

LEAST-COST EXPANSION PLANNING IN THE ELECTRICITY SUPPLY INDUSTRY

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ABSTRACT

Formerly, to meet increases in electricity demand or to replace obsolete stations, the decision to build a new power station of a particular fuel type was not based wholly on economic grounds. Often political pressure (e.g. using coal to keep mines open), national strategy (e.g. building of nuclear reactors) or government policy (e.g. introduction of hydro generation in Scotland to counter population drift) dominated the expansion planning process.

With the advent of the availability of inexpensive computing power, planning based solely on economics, with calculations that are mathematically complex, repetitive and time consuming, can be applied more readily to such decision making. In addition, a wider range of factors can be taken into account. Sensitivity analysis and comparative assessments can be made easily, allowing the Planning Engineer to consider more options and to arrive at decisions with more confidence.

Occasionally, however, the preferred options indicated by such planning (termed least-cost expansion planning) may be overruled through influence of externalities such as those mentioned above, e.g. political pressure. Thus, although least-cost expansion planning software will never replace totally the human involvement in the process, such software has the considerable advantage that it can be used to rank a range of options in order of economic cost. The Planner can then quantify in economic terms the effects of overriding indicated minimum-cost options by making decisions on the basis of some other grounds, e.g. governmental policy.

This thesis examines the factors and techniques which are used in least-cost expansion planning. Their integration into a decision support system is described and suitable software is developed. Using realistic data a typical run of this software demonstrates ranking of minimum-cost candidates that successfully meet expected future electricity demands and planning criteria set before a run is executed. The merits of using the software in a practical application are then discussed.

DECLARATION OF ORIGINALITY

The research recorded in this thesis, and the thesis itself, is the original and sole work of the author.

Jane Hope Holmes

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To my best friend and husband, Scott.

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CHAPTER 1

INTRODUCTION

The purpose of an Electricity Utility is to maintain a power system capable of generating electricity economically with minimum disturbance both to its customers and to the environment¹. The Utility attempts to ensure that the electricity is transferred over transmission lines when customers demand it and that distribution networks, with maximum efficiency, provide a reliable delivery to consumers at virtually fixed voltage and frequency.

The increased number of different uses of electricity have led to the steady increase of growth of the energy generation sector. The introduction of electric appliances, for example irons, refrigerators and ovens in the early part of the twentieth century and industrial processes contributed to the increased demand for electricity which is ever increasing as technology becomes more widespread and easily accessible to the population. Electricity has become a commodity that is used extensively and is an important feature in our society, signifying affluence and prosperity. It is an essential input to industrial production and as a result, is a product upon which society has become dependent.

With this increased demand, there is a need to generate more electricity. With the design and construction skills established to build larger and more technically advanced power stations, the complexity of the facilities and construction time also increases. It has become evident to Utilities that the planning process must be viewed as an integral part of electricity supply if increasing demand is to be met in a timely and economical manner.

The demand for electricity varies over a twenty-four hour period, from day to day and from season to season. In the past the trend has been generally that, for a given week, electricity demand rises annually. To meet customer demands, Electricity Utilities must ensure that they have sufficient installed generating capacity to meet and exceed all load levels. It is general practice of electricity planners to install enough generating plant to meet the peak demand and to accept that at other times the system will not be fully utilised². In addition, the policy is to install generating capacity in excess of the expected peak demand, usually 10% to 20%, to cover for the times

when equipment either fails without warning or becomes unavailable because of maintenance. This concept of building new power stations to meet electricity demand is known as supply side management (SSM).

An alternative approach, demand side management (DSM), tries to influence customer's use of electricity through load management. There are two types of load management; *capacity limiting* and *demand limiting*³. The first method, capacity limiting, encourages customers, normally through monetary incentives⁴, to shift electricity demand from periods when the system is heavily loaded to times when it is more lightly loaded. This flattening out of the daily curve has the effect of increasing the load factor of generating units towards unity^{5,6}. This in turn ensures that the units operate with higher efficiency and better fuel economy. The second technique within DSM, demand limiting, tries to reduce overall demand through improvements in the efficiency of processes using electricity⁷. This usually involves the expenditure of capital (either the Utility's or customer's) in the customer's premises, with recovery of the expenditure through savings in the cost of electricity or through increased electricity prices. To be a viable option, DSM must ensure that customer savings through consumption are greater than the effect of any price increases and that Utilities maintain a reasonable return on investments.

Both methods, SSM and DSM, employ *least-cost planning*, as first defined by Roger Sant in 1979⁸, to minimise the total cost of supplying electricity services. The DSM least-cost technique is outwith the scope of this thesis, which concentrates solely on the methodologies used in least-cost planning of expanding electricity systems as practised in SSM.

1.1. Expansion Planning

As with all other public services, e.g. sewage, gas, water and communications, the electricity supply is an amenity to which customers have become accustomed. However, in terms of invested capital, electricity supply is the most expensive. As a result, it is imperative that adequate electricity supply planning is carried out to ensure that energy generated to meet customer demands is done at a minimum cost.

Electricity supply in the period of nationalisation was planned and operated on a centralised basis. Decisions were made for the whole country through a structure of joint committees covering the different geographic areas. The Electric Utilities were obliged under legislation to supply electricity to all customers in their franchise

area^{9,10}. This electricity had to be supplied to the customer at a fixed price determined by a regulatory body, the Government or the Utility itself¹¹. New generating stations were built in order to meet any increase in demand.

Before any planning can begin, the Electricity Utilities must establish a few base details:

1. *what amount* of electricity is going to be demanded by the Utility's customers within the planning horizon.
2. *when* in the planning horizon will this electricity be demanded. A Utility does not want to build a new power station before it is necessary otherwise its potential output initially will go un-utilised.
3. *where* will the demand be located. Planning must account for the provision of transmission and distribution equipment for all new generating stations.
4. *what type* and *size* of generating plant will be required while still keeping the cost to consumers down.

A flow chart illustrating the steps involved in electricity expansion planning are shown in Figure 1.1. The planning of expansion with least-cost must begin with the assessment of anticipated future demands for electricity. As an exact figure can not always be precisely predicted, the projected electricity demand must be provided for. Additional capacity must also be provided in excess of this estimated maximum. This value is known as the reserve margin and provides security against loss of capacity during unusually high demand peaks.

The amount of new expansion generation plant to be built is dependent not only on the predicted demand but also on existing plant. If the existing plant is economically capable of providing enough electricity to meet demand, additional plant would be superfluous. However, if an existing plant is near to retirement, it might be more economical to build new plant and scrap the ageing plant before its design life has been run.

The planning of additional capacity is carried out within limitations. The size of demand dictates the necessary capacity of new plant, while construction time imposes a constraint on availability of this planned generator. In least-cost expansion planning, the planner has several elements to consider when attempting to find a cheapest option. These are construction, operation and emission costs.

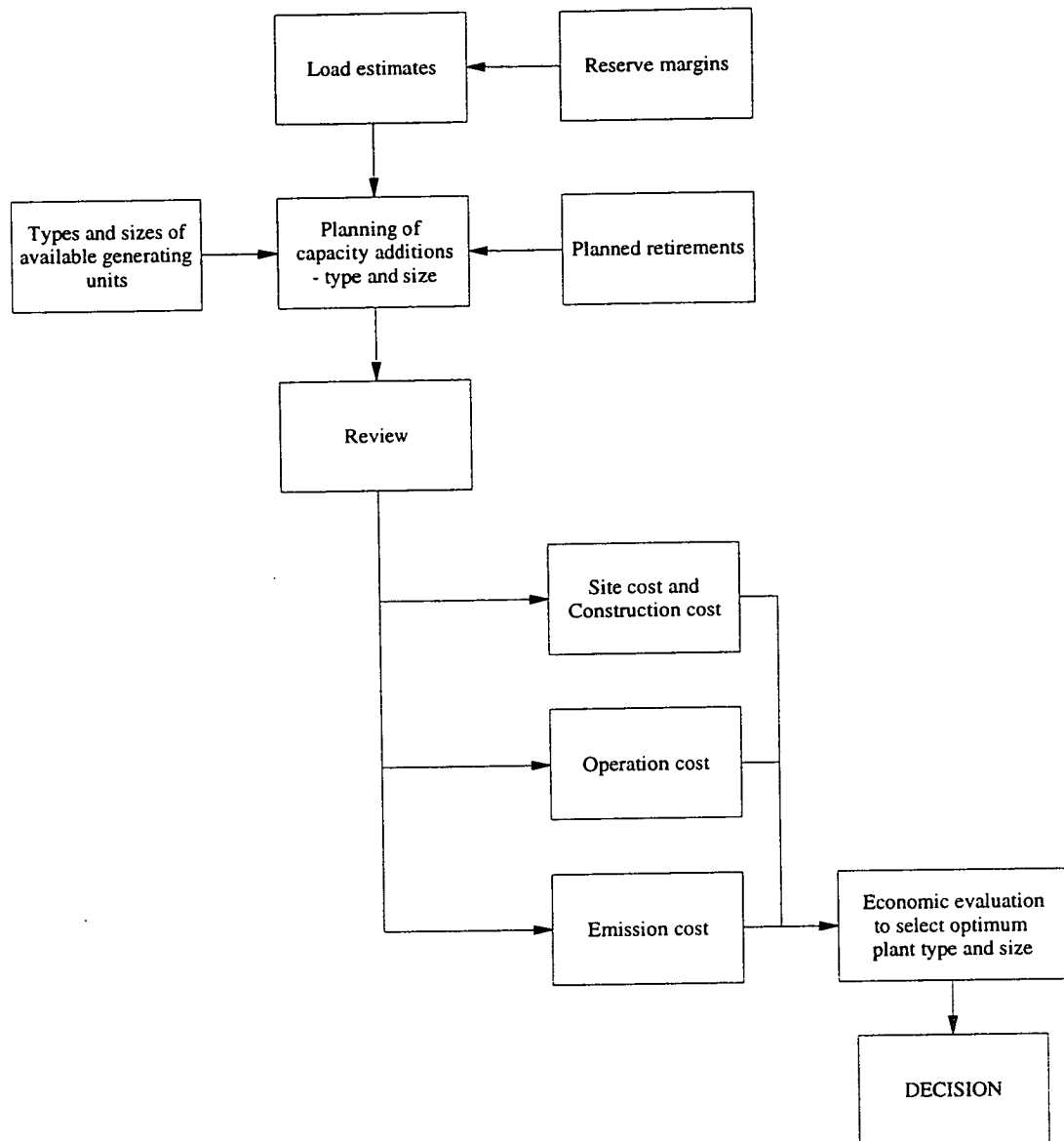


Figure 1.1. Generation planning flow chart.

The planner may wish to base the least-cost expansion plan on all three costs or ignore emission costs and find the least-cost based on only construction and operational costs.

- The construction cost is dependent on several factors including construction time and interest rates. Plants with greater construction time accumulate greater amounts of interest on borrowed money before they earn revenue.
- The operation costs of a plant can be separated into two categories - fixed and variable. Fixed costs are independent of the operation of the generator. These

costs are occurred even if no electricity is generated while variable costs are determined by the amount of energy produced in a year.

- Finally, emission costs vary depending on the technology being used and the legislation of the country in question. Some developing countries still have no fixed penalties for emissions while in other countries Utilities are working at reducing emissions in order to escape financial penalties.

The majority of the planning analyses were performed by experts specialising in a particular field. This had the disadvantage that it required several personnel to establish expansion plans to meet growing electricity demands. Another drawback with this arrangement was that the knowledge accumulated over the years was often lost when experts changed jobs or retired.

With the development of inexpensive computing power and decision support systems (DSS), software can be written to automate expansion planning. Although the software will never replace totally human judgement because of externalities that can not be factored in, e.g. political pressures, it does assist less specialised personnel to conduct expansion studies and quantify in economic terms the effects of decisions made on the basis of other grounds.

Some of the benefits of computers over traditional "pen and paper" methods include:

- *speed* - computers are able to perform many more calculations per minute than the human brain.
- *higher complexity* - because of the speed advantage, computers can consider more features within expansion planning.
- *consistency* - with equations incorporated into the software, there is less room for computational errors.
- *"what if" scenarios* - computers allow planners to perform sensitivity checks on factors within the scenario and determine how they could alter a plan over the period of study.
- *faithful storage of data* - the data regarding expansion planning and the results obtained from simulation runs can be stored permanently on either hard or floppy disk or printed to paper. This allows the data to be re-used if required and results to be examined at a future date.

- *accumulation of rules* - the expertise of the planners are held as a set of rules within the expansion simulation program for use by less experienced planners in the future.

Through the use of computers, different combinations of resources are more easily analysed to see how well they meet future electricity needs and how expensive they are. The analyses can be repeated time and again to test a wide range of resource portfolios for their resilience against various uncertainties. These analyses test different assumptions about externalities (e.g. local economic growth and fossil fuel prices); different estimates of the costs and performances of different resources; and different combinations of resources. Such analysis helps to identify a mix of resources that meet the projected growing demand for electricity, is consistent with the Utilities corporate goals, avoids exposure to risks and satisfies environmental protection criteria.

However, while the use of computing power allows easier analysis of present generation resources and quickly identifies required additional electricity capacity, least-cost expansion planning can never be completely free from political, social and strategic issues.

1.2. Least-Cost Expansion Planning

Least-cost expansion planning is used to determine a mix of new generating stations that will successfully meet increasing electricity demands at minimum expenditure. It considers a variety of economic costs although sometimes it is not always clear as to whether the final expansion decision is to the generator's or the customer's benefit. According to Nelson¹² a least-cost plan should be renamed "non-losers planning" where the unit cost of energy remains the same to the customer while the Utility maintains sufficient profit.

The economics of least-cost expansion planning can be split into three elements. The first determines the costs accumulated during construction of the new generating station. Secondly, the cost of running the station (e.g. fuel price and labour wages) is considered along with the cost of maintaining any equipment throughout the planning period. The third element, consideration of the cost associated with gaseous emissions into the atmosphere, is relatively recent because, previously, the effects were of no great concern to the generators. However, due to new legislations introduced by governing bodies, such as the Large Combustion Plant Directive in the

UK, Electricity Utilities are required to try and minimise emission outputs. The regulations which have been introduced in an attempt to meet pre-defined targets include imposing carbon taxation on Utilities that burn fuels with high carbon content, or allocation of tradable permits which allow Utilities to emit certain levels, with penalties imposed for excess emissions.

In order to compare various plans which meet future expected electricity demands, the cost of each must be referred to a common time base, usually the first year in the study. This cost conversion is achieved using net present value calculations to render investment analysis insensitive to effects of time passing in the planning period.

1.3. Least-Cost Expansion Planning Software

The need for least-cost expansion planning software that considers both traditional costs (construction, running and maintenance costs) and emission costs was identified as part of a joint programme for collaborative research between the Department of Electrical Engineering at the University of Edinburgh and Ian Pope Associates (formerly L.E. Energy), an engineering economics consultancy specialising in overseas projects. Initially, it was ascertained, as far as possible, that there was no existing software of this type. Interest has been, however, expressed by several eminent researchers in the field.

It was decided that the resulting piece of software should be a DSS that ran under Windows™ and would be as user-friendly as possible. This would require the user to have working knowledge of Windows™ and an understanding of least-cost expansion planning but would relieve him from the tedium of large arithmetic calculations.

Kappa-PC, an expert system shell developed by Intellicorp, was chosen because it incorporates several features not found in simple rule based systems. Amongst these is the ability to define the system domain using object hierarchies inherent in Kappa-PC's object oriented programming environment. In addition, a procedural language is provided which allows user development functions to be created. Kappa-PC was designed to be a Windows™-based shell that is capable of running on most IBM compatible computers. This environment simplifies the creation of user interfaces, with Kappa-PC providing its own interface module. The final software can be stand alone providing that Windows™ and the runtime version of Kappa-PC are present, thus denying access to the actual source code.

1.4. EPOPS

The software developed during this study is called EPOPS (Expansion Planning Of Power Systems). It is a decision support system that indicates, in ranked order of cost, a range of generation solutions that successfully meet customers' anticipated demands in a study period of up to thirty years, based on generation, economic and environmental data provided by the user. It is anticipated that this software will be used by system planners in countries that are either proposing to develop a new electricity network or undertaking to increase the installed generating capacity of an existing system.

There are several advantages to automating least-cost expansion planning. The main advantage is the ability to incorporate all of the necessary calculations into the source code thus requiring the user to perform no mathematical computations. This ensures that not only can the calculations be performed much more quickly but also with higher accuracy and repeatability. Without the need for understanding of the repetitive mathematical analysis, the software becomes more universally usable and in some circumstances can even be used as a teaching aid. A higher level of complexity can be incorporated into the source code thus allowing a wider range of issues to be considered. EPOPS has been structured so that simulations cannot be performed until all the relevant data has been entered, thus ensuring that no points are forgotten or ignored. Also, any new criteria that emerge in the future can be readily incorporated into EPOPS. Much of EPOPS is pre-programmed with default values so that a new user can get a feel for the package even if he possesses limited knowledge of electricity system planning.

Another advantage of the DSS is the ability to review quickly and accurately the outcome if any factor were to change, for example, fuel price, discount rates or expected electricity demand. EPOPS enables the user to try a variety of "what-if" scenarios and determine the sensitivity of a plan to externalities. Because EPOPS does not only determine the cheapest expansion plan but a range of options ranked in descending cost order, the planner can select the most appropriate plan for a particular application. This chosen plan may not necessarily be the cheapest one; for example, it may be the plan which uses mainly indigenous fuels that is the preferred option.

Another feature of EPOPS is the ability to save the input data and results to separate files for future consultation. The saved input data can be loaded into EPOPS as a

base to starting a new study. EPOPS also offers the user the option to print screen results which are displayed in both graphical and tabular form.

The numerical values produced by the package are not definitive but purely there to assist in the decision-making process. The output values can only be considered as accurate as the input data.

1.5. Thesis Outline

Chapter 2 outlines the factors that affect construction and operating costs in an expansion plan. This chapter shows that 64% of the world's electricity is generated using three fossil fuels (coal, oil and gas) which accounts for the focus on these fuels throughout this thesis. This chapter shows that it is not only the direct economic costs, such as construction costs and fuel prices that affect expansion planning. The station's annual generating capacity has a direct effect on the operation costs and as a result it is important to consider all the factors that can affect the output. These factors include efficiency, reliability and maintenance time of the generating unit as well as the station's position within the merit order.

Chapter 3 examines the factors that effect the emission costs associated with expansion planning. This chapter concentrates on the production of the four emissions, carbon dioxide, sulphur dioxide, nitric oxides and particulates produced as a result of burning fossil fuels to generate electricity. These emissions are concentrated on because they are believed to be the main causes linked to the formation of acid rain, increased global warming and the effects on human health. Chapter 3 outlines some of the emerging technologies and costs of emission abatement equipment as well as Governmental legislation which administers penalties for excessive emissions in order to encouraging Utilities to reduce emissions below set levels. The installing and operating costs of abatement equipment or excess emission penalties must be included in an expansion plan to ensure that the true least-cost option is determined.

Chapter 4 describes how the stages of expansion planning are implemented. It presents a step-by-step approach to the expansion planning calculations used, illustrating the reasoning process leading to a variety of options that successfully meet anticipated customer energy requirements over a planning period. Chapter 4 demonstrates that expansion planning is achieved through the use of dynamic programming. Chapter 4 shows that through the use of a fifth order polynomial,

expected load duration curves can be simulated. This chapter shows that for each year in the study, dynamic programming determines a range of combinations of units from the three fossil-fuelled generators that satisfy load demands as well as other requirements of the system, for example, reliability. This chapter shows that unlike conventional expansion planning packages which calculate associated costs for all possible combinations, dynamic programming does so only with those that further satisfy built-in constraints. In this way, many combinations are rejected before extensive and time consuming calculations are applied.

Chapter 5 examines the construction and operation calculations used in expansion planning. As in Chapter 4, these calculations are presented in a methodical fashion, showing the order in which they are executed in an expansion plan. Chapter 5 shows that the construction costs need only to be calculated for expansion units. It highlights the various calculations used to determine the net generating capacity for both existing and expansion plants. This is what ultimately dictates the plant's operation and maintenance costs. Chapter 5 also presents costs associated with unsupplied energy. This accounts for a loss of electricity supply to the customer, a factor that is often neglected in expansion planning.

Chapter 6, examines the calculations used to determine the levels of gaseous and particulate emissions when fossil fuels are burnt to generate electricity. Chapter 6 introduces the chemistry behind the combustion reactions, albeit in a simplified manner and explains the assumptions made regarding emission production. Chapter 6 includes examples that demonstrate the levels of emission production. Chapter 6 also presents the cost calculations used if emission abatement technology is installed and shows the calculations used if trading permits, emission penalties or carbon taxation are in operation in the electricity system.

Chapter 7 discusses the merits of Kappa-PC, the expert system shell used to develop the least-cost expansion planning software. It outlines several operations that Kappa-PC performs within EPOPS that are not available in other development packages and shows, through the use of its object-oriented programming and interface modules, that it is a suitable shell for the development of expansion simulation software.

Chapter 8 shows the hardware and software requirements needed before EPOPS can be installed. It also indicates which files must be present before EPOPS can run. Chapter 8 describes the graphical interfaces used within EPOPS to facilitate data

Chapter 1 : Introduction

entry and explains their operation. Finally, Chapter 8 describes the error trapping that has been incorporated into EPOPS and discusses the on-line help index allowing the user quick and easy access to help regarding the correct operation of EPOPS.

Chapter 9 reproduces two typical least-cost expansion planning simulations run on EPOPS. The first run does not consider emission costs while the second run does. This chapter presents the data used in a typical expansion plan and shows the graphs and tables of results that are produced by EPOPS. The results of the two runs are compared and discussed.

Finally, Chapter 10 provides the discussion of this thesis. It also presents the conclusions and some suggestions for further work related to the research area.

CHAPTER 2

THE EFFECTS OF CONSTRUCTION AND OPERATION COSTS ON EXPANSION PLANNING

There are several factors that must be examined before a least-cost expansion plan can be identified. These factors, which are discussed in the following sections, all contribute to affecting the costs associated with electricity generation. This chapter focuses on the factors which affect the construction and operation costs.

Figure 2.1 shows how all these factors are related.

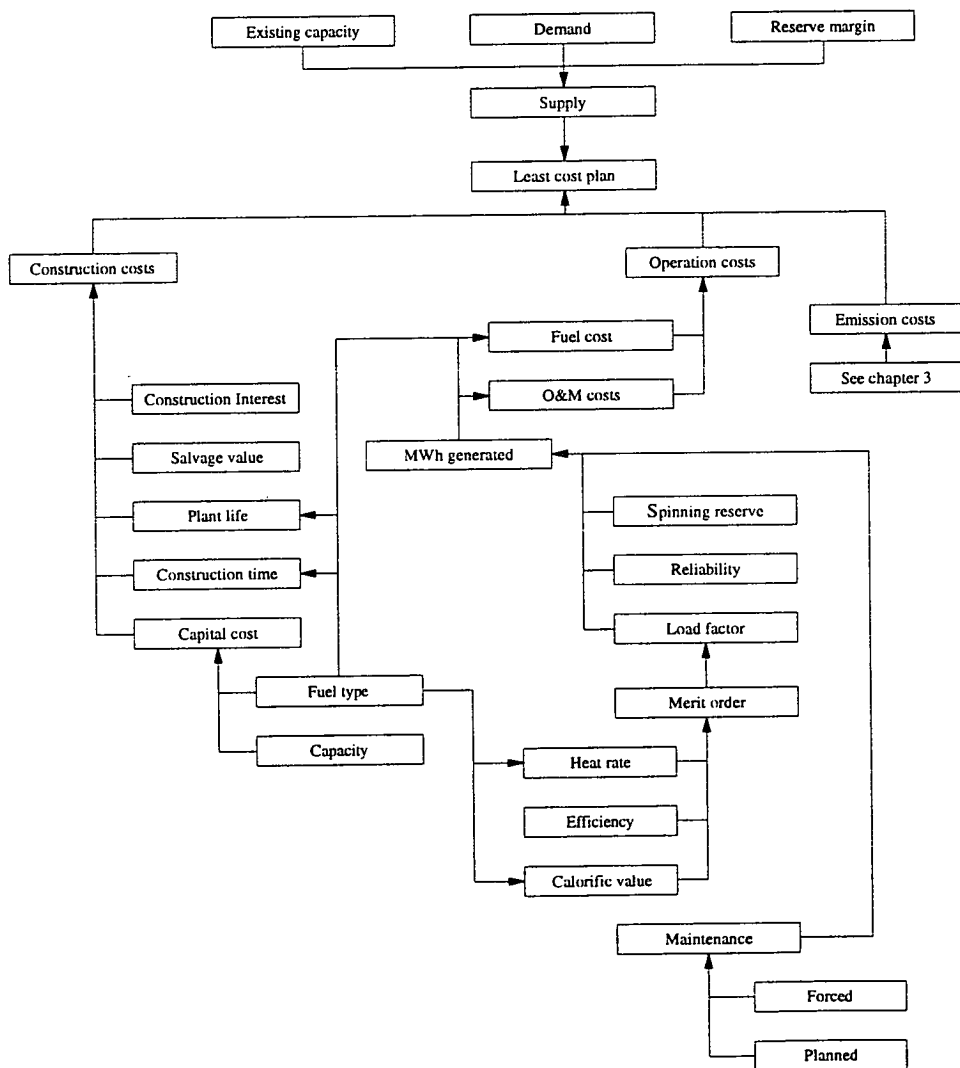


Figure 2.1. Factors influencing construction and operation costs.

2.1. Fuel Types

Only three fossil fuel types are considered for expansion planning in this thesis. Coal, oil and gas are examined because they are the primary fuels used throughout the world to generate electricity. In many developing countries hydro power and nuclear power are not options always available to the electricity planner. Figure 2.2 shows that the three fossil fuel types account for 64% of electricity generated in the world.

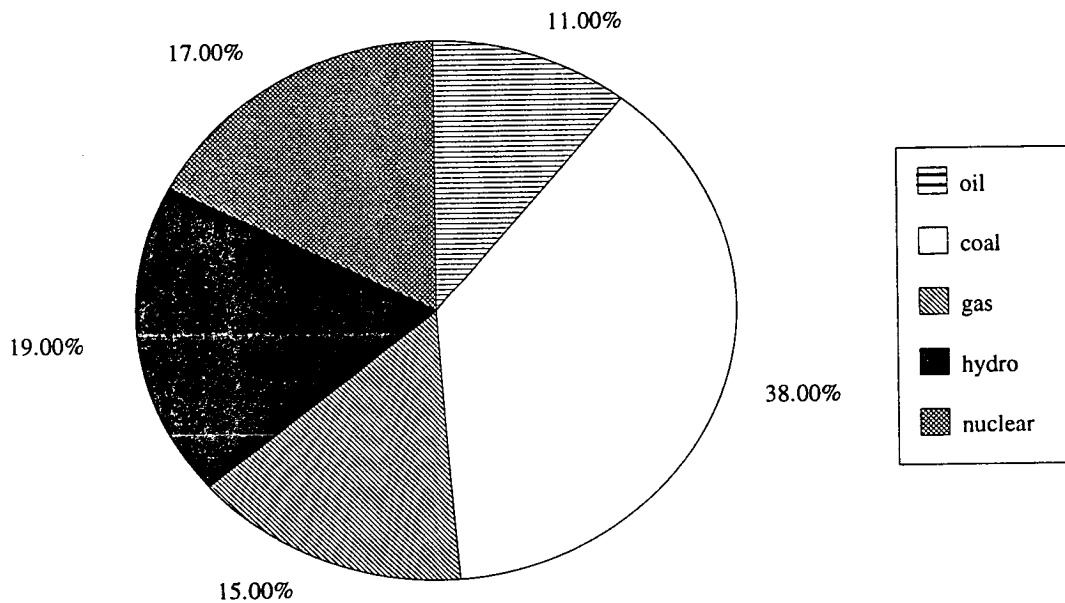


Figure 2.2. Annual global energy use for electricity generation¹³.

Coal has remained the most important resource for electricity production¹⁴ because there are vast quantities in the world although much of it lies in remote and inaccessible areas¹⁵. The total world coal resources are so large that if it was all recoverable, there would be a supply for thousands of years. However, only 55% is proven recoverable and as other fuel types run out, coal usage will increase. The major coal producing countries have between 150 and 500 years of proven reserves, at least 5 times greater than the combined resources of both known and possible oil and gas resources.

Oil is another important generating source in the world¹⁶. Saudi Arabia, a member of OPEC, is the world's largest oil exporter to the major industrialised countries¹⁷ with its oil reserves accounting for 25% of total global reserves. The production of oil in OPEC countries is approaching saturation point, i.e. its production is 95% of its total

capacity. If the demand for oil continues at the current rate, there is the threat of oil shortages in the near future. It is a fair assumption that unless major oil producers such as Saudi Arabia, Kuwait and the United Arab Emirates increase their operation rates, a destructive oil price escalation will occur.

Gas is the newest of the three main fossil fuels to be used in great quantity for electricity generation. The breakthrough in the discovery of gas reserves occurred in the late 1980s with an increased rate of 3% per annum, much above the actual production rate. Known reserves of gas in the world are widely distributed in 80 countries across the world, although 38% of the reserves are in the Soviet Union. At the current world-wide rate of consumption and technology, global reserves of natural gas will only last for 120 years. If gas is substituted for coal it will only last for another 55 years¹⁸.

2.2. Electricity Demand

The high standard of living enjoyed in developed countries, supported by modern technology, depends largely on the consumption of fossil fuels and the depletion of natural resources. As population becomes accustomed to the wide-scale use of energy and industries are established to manufacture energy-consuming products, the rate of demand far outstrips the growth rate of population. Figure 2.3 shows the expected world electricity consumption.

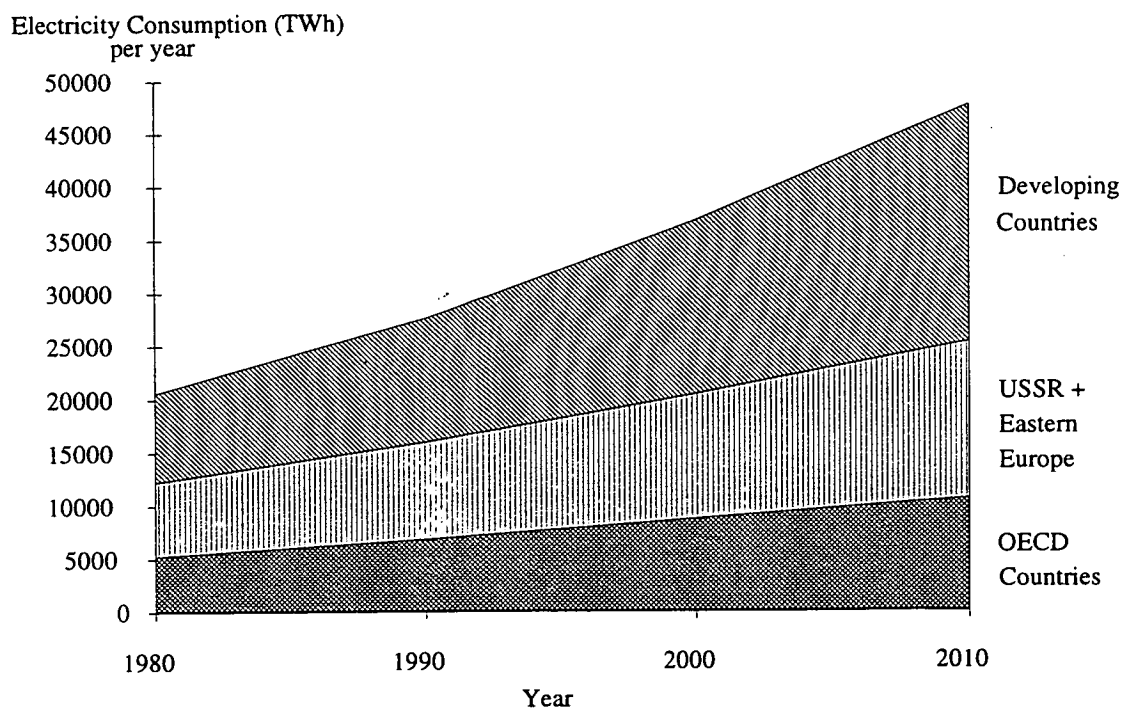


Figure 2.3. World electricity consumption¹⁹.

From this graph it is projected that the majority of expansion will occur in the Developing Countries. The World Bank estimates that about one trillion US dollars is needed to be invested in plant expansion in the next decade to meet this energy requirement²⁰. However, it is estimated that banks and other money lenders will only be able to lend a maximum of \$10 to \$12 billion per year. These large sums of money highlight the importance of estimating, as accurately as possible, the expected demand for electricity before a least-cost expansion plan can be implemented.

Estimates of future energy requirements are determined by analysing past records of electricity supply. These records are obtained from meter readings taken over many years from the three sectors, namely domestic, industrial and commercial. These growth rates in electricity usage are also compared with factors which may effect sales, such as national economy, population and new consumer technologies. Coupled with close examination of demand for competing forms of alternative forms of energy (e.g. direct combustion of gas and oil), a value for customer demand can be evaluated that must be supplied in the future.

The demand for electricity alters throughout the year. For example, in Britain the Electricity Utilities expect an increased demand for energy in the cooler months as customers turn on central heating and experience a drop in demand during the warmer periods. Figure 2.4 shows typical winter and summer load curves. Not only can the reduced demand in summer be observed, but also the significant variations during the day. As would be expected, there is a dip in demand during the night rising steeply around 7 am as industrial and commercial loads are switched on. The two peaks during the day account for lunch and tea time with the switching on of kettles, cookers and other electrical appliances.

These daily load curves showing variation in electricity demand over 24 hours are of use to system dispatch planners. However, for less detailed simulations, i.e. expansion planning, it is more convenient to average the load representation during the year into a yearly load duration curve which represents the aggregate length of time a given demand is expected to be exceeded. A typical load duration curve is shown in Figure 2.5.

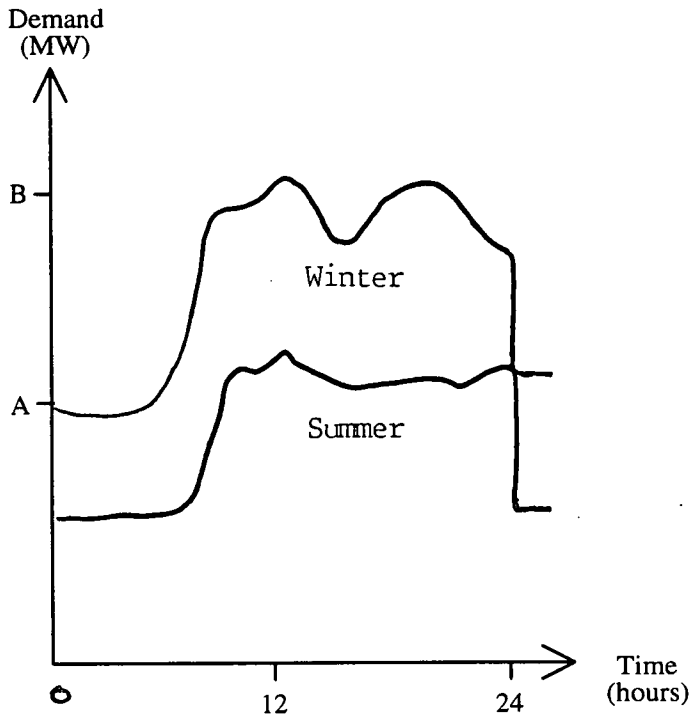


Figure 2.4. Typical summer and winter electrical load characteristics²¹.

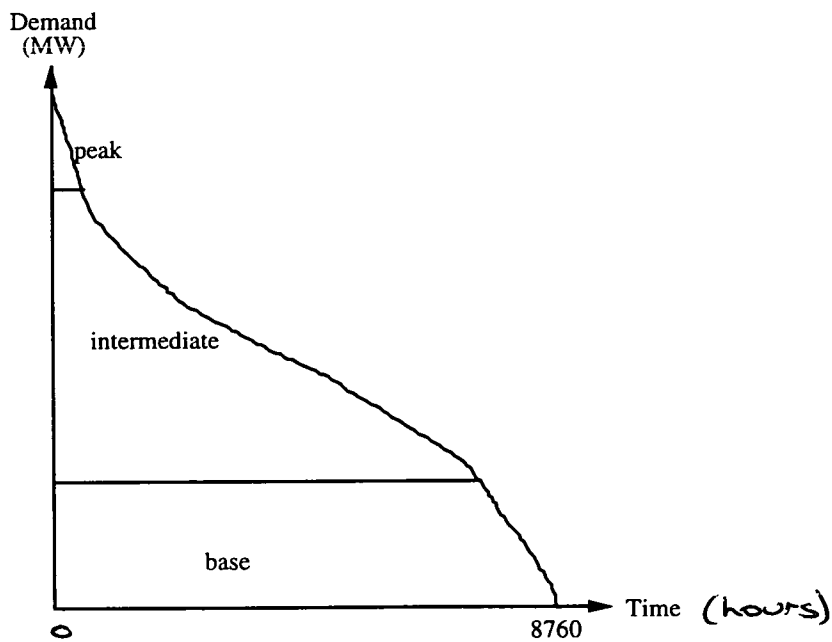


Figure 2.5. A typical load duration curve.

A load duration curve can be subdivided into three sections as shown in the graph and described below. Demarcation between these classifications is not clearly defined, but the following generalisations may be made.

- *base load* - this is the minimum load that has to be supplied constantly throughout the year. The units supplying this load operate at very high load factors, ideally 90-95% although it may be lower if the unit is newly commissioned or experiencing technical problems. This energy is supplied by generators that can be operated economically on a continuous basis such as nuclear or coal-fired generators.
- *intermediate load* - this is met by units that supply intermediate load generally operate with a load factor of 30-75% such as oil-fired generators.
- *peak load* - generally, units with high operation costs are used for generation in this region. They only operate during peak demand periods and therefore operate with very low load factors; in the region of 5-10%. Gas turbines often operate in this region because of their rapid response times.

Where clear seasonal variations exist, a load duration curve can be used to represent each season.

2.2.1. Reserve Margin

Sufficient generating capacity must be installed by the Electricity Utility to supply the forecasted annual peak demands as well as to provide an excess reserve margin. This excess insures against the probability that the demand forecasts are exceeded due to unforeseen circumstances, i.e. a very harsh winter, system outages, or transmission failures. This safety margin provides for the variations in demand. There are many reasons for providing reserve capacity. These include:

1. *Forced maintenance* - an average figure on expected plant breakdown can be obtained from past experience although the number of breakdown hours could easily be higher than usual.
2. *Load* - expected load may turn out to be higher than predicted.
3. *Weather* - since the demand is estimated based on average weather conditions, there is a equal probability that severe conditions may occur. These severe conditions are likely to appear only once in every 100 years but may account for a 9% increase in demand at that time²¹.

The expansion Planner must make certain that a sensible reserve margin is used. If the margin is insufficient to provide a reliable service, the Utility may occur unsupplied energy costs. Conversely, a large reserve margin, ensuring a reliable system, requires the building of additional generating units which increases both construction and operating costs.

2.3. Construction Costs

2.3.1. Capital Cost

Capital cost (often known as the investment cost) is the sum of money required to build a new generating station. As well as building materials, this cost also includes salaries of the engineers employed on the design, development and construction of the plant, together with any fees payable to consultants.

Unit costs are the capital costs of the plant divided by the rating of the plant in kilowatts. Typical unit capital costs of larger modern power stations are shown in Table 2.1.

Fuel	Unit Cost (£/kW)
Gas	750
Oil	800
Coal	900

Table 2.1. Typical unit costs for modern fossil fuel burning stations²¹.

The most important sources of capital investment, in developing countries and Eastern Europe, are the multilateral development banks who invest an average of \$5 billion per year²². Because of the large sums of money involved, these banks have a strong influence on the method of energy generation that is finally chosen.

2.3.2. Construction Time

Construction time is sometimes difficult to predict as the actual construction time is often greater than the expected construction time and can be contributed to several factors²³, for example:

1. If the number of contractors on the site is too large, communication links often break down resulting in bad timing of individual work.
2. Inadequate specifications and insufficient standard design as well as the need to amend specifications during construction.

3. Bad relations between management and contractors.

Typical construction times for fossil-fuelled generators are shown in Table 2.2.

Fuel	Construction Time (years)
Coal	6
Oil	4
Gas	2

Table 2.2. Typical construction times.

Because extended construction time causes a greater amount of interest to be forfeited, (see section 2.2.3), it is important to be able to predict the correct amount of time required to complete a generating plant.

2.3.3. Construction Interest

The interest paid on the capital cost is accumulated and capitalised when the project is completed. Tables 2.3 and 2.4 compare the interest payments during a four and six year construction period. (The initial capital cost of £600M is divided evenly between the years.)

These tables show that the interest accrued over a six year construction period is considerably greater than that amassed in a four year time frame. This shows the importance of predicting the correct length of construction time. However, if in Table 2.4 the interest rate was 7%, the accumulated total would be the same as that shown in Table 2.3.

Year	Annual capital cost (£)	Interest accrued [†] (12%)	Yearly total (£)	Accumulated total (£)
1995	150		150	150
1996	150	18	168	318
1997	150	38.16	188.16	506.16
1998	150	60.74	210.74	716.90

Table 2.3. Interest accrued during a four year construction period.

[†] Interest accrued on accumulated total.

Year	Annual capital cost (£)	Interest accrued† (12%)	Yearly total (£)	Accumulated total (£)
1995	100		100	100
1996	100	12	112	212
1997	100	25.44	125.44	337.44
1998	100	40.49	140.49	477.93
1999	100	57.35	157.35	635.28
2000	100	76.23	176.23	811.51

Table 2.4. Interest accrued during a six year construction period.

Interest rate can significantly influence the construction costs and so when performing an expansion plan it is important that the correct interest rate is used. To make provision for any expected increases in interest rates, an escalation value can be used.

2.3.4. Plant Life

The actual building that houses a power plant is seldom the limiting factor of a plant's life. Most buildings are constructed with the intention that they should last at least 60 years and many exceed this period. Some experts²⁴ assert that even cheaper buildings generally have substantial life in the order of 50 to 60 years. On the other hand, the expected physical life of generating machinery is in the region of 35/45 years²¹. It is possible, however, that advances in technology of new generators may make the plant obsolete before its time. In the interest of planning, therefore, a plant is considered to operate for 25/30 years before it is written off. Often after 25 years of service a plant is still capable of generating and it would be uneconomical and undesirable to scrap it. In this case, a plant may be considered for a further 5 years in the planning stage although it is likely to have been superseded in the merit order by a newer and more efficient technology.

When a plant eventually reaches its retirement age, consideration should be made as to whether it would not be more economical to retain the plant for peak load

† Interest accrued on accumulated total.

generation or whether it would pay to scrap it and thus save on repairs and maintenance.

2.3.5. Salvage Value

After the end of a plant's life, the station may be demolished to permit a more profitable use of the site or because it is found to be more economical to clear and rebuild rather than to adapt the building to meet changed requirements and technology. The expected salvage value is subtracted from the capital cost and incurred interest to produce a net construction cost.

2.4. Operation Costs

Operation costs can be subdivided into 2 headings:

- fuel costs
- operation and maintenance costs

Both of these costs are affected by the output of the generator (MWh). This is influenced by several elements including the generator's load factor, which in turn is dictated by the position of the station within the merit order.

2.4.1. Generation Output

2.4.1.1. Spinning Reserve

A power system continually experiences changes in its operating state and can often undergo a sudden increase/decrease caused by demand, an unexpected outage of a generator or a transmission line, or a failure in any of the system components. This leads to a need for spinning reserve. Spinning reserve can be defined as the extra amount of active power a generating system can supply within a specified time (in the order of minutes).

The spinning reserve in an electricity supply system consists of one or more generators connected to the grid which are unloaded or partially loaded and therefore capable of rapidly picking up these loads. Within reason, the larger the availability of spinning reserve, the greater the system reliability. However, a system planner must always be aware that this additional capacity significantly increases the system fuel cost.

2.4.1.2. Reliability

A power system serves one function only and that is to supply customers, both large and small, with electricity as economically and as reliably as possible. Modern society, because of its pattern of social and working habits, has come to expect the supply to be continuously available on demand. As a result, successful operation of power systems requires the provision of service to Utility customers without interruption²⁵. This is not physically possible in reality due to random system failures which are generally outside the control of power system engineers. However, including reliability calculations in the expansion planning can reduce the probability of an inadequate supply^{26,27}.

Design, planning, operating criteria and techniques have been developed over many decades in an attempt to resolve and satisfy the dilemma between the economic and reliability constraints²⁸. An over-investment in reliability can increase operating costs which must be reflected in the tariff structure. Consequently, increased system cost has to be paid for by the customer. Alternatively, under-investment may result in cheaper energy but at the price of a more unreliable system.

There are three principal components that can affect a plant's reliability²³:

- *size* - the larger the plant the less it will be available due to longer maintenance periods.
- *fuel type* - some plants are more prone to outages than others, for example, coal-fired plants have a lower availability rate than oil-fired ones.
- *age* - newer plants are considered to be less reliable in the first 2-4 years following being commissioned.

There are three basic methods to calculate if a system has adequate reliability. These are:

- *Standard percentage reserve* - installed capacity equals the expected maximum demand plus a fixed percentage of the expected maximum demand.
- *Loss of largest generator* - spinning capacity equals expected load demand plus a reserve equal to one or more of the largest units in the system.
- *Loss of load probability* - installed capacity must exceed predicted load for a predetermined percentage of time.

The first two methods, although simple, are mentioned because they are still used in developing countries. The reasons for this are twofold. Firstly, there is a lack of sophisticated computers to calculate probabilistic reliability and secondly, there is also inadequate data on reliability and forced outage rates of systems.

2.4.1.3. Maintenance

Maintenance can be defined as "The combination of all technical and associated administrative actions intended to retain an item in, or restore it to, a state in which it can perform it's required function". The requirements for maintenance must not be less than those necessary to meet the relevant statutory requirements, and *maintained* is defined in the Factories Act 1961 as "maintained in an efficient state, in efficient working order and in good repair". The *acceptable standard* is defined as "one that sustains the Utility and value of the facility"²⁹.

Maintenance can be subdivided into planned and unplanned maintenance. This is shown in Figure 2.6.

