THE ECONOMICS OF WINDMILLS FOR LARGE ELECTRICITY GRIDS.

by

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Abstract

Windmills are high capital, low fuel cost plant, whose output is intermittent, difficult to predict from one moment to the next, and yet statistically correlated to the output from other devices which are separated geographically. In that conventional plants used for electricity generation are often characterised as sources of firm power which is controllable, windmills are often viewed very differently from conventional plant. The economic evaluation of windmills has, in the past, reflected this perceived difference.

In this thesis the methods that have commonly been used to evaluate the economics of wind power have been examined critically, as have the methods and planning models used for the economic evaluation of conventional power plant. A mathematical model is introduced which can be used in evaluating the economics of both intermittent energy sources and conventional plant, and this model is used throughout the thesis for detailed calculations of the production costs of electricity generation systems which employ wind powered plant.

Less detailed but more versatile mathematical models are also introduced and these are used to examine the sensitivity of the economics of windmills to changes in fossil fuel prices, wind turbine performance, maintenance and capital costs. Results from these studies are used in examining the economics of windmills in the UK, and in predicting the optimal design of wind turbines for use with a given utility system.

From such analysis it is concluded that the economic evaluation of renewable energy sources can be undertaken using concepts developed for application to conventional plant but that much of the simplistic analysis carried out in the past grossly underestimates the economic worth of windmills. It is shown that windmills can have a capacity credit although such credits may not have major impacts on their economics. The affect of the intermittency of the output of wind turbines on the operation of conventional plant in the system is quantified and shown to be of minor importance in large interconnected systems. Although major uncertainties exist both with regard to the cost, acceptability, and durability of modern large wind turbines, analysis in the thesis suggests that a market worth several billions of pounds exists for these machines operating in moderate windspeed sites in the UK.

Acknowledgements

All research necessarily builds and depends on the work of others, a thesis, especially, is the product not only of the authors efforts but also the intellectual, economic, and social support afforded to him. I would like to express my thanks to my supervisor, Dr. N.J.D. Lucas, for his guidance in my research and his help in shaping this thesis. Equally, I would like to thank the other members of the Energy Policy Unit at Imperial College for the interest they have shown in my work and the help they have provided.

My own interest in renewable energy sources and energy policy was kindled during my involvement with the Ontario Royal Commission on Electric Power Planning, and for this I am indebted to all of those who participated in the Commission's work. In the UK, I have been fortunate in being able to apply my ideas, and to further develop them, while with the Generation Studies Branch of the Planning Department of the Central Electricity Generating Board, and I would like to express my thanks to all the members of that Branch. Dr. R.H. Taylor, expecially, provided most useful advice during the final stages of work on this thesis and I am grateful to him.

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Finally I would like to express my thanks to my parents, and all my friends and relatives who put up with what must have, at times, seemed a strange fixation on windmills and energy policy.

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Chapter 1 - Introduction

Windmills convert the kinetic energy of the wind into an energy form which society can more easily use. In the past windmills have been used to produce mechanical energy for pumping water and for grinding corn. More recently windmills have been developed to generate electricity. There is currently little doubt that electricity generating windmills can be built since such machines have been in use for decades. There is, however, uncertainty as to whether they can be built to compete economically with the electricity produced in large interconnected electricity grids by more conventional plant. This thesis attempts to reduce the uncertainty about the latter issue. In doing so an examination is made of the methods used in the economic appraisal of new plant options for the development of the generation system in large electricity grids. This is followed by a detailed examination of the economics of windpower in the United Kingdom.

The economics of windmills have been chosen for analysis though it is hoped that the analysis will be relevant to a wider group of plant. Windmills are but one example of power plant relying on energy sources which have been labelled new, alternative, intermittent, or renewable. Other examples of such plant include wave power devices, tidal barrages, photovoltaic systems, solar thermal devices and, arguably, combined heat and power systems. The conclusions in this thesis will to varying degrees be relevant to each of these.

1.1 The Technology

Modern windmills for electricity generation are dramatically different from the traditional designs that have been used in the UK since the crusades (for a brief history of windmills, see Minchinton, 1980). Modern machines employ designs resulting from developments in the aircraft industry. They make use of slender blades, usually two or three instead of the traditional four, and can use either cylindrical or lattice towers. Their operation is highly automated and they can be controlled remotely. Traditional windmills used the impact of the wind against the sail to push it around; modern machines make use of the lift and drag created by the wind passing on aerofoil. Modern machines can also be much larger than traditional designs and may at some point be used in large clusters sited in shallow coastal water, or perhaps floating in deeper water. To distinguish between the traditional machines and the more modern designs now being tested, some authors use the acronym WECS (Wind Energy Conversion Systems) or the terms aerogenerators or wind turbines. All of these labels are used interchangeably in this thesis.

The technology for harnessing wind power has recently undergone dramatic change and remains in its infancy although several very large devices are operating in several countries around the world. These prototypes have built on knowledge accumulated from research in a number of countries before and during the 1950s, and second generation machines have evolved from machines built during the mid 1970s. It has been claimed that machines built in series production using known technology can be competitive on moderate windspeed sites with nuclear generated electricity. (Divone, 1980.) Even lower costs are claimed from improved designs. (Thomas and Robbins, 1979.) However wind power will not be used on a large scale until both the technology over the machine's life, and the environmental acceptability of wind power are proven. Experiments are now underway which, if successful, will provide such proof. In the UK, utility interest is growing (CEGB, 1980a), and research and development activity is increasing rapidly (Clarke, 1981).

1.2 Need for Research

Existing power systems are generally based on either hydro-electric plant or fossil or nuclear fuelled plant. These types of plant are, to a certain degree, controllable. Output can in principle be scheduled well in advance and plant can operate at a variety of output levels. Especially in the case of fossil fired power plant, fuel costs form a significant proportion of total electricity production costs. Renewable energy sources generally, and windmills in particular, are apparently different from these. They are not easily controlled since it is normally best to generate electricity whenever an adequate energy flow (such as the wind) exists. They are not easily scheduled, nor their output predicted in advance, and their operating costs are usually very low.

Windmills are also often different from fuel-based plant in that the operation or failure of individual plant is not entirely independant of that occurring with other plant. Even if machines are well spread over large geographic areas, and thus their interdependance is low, complete independence in machine failure cannot be guaranteed. Complete independance is an important assumption in system design using conventional plant, and if this assumption cannot be applied to windmills, the economic analysis of such plant may be difficult.

As a result of these factors, and possibly because of general scepticism on the part of power system planners about the practicality of harnessing the wind, economic analysis has generally been primitive and perhaps unnecessarily conservative. It has been suggested (Divone, 1980) that analysis has tended to concentrate on the cost, rather than the value, of the device. Clearly if this is the case and if analysing the value of such plant is difficult, better economic assessment will be needed before a proper evaluation can be made of the future role of wind power and the desirability of introducing windmills into the grid.

Accurate economic analysis may also be important for machine design. There are always tradeoffs that are possible between performance and initial cost. In the case of windpower there may be tradeoffs between increasing continuity of energy output and increasing total energy yield.

A further reason for the interest in the proper economic analysis of plant such as windmills is the influence that such plant may have on the existing and future power system. If windpower, or other similar energy sources, are used on a large scale they will influence the optimal structure of the power system. They may affect the importance of various conventional technologies such as nuclear power, and because of the lead times in plant construction, information of this type is required well in advance of actual need.

1.3 Thesis Format and Areas of Original Research

The thesis is divided into seven chapters: 2 to 4 are broadly concerned with power system planning theory, 5 and 6 with the application of this theory using data relevant to windpower to the analysis of the economics of new plant using intermittent energy sources.

Chapter 2 presents a review of power system planning methods, and figures of merit for comparing the economics of different plant; it also summarises methods used in past assessments of the economics of windmills and other intermittent energy sources. Chapter 3 provides details of the theory used for power system reliability analysis and presents an original method for assessing the impact on system reliability of new plant. Chapter 4 provides an introduction to the modelling technique used in this thesis for detailed simulation of the operation of the power system and an illustration of the effect on total system costs of statistical variations in system loads and plant availability. Chapter 4 also presents an original method by which intermittent energy sources such as windpower can be introduced into such a model. Chapter 5 outlines a framework for analysis of economics analysis of new energy sources and Chapter 6 present several case studies of the economics of wind power in the UK using different levels of detail in the analysis and exploring the sensitivity of the results to changes in internal assumptions and data inputs. In Chapter 7 results and conclusions from previous chapters are drawn together.

The emphasis in the thesis is on providing a useful framework for analysis and for highlighting sensitivities in the economics of plant such as windmills, rather than on providing a definitive assessment of whether the value of a particular new energy source exceeds the cost of harnessing it. The analysis of the capacity credit of intermittent energy sources, the application of a consistent framework for evaluating the worth of such plant, and a design optimisation which maximises the net value of windmills to a specific grid, are all areas where original work has been carried out by the author.

In addition to the main chapters there are 4 appendices. Symbols used throughout the thesis are gathered together in A-1, though they have been defined locally as they are introduced. In Appendix A-2 the details of a data base to describe conditions in the electricity supply industry in the United Kingdom are brought together. Additional data to describe the wind conditions in the UK is also presented. This single data base has been used throughout this thesis for detailed system calculations. In appendix A-3 flow charts for the computer routines developed in this thesis are presented. Appendix A-4 consists of a listing of the published papers by the author relevant to the research undertaken as part of this research.

CHAPTER 2

Power System Planning and the Economic Appraisal of New Energy Sources

2. Introduction

To understand the economics of new plant or new energy sources which produce electricity for power networks it is important to review the background to planning electrical power grids and the methods used in such planning. Section 2.1 of this chapter describes the features of electrical power systems that play a dominant role in determining the type of planning exercises which are carried out. Section 2.2 and 2.3 provide details of the techniques used in planning the future generation system, and the methods which are used in comparing the economic desirability of competing plant options. Section 2.4 is a review of analyses that have been made of the economics of new energy sources. Conclusions are drawn in section 2.5.

2.1 Electrical Power Systems

An electrical power system consists of a number of generators interconnected by a transmission network in order to supply demands created by diverse loads. The demand for electricity is the instantaneous sum of all the loads on the system and normally varies over a wide range with time. Whilst variation in demand is in itself not unusual in energy supply industries, the electrical power industry faces unique problems in the design, operation, and planning of the system since at present there is no feasible technology available for direct storage of electricity in large quantities. Demand has to be met exactly at each instant as and when it occurs.

To serve demand efficiently under these conditions a variety of plant is used. Some plants can expect to be used to the limit of their capability throughout the year, other plant will be used only at times of peak demand. As a result some plant is designed to use low cost fuels and to be as efficient as the technology allows, other plant is less efficient but has a lower initial cost. Still other plant is prized for its ability to pick up load quickly and without advance notice. Whichever plant is in use, and whatever the demand, electricity is expected by the customers instantly and reliably.

Utilities must meet demand reliably in spite of the fact that load levels at any point in the future are always uncertain, and that all plant suffers occasional failure. Reliable service is provided by maintaining a pool of plant such that the total capacity always exceeds the sum of the expected demands, and the capacity of those units undergoing repair. Providing reliable service is made more difficult because of the long construction period required by new plant, and because of the rapid changes which can take place in the need for electricity.

Those responsible for the development of the power system must deal with all of these factors in analysing the desirability of each plant option that is available. Broadly speaking development options are chosen which are socially and environmentally acceptable and which minimise the total costs over the long term. Uncertainty will exist about acceptable planting options, fuel availability and capital expenditure, and tradeoffs will be needed in the light of pricing policies and revenue requirements. Future load levels and capital availability will be affected by the structure of the system, and likewise the structure of the system will be affected by the load and capital availability. Planning is necessarily an iterative procedure.

The planners role is to provide decision makers with information on the range of options available, their costs, the uncertainties involved, the tradeoffs that are possible, and the difficulties inherent in each. The evidence that is presented to the decision makers must be complete enough to be useful, yet simple enough both to be understandable, and to allow the decision makers to focus on matters they deem most important.

2.2 Power System Planning

In view of these difficulties and the need to retain simplicity in the presentation of the relevant information, it is tempting to throw up ones hands, claim that the problem is impossible to solve properly and as a result to judge plant in isolation of the complex interactions that exist. An alternative is to argue that the problem can only be described in highly complex terms and that solutions depend on rigidly defined objective functions. Neither alternative is appealing in the present planning environment where uncertainty is inherent in all options, and where features of the problem which are difficult to quantify ultimately may be of major significance. The approaches to planning used by most utilities have developed in an attempt to balance these extremes. In this respect three tools used in the assessment of different options stand out as being important: models for simulating the operation of the system, optimisation techniques, and methods of economic appraisal. They are discussed separately below, although any separation along these lines must remain artificial since there will always be interplay between them.

2.2.1 Models for Simulating System Operation

Predictions of the total costs of meeting given demands for electricity, or of the adequacy of given plant in meeting peak demands reliably, must always make use of assumptions and simplifications about that plant and load. The assumptions and simplifications which are made constitute the system model. Three broad categories of models can be identified: those based on load duration curves, those based on plant loading simulations, and those based on probabilistic simulation.

(i) Production Costing Based on the Load Duration Curve

Load duration curves (figure 2.1) define the magnitude of the total demand for electricity as a function of the percentage of time that the load is exceeded. They can be used to represent loads over any time period, though weekly, seasonal or annual curves are the most common. Information about the chronological pattern of the load is not shown in a single curve, nor is information about the speed of variation of the load.

Approximations to system operating costs over a given period can be made by direct integration of the curve to predict the energy production by each plant type. As long as plant are loaded in merit order, that is if individual plants are loaded in an order based on their operating costs, then total production costs will be minimised and in this sense normal system operation is simulated.

