the results and to channel the information gained from the models into intelligent use, rather than in the size of the model which can be computed or the time required for the solution of the problem.

As with any new development, one can point to a number of possible improvements and the author suggests that the following three should receive particular attention in the future: the need for more effective interaction between model and user, the necessity for a partial integration of different techniques, and the need for a wider scope of cost benefit analysis and the conservation of natural resources.

In order to achieve the successful application of the appropriate planning models to the planning problems, a supporting information system must be created to enable the effective interaction between the model and the user. Power system planning is inherently an interactive, investigative process, in which intermediate results may indicate the direction for successive analysis. Experience with both batch and interactive models for planning studies strongly suggests that on-line access to the models is necessary to permit their most effective use as creative planning tools. The modelling system described here includes some interactive facilities in the load flow study. These need to be extended

to the point where most of the analysis studies will have interactive facilities.

Since the validity of the information derived from the results obtained from the models is a direct function of the validity of the input data, flexible and comprehensive facilities should be available for the handling of the data. In the system described in this thesis, the power system data base enables the handling of some of the technical data for the transmission system analysis. The data base needs to be extended to include more technical data and also needs to be integrated with the business oriented models and data.

During the development stage, the management expressed the desire for an overall integrated computer-based planning system which would combine the various techniques, input data and reports into a comprehensive system designed specifically to meet the particular needs of the South African electricity supply system. However, the experience gained in this respect has led to the conclusion that, although under certain controlled conditions such integration was technically feasible, the actual integration of the various models and data was extremely difficult and the effort involved was not justified. Also, from the point of view of the planners such integration may well be more confusing than instructive. Nevertheless, it should certainly be possible to achieve a partially integrated system. The first step in this direction has been done here by the integration of the input data for the network analysis programs and by the production of the various output reports on the same basis. It is recommended that similar steps should be followed for the generation planning programs and for the financial analysis programs.

It is also suggested that in the future consideration should be given to combining some of the analysis techniques. For example, the flexibility and the sensitivity characteristics of simulation techniques could be combined with the optimisation power of the linear programming technique for planning

the expansion of the generation system. Such a combination would make it possible to evaluate the economy of the expansion of the generation system against the reserve requirements. This could be done by specifying the acceptable reliability of supply in terms of the loss of load probability as a part of the linear programming optimisation model.

In any planning situation, one of the most important aspects is the selection of the appropriate criteria according to which decisions can be made. The development of the models described here was based on three criteria:

- a) the reliability of the system and technical performances of the various plant components,
- b) the expected present value of capital and operating costs required to support a given plan, and
- c) the anticipated annual revenue and capital borrowing patterns resulting from the selection of a given plan.

Little attention was given to the optimum application of the various forms of other natural resources, namely, manpower, materials, energy resources, environment and land.

In the light of the significantly different situation that exists today, apart from the improvements and the broadening of the existing models to include more related cases, major emphasis must be placed on a wider scope of cost benefit analysis and conservation of resources in the development of new models. The various criteria which may be used to aid in making a choice between alternatives are largely dependent on local conditions. For example, these might include the following:

- a) lowest capital and operating costs,
- b) lowest environmental impact,
- c) optimum use of depletable resources,
- d) minimum dependence on other countries for vital materials and components,
- e) increase in the domestic manufacturing capability, and
- f) the availability of trained or trainable domestic manpower.

These criteria are interrelated and generally speaking no one is truly dominant. Whatever evaluation approach is chosen in the models, human judgment will still be necessary when specific developments are being considered and the role of the computer will be to analyse proposals prepared by engineers.

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