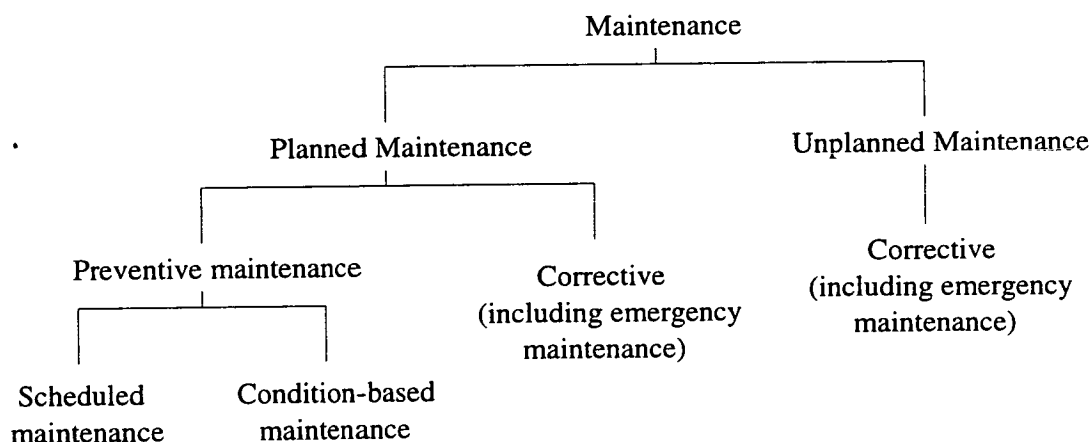


Figure 2.6. Types of maintenance.

Planned maintenance is organised and carried out with forethought, control and the use of records to a predetermined plan while unplanned (or forced outage) maintenance is carried as a matter of necessity.

Table 2.5 shows the number of maintenance days for a typical fossil-fuelled station.

Unit size (MW)	Maintenance Requirements (days)		
	Scheduled	Unscheduled	Total
50	17	7	24
200	24	12	36
400	31	14	45
600	31	14	45
800 - 1200	34	15	49

Table 2.5. Typical fossil unit maintenance requirements and forced outage rates³⁰.

Planned maintenance is a necessity as lack of attention may eventually lead to the need for forced outage maintenance. A plan that includes regular inspections and scheduled maintenance will have initial higher overhead costs than a plan without but the planning should lead to an eventual lower maintenance expenditure as shown in Figure 2.7. This graph shows the cost relationship of planned and unplanned systems. A fully planned system is not always the most appropriate and care is needed in devising the best system for the particular power station.

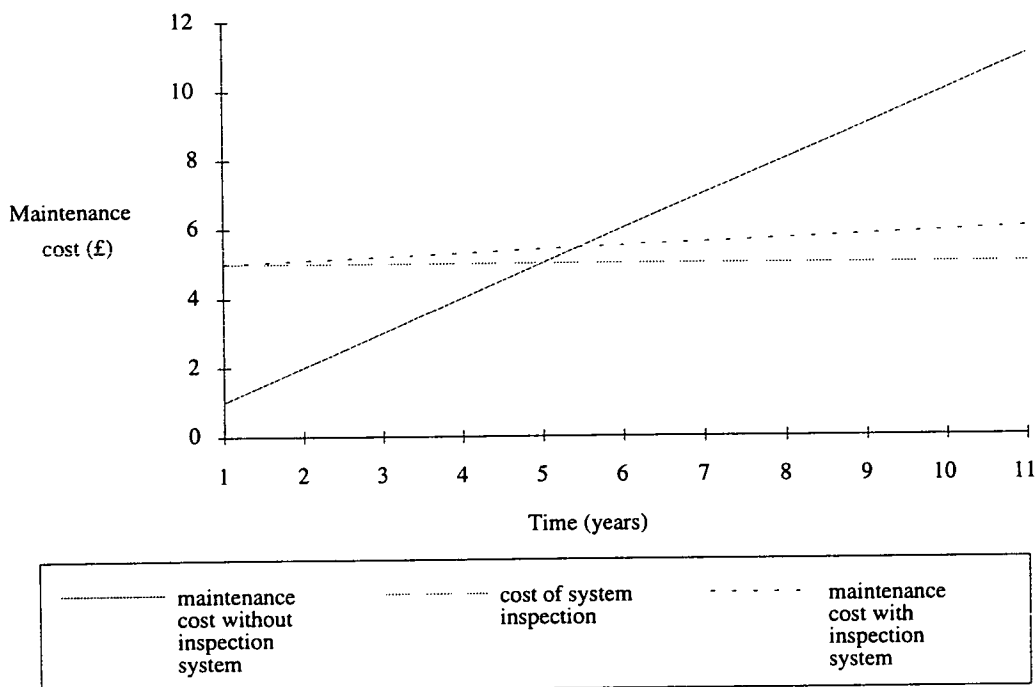


Figure 2.7. Cost relationship between planned and unplanned systems.

Withdrawing units reduces the generators output during the maintenance period. However, it can also lead to an increase in operating costs of the system due to increased generation of uneconomic units lower down in the merit order.

2.4.1.4. Merit Order

The merit order of an electrical system is a categorisation of all the available generating plants based on economic cost and determines the order in which plants are required to generate. This cost was historically based on operation costs alone but with environmental legislation recently introduced, consideration now also has to be made of emission costs. To meet demand in a cost effective manner, the cheapest generating plants are arranged to run to meet base load stations for the maximum amount of time.

Figure 2.8 demonstrates the merit order incorporated into a load duration curve. Stations with the lowest costs run for the maximum amount of time while expensive stations are brought onto line to cope with infrequent peak demands.

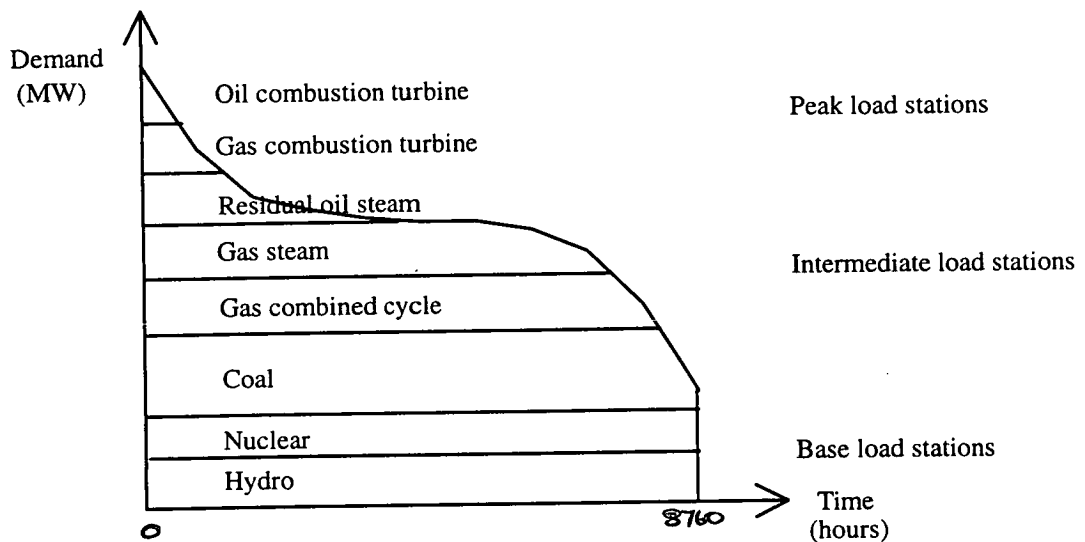


Figure 2.8. Merit order of a load duration curve³¹.

When new generating capacity is introduced into a power system, its position in the merit order is dependent on its operation and emissions cost. Introduction of new capacity can impose significant changes in the position of stations lower in the merit order. Figure 2.9 depicts these changes pictorially.

With the introduction of the new capacity, some existing stations are not expected to meet so much demand. The existing generators, displaced by the new generator, are required to run at a lower load factor. The introduction of new base load plant causes the greatest change in the operation of the existing generators.

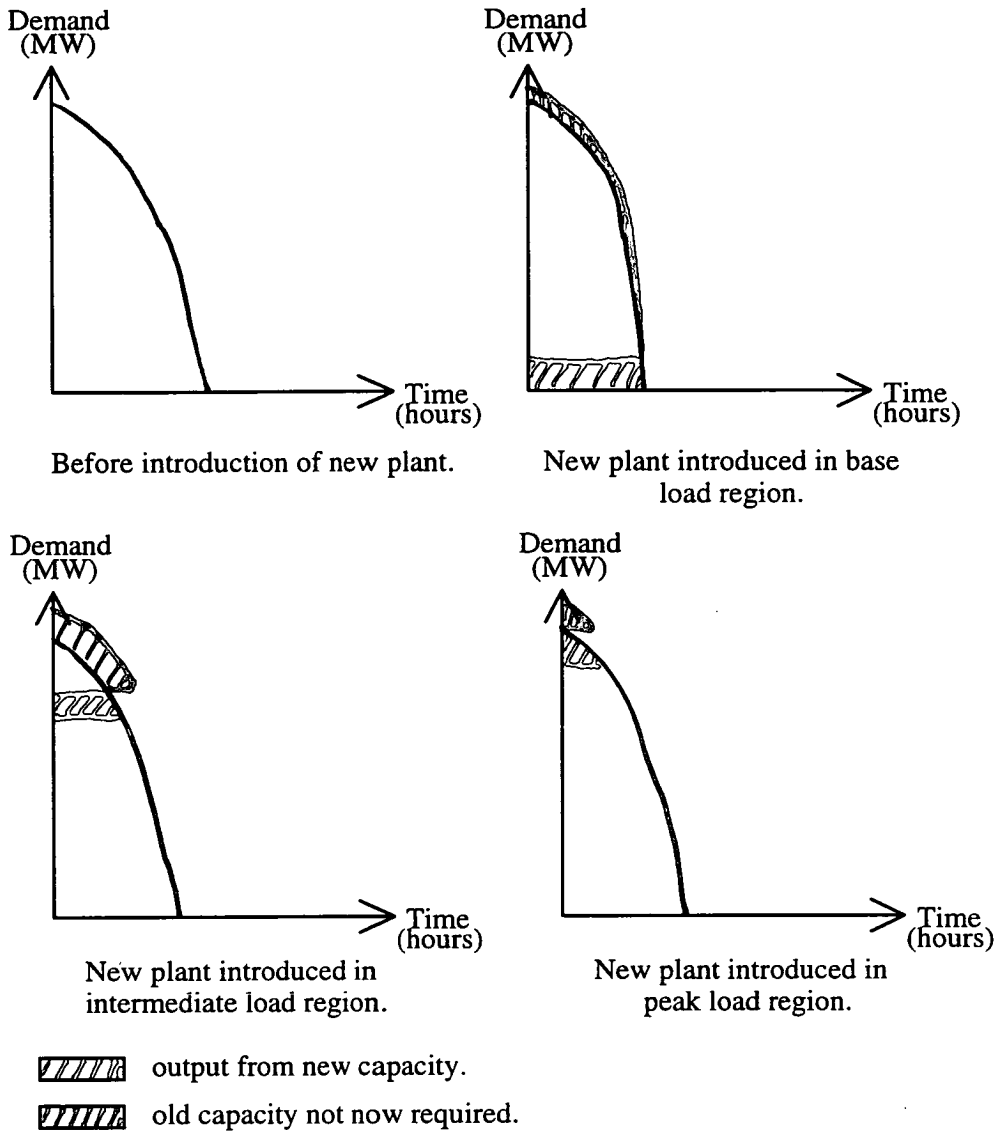


Figure 2.9. Effects of introducing new capacity into a load duration curve²¹.

2.4.1.5. Load Factor

A station's load factor is an indication of how it is being utilised and is expressed as a percentage. It is the amount of electricity generated by the station in a specified time period divided by the total amount of electricity that could have been produced if the station had been running at maximum output for 100% of the time. Therefore a station with a yearly load factor of 85-95% indicates a base station that is running flat out. The missing 5-15% indicates scheduled maintenance and forced outages. The load factor can be used as a reliability index but *only for base load stations*.

The load factor can be influenced by two variables:

- *the availability of capacity* - this indicates total loss of capacity due to planned and forced outages as well as reductions in capacity due to climatic factors and conditions which require the plant to operate at less than its maximum output.
- *the plant's operation and emission costs* - this reflects the demand for electricity and the plant's place in the merit order.

The cost attributed to a kWh is dependent upon how much electricity is generated by a station, and this is largely dictated by the load factor. Figure 2.10 shows how the station's load factor can vary the cost of a kWh produced.

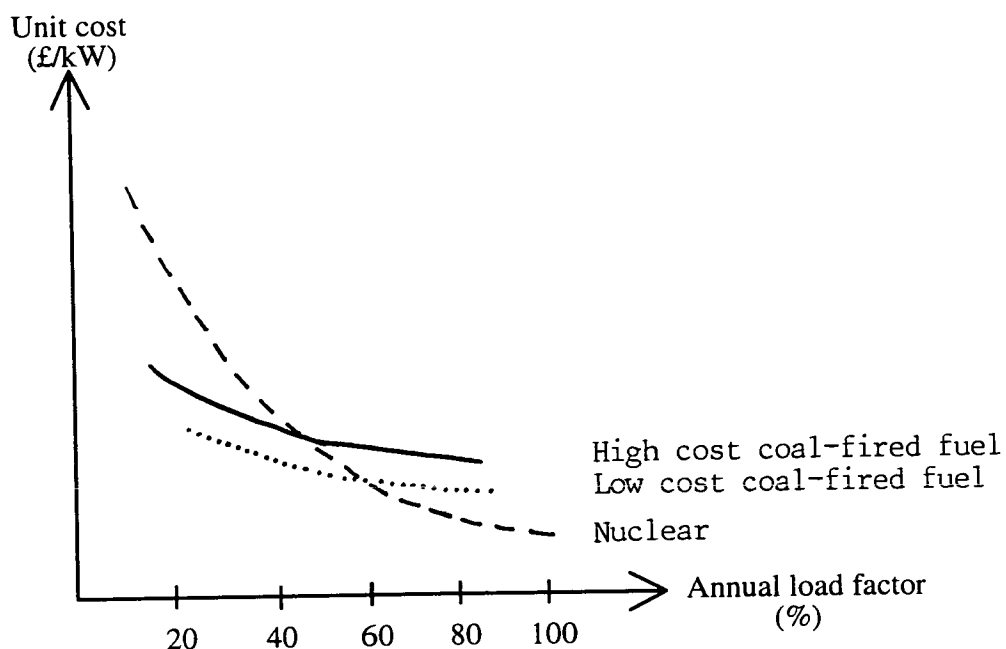


Figure 2.10. Effects of load factor upon unit cost²¹.

It is shown here that the coal-fired stations have cheaper generation costs at load factors as low as 35% while above a load factor of 60% the nuclear generator is capable of generating more economically.

2.4.1.6. Heat Rate

The performance of a generator is determined by the heat rate of the fuel it burns. The heat rate is proportional to the reciprocal of thermal efficiency. Heat rate can be defined as the input energy divided by the output energy. This energy ratio can also be determined using a ratio of energy per unit time, power. Thus the heat rate is the energy per unit time supplied to the system divided by the power output.

The energy supplied to the system is set by the type of fuel burned while the system output is affected by technology and plant efficiency. Heat rate can be viewed as the ratio of energy the station buys to the energy sold. Tables 2.6, 2.7 and 2.8 show typical heat rates for coal, oil and gas burning generating plants³⁰.

unit rating (MW)	Output (Btu/kWh)				
	100%	80%	60%	40%	25%
load factor	100%	80%	60%	40%	25%
50	11,000	11,088	11,429	12,166	13,409†
200	9,500	9,576	9,871	10,507	11,581†
400	9,000	9,045	9,252	9,783	10,674†
600	8,900	8,989	9,265	9,843	10,814†
800-1200	8,750	8,803	9,048	9,625†	

Table 2.6. Typical coal generator unit heat rates.

unit rating (MW)	Output (Btu/kWh)				
	100%	80%	60%	40%	25%
load factor	100%	80%	60%	40%	25%
50	11,500	11,592	11,949	12,719	14,019†
200	9,900	9,979	10,286	10,949	12,068†
400	9,400	9,447	9,663	10,218	11,148†
600	9,300	9,393	9,681	10,286	11,300†
800-1200	9,100	9,155	9,409	10,010†	

Table 2.7. Typical oil generator unit heat rates.

unit rating (MW)	Output (Btu/kWh)				
	100%	80%	60%	40%	25%
load factor	100%	80%	60%	40%	25%
50	11,700	11,794	12,156	12,940	14,262†
200	10,050	10,130	10,442	11,115	12,251†
400	9,500	9,548	9,766	10,327	11,267†
600	9,400	9,494	9,785	10,396	11,421†
800-1200	9,200	9,255	9,513	10,120†	

Table 2.8. Typical gas generator unit heat rates.

† Units should ^{not} be loaded below these limits.

2.4.1.7. Calorific Value

The calorific value of fuel determines how much energy can be released, in the form of heat, when fuel is burned - the higher the calorific value, the more heat is emitted. Coal exists in several forms and can be ranked in an order based on the degree of metamorphism. The more metamorphosed, the higher the calorific value of the fuel. Figure 2.11 shows the calorific value of the different main types of coal.

The calorific value for oil is around 39 GJ per tonne and gas is 50 GJ per tonne.

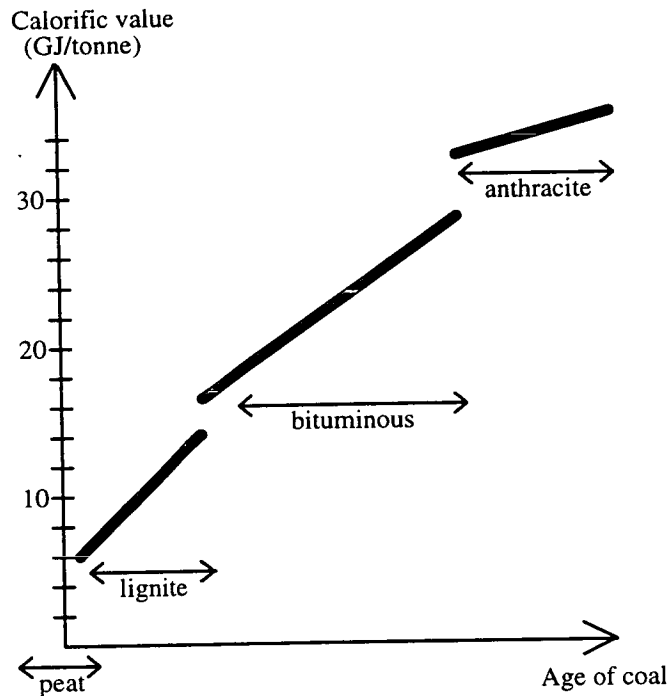


Figure 2.11. Net calorific value of coal (as delivered)¹⁵.

2.4.1.8. Efficiency

The efficiency of a plant dictates how well the burnt fuel can be converted into electrical energy. In each section of electricity production part of the energy is lost in the conversion process. For a typical fossil-fuelled steam electric plant, it has been estimated that the average efficiency for a recently built fossil fuel plant is in the region of 35 - 40% although this figure may be lower if pollution abatement procedures are carried out. Figure 2.12 shows a typical energy flow.

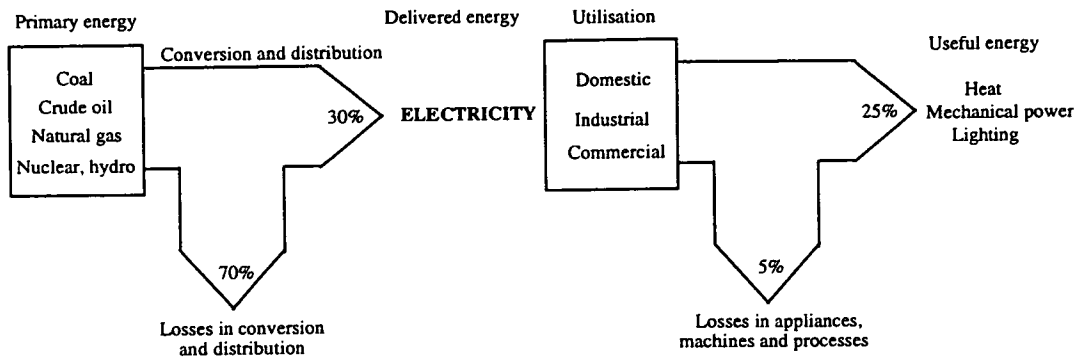


Figure 2.12. Typical energy flow.

2.4.2. Fuel Costs

The fuel consumption depends on the amount of electricity produced. The cost of fuel differs according to fuel type, the calorific value, availability and transport charges. For example, if a coal plant is sited near to a mine where coal is plentiful and cheap, the cost of transportation is extremely small. However, if the location of the plant is remote from the source, the cost of fuel may be excessive.

Coal prices increased in the late 80s due to relatively stringent conditions caused by industrial disputes and bad weather¹⁴. The price of coal is shown in Figure 2.13.

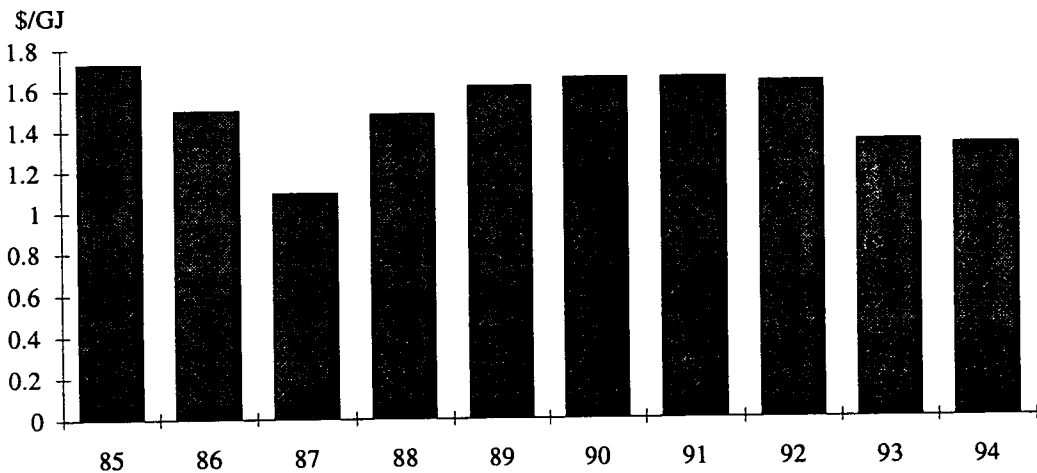


Figure 2.13. Coal prices³².

The oil business is very volatile, characterised by sudden changes in demand and price. Crude oil's selling price however, like other internationally traded commodities, is not governed by the cost of production. The production cost of individual crude oils can vary considerably according to their location and a variety of geological and technical factors. The price of oil is shown in Figure 2.14.

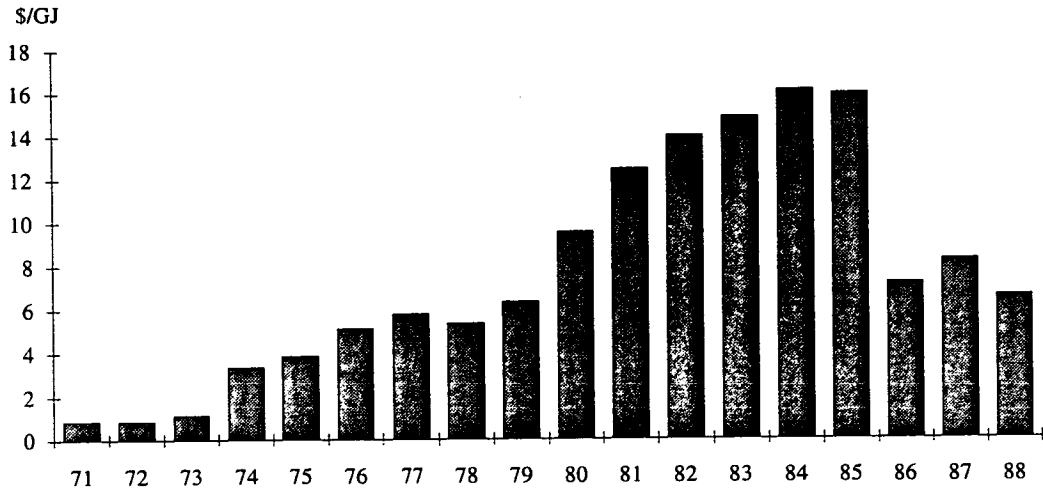


Figure 2.14. Price of crude oil³³.

From Figure 2.14 it can be seen that there were two huge price rises. This can be attributed to the Arab producers' policies during the Arab/Israeli war of 1973/74 and the Iranian revolution of 1978. Despite these price hikes, many speculators believe another rise will not be forthcoming^{34,35}.

Gas-fired stations are more expensive to operate than the other two fossil fuels although its fuel cost maintains a price parity with oil³⁶. The price of gas is shown in Figure 2.15.

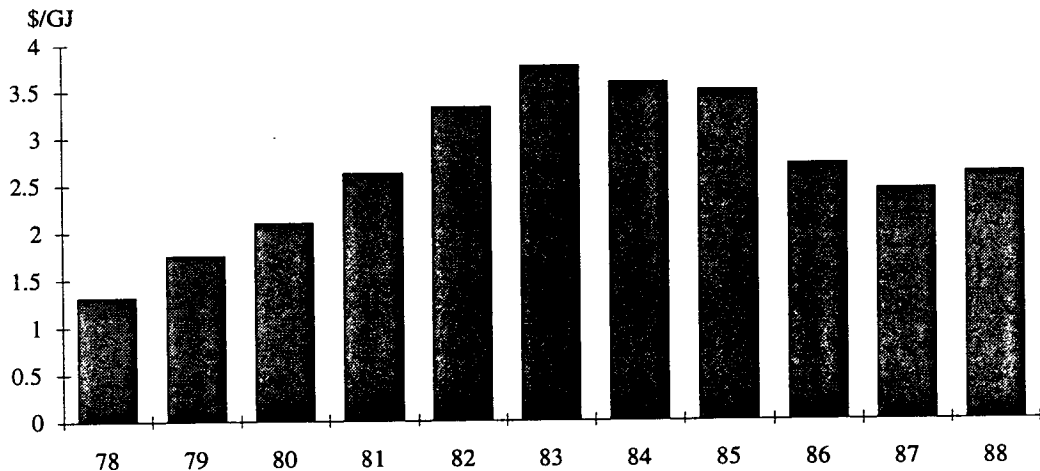


Figure 2.15. Price of natural gas³⁷.

2.4.3. Operation and Maintenance Costs

Operation and Maintenance (O&M) costs are the costs associated with the daily running of the power plant but do not account for the cost of fuel. There are two

types of O&M costs - fixed and variable. Fixed O&M costs are incurred irrespective of the load on the power system and include labour wages, building overheads and miscellaneous supply costs. Variable O&M costs are approximately directly related to the energy output of the generating plant. These costs include replacement parts, lubricants and other supplies (other than fuel) whose consumption is due to operation. Typical O&M costs for fossil-fuelled plants are shown in Table 2.9.

Fuel type	Fixed O&M costs \$/kW per annum	Variable O&M costs \$/MWh per annum
Coal	43.56	3
Oil	27.84	2
Gas	6.6	2

Table 2.9. Typical fixed and variable operation and maintenance costs.

If emission control technology is in place, the operation and maintenance cost of this must also be included. These costs can cause a considerable increase in the total O&M cost, for example, FGD adds approximately 2.5 - 10.4 \$/MWh while solid waste disposal accounts for an increase of 1.2 \$/MWh³⁸.

2.5. Planning Uncertainties

The notion of least-cost must also be presented with some concern for the future in which the plan is executed. The impact of uncertainty and the risks which result from, say, lower-than-expected load growth or higher-than-expected fuel prices can severely influence resultant cost of service provided by the Electric Utility. The approach to incorporate uncertainty into the Utility plan, under the least-cost initiative, is to identify a plan that may not be the lowest cost plan for any single combination of uncertain events but is an attractive plan under most circumstances³⁶.

Each parameter used in determining a least-cost plan is subject to uncertainty. Listed below are some important uncertainties³⁹.

- *load growth* - load demand forecasts are subject to a variety of uncertainties. Load growth is influenced by the national economy, local economy, energy prices, weather and conservation. It is difficult to adapt rapidly to load demand changes because of long construction times.
- *fuel prices* - natural gas and oil are particularly vulnerable to forecast uncertainty. Section 2.4.2 showed how oil prices almost quadrupled in 1974, increased from 1979 and dropped by 50% in 1986. Similarly, gas followed the

same course. Future fuel prices are very uncertain, most likely to be cyclic rather than a gradual price increase.

- *construction time* - this chapter has already shown the consequences of an over-run construction time frame resulting in increased interest payments.
- *interest rates and financial constraints* - the interest rate on capital expenditure is a major force in deciding between expansion alternatives. For example, if the interest rate in Table 2.4 was 7% the total owed would be marginally less than that owed in Table 2.3 (with a 12% interest).
- *technological development* - with more efficient technology both in the house and in industry, the need to build expansion plants might not be as great as predicted. For example, home end-users will demand less and efficient generators produce more.

Although it is impossible to eliminate uncertainty altogether, the intention of least-cost planning is to be robust and flexible in the presence of uncertainty.

2.6. Summary

This chapter has outlined the factors that can effect the construction and operation costs in expansion planning. All of these factors must be considered together before a least-cost expansion plan can be determined. It has shown that the planning process must be viewed as an integral part of electricity supply if increasing demand is to be met in a timely and economical manner.

The following chapter considers the environmental aspect involved in least-cost expansion planning.

CHAPTER 3

THE EFFECTS OF EMISSION COSTS ON EXPANSION PLANNING

The previous chapter examined expansion planning based on construction and operation costs. Equally important in least-cost planning nowadays are the costs which may become associated with the production and release of gaseous emissions and particulates. Figure 3.1 shows the factors which affect the emission costs.

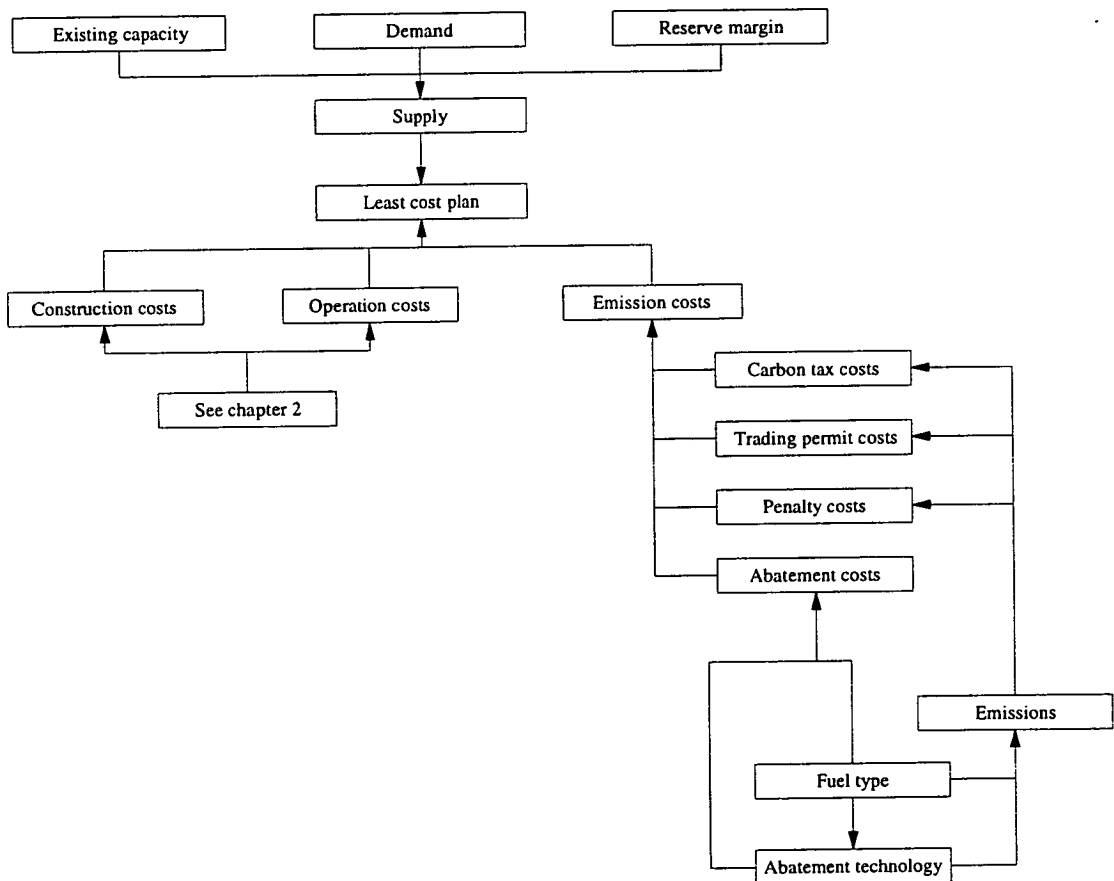


Figure 3.1. Factors influencing emission costs.

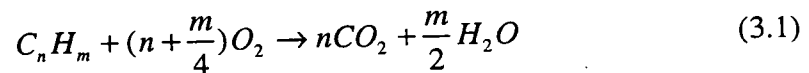
The combustion of fossil fuels (coal, oil and gas) can have a great impact on the environment (locally and internationally)⁴⁰, the most notable being the release of the oxides of carbon, sulphur and nitrogen into the atmosphere via flue gases. The

oxides of nitrogen and sulphur are believed to contribute to the acidification of atmospheric precipitation ("acid rain")⁴¹ while scientific studies⁴² are trying to determine whether the release of excess carbon dioxide from fossil fuel combustion is the cause of the apparent increase in world temperatures ("global warming")^{43,44,45,46,47}.

Because of the increasing awareness of the effects of emissions, Governments have introduced legislation such as the Clean Air Act in America⁴⁸ and the European Environment Protection Act aimed at reducing emission levels. Electricity Utilities are being penalised for releasing excess emissions and as a result future expansion planning will be compelled to take account of emission penalty costs and the cost associated with emission control.

3.1. Fossil Fuel Combustion

Chapter 2 identified that the burning of fossil fuels is still the World's main primary source for power generation in the electricity sector. All fossil fuels contain carbon and hydrogen which on combustion are converted to carbon dioxide and water as shown in Equation 3.1.



Equations 3.2 and 3.2 show that if sulphur and nitrogen are also present in the fuel, sulphur oxides and nitric oxides will be produced during combustion.



In addition to these flue gases, there are also discharges of particulates.

Consideration of fuel composition is important in expansion planning. A typical weight analysis of a middle ranking coal and crude oil is shown in Table 3.1.

Components	Content (% weight)	
	Bituminous coal	Crude oil
carbon	75	82 - 87
hydrogen	5	11 - 15
sulphur	2.3	0 - 8
nitrogen	1.5	0 - 1
oxygen	6.7	0 - 0.5
ash	7.0	0

Table 3.1. Typical weight analysis of medium volatile bituminous coal and crude oil.

Table 3.1 shows that because crude oil has a greater carbon content than bituminous coal it will produce more carbon dioxide during combustion. However since the calorific value (Chapter 2, section 2.4.1.7) of oil is greater than coal, less of it is required to produce one kWh. This makes oil a more attractive candidate in least-cost expansion planning both in terms of fuel cost and emission penalties.

Although natural gas contains hydrogen and carbon they exist mainly as hydrocarbons. Methane, the major component (forming between 85 to 95% of the total volume), is the simplest and most basic compound in the hydrocarbon series. It burns readily and completely to produce carbon dioxide and water. The other hydrocarbon gases are all members of the paraffin series with the general formula C_nH_{2n+2} . Table 3.2 shows a typical weight analysis of North Sea natural gas. The higher members in the series are not included as their contribution is almost insignificant in the combustion process.

Compound	Content (% weight)
Methane	94.36
Ethane	3.2
Propane	0.47
Butane	0.2
Pentane	0.05
Hexane	0.03

Table 3.2. Typical weight analysis of North Sea Natural Gas⁴⁹.

Compared to coal and oil, gas is the most 'environmentally friendly' fossil fuel in emission terms and this has been one of the major factors for the 'dash for gas' recently experienced in the UK⁵⁰. Compared to coal, gas combustion reduces CO₂ emissions by half, SO₂ emissions are virtually eliminated and significantly lower

NO_x emissions are achieved. There is also very little incombustible matter remaining after combustion and negligible amounts of emitted dust. This is clearly shown in Figure 3.2.

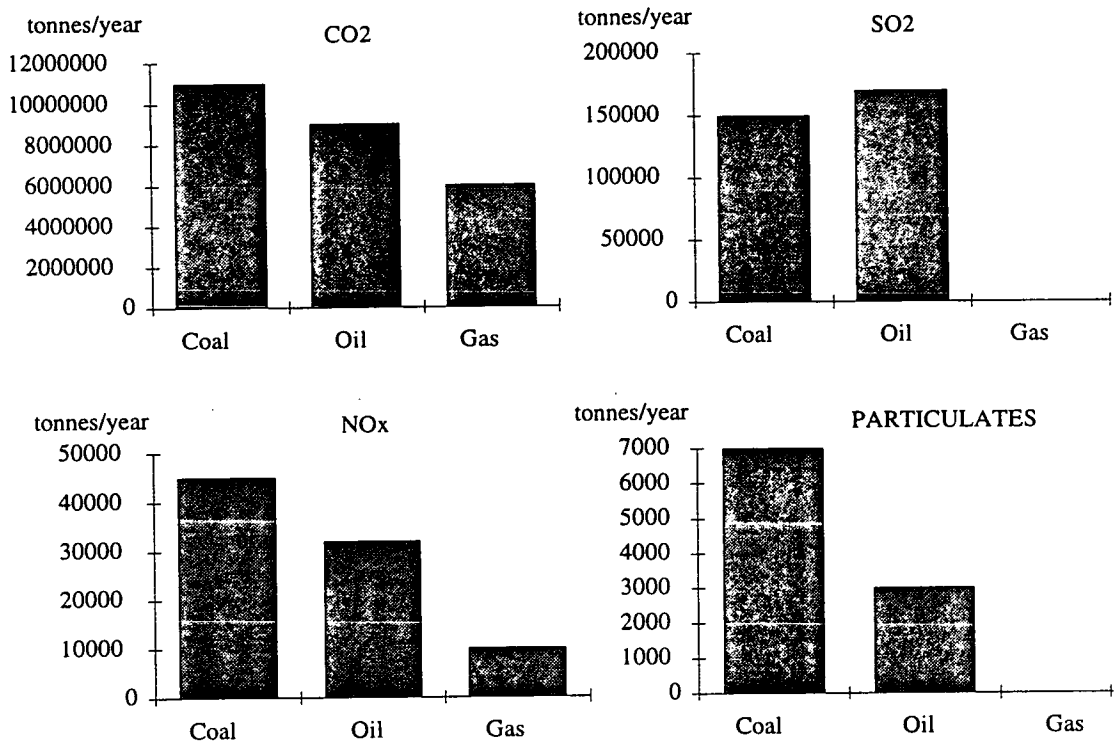


Figure 3.2. Annual emissions from typical 2000 MW power stations⁵¹.

These figures are only typical values as the composition of the fuel varies from one source to another. For example, the sulphur content in coal can vary from as little as 0.2% to as much as 20%⁵². Similarly, the operation and efficiency of the power station also dictates the amount of emissions released into the atmosphere. For example, a generator that operates for a few hours a day will release less emissions than one that runs continuously. Similarly, an inefficient generator burns more fuel to produce the same amount of energy as an efficient generator.

3.2. Costs Associated with Emissions

There is recognition throughout the world that precautionary action against gaseous emissions are needed sooner rather than later if only to avoid the possibility of more costly corrective action in the future. For example, in acknowledgement of the need

to control global warming by various measures, 166 countries, including the UK, signed the United Nations Framework Convention on Climate Change^{53,54}.

As a result of such conventions, Governments are beginning to introduce directives that require Electricity Utilities to reduce emission levels. In some countries penalties are being levied on any Utilities that do not remain within their emission levels. As a result, expansion planning must now account for any costs associated with emissions along with construction and operation costs before a least-cost plan can be determined.

There are four main costs associated with emissions; abatement costs, market based trading permit costs, carbon costs and penalty costs. These four costs are discussed in the following sub-sections.

3.2.1. Abatement Technology and Costs

The introduction of recent legislation, in particular the Clean Air Act (1990), has stimulated designers into developing new air pollution control equipment⁵⁵. This, however, can only be a partial solution. This is best summed up by the USA Department of Energy⁵⁶.

"Pollutants or their precursors are not truly eliminated. Rather, they are transformed into other species and shifted from one medium to another, i.e. from air in the form of sulphur dioxide, to land in the form of calcium sulphite and sulphate sludge, and then possibly to ground water through leachate from a landfill."

There are new technologies regularly being developed which enable the reduction of emissions from power stations. The methods and technologies to reduce these gaseous emissions discussed in the following sections are the more commonly known ones at present.

3.2.1.1. Fuel Switching

Fuel switching away from coal is seen as the easiest and cheapest method of reducing CO₂, SO₂ and NO_x emissions. It is believed by some that it is the effect of deposits of these gases, in the form of acid rain, that does the damage as opposed to the gases themselves. It has been shown that, in America, more than 60% of deposits occur during the summer months so that fuel switching from April to September causes

greater reductions in deposits than would reducing emissions by the same amount all year. Natural gas is the chosen substitute because³⁸:

1. it is very clean burning, producing no SO₂ and negligible NO_x or particulates.
2. the capital cost to retrofit is low compared to scrubber installation costs.
3. existing plants are relatively easy and cheap to convert to burn natural gas.

Although fuel switching may look promising, there are a few disadvantages. These include:

1. *resources* - it is probable that natural gas supplies will start to exhaust towards the middle of next century and as a result future prices will increase.
2. *contracts* - many Utilities have annual coal contracts which cannot be broken.
3. *jobs* - fuel switching away from coal might affect the availability of jobs for miners in local coal pits.
4. *supply* - for some of the poorer countries, low quality coal with a high sulphur content is their primary fossil fuel. To import low-sulphur coal or another fuel requires hard currency which these countries do not possess.

Despite these drawbacks, fuel switching offers a cheaper alternative to many of the emission curbing technologies being introduced into the market.

3.2.1.2. Sulphur Dioxide Control

This Large Combustion Plant Directive (LCPD) adopted by the European Council in 1988 applies to all plants with a thermal rating of 50 MW or greater. The LCPD requires participating countries to draw up a programme for the reduction of both sulphur and nitrogen oxide emissions⁵⁷. The UK values for SO₂ reduction are shown in Table 3.3; the reductions are from a base level in 1980 and the 60% SO₂ reduction in 2003 equates to a drop from 3883 kt in 1980 to 1553 kt in 2003⁵⁸.

Target Date	% SO ₂ reduction required
1993	20
1998	40
2003	60

Table 3.3. Target reduction levels in SO₂⁵⁹.

There are only two viable options available to Electricity Utilities to reduce SO₂ emissions, *coal washing* and *flue gas desulphurisation* (FGD). In the first method,

by washing crushed coal before it is combusted, it is possible to extract up to about 30% of the sulphur. This method also helps to reduce particulates. Alternatively, FGD can be used to reduce SO₂ emissions by as much as 90%. A downward flowing limestone slurry (calcium carbonate : CaCO₃) reacts with the SO₂ in the flue gas to produce a calcium sulphite (CaSO₃) slurry. Compressed air blown over this slurry oxidises the CaSO₃ to form calcium sulphate (CaSO₄) more commonly known as gypsum, a basic raw material in the plaster and plasterboard industry⁶⁰.

Although the benefits of FGD are a 90% reduction in SO₂ (meaning less harmful acid rain), the installation and operating costs are high. Allegheny Power in America recently had to pay \$725 million in capital costs and \$700 per tonne of SO₂ in order to reduce its SO₂ emissions level by 240,000 tonnes/year⁶¹. This increase in costs is expected to raise the unit price of electricity. For example, electricity produced by Drax, the first British station to be retrofitted, will rise by 0.6p⁶². Additionally, 73 MW of electrical power is consumed by the FGD plant and efficiency is reduced by about 1 to 1.5%. This increases emissions of CO₂ by 450 kt/year although dust particles are retained to a level below those required in new plant.

3.2.1.3. Nitric Oxide Control

The LCPD has also been drawn up in an attempt to reduce NO_x levels. The UK values for NO_x reduction are shown in Table 3.4.

Target Date	% NO _x reduction required
1993	15
1998	30
2003	no target set

Table 3.4. Target reduction levels in NO_x⁵⁹.

A 30% reduction of NO_x from 1980 levels by the end of the 1990s is considered by some as an ambitious policy aim⁶³. This is because the level of traffic (another major contributor to NO_x emissions) is increasing substantially. However, with standards being introduced by the EC to reduce passenger car NO_x emissions by 75%, the target reduction should be achieved.

The amount of nitrogen oxide produced depends in part on the composition of the fuel and partly from the air used in combustion. The latter can be prevented by the introduction of *low NO_x burners* that optimise the way the air and fuel combust. One

method controls the amount of air available during combustion in order to minimise excess oxygen combining with atmospheric or fuel-bound nitrogen. Another method lowers the combustion temperature, although this technology cannot be used with coal.

Another method used to remove residual NO_x, *selective catalytic reduction* (SCR), requires the flue gases to be combined with ammonia and passed over a catalytic bed of platinum to produce nitrogen which can be sold to chemical fertiliser producing industries. This process, however, can have high operating costs and results in the emission of undesirable pollutants including greenhouse gases.

3.2.1.4. Carbon Dioxide Control

Although uncertainties still exist in conjunction with global warming, there is sufficient threat to ensure action is taken now. As part of its involvement in the United Nations Framework Convention on Climate Change, the UK has produced a detailed programme of measures aimed at returning CO₂ emissions to 1990 levels by 2000⁶⁴. By encouraging the use of cleaner technology and promoting further energy efficiency, the Government hopes to reduce emissions by 10 MtC by the year 2000.

While it is technically possible to recover CO₂ from flue stacks, no large scale applications have been forthcoming due to the relative low concentration and very high volumes of the gas being released into the atmosphere. In a typical coal-fired station one kilogram of CO₂ is released for every 1.21 kWh produced. Table 3.5. shows the efficiency and energy requirements to remove and recover CO₂ from the flue. Any process which requires more than 1.21 kWh is unlikely to be considered.

Process	CO ₂ removal efficiency (%)	kWh _e lb/CO ₂ recovered
Amine absorption/stripping	90	0.60
Potassium carbonate absorption/stripping	90	0.71
Molecular sieves	90	0.88
Refrigeration	90	0.88
Sea water absorption	60	1.32
	90	1.76

Table 3.5. Energy required to remove and recover CO₂ from flue gas⁶⁵.

Another problem is disposing of the extracted CO_2 to prevent it escaping back into the atmosphere. Figure 3.3 shows the three principal ways of disposing of CO_2 emissions. These solutions are absorption by afforestation, disposal into disused gas fields or into a deep ocean.