Weaknesses in this model arise from the inability of the model to capture either those effects which depend on the chronological pattern of the load, or those which depend on the statistical uncertainty which is associated with future loads and plant operation. Costs associated with the former are the cost of spinning reserves, the cost of plant start-ups, the changes in maintenance costs which might occur as the load pattern changes, and the cost of out of merit operation for whatever reason.

Costs associated with the statistical uncertainty relate to the effect of uncertainty in the load forecast, and to the effect of random plant failures. Often attempts are made to include the effects of random plant failure by restricting the operation of plant so that

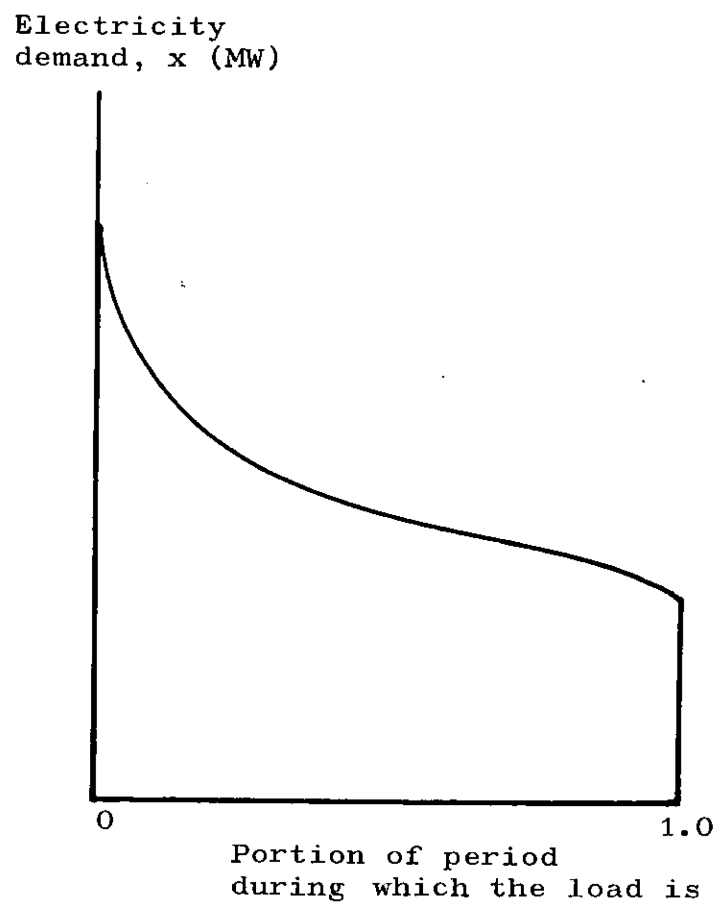


FIGURE 2.1 A Load Duration Curve.

so that total output can never exceed average availability. This is a major simplification whose implications are often not fully understood. In its primative form the model is inadequate for detailed evaluation of whether a given set of plant is able to serve demand reliably. Again similar approximations can be used in an attempt to reflect reliability considerations. It is claimed (Turvey and Anderson, 1978) that these simplifications do not imply any loss of vigous if such approximations are backed up by detailed probability calculations.

(ii) Loading Simulation Models

System cost models have been developed which do not depend solely on the load duration curves and which can take explicit account of plant failure; which recognise the need for spinning reserve; and which can model plant response times, part-load efficiencies and plant cycling limitations. Generally these take the form of hour by hour Monte Carlo simulations (see for example Manzoni et al, 1980) which embody rules for system operation dependant on the present, past and expected loads, as well as the present state and recent history of available plants. Other non-Monte Carlo models have also been described, (Jarass et al, 1979, Whittle et al, 1980).

Computer based hour by hour loading simulation models can, in principle, model the actual operation of power systems very closely indeed. In principle they can also be used to model the uncertainties associated with system expansion (cost over-runs, uncertain construction times, etc.) and normally are capable of detailed probabilistic treatment of system reliability issues. Their great weakness is the large amount of computing time required for statistically useful conclusions to be drawn. Often the inaccuracy of the input data to such models means that such computing effort and cost is not justified in long term planning studies.

(iii) Probabilistic Simulation

Somewhere between the models that depend on simple load duration curves, and those that depend on hour by hour Monte Carlo simulations lies a model which uses simple representations of the load and includes probabilistic assessments. It is called both Probabilistic Simulation (Booth, 1971) and the Baleriaux - Booth Production Cost Model (Fegan and Percival, 1980). The model allows a precise treatment of the major effects of plant failure and long term load forecasting uncertainty on system operating costs and system reliability. It is not capable of precise treatments of issues relating to the speed of load variation, such as the need for spinning reserves or the limitations imposed by plant response times. Probabilistic Simulation plays a major role in this thesis and further details about it are given in chapter 4.

2.2.2 Optimisation Techniques

The system models described above are used to calculate the cost of meeting demand with a given set of plant. If a search is to be carried out for least cost system development options estimates must be made of the investment requirements of each set of plant considered. Optimisation techniques are those which structure the search for, and identification of, least cost solutions.

One method of deciding whether a given development plan will lead to the minimisation of overall costs would be to compare cost in that plan against total costs for all possible systems. In detailed long term studies of large systems, the method is impractical because of the number of options to be considered and, as a result, a variety of optimisation techniques have evolved.

Although the primary purposes of a given optimisation technique is to locate least cost solutions, different techniques can provide a diverse set of information about elements of the solution, and the sensitivity of the solution to variation in state parameters: both are of interest. Since a system planner must be concerned with gaining an understanding of the tradeoffs that have been followed in arriving at an optimal solution, it is the need for information on the sensitivity and structure of the solution that may be of primary importance in choosing an appropriate optimisation technique.

A number of reviews of optimisation techniques are available and the difficulty in defining consistent groupings to structure discussion is evident. As Anderson (1972) points out, while optimisation techniques are outwardly different in form, they can differ only in algorithms since they are different methods of solving the same kind of problem. He has made the distinction between marginal analysis, simulation models and global analysis. His presentation however leads to some confusion between the modelling aspects and the optimisation technique. In the review that follows a similar grouping is used but the emphasis is more clearly on the type of problem to be solved.

(i) Cost Polygons

Cost polygons (Phillips et al, 1969) or screening curves (Marsh, 1980) are simple constructs which can be used for studies of the optimal plant mix for given system demands. They have proven themselves extremely useful for illustrating the type of tradeoff that exists with the use either of high fuel cost, low capital cost plant, or of low fuel cost, high capital cost alternatives. Cost polygons combine simple analytical representations of the annual costs of a given plant with the "direct integration of the load curve" model of system costs.

In the cost polygon approach, the cost of operating a plant throughout a given period t is represented by the sum of the plants fixed costs ϕ and its variable costs γt. The fixed costs are those costs that must be incurred regardless of whether a plant is used and

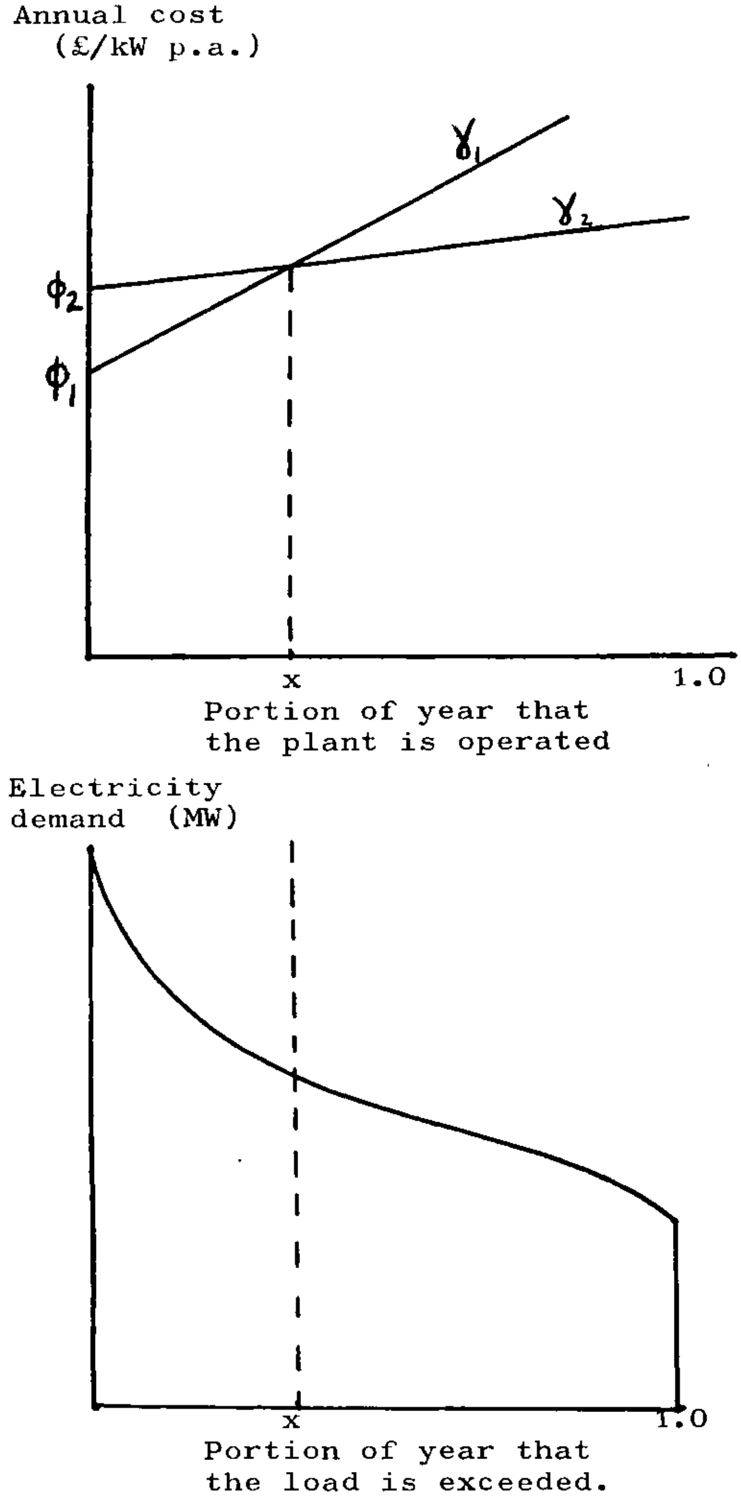


FIGURE 2.2 The Cost Polygon approach for optimizing the system mix.

would include depreciation costs related to capital expenditure and various fixed rents. The variable costs are those that relate to the proportion of the period during which the plant was used. These latter costs tend to be dominated by fuelling costs, but might also include some maintenance component.

In a two plant system the total costs for serving the load shown in figure 2.2 can be calculated using equation 2.1.

$$W = T\left\{\ell(o) - \ell(x)\right\}\phi_1 + \int_o^x \gamma_1\ \ell(t)dt + (\gamma_2 - \gamma_1)\ \ell(x)x \qquad 2.1$$

$$+ T\ \ell(x)\ \phi_2 + \int_x^1 \gamma_2\ \ell(t)dt$$

where $\ell()$ is the load duration curve

ϕ_1, ϕ_2 are fixed costs for plants 1 and 2

γ_1, γ_2 are variable costs for plants 1 and 2

x maximum duration of operation of plant type 1

T is the duration of the period considered

These costs will be at a minimum when

$$\frac{\partial W}{\partial x} = 0 \qquad 2.2a$$

which occurs when

$$\phi_2 - \phi_1 = x(\gamma_1 - \gamma_2) \qquad 2.2b$$

The shortfalls of this approach are well known (Berrie, 1967). It suffers the weaknesses associated with the load duration curve system model in that it does not allow a detailed treatment of statistical uncertainty or costs related to the chronological pattern of the load. It is difficult to use a cost polyon approach using either of the other system models described in section 2.2.1. The simple cost polygon is suitable only for static situations (i.e. where there is no change in the peak load or the shape of the load duration curve over time) and it does not allow a discrete representation of plant so that issues related to plant size cannot be examined.

The methods developed by Phillips et al (1969) have been used to overcome these latter problems. They describe a computer routine which is capable of digesting the complications imposed by load growth; changes in fuel prices and capital costs; planting constraints; plant retirements and the existance of plants of differing vintages; and the distinctions between plants of the same type but of different size. Jenkin (1973) on the other hand argues that for long range planning studies, fine points such as discrete representations of plants are unimportant and he uses the load duration curve in conjunction with an analytical model for calculating the optimal mix over time.

(ii) Marginal Analysis

Marginal analysis starts with an initial programme, a reasonable reference solution, and seeks to improve it (reduce costs) by marginal substitutions. The reference solution, and the solution obtained after a substitution has been made, satisfy the same power and energy demands. When the cost function is convex, marginal analysis should ultimately lead to a least total cost programme. Marginal analysis is used to fine-tune development plans which have been outlined by other means. Figures of merit (discussed later) such as net effective costs or relative profitability naturally evolve from such an analysis (Garlet et al, 1977) and so the economics of two competing plants are often examined in this way.

In marginal analysis it is possible to make use of a wide variety of models of the system and to choose those models with a regard to the level of sophistication required by the task at hand. Marginal analysis, by definition, cannot be used to indicate the profitability of large amounts of new plant. Marginal analysis also depends upon the use of a suitable background plan yet is unfortunately is often used without reference - to this background plan (Central Electricity Generating Board, 1980b).

(iii) Global Models

The term global is used with some trepidation in this section because of the misunderstanding its use can generate. Berrie (1967) talks of global methods as those that deal with the power system as a whole. Anderson (1972) identifies global models as those which are designed to scan and cost a large number of alternatives to select the optimum. The term is used here to group those optimisation techniques that are related in the latter sense; a large number of investment plans, or at least sections of these, are reviewed before an optimum is selected. Methods of global optimisation include linear and non-linear programming, dynamic programming, and optimal control.