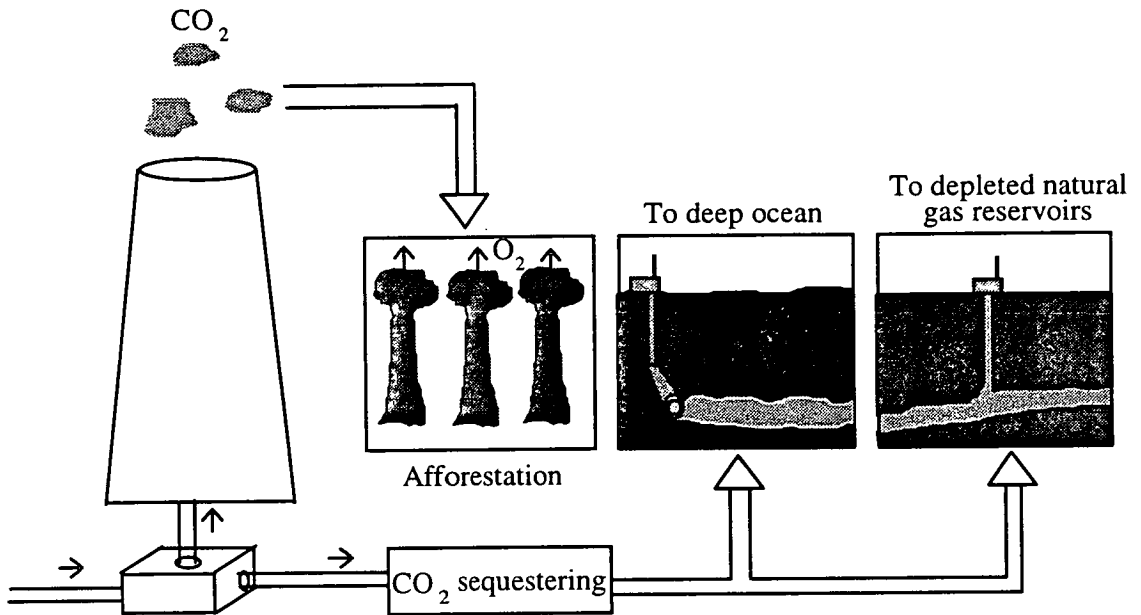


Figure 3.3. Schemes for controlling CO_2 emissions¹⁸.

A German study has calculated the cost of disposing of a tonne of CO_2 into a gas reservoir to be in the range \$22 to \$30 while it could cost between \$90 to \$110 per tonne for the ocean option. The latter is more expensive because the deposition must occur at depth and under high pressure to keep the CO_2 liquid⁴⁷. Again, as with SO_2 reduction, this method causes reduced efficiency from 40% to 29% and thus increases other emissions.

Research has gone into the idea of reforestation to temporarily mitigate CO_2 emissions. At first, this option looks plausible and cheap at around \$12 to \$26 per tonne. On close examination though, the US would have to increase its forested area by over seven times to absorb the carbon it emits annually. This amounts to 65% more than the total US land area. Also, after 30 to 70 years, the trees having reached maturity, will only absorb CO_2 emissions roughly equal to the release of carbon from rotting material .

Therefore at present, the only practical method to reduce CO₂ emissions is to cut down the using of fuels with high carbon content. However, as with SO₂ reductions this sometimes may not be possible. Research on developing new methods of burning coal continues. The two main methods (known collectively as clean coal technology) are:

- Fluidised Bed Combustion (FBC)

In this system fine particles such as sand or ash line the bed of the combustion chamber. Air is injected from below to agitate the particles and it is this turbulence that keeps the ignited fuel (also injected from below) at a constant temperature. This allows even poor grade fuels to be burnt and as the temperature is lower than that found in a conventional system, NO_x is reduced. If limestone is added, the SO₂ content can be reduced by retaining sulphates but this adds to the problem of disposing of more waste.

- Gasification

In this method, gasification takes place in the presence of oxygen and steam when coal and limestone are fed into a pressurised vessel. The gas burns in a gas turbine to generate electricity. The resulting hot exhausts form steam in a conventional boiler which drives a steam turbine to generate further electricity. It is possible to remove up to 90% CO₂ with this system and under careful control NO_x can also be reduced. As with all burning processes there is still the problem of residual waste.

3.2.1.5. Particulate Control

The limit of allowed dust particles emitted from a power station has been reduced gradually over the years. Existing plant must not exceed concentration levels of 140 mg/m³ while new plant (stations which were commissioned on or after 1 July 1987⁶⁶) must retain their particulate levels below a much lower level of 90 mg/m³⁵⁹.

There are two techniques used to remove particulates from flue gases. The most universally used method is the *electrostatic precipitator* (ESP)⁶⁷. The ESP consists of a chamber containing charged plates and wires through which the flue gases pass. A high direct current voltage, usually 40,000 - 65,000 volts, is applied between the negative and the positive electrodes. A resulting corona occurs which ionises the particles. The particles are deposited on a collecting electrode and removed

mechanically at regular intervals. The second method uses *wet scrubbers*. There are several different technologies but generally this method removes the particles by impacting them with water droplets.

Both methods are highly effective, reaching efficiency levels of up to 99%. The collected ash is subsequently removed for sale or disposal.

3.2.2. Trading Permit Costs

As a result of the Clean Air Act (1990), a flexible market-based permit system has been set up in the United States, by the Environmental Protection Agency (EPA). It is intended that sulphur dioxide emissions will be reduced by 50% from the 1980 level of 18 million tonnes per year⁶⁸. Each one-year permit allows the release of a tonne of SO₂, thus to produce 2000 tonnes of SO₂ per year a Utility requires 2000 permits. Utilities that emit above their allowed level are heavily penalised, the present rate being \$2000 for each illicit tonne^{69,70}. Firms that reduce emissions by retrofitting equipment such as flue gas desulphurisation scrubbers or fuel switching, may accumulate excess permits for future use or sell them on to other Utilities. For example Wisconsin Power and Light sold 25,000 permits to the Tennessee Valley Authority and Duquesne Light for more than six million dollars⁷¹. Some environmental groups, such as Greenpeace, have even bought and destroyed permits in order to keep the associated emissions out of the atmosphere.

Although trading permits exist at present for SO₂ alone, it is hoped that similar permits for control of NO_x and CO₂ will be developed.

3.2.3. Carbon Tax Costs

The Earth Summit in Rio de Janeiro in 1993 increased the realisation amongst the developed countries that the levels of greenhouse gases had to be reduced by the end of this century. Virtually all OECD countries have expressed an interest in the reduction of CO₂ emissions, either by stabilising CO₂ output at 1990 levels by early next century or by producing a 20% decrease. One of the methods proposed was the introduction of a carbon tax⁷² to be levied on fuels with high carbon content. This tax, set at approximately \$28 per tonne of carbon burnt, could be expected to generate about \$163 billion⁷³.

Table 3.6 shows the typical mass of carbon from each fuel type that is burnt to produce one MWh.

Fuel	Carbon burnt per MWh (kg)
Coal	367
Oil	205
Gas	118

Table 3.6. Typical quantities of carbon burnt to produce 1 MWh.

Table 3.6 highlights the quantities of carbon that are burnt when each fossil fuel type is burnt to produce 1 MWh. From this table it can be seen why many Electricity Utilities will favour gas-fired generators if they are liable to pay carbon taxation.

There have been many papers written on the advantages and disadvantages of introducing a carbon tax^{72,74,75}. Many argue⁷⁵ that to achieve even a moderate drop in CO₂ levels would require a high tax to be levied, somewhere in the region of \$300 per tonne of carbon burnt⁴⁶. Another disadvantage is that the introduction of a carbon tax in the European community is unlikely to occur until it has been introduced in the USA⁷⁶. Some scientists in the International Energy Agency believe that carbon taxing alone would not reduce current levels of emissions³⁹, while Greenpeace maintains that if taxes were introduced, the generated revenue could be spent on developing and installing technology to reduce emissions.

3.2.4. Penalty Costs

Penalty costs can be imposed on each type of emission produced by the electricity generator. The charges are related to the individual environmental impacts associated with the generating source⁷⁷. Table 3.7 shows penalty values that have been adopted by the Massachusetts Department of Public Utilities.

Emission	Penalty (\$/kg)
CO ₂	0.026
SO ₂	1.72
NO _x	7.46
Particulates	4.64

Table 3.7. Penalties for emissions⁷⁸.

By using the typical fuel compositions given in Tables 3.1 and 3.2 and the calorific values from section 2.4.1.7, Chapter 2, the emission penalty for producing one kWh can be calculated. This is shown in Table 3.8.

Fuel	Emission penalty (\$/MWh)			
	CO ₂	SO ₂	NO _x	Particulates
Coal	9.9	10.9	33.2	45
Oil	7.4	11.3	0	0
Gas	5.1	0	0	0

Table 3.8. Emission charges for one MWh.

It is hoped that by penalising Utilities for emitting over set levels, they will be discouraged from producing emissions that carry a high forfeit i.e. coal. Utilities are being encouraged to change to a less-polluting power source, i.e. gas, because whether through the damages sustained, or efforts to repair the damages, these costs are ultimately borne by society, even if that burden is not distributed equally across geography or generations.

3.3. Uncertainties

Formulating sensible policies to deal with power station emissions is greatly complicated by some fundamental scientific uncertainties that are unlikely to be fully resolved in the near future⁷⁹. While it might be possible to predict the outcome of global warming and acid rain due to a single power station, trying to determine the overall effect on a whole ecosystem is most unlikely.

Some of the uncertainties associated with emission production are listed below^{19,80}.

- *emission levels* - although present and past reading of emission levels are obtainable, it is hard to predict future readings. The growth in population, demand for energy and conservation can increase/decrease levels of potentially polluting gases.
- *climate changes* - scientists cannot agree as to whether global warming is a naturally occurring phenomenon or whether the release of greenhouse gases is causing the increase in temperature.
- *economic cost* - the future cost associated with gaseous emissions can only be guessed at. New technologies are constantly being developed to reduce

emissions but the ultimate cost to the Utility and their customers is as yet unknown.

These uncertainties pose a dilemma. By the time reliable answers are forthcoming, the damage inflicted on the environment might be as bad as the pessimists predicted. On the other hand a drastic programme may impose economic costs and social disruptions. However, by applying least-cost expansion planning to varying scenarios, the Planner is able to determine the extent and variation in economic terms.

3.4. Summary

This chapter has discussed the costs associated with the release of carbon dioxide, sulphur dioxide, nitric oxides and particulates into the atmosphere when generating electricity. In an attempt to reduce these output levels to acceptable limits, Governments have introduced directives.

This chapter has examined some of the technologies that are available to reduce emissions and has included some typical installation and operational costs. These costs can contribute significantly to the overall operational costs of a power plant. This chapter has also examined the effects of introducing trading permits, carbon taxes and emission penalties.

Emission costs can significantly change the optimum expansion solution because of the large sums involved. As a result Planners must account for all of these additional costs in least-cost expansion planning in order to obtain an accurate minimum cost solution.

CHAPTER 4

EXPANSION PLANNING CALCULATIONS

This chapter describes the calculations used in electricity supply expansion planning. A step-by-step approach is presented, illustrating the reasoning process leading to the variety of expansion plans that successfully meet future customer electricity requirements. These steps are shown schematically in Figures 4.1 and 4.2.

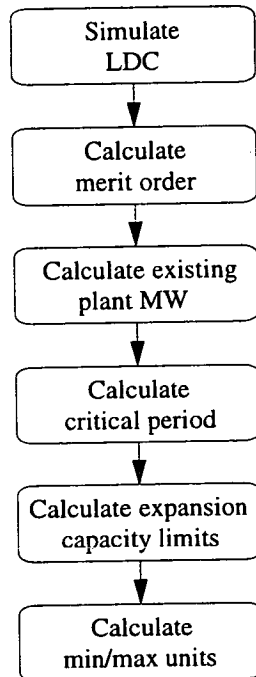


Figure 4.1. Yearly initialise defined.

In this study, *existing plant* or *existing stations* refers to stations that are already generating electricity or are committed (i.e. plans for their future generation have been granted and loans endorsed even though the plant may not yet exist). *Expansion/additional plants* or *stations* are power stations under consideration which may be built in the future to provide extra electricity generation to meet increases in load demand. A station may be composed of more than one generator, and for the purposes of this chapter and the rest of this thesis, these single generators will be referred to as *units*. An *expansion combination* refers to the aggregate number of generating units in the expansion stations that need to be built and operating by a particular year in order to meet the expected generation expansion demand. Each year in the study may have more than one expansion combination. A list of

expansion combination from each year in the study makes an *expansion plan*. Generally more than one expansion plan can be determined.

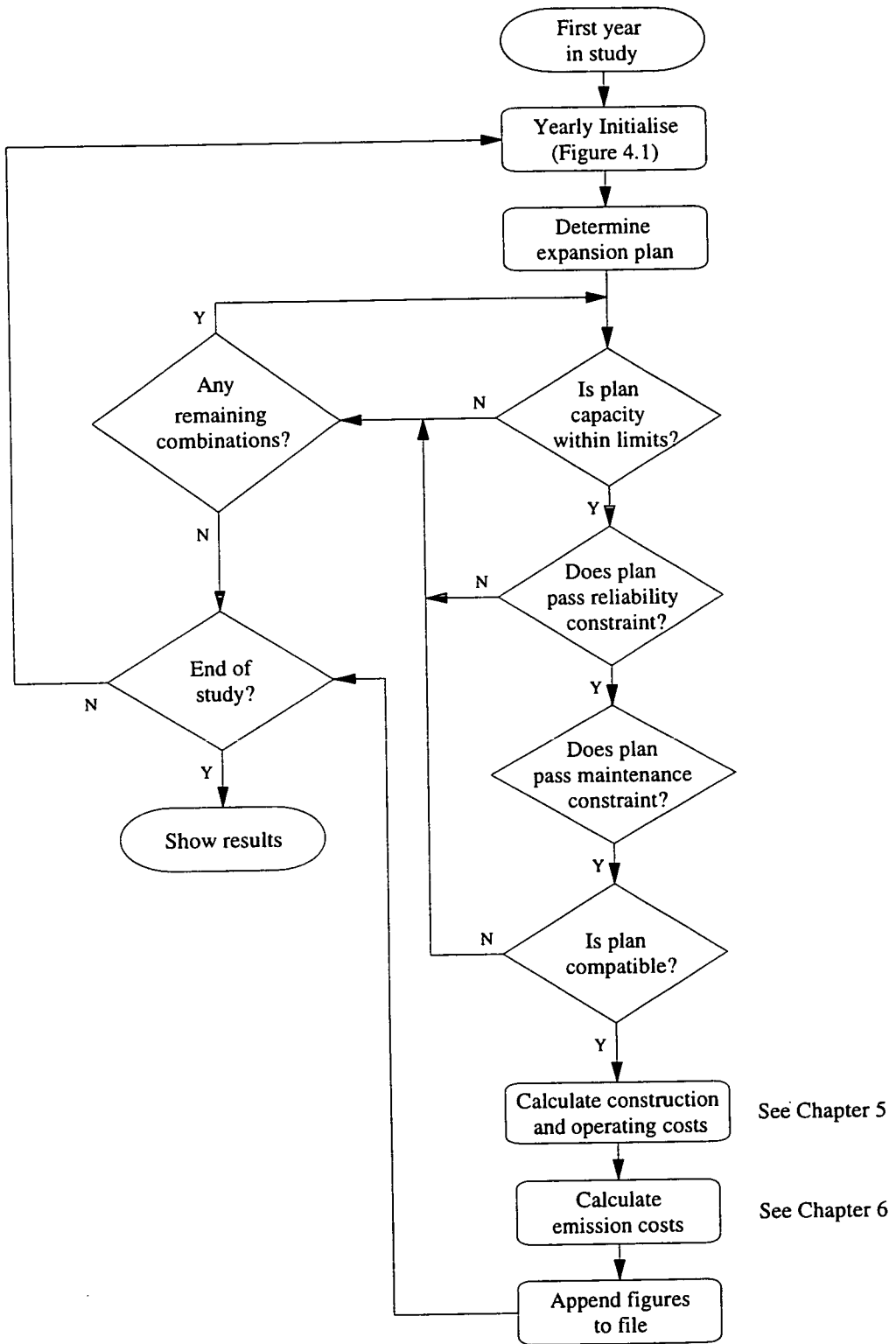


Figure 4.2. Schematic diagram of plant mix calculations.

Each step in Figures 4.1 and 4.2 is discussed in more detail in the following sections.

4.1. Load Duration Curves

The annual electricity demand is represented by an annual peak load, periodic load ratios and periodic load duration curves. The annual peak load is the maximum demand for electricity at any one time in a year. The load ratio represents the ratio of the period peak load to the annual peak load. A load duration curve shows variation in electricity demand over a period of time, be it twenty four hours, a month, three months or a year. A load duration curve data can be represented either as *x-y co-ordinates* or as a *fifth order polynomial*.

4.1.1. X-Y Co-ordinates

Most Electricity Utilities have data regarding past load demands. These values may have been obtained from past measurements or numerical results from probabilistic analysis⁸¹ and usually predict the number of hours a given demand is expected to be exceeded. Two options are available to convert the x-y co-ordinates to a polynomial; *least square fit* or *exact fit*.

- Least square fit

This is the preferred method, as the number of polynomial coefficients is kept to a minimum of six. From n number of x-y co-ordinates (where n is an integer between 6 and 30 inclusive), a 5th order polynomial that best approximates the curve is determined. The 5th order polynomial is chosen because it represents the curve adequately while requiring a minimal amount of computational time.

- Exact fit

This option allows the load duration curve to be defined more precisely. From n+1 data points on a load duration curve, a polynomial of degree n or less that exactly passes through all n+1 x-y co-ordinate points is determined. This method is not recommended as although it is more accurate the larger number of polynomial coefficients requires extra computational time.

4.1.2. Polynomials

Load duration curves can be represented in the form of an nth order polynomial. For the purpose of this thesis a 5th order polynomial is examined. The load duration curve equation is shown in Equation 4.1.

$$y = c_0 + c_1x^1 + c_2x^2 + c_3x^3 + c_4x^4 + c_5x^5 \quad (4.1)$$

Here, y is the normalised load magnitude for a given normalised time duration x , c_0 is the constant coefficient (usually 1) and c_1, c_2, \dots, c_5 the first, second, ..., fifth order coefficients. A value for each of the six coefficients used to represent a typical shaped load duration curve similar to the one shown in Figure 2.5 is given in Table 4.1.

C_0	C_1	C_2	C_3	C_4	C_5
1	-4	17	-37	35.6	-12.4

Table 4.1. Coefficients of a typical shaped load duration curve.

4.2. Merit Order

To determine load allocation at minimum cost between generating stations it is generally necessary to carry out continuous simulation calculations as customer demand changes⁸². In a future dispatch simulation this would not be practical as many load changes would be needed while solving the problem for only one simulation. To simplify matters, it is common practice to order the list of stations based on total fuel costs, maintenance costs and emission costs per mega watt hour (MWh) at the full-load point for each unit. The station with the lowest operating cost meets base loads, while the more expensive generating stations cope with peak loads that occur part of the time.

4.2.1. Full-Load Emission Costs

The chemical composition of a fuel determines the waste it produces during combustion. The weight of waste produced is directly related to the amount of fuel burnt and the proportion of elements in the fuel. The weight of fuel to produce one MWh is calculated from the fuel's calorific value.

Stoichiometric reaction equations are used to calculate the formation of combustion waste products; namely carbon dioxide (CO_2), sulphur dioxide (SO_2), nitrous oxide (NO_x) and particulates. These equations use molecular weights to calculate the weight of the four compounds when one MWh is produced from fossil fuel combustion. This is shown in Equation 4.2.



$$\text{gas weight} = \frac{\text{element weight}}{\text{element molecular weight}} \times \text{gas molecular weight} \times \text{fuel weight} \quad (4.2)$$

For example, to produce one MWh, 92.3 kg of oil with a calorific value of 39 GJ/tonne must be burnt. If the oil is composed of 79% carbon then 0.267 tonnes of carbon dioxide is formed. $(0.79/12 \times 44 \times 0.0923)$

A monetary value is assigned to every tonne of gas produced⁸³, from which the full-load cost of emissions for the production of one MWh is calculated.

4.2.2. Full-Load Fuel and Maintenance costs

In order to find the full-load fuel and maintenance cost of a power station, it is first necessary to determine its full-load heat rate (FLHR). A method known as the *incremental method* was first formally derived by Steinberg and Smith⁸⁴ in 1934 even though it was recognised as early as 1930. In this method, each increment in the load is picked up by the generating unit with lowest incremental cost. The full-load heat rate calculation is shown in Equation 4.3.

$$\text{FLHR} = \frac{(\text{BLHR} \times \text{MOL}) + \text{AIHR} \times (\text{MC} - \text{MOL})}{\text{MC}} \quad (4.3)$$

Where:

BLHR = base load heat rate

MOL = minimum operating level

AIHR = average incremental heat rate

MC = maximum capacity

A full-load fuel and maintenance cost (FLC) is calculated for both local and foreign fuel costs for all generation stations in the study. Fixed operation and maintenance charges are ignored because the cost is incurred whether the station is run or not and is independent of the number of generation hours. The FLC calculations (for both domestic and foreign expenditure) are shown in Equation 4.4.

$$\begin{aligned} \text{domestic FLC} &= \text{domestic fuel cost} \times \text{MF}_d \times \text{FLHR} + \text{variable O\&M} \\ \text{foreign FLC} &= \text{foreign fuel cost} \times \text{MF}_f \times \text{FLHR} \end{aligned} \quad (4.4)$$

Variable operation and maintenance (O&M) costs are assumed to contribute to domestic costs. A domestic/foreign annual fuel cost multiplying factor (MF_d/MF_f) is used to account for any escalation in the fuel price over the study period.

Finally, the total costs of operating each unit at full load are calculated by adding the domestic FLC, the foreign FLC and the full-load emission cost. This is shown in Equation 4.5.

$$\text{total full - load operating costs} = \text{domestic FLC} + \text{foreign FLC} + \text{emission cost} \quad (4.5)$$

The loading order is thus based on the total full-load operating costs.

4.3. Existing Installed Capacity

The additional electrical energy to be generated by potential new plant is determined from the difference between the projected load demand and the existing installed capacity. The calculation to find existing installed capacity is shown in Equation 4.6, where maximum capacity is the electrical output of the generating unit (MW_e). The number of available generating units takes account of any unit retirements in previous years.

$$\text{installed existing capacity} = \sum_{\text{existing candidates}} \text{no. of units} \times \text{maximum capacity} \quad (4.6)$$

4.4. Critical Period

In the study of future electricity demand, it is possible to split a study year into periods. These periods represent different load demands within a yearly time span. For example, in Britain a year could be split into four periods to represent each of the seasons, where during the cold seasons (Autumn and Winter) the demand for electricity is much higher than in the warmer seasons (Spring and Summer).

Rather than determining combinations of additional units to meet demand in each individual period, only the critical period is used. The critical period is evaluated as the period during which the difference between the projected load and the existing capacity is maximum. In other words, this is the period where the greatest amount of expansion capacity has to be supplied. This is shown with a simple example. Consider a year defined by the following load and existing plant characteristics:

- load characteristics (annual peak load = 12000 MW)

	period 1	period 2
load ratio (%)	75	100
period peak load (MW)	9000	12000

- existing plant characteristics
capacity (MW) : 7700

The difference in each period is:

$$\begin{aligned} \text{period 1 } & 9000 - 7700 = 1300 \text{ MW} \\ \text{period 2 } & 12000 - 7700 = 4300 \text{ MW} \end{aligned}$$

Period 2 has the greater margin between demand and installed capacity and thus is the critical period.

4.5. Expansion Capacity Limits

The maximum and minimum acceptable expansion capacity limits (in MW) are calculated only for the critical period of each year in the study plan. The power generated by the sum of expansion candidate units must lie between these limits in order to meet customer demand. The expansion capacity limits are determined by minimum and maximum reserve margins over and above the expected peak load. The minimum reserve margin is usually taken to be the required spinning reserve of the system while the maximum reserve margin is included to avoid the likelihood of generating unnecessary electricity in excess of demand. The required calculations are shown in Equations 4.7 and 4.8.

$$\text{min expansion capacity} = \left(\frac{\text{reserve}_{\min}}{100} + 1 \right) \times \text{peak load} - \text{installed existing capacity} \quad (4.7)$$

$$\text{max expansion capacity} = \left(\frac{\text{reserve}_{\max}}{100} + 1 \right) \times \text{peak load} - \text{installed existing capacity} \quad (4.8)$$

By following on from the critical period example with a peak load of 12000 MW and existing capacity of 7700 MW, if the minimum and maximum reserve margin are

15% and 25% respectively, the minimum expansion capacity limit must be equal to or greater than 6100 MW while not exceeding the maximum expansion capacity limit of 7300 MW.

4.6. Minimum and Maximum Expansion Candidate Units

Limits have to be set on the minimum and maximum number of additional units in each plant that can be considered for expanding the generating system each year. This allows unnecessary calculations to be cut out, thus reducing computational time.

The minimum number of generating units to be considered in each plant is set depending on the acceptable combinations of units for that plant in the previous year. In the first year (y) the minimum number of units will always be 0 but in the following years, ($y+n$), the minimum number of units for each plant will be the minimum accepted number of units for that plant in the previous year, ($y+n-1$). Consider the accepted combinations in 1996 shown in Table 4.2 where each horizontal line represents the number of generating units in each plant needed for the total capacity to lie between the expansion capacity limits.

1996	coal units 600 MW each	oil units 400 MW each	gas units 200 MW each
	2	3	0
	1	2	5
	1	3	3
	3	0	3

Table 4.2. Combinations of generating units to meet a maximum demand of 2400 MW.

The minimum number of coal units considered for expansion in 1996 is 1, the minimum number of oil units is 0 and the minimum number of gas units is 0. Thus, in the following year, 1997, the minimum number of coal generating units considered will be 1, since this is the minimum number which forms the coal contribution for an acceptable expansion combination in the previous year, 1996. Similarly the minimum number of oil and gas generating units considered will be 0.

The maximum number of units assigned to each plant ensures that if the number of generating units of other plants remains unchanged, the maximum capacity of the plant considered will not exceed the maximum expansion capacity limit. This

maximum number of units for each plant is determined by Equation 4.9 where *floor* (*x*) finds the largest integer not greater than *x*.

$$\text{maximum number of units} = \text{floor} \left(\frac{\text{maximum expansion capacity} - \sum \text{min. of other plant}}{\text{unit maximum capacity}} \right) \quad (4.9)$$

For example, from Table 4.2 where the minimum number of coal and oil units considered in 1996 is 1 and 0 respectively, the maximum number of gas units that would be considered in 1997 where the maximum expansion capacity must not exceed 2650 MW would be 10 ($[2650-600-0]/200$). Similarly the maximum number of units for coal and oil would be 4 ($[2650-0-0]/600$) and 5 ($[2650-600-0]/400$) respectively.

4.7. Calculating Expansion Combinations

To find every possible combination of expansion units in a year in a systematic manner, counting begins at the minimal acceptable number of generating units for each expansion plant and increments by one up to the maximum acceptable number of generating units. The possible permutations from the minimum number of generating units up to and including the maximum number of generating units are shown in Table 4.3.

4.8. Expansion Combination Constraints

If the maximum number of units is large, the total possible number of combinations can be extremely large. Equation 4.10 calculates the number of possible combinations.

$$\text{coal (max - min +1)} \times \text{oil (max - min +1)} \times \text{gas (max - min +1)} \quad (4.10)$$

The calculations needed for simulation of system operation for each expansion combination and the economic comparison between alternative expansion plans are complex. As a result, the computer time to perform the simulation and comparisons is relatively high. It is necessary, therefore, to limit the number of expansion combinations, and consequently the number of expansion plans to be economically evaluated and compared.

coal units	oil units	gas units
min	min	min
min	min	min +1
min	min	min +2
:	:	:
min	min	max
min	min +1	min
min	min +1	min +1
:	:	:
min	min +1	max
min	min +2	min
min	min +2	min +1
:	:	:
min	max	max
min +1	min	min
:	:	:
min +1	min	max
:	:	:
min +1	max	max
:	:	:
max	max	max

where:

min = minimum number of units allowed.

min +n = minimum number of units incremented by n.

max = maximum number of units allowed.

Table 4.3. Systematic determination of possible combinations.

Table 4.4 shows an example of every possible expansion combination of coal, oil and gas generating units. At this point no constraints have been set to determine if the expansion combinations lie between the minimum and maximum expansion capacity limits.

coal units 600 MW each	oil units 400 MW each	gas units 200 MW each
0	2	4
0	2	5
0	2	6
0	3	4
0	3	5
0	3	6
1	2	4
1	2	5
1	2	6
1	3	4
1	3	5
1	3	6

where:	min.	max.
coal units	0	1
oil units	2	3
gas units	4	6

Table 4.4. Example of every unit combination.

To reduce the number of possibilities, a combination is only accepted if it passes a set of four constraints. These constraints are:

- Expansion capacity constraint
- Reliability constraint
- Maintenance constraint
- Compatibility constraint

These four constraints are discussed in the following sections.

4.8.1. Expansion Capacity Constraint

The expansion capacity of a system for a particular year is the sum of all expansion station's generating capacities. The calculation for expansion plant capacity is shown in Equation 4.11.

$$\text{Expansion Capacity (MW)} = \sum_{\text{expansion candidates}} \text{no. of units} \times \text{maximum capacity} \quad (4.11)$$

The total capacity of the expansion candidates must lie between the expansion capacity limits (calculated in Equations 4.7 and 4.8), as shown in Equation 4.12.

$$\text{minimum capacity} \leq \text{expansion capacity} \leq \text{maximum capacity} \quad (4.12)$$

Failure to do so will mean either insufficient or excess plant will be installed. All combinations outwith these limits are rejected. Figure 4.3 shows the aggregate potential expansion capacities of the twelve combinations from Table 4.4. The graph shows that only options 3, 4, 5, 6, 7 and 8 lie between the minimum and maximum capacity limits. The options 1 and 2 are rejected for insufficient generation while options 9, 10, 11 and 12 are rejected for excess generation.

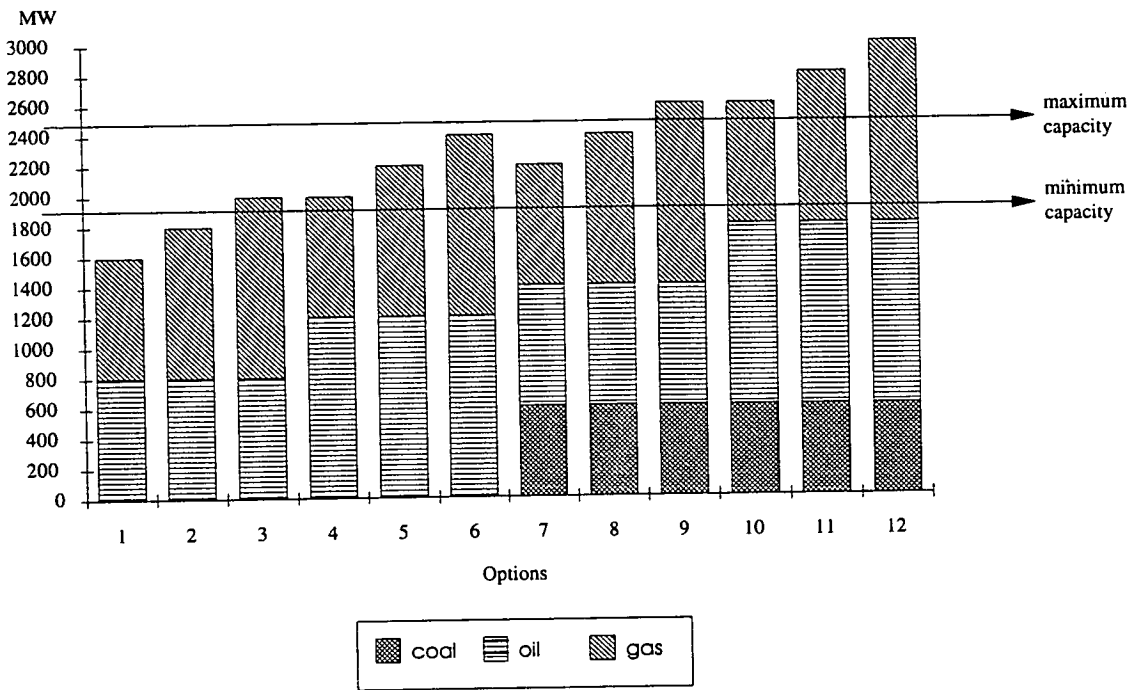


Figure 4.3. Aggregate capacities of expansion combinations from Table 4.4.

4.8.2. Reliability Constraint

To be an operational success, an electricity power system must be able to provide a service to customers with minimal interruption. The reliability of a generation system expansion plan is crucial to the success of any Electricity Utility. A suitable generation expansion plan must provide the Electricity Utility with the capability of meeting customer needs with reasonable reliability.

To determine whether a generation expansion plan satisfies a required level of reliability, three reliability indices are discussed here; *standard percentage reserve*, *loss of largest generator* and *loss of load probability*. Any expansion combination that does not satisfy reliability levels is rejected.

4.8.2.1. Standard Percentage reserve

The *standard percentage reserve reliability method* is the earliest method used to calculate reliability and the easiest to compute as it only requires two factors to be considered. This method compares the total installed capacity with the expected peak load demand. Providing that this ratio is greater than the standard percentage reserve given by the user, (in the range of 15 - 25% based on past experience), then the system is assumed to have satisfactory reliability and is capable of meeting demand with reasonable frequency and magnitude.

The calculation is shown in Equation 4.13.

$$\frac{\text{existing capacity} + \text{expansion capacity}}{\text{peak load}} \geq \text{standard percentage reserve} \quad (4.13)$$

There are, however, a few drawbacks of using this simple method. These include its inability to consider forced outage rate and unit size as well as differing load characteristics which result in an incomplete answer as to whether a load will be served adequately or not⁸⁵.

4.8.2.2. Loss of largest generator

The *loss of largest generator reliability method* determines if a system can still continue to provide peak load even if its largest generator is out of action. Although this involves simple calculations, it provides a degree of sophistication over the previous method by taking account of unit size. As new and bigger units are added into the system, installed capacity must take account of this to provide a reliable service.

The calculation used is shown in Equation 4.14.

$$\text{existing capacity} + \text{expansion capacity} - \text{largest generator} \geq \text{peak load} \quad (4.14)$$

If the system is large, planners tend to use the two largest units to calculate reliability⁸⁶.

4.8.2.3. Loss of Load Probability (LOLP)

The *loss of load probability reliability method* (LOLP), in days per year, is the most widely used probabilistic index for generation reliability assessment⁸⁷. During a normal period of operation, all units are randomly forced off-line because of technical problems. It is therefore necessary to determine a probability density function that will describe the probability that a unit will be forced off-line or will be available during its normal period of operation. The random failure and repair of a unit can be defined as a two-state stochastic process. This stochastic process defines a process that develops in time in a manner controlled by probabilistic laws. The stochastic process considered here is a zero order, discrete state, continuous transition Markov process. It is a fairly accurate model of real life and the mathematical

description is simple. A "state-space diagram" for the stochastic process is shown in Figure 4.4 where, for simplicity, only two states are assumed.

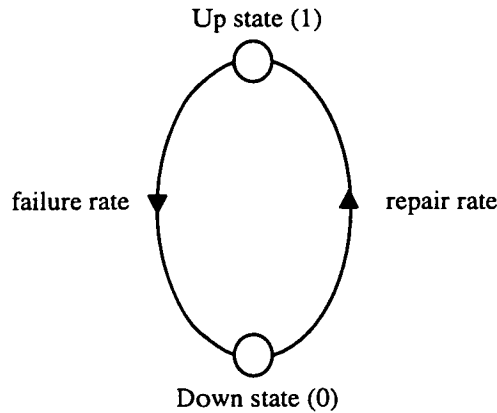


Figure 4.4. Markov stochastic "state-space diagram"⁸⁸.

The Markov stochastic process has the following properties:

- the generating unit can only be in one state at a time.
- changes of state are possible at any time.
- the probability of departure from one state depends only on the present state.
- the probability of a change of state during a small time interval is negligible.

In order to calculate the probability of being in either state, it is necessary to define two quantities:

- unit availability, denoted by variable p
- unit forced outage rate, denoted by variable q

The sum of these two variables ($p + q$) must always be equal to 1. The *effective load* (L_e) of the system is the actual capability of the system to supply power and its calculation is shown in Equation 4.15.

$$L_e = \sum_i MW_{ei} \times q_i \tag{4.15}$$

The LOLP, $F^i(L_e)$, is the probability that effective load will exceed installed capacity and is found by using Equation 4.16.

$$F^i(L_e) = F^{i-1}(L_e)p_i + F^{i-1}(L_e - MW_{ei})q_i \tag{4.16}$$

4.8.3. Maintenance

During a normal period of operation, all units are forced off-line either randomly because of technical problems or due to planned maintenance. Chapter 2 showed that regular planned maintenance is an important consideration in any electricity generating system.

In order for an expansion combination to be accepted it has to pass a maintenance constraint. The *maintenance hours availability* constraint is discussed in more detail in section 4.8.3.3. Any expansion combination that fails to meet this constraint is rejected.

4.8.3.1. Planned Maintenance

Annual planned maintenance is necessary for the reliable operation of the power generating system. The frequency of maintenance depends on the following.

1. size of the system, i.e. number and size of units.
2. maintenance duration of each set, which may change from year to year.
3. labour and parts constraints.
4. reliability constraints which are dependent on the load during different months and the availability of the sets.

Equation 4.17 calculates the number of MWh lost due to planned maintenance. *Scheduled units* refers to the number of units within a particular generating plant that are to be maintained during the year. An electricity Utility is unlikely to maintain all the units every year. Planned maintenance (PM) is expressed in number-of-days so this value must be multiplied by the number of hours in a day (24) to express lost generation in MWh.

$$\text{lost MWh}_{\text{planned}} = \sum_{\text{all plants}} \text{scheduled units} \times \text{maximum capacity} \times \text{PM} \times 24 \quad (4.17)$$

4.8.3.2. Forced Outage Maintenance

The probability of a unit being unavailable for generation is known as forced outage. The forced outage rate can be determined in a variety of ways, including examination of the unit's own history of operation, national experience with units of similar type, and/or extrapolation of data for the newer types and sizes of units. The forced outage

of a generator can be considered to be an independent event, neither influenced by the outages of other generators nor influencing other generation outages.

Equation 4.18, calculates the lost MWh per period through forced outages (FOR). *No. of units* refers to the total number of generating units that are in the plant. The number of hours in a year (8760) must be considered in order to express lost maintenance in MWh.

$$\text{lost MWh}_{\text{forced}} = \sum_{\text{all plants}} \text{no. of units} \times \text{maximum capacity} \times \text{FOR} \times \frac{8760}{\text{no. of periods}} \quad (4.18)$$

The total MW hours lost is the combination of lost $\text{MWh}_{\text{planned}}$ and $\text{MWh}_{\text{forced}}$.

4.8.3.3. Maintenance Hours Availability Constraint

In order that a Utility is capable of providing a continuous supply of electricity to its consumers, it must ensure that there is sufficient excess capacity to cover units that are not generating due to planned or forced maintenance.

Figure 4.5 shows a normalised load duration curve.

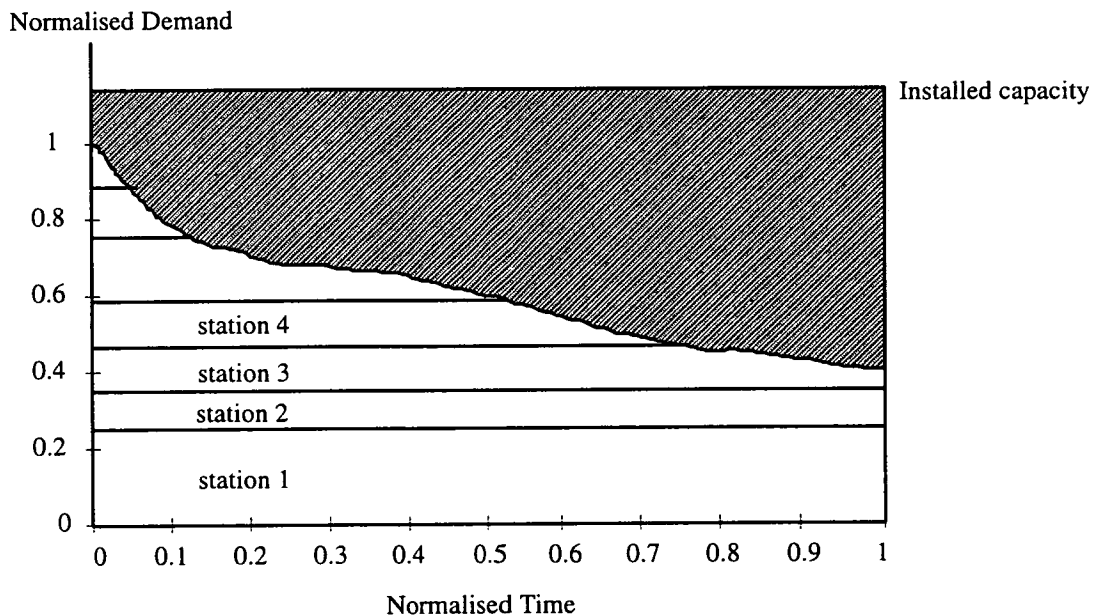


Figure 4.5. Graph showing available maintenance MWh.

The shaded area represents the normalised available mega watt hours for planned maintenance and forced outages. The shaded area is found by integrating the difference between the normalised installed capacity and the 5th order polynomial curve (F(x)). This is shown in Equation 4.19.

$$\text{available maintenance area} = \int_0^1 \text{normalised installed capacity} - F(x) \quad (4.19)$$

Available maintenance MWh are then found by multiplying the normalised available maintenance area by the total installed capacity and number of hours in the period, as shown in Equation 4.20.

$$\text{available maintenance MWh} = \text{available maintenance area} \times \text{installed capacity} \times \frac{8760}{\text{no. of periods}} \quad (4.20)$$

Providing this calculated value is greater than the number of MWh required for planned maintenance and forced outages (calculated in Equations 4.17 and 4.18), the expansion combination will be accepted.

4.8.4. Combination Compatibility Constraint

Rather than determining all the possible expansion combinations for each year in the study before finding overall expansion plans to meet specifications, this method works one year at a time. Apart from the first year (y) in which all combinations that comply with the above three constraints are accepted, the compatibility method evaluates which combinations in the following years (y+n) are compatible with combinations in the previous year (y+n-1). To be compatible, the number of expansion units for each fuel type in the latter year (y+n) must equal or be greater than the number of units in the former year (y+n-1). If a combination in the latter year is not compatible with any combinations in the former year it will be rejected before any cost calculations are performed. All combinations in the latter year that are compatible with former year combinations are accepted, their costs calculated and accumulated with the costs from previous years.

For example, consider the combinations of two consecutive years shown in Table 4.5. The maximum electricity demand to be met is shown in the top left box under the year.

1999 (1400 MW)	coal units 600 MW each	oil units 400 MW each	gas units 200 MW each
A	0	3	1
B	1	0	4
C	2	0	1

2000 (2000 MW)	coal units 600 MW each	oil units 400 MW each	gas units 200 MW each
D	0	2	6
E	0	3	4
F	1	1	5
G	1	3	1
H	2	0	2

Table 4.5. Example of two consecutive years expansion combinations.

The combinations in 2000 that are compatible with combinations in 1999 are shown in Table 4.6.

1999	2000
A	E, G
B	F
C	H

Table 4.6. Example of compatibility.

Although not shown in Table 4.6, it is possible that some combinations in the latter year are compatible with more than one combination in the former year while some are not compatible at all. In the above example, the combination D in year 2000 is not compatible with any combinations from 1999 and so is rejected.

The combinations in the next year in the study ($y+n+1$) are compared only with those combinations in the previous year ($y+n$) that were not rejected. For example consider the combinations for 2001 shown in Table 4.7.

2001 (2200 MW)	coal units 600 MW each	oil units 400 MW each	gas units 200 MW each
K	1	1	6
L	1	3	2
M	2	0	5
N	2	1	2
P	2	2	1

Table 4.7.

The compatible combinations of 2000 and 2001 are shown in Table 4.8.

2000	2001
E	
F	K
G	L
H	M, N

Table 4.8.

In Table 4.8, it can be seen that combination E has no compatible combination in 2001 and so is rejected. A family tree is formed and once all the years in the study have been simulated, several plans that meet demand constraints will have been found, while implausible options have been rejected along the way, thus reducing computational time and data storage space. The family tree of the example is shown in Figure 4.6.

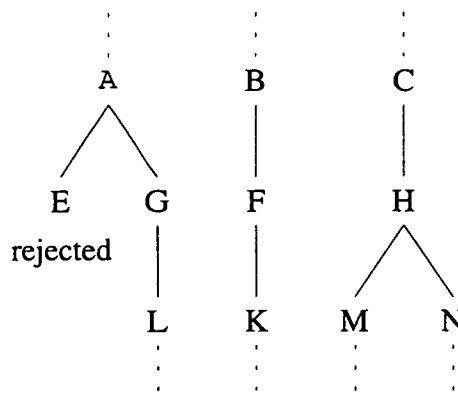


Figure 4.6. Tree structure of possible expansion plans.

Using this type of reasoning it is possible to reduce the number of viable plans from 90 ($3 \times 6 \times 5$) to 4.

The costs associated with the reduced number of combinations are then calculated. The construction and operation cost calculations are examined in Chapter 5 and the calculations required to determine environmental costs are reviewed in Chapter 6.

4.9. Summary

This chapter has examined the calculations that are used to determine combinations of additional expansion plant units which are capable of meeting future electricity demand. The total number of combinations in a particular year can be high although by introducing constraints this number can be reduced. This chapter has considered four constraints that the combination must comply to before it is accepted. It was shown that by applying the compatibility constraint the number of combinations was reduced from ninety down to four. Not only does this reduce the amount of data storage space required but also dispenses with redundant cost calculations.

CHAPTER 5

CONSTRUCTION AND OPERATION COST CALCULATIONS

This chapter describes the calculations used to determine the construction and operation cost of expansion combinations which successfully meet expected future electricity demand and pass all the constraints discussed in Chapter 4. The first half of this chapter is concerned with construction cost calculations and the second half concentrates on the operation cost calculations.

5.1. Construction Costs

The economic values associated with constructing new power plants can be split into three separate entities:

- *capital cost* - the sum of money required to build a new generating unit.
- *interest* - the payments on the loan of the capital cost.
- *salvage value* - the expected return of money on equipment, buildings and land at the end of the station's lifetime.

The first two factors are handled together as they are both expenditures whereas the salvage value is a future income to be expected by the Electricity Utility. In order to be able to compare prices with other combination options, all of the costs must be referred to a base year; usually the first year in the study. To do this it is necessary to make five calculations. These are:

- uniform-series compound-amount factor calculations
- capital recovery calculations
- sinking-fund factor calculations
- total expenditure calculations
- net-present value calculations.

These are discussed in the following sections. It is necessary to calculate construction cost only for the additional units that will be built, as the capital cost of existing units should already have been accounted for.

All the values discussed in the following sections are shown schematically in Figure 5.1.