Some of the problems in global optimisation studies can be illustrated using a general formulation based on that presented by Anderson (1972).

In power system planning the investors objective is to minimise the sum of capital and operating costs over some future time period 0 to T.

$$\text{Minimise} \quad \sum_{\nu=1}^{T} \sum_{j=1}^{J} K_{j\nu} \, . \, X_{j\nu} + \int_{t=0}^{T} \sum_{\nu=-V}^{t} \sum_{j=1}^{J} H_{j\nu}(t) \cdot U_{j\nu}(t)dt \qquad 2.3$$

where $K_{j\nu}$ is the present worth of the capital costs (per unit) of electricity plant j, vintage ν

$X_{j\nu}$ is the capacity of plant type j which is installed in year ν

$H_{j\nu}(t)$ is the present worth of the operating cost of each unit of energy produced by plant type j, vintage ν, in the period dt at time t

$U_{j\nu}(t)$ is the amount of energy produced by plant j, vintage ν in time dt

Plant types range from 1 to J

Plant vintages range from -V to T

This objective is constrained as follows:

$0 < U_{j\nu} < X_{j\nu}$ which limits the power output to less than or equal to the installed capacity 2.4

$$\text{Prob} \left\{ \sum_{j=1}^{J} \sum_{\nu=-V}^{t} b_{j\nu t} U_{j\nu t} > \ell_t \right\} = e_1 \quad \text{which is a constraint forcing the system to meet the energy demand} \tag{2.5}$$

where ℓ_t is the system demand at time t

e_1 is the risk level of not meeting demand which is deemed acceptable

$b_{j\nu t}$ is the availability of plant type j vintage ν at time t

$$\text{Prob}\left(\sum_{j=1}^{J} \sum_{\nu=-V}^{t} A_{j\nu} \cdot X_{j\nu} - \hat{\ell}_t > 0 \right) = e_2 \qquad t = 1, \ldots T \tag{2.6}$$

where $\hat{\ell}_t$ is the peak demand on the system

e_2 is the risk level of not being about to meet demand which is deemed acceptable

$A_{j\nu}$ is the availability of the plant type j vintage ν at peak hours

Prob ( ) is the probability of an event occurring

In principles K, H, X, ℓ, A, b, are all variables with stochastic components which respectively reflect uncertainties in construction costs, fuel costs, construction schedules, demand levels, annual plant performance and peak hour plant performance.

In this form it is possible to isolate those parts of the problem where the choice of optimisation techniques has implications for the model of the system which can be adopted. As described in section 2.2.1 loading simulation models seem best able to mirror the costs associated with the complete range of factors that can be considered. By using a loading simulation model of the system each of equations 2.3 to 2.6 could retain its statistical flavour. However, few mathematical programming techniques can incorporate this degree of complication within their structure. On the other hand, if direct integration of the load duration curve is used and the statistical flavour of the equations 2.3 to 2.6 is ignored then the problem is easily solved using linear programme techniques (Massé and Gibrat, 1957). Since linear programming is well developed and is very useful in providing information for sensitivity analysis, the coarse nature of the cost formulation may often be forgiven. A third possibility is to use probabilistic simulation in dealing with the second term in equation 2.3 and with equations 2.5 and 2.6 and the use of non-linear programming (combined costs method, Beglari and Laughton, 1975) for the optimisation.

Finally optimal control techniques (Breton and Falgorone, 1972) can be used to optimise problems where the peak load reliability constraint has been replaced by an unserved energy cost. This type of formulation has been advocated widely; as discussed in later chapters probabilistic simulation models can be used in this type of model with great success.

2.3 Economic Appraisal

For a number of reasons it is necessary to calculate the economics of individual plants as well the economics of different development strategies. For the latter one is able to simply compare total costs over the long term since, in principle, each option provides identical service. For the former, the comparison of the economics of individual plant, more complicated expressions must be used because individual plants will have different characteristics, and make different contributions to the system. A variety of figures for economic comparisons are in use in the electricity supply industry, a number of these are described below.

2.3.1 Busbar Energy Costs

The busbar energy cost (BBEC) reflects the overall cost of electricity produced over the life of the plant and can be calculated independantly of detailed systems considerations. Using the symbols introduced earlier (equations 2.3 to 2.6) it can be calculated as:

$$BBEC_1 = \left\{ K\ X + \int_{t=0}^{T} H(t)\ U(t)dt \right\} \Big/ \int_{t=0}^{T} U(t)dt \qquad 2.7a$$

More frequently costs are based on annuitised figures and the BBEC can be calculated as 2.7b.

$$BBEC_2 = \left(\frac{K\ X}{D} + H \cdot U \right) \Big/ U \qquad 2.7b$$

where D is the appropriate annuitising factor

and U, H are the averaged values of U( ) and H( )

Berrie (1967) has argued that tenders for plant can be evaluated on the basis of a pence per kilowatt hour figure such as BBEC as long as the performance of each plant is similar over time. Utilities frequently (Royal Commission on Electric Power Planning, 1978, Central Electricity Generating Board, 1980) make use of similar figures of merit in presentations of the economics of various plant types. However a problem arises in that plant is inevitably needed in the system to perform different roles. If new plant is needed in a system it is not always true that building plant for baseload duty is the most sensible option.

Comparisons made on the basis of BBEC may also be inadequate where questions of system reliability are important. Plant which produces low cost electricity but which is also unreliable may impose a penalty on the system because of the need for increased reserve margins. Equally other plant may be added to the system as the most economic means of increasing system reliability yet rarely actually inject electricity into the grid. The different construction lead times, the different financial requirements and a host of other considerations are also important yet may not be considered adequately, if at all, in the BBEC.

2.3.2 Net Effective Cost

The Net Effective Cost (NEC) of a plant is the total present value cost of a project minus the total present value savings, converted to an annuitised figure and quoted on a per kilowatt basis (Central Electricity Generating Board, 1980). On occasion NEC is also calculated after correcting all costs to a common peak availability (Hawkes, 1978).

Net Effective Costs can thus be described mathematically as in equations 2.8a and 2.8b.

$$NEC_1 = \left[K\,X + \left\{ \int_{t=0}^{T} \sum_{\nu=-V}^{t} \sum_{j=1}^{J+1} H^*_{j\nu}(t)\, U^*_{j\nu}(t)\, dt - \int_{t=0}^{T} \sum_{\nu=-V}^{t} \sum_{j=1}^{J} H_{j\nu}(t)\, U_{j\nu}(t) dt \right] \right\} \Bigg|\, X \qquad 2.8a$$

where the * indicates the values associated with the new expansion plant

The difference between total system production costs before and after the addition of the new plant is used frequently below, and will be referred to as the net system savings, M. Using this, the second version of NEC can be shown in equation 2.8b.

$$NEC_2 = \frac{A^*}{A} \cdot \frac{K\,X + M}{X} \qquad 2.8b$$

A* is the system peak hour availability

As Berrie (1967) states a basic assumption associated with NEC is that the system is in a state of growth: that the addition of plant to the system is justified by the need for new capacity to meet peak demands. As will be shown later in this thesis,different plant types and sizes have different effects on the need for capacity and normalising by the peak hour availability is only a crude method of including system reliability concerns in the measure. A more important factor to consider is that at the moment it is not clear that future additions to the system will be driven by the need for capacity to meet load growth.

2.3.3 Total Net Value

In principle the value of any station can be broken down into its value as a source of energy, and its value as a source of capacity. A reasonable measure of the value of a plant is the total of these two figures minus the cost. The total net value is described in equation 2.9.

$$TNV_1 = \left\{ \sum_{\nu=1}^{T} \sum_{j=1}^{J+1} K^*_{j\nu} X^*_{j\nu} - \sum_{\nu=1}^{T} \sum_{j=1}^{J} K_{j\nu} X_{j\nu} \right\} + M \qquad 2.9a$$

Since it is often necessary to made comparisons of plant of different sizes this figure is sometimes normalised to a per unit capacity figure. This is a measure described by Cotterill (1979). The first term in equation 2.9a is used frequently and will be referred to below as the system capital savings, K_s. Using this, the second version of total net value total net value per unit capacity can be shown in equation 2.9b.

$$TNV_2 = \frac{K_s + M}{X} \qquad 2.9b$$

As will be illustrated later these measures seem reasonable where plants of similar load factors are compared, but could breakdown in comparing plants which see dissimilar duty.

2.3.4 Benefit Cost Ratio

The Benefit Cost Ratio is similar to the Total Net Value measure in that the value of the plant being considered can be derived from basically two sources (although further sources could be considered). In this measure capital costs and net benefits are aligned as a ratio rather than a difference.

$$BCR = \frac{K_s + M}{K\ X} \qquad 2.10$$

Benefit cost ratios have been a standard figure of merit for industrial investment but have only recently been used in the evaluation of new energy sources (Department of Energy, UK, 1981). Other possible figures of merit with a similar background are the Internal Rate of Return, and the Payback Period (Grant and Ireson, 1964).

2.3.5 Return on Incremental Capital

A slight variant on the Benefit Cost Ratio is the Return on Incremental Capital measure which Berrie (1967) describes. He argues that so long as both the demand for electricity increases and the utility is required to provide high standards of reliability, a decision whether to build a generating station or not is not a meaningful one. For system expansion the minimum capital costs would be incurred if gas turbines were installed to meet peak demands. If more than minimum capital costs are to be expended then the projects can be ranked on the basis of the ratio of the additional operating savings to the additional expenditure.

Return on Incremental Capital is defined in equation 2.11.

$$ROIC = \frac{K_s + M - K^+}{K\ X - K^+} \qquad 2.11$$

where K^+ is the capital expenditure which is deemed necessary

An immediate concern here is the need to distinguish optional and non-optional expenditure; in practice the separation may be extremely difficult to make.

2.3.6 Discussion

As with the system models and optimisation techniques discussed earlier one must choose carefully when selecting a useful figure of merit. If the need for new plant is driven by the need to meet an increasing peak demand, and if the availability of capital is not constrained then Net Effective Costs can be used with good effect. However, though mathematically correct, they may be misleading when used in connection with intermittent energy sources. A Benefit Cost ratio would be favoured where restrictions on capital exist. The Internal Rate of Return or Payback Period may be more trustworthy where uncertainty increases over the life of the project. As will be shown there may also be situations where the Busbar Energy Cost finds a use. The various alternatives have been discussed in more detail elsewhere (Norris, 1970).

2.4 The Economics of New Energy Sources - Past Analyses

The economics of new energy sources have in the past been considered only in terms of very simple system models. In these models the feature of new energy sources that has dominated the evaluation of their worth is their intermittency. As will be shown later in this thesis results from such analyses must be treated with caution. A review is presented below of past economic appraisals of the economics of wind turbines or wind energy conversion systems (WECS). As explained earlier it has been necessary to concentrate on this particular technology to focus the work on a manageable size. Historically the type of appraisals carried out for wind turbines are similar to those for solar electric technologies (see for example Mueller et al, 1981) and wave power devices (see for example Cotterill, 1979).

2.4.1 Analysis as Fuel Savers

Since the early days of their development as means of producing electricity, WECS have been described as fuel savers. The argument has been as follows: since a single windmill does not produce a firm supply of electricity, it cannot, by itself, be used as a reliable means of serving system demands. Therefore in an electricity grid windmills can only be used to reduce the fuel used by the system, and could not replace conventional power stations. It has been implied (Musgrove, 1980) that it follows from this argument that to be economic in a grid without storage, the total costs of the machine, on a unit energy basis, must compare with the fuelling cost of conventional plant.

This view of windmills as fuel savers, and thus this assessment of economic targets for WECS has dominated the economic appraisal of WECS over the past 30 years (see for example, Putnam, 1948, Golding, 1955, Denton, 1975, Kirschbaum et al, 1976, Bae and Devine, 1978, Bontius et al., 1978, Taylor et al., 1979).

The major difficulty with analysis based on these views stems from the use of the word firm and the need to find a usable definition of it. It is commonly argued that although a single machine suffers periods of lulls in the wind and thus zero power output, several machines, if sited at widely separated sites tend to have a smoother more continuous output. The periods when all machines suffer lulls in the wind is reduced and thus the firmness of the group of machines exceeds the firmness of the single machine. But by how much? How is firmness quantified?

A similar problem arises in regard to WECS systems making use of dedicated storage. A short term store can smooth the output of WECS, but periods of zero output are still possible. Again the question arises: how firm is the combination of storage and inputs from windmills, and how does this change as the storage capabilities of the WECS designs change?

Quantitative studies of the effects of dispersed siting using power duration curves (Molly, 1976, Grylls, 1978, Justus, 1976) and persistance records (Taylor et al, 1979) have been reported, but few studies actually define firm power, or have attempted to extend the analysis to examine the effect of the changing firmness on the economic evaluation of the WECS. Exceptions to this trend are the papers by Jorgenson et al (1976) and Lindquish et al (1975), which provide examples of attempts to introduce systems concepts into the study of WECS economics. Both are reviewed below.

2.4.2 Analysis as Base Load Plant

In one analysis suggested by Jorgensen et al (1976), studies should be done to determine the fraction of the wind power capacity which will have an availability factor approaching that which would be expected from a conventional base load station. It was suggested that such an availability would be 75%.

It was proposed that after an estimate is made of the proportion of the capacity that can be treated as firm, that the energy produced by this plant be valued at the total cost of electricity produced by an equivalent amount of base load conventional plant. The energy produced by the portion of WECS capacity that was not firm was then valued at the incremental cost of energy from competing conventional plant. The total value of the WECS was the sum of these two figures. For conditions in the specific system that was analysed Jorgensen et al estimate that this analysis which effectively treats WECS as partially firm increases the value of WECS over their value as fuel savers by about 5%.

The analysis of Lindguist et al (1975) is similar. It is suggested that the dispersed WECS array can be treated as an equivalent hydroelectric plant, and thus analysed by the existing utility planning model. Though details of this analysis were not given it suggests a very low firm power fraction since typically firm power from hydroelectric plants must be exceeded 97% of the time (Ontario Hydro, 1976).

Another line of analysis can be identified. It has been argued that to obtain a substantial amount of firm power from WECS it is necessary to combine WECS with storage.

2.4.3 Analysis with Storage

Early studies of the effects of storage typically analysed dedicated storage schemes. Sorenson (1976) and Coste and Lotker (1977) analysed the amount of storage needed so that the normalised power duration curves of WECS at specific locations would compare with those of specific base load plant. Elliott (1975) asserts that the combination of windmills with water storage,to provide a measure of 'firm' power, would enhance the value of the windmills. In another study Ryle (1977) has argued that in a UK context WECS and 150 hour storage could in the future economically replace the use of the nuclear plant for meeting national heating needs. Jorgenson et al (1976) proposed the use of storage to retime the output of WECS so that they can be evaluated as peaking plant rather than base load plant. Bae and Devine (1978) report analysis designed to optimise storage design and WECS configuration to achieve either base load or, alternatively, peaking operation.

In spite of the variety of approaches taken, each of the definitions of firm which have been adopted are inconsistent and inadequate for system planning studies. In planning a system there is no need to prejudge plant as firm or non-firm sources of power, nor is there a need for a prior linking of specific plant with storage. System planning implies that the system as a whole is optimised and that the operation of components of the system is defined only after the optimisation of the system is achieved.

2.4.4 WECS and System Studies

One of the first examples of a systems study of the value of WECS to utilities is found in the papers by Jones and Moretti (1976). They examined the costs of a system supplying demand in a system where the mix of plant has been optimised before the introduction of WECS and again in the system after the mix has been re-optimised after the WECS output has been subtracted from the customer load. For conditions in the mid-western USA they reported that this more comprehensive analysis increases the value of WECS over that calculated assuming a fuel-saver-only role by 17%. Though the study is important since it points to the need for a more consistent approach to the analysis of competing plant options, it can be criticised in a number of areas. The study is forced to ignore the variability and unpredictability (as opposed to it intermittency) of the wind since it is a rigid deterministic model, and calculations of capacity credits are necessarily superficial.

Other early reports (Allen and Bird, 1977) have included suggestions that WECS will influence total system capital costs as well as system fuel costs but have not suggested methods for appraising the full system costs or the mechanism through which these total costs will change.

During the course of the research related to this thesis a number of studies (Marsh, 1979, Johansen and Goldenblatt, 1978, Van Kuiken et al, 1980) have been reported that have followed a systems approach,and which have improved upon the analysis of Jones and Morretti. Descriptions of these studies have been summarised elsewhere (Taylor and Rockingham, 1980) and pertinent details of the studies will be given at appropriate stages of the thesis. Their conclusions in most cases support the conclusions, described later,that result from the authors own research. They have reinforced the authors basic hypothesis that new energy sources must be analysed as part of a system. The analyst must have an understanding of power systems; their characteristics and their behaviour, and as well, must have a knowledge of power system planning concepts and the economic models in use.

2.5 Summary and Conclusions

Power system planning is carried out using models which reflect acceptable simplifications of the interactions and complexities inherent in power systems. Different models of the system and therefore different assumptions about the system can be used depending on the nature of the study being carried out. There is some evidence that analyses of new energy sources have in the past relied on simplifications which are inappropriate for consistant economic evaluation.

Chapter 3 - Power System Reliability

3.0 Introduction

The reliability of an electricity supply system refers to its ability to meet customer demands and withstand the effect of equipment failure. Power systems combine facilities for the generation, transmission, and distribution of electricity and a measure of system reliability should include the effects of all the components. Because of the complexity of the task this global approach is rarely taken in practice. Instead detailed analyses are usually made of each system and results from these separate studies tied together in later studies. The tradeoffs are between accuracy, flexibility and utility.

In this chapter only reliability in the generation sub-model is considered. The power system is assumed to provide service of satisfactory quality as long as there is sufficient plant available to meet the load. It will be assumed that the transmission and distribution network are capable of delivering energy from any generation source to any load without losses, and that system security is such that the network can withstand disturbances caused by plant failure without further loss of facilities. For this chapter the hour by hour strategies for operating the system are ignored. Though these have been common assumptions in long range planning exercises (Turvey and Anderson, 1978), other approaches are possible (Cheong and Dillon, 1978) and may be necessary to model in detail the impact of new energy sources. This limitation of the work is discussed later in Chapter 5.

The purpose of this chapter is to review the methods used to study generation reliability quantitatively, and to propose methods that might be used in analysing the effect on system reliability of new energy sources. Section 3.2 presents the theory upon which quantitative reliability assessment is based, the measures of system reliability that are used, and the methods used for calculating each of these. Section 3.3 presents methods that are used to relate system reliability calculations to project analysis. Section 3.4 is a discussion of some issues relevant to the quantitative reliability analysis.

3.1 System Reliability Calculations

3.1.1 Generation Models

A plant is said to fail if it is unable to provide electricity when called upon to do so. In large power stations failure can occur for a variety of reasons ranging from turbine failure, to fuel shortage, to safety shutdowns. In this chapter only the resultant operation, or failure, of the station is important, not the reason.

It is often adequate for models of the behaviour of conventional plant to describe plant failure as occurring with a constant probability throughout given intervals of the study period (Billinton, 1974). This is equivalent to assuming that repairs and maintenance occur to replace components in the plant before they enter a high risk of failure "wear out" period. It is assumed in most cases that required maintenance can be scheduled and does not have major effect on the plant failure rates. Given this assumption the probability r(t) of a plant surviving at time t can be defined as:

$$r(t) = e^{-\lambda t} \qquad 3.1\ a$$

If the failure density function f(t) is defined so that

$$f(t) = \frac{-dr(t)}{dt} \qquad 3.1\text{ b}$$

then

$$f(t) = \lambda e^{-\lambda t} \qquad 3.2$$

Given this classical formulation, the mean time to failure (MTTF) can be calculated as

$$E(t) = \int_0^\infty t\, f(t)dt = \int_0^\infty \lambda t e^{-\lambda t} dt = \frac{1}{\lambda} \qquad 3.3$$

From this, the unit failure rate can be defined as 1/MTTF and is equal to λ. It is important to note that by representing the failure rate in this form, independant of t, models of plant failure and thus plant availability are Markovian. Subsequent analysis can thus be simplified.

The unit repair rate can similarly be defined as μ (which, by the same logic, is equal to the inverse of the mean time to repair, MTTR).

With these definitions it can be shown (Billinton, 1974) that the long term probability that a plant is operable is A where

$$A = \frac{\mu}{\lambda+\mu} \qquad 3.4$$

and that A^1, the probability that a plant is unavailable for operation at time t, is

$$A^1 = \frac{\lambda}{\lambda+\mu} \qquad 3.5$$

A traditional term for this unit unavailability is the forced outage rate FOR (which infact is a misnomer since it is not a rate). The FOR is thus defined as

$$\text{FOR} = \frac{\text{forced outage hours}}{\text{in-service hours + forced outage hours}} \qquad 3.6$$

This can be extended to an n state representation which would include partial outages as follows:

$$\text{FOR}_i = \frac{\text{state i hours}}{\sum_{j=1}^{n} \text{state j hours}} \qquad i = 1, n-1 \qquad 3.7$$

In fact the usual method for accounting for partial outages is to increase the forced outage hours by an appropriate amount of time called equivalent forced outage hours. This duration is calculated as the sum of the actual partial outage hours multiplied by the corresponding fractional capacity reduction. Based on this an equivalent forced outage rate, EFOR, can be defined as

$$\text{EFOR} = \frac{\text{forced outage hours + equivalent forced outage hours}}{\text{in service hours + forced outage hours}} \qquad 3.8$$

A further modification to the unit unavailability might result from a detailed consideration of maintenance needs. Maintenance is normally scheduled to occur at off peak periods and in some analyses does not enter into reliability calculations. However since maintenance requirements are not precisely predictable it is possible that the scheduled length of maintenance outage is exceeded resulting in reductions in plant availability during peak hours. The effects of such unscheduled extensions to planned maintenance can be included in the performance index in much the same way as in equation 3.8, (Ontario Hydro, 1976) or collected as part of plant performance data (equation 3.7).

Having described the behaviour of individual plants it is useful to now describe how these plants act as a group. If n independant units of similar size, failure rates, and repair rates are considered, the probability P_g of state g (where g units out of the n have failed) is

$$P_g = \binom{n}{g} A^{1g} A^{n-g} \qquad 3.9$$

where A^1 is the unavailability of each unit

A is the availability, $(A + A^1 = 1)$.

Where large numbers of plants are considered the distribution of available capacity states tend to form a normal distribution.

The frequency of encountering state g is

$$f_g = P_g (\lambda_{g+} + \lambda_{g-}) \qquad 3.10$$

where λ_{g+} is the transition rate from state g to the states with a lower g index (higher capacity states) and λ_{g-} is the transition rate from state g to the states with a higher g index (lower capacity state).

In this example where identical units are considered

$$\lambda_{g+} = g\mu \qquad 3.11$$

$$\lambda_{g-} = (n-g)\lambda \qquad 3.12$$

If a more realistic system is considered where units have different ratings and different availabilities, capacity states can result from different combinations of plant outages. To combine these different combinations note that if

$$C_z = C_y = C_x \qquad 3.13$$

where C_z is the resultant capacity state

and C_y, C_x are the states originally considered.

$$P_z = P_x + P_y \qquad 3.14$$

$$P_z \lambda_{zi} = P_x \lambda_{xi} + P_y \lambda_{yi} \qquad 3.15$$

Equations 3.12 - 3.15 can be combined with recursive relationships to provide attractive means of calculating the necessary parameters for generation models. (In fact, as will be seen, after a description of the load models, the same recursive relationships can be used to combine models of generation availability and of load.)

Plant outage functions can be calculated recursively. In the general case

$$F_{N+1}(S) = \sum_{i=1}^{j} F_N(S - v^1{}_i Z)\ P(v^1{}_i) \qquad 3.16\ a$$

where $F_N(S)$ is the probability of more than S capacity being unavailable.

$v^1{}_i$ is the capacity state i, representing the proportion of a plant's capacity which is unavailable.

$P(v^1{}_i)$ is the probability of state i occuring.

Z is the installed capacity of the unit.

Two state models usually provide adequate accuracy for long range studies and equation 2.16a reduces to:

$$F_N(x) = F_{N-1}(x)\ (1-FOR_n) + F_{N-1}(x-C_n)\ FOR_n \qquad 3.16\ b$$

where $F_N(x)$ is the probability that, in a system composed of N units, x MW of capacity or more is unavailable.

FOR_n is the forced outage rate for plant n.

C_n is the capacity of plant n.

For the cumulative frequency calculations, the frequencies of departure from capacity states can be calculated recursively (see Albrecht et al, 1981) in the two state models as follows:

$$FREQ_N(x) = (1-FOR_n)\ FREQ_{N-1}(x) - \mu_n\ FOR_n\ F_{N-1}(x)$$

$$+ FOR_n\ FREQ_{N-1}(x-C_n) + \mu_n\ FOR_n\ F_{N-1}(x-C_n) \qquad 3.17$$

where $FREQ_N(x)$ is the expected number of occurrances of state x or greater during the period of concern for the system with N units.

3.1.2 Load Models

As described in Chapter 2 the load that utilities face is the sum of many different, yet simultaneous demands by individual customers. Typically the total load varies seasonally, daily and hourly according to a fairly regular pattern. Peak demands are likely to occur during a given season in some climates, though in other situations this is less predictable. Generally since a significant proportion of the electricity production is for industrial use, weekend and holiday demand is less than weekday demand. Peaks in daily demand cycles generally occur during the working hours or early evening. Figure 3.1a shows a plot of the hourly load which might be experienced over a typical 1 week period. The regular cycle can be seen, as can the apparent random noise which is imposed on this. An analysis of electricity demand as a function of weather shows that wind speed, temperature and cloud covers all influence the demand for electricity (Davies, 1958). Equally business conditions and industrial activity play an important role.

A number of representations of this load are possible. For planning studies, attention may focus on the yearly peak, on daily peaks, on the entire load, or on some combination of these. The most appropriate model is dependant on the characteristics of the load, of the plant, and the utility generally.