5.1.1. Uniform-Series Compound-Amount Factor Calculations

The capital cost includes all expenditure made prior to and during the construction period with accrued interest increasing the sum owed. For example, consider a coal-powered generating unit that is required to be operating by the year 2003 and will take five years to build at an overall capital cost of £900 million. Work will have to begin in 1998. For simplicity it is assumed that the borrowed money is split evenly between the number of construction years, namely £180 million (£900/5) is borrowed from the lending company (i.e. bank) each year. This is known as the *annualised capital cost* (ACC). The money owed to the bank for each of the five years can be tabulated as shown in Table 5.1. The construction interest rate used in this example is 7%. The interest shown in the third column, is the interest accrued on the accumulated total (shown in the fifth column).

Year	ACC (£M) ①	Interest Accrued (£M) ②	Yearly Total (£M) ① + ②	Accumulated Total (£M) Σ① + ②
1998	180		180.00	180.00
1999	180	12.60	192.60	372.60
2000	180	26.082	206.082	578.682
2001	180	40.508	220.508	799.190
2002	180	55.943	235.943	1035.133

Table 5.1. Example showing built up of interest on capital cost.

The above calculations demonstrate the financial disadvantages of long construction periods.

The same results can be obtained using the *uniform-series compound-amount factor* calculation (USCAF). This is shown in Equation 5.1, where *i* is the construction interest rate and *c* the construction time in years. (The USCAF is expressed in dollars).

$$USCAF = \frac{\text{capital cost} \times \text{capacity}}{c} \times \left[\frac{(1+i)^c - 1}{i} \right] \quad (5.1)$$

As there can be both domestic and foreign capital costs and interest rates two equations are required; one for domestic values and the other for foreign values.

5.1.2. Capital Recovery Calculations

The total owed at the end of the construction period is USCAF, repayment of which is usually spread over the lifetime of the generating unit (t). The calculation used to determine how much must be paid each year is the *capital-recovery factor* equation (CRF). This is shown in Equation 5.2. The domestic/foreign USCAF value must be used with the corresponding domestic/foreign discount rate (d).

$$CRF = USCAF \times \frac{d}{(1+d)^t - 1} + d \quad (5.2)$$

The capital-recovery factor, when applied to an investment, gives a uniform end-of-year payment. This value ensures the recovery of the investment together with interest on the investment. Continuing with the previous example, if the generating unit has an expected productive lifetime of 30 years and the discount rate is 9%, the amount owed each year is \$100.76 million. In other words, this value represents the minimum annual rate of return required to be received by the Electricity Utility before profit can be realised.

5.1.3. Sinking-Fund Factor Calculations

The salvage value of a generating unit is the anticipated monetary value to be realised at the end of its lifetime. Thus, although the generating unit may have reached the end of its usefulness, there may still be a value attached to the buildings, equipment and the plot of land. Rather than subtract this value in the final year of the generating unit, it is usual practise to find an annual equivalent cost, over the lifetime of the unit (t), using a domestic discount rate (d). This is achieved using the *sinking-fund factor* equation (SFF) shown in Equation 5.3.

$$SFF = \text{salvage value} \times \frac{d}{(1+d)^t - 1} \quad (5.3)$$

5.1.4. Total Expenditure Calculations

As well as the annual capital-recovery value (CRF) there is another additional construction cost which must be accounted for - the *non-depreciable capital cost*

(NDCC). This cost is a single, one-of payment in the first operational year of the generating unit and unlike the capital cost it is not spread over the construction period. The NDCC is considered along with the CRF in the first year that the unit generates as shown in Equation 5.4.

An *annual capital cost multiplying factor* (MF) is included to allow provision for expected increases/decreases in the future construction interest and may differ from year to year. Multiplying factors that are less than one are decreasing factors while those greater than one are increasing factors.

The annual salvage value (SFF) is subtracted from the annual capital-recovery value (and non-depreciable capital cost in the first year) to determine the overall yearly expenditure value. The first-year-in-operation total expenditure is shown in Equation 5.4 while Equation 5.5 shows total expenditure for the remaining years.

$$\text{total expenditure}_{\text{1st year}} = [(\text{CRF} + \text{NDCC}) \times \text{MF}] - \text{SFF} \quad (5.4)$$

$$\text{total expenditure} = (\text{CRF} \times \text{MF}) - \text{SFF} \quad (5.5)$$

5.1.5. Net-Present Value Calculations

In order to be able to compare different plans which project into the future on an equal basis, all the costs have to be referred to a common year using a discount rate (d). Normally the base year is the start year of the study. The net-present value calculations are achieved using the *single-payment present-worth function* (SPPWF), shown in Equation 5.6, where n is the number of years between the year where the costs are incurred and the first year in the study (base year).

$$\text{SPPWF} = \text{total expenditure} \times \left[\frac{1}{(1+d)^n} \right] \quad (5.6)$$

This expression allows the determination of a present worth of a given future amount of money. The various present-worth construction costs of each expansion combination can be compared to find the most favourable.

Figure 5.1 shows the income and expenditure of a generating unit. The initial outlays are shown as a upward pointing dotted line while the annual equivalent expenditure is shown as a upward pointing solid line. The final income (the salvage value) is

shown as a downward pointing solid line with the annual equated income shown as a downward pointing dotted line.

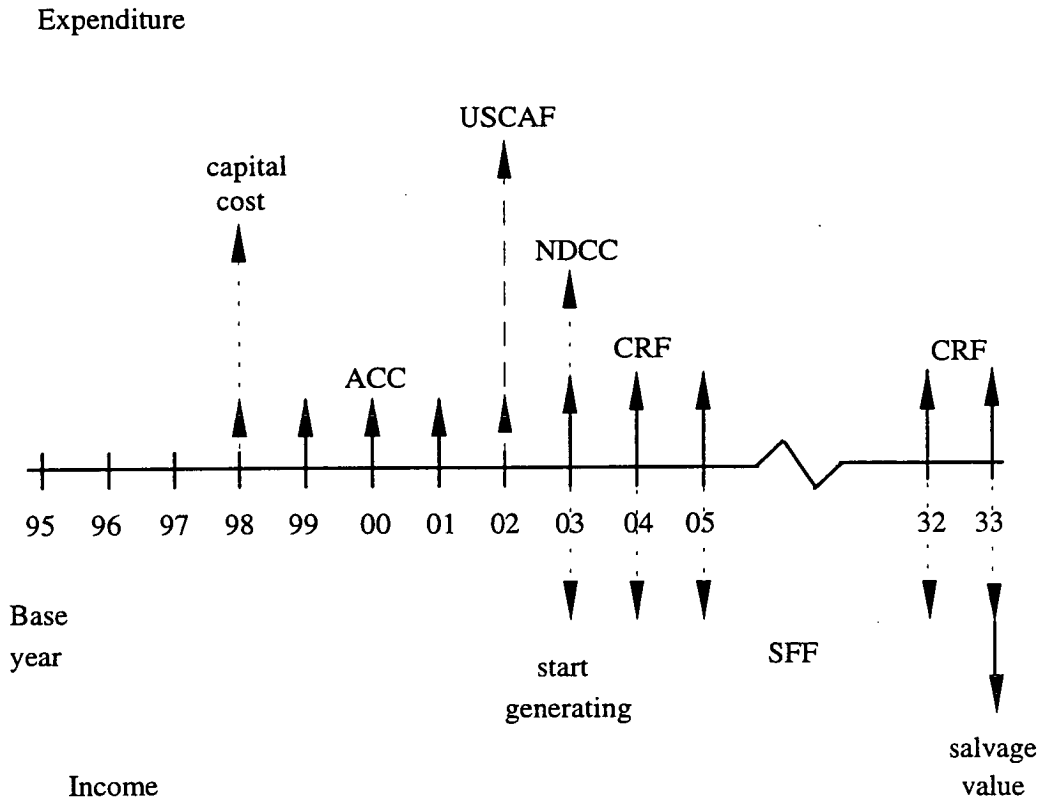


Figure 5.1. Diagram showing income and expenditure (not to scale).

5.2. Operating Costs

Operating costs can be split into three components; fuel costs, operation and maintenance (O&M) costs and unsupplied energy costs. Unlike the construction costs previously discussed (Section 5.1), fuel, O&M and unsupplied energy costs take account of both existing and expansion plants. Figure 5.2 shows a flow chart depicting the separate stages in calculating the operating costs.

5.2.1. Finding X and Y Co-Ordinates

The operating cost associated with the production of electricity is ultimately dependent upon the number of MW hours produced by each generating unit. The area under a load duration curve represents the total MW hours required to meet system demand as shown in Figure 5.3.

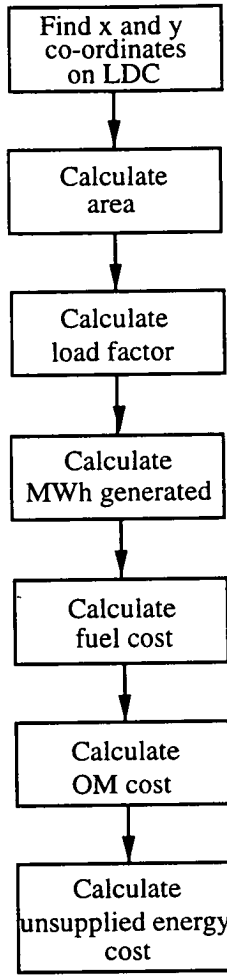


Figure 5.2. Operating cost flow chart.

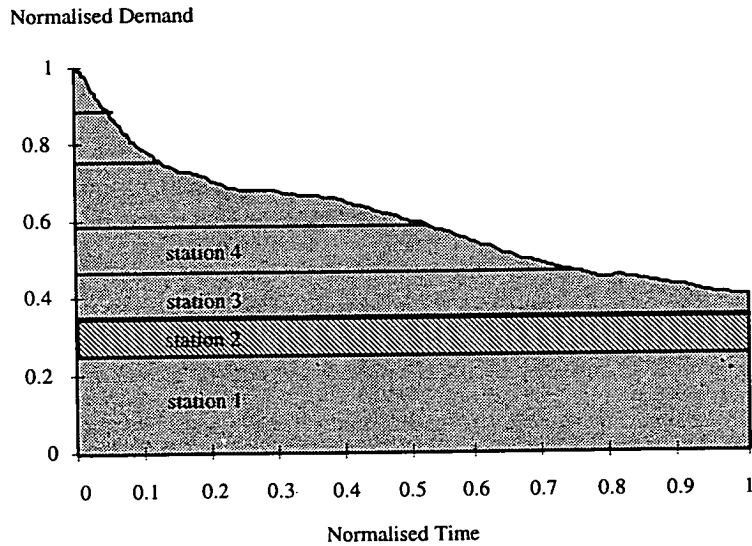


Figure 5.3. Area depicting total MW hours demanded.

The area in the load duration curve for a particular plant is the total number of MW hours produced by that plant (see striped area of station 2). In order to calculate the area for each generating plant it is first necessary to determine the plant's position within the load duration curve. This requires the calculation of four ordinates for each plant ($X_{(n)1}$, $X_{(n)2}$, $Y_{(n)1}$ and $Y_{(n)2}$), see Figure 5.4.

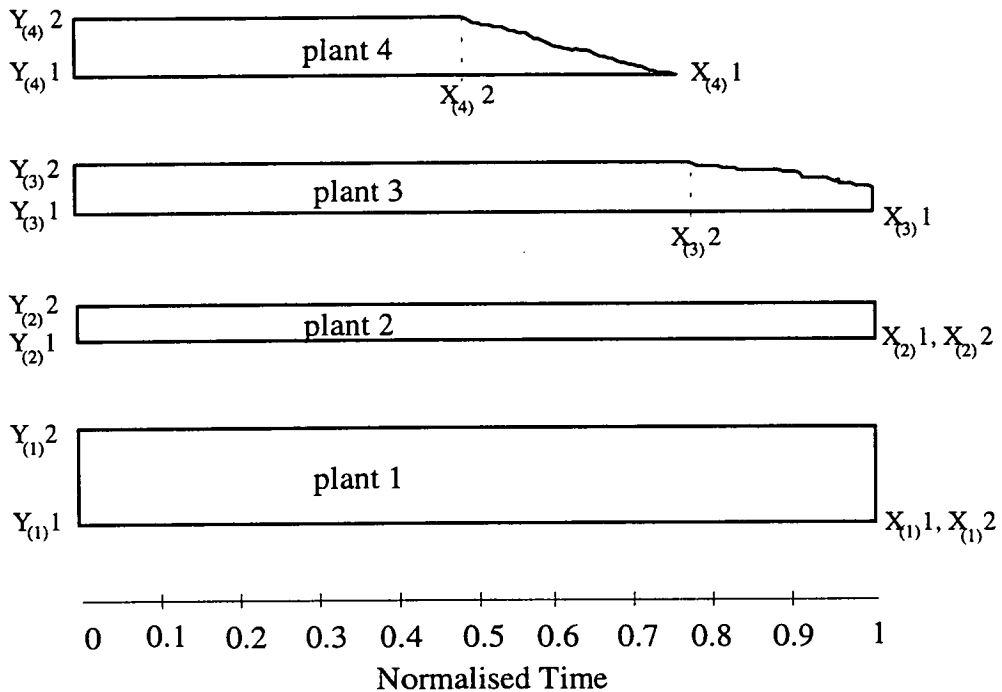


Figure 5.4. Determining x and y co-ordinates on a load duration curve.

5.2.1.1. Y Ordinates

The two y ordinates are $Y_{(n)1}$ and $Y_{(n)2}$, where n is the plant's position in the merit order. The y ordinate values are determined from the plant's normalised net generating capacity value which is the total number of MWs a plant can produce in a year. The net generating capacity value takes account not only of the plant's maximum capacity rating (MC) but also nominal output (NO), spinning reserves (SR), forced outages (FOR) and lost days due to planned maintenance (PM). The net generating capacity value calculation is shown in Equation 5.7.

$$\text{net generating capacity} = \text{MC} \times \text{no. of units} \times \text{NO} \times \left(1 - \frac{\text{FOR}}{100}\right) \times \left(1 - \frac{\text{SR}}{100}\right) - \left[\frac{\text{PM}}{365} \times \text{scheduled units} \times \text{MC}\right] \quad (5.7)$$

The generating capacity is normalised by dividing the value by the peak load in the period.

For plant 1, the first in the merit order, $Y_{(1)1}$ will always be 0. $Y_{(1)2}$ is found by adding its normalised net generating capacity value to the $Y_{(1)1}$ value of plant 1 as shown in Equation 5.8.

$$Y_{(n)2} = \frac{\text{net generating capacity}_{(n)}}{\text{period peak load}} + Y_{(n)1} \quad (5.8)$$

As can be seen in Figure 5.4, the value for $Y_{(2)1}$ is the same as $Y_{(1)2}$. The calculation for $Y_{(n+1)1}$ is shown in Equation 5.9.

$$Y_{(n+1)1} = Y_{(n)2} \quad (5.9)$$

5.2.1.2. X Abscissa

The two x abscissas are $X_{(n)1}$ and $X_{(n)2}$, where n is the plant's position in the merit order. The x abscissa values are determined from the plant's normalised generating time values. For plant 1, the first in the merit order, $X_{(1)1}$ will always be 1. The calculations to determine the second x abscissa ($X_{(n)2}$) on a load duration curve are slightly more complicated. A method called "inverse linear interpolation" is used which determines $X_{(n)2}$ from the $Y_{(n)2}$ value. Initially, a straight line is taken from the normalised peak load, $Y_a = 1$, to the base load, in this case $Y_b = 0.4$, to simulate very roughly the load duration curve, as shown in Figure 5.5.

Using linear interpolation, a corresponding value of x, X_a is found for the y coordinate, $Y_{(n)2}$. A test is performed to determine whether this value of x is too great or small. Depending upon the result, the corresponding y position to X_a , becomes either the new Y_a or Y_b , in this case Y_b . This ensures that after each computation the straight line more closely simulates the curve in the corresponding section of the curve. This procedure is repeated until the actual x abscissa, $X_{(n)2}$, is found.

Normalised Demand

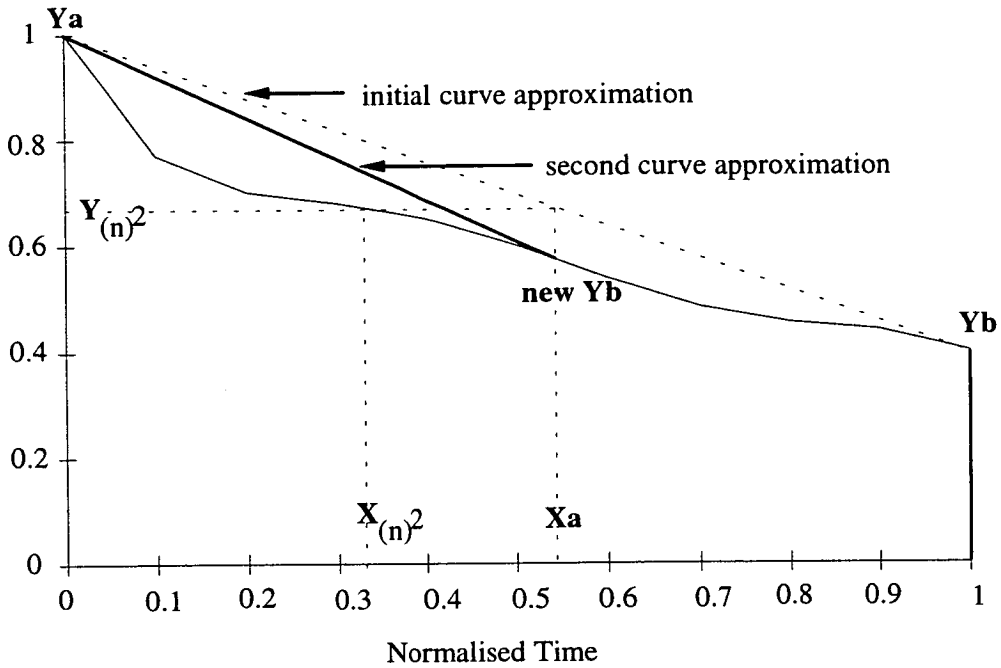


Figure 5.5. Calculation x-y co-ordinates using inverse linear interpolation.

As can be seen in Figure 5.4, the value for $X_{(2)1}$ is the same as $X_{(1)2}$. The calculation for $X_{(n+1)1}$ is shown in Equation 5.10 while the calculation of $X_{(n)2}$ is shown in Equation 5.11.

$$X_{(n+1)1} = X_{(n)2} \quad (5.10)$$

$$X_{(n)2} = \text{Secant}(Y_{(n)2}) \quad (5.11)$$

5.2.2. Finding Generation Area

Once the x and y co-ordinates have been calculated, the area under the curve for each plant can be determined. This area equates to the normalised number of MW hours produced by the plant. The generation area is calculated by first dividing the plant's sector in the load duration curve into rectangular and, if required, approximate triangular shapes as shown in Figure 5.6. This enables integration between limits.

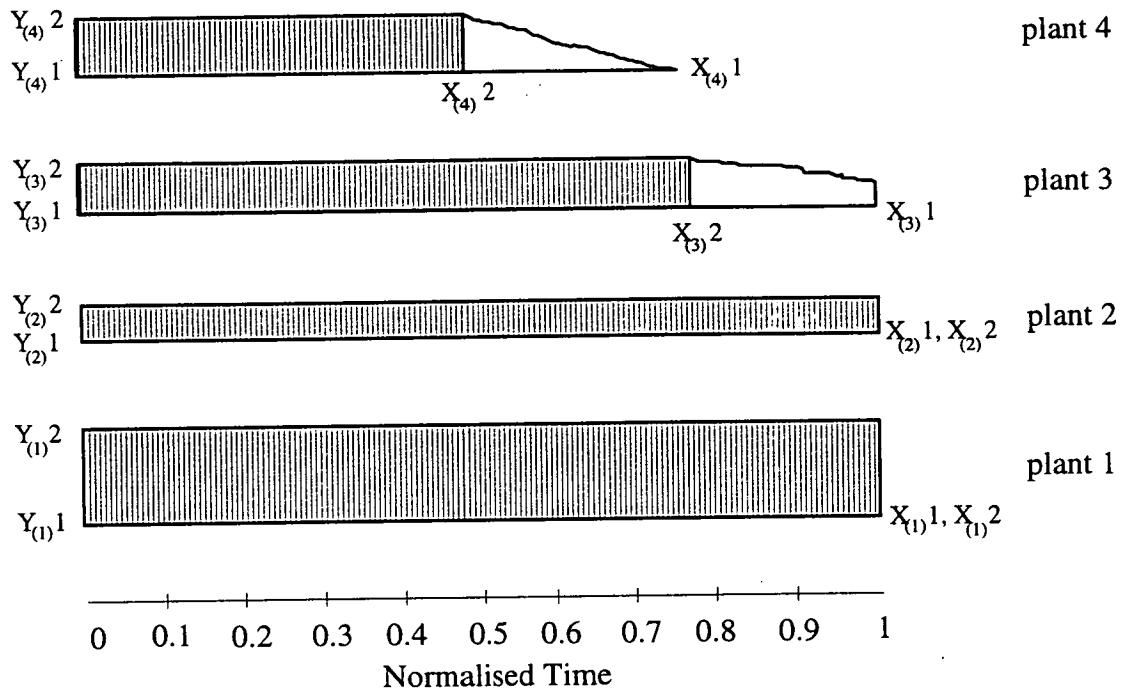


Figure 5.6. Equating plant's area in load duration curve.

If the section is composed solely of a rectangle like plant 1 and 2 in Figure 5.6, then the area is found by subtracting $Y_{(n)1}$ from $Y_{(n)2}$. However, if the section has both a rectangle and a triangular shape, integration is required. The area of the rectangle is found by integrating the difference of $Y_{(n)2}$ and $Y_{(n)1}$ between the limits 0 and $X_{(n)2}$ (Equation 5.12). The triangular area is calculated by integrating the difference of the 5th order polynomial curve ($F(x)$) and $Y_{(n)1}$ between the limits $X_{(n)2}$ and $X_{(n)1}$ (Equation 5.13).

$$\text{rectangle area} = \int_0^{X_{(n)2}} Y_{(n)2} - Y_{(n)1} \quad (5.12)$$

$$\text{triangle area} = \int_{X_{(n)2}}^{X_{(n)1}} F(x) - Y_{(n)1} \quad (5.13)$$

The total generation area of the plant's section under the load duration curve is the addition of the rectangle and triangular areas.

5.2.3. Load Factor

Load factor is the ratio of average demand to peak demand. Put another way, a plant's load factor is the ratio of its actual energy output to maximum energy output if

it were run flat out. As already shown, the area under the load duration curve between the x and y co-ordinates is the normalised energy output that the plant produces. The further up the merit order the less energy is produced by the plant and the load factor decreases. The plant's average load ratio over a period in a year is calculated as shown in Equation 5.14.

$$\text{load factor}_{\text{plant n}} = \frac{\text{area}_{\text{plant n}}}{\text{net generating capacity}_{\text{plant n}}} \quad (5.14)$$

5.2.4. MWh Generated

The area under the curve determines the normalised number of MWh generated by the plant. However, since normalised demand and time values were used, the area value needs to be denormalised. This is achieved by multiplying the station's area with the station's net generating capacity and the number of hours in the generating period. The calculation to find the number of MW hours generated is shown in Equation 5.15.

$$\text{Plant MWh generated} = \text{load factor} \times \text{net generating capacity} \times \text{hours} \quad (5.15)$$

5.2.5. Fuel Costs

Finally, the first half of the operating costs, the fuel costs, can be calculated. If the fuel price is given as \$/GJ it has to be converted to \$/MWh. The calculation shown in Equation 5.16 is used.

$$\text{fuel price } (\$/\text{MWh}) = \text{fuel price } (\$/\text{GJ}) \times 3.6 \quad (5.16)$$

As there can be two fuel prices, a domestic and a foreign fuel price, two calculations must be executed. The total fuel cost of each plant is dependent upon the number of MW hours produced, the fuel price (\$/MWh) and the percentage of time the fuel is burnt. (Utilities are likely to burn the cheaper of the two fuels more often providing there are sufficient stores). Equation 5.17 shows the calculation used to determine fuel cost. An *annual fuel cost multiplying factor* (MF) is included to allow for the provision of increased fuel prices during the study. This equation is executed twice, once for domestic fuel prices and multiplying factors and once for foreign expenditures.

$$\text{fuel cost} = \text{MWh generated} \times \text{fuel price} \times \text{MF} \times \% \text{ time used} \quad (5.17)$$

5.2.6. Operation and Maintenance Costs

Operation and maintenance (O&M) costs are the non-fuel prices associated with the operating of the generation plant. Fixed O&M costs (\$/kW) are relatively independent of the amount of electricity generated by the units within the plant. These costs include labour expenses and miscellaneous materials costs. If emission abatement technology exists, its O&M costs must also be included. Variable O&M costs (\$/MWh) are directly related to the energy produced by each unit. These costs include replacement part and clean-up costs. Total O&M costs are calculated as shown in Equation 5.18. An *annual operating cost multiplying factor* (MF) is included to allow for the provision of increased O&M prices during the study.

$$\text{OM Costs} = [\text{fixed OM costs} \times 1000 \times \text{maximum capacity} \times \text{no_of_units}] + (\text{variable OM costs} \times \text{MWh generated}) \times \text{MF} \tag{5.18}$$

5.2.7. Unsupplied Energy Costs

Unsupplied energy is the amount of electricity demanded in excess of the installed capacity of a system. In Figure 5.7, the unsupplied energy is shown as the shaded area.

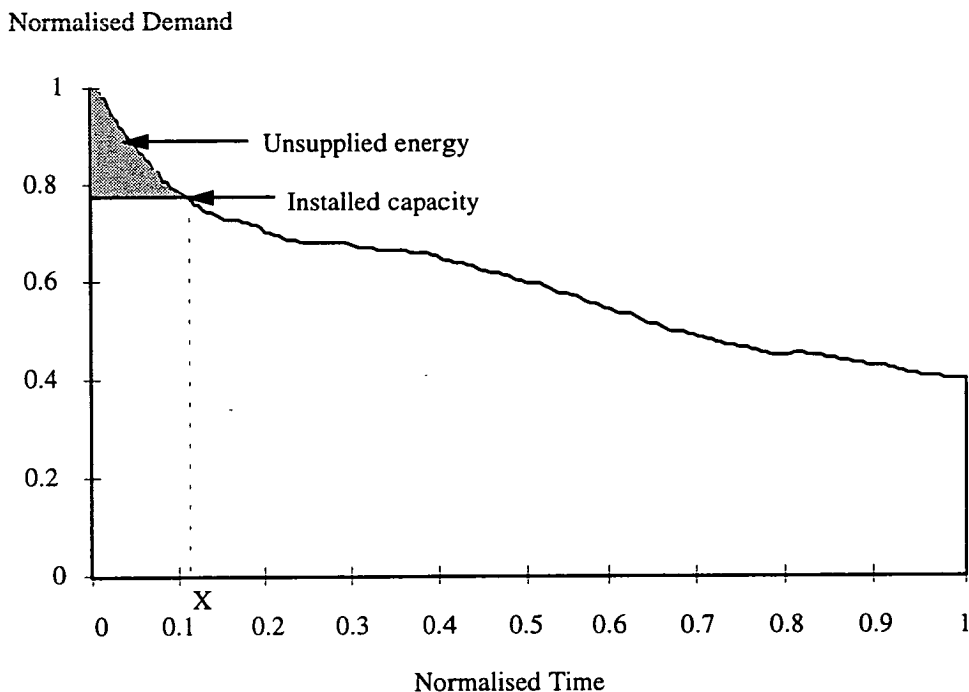


Figure 5.7. Unsupplied energy.

The unsupplied energy costs is not always included although it is advisable as the cost can contribute considerably to operating costs. For example, for the UK in the period 1993/94 the unsupplied energy was set as £2.345/kWh⁸⁹.

The shaded area is found by integrating the difference between the 5th order polynomial curve (F(x)) and the normalised installed capacity. This is shown in Equation 5.19. X is the x ordinate that corresponds to the y ordinate of installed capacity. It is found using the secant function (section 5.2.1.2).

$$\text{unsupplied energy (MWh)} = \int_0^X F(x) - \text{normalised installed capacity} \quad (5.19)$$

This unsupplied energy is then multiplied by a unsupplied energy value (\$/MWh) to determine the unsupplied energy cost, see Equation 5.20.

$$\text{unsupplied energy cost} = \text{unsupplied energy} \times \text{unsupplied energy value} \quad (5.20)$$

If the unsupplied energy cost (paid by the Utility) is ridiculously high, the Electricity Utility may decide that it is cheaper to install more capacity and pay the operating costs.

5.3. Summary

This chapter has described the calculations used to determine the construction costs of additional units into the system and shown how operating costs are calculated for the whole of the system. All of these calculations have been incorporated into EPOPS. All the resulting costs are referred to the first year in the study allowing the user to compare the values on an equal basis.

The next chapter considers the calculations used to determine the emission costs associated with each generating unit.

CHAPTER 6

EMISSION COST CALCULATIONS

This chapter examines the calculations used to determine the associated emission costs with electricity generation. The initial calculations are used to determine levels of the four main emissions, namely carbon dioxide, sulphur dioxide, nitric oxide and particulates, when fossil fuels are burnt. Because of the complexity of the combustion reactions the following assumptions are used to simplify calculations:

1. *The fuel may be completely defined on an elemental basis.*

While the composition of fossil fuels can vary, the constituents of interest, i.e. carbon, sulphur, nitrogen and ash, are usually in the majority accounting for at least 90% of the fuel mass.

2. *The constituents of the fuel will react according to this elemental definition.*

This assumption appears to be a gross simplification as the reaction paths during combustion are many and complex. However, in the case of emissions occurring in relatively large quantities, such as CO₂ and SO₂, it is reasonably valid.

3. *All elements of the fuel will be completely oxidised, where applicable, to form gaseous emissions, with any oxygen in the fuel being available for oxidation.*

This is reasonably accurate for carbon and sulphur (85-90% uptake)⁹⁰ but has limited validity regarding nitrogen.

4. *The ash content of the fuel will be emitted completely as a particulate pollutant.*

5. *Combustion releases the full amount of energy per kg as indicated by the fuel's calorific value.*

This assumption is sustained when it is considered that the average burning time for a coal particle is one-tenth of its average residence time in the combustion zone⁹¹, and that excess combustion air is present.

This chapter discusses the calculations used to determine reduction in emission levels if abatement technology is available, along with the associated cost of installation and operation.

6.1. Fuel Mass used in Combustion

The mass of fuel used during combustion must be found before the individual emission levels can be calculated. The mass of fuel burnt is related to the total energy released during combustion. Chapter 5 calculated the total energy (MWh) produced by each generating plant (Section 5.2.4). Using the calorific value of the fuel and the efficiency of the generating plant (η), the mass of fuel required to be burnt to produce this energy can be calculated. The calculation is shown in Equation 6.1.

$$\text{mass of fuel (kg)} = \frac{\text{MWh generated} \times 3600}{\eta \times \text{calorific value}} \quad (6.1)$$

With the mass of fuel burnt determined, it is then possible to calculate the combustion emissions based on the elemental composition of the fuel. These calculations use molar quantities⁹².

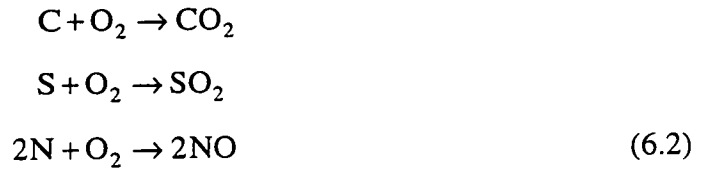
6.2. Coal and Oil Combustion Reactions

In the formation of gaseous emissions from coal and oil combustion, the following points are assumed.

1. *Carbon is completely oxidised to carbon dioxide.*
If combustion takes place in excess air, negligible levels of carbon monoxide to be formed⁹³.
2. *Sulphur is completely oxidised to sulphur dioxide.*
In the case of stationary combustion plant, the levels of excess air are kept low enough that the formation of sulphur trioxide (SO₃) is negligible⁹³.
3. *Nitrogen is completely oxidised to nitric oxide and constitutes the only source of NO_x emissions.*
That is, the effects of increasing the temperature of combustion are not taken into account⁹⁴.

The reaction formulae used are shown in Equation 6.2.





6.2.1. Coal Combustion

Using the mass of the fuel burnt along with the reaction equations and elemental composition of the fuel, the mass of CO_2 , SO_2 , NO_x and airborne particulates produced during combustion can be calculated. These calculations are carried out in three stages⁹⁵, illustrated by a worked example shown in Section 6.2.1.1.

1. The first stage calculates the number of moles of gaseous emissions produced for every mole of elemental constituent. (Atomic masses are relative with no units. However, a mole of atoms of any element has a mass equal to the relative atomic mass with units of kg.)⁹⁵
2. The second stage finds the corresponding weight of resultant gaseous emissions per kg of fuel.
3. The final stage calculates the total theoretical mass of each emission (CO_2 , SO_2 , NO_x and airborne particulate) from a plant by multiplying the value from step 2 by the mass of fuel burnt.

6.2.1.1. Coal Combustion Example

Consider a coal burning station whose output rating is 600 MWe (only one generating unit is present) and has an efficiency of 30%. If the coal being burnt has a calorific value of 26 MJ/kg then the mass of coal required to produce the required electricity is:

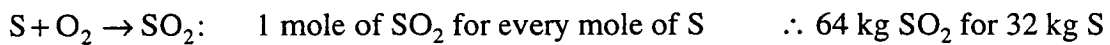
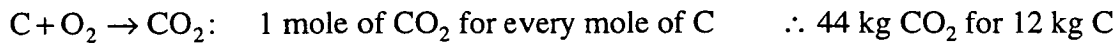
$$\begin{aligned} \text{mass of coal} &= \frac{3600 \times 600}{26 \times 0.3} \\ &= 277 \text{ tonnes / hour} \\ &= 2.4 \times 10^6 \text{ tonnes per year} \end{aligned}$$

Table 6.1 shows the percentage mass of the elemental constituents in a kg of coal and their corresponding atomic masses⁹⁶.

Constituent	% Mass of fuel	Atomic mass
carbon	79.7	12
sulphur	0.8	32
nitrogen	0.9	14
ash	9.6	-

Table 6.1. Percentage mass of the elemental constituents in coal.

Step 1 - determining the number of moles of gaseous pollutants emitted per mole of constituent.



Step 2 - finding the corresponding weight of resultant gaseous emissions per kg of coal.

$$\frac{44 \times 0.797}{12} = 2.92 \text{ kg of } CO_2 \text{ per kg of coal}$$

$$\frac{64 \times 0.008}{32} = 0.016 \text{ kg of } SO_2 \text{ per kg of coal}$$

$$\frac{30 \times 0.009}{14} = 0.019 \text{ kg of } NO \text{ per kg of coal}$$

Step 3 - finding mass of resultant emissions.

$$CO_2 \text{ emissions (theoretical)} = 2.92 \times 2.4 \times 10^6 = 701 \times 10^4 \text{ tonnes/year}$$

$$SO_2 \text{ emissions (theoretical)} = 0.016 \times 2.4 \times 10^6 = 3.8 \times 10^4 \text{ tonnes/year}$$

$$NO \text{ emissions (theoretical)} = 0.019 \times 2.4 \times 10^6 = 4.6 \times 10^4 \text{ tonnes/year}$$

$$\text{ash emission (theoretical)} = 0.096 \times 2.4 \times 10^6 = 23 \times 10^4 \text{ tonnes/year}$$

From these calculations, it can be seen that without any emission controls, the level of combustion gaseous emissions can be huge.

6.2.2. Oil Combustion

Similar calculations as those used in the coal example are employed to determine the emissions from oil combustion except that, because oil contains negligible amounts

of nitrogen and ash, only the calculations for CO₂ and SO₂ are performed. An example follows.

6.2.2.1. Oil Combustion Example

Consider a oil burning plant whose output rating is 600 MWe (two generating units each rated at 300 MWe) and has an efficiency of 38%. If the oil being burnt has a calorific value of 39 MJ/kg then the mass of oil required to produce the required electricity is:

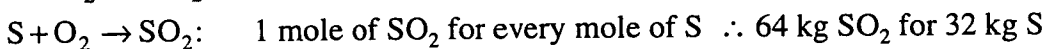
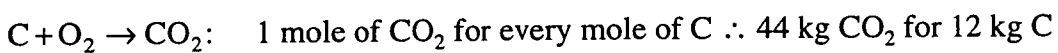
$$\begin{aligned} \text{mass of oil} &= \frac{3600 \times 600}{39 \times 0.38} \\ &= 146 \text{ tonnes / hour} \\ &= 1.3 \times 10^6 \text{ tonnes per year} \end{aligned}$$

Table 6.2 shows the percentage mass of the elemental constituents in a kg of oil and their corresponding atomic masses.

Constituent	% Mass of fuel	Atomic mass
carbon	84.60	12
sulphur	4.0	32

Table 6.2. Percentage mass of the elemental constituents in oil⁹⁷.

Step 1 - determining the number of moles of gaseous pollutants emitted per mole of constituent.



Step 2 - finding the corresponding weight of resultant gaseous emissions per kg of oil.

$$\frac{44 \times 0.846}{12} = 3.102 \text{ kg of CO}_2 \text{ per kg of oil}$$

$$\frac{64 \times 0.04}{32} = 0.08 \text{ kg of SO}_2 \text{ per kg of oil}$$

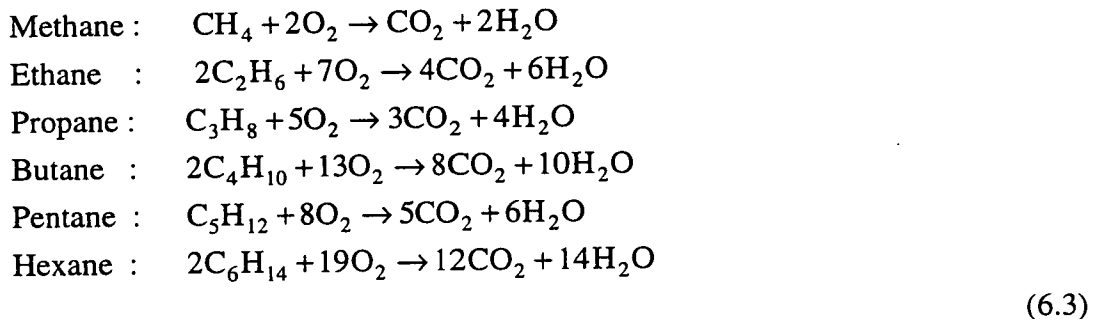
Step 3 - finding mass of resultant emissions.

CO₂ emissions (theoretical) = 3.102 × 1.3 × 10⁶ = 403 × 10⁴ tonnes/year

$$\text{SO}_2 \text{ emissions (theoretical)} = 0.08 \times 1.3 \times 10^6 = 10 \times 10^4 \text{ tonnes/year}$$

6.3. Gas Combustion Reactions

The constituents of gas are taken to be methane, ethane, propane, butane, pentane and hexane, since these add up to over 98% of the total constitution of gas⁹⁸. The alkanes are assumed to be completely oxidised to give carbon dioxide and water vapour⁹⁹. This can also be taken as true since in the presence of excess air, negligible levels of carbon monoxide are formed. The reaction formulae for these alkanes are shown in Equation 6.3¹⁰⁰.



It is also assumed that there is no formation of NO_x emissions from the oxidation of nitrogen in the atmosphere. That is, the effects of increasing the temperature of combustion are not taken into account¹⁰¹.

6.3.1. Gas Combustion

Similar calculations are used to determine the gaseous products from gas combustion as for coal. Here, because gas consists mainly of alkanes formed from carbon and hydrogen, only the calculations for CO_2 are performed.

6.3.1.1. Gas Example

Consider a gas burning plant whose output rating is 600 MWe (three generating units each rated at 200 MWe) and has an efficiency of 45%. If the gas being burnt has a calorific value of 50 MJ/kg then the mass of gas required to produce the required electricity is:

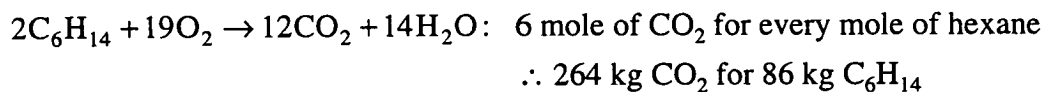
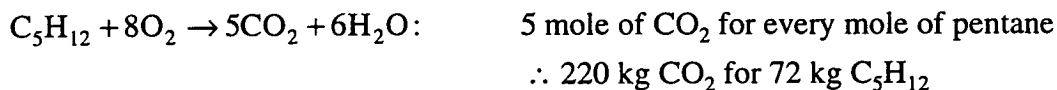
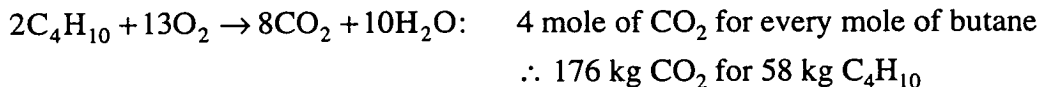
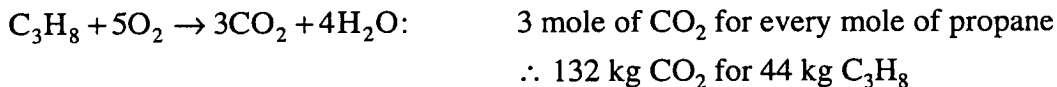
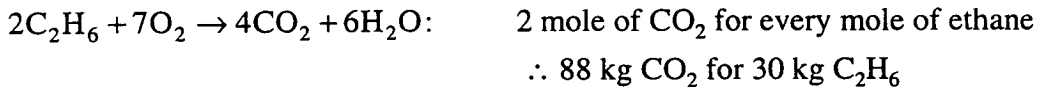
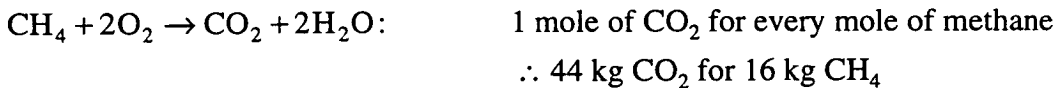
$$\begin{aligned} \text{mass of gas} &= \frac{3600 \times 600}{50 \times 0.45} \\ &= 96 \text{ tonnes / hour} \\ &= 8.4 \times 10^5 \text{ tonnes per year} \end{aligned}$$

Table 6.3 shows the percentage mass of the elemental constituents in a kg of gas and their corresponding molecular masses.

Constituent	% Mass of fuel	Molecular mass
methane	91.98	16
ethane	4.50	30
propane	1.38	44
butane	0.25	58
pentane	0.03	72
hexane	0.01	86

Table 6.3. Percentage mass of the elemental constituents in gas¹⁰².

Step 1 - determining the number of moles of gaseous pollutants emitted per mole of constituent.



Step 2 - finding the corresponding weight of resultant gaseous emissions per kg of gas.

$$\frac{44 \times 0.9198}{16} + \frac{88 \times 0.045}{30} + \frac{132 \times 0.0138}{44} + \frac{176 \times 0.0025}{58} + \frac{220 \times 0.003}{72} + \frac{264 \times 0.0001}{86}$$

= 2.719 kg of CO₂ per kg of gas

Step 3 - finding mass of resultant emissions.

$$\text{CO}_2 \text{ emissions (theoretical)} = 2.719 \times 8.4 \times 10^5 = 229 \times 10^4 \text{ tonnes/year}$$

6.4. Emission Limiting

At present there are four main costs associated with emission production. The first cost is associated with the Electricity Utility using abatement technology to physically reduce limits. The other three costs, trading permits, carbon taxes and emission penalties may be introduced by Governments to encourage emission reductions. All four are concerned with reducing emission levels. Figure 6.1 shows a flow chart depicting how these factors are related.

6.4.1. Abatement Installation and Operation

The cost to install abatement equipment can be considerable and must be considered in a least-cost expansion plan. An Electricity Utility may find that fitting new abatement technology is a cheaper option than either building a new power station with emission controls or paying environmental penalties. In existing stations, if the equipment is already in place, the installation cost is ignored as the economics should already be accounted for.

The installation cost must be referred to the base year of the study using the net-present value (NPV) calculations previously discussed in Section 5.1.5. This NPV cost is then added to the construction and running costs (Chapter 5).

If a generating plant has abatement equipment installed, for example flue gas desulphurisation to remove SO₂ or electrostatic precipitators to remove particulates, its ability to reduce emissions must be accounted for. The percentage abatements that occur to the four combustion gaseous emissions for each plant in the study (existing and expansion) is used to determine the actual weight of emissions produced, see Equation 6.4.

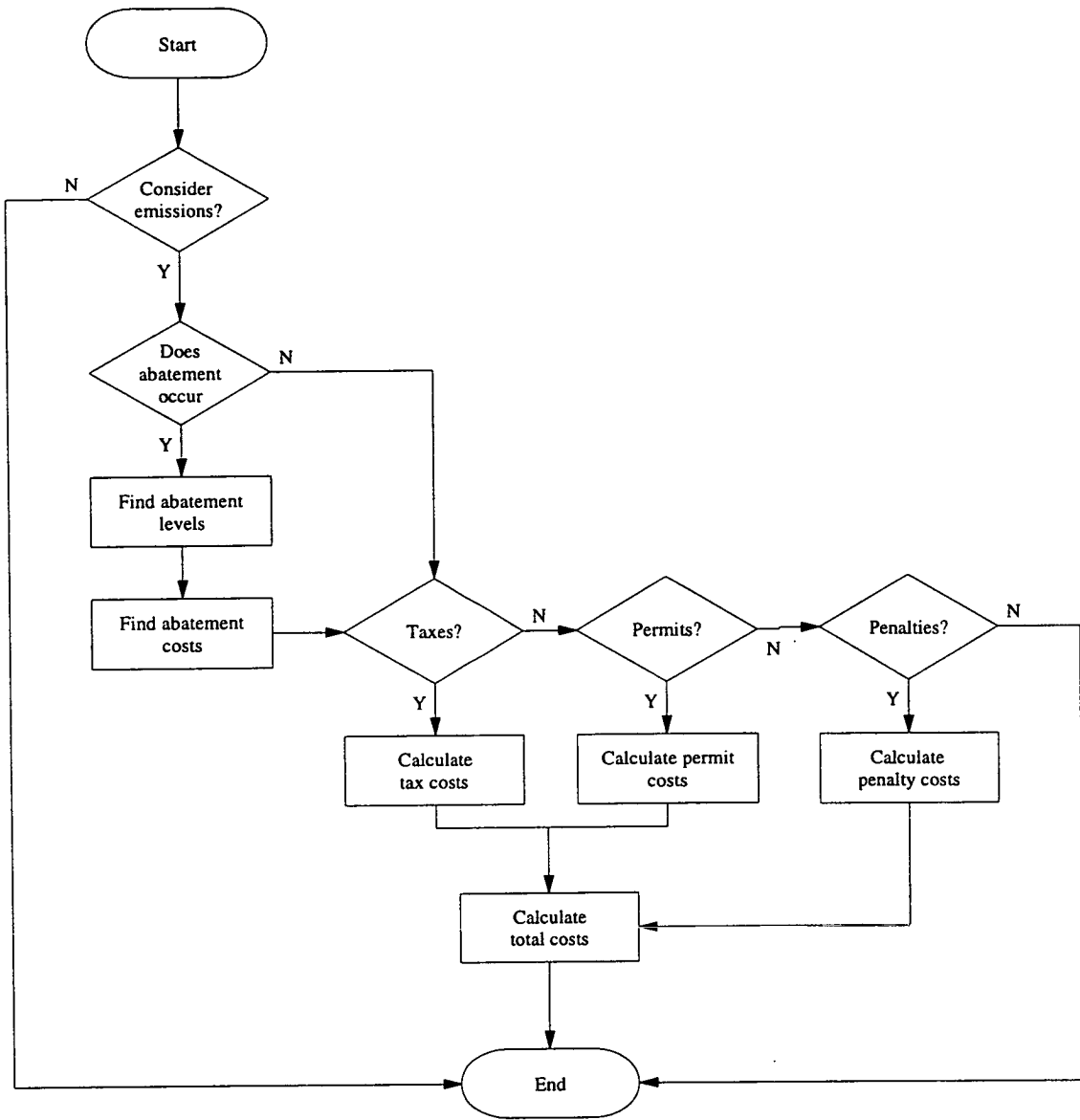


Figure 6.1. Flowchart of emission limiting.

$$\text{CO}_2 \text{ emitted (actual)} = \text{CO}_2 \text{ emissions (theoretical)} \times (1 - \text{CO}_2 \text{ abatement})$$

$$\text{SO}_2 \text{ emitted (actual)} = \text{SO}_2 \text{ emissions (theoretical)} \times (1 - \text{SO}_2 \text{ abatement})$$

$$\text{NO}_x \text{ emitted (actual)} = \text{NO}_x \text{ emissions (theoretical)} \times (1 - \text{NO}_x \text{ abatement})$$

$$\text{Ash emitted (actual)} = \text{Ash emissions (theoretical)} \times (1 - \text{Ash abatement})$$

(6.4)

6.4.2. Abatement Costs

Abatement control in power generating stations can add a considerable increase to the operation costs. For example, Europe's largest coal-fired station, Drax, which cost £400 million to install sulphur dioxide scrubbers, has to increase the unit price of electricity by 0.6p when the scrubbers are operational. As a result, National Power, the owner, does not always operate the scrubbers in order to compete with cheaper, dirtier coal-fired stations¹⁰³.

Equation 6.5 is used to find the total abatement cost for station n, where AC_x is the abatement cost associated with emission x.

$$\text{Abatement cost}_{\text{station n}} = [\text{MWh generated} \times (AC_{\text{CO}_2} + AC_{\text{SO}_2} + AC_{\text{NO}_x} + AC_{\text{ash}})]_{\text{station n}} \quad (6.5)$$

This cost must be referred to the base year of the study using the net-present value (NPV) calculations. This NPV cost of Equation 6.5 is then added to the construction and operation costs.

6.4.3. Carbon Taxing Costs

The amount an Electricity Utility is taxed depends on the content of carbon in the fuel being burnt. The tax was introduced to encourage Utilities to move away from high carbon content and thus reduce carbon dioxide emissions. The calculation to find the carbon tax cost is shown in Equation 6.6.

$$\text{carbon tax cost} = \text{mass of fuel} \times \% \text{ carbon content} \times \text{carbon tax} \quad (6.6)$$

This cost must be referred to the base year of the study using the net-present value (NPV) calculations. This NPV cost of Equation 6.6 is then added to the construction and operation costs.

6.4.4. Emission Penalty Costs

The cost calculation associated with emission penalties is shown in Equation 6.7.

$$\text{emission cost} = \sum_{\text{waste}} \text{waste tax} \times \text{waste emitted (actual)} \quad (6.7)$$

This cost must be referred to the base year of the study using the net-present value (NPV) calculations. This NPV cost of Equation 6.7 is then added to the construction and operation costs.

6.4.5. Trading Permits

In some countries, trade permits have been introduced in order to encourage Electric Utilities to reduce their emissions. At present trade permits only exist for SO₂, although it is hope that similar trading permits will be developed for NO_x and CO₂.

If trading permits are enforced in the country in which the Electricity Utility is operating, the following data that applies to the four combustion gaseous products must be provided.

- number of permits
- cost of permit
- penalty for excess emissions
- whether excess permits can be sold
- permit selling price.

Each trading permit allows for the emission of one tonne of a particular combustion gas, i.e. a sulphur permit allows the Utility to emit one tonne of SO₂. The yearly cost associated with buying the trading permits is shown in Equation 6.8.

$$\text{trading cost} = \text{number of permits} \times \text{permit cost} \quad (6.8)$$

Providing the plants (existing and expansion) in the plan do not generate more emissions than permitted the Electric Utility will not be penalised. Equation 6.9 accounts for the ability for Utilities to sell redundant permits.

$$\text{emission income} = \sum_{\text{waste}} \text{permit selling price} \times [\text{number of permits} - \text{waste emitted (actual)}] \quad (6.9)$$

Any emissions over and above the limits are penalised by a value provided by the user. This value should generally be set high to encourage emission constraints. The cost associated with excess emissions is shown in Equation 6.10.

$$\text{emission cost} = \sum_{\text{waste}} \text{penalty cost} \times [\text{waste emitted (actual)} - \text{number of permits}] \quad (6.10)$$

The two costs calculated in Equations 6.8 and 6.9 or 6.10 must be referred to the base year of the study using NPV calculations. These NPV costs of Equations 6.8 and 6.10 are then added to the construction and operation costs while the NPV cost of Equation 6.9 is subtracted.

6.5. Summary

This chapter has developed the calculations used to determine the theoretical level of combustion gaseous emissions produced during electricity generation. The calculations used to determine actual emission levels if abatement technology is in place along with the associated cost of installing and operating the equipment have also been discussed.

This chapter has shown the cost calculation of three different methods recently introduced to encourage the reduction of gaseous emissions; carbon taxation, emission penalties and trading permits. These legislations have been proposed in Europe with some countries already operating them. The resulting cost of environmental penalties to Utilities who generate in excess of allowed limits can be significant. As a result, it is important to consider all environmental cost in a least-cost expansion simulation.

All of the calculations examined in this chapter have been incorporated into EPOPS. As with the construction and operation cost calculations, these calculations are performed automatically each time an expansion plan which considers emission costs is executed although they can be ignored if requested by the user. EPOPS determines the average hourly output levels of the four emissions and determines all the associated costs. These costs are referred to the first year in the study, allowing comparative analysis by the user. This is all achieved without the user requiring an understanding of the mathematical processes. Chapter 9 includes typical results from a study that includes emission charges into its expansion plan.

CHAPTER 7

KAPPA-PC EXPERT SYSTEM SHELL

The previous chapters have discussed the various factors that must be considered and the numerous calculations to be performed before a least-cost expansion plan can be determined. Many of the calculations are mathematically complex, repetitive and not suited to paper-based computation where the volume flow of data facilitates numerical errors or mis-interpretations. With the availability of inexpensive computer power such procedures can be automated. Decision support systems can now embody the necessary mathematical techniques which avoid intermediate computational error. Least-cost planning can be carried out more rapidly and comprehensively in a way which takes account of a wide range of factors without involving extended computational time.

Kappa-PC was selected to develop a least-cost expansion planning package. The resulting software is called EPOPS (Expansion Planning Of Power Systems). This chapter describes the features and application of Kappa-PC to develop EPOPS. The features of Kappa-PC are discussed, outlining its ability to represent and simulate problems using object hierarchies inherent in Kappa-PC's *object oriented programming* environment. This chapter also presents the procedural language (KAL) which is provided for the development of *functions, methods* and *rules*. The ability to use an *inference engine*, both in forward and backward chaining is examined along with the external sources with which Kappa-PC has to interface. Finally, the graphical interfaces used to create windows for data collection and presentation of results in EPOPS are discussed.

7.1. Selection of Expert System Shell

An expert system or knowledge-based system can be described as a computer program that represents the same domain-specific knowledge as the human expert and attempts to mimic the expert's reasoning process to arrive at a given solution. A expert system consists of three main components. These are:

- *database* - this contains information about the problem to be solved. It is often regarded as short term memory.
- *rule base memory* - this long term memory contains knowledge about the problem domain.
- *inference engine* - this performs the problem solving.

Any expert system shell used to implement a particular application must be selected based on the nature of the problem to be addressed. If the problem can be solved by the application of heuristics (or rules of thumb) alone - such as determining the water levels of hydro dams - then an expert system relying solely on rules is ideal. However, a more complex problem requiring operation simulation necessitates the use of an expert system with a model-based approach. The Kappa-PC expert system shell was chosen because it incorporates several features not found in simple rule based systems. These features are described in the following sections.

7.2. Kappa-PC Expert System Shell

Kappa-PC is a product of Intellicorp Inc. It was designed to be a Windows™ based package, to run on most IBM compatible computers. Kappa-PC simplifies the creation of user interfaces and provides its own interface module. The final program developed in Kappa-PC can be stand alone, providing that Windows™ and the runtime version of Kappa-PC are present, thus denying access to the actual coding.

Kappa-PC provides a set of pre-defined knowledge elements for developing applications as well as allowing the user to define additional functions for a specific application. The components of any problem can be represented by structures called *objects*. The use of object-oriented programming within Kappa-PC enables a system to be constructed that specifies how these objects should behave while rules enable a system to reason about the objects. Finally, Kappa-PC also provides a wide range of tools for presenting results, enabling the user to observe and control the operation of a simulation.

The different components of Kappa-PC are displayed in Figure 7.1.

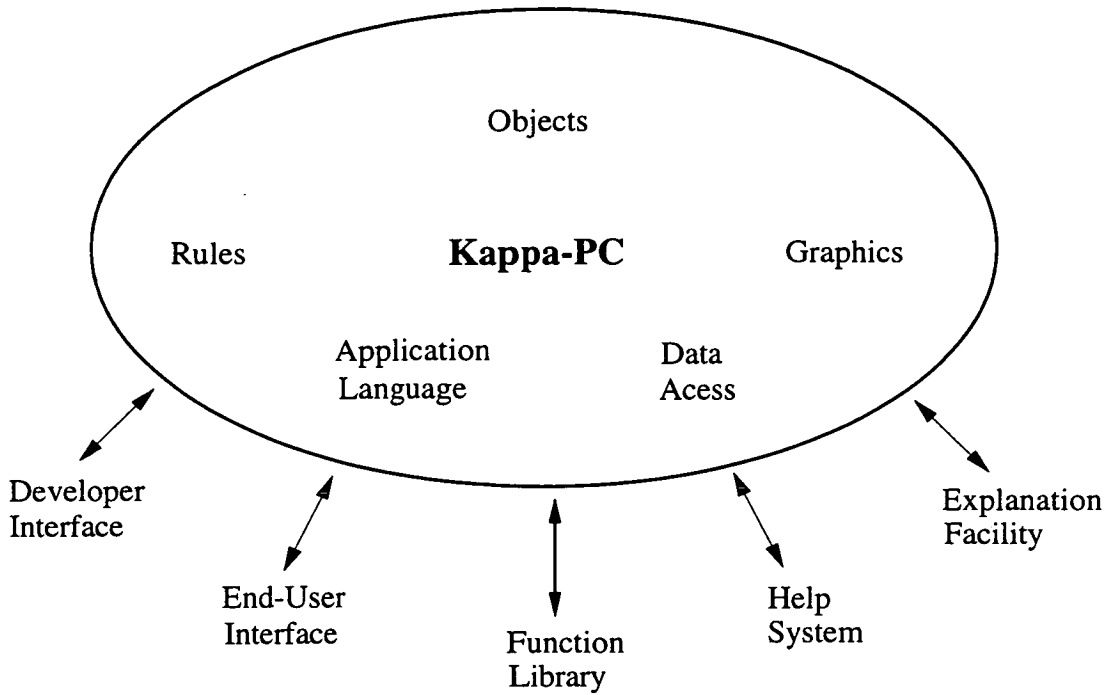


Figure 7.1. Kappa-PC components¹⁰⁴.

7.3. Domain Representation

In a model-based system, tools are needed that represent 'things' in the world and processes that determine their behaviour. In Kappa-PC, the basic building blocks in the knowledge base are objects. Figure 7.2 shows a section of the object hierarchy from the EPOPS knowledge base. These objects represent articles and concepts, both tangible and abstract. The objects form a hierarchy of which all are descendants of a pre-defined class, **Root**, shown in capitals in Figure 7.2. Upper members of the hierarchy represent the general object *class*, which in Figure 7.2 are shown in bold text such as 'GeneralData'. These contain *slots* holding *values* describing members of the class and methods that specify actions to be performed on class members such as 'Thermal'. Figure 7.3 shows the class editor of 'Image' containing slots, slot values and methods.

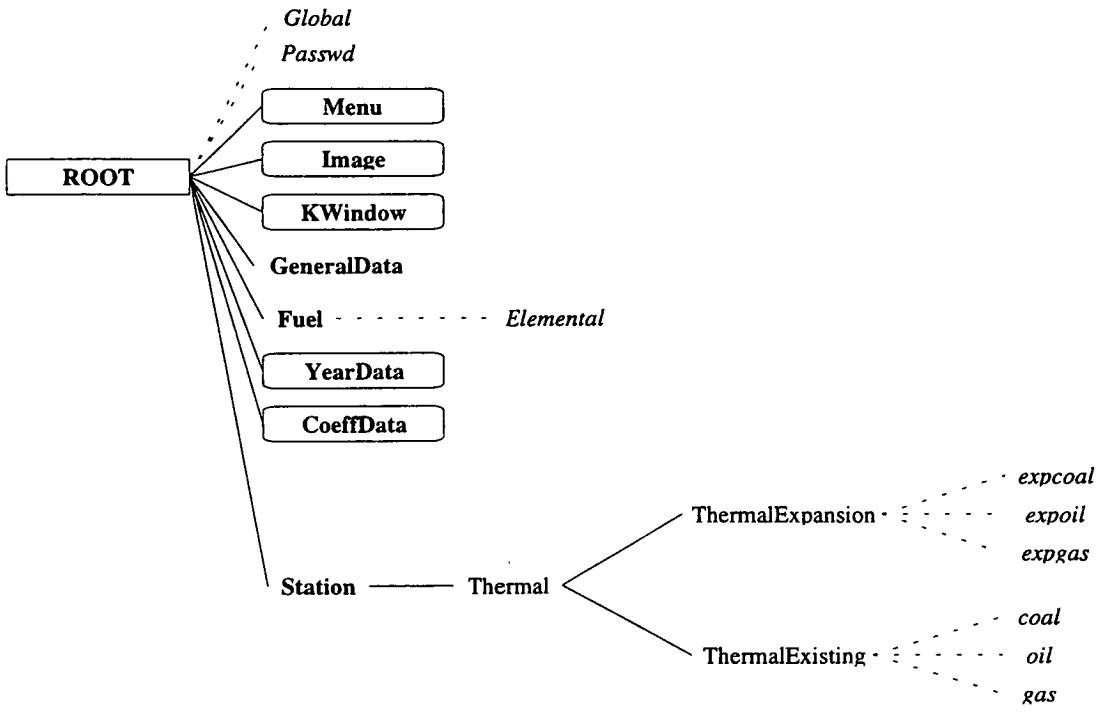


Figure 7.2. EPOPS knowledge base.

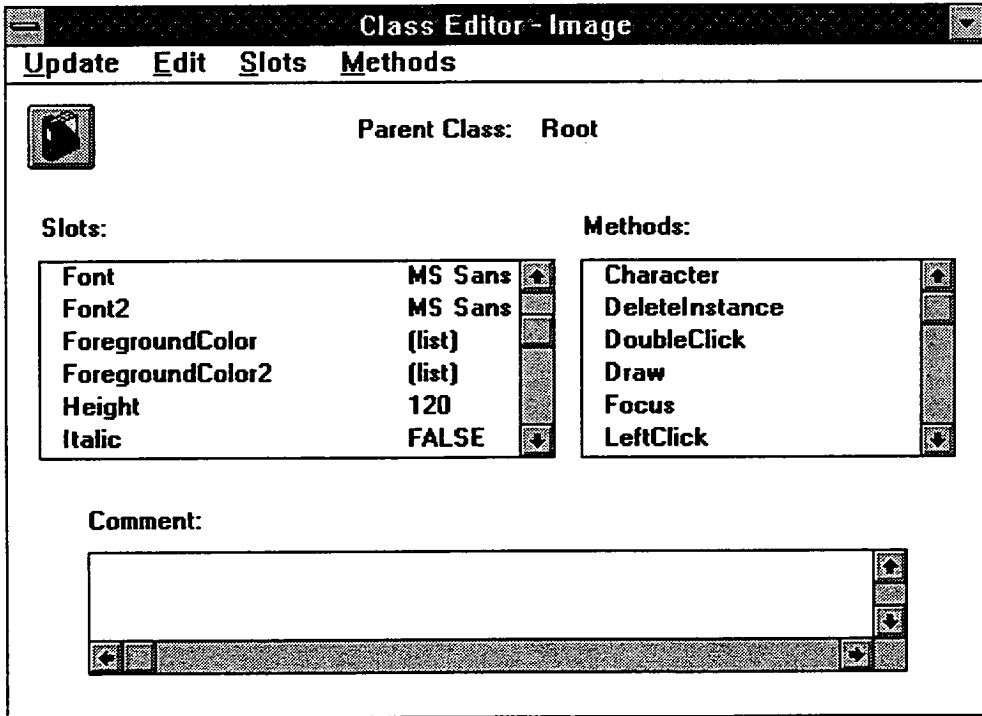


Figure 7.3. Kappa-PC Class Editor.

At the next lower level in the hierarchy are the *sub-classes*, such as 'Thermal' and 'ThermalExisting' which inherit the slots and methods from the *parent class* but also add slots and methods of their own to produce more specialist descriptions. The lowest level in the hierarchy is represented by *instances* such as 'expcoal' (shown in italics in Figure 7.2). Like sub-classes, these inherit slots and methods from their parent while also contributing their own.

The relationship between classes and sub-classes is shown by solid lines in Figure 7.2 while the relationship between classes and their instances is shown by dashed lines. Classes surrounded by a box denote that lower sub-classes and instances are hidden.

The advantage of the object hierarchy structure is that attributes shared by a group of instances need only be set up initially in the parent class (or sub-class). For example, the class 'Station' holds slots that are used by both 'ThermalExisting' and 'ThermalExpansion', i.e. the slot that holds the unit's maximum capacity value. 'Stations' slots and their values are inherited by both sub-classes. However, the sub-class 'ThermalExpansion' also requires additional information that is not required by 'ThermalExisting', such as capital costs, and so adds its own slots that are only inherited by its instances and no others. New instance similar to existing ones are created in the common parent. The slots and slot values are inherited by the new instance although slot values can be altered if required. Similarly, if a slot is no longer required, it only needs to be deleted once in the upper parent class.

7.4. Kappa-PC Application Language (KAL)

KAL is used to write methods, functions and rules, all three using exactly the same syntax. Whereas the classes, sub-classes and instances are known as the static knowledge base, methods, functions and rules are referred to as the dynamic knowledge base. These three applications are used to change the values of variables held in the slots contained within the objects to achieve the desired objective of the expert system.

KAL is a English-like language that has a library containing over 300 pre-defined functions¹⁰⁵ which can be split into the following types of operations:

- Knowledge
- Math
- String
- List
- Logical
- File
- Control
- Windows

These pre-defined functions can be linked together to form methods, functions and rules which are able to access and modify knowledge elements, files, databases and spreadsheets before displaying results on an end-user graphical interface. The methods, functions and rules used in EPOPS are included in Appendices A.3, A.4, A.5 and A.6 respectively.

7.4.1. Methods

Methods are functions that are associated directly with objects. A method may be attached to a slot to respond automatically when an operation is performed on a slot value¹⁰⁶. Linked methods are called monitors of which there are four types:

1. *If needed* - this monitor is triggered when a slot with no value is accessed.
2. *When accessed* - this monitor is triggered whenever a slot is needed regardless of whether it has a value or not.
3. *Before change* - this monitor is automatically executed just before a new value is assigned to a slot. It is generally used to determine if the value is within allowable limits.
4. *After change* - this monitor automatically runs just after a slot receives a new value.

The advantage of methods is that they respond to changes in slot values that may not be previously predicted. For example, if a calculation has to be performed every time a slot value matches a pre-determined value, it is more practical to have the calculation performed automatically rather than applying a rule pattern matcher every time the slot value changes.

7.4.2. Functions

Functions play an important role in the control of a simulation. Functions are used to perform complex algorithms not easily implemented by rules. For example, a

function can perform the necessary actions to display a screen for data input. Functions can either be developed in Kappa-PC using the KAL syntax or in other development systems such as Turbo C++, Microsoft Excel™ or Visual Basic™. Kappa-PC also has a set of pre-defined C functions which can be used with the usual C code¹⁰⁷ to produce dynamic link libraries (DLL). These DLL can be linked to the expert system shell so they are automatically loaded in exactly the same fashion as the native KAL functions¹⁰⁸.

7.4.3. Rules

Rule based reasoning is of particular importance when a problem is to be diagnosed or a process has to be simulated. It is through the use of rules that methods, attached to slots, or functions can be activated when slot values are altered.

A rule is made up of two statements. A condition statement determines whether a rule should be applied or not and the conclusion statement performs the necessary actions when the rule is applied. In Kappa-PC the conditional statement always refers to the values of slots in objects.

An advantage of the rule based reasoning in Kappa-PC is that each rule can be assigned a priority number. These numbers range from -32,000 to 32,000 where the higher the number, the higher the priority. This determines the order in which rules are executed during software execution.

7.5. Kappa-PC Inference Strategies

Rules are managed by an inference engine which applies the rules to the problem at the appropriate point in the process of problem solving. By contrast, a conventional program is developed by explicitly defining when a set of conditions should occur. Kappa-PC offers two distinct inference processes; forward chaining and backward chaining. The choice of which to use depends on the application although each process uses the same rule set.

7.5.1. Backward Chaining Process

The backward chaining inference process is most usually found in diagnostic applications. Backward chaining starts with a *goal*. This is a slot whose value has to be confirmed, e.g. is the value of slot `units_number` equal to 10? Backward chaining begins by examining all the rules until it finds a conclusion statement verifying the

goal. If all the condition statements are valid then the rule is applicable with the conclusion statement being applied to the knowledge base. If, however, any of the condition statements cannot be verified, then that condition statement becomes a new goal requiring further backward chaining. This cycle continues until all the goals have been resolved and a rule chain created that alters slot values inferred by the rules.

For example, two rules to determine the state of a cup of tea are shown below (written in English not Kappa-PC's kal language).

GoodCuppaTea

IF the WaterTemp is Hot
and the MilkinCup is True
and the TeabaginCup is True

THEN the CuppaTea is Good

BadCuppaTea

IF the WaterTemp is Cold
or the MilkinCup is False
or the TeabaginCup is False

THEN the CuppaTea is Bad

In this example of backward chaining, the goal is "What is the status of the CuppaTea?". Assuming that the values for WaterTemp and TeabaginCup are Hot and True respectively, the backward chaining process needs to find only the value for MilkinCup. If this is found to be True, the backward chaining process halts and concludes that the CuppaTea is Good. If MilkinCup is False then the CuppaTea is concluded to be Bad.

7.5.2. Forward Chaining Process

Forward chaining is most commonly used in applications involving simulation, and is used in EPOPS. Forward chaining is initialised by the value of a slot being altered. The condition statements of the rules involved in the chaining process are examined until one is found which matches the pattern of the new fact. Providing the other condition statements in the rule are verifiable then the actions of the conclusion

statement are taken. These actions will alter more slot values requiring more forward chaining. This cycle will continue until the rule chain has been resolved and the actions of the conclusion statement no longer fire additional rules.

For example, using the two rules shown above with the values for WaterTemp and TeabaginCup set as Hot and True respectively, if the value of MilkinCup changes to True, Kappa-PC's inference engine finds the rule that had a conditional statement to match. It then checks the other two conditions and in this case would conclude that the CuppaTea is Good. Similarly if the value of MilkinCup were to change to False, the forward chaining process would conclude that the CuppaTea is Bad.

7.6. External Sources

Kappa-PC enables data transfer between other software. This is achieved in a variety of ways of which three are discussed further below.

- ASCII Files - Kappa-PC is capable of reading and writing to ASCII files although only one file at a time may be open. There are fifteen Kappa-defined write functions and two Kappa-defined read functions.
- Spreadsheets and Databases - Kappa-PC is able to access both Lotus® 1-2-3® spreadsheets and dBASE® files without either package running. A variety of Kappa-defined functions allows data to be written to and read from both packages. It is possible to have more than one spreadsheet or database open although only one file is selected at a time^{109,110}. EPOPS uses a spreadsheet to produce a final summary of an expansion planning simulation.
- Executing Other Programs - From within Kappa-PC, other executable (*.exe) files can be run. A non-Windows™ application without an associated .PIF file will run in a DOS shell resulting in the screen resembling the DOS environment rather than the Windows™ environment¹¹¹.
- DLLs - A Dynamic Link Library (DLL) is a file containing source code that has been written and compiled in another package i.e. Turbo C++. Kappa-PC is able to access these files without the other package running, only the number and format of the input parameters to the DLL need to be known¹¹².

7.7. User Interface

Kappa-PC session windows, which replicate Microsoft® Windows™, are the main interface for the end user. These windows can be customised by the developer to

create graphics and displays as well as allowing customer defined menus. These are discussed in the following subsections¹⁰⁸.

7.7.1. Menus

Kappa-PC menu options and items on Kappa-PC pull-down menus can be accessed using either keystrokes or mouse clicks.

- menu options - these can be activated by the user by pressing the **Alt** key and the code key simultaneously. The code key is the underlined letter of the menu option word. For example, the code key for **File** is "F". Pressing **Alt F** displays the file pull-down menu (if present) or activates the menu.
- pull-down menus - these are activated by typing the code key which, as above, is the underlined letter of the menu option word. For example, the code key for **Print** is "P". Pressing **P** prints the window or activates a cascade menu which is accessed in the same manner as a pull-down menu.

7.7.2. Graphics

There are fifteen different types of images supplied by Kappa-PC. These include button, text, edit, transcript, bitmap, line plot and slider and are described below.

- button - a rectangular image which has an associated function.
- text - an image displaying static text.
- edit - an image which allows input from the user.
- transcript - another form of displaying text which can be altered when required.
- bitmap - an image allowing bitmaps to be displayed in a session window.
- line plot - an image enabling six differently coloured x-y line plots to be displayed.
- slider - an image which enables the monitoring of a changing numeric value.

The use of these graphical interfaces within the EPOPS package is discussed in the following chapter.

7.8. Summary

The need for software which would aid Utility planners in their choice of plant for system expansion was identified in Chapter 1. With the advent of computing power, these calculations can be carried out not only in a way that considers the wide range of factors discussed in Chapters 2 and 3 but in a manner that does not involve

extensive computational time. Also, because the calculations are built into the expansion simulation software, the user does not need prior knowledge or understanding behind the mathematics.

The reasons for using an expert system shell to develop a decision support package for expansion planning were explained in this chapter. Kappa-PC was chosen as a suitable development shell because it provides a wide range of tools for constructing and using applications. As well as its ability to create objects and use object-oriented programming, Kappa-PC can also apply rule based reasoning. This chapter also showed that through object-oriented programming tools, an object hierarchy knowledge-based system could be quickly built up within Kappa-PC. The development of functions and methods, forming the backbone of the software, enables the creation of an expansion planning package which could consider a variety of factors and apply user values to built-in calculations. This chapter discussed how the use of an inference engine allowed the application of rules to the knowledge-based system. Each rule specifies a set of conditions that can apply a set of conclusions if the conditions are true. The conclusions either represent logical deductions about the knowledge base or specify how it changes over time.

Another benefit of Kappa-PC is its ability to interface with other Windows™ applications. Data can be imported and exported to several different outside sources directly by an application. Finally, this chapter examined how Kappa-PC provides the facility to create a high-level graphical environment, enabling the user to observe and control the operation of an application. The graphical images display the values of important parameters as well as to show how they change while the simulation is in operation. Wherever possible, the interface screens have been developed to simulate other Windows™ applications. As a result, a user with prior knowledge of Windows™ based software should find most of the menu-bar options self-explanatory.

CHAPTER 8

EXPERT SYSTEM SIMULATION OF EXPANSION PLANNING

The expert system shell, Kappa-PC, has been used to develop a least-cost electricity supply expansion planning simulation package. This package, EPOPS (Expansion Planning Of Power Systems) is designed to aid the planning of a programme of system expansion by establishing and indicating which options represent lowest cost. The cost of a proposed power system expansion plan is determined by a combination of capital, operation and emission costs as previously discussed in Chapters 2 and 3. If the user prefers, the emission costs may be ignored and the final least-cost plan will be determined only by building, operation and maintenance costs.

This chapter concentrates on the operation of EPOPS within the Kappa-PC shell. Figure 8.1 showing the schematic layout of the package.

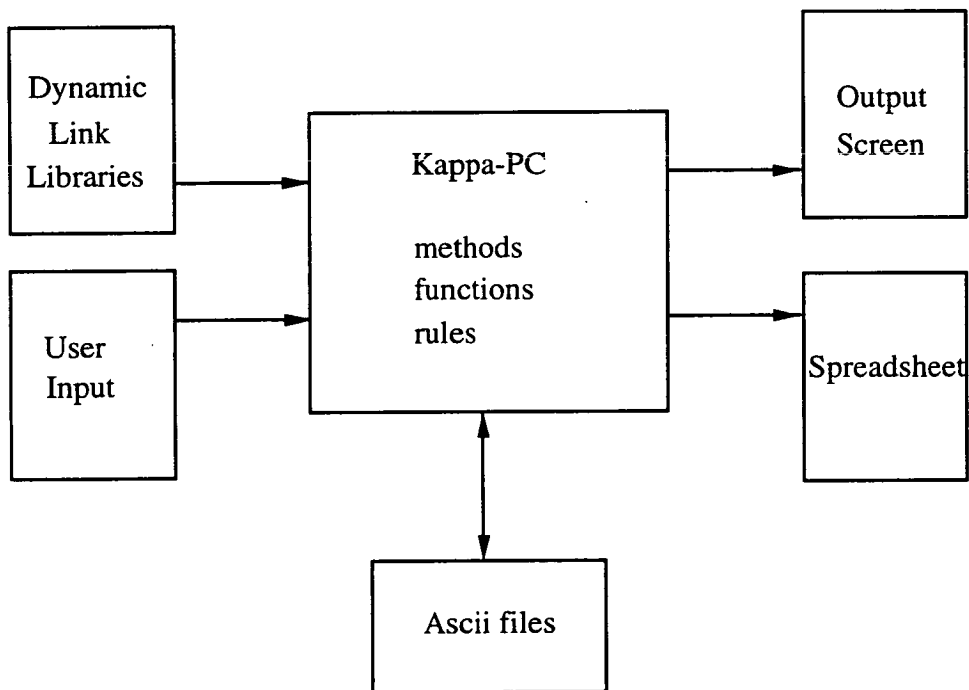


Figure 8.1. Block diagram of EPOPS.

This chapter describes the hardware and software required to run EPOPS. A guide on how to run the simulation software is presented, as well as a list of software files that must be present before EPOPS can be executed. This chapter also gives details on how to operate the various user data and graphical interfaces found in EPOPS and ends with descriptions of help functions and error trappings used in EPOPS.

8.1. Hardware Requirements

In order to run EPOPS, the following hardware must be available:

- 286, 386 or 486-based, IBM-compatible central processing unit (486 is preferred).
- Monochrome or colour graphics board with resolution equal to or above 640×350 (for example Hercules®, EGA or VGA).
- At least 2 Mb RAM.
- Hard Disk with a minimum of 1.3 M bytes of available storage space.

A mouse and a 33 MHz clock speed (or faster) is also recommended.

8.2. Software Requirements

Before the EPOPS package can be loaded, the following software must be installed: (Information on installing the software can be found in the software installation manual).

- Kappa-PC Runtime software Version 2.0 or higher.
- Microsoft® Windows™ Version 3.0 or higher.
- MS-DOS Version 3.0 or higher.

Details of installing EPOPS is given in the User's manual included in Appendix A.1. If installation is successful, the following files should appear in the C:\EPOPS directory (or whichever directory was specified):

C:\EPOPS

epops.kal	retrieve.txt	epophelp.hlp
password.kal	start.txt	using.hlp
epopsdll1.dll	calc.txt	report.wk1
epopsdll2.dll	epops.bmp	printer.exe
epopsdll3.dll	epops.ico	

Two directories should also be present in C:\EPOPS directory (or whichever directory was specified); DATA and EXAMPLES. The C:\EPOPS\DATA directory should initially be empty until EPOPS has been used and the user has saved data. C:\EPOPS\EXAMPLES should initially hold three files:

C:\EPOPS\EXAMPLES

example.kal
newslots.kal
default.kal

These are files that hold expansion planning variable values and are accessed by EPOPS at the beginning of its operation.

8.3. Starting EPOPS

Once all the software has been installed, EPOPS can be started by positioning the mouse pointer over the EPOPS icon and double-clicking the left button. The icon depicts a set of power stations with a dollar sign applied on top and is shown in Figure 8.2.

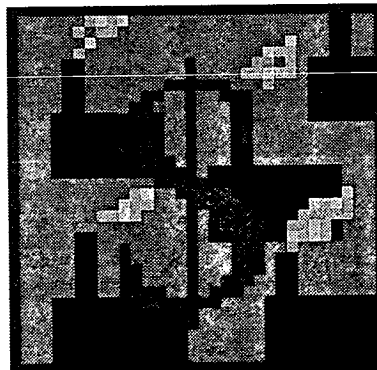


Figure 8.2. EPOPS icon.

This will automatically load all the methods, rules, functions and DLLs needed to execute a least-cost expansion plan. EPOPS has been written so that at any point during operation it is possible to exit from the software. Error trapping has been included to ensure that any changes that have been made are saved if wanted before closing down the software. EPOPS also includes the ability to save data at intervals as and when required.

8.4. EPOPS User Interfaces

EPOPS was developed to determine combinations of generating units in economic order of three fossil fuel types (coal, oil and gas) that meet future expected load requirements previously defined by the user. A study can be up to a maximum of thirty years although it is recommended that no greater than a fifteen year study should be attempted. The reasons are twofold. Firstly, the data regarding the future becomes more unreliable the longer the length of study and the output results are less accurate. Secondly, a long study period will result in a great number of combinations being determined. During the calculation stages this may use up a lot of the user's RAM space. If there is insufficient RAM to hold all the resulting calculations the software is liable to stop responding to the system.

Chapters 2 and 3 examined the various factors which can affect a least-cost expansion plan. EPOPS has been written to minimise the amount of data to be entered by the user. This is achieved through the use of a file, *default.kal*, that contains default values for much of the data that is required in least-cost expansion planning. While these default values may be altered by the user if required, their inclusion notifies the user to the type and magnitude of values expected by EPOPS. Alternatively, when beginning a new simulation, an experienced user may choose to load in *newslots.kal*, a skeleton file that contains the necessary classes, instances and slots but holds no variable values at all. A third file included in the EPOPS package, *example.kal*, is a complete typical electricity supply expansion study included to allow a user to execute EPOPS without prior knowledge of data relating to least-cost expansion planning. This enables the user to become experienced with EPOPS and assess its performance without being concerned with entering sensible data variables. This file is used to perform the second example shown in Chapter 9.

The different data entry and graphical interfaces used in EPOPS are discussed below. Their operation is given in greater detail in the EPOPS User's manual included in Appendix A.1. Wherever possible, the layout and operation is similar to other Windows™ packages, for example both keyboard strokes or mouse clicks can be used interchangeably. By standardising all the user interfaces to resemble Windows™ packages, users with previous experience with the layout of Windows™ should readily become experienced with EPOPS. Even without prior knowledge of Windows™, EPOPS has been written with on screen prompts thus creating a friendly

interface with the user. For additional information on Microsoft® Windows™ the user should refer to the Windows™ guide¹¹¹.

8.4.1. Password Box

A password facility has been included in EPOPS to insure against unauthorised use. As with other password entry schemes, the password is not echoed onto the screen as it is typed. Instead, asterisks replace all letters/numbers/characters as they are entered. Figure 8.3 shows the password entry box in the initial EPOPS screen.

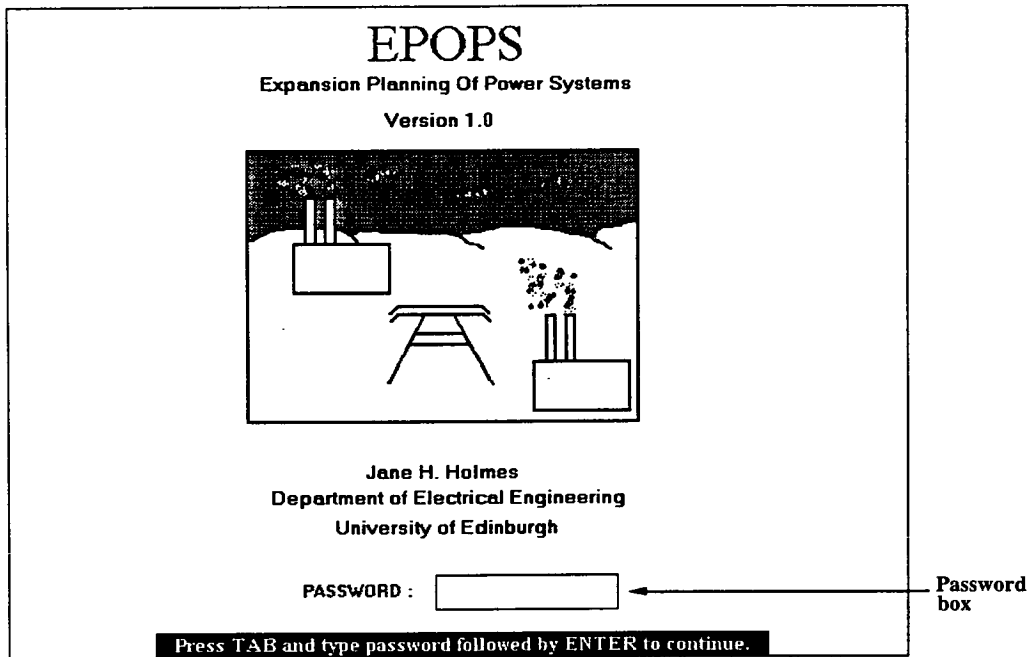


Figure 8.3. Password box used for security.

The password entry function has been written to allow only three attempts at entering the correct password. On the first two incorrect attempts an error message will appear on the screen alerting the user to the fact. On the third incorrect attempt no warning is given and EPOPS will automatically exit.

EPOPS is initially delivered with a password that was used during its development. A facility has been included that allows the user to change the password once passed the initial security check. The password must not be longer than eight characters although letters, numbers and symbols may be used. It is advisable to keep a note of the password as the security check cannot be switched off.

8.4.2. File Handling

EPOPS has been developed so that at any time during data entry the user may save the variable values to a custom-named file. At any point in the future, this file may be loaded back into EPOPS. In being able to do this, the user can repeatedly perform similar least-cost expansion plans with slight variations to the data values without having to type the data in each time. For example, the first EPOPS run in Chapter 9 shows the results from a typical expansion plan that does not consider emission costs to find the least-cost option. A second run, only requiring a change to the fact that emission calculations are to be included can then be performed and the two sets of results compared.

The file handling routine has been developed to emulate Windows™. Figure 8.4 shows a typical file handling box that is used within EPOPS to save or open files.

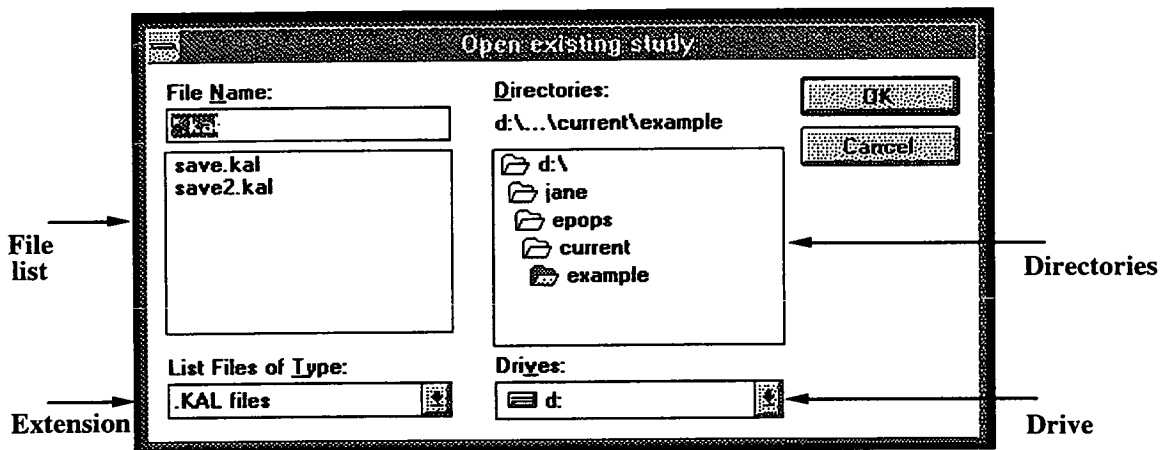


Figure 8.4. File handling box.

There are four components that make up the file handling box.

- *Drive* - The drive box shows the current drive in which the user is working. This can be changed.
- *Directories* - A default directory is chosen where EPOPS expects the relevant file to be saved/found. This path always defaults to the directory where the examples are held, i.e. c:\epops\examples, but it can be changed.

- *Extension* - All files with this extension are shown in the file list box. EPOPS always defaults with the *.kal extension although the user may also save/open a *.bin file. No other file extension will be accepted.
- *File List* - The files list box displays the names of the files in the directory. If the chosen file is not displayed, the user should check that the correct file extension has been keyed in and the correct directory/drive is being used.

EPOPS has been developed with the maximum amount of error trapping thought necessary. Each time the user chooses to save a file, EPOPS determines whether a file of that name already exists. If it does, the user is prompted as to whether the existing file should be over-written or not. This prevents data being unnecessarily lost. Similarly, if the user chooses to load an existing file and has not saved current data values, EPOPS will issue an alert message. The user may then save data before proceeding with opening the existing file. This type of prompting, which requires an answer, is achieved using *single menu items* as described below.

8.4.3. Single Menu Items

Single menu items allow the user to respond to a prompt issued by EPOPS. The user must choose one reply from a list, usually with two options. Due to a drawback in the Kappa-PC development system, the single menu item can be accessed using the mouse only in the normal way, i.e. positioning the pointer over the required item and clicking the left mouse button. A typical single menu item is shown in Figure 8.5.

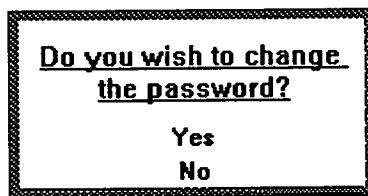


Figure 8.5. A typical single menu item.

8.4.4. Multiple Menu Items

Within EPOPS it is sometimes necessary to choose more than one option in response to a question. For example, a user may wish to edit values in more than one year. EPOPS allows for this by including multiple menu items. A typical multiple menu item is shown in Figure 8.6.

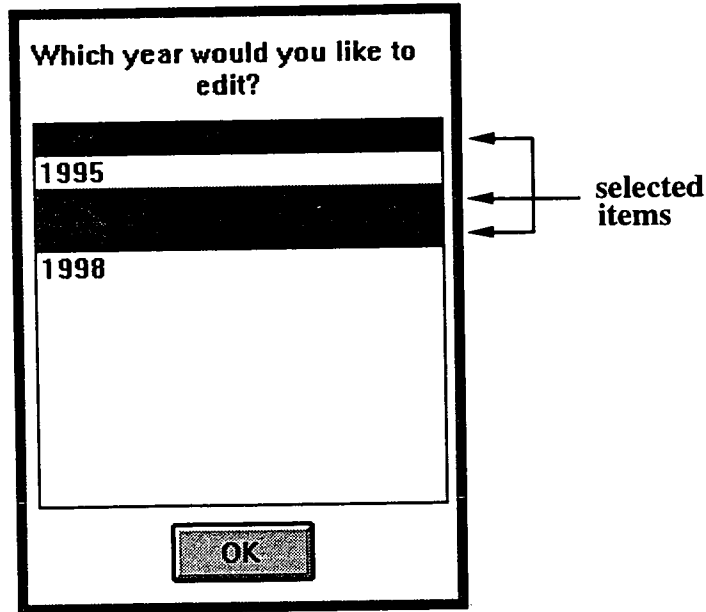


Figure 8.6. A typical multiple menu item.

The multiple menu item works on the same principle as the single menu item although multiple choices can be made and keyboard strokes can be used. By default, the first item is always chosen.

8.4.5. Menu Bars

The menu bars within EPOPS have been set up to emulate Microsoft® Windows™ menus. Each screen has its own menus although several options are common with other menu bars. The items listed on the menu bar are known as menu bar options. A menu bar option may be a command or it may call a pull-down menu. Similarly each pull-down menu item may be a command or call a cascading menu which is denoted by an arrow (▷). In a cascade menu all items without an arrow are commands. Figure 8.7 shows a menu bar option which has a pull-down menu with three cascading menus.