One possible model is that which represents the single annual peak load. For this it may be adequate to use a probability density function of that load. The density function can be constructed using

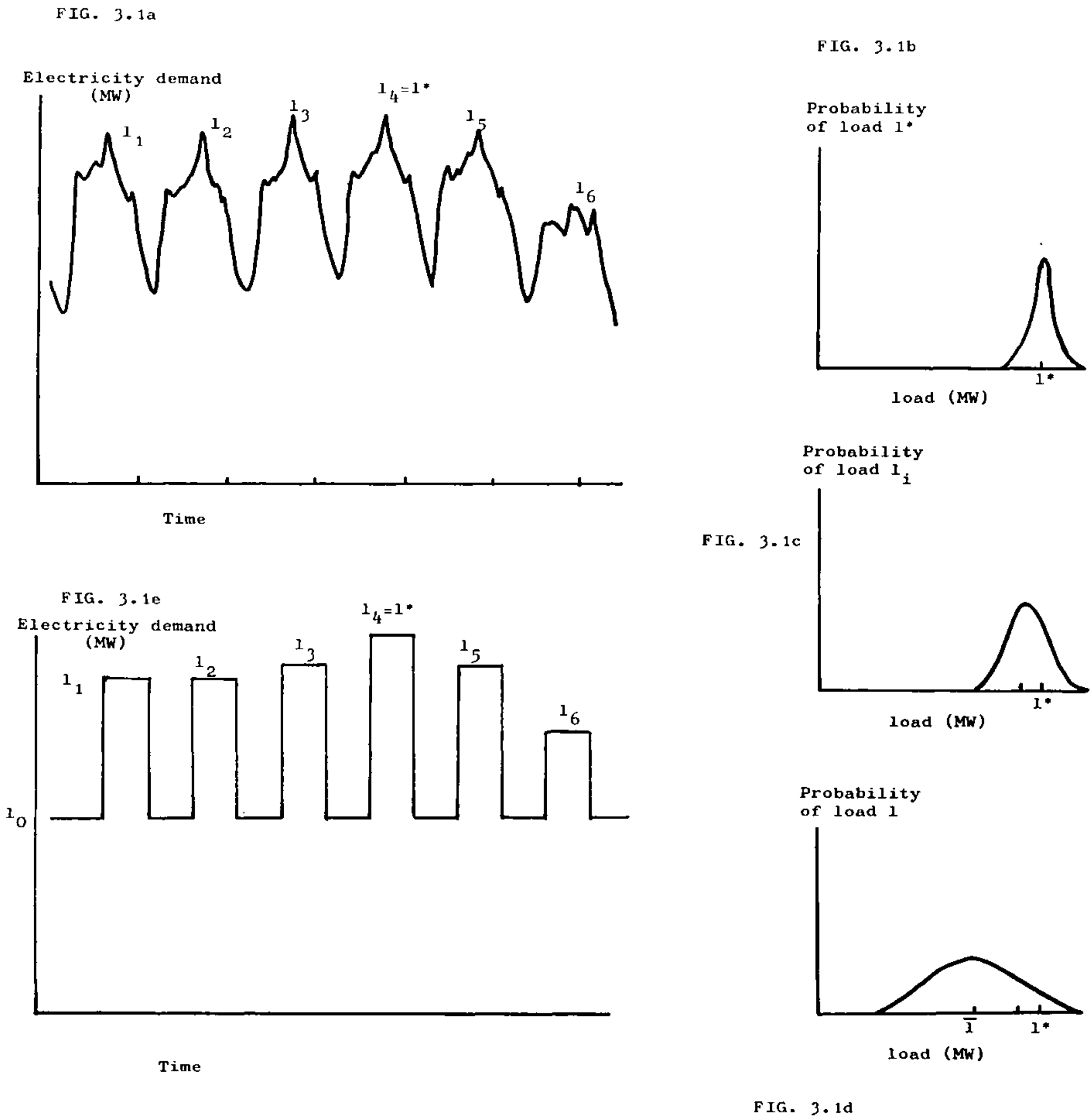


FIGURE 3.1 Load models
a recorded chronological load curve
b single peak-load model
c multiple peak-load model
d complete load model
e multi-level exposure factor model

estimates of the mean and variance of the load forecast, as well as the variance caused by weather or other relevant parameters. Jenkin (1978) has described the construction of a single annual peak load model as follows:

"... The CEGB uses statistical models with random numbers which represents weather and demand characteristics - trends, variations, correlations between different parameters and different times - over the winter period. It is then possible to simulate a large number of hypothetical winters and form the probability distribution of possible values of winter peak demand".

Alternatively a demand model can be used which represents not the probability distribution of the annual peak load, but rather the distribution of the daily peak loads. Ontario Hydro uses the distribution of peak loads expected during December weekdays as the basis for the annual load model (Slater et al, 1976). (It is assumed that the effect on reliability of seasonal variations in load, is offset by the need to perform maintenance). In figure 3.1b, which provides illustration for comparison with the previous load model, Ontario Hydro's model would represent information about all of the points l_i rather than only the single peak point l^*. This type of model is referred to later as the multiple peak load model.

A third alternative for a load model would be to use the probability density function of the load at any time during the year. In a slightly different form this is the same as the load duration curve used in the production cost models used in Chapter 2.

A fourth model, a Multilevel Exposure Factor (MLEF) load model, has been introduced by Billinton and Singh (1972). Primarily it has been developed for use with frequency and duration generation models but is more widely applicable. It is illustrated in figure 3.1 e. If sub-loads are used in each daily cycle, they are assumed to be sequentially correlated. The sequence of daily cycles is assumed to be random. After each daily cycle the load returns to a low level which is assumed to be the same for all days. For the model key parameters are:

e_i the fraction of the sub-period i during which elevated load l_i is experienced.

λ_1 the transition rate from load level 1.

l_{ij} the load levels $i = 1$ to N experienced during day j, $j = 1, K$.

For the simple model in figure 3.1e

$$\lambda_{1o} = 1/(1-e) \qquad 3.18\text{ a}$$

$$\lambda_{1i} = 1/e \qquad 3.18\text{ b}$$

and the state probabilities are

$$P_{1o} = 1-e \qquad 3.19\text{ a}$$

$$P_{1i} = \alpha_i e \qquad 3.19\text{ b}$$

where α_i is the relative frequency of peak i.

3.2.3 Reliability Indices

In any system whose components are subject to random failures, or where demands to be placed upon the system are unpredictable the possibility of failure must be accepted. To quantitatively compare reliability of different systems to evaluate the effect of a modification to a given system, it is necessary to have indices which can express system failure events on a frequency or probability basis.

Reliability indices for adequacy assessment may be classed generally under the categories, probability, frequency, duration, and expectation. As will be seen, these categories often overlap, and infact in some circumstances conversion from one index type to another is possible or even trivial (Endrenyi, 1979).

(i) Loss of Load Probability

The most widely used risk index seems to be the Loss of Load Probability which has been defined as "the long run average number of days in a period of time that the load exceeds the installed capacity" (IEEE, 1978). As shown in section 3.2.2 a number of models of load are possible and are in common use in utilities. As a result, a LOLP defined by this simple definition can take on several different meanings. However it is possible to relate a number of risk indices by introducing a general term which is applicable to each. Let the capacity deficiency risk index, CDRI, be defined as

$$\text{CDRI} = \text{Prob}\ (x<l) \qquad 3.20$$

where x is the available capacity

l is the load.

Equation 2.21 can be written more explicitly as

$$\text{CDRI} = \int_{l=o}^{\infty} p(l) \int_{y=\text{CAP}-l}^{\text{CAP}} f(y)\ dy\ dl \qquad 3.21$$

where p( ) is the density function of load

f( ) is the density function of unavailable capacity

CAP is the installed capacity of the system

l is the load.

Depending upon which model of load is used, a variety of interpretations of CDRI are possible. If the single peak load model is used in the CDRI calculation, the result can be interpreted as the probability that, at the time of simultaneous maximum demand, the system capacity that is available for duty is insufficient to serve the system load. This is the definition adopted in the UK (Jenkin, 1978).

If the second or third models of load are used, the CDRI figure is equivalent to the LOLP index. (Although it is infact not a probability since it represents an expectation, being the sum of the weighted probabilities of several events. With this in mind the index has been renamed by some (Billinton, 1977a) as the Loss of Load Expectation, LOLE). Use of the multiple peak model would mean that the LOLP (LOLE) should be interpreted as the expected percentage of daily peak hours during the critical period that load cannot be satisfied. This is the interpretation of LOLP as defined by Billinton (1974).

If the third type of load model is used, i.e. the full Load Duration Curve (LDC), then the LOLP (LOLE) figure should be interpreted as the expected percentage of time during the period that load cannot be satisfied. This is the interpretation of LOLP defined by Melton (1975).

CDRI records the occurance of capacity deficiency events, and does not make use of information about the severity of capacity deficiency. The method is thus open to criticism. A measure which does not have this short-coming is the Loss of Energy (LOE).

(ii) Loss of Energy (LOE)

The LOE notionally is a figure describing the total unserved demand in the system. It is calculated as follows

$$\mathrm{LOE} = \int_{o}^{\infty} p(l) \int_{y=\mathrm{CAP}-l}^{\mathrm{CAP}} f(y)\cdot y\cdot dy\, dl \qquad 3.22$$

where $p(\ )$ is the density function of the peak load

$f(\ )$ is the density function of plant outage

CAP is the installed capacity in the system

y the shortfall of capacity relative to load

l is the load level.

The meaning of the LOE is, like the CDRI, open to a variety of interpretations depending on the load model used. If the load which is modelled is the single annual peak demand, then LOE is the expected capacity shortage during the annual peak hour. If the load model represents the range of peak daily demands, then the LOE is the expected capacity shortage at peak hours. If the load model is a simple prediction of the future LDC then the LOE is a prediction of the expected energy demand which cannot be served.

Note that using a LOE criteria may still be unsatisfactory for certain applications since no distinction is made between slight shortages which last for a long period (or which happen frequently) and major capacity deficiencies which last for a short period (or which happen infrequently). Equation 3.23 can be modified to apply a weighting factor, represented by $g(y)$, to capacity shortfalls. Equation 3.23 then is as follows:

$$\text{Risk} = \int_{o}^{\infty} p(l) \int_{y=CAP-l}^{CAP} f(y)\ g(y) y\ dy\ dl \qquad 3.23$$

French planners (Parmentier, 1979) have suggested that a quadratic weighting factor is appropriate.

Alternatively the simple LOE can be normalised either by dividing equation 3.22 by the total energy produced by the system

(Fernando, 1979), or by using the complement (Berrie, 1977). It has also been suggested that a similar measure would be more meaningful if it represented the average energy deficiency during outage events. This is the basis for the XLOL measure.

(iii) Expected Loss of Load (XLOL)

This index is defined as the expected value of capacity deficiency given an capacity deficiency event. It is equal to the expected capacity deficiency divided by the probability of capacity deficiency.

$$XLOL = \frac{\int_{o}^{\infty} p(l) \int_{y=CAP-l}^{CAP} y\ f(y)\ dy\ dl}{\int_{o}^{\infty} p(l) \int_{y=CAP-l}^{CAP} f(y)\ dy\ dl} \qquad 3.24$$

It has been pointed out that though XLOL has been developed as an absolute measure, it cannot be used to compare the reliability of generating systems of different sizes (Berrie, 1977). Nor does the XLOL indicate the expected frequency of capacity shortages.

(iv) Frequency and Duration of Capacity Deficiency

Frequency and duration indices employ load models illustrated by figure 3.1-e and make use of the average rate, A_R, at which a capacity deficiency is encountered and the average duration, A_D, of capacity deficiency. Following Albrecht et al (1981) these can be expressed as follows: if m is the margin state defined by the available capacity minus the load, then

$$A_R = \frac{1}{FREQ_N(m)} \quad m=o \tag{3.25}$$

$$A_D = \frac{F_N(m)}{FREQ_N(m)} \quad m=o \tag{3.26}$$

where $F_N(m)$ is the probability that m megawatts or less are available.

$FREQ_N(m)$ is the number of occurrences of capacity state m or less during the period.

3.2 System Reliability and Project Analysis

In Chapter 2 a review was made of the methods that are in use for estimating the economic value of plant. It was noted that a tradeoff exists between the simplifications that add clarity to the analysis, but which may introduce approximations into the model, and numerical techniques which retain their accuracy, but which may not expose the interactions in the model. A similar situation exists with respect to system reliability calculations. As Kahn (1979) notes:

> "It is tedious and cumbersome to calculate manually and exactly the various probability measures of interest in practical cases. The amount of data typically considered in such calculations is large. As a result, the main emphasis in reliability analysis has shifted toward numerical simulation in recent decades. If all that is needed is a very specific answer to a very specific question, this is a perfectly reasonable procedure. But the flexibility required for policy analysis is difficult to achieve with numerical simulation. The sensitivity of a particular result to changes in parameter values is hidden from easy observation. Analytical models, on the other hand provide a conceptual picture of the factors affecting reliability ...".

With this in mind the following section reviews the terms and calculations that have been proposed to describe the effect of a single plant on overall power system reliability. A later section builds on this to derive a useful analytical description of this effect.

3.2.1 Load Carrying Capability and Capacity Displacement

Any plant that has a finite probability of producing power at times which contribute to overall system risk will, when added to the system, reduce the risk of capacity shortage in that system. If system reliability models similar to those developed earlier in this chapter are used, the amount of this reduction in risk, for a given system, will vary according to the size of the plant, and its outage rates. Except for the difficulties imposed by discrete unit sizes it should be possible to calculate the degree to which one type of plant could, purely on the basis of system reliability, substitute for other plant. Thus one measure to compare the contribution that different plants could have in meeting system reliability constraints would be the capacity displacement of a unit relative to some notional, perfectly reliable plant.

It can also be said that the addition of a plant which has a finite probability of producing power at the time of system peak will allow a certain growth in demand before the system risk falls below that risk which existed previously. This "allowable growth" provides another measure which can be used to compare the importance of different projects for satisfying customer demands and has been labelled "the load carrying capability" of a unit (Garver, 1966). Figure 3.2 provides an illustration of the load carrying capability ΔL and the risk reduction ΔR (and thus the capacity displacement) attributable to a unit of generating plant which modifies a given risk function G_N to form G_{N+1}.