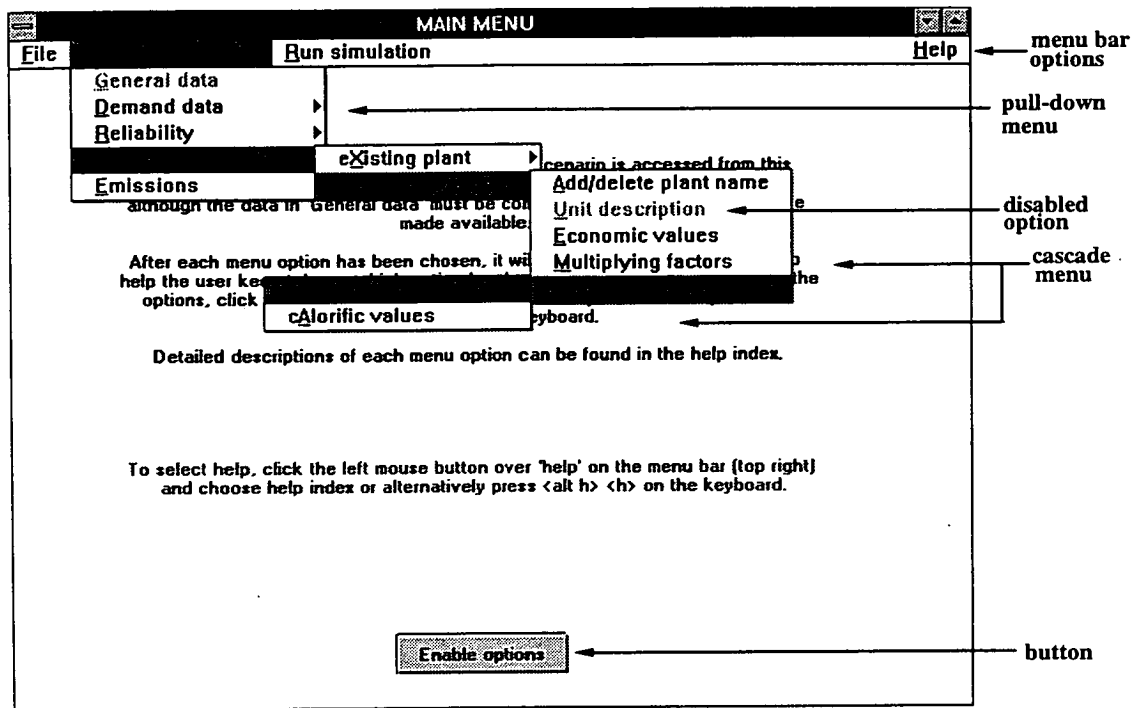


Figure 8.7. Typical EPOPS screen showing menu bar and button.

Some menu items in Figure 8.7 appear dimmed, denoting that the command has been intentionally disabled. The reasons for this are threefold. Firstly, if this item has previously been chosen it is purposely dimmed in order that the user can keep track of which commands have been executed. To overcome this the user must select the "enable options" button. The second reason for the option being disabled is that the option may not be available to the user. For example, the 'print' option within the file menu is disabled until an expansion simulation has been performed and there are graphs to print. Thirdly, 'Run simulation' may be dimmed. This option can only be activated once all the required data has been entered. This is described in more detail in the error trapping section, Section 8.6. Selecting the "enable options" button will have no effect on the latter two situations.

As with all Microsoft® Windows™ applications, there are two ways to select a menu; using mouse clicks and keyboard strokes. The user can either:

- point to the menu bar option and click the left mouse button to select it. Then, with the left button still depressed, drag the selection cursor down the pull-down menu to highlight the required option. If the option has a cascading menu it will be displayed otherwise releasing the mouse button will activate the command,

or

- press **Alt** and the underlined letter (the code key). The pull-down menu option is then chosen merely by pressing the code key. For example in Figure 8.7, the 'Economic values' command in the 'exPansion plant' pull-down menu (within the Station Information menu bar option) can be accessed by pressing **Alt s** followed by **p** and **e**.

8.4.6. Input Form

Input forms are used in EPOPS to allow the user to enter data values. A typical input form is shown in Figure 8.8.

The figure shows a graphical user interface for data entry. It features a title 'Please enter data:' at the top. Below this, there are seven rows of input fields. The first five rows are for numerical data: 'Start year of study' (1997), 'End year of study' (2004), 'Number of periods per year' (1), 'Domestic discount rate (%)' (10), and 'Foreign discount rate (%)' (7). To the right of these fields are their respective ranges: '1994 ..', '1995 ..', '1 .. 12', '0 .. 100', and '0 .. 100'. The next two rows are for categorical data: 'Emission Calculations' and 'Unsupplied energy calculations', both set to 'No calculation'. To the right of these are two small boxes with down arrows, labeled as 'input box' and 'combo box'. At the bottom of the form are two buttons: 'OK' and 'Reset'.

Figure 8.8. A typical EPOPS input form.

Down the left side of the form, textual expressions denote the data required for each individual input box. On the right side of input boxes that expect numerical data, there may appear two numbers separated by two periods. These numbers denote the minimum and maximum values allowed for that particular input box. For example, Figure 8.8 shows that the value for the number of periods per year must fall between 1 and 12 inclusive. If a value is entered outside of these limits, Kappa-PC displays an error message. If there are no numbers, this denotes that there are no minimum/maximum limits.

Also shown in Figure 8.8 is an input box which has a second box on the right. This second box, known as a combo box, contains allowable values (either numerical or textual but normally the latter) for the input box. By clicking on the down arrow (↓)

the allowable list of values is displayed. The user may choose the data value for the input box by double clicking the left mouse button over the word/s in the combo box.

To exit from an input form, the user must click the left mouse button on the **OK** button or use the **Tab** on the keyboard to highlight **OK** and then press **Enter** (↵). As part of error checking, if any input box is left empty, EPOPS will generate an error message which is repeatedly displayed on exit attempts until all the boxes are filled.

8.4.7. Data Boxes

Input forms can only be used to prompt the user for ten variable values. Often, more than ten values have to be entered, for example peak load values in a twelve year study plan. In this case, EPOPS has been developed to use data boxes for manual data entry via the keyboard. Figure 8.9 shows a typical EPOPS screen with twelve data boxes.

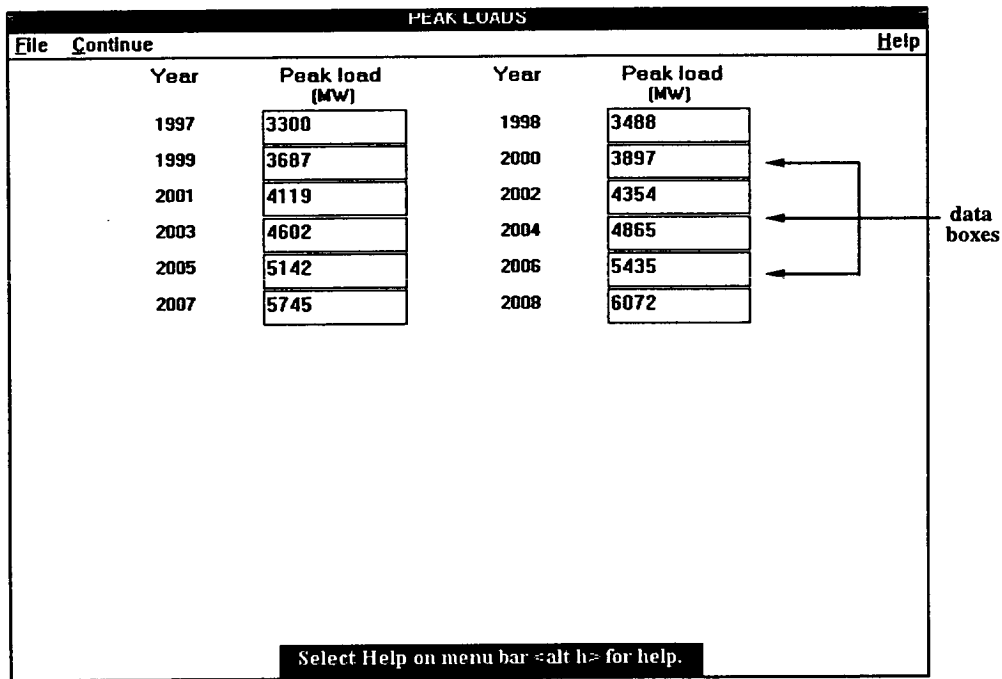


Figure 8.9. Typical EPOPS screen with data boxes.

Movement around the data boxes is the same as in other Windows™ applications, i.e. pressing the **Tab** key on the keyboard will circulate round all the boxes. Screens with these data boxes also include error trapping. If any of the boxes are left blank or contain non-numerical values, EPOPS will repeatedly display an alert message until the problem is rectified. Screens also contain individual error trappings that alert the

user if an unusual value is entered. For example, if the user entered a value less than zero for a peak load demand, EPOPS would display an error message. Although negative values can be trapped, EPOPS does not trap exceeding high values. As a result, a slight working knowledge of expansion planning values is still required.

8.4.8. Graphical Results

Figure 8.10 shows one of the graphs generated by EPOPS. This graph displays the cost of the twenty options found that meet electricity supply expansion requirements. The user has a choice as to how to display the graphical data, either as a line, a bar or a column chart[†]. The choice is determined using radio buttons found on the right-hand side of the screen.

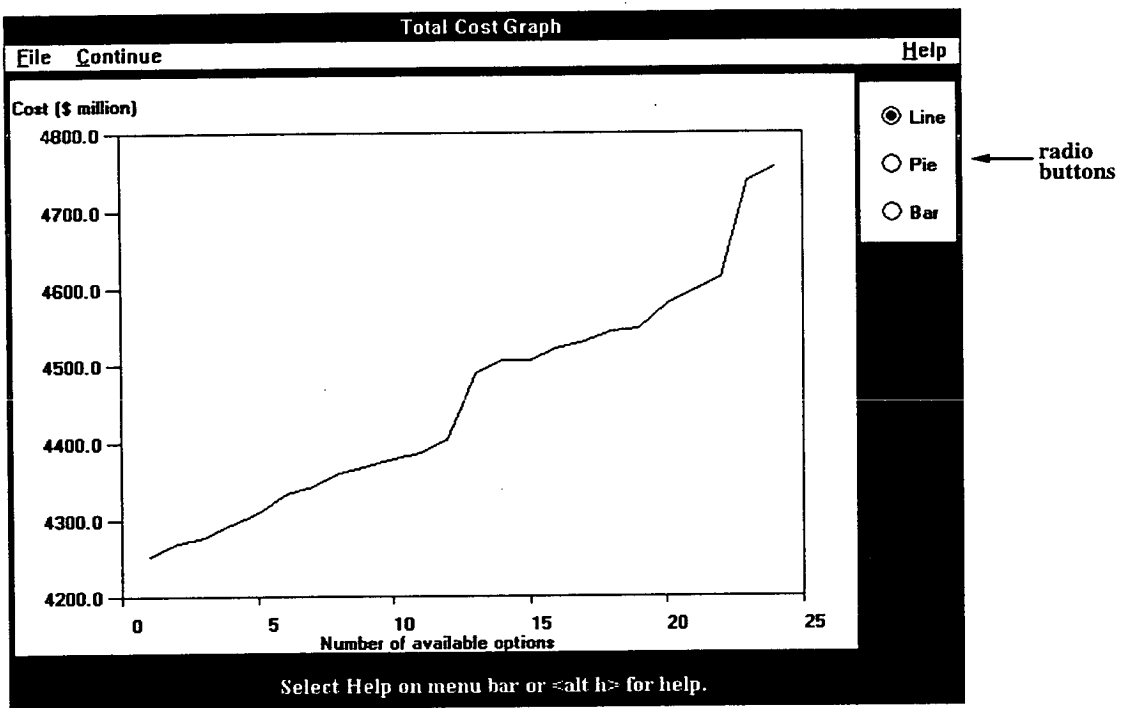


Figure 8.10. Graph showing EPOPS simulation results.

The individual breakdown of the graph is shown more clearly in an example. More details of typical EPOPS results are given in the following chapter, Chapter 9.

[†] At present only the line chart option is available.

8.5. Help Functions

One of the drawbacks of many non-Windows™ based software packages available on the market (based on personal experience) is the lack of on-line help. EPOPS has been developed to be as user friendly as possible and as such it was thought important (like other Windows™ packages) that it should have a help index to give the user quick and easy access to information regarding the software. The help file was developed using a software package called drhelp. A copy of the help file is included in the appendix (A.1). Each word in the text that is double underlined (shown as a single line on screen) is a user-defined keyword that enables the user to jump to related topics. Clicking the left mouse button on a single underlined word (shown as a dashed line on screen) results in a popup screen that offers definitions and short explanations. Popup screens are similar to footnotes in normal texts.

The help file includes the following features:

- a browse sequence allowing the user to read from start to finish in a linear fashion giving the document the same feel as a book.
- a search function allowing the user to find keywords.
- an annotate function allowing the user to add their own notes.

Within the help file, there are many hotspots (underlined words, either solid or dashed), which when selected display a new help topic. When the cursor is moved over a hotspot, it will change shape to a hand with a pointing finger, see Figure 8.11. Most of the time this visual cue is not required as text hotspots as well as being underlined are also of a different colour (usually green).



Figure 8.11. Cursor shape when placed over a hotspot.

Also included in the EPOPS help file is the option to open another help file which the user can read if they need help in reading Windows™ help files.

8.6. Error Trapping

EPOPS has been programmed with the maximum amount of error trapping thought necessary. The error trapping messages produced by EPOPS are included in Appendix A.2, along with some of the more commonly encountered error messages produced by Kappa-PC. While EPOPS can trap errors such as text being entered when digits are expected, it has not been set up to trap entered data that is a factor of ten different from the expected answer. This is because a certain prior knowledge of the parameters required in power system expansion planning is presumed before operation of the software.

The error trapping routines include checking that:

- all data points are entered.
- entered data is in correct format (i.e. text/numeric).
- data lies between set limit.
- calculations cannot begin until all data has been entered.

The fourth point in the above list is very important. If this error trapping were not in place, EPOPS is liable to stop responding to the system if, for example, calculations tried to divide by either null or zero. The error trapping is achieved by disabling the 'Run simulation' option on the main screen menu. To the user, the option will appear dimmed similar to 'Unit description' in Figure 8.7. The 'Run simulation' menu option will only be enabled once all the required data has been entered. To find out which data is still to be entered, the user has to choose the 'Missing data' command in the Help menu. A window similar to the one shown in Figure 8.12 tells which menu options are still to be executed.

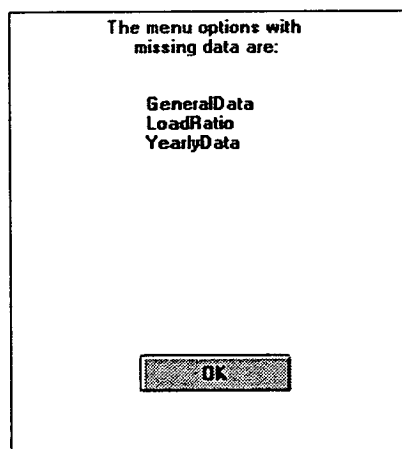


Figure 8.12. Missing data screen.

8.7. Summary

The availability of inexpensive computing power allows least-cost expansion planning to be more readily applied to decision support systems. This chapter has discussed the hardware and software required for the successful operation of EPOPS. This chapter has given a general overview of the operation of user interfaces that are used in EPOPS and highlighted the purpose of their use. These interfaces are intended to facilitate the retrieval and presentation of data relating to expansion planning, and by suitable prompting no relevant factors can be inadvertently forgotten. Data entry is also made easier with the inclusion of a file that includes default values for many of the variables required in least-cost expansion planning.

The various graphs and textual interfaces that have been incorporated into EPOPS ensure quick and easy access to expansion planning results. The following chapter presents the results obtained from typical EPOPS runs.

CHAPTER 9

TYPICAL EPOPS RESULTS

Chapters 4, 5 and 6 discussed the calculations that are used to determine a least-cost expansion plan. These calculations are mathematically complex, repetitive and time consuming. In addition, if the value of one variable were to change, the results needed to be recalculated. The development of EPOPS decision support system, avoids the manual calculations in a manner that allows the user to perform expansion planning under varying scenarios without continual involvement with the mathematics. Because the calculations can be performed much more quickly on a computer, the user has more time to compare the resulting costs between options and analyse the sensitivity of the plans.

Although it is impossible to demonstrate on paper the ease of using EPOPS to combine data collection and results formulation, it is possible to demonstrate the clarity of final results. All the calculations within EPOPS are believed to be correct but the results obtained from EPOPS can only be as accurate as the data entered by the user. However, providing each option is based on the same set of assumptions, the relative results enable an effective comparison.

This chapter evaluates the results from two typical EPOPS runs. The first example does not consider emission charges, the second run does. The results of the two runs are compared.

9.1. Run 1 : Input Data

9.1.1. General Data

This first example is an eight year expansion study without emission cost calculations. To reduce the quantity of input data, the load demand in a year is represented as a single period. Normally, Utilities are encouraged away from using external construction materials and fuel sources by their Governments in attempts to improve the Country's economy and reduce the susceptibility of exchange rate movements. In EPOPS this can be contrived by using a foreign discount rate that is smaller than the domestic discount rate. The general data used in this example is shown in Table 9.1.

Start Year	1997
End Year	2004
Number of periods per year	1
Domestic Discount Rate	10%
Foreign Discount Rate	7%
Emission Calculations	No calculations
Unsupplied Energy Calculations	No calculations

Table 9.1. General data for EPOPS.

9.1.2. Demand Data

Input data concerning the load duration curve (LDC) is shown in Table 9.2.

Year	Peak Load (MW)	LDC 5th Order Polynomial coefficients					
		c0	c1	c2	c3	c4	c5
1997	3300	1	-4	17	-37	35.6	-12.4
1998	3488	1	-2.4	14.6	-37	36.6	-12.6
1999	3687	1	-3.1	13.6	-31.8	33.2	-12.7
2000	3897	1	-3.7	14.3	-31.8	32.5	-12.1
2001	4119	1	-3.2	14	-32	32	-11.5
2002	4354	1	-3	13.3	-31.5	33.1	-12.6
2003	4602	1	-3.5	14.2	-31.7	31.5	-11.2
2004	4865	1	-4.3	16.6	-35.2	36	-13.7

Table 9.2. Load duration polynomial coefficients.

In this example, the load duration curve data has been entered as 5th order polynomial coefficients. Because the year is only represented by one period, only one set of coefficients is required. The peak load increases at a steady rate of 5.7%, the projected rate of demand growth previously shown in Figure 2.3, Chapter 2.

These 5th order polynomial coefficients were chosen to represent a typical load duration curve similar to the one shown in Figure 2.5, Chapter 2.

9.1.3. Installed Plant at Start of the Study

In this example there are ten existing power plants in the study, some containing more than one generating unit. Table 9.3 contains information regarding the operation and cost of these existing units. From the generating capacities of these existing units, EPOPS is able to determine the amount of new capacity that must be added to the system to meet expected electricity load requirements. The operating

levels and heat rates are used by EPOPS to determine the station's position within the merit order.

In this study there is only one coal-fired plant. It uses imported coal which accounts for the expensive fuel cost. The four oil-fired plants and five gas-fired plants all use indigenous fuel. The distance from the fuel source accounts for the spread of fuel costs. This is to allow for transportation costs. The nearer the plant is to the fuel source, the cheaper the fuel.

The fixed and variable operation and maintenance (O&M) costs are based on the typical values given in Table 2.9, Chapter 2.

All the units are required to maintain a 10% spinning reserve in order that the system can sustain unexpected outages such as generating equipment failure or transmission line faults. In addition, the units are not operated above 95% of their output capacity.

The forced outage rates and number of scheduled maintenance days are based on the typical unit maintenance requirements shown in Table 2.5, Chapter 2.

station name	Mult	Fdst	Gu1	Gu2	Qtst	Gucc	Kacc	Fdcc	Kocc	Kbrc
Fuel type	oil	oil	oil	oil	coal	gas	gas	gas	gas	gas
Number of units	4	2	2	2	2	3	5	1	1	1
Minimum operating level (MWe)	17	27	44	80	3	110	109	56	56	46
Maximum capacity (MWe)	62	62	106	201	7	272	272	140	140	90
Base load heat rate (MJ/kWh)	12	12	11.8	10.9	24	8.9	9.1	14.9	14.9	16.5
Average incremental heat rate (MJ/kWh)	11.8	11.8	11.6	10.5	20.5	8.2	8.9	3.1	3.1	1.5
Domestic fuel costs (\$/GJ)	3	3.1	2.9	2.9	0	4	4	4	4	4
Domestic fuel use (%)	100	100	100	100	0	100	100	100	100	100
Foreign fuel cost (\$/GJ)	0	0	0	0	2.2	0	0	0	0	0
Foreign fuel use (%)	0	0	0	0	100	0	0	0	0	0
Fixed O&M (\$/kW pa)	27.84	27.84	22.27	16.7	43.56	3.67	1.5	6.6	6.6	6.6
Variable O&M (\$/MWh pa)	2	2	1.4	0.92	2	0.46	0.25	2	2	2
Maximum nominal output (%)	95	95	95	95	95	95	95	95	95	95
Spinning reserve capability (%)	10	10	10	10	10	10	10	10	10	10
Forced outage rate (%)	2	2	2	3	3	4	4	3	3	3
No. of units for scheduled maintenance	2	1	1	1	1	1	1	1	1	1
Scheduled maintenance per unit (days)	17	17	20	24	10	26	26	21	21	19

Table 9.3. Unit description of existing plant¹¹³.

9.1.4. Retirements of Existing Units

Table 9.4 shows the retirement of existing units. The minus sign and numerical value denote how many units from a specific plant are to be retired in each year.

Name	1997	1998	1999	2000	2001	2002	2003	2004
Mult					-2		-2	
Fdst								
Gu1								
Gu2								
Qtst								-2
Gucc		-1		-1		-1		
Kacc			-2		-2		-1	
Fdcc								
Kocc								
Kbrc								

Table 9.4. Unit retirements of existing plant.

9.1.5. Reliability

In this study the standard percentage reliability index is used. Table 9.5 shows the minimum and maximum reserve margins which dictated the acceptable expansion capacity limits. Table 9.6 shows the total installed capacity of existing plant (calculated from Tables 9.3 and 9.4) and shows the minimum and maximum expansion capacity limits which are calculated using Equations 4.7 and 4.8 shown in Chapter 4.

Year	Min. reserve margin (%)	Max. reserve margin (%)
1997	5	10
1998	5	10
1999	5	10
2000	2	10
2001	2	5
2002	2	5
2003	2	5
2004	2	5

Table 9.5. Reserve margins.

Year	Installed existing capacity (MW)	Minimum expansion capacity limit (MW)	Maximum expansion capacity limit (MW)
1997	3546	0	84
1998	3274	388	563
1999	2730	1141	1326
2000	2458	1517	1829
2001	1790	2411	2535
2002	1518	2923	3054
2003	1122	3572	3710
2004	1108	3854	4000

Table 9.6. Installed capacity and expansion capacity limits.

9.1.6. Proposed Expansion Units

In EPOPS only fossil-fuelled candidates can be considered. Table 9.7 contains information regarding the operation and cost of the three expansion units that are to be considered for system expansion by EPOPS in this example. The high coal price is because it is imported coal. The oil-fired unit and gas-fired unit use indigenous fuel.

station name	imcl	0300	vgt
Fuel type	coal	oil	gas
Minimum operating level (MWe)	200	118	10
Maximum capacity (MWe)	600	300	200
Base load heat rate (MJ/kWh)	11.5	11.8	14.3
Average incremental heat rate (MJ/kWh)	8.6	9.3	12.2
Domestic fuel costs (\$/GJ)	0	3	4
Domestic fuel use (%)	0	100	100
Foreign fuel cost (\$/GJ)	2.2	0	0
Foreign fuel use (%)	100	0	0
Fixed OM (\$/kW pa)	43.56	27.84	6.6
Variable OM (\$/MWh pa)	3	2	2
Maximum nominal output (%)	95	95	95
Spinning reserve capability (%)	10	10	0
Forced outage rate (%)	4	4	3
No. of units for scheduled maintenance	1	1	1
Scheduled maintenance per unit (days)	31	27	24

Table 9.7. Unit descriptions of expansion plants.

The fixed and variable operation and maintenance (O&M) costs are based on the typical values given in Table 2.9, Chapter 2.

The forced outage rates and number of scheduled maintenance days are based on the typical unit maintenance requirements shown in Table 2.5, Chapter 2.

9.1.7. Construction Cost Description of Proposed Additional Units

In EPOPS it is assumed that the capital costs of existing units are already recovered. Therefore it is necessary to enter only data concerned with associated construction costs for the proposed expansion units. Table 9.8 shows the construction cost data for the three expansion candidates in this study. The capital costs for each candidate are based on the typical unit costs for modern fossil fuel burning stations shown in Table 2.1, Chapter 2.

The construction time of the units is based on the typical values given in Table 2.2, Chapter 2. For the purpose of this study it is assumed that there is no salvage value at the end of the plant's lifetime.

station name	imcl	0300	vgt
Depreciable domestic capital cost (\$/kW)	497.9	291	390.3
Depreciable foreign capital cost (\$/kW)	767.1	888	730.2
Non-depreciable domestic capital cost (\$/kW)	10.4	10.1	4.8
Non-depreciable foreign capital cost (\$/kW)	40.4	23.1	14.9
Plant life (years)	25	25	15
Interest during construction (%)	8.79	8.79	8.79
Construction time (years)	6	4	2
Salvage value at end of plant life (\$)	0	0	0

Table 9.8. Construction costs of expansion plants.

9.2. Run 1 : Results

The total cost graph in Figure 9.1 shows in ranked order of economic cost the number of options available to the planner to meet anticipated customer electricity demands. If there are more than a hundred options, only the top hundred are shown on the graph although the individual information can be accessed at a later stage.

The costs shown in the total cost graph include construction costs of new generating units as well as operation and maintenance costs of both existing and new units within power stations. The graph can be used to determine the difference in costs between options and also to see where any large cost steps occur.

The difference in cost between the cheapest and most expensive option is \$80 million. In monetary terms this is a significant amount but only equates to a 2.5% price increase. This approximates to a 0.1% increased price difference between adjacent alternatives. This marginal difference appears low especially when the inaccuracies in input data may be higher. However, the input data inaccuracies can be considered neutralised since all the numerical figures produced by EPOPS come from the same data. Providing the user does not view the resulting values to be absolute but rather to offer comparisons of alternatives on a relative basis the relative indicators are valid.

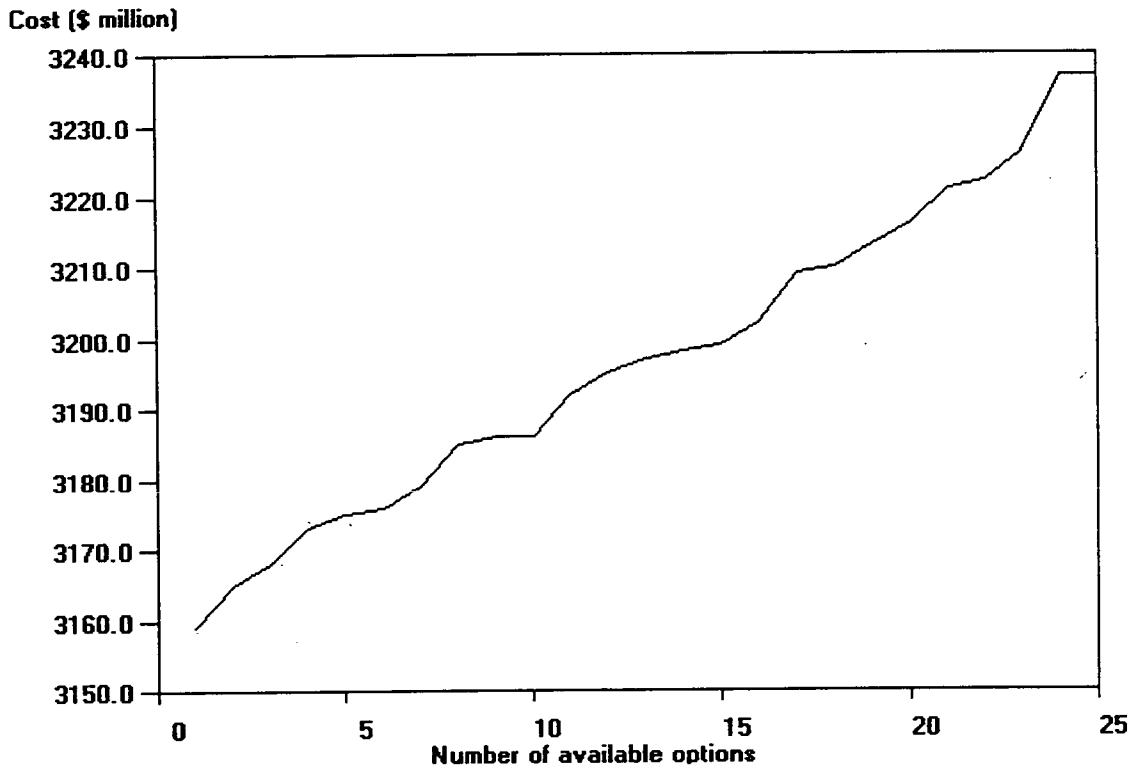


Figure 9.1. Total cost graph (without emission costs).

More detail of the individual options is found on the EPOPS 'expansion plan breakdown' screen. Figure 9.2 shows a detailed analysis of the unit mix in the cheapest option available to the Planner.

OPTION 1

YEAR	imcl	o300	vgt	cost [economic] (\$)
1997	0	0	0	2.20e+08
1998	0	0	0	2.55e+08
1999	0	0	6	3.81e+08
2000	0	0	8	3.64e+08
2001	0	3	8	4.69e+08
2002	0	4	9	4.98e+08
2003	0	6	9	4.89e+08
2004	0	7	9	4.83e+08

At a total cost over the 8 year study plan of \$3.16e+09

Figure 9.2. Detailed analysis of unit mix within an option.

For every year in the study, the table denotes the number of units for each expansion plant candidate (in this example imcl, o300, and vgt) that must be operating at the start of the year. In this example, in the year 2002 there must be four o300 oil units and nine vgt gas units up and running. The net present annual cost (referred to the first year 1997) is shown in the far right column. The total cost of the plan over the length of the study is shown at the bottom of the figure.

The user is able to look at all the options individually and can refer back to the total cost graph (Figure 9.1) at anytime. In being able to examine several options rather than the cheapest alone, the user is able to quantify in economic terms the effect of overriding the minimum-cost option by making decisions on the basis of some other grounds. For example, if the policy of the Electricity Utility is to have a combination of generating units of each fuel type, the Planner may consider Option 9 shown in Figure 9.3.

OPTION 9

YEAR	imcl	o300	vgt	cost [economic] (\$)
1997	0	0	0	2.20e+08
1998	0	0	0	2.55e+08
1999	0	0	6	3.81e+08
2000	0	0	8	3.64e+08
2001	0	3	8	4.69e+08
2002	0	4	9	4.98e+08
2003	1	4	9	5.03e+08
2004	1	5	9	4.96e+08

At a total cost over the 8 year study plan of \$3.19e+09

Figure 9.3. Option showing an even spread of generating units.

Although this option complies with the Utility's policy, it will cost \$30 million more over the eight years than the cheapest option. By comparing the numerical values in Figure 9.3 to those in Figure 9.2 it is seen that this extra cost begins in the year 2003 when one new coal-fired unit is in operation in preference to two gas-fired units.

Alternatively, if (for example) the policy of the Electricity Utility were to construct the minimum number of new oil-fired generating units but still maintain the use of all three fuel types, the user can examine the available options until an acceptable one is found. Figure 9.4 shows Option 13 which, while retaining a more suitable mix of units than either Option 1 or Option 9, i.e. it does not utilise as many new oil-fired units, it is \$40 million more expensive than the cheapest option and \$10 million more than Option 9.

OPTION 13

YEAR	imcl	o300	vgt	cost [economic] (\$)
1997	0	0	0	2.20e+08
1998	0	0	0	2.55e+08
1999	0	0	6	3.81e+08
2000	0	0	8	3.64e+08
2001	0	1	11	4.74e+08
2002	0	2	12	5.03e+08
2003	0	2	15	4.97e+08
2004	0	2	17	5.03e+08

At a total cost over the 8 year study plan of \$3.20e+09

Figure 9.4. Generation mix with no coal-fired units.

Ultimately the overall decision is made by the user, based not only on the economical values produced by EPOPS, but also on externalities such as Governmental or Utility policy. Although EPOPS will never totally replace the human involvement in the expansion planning process it is able to quantify in economic terms the effects of overriding the indicated minimum-cost option by making decisions on the basis of these other grounds.

9.3. Run 2 : Input Data

This second run of EPOPS uses the same data as shown for Run 1 (Section 9.1) but it also considers the cost associated with emissions. The additional input data that is required is shown below. It is assumed that there are no abatement controls available to any of the generating units (existing or proposed) but there are penalties for emission production.

9.3.1. Elemental Composition

The elemental composition for coal and oil is taken from the typical weight analysis values given in Table 3.1, Chapter 3. The composition for gas is taken from the typical weight analysis of North Sea natural gas shown in Table 3.2, Chapter 3. These values are shown in Table 9.9.

Element	Coal (%)	Oil (%)	Compound	Gas (%)
Carbon	75	84.6	Methane	94.36
Sulphur	2.3	4.0	Ethane	3.20
Nitrogen	1.5	0.0	Propane	0.47
Ash	7	0.0	Butane	0.20
			Pentane	0.05
			Hexane	0.03

Table 9.9. Fuel elemental composition.

9.3.2. Calorific Value

The calorific values for the three fuel types under consideration in this example are taken from typical values given in Section 2.4.1.7, Chapter 2. They are shown in Table 9.10.

Fuel	Calorific value (MJ/kg)
Coal	26
Oil	39
Gas	50

Table 9.10. Expansion fuel's calorific values.

9.3.3. Emission Charges

In this example the Electricity Utility is acquiring charges for every kilogram of emission. The charge values shown in Table 9.11 are the cost factors derived by the OKO-Institut to gauge the results of ascribing charges to air emissions in Germany¹¹⁴.

Emission	Charge (\$/kg)
CO ₂	0.005
SO ₂	2.5
NO _x	2.0
Particulate	0.5

Table 9.11. Emission charges.

9.4. Run 2 : Results

Figure 9.5 shows a similar total cost graph to that in Figure 9.1 with the difference that this one also includes costs accrued as a result to emission charges.

The marginal cost difference between adjacent options in this example is approximately 0.4%, roughly \$18 million compared with a \$3 million difference in the first example run. It can be seen that when emission costs are accounted for, the cost savings of avoiding a wrong choice are much higher and thus highlight the importance of their inclusion.

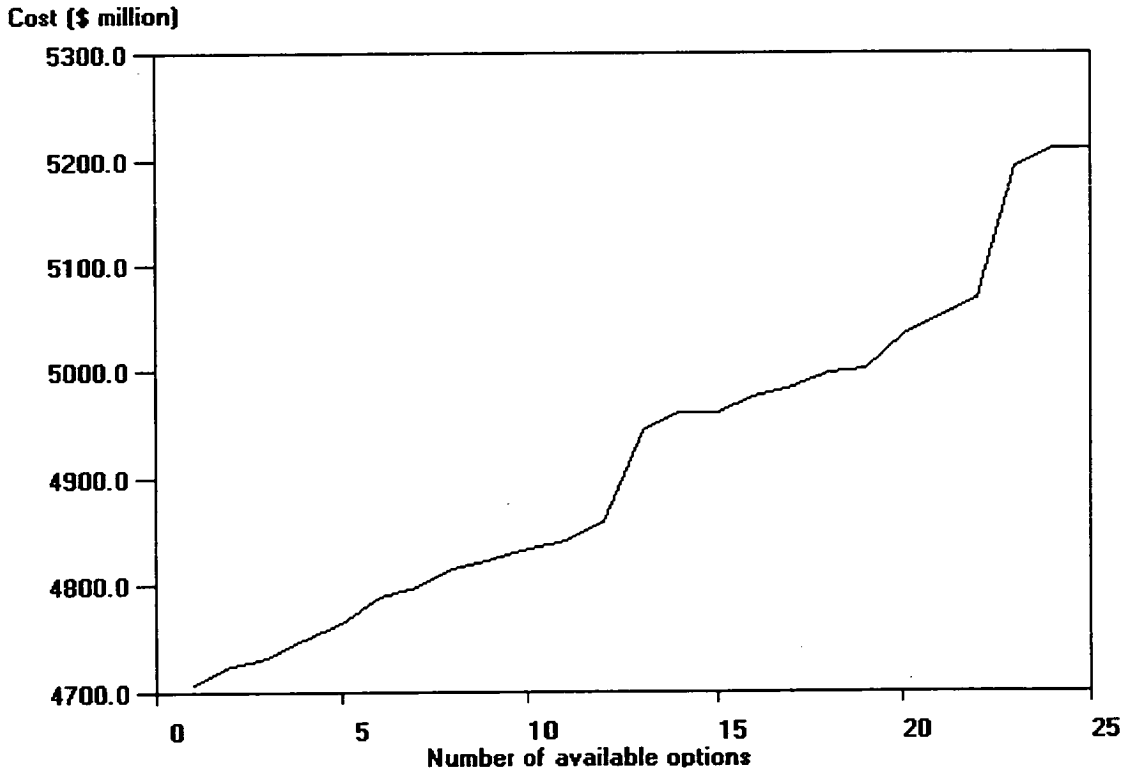


Figure 9.5. Total cost graph including emission costs.

Figure 9.6 shows the cheapest option available to the Planner while the cheapest option from the previous example is Option 22 in this run as shown in Figure 9.7.

OPTION 1

YEAR	imcl	o300	vgt	cost [economic + emission] (\$)
1997	0	0	0	4.48e+08
1998	0	0	0	4.55e+08
1999	0	0	6	5.74e+08
2000	0	0	8	5.41e+08
2001	0	1	11	6.59e+08
2002	0	2	12	7.08e+08
2003	0	2	15	6.71e+08
2004	0	2	17	6.51e+08

At a total cost over the 8 year study plan of \$4.71e+09

Figure 9.6. Cheapest option when emission costs are included.

OPTION 22

YEAR	imcl	o300	vgt	cost [economic + emission] (\$)
1997	0	0	0	4.48e+08
1998	0	0	0	4.55e+08
1999	0	0	6	5.74e+08
2000	0	0	8	5.41e+08
2001	0	3	8	7.27e+08
2002	0	4	9	7.68e+08
2003	0	6	9	7.83e+08
2004	0	7	9	7.71e+08

At a total cost over the 8 year study plan of \$5.07e+09

Figure 9.7.

By comparing Figures 9.6 and 9.7 it can be seen that the addition of more new gas-fired units in this example is favoured over the addition of oil-fired units. This is because burning gas does not produce sulphur dioxide, nitric oxide or particulate emissions whereas burning oil does and thus procures higher emission charges. Even though the cheapest expansion plan accrues minimum amounts of emissions charges it is \$1.6 billion more expensive than the cheapest option in the first example.

These costs appear to be very high, but this is explained by looking at the level of emissions produced by the generating units. A table of yearly emission values can be found on the EPOPS 'emission table' screen. Figure 9.8 shows the emissions produced by Option 1. It shows that 1.12×10^6 kg/hour of carbon dioxide is produced in the year 2004. This equates to 9.8 million tonnes per year. At a charge

of \$0.005 per kilogram the Utility could expect to pay charges of \$49 million a year for carbon dioxide alone. This highlights the importance of accounting for emission charges in least-cost expansion planning.

YEARLY EMISSION VALUES (kg/hour)

OPTION 1

YEAR	CO2	SO2	NOx	ASH
1997	7.85e+05	7.37e+03	6.23e+02	1.36e+02
1998	7.85e+05	7.37e+03	6.23e+02	1.36e+02
1999	8.60e+05	7.37e+03	6.23e+02	1.36e+02
2000	8.85e+05	7.37e+03	6.23e+02	1.36e+02
2001	9.46e+05	8.67e+03	6.23e+02	1.36e+02
2002	1.02e+06	1.09e+04	6.23e+02	1.36e+02
2003	1.05e+06	9.97e+03	6.23e+02	1.36e+02
2004	1.12e+06	9.88e+03	0.00e+00	0.00e+00

Figure 9.8. Yearly emission values.

Figure 9.9 shows the emissions produced by Option 22. By comparing Figures 9.8 and 9.9 it can be seen that it is increased CO₂ and SO₂ emission levels that contribute to the difference in expansion cost. The level of SO₂ emissions are almost double in the last two years.

YEARLY EMISSION VALUES (kg/hour)

OPTION 22

YEAR	CO2	SO2	NOx	ASH
1997	7.85e+05	7.37e+03	6.23e+02	1.36e+02
1998	7.85e+05	7.37e+03	6.23e+02	1.36e+02
1999	8.60e+05	7.37e+03	6.23e+02	1.36e+02
2000	8.85e+05	7.37e+03	6.23e+02	1.36e+02
2001	1.00e+06	1.31e+04	6.23e+02	1.36e+02
2002	1.07e+06	1.53e+04	6.23e+02	1.36e+02
2003	1.16e+06	1.88e+04	6.23e+02	1.36e+02
2004	1.24e+06	2.10e+04	0.00e+00	0.00e+00

Figure 9.9.

Figures 9.10 to 9.13 depict graphically the emission outputs of carbon dioxide, sulphur dioxide, nitric oxides and particulates respectively produced by Option 1.

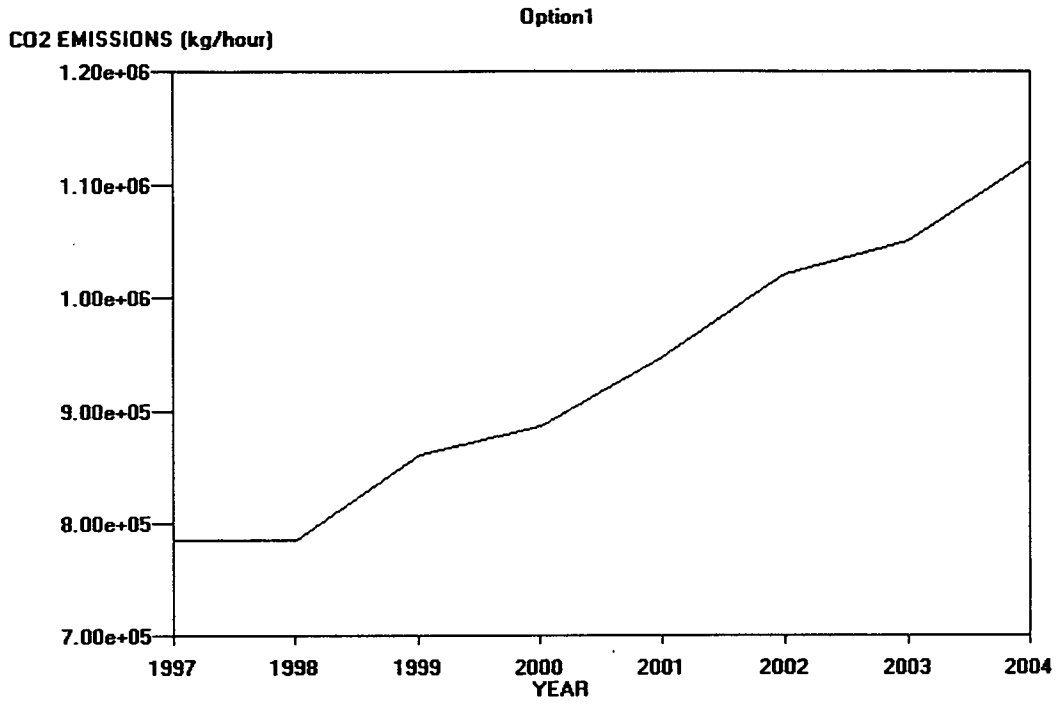


Figure 9.10. CO₂ emission levels.

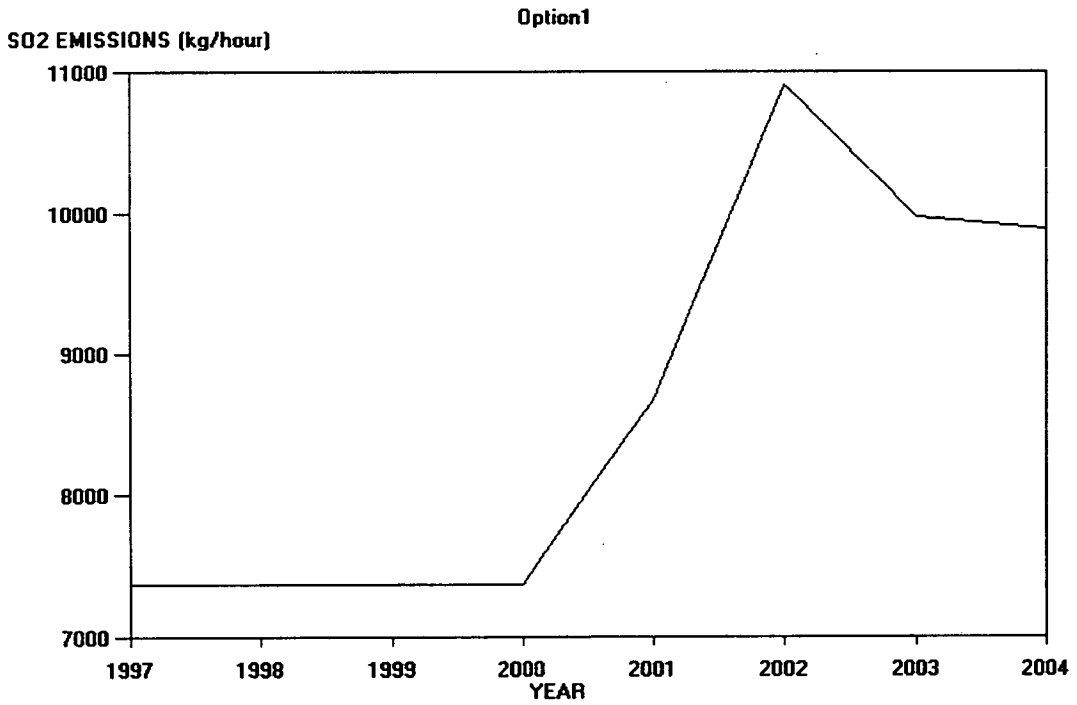


Figure 9.11. SO₂ emission levels.

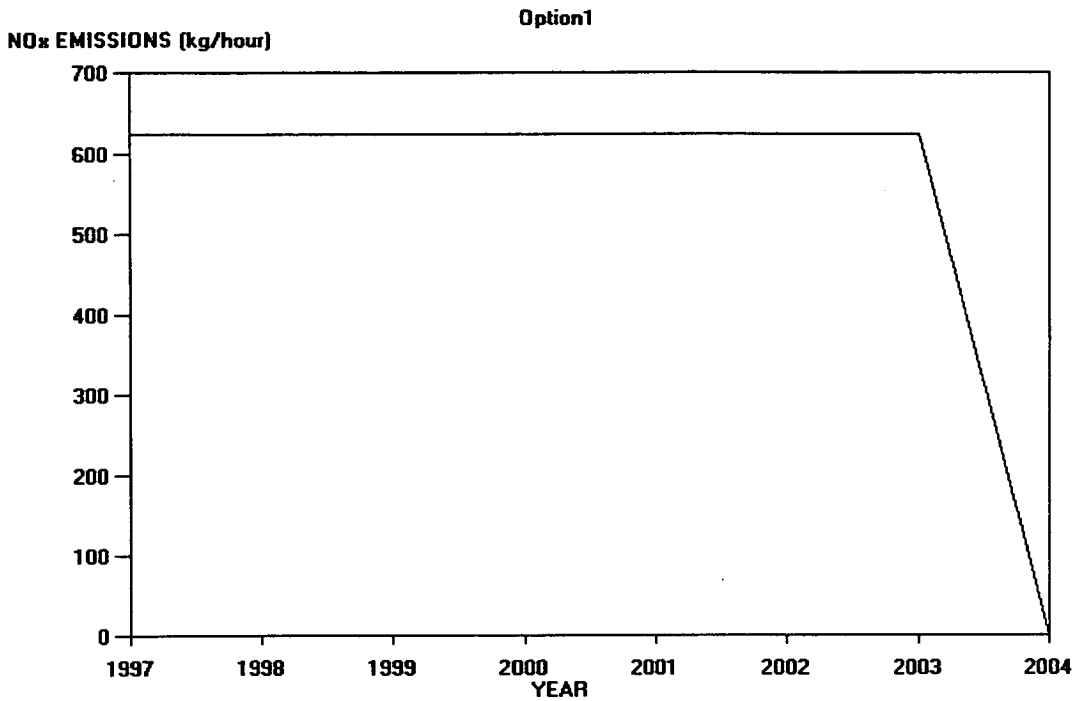


Figure 9.12. NO_x emission levels.