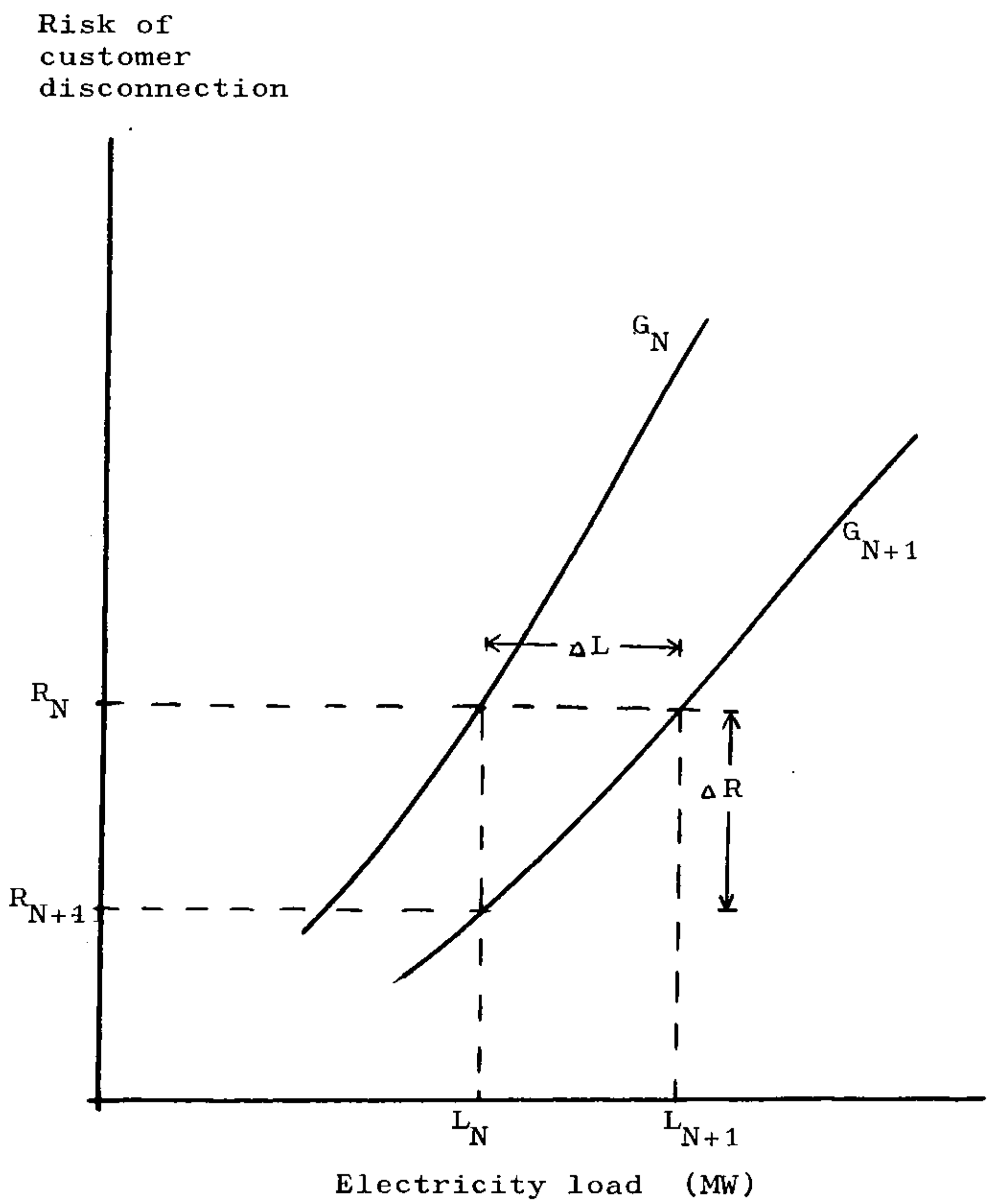


FIGURE 3.2 Load Carrying Capability and Reduced System Risk.

For the simplest type of load and plant models it is clear that the two measures are equivalent: a perfectly reliable plant, when added to a system, can be modelled as a negative load (Sullivan, 1977). For more complex reliability models the two measures may be more difficult to equate. In spite of this it has generally been assumed (Marsh, 1979) that as long as capacity displacement measures are made relative to perfectly reliable plant, and that load carrying capability is measured using a load growth which occurs in such a manner as to spread risk equally over the entire period of concern, that the two measures can be equated.

For conventional plant capacity displacement figures and load carry capability figures should provide similar rankings in plant comparisons. It is not clear that this is true for unconventional plant where it may be necessary to model many individual units as a single large plant. Further analysis of this is provided in Chapter 5, for the discussion below the load carrying capacity and capacity displacement measures are assumed to be compatible.

In defining the capacity displacement and load carrying capacity it is useful to introduce the notion of a system risk function which represents the risk of customer disconnection, as defined in section 3.2.3, as a function of the expected load. Further details of this (and the concept of equivalent load) are provided in Chapter 4. It is sufficient to note that the effect on the system risk function of adding one unit to the system, can be calculated as follows:

$$G_{N+1}(x) = G_N(x)\ FOR_{n+1} + G_N(x-C_{n+1})(1-FOR_{n+1}) \qquad 3.27$$

where $G_{N+1}(x)$ is the probability that surplus capacity, including that from the N+1 unit, is less than x

$G_N(x)$ is the probability that surplus capacity from the first N units is less than x

C_{n+1} is the capacity of the N+1 unit

FOR_{n+1} is, in a 2 state plant model, the forced outage rate of the N+1 unit.

The reduction in risk is Z where

$$Z = G_N(x) - G_{N+1}(x) \qquad 3.28$$

The load carrying capacity of the N+1 unit can be defined as Q where

$$Q = G_{N+1}^{-1}(R) - G_N^{-1}(R) \qquad 3.29$$

where $G_{N+1}^{-1}(R)$ is the inverse function of $G_{N+1}(R)$ and R is the predetermined acceptable risk level.

Since the repeated use of equations 3.27, 3.28 and 3.29 can be quite tedious a variety of approximations which are easier to use have been suggested.

3.2.2 Approximations to LCC and CD

Garver (1966) notes that the annual risk v.s. load curve can be approximated over short distances by a straight line if risk is plotted on a logarithmic scale, and the load scale is linear. Advantage can be taken of this and the load carrying capability can be approximated by an equation as follows:

$$Q = C - M \ln \left[(1-FOR) + FOR\ e^{C/M}\right] \qquad 3.30$$

where C is the capacity of the unit

M is the "system characteristic" (the slope of the risk v.s. load curve) which can be approximated as

$$M = \sum_{1=1}^{N} FOR_i C_i \qquad 3.31$$

FOR is the forced outage rate of the unit

N is the number of units presently in the system.

As Garver notes, equation 3.31 shows a number of important relationships been a unit and its LCC.

"A unit with no forced outage rate does not affect the slope of the annual risk characteristic [and has a load carrying capability exactly equal to its capacity]. The larger the unit or the larger its forced outage rate the greater its effect on the slope M [and the less its load carrying capability].
Thus the first large unit on a system while not having a large percentage of load carrying capability will have a great effect on the characteristic M, and prepare the system to make better use of the second and third units".

Garvers approximation has been used widely (Ford and Flaim, 1979, Marsh, 1979). A more complicated expression based on similar principles has been suggested by Guminiski and Kuminiski (1968).

Alternatively, in some cases estimates of a units capacity displacement can be made which take advantage of the central limit theorem and which make use of the Gaussian shape of the system risk function. Yousif (1977) suggests one formulation which can be applied to notional systems with units of equal size and outage rate. Kahn (1977) has suggested a formulation which is adequate for large systems, but for which modifications are suggested in small systems (Levy and Kahn, 1980).

Each of these expressions can be useful for gaining a better understanding of reliability issues. In the following section an expression, developed by the author is described. It is presented as a useful supplement to numerical simulation techniques.

3.2.3 An Original Approximation for Estimating Capacity Credits

In section 3.2 capacity deficiency risk, R, was defined as:

$$R = \text{Prob}\ (x < 1) \tag{3.33}$$

where x is the available capacity

1 is the demand.

Jenkin (1978) describes one method of calculating this risk. If the available capacity can be represented by aP then

$$R = \text{Prob}\ (aP < D) \tag{3.34}$$

where a is a random variable representing the percentage of the installed capacity that is available to meet load

P is the installed capacity in the system

D is a random variable representing the load on the system.

Jenkin further notes that for large systems each of the parameters involved can be modelled as random variables having normal distributions. (As pointed out earlier Jenkin has used a single annual peak load model, other authors (Haslett, 1980) have used other load models). The risk that is calculated is the risk of the actual surplus Y being less than the mean surplus by a significant amount.

$$\text{If } Y = aP - D \tag{3.35}$$

$$\text{then} \quad R = \text{Prob}\left[\frac{Y-(\bar{a}P-\bar{D})}{\sigma} > \theta\right] \tag{3.36}$$

where θ is a predetermined constant which can be referred to as a security constant and where the bar over a parameter indicates that these are the mean values of the parameters

σ, the standard deviation of the total system uncertainty function, is defined as

$$\sigma = \left(\left(\delta_f^{\,2} + \delta_w^{\,2}\right)\overline{D}^2 + \delta_a^{\,2}\,\overline{a}^2\,P^2\right)^{\frac{1}{2}} \qquad 3.37$$

where δ_f is the coefficient of variation of the load forecasting error (%)

δ_w is the coefficient of variation of the load uncertainty from weather induced variation (%)

δ_a is the coefficient of variation of the plant availability (%).

The amount of capacity P in the system is thus determined by an equation of the form

$$\overline{a}P = \overline{D} + \theta\sigma \qquad 3.38$$

To determine the effects of small amounts of new plant on the risk, equations 3.35 and 3.36 need only be modified as follows

$$Y = aP + vZ - D \qquad 3.39$$

$$R = \text{Prob}\left[\frac{Y-\overline{a}P+\overline{v}Z-\overline{D}}{\sigma_*} > \theta\right] \qquad 3.40$$

where $\overline{v}$ is the mean availability at peak hours of new plant (%)

Z is the installed capacity of the new plant

and $$\sigma_* = (\sigma^2 + \delta_v^{\,2}\,\overline{v}^2\,Z^2)^{\frac{1}{2}} \qquad 3.41$$

where δ_v is the coefficient of variation of the availability of the new plant at peak hours.

If the distribution of Y is still represented adequately by a normal distribution, then for a given risk criteria R^1, the security constant derived for equation 3.38 can be used again. The need for capacity in the system is now defined as

$$\bar{a}P_* = \bar{D} - \bar{v}Z + \theta\sigma_* \qquad 3.42$$

where P_* is the installed capacity requirement after consideration is taken of the effects of the new plant.

Total capacity displacement of the new plant will be CC where

$$CC = P - P_*$$
$$= \bar{v}Z - \theta(\sigma_* - \sigma) \qquad 3.43$$

The capacity displacement that small increments of new plant should receive will be the first derivative, with respect to additions of new plant capacity, of the capacity of conventional plant as defined by equation 3.42.

$$\frac{\partial P}{\partial Z} \cong \frac{1}{\bar{a}}\left(-\bar{v} + \theta\delta_v{}^2\ \bar{v}^2Z/\sigma_*\right) \qquad 3.44$$

Alternatively a capacity displacement relative to the expected capacity of the system could be defined as

$$\frac{\partial \bar{a}P}{\partial Z} \cong \left(-\bar{v} + \theta\delta^2{}_v\ \bar{v}^2Z/\sigma_*\right) \qquad 3.45$$

Equations 3.44 and 3.45 are potentially very useful since they relate the contribution that a plant can make to system reliability to the characteristics of the system, the characteristics of the new plant and the level of system reliability required in the system. However, before these equations can be used for detailed work, it is necessary to check their validity and accuracy.

As well as depending on the adequacy of the other assumptions regarding plant failure, and load behavour, that are common to other reliability assessments, equation 3.40 is adequate only if the distribution of plant surplus in the system defined by equation 3.39 retains its original characteristics.

Table 3.1 - Plant and System Data for the Calculation of Capacity Credits in Figures 3.3 and 3.4

System data for use in equations 3.37, 3.41, 3.42

$\bar{D}$ = 51.2 GW

P = 65.5 GW

$\bar{a}$ = .85

δw = 3.87

δa = 3.75

δf = 9.0

Θ = .74

$\bar{v}$ = .14

δv = 1.88

Data for the new plant (equations 3.27, 3.29)

10-State Model		3-State Model		2-State Model	
P	Prob.	P	Prob.	P	Prob.
0	.632	0	.632	0	.86
5.3	.071				
15.1	.071				
23.5	.041	27.6	.315		
34.2	.041				
44.9	.041				
51.6	.01				
63.1	.02				
74.8	.02				
100.0	.053	100.0	.053	100.0	.14

P - power, % of rated power

Prob. - probability of occurance.

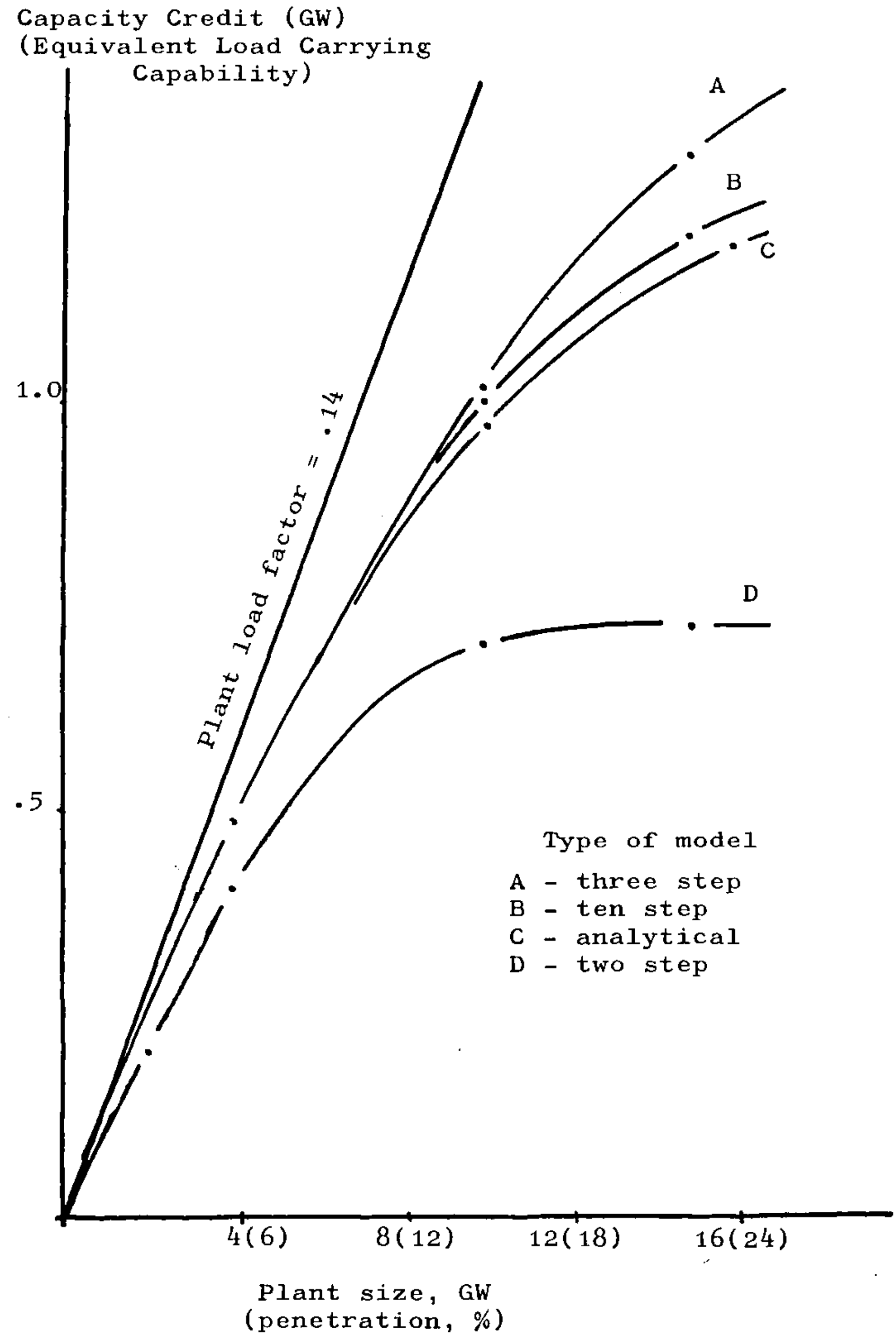


FIGURE 3.3 Testing plant models: Capacity Credit versus penetration (% of conventional capacity)

It is evident that for small amounts of new capacity, if

$$R_* = \text{Prob}\left[\frac{Y-\bar{a}P_*+\bar{v}Z-\bar{D}}{\sigma_*} > \theta\right] \qquad 3.46\ a$$

then $R \simeq R_*$

$$\text{where}\quad R = \text{Prob}\left[\frac{Y-\bar{a}P-\bar{D}}{\sigma} > \theta\right] \qquad 3.46\ b$$

and the model is adequate. For large (relative to the total system capacity) amounts of new capacity with outage distributions which may modify the general shape of the plant surplus distribution, the risk defined by equations 3.46a and 3.46b will differ, and the capacity displacement calculated on the basis of these equations will become inaccurate.

The accuracy of equation 2.43 has been tested by comparing its predictions against those made by numerical analysis. The method used in the test is similar to that used by Allan and Takieddine (1977) who examined the error inherent in using Gaussian distributions as generation models for convention plant. The tests here were performed using the system and plant described by Table 3.1. The plant output described in Table 3.1 is representative of that from current designs of large wind powered generating operating in UK wind regimes (see Chapter 6 for further details of this).

Results shown in figure 3.3 indicate that for the particular system, the particular plant, and at the given risk level the capacity credits predicted by the two methods differ by less than 5% if a 10 state plant model is used even at penetrations of over 25% of total system capacity.

The use of multi-state models of a similar type are recommended by Deshmukh and Ramakumar (1979) and Kahn (1978).

Equation 3.43, if applied properly, can be used with the load models, identified earlier as the single peak load model, the multiple peak load model, or the full load model. However the model depends on a particular family of risk indices (the capacity deficiency risk indices) and, though these are the risk indices presently in most common use by the utilities, it may be that they are inadequate for evaluating new energy sources. As will be seen in Chapter 5, for some new energy sources, plant outage will be highly correlated thus producing a large variance associated with the estimate of plant availability and as well may increase the frequency of major (thousands of megawatt) capacity deficiencies, rather than minor (hundreds of megawatts) events. It may be that in these situations Loss of Energy risk indices, or Frequency and Duration models may be more appropriate.

As will be discussed later, the capacity credit of which a plant is capable, is a function of the standard of reliability chosen for the system. It is not clear how the different reliability standards in use by different utilities compare with each other. The reliability calculations above have also neglected any consideration of maintenance. It may be that including large blocks of intermittent energy sources may make maintenance scheduling more difficult and this in turn would affect system reliability.

3.3 Discussion

Having described the accuracy, as measured against numerical simulations, of an analytical solution to the capacity credit problem, it may be useful to note the limitations of numerical simulations themselves. In addition, this section includes a discussion of the difficulties and weaknesses in the application of risk indices.

3.3.1 Limitations of System Models

Equations provide realistic models of actual generation system behaviour only as long as the assumptions and simplifications basic to the equations remain valid. Major simplifications in the generation models described are possible because it was assumed that plant failures occur on a statistically independant basis. Similarly simplifications were possible because it was assumed that total installed capacity was known with certainty. Both assumptions may, in some circumstances, be questionable.

There can be numerous occasions when failure in several units is highly correlated. For example hydro-electric plants experience outage due to icing or lack of water that may affect a significant number of units at the same time. In climates which are characterised by highly variable temperatures, steam plant and gas turbine efficiency (and thus net capacity) can be affected by the outdoor temperature and thus are affected simultaneously. Equally plants which are dependant on similar fuels tend to suffer correlated outage if fuel availability is reduced. Utilities recognise these examples as important (Ontario Hydro, 1976) and generally adapt either their generation model, or the interpretation of risk measures calculated from such generation models as required.

Likewise the assumption that total installed capacity can be known with certainty may be weak for a number of reasons. The useful installed capacity may vary because of planned outages in the system. If the required length of planned outage is uncertain then plant performance indices may have to be changed to include these uncertainties as discussed earlier. Of more concern is the increasing uncertainty about total construction times for large power stations that makes estimates of total installed capacities subject to significant uncertainty (Jenkin, 1978).

3.3.2 Simple Comparisons of Reliability Targets

Casual reference to capacity deficiency risk index typically takes the form of "loss of load of x days in y years". In that form, it is tempting to compare the reliability targets of different utilities using the ratio x/y or to utilise different load models but retain the same ratio (see Côté and Laughton, 1980 for one such example). It would seem that utilities using small ratios have stricter reliability targets than those using a large risk ratios.

To test this hypothesis, the details of the reliability calculations of three large utilities were examined and system risk using a common data base (see Appendix A-2) evaluated using the models of unit availability and system load which are used by these utilities. Details of the reliability models are provided in Table 3.2; results are shown in figure 3.4.

Reliability model A is similar to that which is currently used by the CEGB (Jenkin, 1978). The model of load focusses on the single hour peak load which, for this example, has a mean value of 52.8 GW and a coefficient of variation of 9.75%. The loss of load probability of the postulated system using this load model is 0.2 and could loosely be labelled 20 events per 100 years.

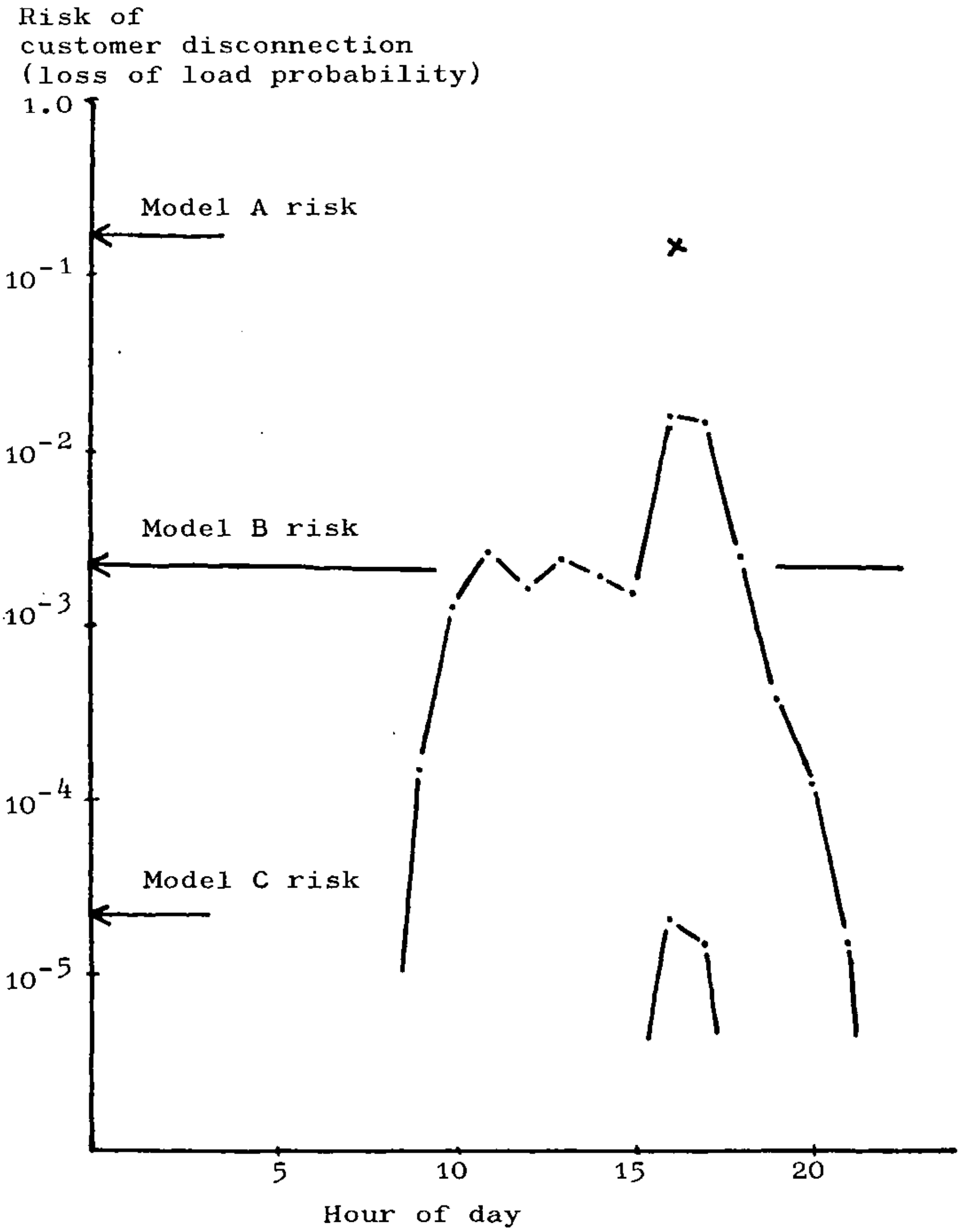
Reliability model B is similar to that used by many utilities in the United States. The load model includes all loads experienced during the peak season. Load forecast uncertainty is included, and is assumed here to be 9%. The mean load is 31 GW and the loss of load probability is .003.

Table 3.2 - A Comparison of the Reliability Models Used by 3 Utilities

	Ontario Hydro (1)	Hydro Quebec (1)	Central Electricity Generating Board (2)
Current Risk Index	1 day in 10 years	1 day in 10 years	24 in 100 years
Load Model	- 20 minute integrated daily peaks for the month of December	- monthly load duration curve	- annual single half-hourly integrated peak
	- a year is 240 week-days	- a year is 365 days	- as above
Load Forecast	estimated load forecast error is not included	estimated load forecast error is included and represented by a normal distribution	estimated load error is included and represented by a normal distribution
Load Management	no voltage reduction is considered	no voltage reduction is considered	voltage reduction is considered as part of a 3 day in 100 year criteria
Plant Availability	point estimates for each plant (∴ excludes consideration of errors in estimates of forced outage rates and planned outages)	?	mean and variance estimate for total capacity (implicitly accounts for errors in forced outage and planned outage)

(1) Slater et al, 1979

(2) Jenkin, 1979.



Model A - single hour peak load, including load forecast uncertainty and weather sensitivity.
Model B - complete season load, including load forecast uncertainty.
Model C - peak loads,no load forecast uncertainty.

FIGURE 3.4 Comparing utility reliability models.
(see table 3.2 for further details)

Reliability model C is similar to that which as been used by Ontario Hydro (Slater et al, 1976). The load model focusses on the peak loads experienced during week days in the peak season. No forecast error is included. For the data set analysed the mean value of these loads was 45.0 GW with 4% of the load being greater than 56 GW. The loss of load probability would be .00003 or approximately 1 day per 100 years.

Figure 3.4 does not show that some utilities have more reliable systems than others, it shows only that it is dangerous to compare system reliability targets without detailed study of the assumptions that are used in the reliability calculations. The simplistic descriptions applied to a variety of reliability criteria and the hidden assumptions in the system models used in reliability studies have lead to considerable confusion in discussions of system reliability (as noted in the IEEE Sub-committee on System Reliability, 1980). This confusion has extended to analysis of new energy sources.