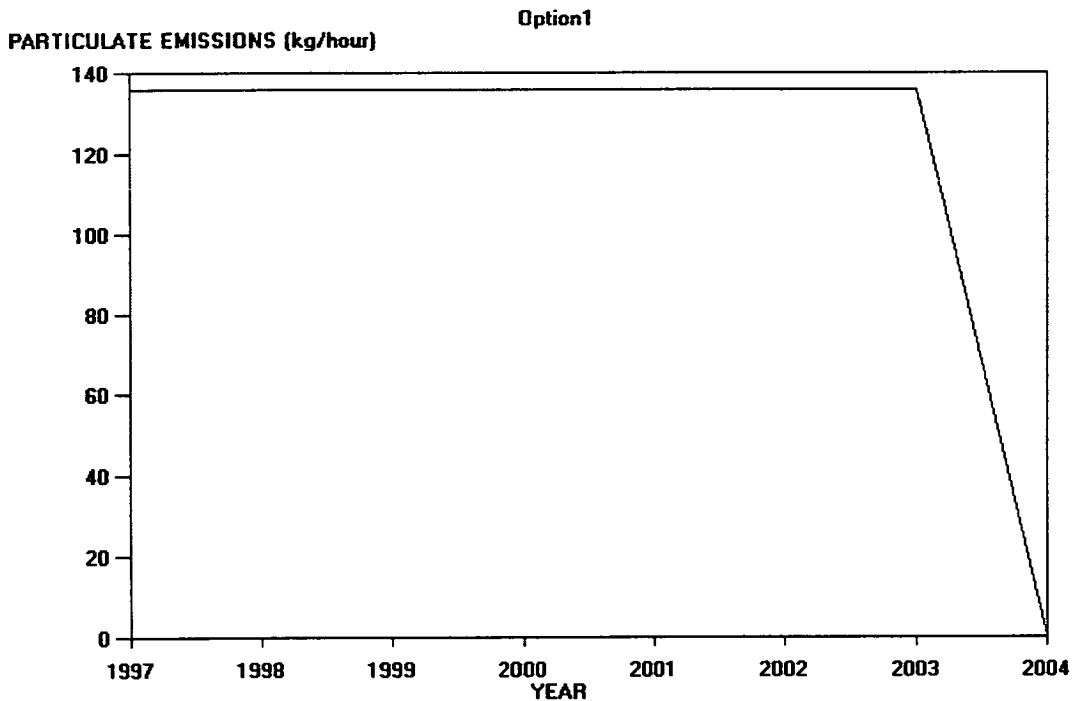


Figure 9.13. Particulate emission levels.

The level of CO₂ rises as additional generating units are added onto the system. The level of SO₂ rises in the year 2001 when a new oil-fired unit is added. This addition is counterbalanced by the retiral of two generating units from the oil-fired station

Mult (see Table 9.4). Another two units from Mult are retired in 2003 and this accounts for the decrease of SO₂ in that year. The level of NO_x and particulate emissions remain constant as a result of the coal-fired station Qtst. The level does not rise as no new units are added although the drop in 2004 corresponds to the retiral of both units within Qtst.

9.5. Summary

EPOPS has been developed to consider all the factors examined in Chapters 2 and 3. Through the use of these factors and the calculations discussed in Chapters 4, 5 and 6, EPOPS determines a range of generation options that meet anticipated demand and displays them in ranked economic order. All of this is achieved without involving expensive computational time or requiring any understanding of the mathematical processes.

One of the main advantages of using EPOPS is its ability to test a variety of options. The planner may explore "what-if" scenarios to determine the sensitivity of a plan against, for example, changes in fuel price, availability of fuel, or movements in discount rates. As well as being able to assess the sensitivity of plans, EPOPS also enables comparative studies. EPOPS has the ability to rank all the permutations of expansion plans in economic order rather than just displaying the cheapest option. As a result the user can quantify in economic terms the effects of not selecting the optimum solution because of externalities, such as political pressure and Utility policy, dominating the outcome of an expansion plan. EPOPS will never totally replace the human involvement in the planning process. It does, however, highlight the economic penalties of overriding the indicated minimum-cost option on the bases of these other grounds.

This chapter has shown the results from two typical EPOPS runs. The first example did not consider emission charges whereas the second did. The graphs and tables reproduced in this chapter from a typical EPOPS run show the clarity and ease of using decision support software to perform a least-cost expansion plan. The graphs and tables not only show the costs of expanding and operating scenarios but also show emission levels of carbon dioxide, sulphur dioxide, nitric oxide and particulates.

The comparison between the results of the two examples highlights the importance of accounting for emission costs within a least-cost expansion plan. It has been shown

that these high costs can significantly change the economically ranked order of available options to the Planner. The option that appeared the cheapest in the expansion plan without emission charges turned out to be the second option when emission charges were considered.

CHAPTER 10

DISCUSSION AND CONCLUSIONS

10.1. Demand and Supply

Electricity has become one of the most important commodities in modern society. Its provision is associated with the growth of industrial output and can be linked to economic prosperity. Frequently it is seen as a vector for social improvement and because of this and population growth along with advances in energy consuming products there will probably be a steady increase in electricity demand. Figure 2.3 in Chapter 2 indicated an annual growth rate of 3.3% over the next decade.

If, as is likely, Utilities are unable to control completely electricity use by applying demand side measures, such as load management or improved efficiency of processes using electricity, the only other option available is supply side management. This method expands the electricity supply system to meet projected load demand by building new power generating stations.

The fuels used by Utilities to generate electricity fall into three categories; nuclear, hydro and other renewables and fossil fuels. The availability of the resources and their associated costs play a major role in deciding which fuel to use for expansion although externalities such as political pressure or governmental policies may influence the ultimate decisions. The following sections considers each possible primary energy source.

10.1.1. Nuclear

There are two energy producing nuclear reactions, *fusion* and *fission*, although fusion reactors have not yet become a viable option. Fission power produces energy when, on collision with a neutron, a fissionable isotope breaks into two smaller atoms. The most commonly used fuel in fission generation is uranium¹¹⁵ which unlike conventional fossil fuels has little other peaceful use other than for the production of energy. However, the availability of uranium is similar to that of oil¹¹⁶, i.e. if used at present levels, the supplies are expected to be depleted by the middle of the next century¹¹⁷.

The nuclear option for generating electricity is not available in all countries: the reasons for this may be either political, environmental or due to lack of hard currency. Plans for the future of nuclear power are mixed. Many countries are choosing to remain with what they have (e.g. France and UK), some are attempting to close down plant and will build no more (e.g. USA) and some are rapidly expanding nuclear generation (e.g. Japan). Eastern Europe falls into the second category although decommissioning attempts are not always successful. A particularly relevant example of this is the case of the RBMK Russian reactors. After the Chernobyl accident in 1986 it was expected that the remaining reactors would be rapidly taken out of service. In the event, number three reactor was brought back into service in 1987. In addition, several other reactors are considered unsafe. For example, the plant at Kozloduy in Bulgaria has been virtually condemned by the International Energy Agency as a safety hazard and recommendations for its closure have been made.

The threat of a nuclear incident and other uncertainties associated with nuclear power generation are difficult to factor into least-cost expansion planning. Lack of knowledge regarding the potential implications in the future of disasters such as Chernobyl may invalidate the indicated least-cost option if it involves Nuclear power.

10.1.2. Renewable

While renewable energy technology looks like a plausible alternative to the other, more traditional forms of electricity generation, it still has not been proven to work on a large scale. There has been a recent drive for renewable energy because of increased awareness of potential climate change. There is, in some areas, what might be regarded as an excessive optimism about the scale and pace of renewable energy. The findings of the World Energy Council^{118,119} however, show that, under a conventional range of circumstances, only 25% of global primary energy supplies could come from new renewable resources by the year 2100. There are a number of reasons why the predicted pace and scale of development is slower than scientists first assumed. Some of these reasons include¹²⁰:

- the time needed to achieve really substantial changes
- existing fossil fuel interests, investments and employment
- the continuing failure fully to cost and price externalities
- other technological, economic and institutional barriers
- problems of financing.

One of the main arguments for renewable energy is their lack of environmental impact. However, several studies^{121,122} have shown this is not necessarily the case. Development of tidal power in estuaries has been linked to problems of siltation, interference with shipping movements, loss of invertebrates and fish and visual intrusion. The main concerns linked with wind farms are visual intrusion and noise. While the actual energy production may be a "green issue", the technology behind it may not be always. For example, huge solar farms have the effect of stopping the sun's radiation reaching the ground and warming it up. Although the effects are not fully understood, it is believed that this may result in measurable weather changes¹²³.

Although renewable energy may have potential in the future, it is not yet fully developed and ready for the market. The sources that it utilises, i.e. wind, sun or rain, are unpredictable and there is a lack of agreement to its environmental impact. When a better understanding of its impact has been obtained and a taxation levy can be applied, it will become more suited for inclusion in a least-cost expansion plan.

10.1.3. Hydro

While hydro has been a proven renewable technology for the generation of electricity, there are still some misgivings over its economics and applicability. The ability to use hydro technology is confined to countries with the correct geographic formations and hydrological resources. Unless adequate hydrological research exists (records going back at least twenty five years), a hydro plant cannot be guaranteed to be as effective. In addition, it has been concluded that due to global warming, precipitation levels may fall in many countries lessening the effectiveness of hydro power¹²⁴. Even if the conditions are perfect the construction of hydro plant has proved to be an expensive option mainly because of associated long lead times and high capital costs. In addition the optimal sites for hydro generation are usually in mountainous country. This presents difficulties in site development and, because the load centres are likely to be some distance off, there is the additional cost of electricity transmission.

Experience of hydro has been disappointing in some cases and projected benefits have not occurred. The problems associated with hydro generation are numerous and often the consequences are irreversible. For example, in Egypt, the Aswan Dam on the River Nile is causing considerable silting in the lake. As a result, this fertile nourishment is not reaching the Nile Delta, a very important agriculture area. In

Zimbabwe, the construction of Kariba Dam displaced thousands of indigenous tribes from Kariba Valley and resulted in the death of many animals. The slowed-down waters of reservoirs become ideal breeding grounds for water parasites resulting in increased cases of, for example, bilharzia and malaria.

The majority of good hydro-power sites have already been developed. As a result, because there is little hope for further significant expansion it is not an energy source considered in the present least-cost exercise.

10.1.4. Fossil Fuels

Fossil fuels originate from the earth as a result of the slow decomposition and chemical conversion of organic material. They come in three basic forms: *solid* (coal), *liquid* (oil) and *natural gas*. Fossil fuels are ubiquitous with reserves of coal, oil and gas lasting well beyond the next century providing that they are used efficiently and economically. There is a wide range of fossil fuel generation technology which has been proven to work with new versions continually being developed to operate with varying fuel consistencies and fuels whose constituents can vary in a huge way. For example, the versatility of fossil fuel electricity producing technology is evidenced by the fact that it ranges from small portable petrol-driven generating sets to large 600 MW steam turbo alternators.

Figure 2.2 in Chapter 2 indicates that the burning of fossil fuels is still the World's main primary source for power generation in the electricity sector. The three main fossil fuels, namely coal, oil and gas, account for 64% of electricity generated. This thesis has concentrated on expanding electricity systems solely through the use of fossil fuels because of this fact and the reasons mentioned in the above sections. However, a major problem associated with the burning of fossil fuels is the release of emissions into the atmosphere.

10.1.4.1. Fossil Fuel Emissions

In the past, as a result of the concern for human health due to power station emissions, the Utilities built taller flue stacks as a method to reduce concentration of gases at ground level¹²⁵. Their maxim was "the solution to pollution is dilution"¹²⁶. However, recent studies have shown that although this method reduces local pollution, it does not alleviate the global situation. A major problem is that air

currents are capable of transporting the pollutants over a great distance and so it is not necessarily the producer of the pollutant that suffers from the after effects.

The emissions of greatest concern, because of their believed impact on the environment are carbon dioxide, sulphur dioxide, nitric oxides and airborne ash particulates. Sulphur and nitrogen oxides are the main contributors to "acid rain". In the presence of sunlight, these are transferred to nitrate and sulphate aerosols in the atmosphere. In the presence of water, nitric and sulphuric acids form causing precipitation (in the form of rain or snow) to become more acidic. Carbon dioxide is one of four gases that principally contribute towards the greenhouse effect. As a result of increased CO₂ concentrations the Earth's temperature is increasing. In the last century the Earth's temperature has increased by 0.5°C. Predictions for the next century range from the increase of 1.5°C to more than 4.5°C^{127,128,129,130,131}.

Despite lack of scientific confirmation of the effect of acid rain¹³² or greenhouse gases on our environment^{133,134,135}, the European Community and other international organisations believes that there is sufficient evidence to warrant tighter controls of the gases. This control is being introduced in some countries in the form of charges levied on Electricity Utilities who release excess emissions. These penalties have the potential to change significantly the cost of an expansion plan. As a result, provision should be made during expansion planning for the assessment of the release and reduction of discharges through attributing abatement or penalty costs.

These penalty costs however must be set at a rate that encourages Utilities to introduce abatement technologies. The costs accrued for excess emissions must be higher than the cost to install and operate the abatement control equipment if the levels of emissions are to be reduced. In addition, the regulators must ensure that the technology is being used. For example, although National Power installed FGD at Drax, the plant with the scrubbers often does not generate because the increased unit price of electricity is unable to compete with cheaper dirtier coal-fired stations.

10.2. Least-Cost Expansion Planning

There will probably continue to be an increasing demand in electricity. This will necessitate Electricity Utilities to either build new power stations or replace plants that are no longer generating as effectively and efficiently as emerging technology. Either way, Utilities will be required to invest large sums of money into these

ventures. Because of the many choices available to the Planner and the varied and diverse lifetime costs of the stations, system planning must produce a solution which appears to offer a minimum cost over the length of the study.

Expansion planning analyses the estimated future electricity demand and determines a mix of generating units that successfully meet this load requirement after accounting for existing installed capacity. The least-cost option is determined on the basis of a discounted cost over the study period. There are many factors involved in expansion planning which can influence the cost of the optimum solution. Least-cost expansion planning can be used to determine which factors dominate the final results. For example, by applying least-cost expansion planning, a Planner can determine whether it is more economical to build expensive new plant quickly and incur minimum amounts of interest or build cheap plant over an extended period. By considering a range of capital costs, construction interest rates and construction times the Planner can find the cheapest option. However, because there are other costs involved, such as operation costs, these must also be repeatedly re-calculated. For example, presently it is more economical to construct cheaper gas-fired units. However, using least-cost expansion planning it can be shown that if the fuel price of gas was to rise in a way similar to that of oil prices in the 1970's it would no longer be the dominant fuel in an expansion plan.

Of increasing importance are potential emission costs. In many countries, where there are no penalty charges for releasing excess emissions into the atmosphere, this cost is not considered. The incorporation of emission costs into least-cost expansion planning is relatively recent and its inclusion is of particular interest in some countries where the perception of environmental problems is not as well developed as, say it is in the EU countries. In countries where Electricity Utilities continue to burn coal with a high sulphur content, e.g. Poland, the use of least-cost expansion planning which accounts for emission penalties can highlight expansion options that are not as economic as previously thought. The accumulated penalty costs for releasing emissions into the atmosphere can significantly alter the outcome of a least-cost expansion plan. For example, typical financial penalties can add approximately three cents per kWh generated. This extra cost encourages the move towards 'cleaner' fuels, such as gas, rather than coal and gas because fewer emissions are released and thus the Utility accrues less penalty costs.

The Soviet Union and Eastern Europe have substantial potential to contribute towards impact reduction if financial and other resources are available. The OECD countries have the expertise, experience and financial resources for pioneering alternative strategies. Least-cost expansion planning can be used by them to educate and secure financial support for emission abatement technology and aid in the improvement of the environment which has been neglected for many years. This support would not only be beneficial to the developing countries but also to the developed countries themselves.

10.2.1. LCEP Users

As a secondary fuel, electricity is fast becoming a highly valued commodity within the international money market. Increasingly, large sums of money are being invested into electricity supply expansion and operation, for example Sizewell PWR in Suffolk is estimated to have cost more than £2000 million for 1175 MWe.

There are two types of investors in electricity expansion; the traditional Planner of National monopolies and, increasingly, private businesses. Although both investors have motives to supply electricity, the reasons for doing so are completely different. The Planners within a National monopoly must ensure that sufficient electricity is generated to comply with statutory obligations as determined by Governmental acts. This energy must be supplied at a reasonable cost to the customer while continuing to maintain sufficient funds for future expansion.

Private businesses, on the other hand, are interested in investing money in order to make a profit, usually in a short time scale. These entrepreneurs fall into three categories:

- Build-own-operate (BOO) - Economically prosperous companies meet the electricity needs of target countries by investing capital into the construction and operation of electricity generators. The private sector is required to finance, design, build, operate and manage the facility, in addition to paying a levy to the host country. The return period of this investment is ten to fifteen years.
- Build-operate-transfer (BOT) - This type of investment is similar to BOO except that after an agreed time period, the investors transfer the ownership of

the generators over to the host country free of charge. This venture can make a high profit in a short time scale¹³⁶.

- Providers of venture capital - This encompasses the more traditional type of money lenders. Investors, such as The World Bank, arrange to finance expansion projects with a view to make a profit over a twenty five year loan term through interest rates set at approximately 8 - 10%¹³⁷.

These private ventures are increasingly being encouraged by Governments in their drive to privatise major public projects. This unique method represents a step forward in meeting the World's need for more infrastructure development especially in the rapidly developing countries.

The whole process of project development is a complex, time-consuming and expensive business. The financial risks are high, competition is often keen and opportunity costs are considerable. As a result, all financing categories must perform adequate expansion planning before any large sums of money are invested. Through the use of least-cost expansion planning the investor can have confidence that the chosen expansion strategy approaches the optimal one. This initially is based on the cost of the project although externalities such as Governmental policy, political pressure or national strategy may ultimately dominate the final decision. Each proposed solution must be fully examined in terms of cost, sensitivity and robustness to allow competitive comparisons.

In addition to investors, least-cost expansion planning techniques can be of great use to emission taxation setters. Through its use, taxes can be set at levels that do not penalise too severely Electricity Utilities but encourage them to clean up by either installing abatement technology or switching to cleaner fuels. By applying differing tax levels to emissions, regulators can determine the critical value when it becomes more financially rewarding to the Utility to introduce abatement controls rather than paying a hefty fine.

10.3. EPOPS

Many of these calculations used in least-cost expansion planning are mathematically complex, repetitive and not suited to paper-based computation where the volume flow of data facilitates numerical errors or mis-interpretations. Decision support systems can now embody the necessary mathematical techniques which avoid

intermediate computational error. Least-cost planning can be carried out more rapidly and comprehensively in a way which takes account of a wide range of factors without involving extended computational time.

EPOPS decision support system resulted from the collaboration between the University of Edinburgh and Ian Pope Associates (formerly L.E. Energy). It has been designed to aid the planning of electricity system expansion. It is a package that will benefit system planners in countries which are either endeavouring to increase present installed capacity or are developing a new electricity network. Both projects, requiring the building of new power stations, are carried out with the intention of keeping the cost to a minimum. One area of the World which falls into the second category is Eastern Europe. Since the dismantling of the Communist system in the beginning of the late 1980's it has become apparent to both system operators and planners that a significant upgrade of the present electricity scheme is necessary¹³⁸.

EPOPS has been developed to consider all the factors that can influence a least-cost expansion plan without involving the user in extensive computational time or requiring any understanding of the complex mathematical processes. EPOPS determines the full range of generation options that meet anticipated demand and displays them in ranked economic order. The costs are all referred back to the first year using the net present value calculation so that the values can be compared on an equal basis. The disadvantage of using this method is that it does not allow the user to make intermediate changes to proposed investment policies. As a result EPOPS is able only to indicate the solution that is minimal cost and offers a guidance to the expected cost of the expansion plan. All the calculations within EPOPS are correct but the results obtained from EPOPS can only be as accurate as the data entered by the user. The challenge of predicting future values is a formidable one and is the main problem encountered in least-cost expansion planning. However, providing the assessment of each option is based on the same set of assumptions, the relative results enable an effective comparison.

One of the main advantages of using EPOPS, however, is its ability to test a variety of options. The planner may explore "what-if" scenarios to determine the sensitivity of a plan against, for example, changes in fuel price, availability of fuel, or movements in discount rates. This capability to assess the suitability of a plan against various uncertainties allows Planners to arrive at final decisions with more confidence. For example, a Planner may wish to determine if the optimum solution

of one simulation will remain so if the capital cost of the fuel type used in majority were to rise by, say, 10%. In such a case, the Planner may intuitively think that this increase would cause a shift to favour another fuel type. However, if initially the capital cost were more than 10% cheaper than the next expensive fuel type, this increase would have no effect at all. On the other hand, if the construction interest was also to increase, the extra expense might be enough to relegate the fuel to second or third place. This ability to perform repeated expansion plans in a shorter time scale than can be calculated manually is further evidence of the usability of EPOPS.

Because EPOPS has the ability to rank all the permutations of expansion plans in economic order rather than just displaying the cheapest option, the user can quantify in economic terms the effects of not selecting the optimum solution because of externalities, such as political pressure and Utility policy, dominating the outcome of an expansion plan. EPOPS will never totally replace the human involvement in the planning process. It does, however, highlight the economic penalties of overriding the indicated minimum-cost option on the basis of these other grounds.

10.4. Conclusions

With the large sums of money involved, many capital investors, i.e. The World Bank, are insisting that least-cost expansion planning is performed before system expansion is implemented. It is often argued that least-cost expansion planning should be dismissed because some countries, in particular Eastern Europe, have soft currency, with neither exchange rates nor discount rates. Here the expansion plans are dictated by Governments who, in many circumstances, often choose more politically acceptable routes and the recommendations of the planners are either modified or completely ignored. Despite these drawbacks it is believed that least-cost expansion planning and the development of a decision support system has potential benefits¹³⁹. Least-cost expansion planning allows the user to quantify in economic terms the financial effects of superseding the optimum economic choice by another dictated by external influences.

The use of EPOPS decision support system can greatly decrease the time spent on least-cost expansion planning. With built-in equations, the software not only automatically performs the tedious task of repetitive calculations but also has the ability to consider more features within expansion planning. Through the use of this computer aided least-cost expansion planning package it reduces the risk of errors

initiating within the calculations and allows the Planner to arrive at decisions with more confidence.

Through the use of EPOPS a great deal of knowledge regarding electricity expansion and generation can be attained more easily than through the manual 'pen and paper' calculations. In the conventional method of least-cost expansion planning, the planner may confine the choice of options to those that look intuitively viable. This type of reasoning, often called 'rule-of-thumb', while still remaining an important aspect within least-cost expansion planning may unintentionally lead to options being overlooked because they do not look practicable or feasible. EPOPS, on the other hand, systematically determines every possible conceivable option using dynamic programming and by applying built-in and user-defined constraints rejects implausible options while retaining the remaining viable ones.

If specified by the user, EPOPS also determines the costs associated with gaseous emissions. It accounts for all the reduction mechanisms that are imposed on the system, for example abatement equipment installation and operation costs or penalty costs. Each cost is individually referred to the first year in the study so that EPOPS can compare the values on an equal basis and ultimately rank the options in ascending economic order.

In addition to graphs showing these costs, EPOPS also produces graphs and tables that show annual emissions over the study period. This is to allow the user to view the absolute output emission values each year and determine which is responsible for attributing the most cost to an overall plan.

EPOPS main advantage of least-cost planning is its ability to repeatedly explore 'what-if' scenarios with the minimum of effort and time. The repeatability of performing calculations on scenarios which only has one changed variable value allows the user to determine if that variable has a major effect on the overall ranking of options.

10.5. Recommendations for Future Work

As a complement to the research and findings presented here, the author considers the following research and modifications to EPOPS to be necessary to enable the production of an even more universally usable piece of software. Although the list is

not definitive, it includes major issues that the Author believes will benefit the least-cost expansion package.

1. The ability to consider more than three expansion candidates needs to be included in EPOPS because although at present it only considers the three main fossil fuels, the Electricity Utility may have access to more than one source of fuel. For example, if a least-cost expansion plan were being performed on Poland, there might be the choice of indigenous brown coal or imported coal from The Soviet Union.
2. Although it was argued at the beginning of this chapter that fossil fuels meet the majority of electricity generation needs, the author considers that it would still be of value if EPOPS could consider nuclear, hydro and other renewable alternatives.
3. To make EPOPS more akin to an expert system, a set of "rules", specific to a country or region, should be included. These rules, derived from experts in the field of least-cost expansion planning, would allow the inclusions of externalities that have been discussed in this thesis.
4. At present, EPOPS only displays the aggregate emission output of all the stations in the system. An improvement would be to include an option which allowed the user to view the emissions from any one particular station.
5. A further improvement to EPOPS would be to not only consider the costs associated with expanding a electricity supply system, i.e. supply side management but to also include demand side management (DSM). This would include the need to encompass the following critical components of Utility planning:
 - influence on customer use.
 - evaluation against non-DSM alternatives.
 - identification of how customers will respond.
 - focus on load shape.
 - analyse of uncertainties and risks posed by different resource portfolios and by external factors.
6. The approach to incorporate uncertainty into EPOPS is a further recommendation. This would enable an electricity supply planner to identify a

plan that, although may not be the lowest cost plan for any single combination of uncertain events, will be the most robust plan under most unfavourable circumstances.

7. A final improvement to EPOPS would be the inclusion of risk analysis. As the capital expenditure of any large venture such as electricity supply is significant, and changes to constraints such as delays in construction or changes to fuel prices can cause a substantial increase in overall costs, the consequence of involved risks is becoming a more important component within planning. Risk management can be described as planning for possible consequences in advance rather than acting when it happens. Thus the risk factors are systematically identified, assessed in the measurement of their occurrence probabilities, estimated in their consequences and provided for. A comprehensive study of involved risks will not prevent cost and schedule overruns but it will allow managers to apply a more rational basis on which to make decisions.

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APPENDIX A.1

EPOPS USER'S HELP MANUAL

Help topics available for EPOPS are listed below. Use the scroll bar to see entries not currently visible in the Help Window.

To learn how to use Help press the F1 key or choose Using Help from the Help menu.

To read the Help information sequentially, use the buttons labelled ">>" and "<<" on the Help toolbar.

Click here for more help - [Help Instructions](#)

Introduction

EPOPS (Expansion Planning Of Power Systems) is a decision support system that will indicate the most economical generation solutions to meet customers' demands in a study period of up to thirty years, based on generation, economic and environmental data provided by the user. The figures produced by the package are not definitive values but purely there to assist in making a current decision using the insight obtained by considering the future. It is anticipated that this program will be of great assistance to system planners in countries that are either considering to develop a new electricity network or undertaking to increase the installed generating capacity.

In order to simulate operation of the system with respect to both reliability and economics of the electric power supply, it is necessary for the user to input data concerned with the whole system. This includes data relating to existing and expansion generating stations. There is a great deal of data required although an example file is included with the software that gives an indication to the magnitude of the values that are expected.

From all the entered data, EPOPS is able to determine a variety of generation plans that successfully meet customer demands. Expansion planning is based on two separate calculations; the first part is concerned with determining the economic cost of building and running various scenarios while the second part concentrates on calculating emissions from the generating stations and assigns a cost to the pollutants. Depending upon whether the user wishes to calculate emission costs or not, the final least cost plan to meet customer demand is based upon the aggregate economic and emission cost or the economic cost alone. It is important to note that the outcome is *based on the data values* and could be entirely different for a variety of, say, capital cost discount rates or unit heat rates. The values are therefore significant to the final result. Bearing this in mind, the user should examine carefully the default values before accepting them.

Wherever possible, the options in the package can be selected using either the keyboard or the mouse. Both selection methods (if available) are described in detail under the relevant section.

Installation

To install the EPOPS software, the following steps must then be executed:

1. Insert EPOPS disk into disk drive.
2. Type EPOPS followed by **Enter** (↵).
3. Type preferred directory for EPOPS (C:\EPOPS is default).
4. Follow instructions on the screen.

User Interface

The operations of user data and graphical interfaces used in EPOPS are described in the following sections. Wherever possible, the layout is similar to other Windows™ packages. For additional information on Microsoft® Windows™ the user should refer to the User's guide.

Title Page

This is the first screen accessed when the user starts EPOPS. In order to continue, the user is required to enter a password in the password box. This entry point can be accessed in two ways. The user can either press the **Tab** key or position the mouse pointer over the box and click the left button. The actual password does not appear on the screen, instead each letter, number or character is replaced by an asterisk (*). To continue press the **ENTER** key (↵).

The user is given three attempts to input the correct password. On the first two attempts an error message will appear on the screen if the incorrect password is entered. The user must clear the password entry box and retype the password. On the third wrong attempt, EPOPS will automatically exit.

Immediately after typing in the correct password, the user is offered the chance to change the password. Due to Kappa-PC limitations, the option choosing (Yes or No) is not keyboard supported, so the mouse must be used. Place the pointer over the preferred option and click the left mouse button. If the password is to be changed, the user may type in a combination of words, numbers or characters of any length.

File Retrieval

The data concerned with study plans is held in separate *.kal files. These are files produced by Kappa-PC and are only accessible at this stage. An example file, *example.kal*, is provided to enable a user to execute EPOPS without prior knowledge of data relating to expansion planning. Alternatively, when beginning a new simulation, the user may choose to load in *default.kal*, a file that contains default

values for much of the data that is required in least cost expansion planning, or *newslots.kal*, a skeleton file.

A dialogue box will be displayed with the default path set to EPOPS example directory. This path can be changed by double-clicking the left mouse button on the directory that contains the wanted file or by pressing the **UP** (↑) or **DOWN** (↓) arrow to highlight the directory followed by **ENTER** (↵). On the right hand side, a files list box displays the names of the files in that directory. Select the required file by highlighting the desired *.kal file either with the mouse or the **Tab** button followed by **ENTER** (↵). (A fast double click on the mouse button has the same effect). If the desired file is not displayed, check that the correct file extension has been keyed in. While the file is loaded into EPOPS, the cursor shape will change from an arrow to an hourglass. Depending on the size of the file, it may take a while to load.

Description Page

If a existing study has been loaded, this page holds a description of the study plan. If a new study is to be set up or if several different study cases are being examined, it is a good idea to describe the plan here in detail to ensure the correct one is loaded at a future point. There are three separate lines, each of which will accept up to forty characters. The user can move between these three boxes either by clicking the mouse pointer over the box or by using the **Tab** key.

If the wrong file has been loaded, choose the File menu and activate the new option (**Alt f n**).

To continue, either position the mouse pointer over 'continue' on the menu bar or press **Alt c**.

Main Menu Screen

The *main menu screen* is the main window that enables the user to access the data input forms and run an expansion simulation. There are four menu options on this screen. Two of the menu options, File (**Alt f**) and Help (**Alt h**) are available on most other screens as well. The menu option Data input options (**Alt d**) gives access to data entry, while Run simulation (**Alt r**) accesses the simulation coding.

Initially, Run simulation may be disabled. This is because if any data is not entered, the program is liable to stop responding. By choosing the Missing values menu option within Help a text box will appear informing the user on the location of the missing data.

After each menu option within Data input options has been chosen, it will be disabled on the menu bar. This is just so that the user can keep tags with which option has been executed. To enable all the menu options, in order to change some data, press the enable options button in the bottom middle of the screen.

File Menu

- *New*
This option will delete all the data present unless saved at the prompt. If the data is not to be lost, choose '*cancel*'. If '*continue*' is chosen the user is then requested to open another data file.
- *Save*
If the data typed into EPOPS is to be used again, it must be saved. Upon saving data, the user will encounter a dialogue box. A default path for the data will be displayed on the left hand side. This path can be changed by double-clicking the left mouse button on the directory that contains the wanted file or by pressing the **UP** (↑) or **DOWN** (↓) arrow to highlight the directory followed by **ENTER** (↵). On the right hand side, a files list box displays the names of the files in that directory. Type in a different name (unless a previous file is to be overwritten) followed by **ENTER** (↵). If **cancel** is chosen, the user will automatically exit from EPOPS.
- *Main Menu*
If this option is enabled, it takes the user back to the main menu. All the Data input options are enabled. If all the data has been entered Run simulation is also enabled otherwise it is disabled.
- *Report*
This option is only enabled after a simulation has been run. When enabled, this option allows the user to produce a summary report of the expansion plan. It includes the data and simulation run results.
- *Print*
This option is only enabled after a simulation has been run. When enabled, this option allows the user to print the current screen. If the screen to be printed is a graph, it cannot be saved to disk (a limitation of Kappa-PC) and a message appears on the screen warning the user. A text screen can be saved to file as well as be printed. The procedure for saving is the same as *save* described above.
- *Exit*
This option is used to quit from EPOPS. Confirmation is required for this action and once received, the user has to choose whether to save the data of the study plan. If the information is to be saved, the user must provide a filename.

Help Menu Option

Help Index

Use this command to display the opening screen of Help. From the opening screen, you can jump to step-by-step instructions for using EPOPS and various types of reference information.

To use the Help Index

> Do one of the following:

- Click an underlined topic.
- Press the TAB key until you highlight the topic you want, and then press the ENTER key.

To scroll in the Help window

> Do one of the following:

- Press ↓ and ↑.
- Use the scroll bars with the mouse.

To return to the previous topic

> Click the Back button or press the B key.

To open the Search feature in Help

> Click the Search button or press the S key.

To close the Help window

> From Help's File menu, choose Exit (ALT, F, X).

For complete instructions on how to use Help, press the F1 key while the Help window is active.

Missing Values

This option is only enabled while the user is in the main menu. Use this command to display a text box that will inform which menu options need to be activated to fill in the missing data.

About EPOPS

Use this command to display the version number of your copy of EPOPS, the copyright notice, and Email address for software support.

Data Input Options

There are five items within the "Data input option". Some of these are commands while others have cascading menus which are denoted by an arrow (▷).

General Data

As part of error checking, if any of the boxes inside general data are left empty, EPOPS will generate an error message which is repeatedly displayed upon trying to exit the input form until all the boxes are filled.

- *start year of study*
The start year of a study can be as far ahead as required, although the exactness of data is likely to decrease over time. As a consequence the results will become less

accurate, although if we assume an equal margin of error, the results will still allow some conclusion to be reached.

- *end year of study*

The final year in the study plan must be at least one year greater than the start year (in order to make it a yearly planner) but less than thirty years (the limit of the program). A usual study length is in the region of 15 to 20 years - this is within the lifetime of the generating plants.

- *number of periods per year*

This value represents the number of periods into which a year is split. The default is set at 1 to reduce calculation time although load demand in a year can be more accurately represented if there are 4 periods (1 for each season). The drawback of choosing a large number of periods is that a larger volume of information regarding the load duration curve (polynomial coefficients or (x,y) co-ordinates and load ratios) is required for each period.

- *domestic discount rate*

This represents a single discount rate to be applied to all domestic costs for all years in the study.

- *foreign discount rate*

A single discount rate applied to all foreign costs incurred during the study plan years.

- *emission calculations*

The user is given the option of whether to calculate the cost of emissions or not. If 'no calculation' is chosen, the Fuel constituent in both existing and expansion plant options is disabled as well as the Emissions option in Data input options.

- *unsupplied energy calculations*

The user is given the option of whether to calculate the cost of unsupplied energy or not. If 'calculation' is chosen, the user is required to input a value (\$/kWh) which enables EPOPS to calculate a monetary amount based on the loss of electricity to the customer.

If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Demand Data

The electricity demanded by consumers changes continuously from day to day, month to month and year to year. It is possible to chart demand against time to achieve a load duration curve. This curve depicts the percentage of time a specific load is exceeded.

The user is required to enter three variable to simulate this curve.

Peak Load

Peak load is the maximum amount of electricity that is expected to be demanded in the year. In this option the user is required to enter the peak load (MW) of every year in the study. Depending upon the number of years in the study, the user may have to wait a while as the input screen is been generated.

There are two ways to move around the screen. The user can either point the mouse pointer over the data entry box and click the left mouse button, or press the **Tab** to cycle round all the entry points.

To exit, either click on the mouse over 'continue' on the menu bar or press **Alt c**. This is only possible once all the data has been entered. As with all data entry boxes if any are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are correctly filled.

Peak Load Ratio

The peak load ratio represents the ratio of period peak load to the annual peak load. It is only necessary to fill in this data if the years are split into more than one period, as the peak load ratio for each year with only one period is automatically set to 1.

If there are many years in the study, the user will have to wait for a couple of seconds while the screen is being generated. If the study is greater that 15 years, there are two screens, one after the other.

There are two ways to move around the screen. The user can either point the mouse pointer over the data entry box and click the left mouse button, or press the **Tab** to cycle round all the entry points.

To exit, either click on the mouse over 'continue' on the menu bar or press **Alt c**. This is only possible once all the data has been entered. As with all data entry boxes if any are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled.

Load Duration Curve

In EPOPS there are two methods to represent the load duration curve; (x,y) co-ordinates and 5th order polynomials. The first time 'load duration curve' is accessed the user is presented with a choice of how to represent the curve. Once a choice has been made it cannot be reversed.

In EPOPS the load duration curves are simulated in the calculations through the use of polynomials, therefore if the x-y co-ordinate data entry method is used, extra

computation time is needed while EPOPS determines polynomial coefficients from the co-ordinates given by the user.

The user must choose on a multiple menu which years to edit. By clicking the left mouse button over individual years, the chosen years for data entry/amendment are highlighted. Press **ENTER** (↵) or **OK** button to continue. The first year of the study plan is automatically highlighted. If the user does not wish to view this year de-highlight that option. If no years are chosen, EPOPS will automatically display the values in the first year.

Co-ordinates

Load demand values must be normalised in order to be understood by EPOPS. EPOPS has been developed to accept the number of x-y co-ordinates entered by the user to lie between the minimum and maximum limits of 6 and 30 respectively. The minimum limit of 6 was chosen to ensure that a fifth order polynomial could be represented (see below), while the upper limit of 30 was the maximum number of data points that could be displayed on the screen. From tests it has been found that the minimum of 6 data points is sufficiently accurate enough to represent a load duration curve, with more data points showing only a very marginal improvement in accuracy but significant additional computation time.

There are two mathematical methods of converting the (x,y) co-ordinates into polynomial coefficients:

- *least fit*
This is the preferred method as calculation time is reduced. From the n number of (x,y) co-ordinates entered by the user, EPOPS determines a 5th order polynomial that best approximates the curve. The 5th order polynomial was chosen because it was found to accurately represent the curve while requiring little computational time.
- *exact fit*
This option was included to allow the user to precisely define the load duration curve. This method however is not recommended as the computational time may be high. If the user inputs n+1 data points of a load duration curve, EPOPS determines the only one polynomial of degree n or less that passes exactly through all the supplied co-ordinates.

There are two ways to move around the screen. The user can either point the mouse pointer over the data entry box and click the left mouse button, or press the **Tab** to cycle round all the entry points.

To exit, either click on the mouse over 'continue' on the menu bar or press **Alt c**. This is only possible once all the data has been entered. As with all data entry boxes if any are left blank, contain non-numeric values or are outwith the numeric limits

EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled.

Coefficients

Load duration curves can be represented in the form of an nth order polynomial. In EPOPS the load duration curve is represented by a 5th order polynomial for ease and because it was found to accurately represent the curve while requiring little computational time. The curve equation takes the form :

$$y = c_0 + c_1x^1 + c_2x^2 + c_3x^3 + c_4x^4 + c_5x^5$$

where y is the load magnitude for a given time duration x, c0 is the constant coefficient (usually 1) and c1, c2, ... c5 the first, second, ..., fifth order coefficients.

This is the quickest option to represent the load duration curve in EPOPS as it requires no extra computational time. It does, however, require the user to have previous knowledge on the coefficient values of a fifth order polynomial to represent the load duration curve for each period in each year of the study.

There are two ways to move around the screen. The user can either point the mouse pointer over the data entry box and click the left mouse button, or press the **Tab** to cycle round all the entry points.

To exit, either click on the mouse over 'continue' on the menu bar or press **Alt c**. This is only possible once all the data has been entered. As with all data entry boxes if any are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled.

Reliability

Reliability Index

This is a measure of generating system reliability with respect to a load being served. In this context, the use of the word "probability" is misleading as in fact, mathematically, the quantity calculated is an expected value, not a probability. A list of reliability index options is given in the software. It is recommended to use either "Standard Percentage" or "Loss of Largest" as the "Loss of Load Probability" (LOLP) calculation is inaccurate and increases computing time considerably. The reason it is included is because it is often a requirement of banks/loaners that this calculation should be conducted before any money changes hands.

If LOLP is chosen, the user must supply a critical value of annual LOLP (%). This value (%) determines which least cost solutions will be considered. Any values of LOLP that are greater than this critical value will be rejected. The default value is 100%.

If the reliability index entry box or critical value of annual LOLP is left blank, contains a non-numeric value or has a value less than zero EPOPS will generate an error message that is repeatedly displayed upon trying to exit until the box is correctly filled.

Reserve Margins

The user must choose on a multiple menu which years to edit. By clicking the left mouse button over individual years, the chosen years for data entry/amendment are highlighted. Press **ENTER** (↵) or **OK** button to continue. The first year of the study plan is automatically highlighted. If the user does not wish to view this year de-highlight that option. If no years are chosen, EPOPS will automatically display the values in the first year.

- *Minimum reserve margin*
Minimum permissible reserve margin (% of peak load) in the critical period. The reserve is the difference between capacity and load. It is a rough measure of the potential operating reliability of the system for the year.
- *Maximum reserve margin*
Maximum permissible reserve margin (% of peak load) in the critical period.

If either of the entry boxes are left blank, contain non-numeric values or have values that are less than zero EPOPS will generate an error message that is repeatedly displayed upon trying to exit until the boxes are correctly filled. If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Station Information

Existing Plant

Existing plant refers to stations that are already generating or committed (i.e. plans for their future generation have been granted and loans endorsed even though the plant may not yet exist).

Add/Delete Plant Names

When this choice is activated, the user has three choices:

- *Add*
If "Add" is chosen, the user must type, separately, the names of the thermal power plants being used in the study plan. In the existing option the user must also include plants that are committed even though they may not be operating in the first few years of the study. If the user types in a plant name already present, EPOPS will generate an error message warning the user. Once all the thermal plant names have been typed in, the user must type "q" or "Q" to exit.

- *Delete*

If "Delete" is chosen, the user will be asked if they really want to delete a plant name. If the answer is "yes", the user is shown a list of the plant names. The user must choose which names to delete by highlighting the names to delete using the left mouse button and then press **OK**. The first plant name on the list is always automatically highlighted. Care must be taken to de-select this name if it is not to be deleted from the list. The number of names to be deleted is shown and if the user is happy they must choose "yes" otherwise to ignore everything choose "no".

⊗ Care must be taken when deleting. If a plant name is deleted all the plant's data is also deleted.

- *Cancel*

If the user is using a previous study and has forgotten which plants were included, it is best to use this option to view the plant names and then choose "Cancel". In this case nothing is altered.

Unit Description

For each of the plant names entered above, the user must fill in the plant description. If any of the entry boxes are left blank EPOPS will generate an error message that is repeatedly displayed upon trying to exit until the boxes are filled.

- *Fuel type*

At present the user is offered a choice of three different fuel types. These options can be found in the pull down list on the right. To pull the menu list down click the left mouse button on the arrow (↓). Move the pointer over the required fuel type and again click the left mouse button.

- *No. of units*

This value represents the number of fixed identical units at the beginning of the study.

- *Min. operating level*

This is the minimum operating level (MWe) of each unit.

- *Max. capacity*

This represents the maximum generating capacity (MWe).

- *Base load heat rate*

This number represents the heat rate (MJ/kWh) at the minimum operating level. (The heat rate is a measure of the thermal input energy [kcal] of fuel needed to produce 1 kWh.)

- *Average incremental heat rate*

This value represents the average incremental heat rate (MJ/kWh) between minimum and maximum operating levels.

- *Domestic fuel costs*
This is the domestic cost of fuel (\$/GJ).
- *Domestic fuel use*
This value is the percentage of hours per period domestic fuel is used (%).
- *Foreign fuel costs*
This is the foreign cost of fuel (\$/GJ).
- *Foreign fuel use*
This value is the percentage of hours per period foreign fuel is used (%).
- *Fixed OM*
This value represents the fixed component of non-fuel operation and maintenance costs (\$/kW per annum) of each unit; it is assumed to be a domestic cost. These costs are relatively independent of the operation of the generating unit. Costs include labour expenses of operation and maintenance personnel, administrative personnel and miscellaneous supply costs. If emission costs are to be considered, the OM costs must also consider clean-up operation costs.
- *Variable OM*
This field contains the variable component of non fuel operation and maintenance cost (\$/MWh) of each unit; it is assumed to be a domestic cost. These costs are approximately direct functions of the energy output of the unit. Costs include replacement parts, lubricants and other supplies whose consumption is due to unit operation. Maintenance procedures and inspections performed relating to hours of unit operation must also be accounted for.
- *Maximum nominal output*
This field contains a percentage that represents the maximum level at which a unit should be normally be operated at. If this value is less than 100%, it leaves a reserve that can be called upon in dire emergency.
- *Spinning reserve capability*
This value represents the percentage of unit output to be set aside as spinning reserve (%).
- *Forced outage rate*
This number represents the equivalent full forced outage rate (% of the time)
- *No. of units for scheduled maintenance*
This value represents the number of units within the station that will be out for scheduled maintenance during the year.

- *Scheduled maintenance per unit*

This value represents the number of days per year required for scheduled maintenance of each unit.

If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Multiplying Factors

The annual multiplying factors for each year are a provision against escalating operating and fuel costs. Initially the user is asked which years are to be viewed. The user must choose which years to enter/amend by highlighting the years using the left mouse button and then press **OK**. The first year on the list is always automatically highlighted. Care must be taken to de-select this year if it is not required. Multiplying factors must be entered for every existing plant in the study.

- *Domestic annual operating cost multiplying factor*

This field contains the domestic annual multiplying factor for domestic operating cost for each expansion candidate. The default value is 1. The effect of this value is cumulative.

- *Domestic annual fuel cost multiplying factor*

This field contains the domestic annual multiplying factor for domestic fuel cost for each expansion candidate. The default value is 1.

- *Foreign annual fuel cost multiplying factor*

This field contains the foreign annual multiplying factor for foreign fuel cost for each expansion candidate. The default value is 1.

If any of the entry boxes are left blank, contain non-numeric values or values less than 0, EPOPS will generate an error message that is repeatedly displayed upon trying to exit until the boxes are correctly filled. If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Additions and Retirements

In EPOPS it is only possible to retire units of existing stations. Initially the user is asked which existing plants are to be considered. The user must choose which plants to enter/amend by highlighting the names in the list box using the left mouse button and then press **OK**. The first name on the list is always automatically highlighted. Care must be taken to de-select this if it is not required.

There are two ways to move around the addition/retirement screen. The user can either point the mouse pointer over the data entry box and click the left mouse button, or press the **Tab** to cycle round all the entry points.

The text at the top of the screen reminds the user how many units exist in the plant. No more than this number can be retired unless additional units are added in previous years. A minus sign (-) denotes retirement. The default value for the number of plant units to be retired each year is zero. If the user tries to retire more units than actually exist, an error warning is given.

To exit, either click on the mouse over 'continue' on the menu bar or press **Alt c**. This is only possible once all the data has been entered. As with all data entry boxes if any are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are correctly filled.

Fuel Constituents

If the option to include emission calculations was chosen in general data, this option will be enabled otherwise it will appear dimmed on the menu bar and inaccessible.

Elemental Composition

The user must choose which plants to enter/amend by highlighting the names in the list box using the left mouse button and then press **OK**. The first name on the list is always automatically highlighted. Care must be taken to de-select this if it is not required.

The elemental composition of coal and oil can be split into:

- carbon
- nitrogen
- sulphur
- ash

The elemental composition of gas can be split into:

- methane
- ethane
- propane
- butane
- pentane
- hexane

The compositions must be entered as percentages. The aggregate total of composition percentages should be equal to or less than 100%. If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Calorific Value

This value (MJ/kg) determines how many kilograms of fuel have to be burned to produce 1 MJ of energy. The user must choose which plants to enter/amend by highlighting the names in the list box using the left mouse button and then press **OK**. The first name on the list is always automatically highlighted. Care must be taken to de-select this if it is not required.

If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled.

Expansion Plant

At present only three expansion plants can be examined.

Add/Delete Plant Name

This is the same as add/delete plant names in existing plants.

Unit Description

This is the same as unit description in existing plants except that the *no. of units* is not required as that is what EPOPS is to calculate.

Economic Values

The user must choose which plants to enter/amend data by highlighting the names in the list box using the left mouse button and then press **OK**. The first name on the list is always automatically highlighted. Care must be taken to de-select this if it is not required.

- *Depreciable domestic capital cost*
This field contains the depreciable domestic capital cost (\$/kW) of each expansion candidate. If emission calculations are to be included, the user must remember to include emission reduction capital costs (i.e. flue gas desulphurisation FGD).
- *Depreciable foreign capital cost*
This field contains the depreciable foreign capital cost (\$/kW) of each expansion candidate.
- *Plant life*
This value of plant life is used to calculate the salvage value. The lifetime of a plant (in years) is determined more on economic parameters than wear-out. Newer and more efficient plants cause existing plants to become obsolete before their time.

- *Non-depreciable domestic capital cost*
This value is measured in \$/kW and represents a one-off payment in the first operational year of the generating unit and unlike the capital cost is not spread over the construction period.
- *Non-depreciable foreign capital cost*
This value is measured in \$/kW.
- *Interest during construction*
The interest during construction is expressed as a percentage of total domestic and foreign capital costs that has been included in depreciable domestic and foreign capital costs.
- *Construction time*
This value represents the time require to construct the expansion candidate.
- *Salvage value at end of plant life*
The default for the salvage value is \$0 but if either the plant or the land it is built on will be worth anything at the end of the plant life it must be entered here.

If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Multiplying Factor

The annual multiplying factors for each year are a provision against escalating operating and fuel costs. Initially the user is asked which years are to be viewed. The user must choose which years to enter/amend by highlighting the years using the left mouse button and then press **OK**. The first year on the list is always automatically highlighted. Care must be taken to de-select this year if it is not required. Multiplying factors must be entered for every expansion plant in the study.

- *Domestic annual capital cost multiplying factor*
This field contains the domestic annual multiplying factor for domestic capital cost for each expansion candidate. The default value is 1. This factor is cumulative.
- *Foreign annual capital cost multiplying factor*
This field contains the foreign annual multiplying factor of foreign cost for each expansion candidate. The default value is 1. This factor is cumulative.

- *Domestic annual operating cost multiplying factor*
This field contains the domestic annual multiplying factor for domestic operating cost for each expansion candidate. The default value is 1. This factor is cumulative.
- *Domestic annual fuel cost multiplying factor*
This field contains the domestic annual multiplying factor for domestic fuel cost for each expansion candidate. The default value is 1.
- *Foreign annual fuel cost multiplying factor*
This field contains the foreign annual multiplying factor for foreign fuel cost for each expansion candidate. The default value is 1.
- *Maximum units to be added*
This field contains a value that represents the maximum number of units for each expansion candidate that the user wishes to be used in the year. The default value is 50.

If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Fuel Constituents

This is the same as Fuel constituents for existing plants.

Emissions

Abatement Control

If abatement control is to be considered, the user must enter the abatement levels of CO₂, SO₂, NO_x and ash for each plant in the study. The value entered must be the percentage expected as a result of emission abatement equipment. The user must then enter abatement installation and operation costs for each emission.

If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any abatement level by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the abatement levels, the user must select the **OK** button.

Carbon Taxation

If carbon taxation is to be considered, the user must enter a taxation value. This value is multiplied by the amount of carbon present in the fuel.

If any values are left blank or contain non-numeric values EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any charge value by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the emission charges, the user must select the **OK** button.

Emission Penalties

If emission penalties are to be considered, charges for each kilogram of emission (CO_2 , SO_2 , NO_x and ash) must be entered. These values when multiplied by the amount of each output produced represent the societal cost of emissions.

If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any charge value by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the emission charges, the user must select the **OK** button.

Trading Permits

If trading permits are to be considered the user must enter values for:

- *no. of permits*
This is the number of permits that the Utility holds. Each permit allows for the emission of one tonne of a particular combustion gas, i.e. a sulphur permit allows one tonne of SO_2 to be released into the atmosphere.
- *cost per permit*
This is the cost to buy one permit. The cost is expressed in dollars (\$).
- *penalty*
This is the penalty cost that the Utility incurs when they release emissions above their quota limit. This cost is expressed in \$/tonne.
- *selling price*
If the Utilities are to sell any excess permits (i.e. if they emit below their allowed levels), the user must input a selling price expressed in \$/permit.

If any values are left blank, contain non-numeric values or are outwith the numeric limits EPOPS will generate an error message that is repeatedly displayed upon trying to exit until all the boxes are filled. If the user changes any values by mistake, all values will be reverted back to the original values by selecting the **reset** button. To accept the values, the user must select the **OK** button.

Run Simulation

This option will only become enabled once all the data has been entered. This measure is included to ensure that the program will run as smoothly as possible

without falling over. Once the simulations option has been chosen, there is no user interaction until all the possible combinations to meet demand for each year in the study plan have been determined (the cursor shape will change into an hourglass until the simulation is complete). A slider at the bottom of the screen indicates the percentage of years simulated while the box at the bottom shows the number of combinations.

Results

Total Cost Graph

This graph shows the top twenty cheapest expansion plan costs. These costs are the summation of traditional costs (construction, operation and maintenance costs) and emission costs (if they are to be considered). The costs are expressed in dollars (\$). There is an option as to view the costs as a line graph, a bar chart or a pie chart. At present only the line graph option is available.

The graph can be printed by selecting the 'print' option from the File menu.

To continue, either position the mouse pointer over 'continue' on the menu bar or press **Alt c**.

Expansion Plan Breakdown

This screen shows the breakdown of the expansion plan. The text box in the middle of the screen shows how many units for each expansion plant *must be operating* in each year of the study and the cost of running the system for each year. At the bottom of the text box, the total cost over the study plan is given.

Each expansion plan is given an option number, 1 for the cheapest, 2 for next cheapest, etc. To view the next cheapest option, the user should select 'Next option' on the menu bar. The user will be presented with an input box to enter the required option number. The option number is automatically incremented by one. If the user changes the option number by mistake, it can be reverted back to the original number by selecting the **reset** button. If the user chooses a number that is greater than the number of expansion plans then EPOPS displays an error message and decrements the number by one. To accept the option number, the user must select the **OK** button.

The text box can be printed by selecting the 'print' option from the File menu.

At any time, the user can view the total cost graph by choosing the same title on the menu bar (**Alt c**).

Emission Graphs

When this option is chosen, four graphs are shown one after the other. The graphs show the total emission levels of the four outputs (CO₂, SO₂, NO_x and ash) from all the plants in the system for each year in the study. The emission levels are displayed

as kg/hour. The option number of the expansion plan is shown in the top middle of the graph.

The graphs can be printed by selecting the 'print' option from the File menu.

To continue from each graph, either position the mouse pointer over 'continue' on the menu bar or press **Alt c**. At any time the user can view the expansion plan breakdown by choosing expansion plan breakdown on the menu. Choose back to return to the emission graphs.

Emission Table

When this option is chosen, a table of the emission levels of the four outputs (CO₂, SO₂, NO_x and ash) from all the plants in the system for each year in the study is shown. (It is the same data as shown in Emission graphs but in tabular form).

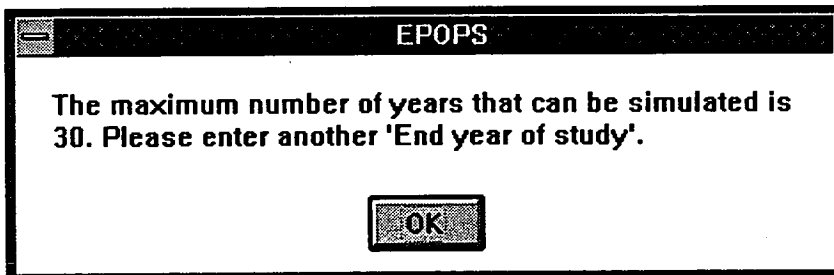
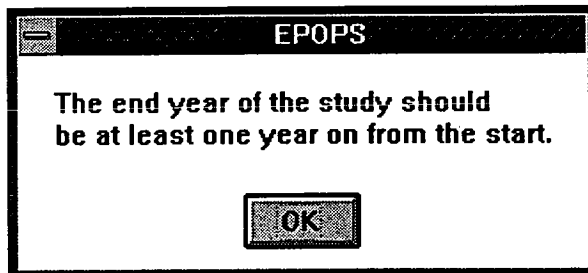
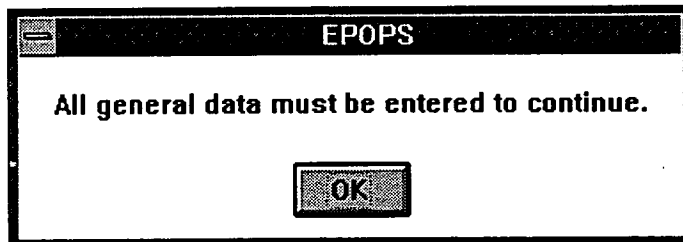
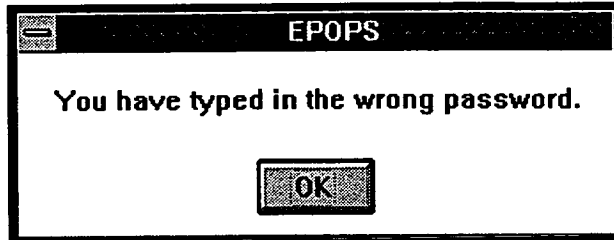
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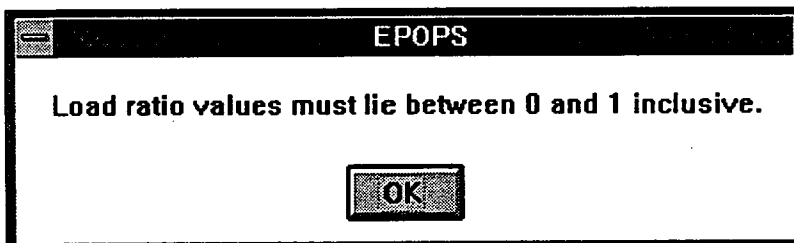
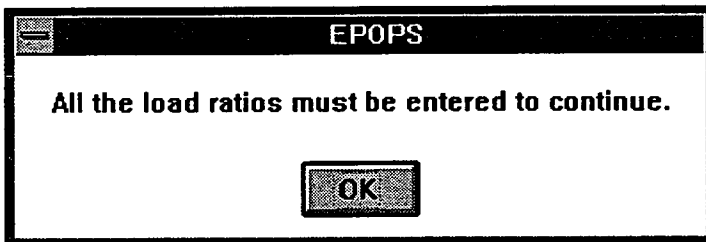
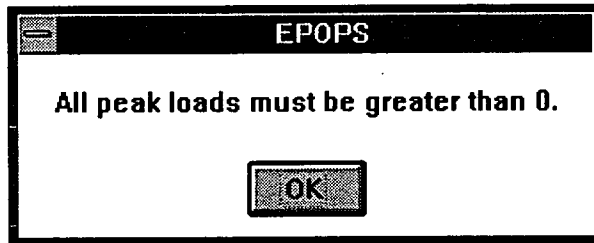
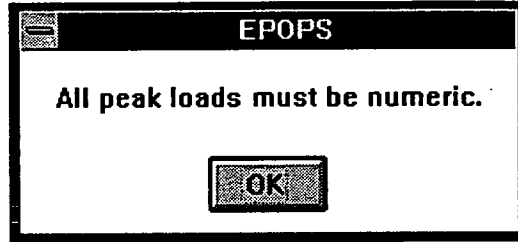
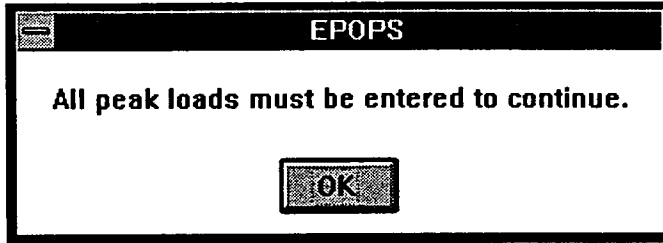
To continue, either position the mouse pointer over 'expansion plan breakdown' on the menu bar or press **Alt e**.

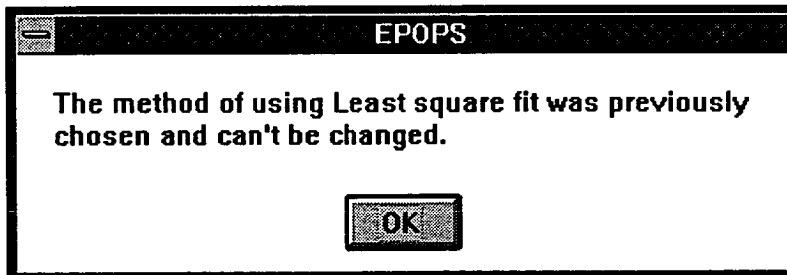
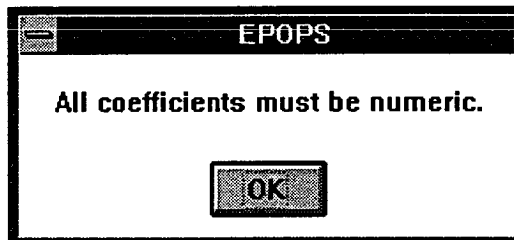
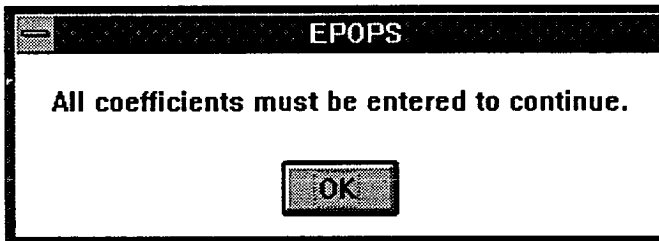
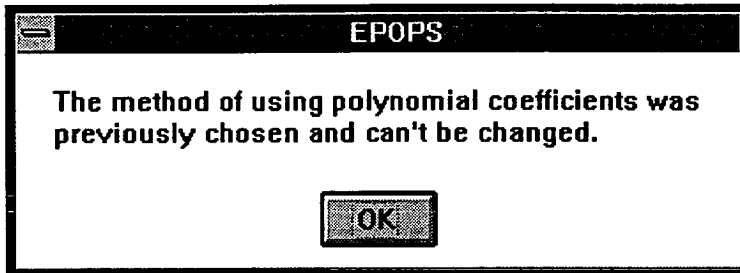
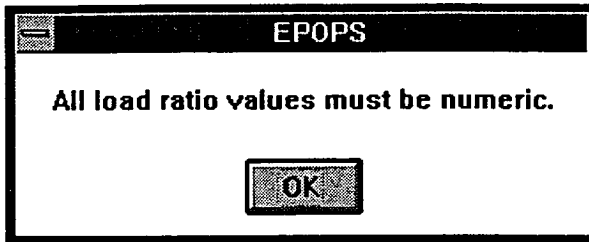
APPENDIX A.2

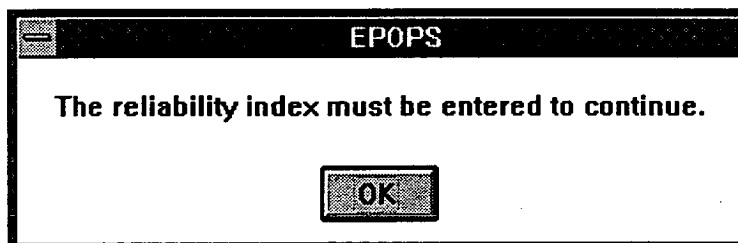
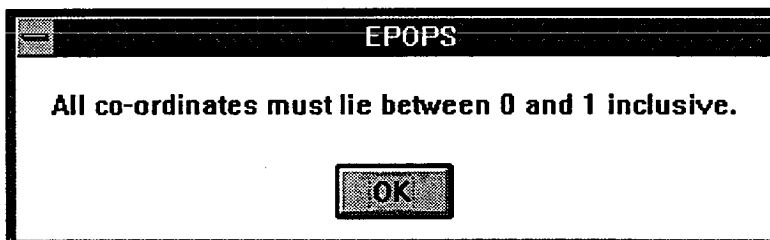
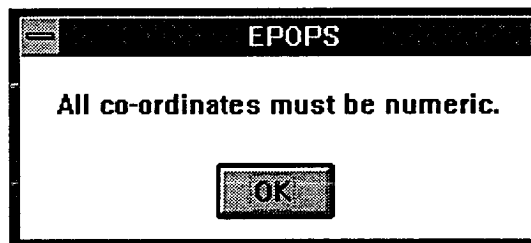
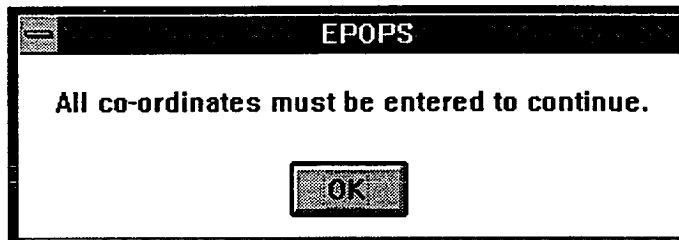
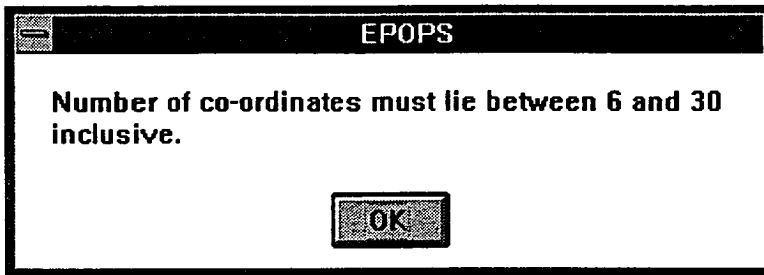
ERROR TRAPPING MESSAGES

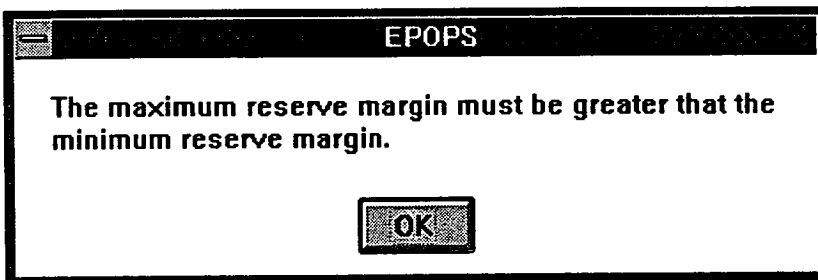
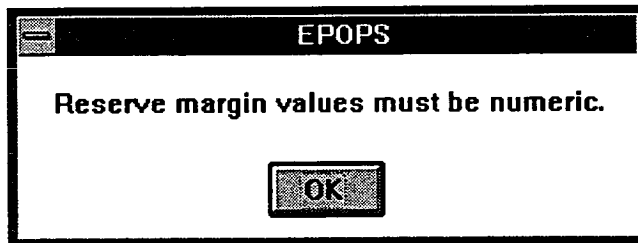
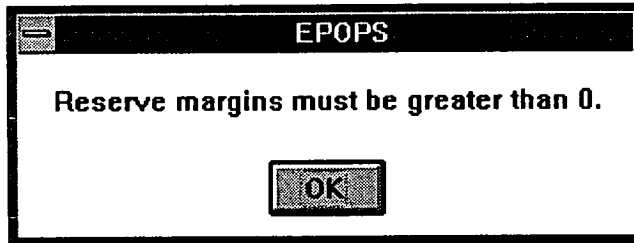
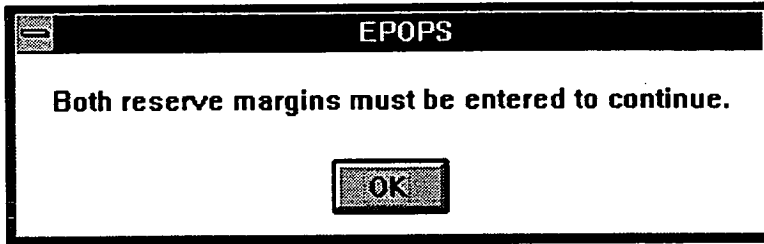
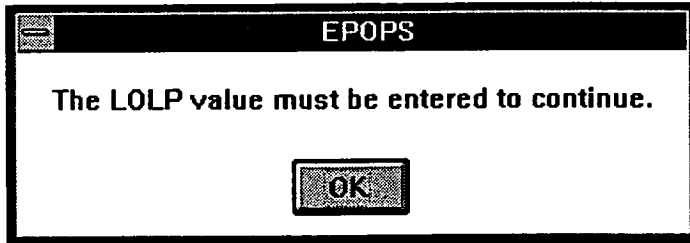
Error messages produced by EPOPS.

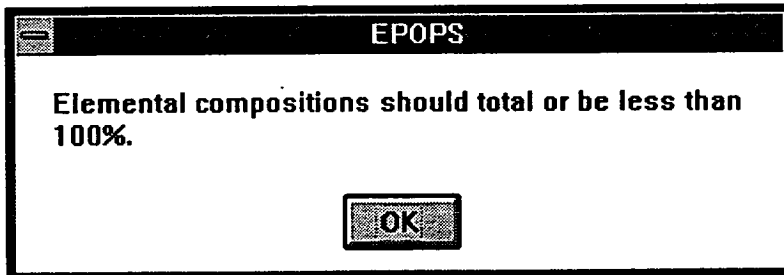
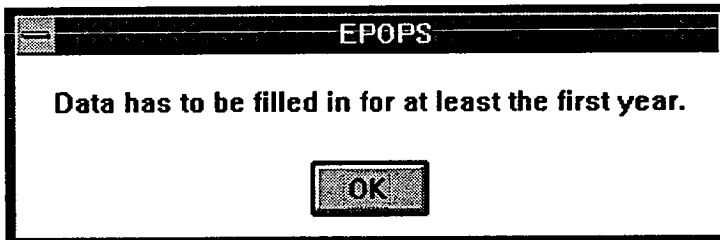
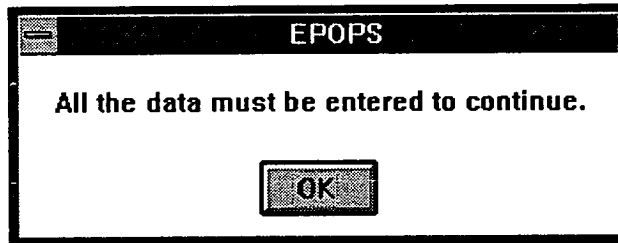
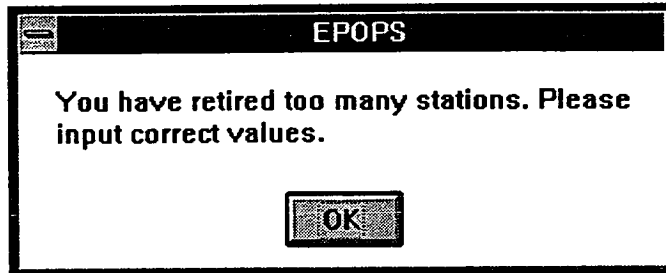
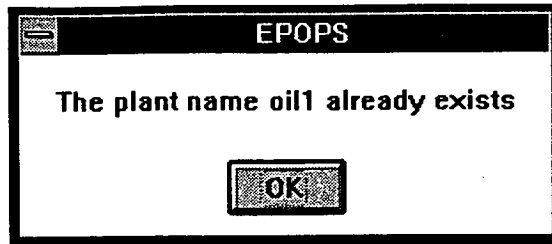


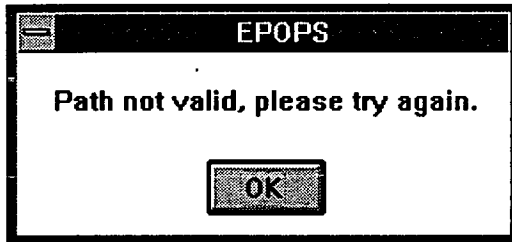
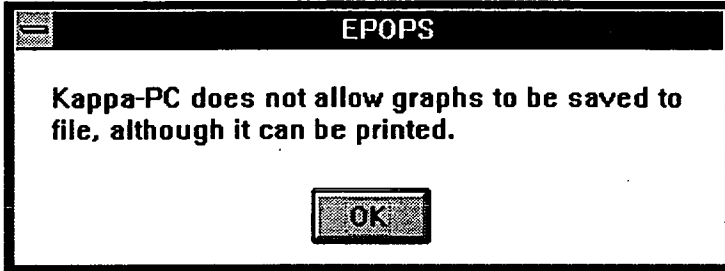
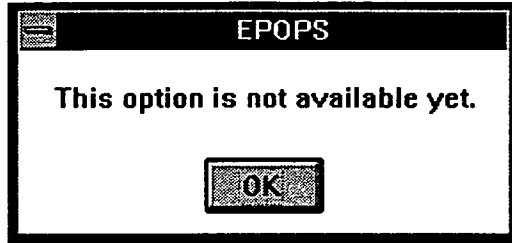




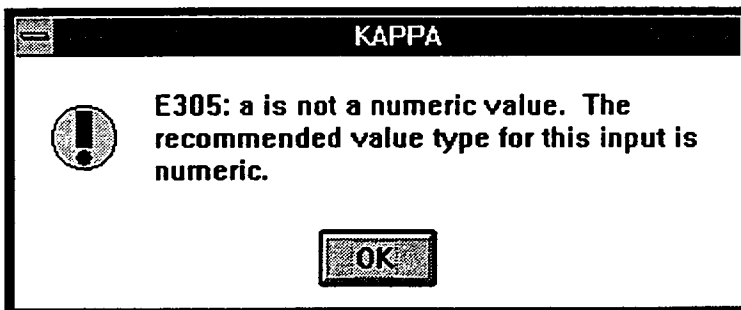
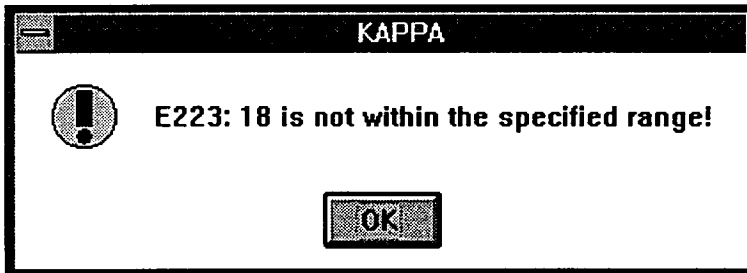


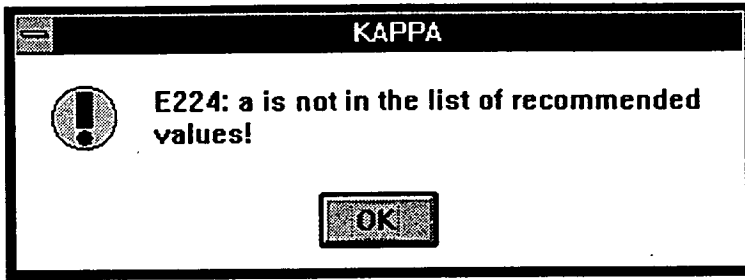






Some of the more common error messages produced by Kappa-PC.





APPENDIX A.3

METHODS

AboutE pops - displays copyright details.

AddRetire - determines which plants user wants to access.

AddRetireContinue - returns to main menu and deletes unit addition/retirement screen.

Calculations - method which calls all relevant calculating functions.

Calorific - displays an input form to enable user to type in calorific value.

Change - change to option to view.

Charges - displays an input form to enable user to type in charges for emissions.

CoefficientContinue - returns to main menu and deletes coefficient data screen.

CoordinateContinue - returns to main menu and deletes co-ordinate data screen.

DescriptionContinue - returns to main menu.

Disable - disables menu items.

Economic - displays an input form to enable user to type in economic data for expansion plants.

EmissionGraphContinue - initialises the emission graphs.

EmissionGraphPrint - prints emission graphs.

ExistingAnnual - displays an input form to enable user to type in annual data for existing plant.

ExistingComposition - determines which existing plants user wants to access.

ExistingUnit - displays an input form to enable user to type in data about existing plants.

ExpansionAnnual - displays an input form to enable user to type in annual data for expansion plants.

ExpansionComposition - determines which expansion plants user wants to access.

ExpansionUnit - displays an input form to enable user to type in data about expansion plants.

Appendix A.3 : Methods

FillinYearlyBlanks - blank yearly slots take on the previous year's value.

GeneralData - displays an input form to enable user to type in all general data.

GraphContinue - returns to main menu and deletes graph screen.

GraphPrint - prints graph.

HelpIndex - calls up on-line help file.

LoadDurationCurve - determines which representational method is to be used.

LoadRatio - creates and displays screen for inputting load ratio data.

LoadRatioContinue - returns to main menu and deletes load ratio screen.

MainMenu - shows the main menu screen.

NewFile - deletes existing study plan and loads in a new one.

Password - checks whether the user has typed the correct password. The user is given three chances before EPOPS automatically closes.

PeakLoad - creates and displays screen for inputting peak load data.

PeakLoadContinue - returns to main menu and deletes peak load screen.

Plant - choice of adding or deleting a plant from the study.

Quit - closes down EPOPS.

ResultContinue - continues to emission graph screen.

ResultPrint - prints results.

RetrieveExisting - loads in an existing study plan.

RetrieveNew - loads in the new study plan template.

SaveFile - saves all the data of the study plan to a *.kal file.

Yearly - displays an input form to enable user to type in all yearly data.

APPENDIX A.4

FUNCTIONS

AddPlantName - adds a plant to the study.

AddRetirePlants - displays unit addition/retirement screen.

AnnualCost - calculates capital recovery costs for expansion plants.

CalcSystemCost - calculates cost of each combination.

CalcTotalCapacity - determines total capacity of existing plants.

ChangePassword - allows the user to change the password.

CheckAddRetire - checks that no more than available units are retired.

CoalOilCalculations - calculates emissions from coal and oil burning.

CoalOilGather - displays an input form to enable user to type in composition of coal or oil.

Coefficients - creates coefficient data screen.

Combinations - determines unit combinations of expansion plant.

Coordinates - creates co-ordinates data screen.

CreateYearInstance - creates instances for each year in the study.

CriticalPeriod - finds critical period in the year.

DeletePlantName - deletes a plant from the study.

DemandLimits - finds minimum and maximum expansion generation limits.

DisplayCoefficients - displays coefficient data screen.

DisplayCoordinates - displays co-ordinates data screen.

DisplayEmissionValues - displays the values of gaseous emissions for each option.

DisplayPlantNames - displays plant names on the main menu screen.

DisplayUnitResult - displays unit combinations for each year for a particular option.

EmissionCosts - calculates emission costs.

EmissionOutput - calls relevant emission calculations function.

EnableBack - enables the option back on the result screen.

Appendix A.4 : Functions

EnableCalculations - determines if all the data has been inputted before it enables the user to begin calculations.

EnableStationOptions - enables menu options related to station data.

GasCalculations - calculates emissions from gas burning.

GasGather - displays an input form to enable user to type in composition of gas.

GetYears - determines which years the user wants to edit.

MultiplyingFactors - ensures multiplying factors are all entered.

MultValues - if no multiplying factor is present, copies from previous year.

PresentValue - calculates present value of costs.

ScheduledMaintenanceHours - calculates number of hours needed for scheduled maintenance.

StationMaxUnits - determines maximum number of unit each expansion plant can have.

ThermalOrder - determines merit order of load duration curve.

UncheckMenuItems - enables all the menu items in the main menu.

APPENDIX A.5

C FUNCTIONS

addretir - creates unit addition/retirement data screen.

changedir - changes the current working to a specified directory.

check - determines if unit combinations are compatible with previous combinations.

cursor - changes the cursor shape.

emissgraph - gets values for emission graphs.

exactcoeff - finds the exact number of polynomial coefficients to represent load duration curve.

getdir - retrieves the current working directory.

graph - gets values for a cost graph.

leastcoeff - finds a 5th order polynomial coefficients to represent load duration curve.

loadfactor - calculates load factor of each plant in load duration curve.

rename - renames files.

repeatcomb - repeat copying of unit combinations to a text file.

results - gets results from the text file.

secant - finds x ordinate from y ordinate.

sort - sorts options into cheapest first.

APPENDIX A.6

RULES

Emission1 - determines if abatement occurs.

Emission2 - determines if carbon taxing occurs.

Emission3 - determines if permit trading occurs.

Largest - determines if reliability passes loss-of-largest generator test.

LossofLoadProb - determines if reliability passes loss-of-load probability test.

Reliability1 - determines if reliability test is standard percentage.

Reliability2 - determines if reliability test is loss-of-largest.

Reliability3 - determines if reliability test is LOLP.

Standard - determines if reliability passes standard percentage generator test.

APPENDIX A.7

PAPER SUBMITTED TO

**PROCEEDINGS OF THE 29TH UNIVERSITIES
POWER ENGINEERING CONFERENCE 1994.**

LEAST COST EXPANSION PLANNING OF ELECTRICITY SUPPLY

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ABSTRACT

When electricity demand increases, generating authorities must decide which option for system expansion to take. This paper describes decision support software which has been written to ease the task undertaken by system planners.

1. ELECTRICITY DEMAND AND SUPPLY

The high standard of living enjoyed in developed countries, supported by modern technology, depends largely on the consumption of fossil fuels and the depletion of natural resources. As population becomes accustomed to the wide-scale use of energy and industries are established to manufacture energy consuming products, the rate of use of energy demand far outstrips the growth rate of population. For example, figure 1 shows the increase in Western Europe population over a five year period. This growth rate of around 0.3% per annum may be contrasted with the growth rate of 1% per annum in energy demand, shown in figure 2.

Population in Europe (million)

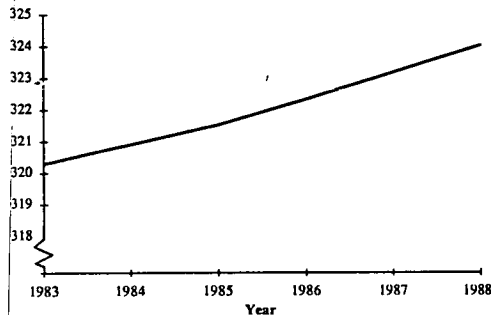


Figure 1: Population growth in Western Europe

Gross consumption per capita (kgpe)

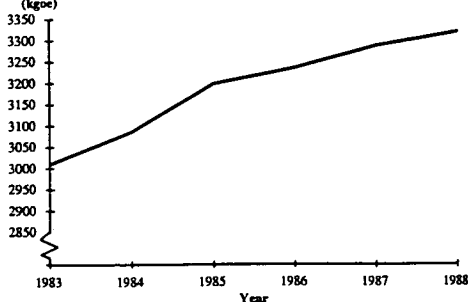


Figure 2: Consumer growth in Western Europe

It has been estimated that the total European electricity demand in 1990 was in the region of 1720 TWh [1]. Although predictions are traditionally difficult to make accurately, it is certain that electricity demand will increase. Estimates range from 16 to 37% by the year 2000 and by up to 45% by 2010. It is the electricity Utility's responsibility to supply all of its customers. There are three methods of achieving this goal:

- Demand side management
The use of load management which does not alter the users' lifestyle can result in reduced peak demands and lessen the need for additional generation.
- Refurbishment
By upgrading existing power stations, it is often possible to generate sufficient additional energy to meet increasing demand.
- Growth
The building of new power stations is sometimes the only solution to cope with increased demand. Many options present themselves to those responsible for the extension of system capacity. Decisions must be made within a framework of financial, technical and environmental constraints. The process of choosing the most acceptable alternative is usually termed "least cost expansion planning" and is the subject of this paper.

2. LEAST COST EXPANSION PLANNING

Electricity Generating Authorities are concerned with minimising the total costs of the electric service to operate at acceptable tariffs while still making a profit or return on investment. In the past this required the Utility to calculate the cost of additional units solely on fuel costs and operation and maintenance costs. However, with the introduction of the Clean Air Act (1990) in America and the European Environment Protection Act (1990) future planning will have to take account of emissions and their cost.

3. LEAST COST EXPANSION PLANNING DECISION SUPPORT SYSTEM

Least cost expansion planning considers in a symmetrical and consistent way the options for supply side expansion. All options are considered on the basis of minimising the total cost of electric services over the planning horizon. In order to determine the least cost solution, the planner needs to consider all potential combinations of possible new power plants that would meet the electricity load requirements and choose the cheapest. The calculations required to do this are numerous.

A decision support system (DSS), a computer package that is able to assist its user in achieving an answer to a set problem, can be very beneficial to least cost expansion planning as it can undertake the tedious, repetitive calculations necessary for all the scenarios under consideration in the plan. Because a DSS may be operated by a less experienced operator the package must have the following features:

- Usability
A computer program should always be "user-friendly" encouraging the user to make use of the package rather than shy away from it. An on-line help manual is an important feature as is on-screen instructions.

- **Incoded calculations**
Users are not generally interested in the calculations being performed. It is best to make them an integral part of the program.
- **Clear Representation**
The results obtained by running a package must be clear and easily understood.

4. CANDIDATE SCENARIOS

In order to meet an ever expanding demand, an electricity Utility must plan in advance what actions are necessary to meet the required capacity. This planning may be short term or long term depending upon the availability of relevant data. A variety of plant mix may be found to meet the demand when considering the various fuel types available for expansion, however not all may be practical. By following sets of rules, a DSS is capable of determining which options to consider and which to discard and in doing so considerably reduces calculation time.

5. NUMERICAL CALCULATIONS

The computation of a least cost expansion plan necessitates the use of a variation of calculations. These calculations can be split into two sections - those concerned with construction and operation costs and those concerned with emission costs. The procedures involved in these two steps can be seen in figures 3 and 4 respectively.

6. CONSTRUCTION AND OPERATION COSTS

Successful operation of power systems requires attention to the provision of service to Utility customers without interruption and at the lowest feasible cost. The problem of providing low-cost electrical energy is affected by such items as efficiencies of power-generating equipment, cost of installation, and fuel costs. Factors involved in the cost of producing energy can be divided into those that are fixed and those that are variable.

- **Fixed Costs**
Fixed costs include capital investment, interest charges on borrowed money, labour and other expenses that continue irrespective of the load on the power system. Persons responsible for the operation of a power system have little control over these costs.
- **Variable Costs**
Variable costs are those which are affected by the loading of generating units of different fuel rates and generation to meet daily load requirements. These costs are materially controlled by power system operators and are proportional to the production of electrical energy.

The total cost (i.e. fixed plus variable costs) must be referred to a base year using the single-payment present-worth function to enable cost comparisons. The simplified flow chart in figure 3 depicts the necessary steps required to obtain a present value for all scenarios under consideration.

Annual Cost

The cost of buying land and other real estate, the cost of designing and planning the station, the cost of building the power plant and equipment and the cost of installation is known as the capital cost. The cost of plant differs with fuel type, the site (urban plots are more expensive) and the location of the plant (costs are higher if transmission lines have to be included). Prices also vary to a great extent in time, depending partly on developments in equipment design and manufacturing techniques but mainly on the state of the market. The annual cost represents a uniform value that must be realised by the generating Utility to compensate for the capital cost expenditure.

Fuel Cost

The fuel consumption depends on the amount of electrical energy produced. The cost of the fuel is different for different types of fuel, depending on their calorific values, availability and transportation charges.

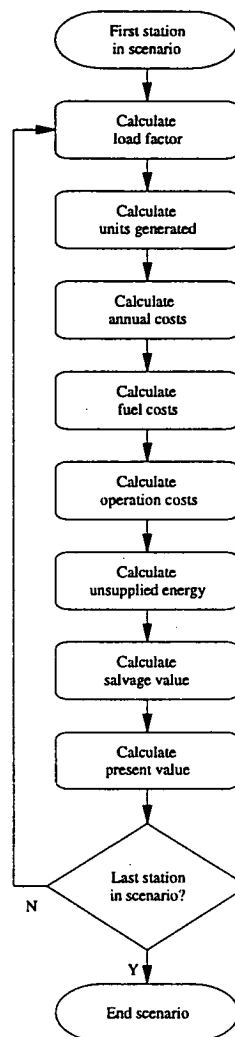


Figure 3. Schematic diagram of construction and operation costs

Operation Costs

The costs for operation of the plant and salaries of the staff and labour for the purpose of generation are taken as variable costs.

Unsupplied Energy Costs

This is a cost applied for every unit of electricity demanded that can not be supplied.

Salvage cost

Although a station will be retired once it reached its maximum lifetime, its land may still be of value. This is known as the salvage value and can be deducted from the total cost.

7. EMISSIONS LIMITS

Each generator must now ensure that generation is done within the framework of the new legislation: to control the level of emissions from the combustion of fossil fuels. There are two proposed methods to help reduce the emission levels:

1. **Trading permits**
 A marketable permit system is a fairly flexible system. Emission limits would be set by the government and permits allocated to polluters allowing emissions up to the limit. These permits could be traded with other Utilities if the emissions fall short of the set limit. However, the price should never exceed the amount payable for exceeding the legal emission limit as the Utility could then choose the easier option of polluting and paying the consequence.

2. **Carbon taxes**
 A penalty cost is levied proportional to the fuel's carbon content, thus providing a direct incentive for Utilities to reduce their carbon emissions. The revenue raised in this manner would be used by the government to implement its policies.

8. **EMISSION CALCULATIONS**

The steps to determine the emission penalty costs are shown in figure 4. As with the construction and operation costs, the resulting emission cost of a particular plan is referred back to a base year for comparison with other options.

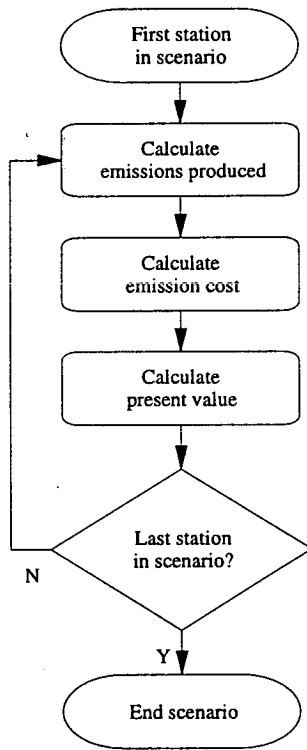


Figure 4. Schematic diagram of emission costs

Emission Production

Air emissions are most commonly associated with the combustion of fossil fuels, the main source of generation in the electricity sector. The majority of pollutants arise by burning the fuel in excess oxygen, for example carbon dioxide, sulphur dioxide and nitric oxides. These gases can be regulated by retrofitting plants that either control the combustion process or scrub the flue outputs.

Emission Costs

Most Utilities know how to generate an additional unit at the least cost. However, the calculations are based on direct costs such as run-up costs, generation and distribution. A more important aspect nowadays is the indirect costs of electricity production. The main concern is the cost to the environment caused by the production of millions of tonnes of air pollutants. An environmental price is now included to the cost of adding new electric resources. The charge is related to the environmental impact associated with the generating source. Figure 5 shows emission values (cost per kilogram) for each air pollutant.

Pollutant	1990 p/kg
SO ₂	92.6
NO _x	393.7
CO ₂	1.4
CH ₄	13.3
CO	52.7
Particulates	243.2

Figure 5. Emission costs for emissions [2].

Using these values, the societal cost of air pollution can be estimated. Utilities will be discouraged from producing pollutants that carry a high penalty on them and will be encouraged to change to a less-polluting power source.

9. **LEAST COST PLANNING SOFTWARE**

POPS (Planning Of Power Systems), a DSS, has been developed at the University of Edinburgh. It determines the most economical option to meet customers demands in a study period of up to thirty years, based on generation and economic data provided by the user. The software has been developed within the expert system shell of Kappa-PC to run on any IBM compatible computer.

POPS considers only fossil fuel types (i.e. coal oil and gas) as possible expansion candidates as hydro-electricity and nuclear fission are often not options. Alternative power is also not considered.

The software performs all the necessary calculations required to determine plans that meet predicted demand, rejecting options that may look feasible on paper but are impracticable. The user has the option of whether emission calculations costs should be considered in determining the least cost expansion plan as these values have been shown to significantly alter the ordering of scenarios from cheapest to most expensive. This is important as at present many developing countries are not being penalised for emission production.

The set-up of the program allows the user to try "what if" scenarios, for example what if the fuel price dropped or construction time increased. The results are presented in a clear graphical manner as well as in tabular form.

10. **CONCLUSIONS**

The development of a decision support system has been shown to offer potential time saving and better long term solutions to the planning of generating system expansion.

ACKNOWLEDGEMENT

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