3.3.3 Reliability Indices can be Characterised by Means and Variances

Reliability models take as their inputs, estimates of forced outage rates and future loads. The adequacy of the reliability calculations depend very much on the adequacy of the input data. Recently much attention has focussed on the importance of uncertainty in the input to these models in affecting the confidence which can be placed on the reliability indices which form the output of the model (Patton and Tram, 1978, Wang, 1977).

The inputs in use by most utilities for parameters such as forced outage rates are in fact estimates, usually expected values, of these parameters. The results of calculations using these parameters are thus themselves random variates. Though usually only one figure is

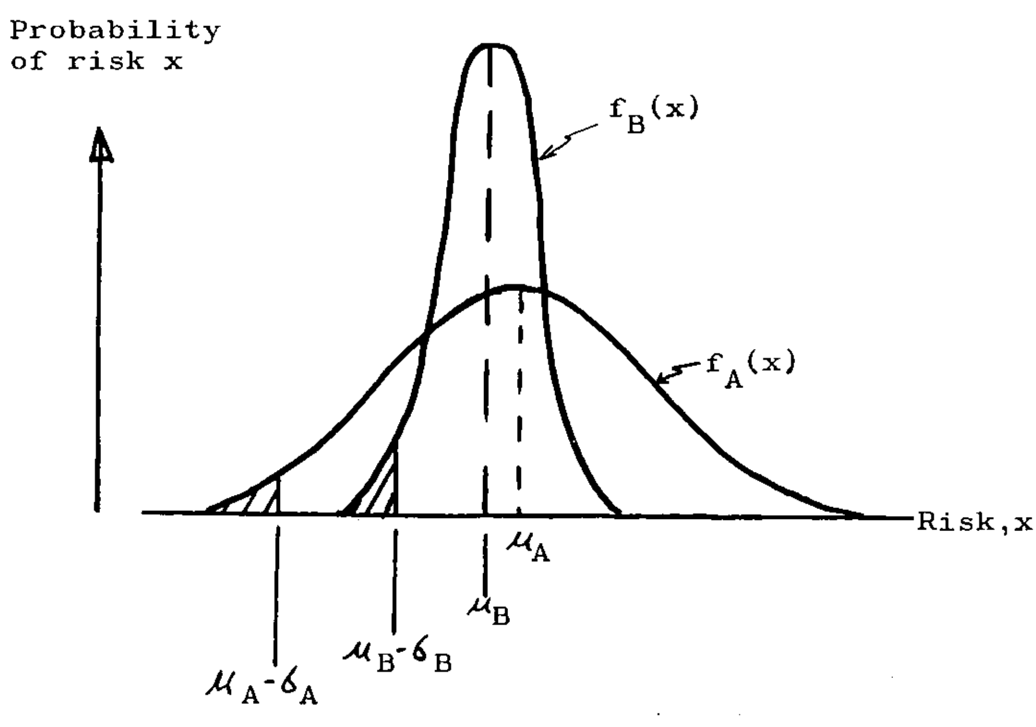


FIGURE 3.5 System risk as a probability density function.

quoted, again usually a mean, the results would more properly be described by distributions.

When only point estimates are considered it is reasonable to judge expansion options as follows;

system A is preferable to system B

if $$\mu_A < \mu_B \qquad (3.47)$$

where μ_A is the expected LOLP of system A

μ_B is the expected LOLP of system B.

It may be argued that, given a better understanding of system reliability, system B would be favoured if

$$\mu_A < \mu_B$$

but $$\mu_A + \phi\sigma_A > \mu_B + \phi\sigma_B \qquad (3.48)$$

where ϕ is a dimensionless constant

σ_A is the standard deviation of the estimate of the reliability of system A.

σ_B is the standard deviation of the estimate of the reliability of system B.

This situation is illustrated in figure 3.5.

If this argument is accepted it implies that the cost of failure in the system is a non-linear function of the frequency or severity of the failure.

A great deal of effort has been devoted to estimates of the dispersion of "point" reliability indices. As yet, though useful work has been done, arriving at accurate estimates of this dispension is computationally difficult (Patton and Stasinos, 1976).

3.3.4 Required Level of Reliability in the System

It is shown later in the thesis that the level of reliability demanded of a system could have impacts on the economics of new energy sources for use with large grids. Several authors have questioned whether present levels of generation system reliability are suitable. Certainly, as costs and opportunities for load shaping in power systems change, it is possible that the appropriate reliability level for generation systems will change.

Several points in this respect are worth summarising.

(1) It can be shown (Telson, 1975) that the expected cost of constructing, maintaining and operating the last unit of capacity added to a system to provide a LOLP level of "1 day in 10 years" is likely to exceed the possible revenue from the energy produced by that machine. Of course reliability standards have developed from a consideration of acceptable social costs and it may not be desirable to match actual revenue and expenditure. Social costs are however difficult to quantify and therefore optimal reliability levels are controversial.

(2) Customer service interruption statistics from a variety of utilities show that interruptions are generally due to failures in the transmission and distribution system rather than from failures in the generation system (Scott and Cash, 1969). It is likely that the return (improvement in reliability) on investment in the transmission and distribution system would exceed the return on investment in the generation system.

(3) The possibility of system failure will always exist. It maybe more cost effective to develope contingency plans to reduce the cost of that failure rather than using large amounts of capital to sustain large reserve margins. Since the effects of failure in the electricity supply system are not felt homogenously throughout society, selective load shedding or the provision of backup systems for certain components of society could prove beneficial (Lovins, 1977).

(4) There is no intrinsic reason why reliability should be thought of in power system planning in terms of a constraint. Customer disconnection could be thought of as a cost, similar to costs for constructing plant, for maintaining plant, or the costs of burning fuel. The best reliability for the system would be that which occurs when total system costs are minimised subject to the other constraints that society applies to the power system. The need for this type of treatment of reliability has been argued by Munasinghe (1981) and has been adopted by a variety of utilities around the world (Breton and Falgarone, 1972).

It may be adequate to summarise the discussion in this section by pointing out that although reliability targets for power systems are often represented as extremely small numbers, this is a reflection neither of precision in describing the reliability of the system nor of confidence in the validity of the targets themselves; there is still a great deal of work to be done in both areas.

3.4 Conclusions

The theoretical basis for models of failures in individual plants has been described, as have the details of models of the availability of groups of plants, and models of net customer demands. A review has also been presented of both the reliability criteria in current use by utilities and those that have been suggested as improvements to these criteria. Methods used to describe the effect of individual projects on overall system reliability have been reviewed and a model useful for elucidating the behaviour of capacity credits for new energy sources has been developed and assessed. Areas of weakness in current reliability criteria have been discussed.

Chapter 4 - Probabilistic Simulation

4.0 Introduction

As noted in Chapter 2, conventional deterministic production cost models either ignore the random nature of plant failure and the uncertainty inherent in predictions of future loads, or make use of gross approximations to include the effects of the uncertainties that these produce. New energy sources are characterised by frequent stochastic fluctuations in output and rigorous analysis of their economics has been impossible using deterministic models. Since stochastic variation can easily be included in probabilistic simulations, it is natural to use probabilistic simulation in studies of new energy sources. This chapter describes probabilistic simulation in detail and present a method of introducing the output of new energy sources into probabilistic simulation models.

The chapter starts with a review of the history and principles of probabilistic simulation. In sections 4.2 and 4.3 algorithms for the application of probabilistic simulation are presented and trends which increase the importance of probabilistic effects are studied. In section 4.4 descriptions of the extensions to probabilistic simulation that are useful for modelling power systems which include plant dependant on intermittent energy sources are given. Section 4.5 presents an outline of computer packages developed by the author for the study of new energy sources. Section 4.6 draws together conclusions from the chapter.

4.1 The Development of Probabilistic Simulation

Though, as will be shown, probabilistic simulation seems to be well suited to the study of the system economics of new energy sources, it has only recently been applied to the task. In 1967 the basic ideas upon which the present techniques for probabilistic simulation are based were described by Baleriaux et al (1967). A paper by Booth in 1971, lead to a wider awareness of the method, and numerous papers describing applications of the method (Joy and Jenkins, 1974) followed. In addition a variety of papers have presented other descriptions of the method (Vardi et al, 1977), improvements (Sager et al, 1972), and extensions (Hilson, 1977). Probabilistic simulation presently appears in a number of production costing routines [i.e. PROCOS (Goodrich, 1972), PROMOD (Slater, 1979), O.G.P. (Marsh et al, 1974), XRELCOMP, (Van Kuiken et al, 1980)] and has become part of a number of expansion planning packages which employ sophisticated routines to search for optimality [i.e. dynamic programming (Covarubias, 1978), integer programming (Fernando, 1976) and optimal control theory (Breton and Falgerone, 1972)].

Establishing the accuracy of any model of a large, complex, and dynamic system is difficult. In the case of a power system it is impossible to test the predictions of the model against experience with the system in tightly controlled situations. Too many parameters such as the actual distribution of plant shutdowns are unknown. Periods between events such as plant failure are generally long, so that observations to test the model rigorously should be made under unchanging conditions over many years. Tests of this nature are impossible in real power systems. In addition, tests of the model are made more difficult because of the need to include the effects of operating constraints or of operational mistakes, the effects of which are difficult to quantify and the frequency not well documented.

Tests of the accuracy of probabilistic models have been reported (Goodrich, 1972) (Sager and Wood, 1972) and it seems that there is little doubt that these models are generally more accurate than deterministic models (Booth, 1971). In particular, it has been noted that deterministic models generally provide poor estimates of the load factor of low merit plant. Probabilistic simulation makes more accurate assessments of these load factors and this has been an important reason for its widening acceptance. More rigorous testing is perhaps unnecessary.

It appears that probabilistic simulation will aquire an even greater popularity in future years for an additional reason relating to system reliability analysis. In the past, system planners have attempted to assume adequate system reliability in future systems by constraining options for expansion to those which meet a given risk criterion. As mentioned in Chapters 2 and 3, the need, indeed the validity, of this approach has been questioned (Munasinghe, 1980). It has been suggested instead that the costs of the interruptions that occur in customer service should be added to the total system costs and should be treated as a parameter that can be varied in any search for optimality. Because of the flexibility of probabilistic simulation it can be expected that any trend in this direction will mean that probabilistic simulation will become more widespread. Probabalistic simulation is applicable to both "reliability cost" and "reliability constraint" situations and as will be shown allows a great deal of latitude in how these costs or constraints can be applied.

4.2 Techniques for Probabilistic Simulation

Probabilistic simulation makes use of load and outage distributions rather than just single point estimates (i.e. mean values) of load or forced outage rates. At present there appear to be 4 major approaches to the calculations required. However since the basic load and plant representations are similar in each approach it is convenient to describe these general representations first.

For any given period, the load which an electricity utility must respond to can, as discussed in Chapter 2, be represented by a load duration curve (LDC). Most commonly, load duration curves have been produced, to represent the fraction of time in a given year or season that specific loads levels are equalled or exceeded. Estimates of possible LDC have been based on analysis of historical data and predictions of future trends. Much shorter time spans can also be considered in which case it becomes more satisfactory to exchange the axis of the LDC, and to recognise the load duration curve as a cumulative distribution of the load which is now conveniently described in probabilistic terms.

Plant failure, as discussed in Chapter 3, can also be modelled as a random variable. An arbitrary number of capacity states and probabilities of occurance can be defined. Because of data limitations from operating plant and computational burdens, conventional plants have generally been modelled as having just two states; 100% of the nameplate capacity available, or complete failure with no available capacity. (See Chapter 3 for the definition and calculation of outage states).

4.2.1 The Deconvolution Method

It is at this point that the techniques used in probabilistic simulation can be separated. The method used by Balereaux et al (1969) orginally, can be labelled the deconvolution method. It is most easily explained using a notional load called an equivalent load, which combines the stochastic representation of demand and of plant outage.

The load imposed by customers on a power system may in a simple model be considered to be served by the total of installed capacity minus the capacity which is out of service. The alternative approach used here, is to assume that the units suffering forced outages contribute their rated capacity to the total system capacity, but at the same time impose an "outage load" exactly equal to their rated capacity. The total of this "outage load", plus the customer load is the equivalent load. If the equivalent load (L_E) is defined by equation 4.1

$$L_E = L_D + L_O \tag{4.1}$$

where

L_D is system demand (MW)

L_O is the load imposed by plant outage (MW)

then the distribution of (F_E) the equivalent load is defined by equation 4.2.

$$F_E = F_D * F_O \tag{4.2}$$

where

F_D is the distribution of the load

F_O is the distribution of plant outage

* signifies a convolution operation.

Convolution can be accomplished with density functions where

$$F_E(x) = \int_{y=0}^{x} \int_{s=0}^{y} f_D(y)\ f_O(y-s)\ ds\ dy \qquad 4.3$$

where f_D is the demand density function

f_O is the plant outage density function

or by convolution using a distribution function.

$$F_E(x) = \int_{s=0}^{s=s_{MAX}} F_D(x-s)\ f_D(s)\ ds \qquad 4.4$$

In computer routines, it is often more convenient to use a recursive relation to accomplish the convolution plant by plant. For a two state plant representation this can be done as follows:

$$F_N(x) = F_{N-1}(x)(1-FOR_n) + F_{N-1}(x-C_n)(FOR_n) \qquad 4.5$$

where

$F_N(x)$ is the probability of the equivalent load after N plants have been considered being greater than x

FOR_n is the forced outage rate of the nth plant

C_n is the capacity of plant n.

Once the equivalent load distribution has been calculated, various aspects of system reliability, and expected energy production by individual units can be deduced as follows:

The system loss of load probability is $F_N(C_N)$

were C_N is the system capacity $C_N = \sum_{n=1}^{N} C_n$ 4.6

C_n is the individual plant cpacity,

N is the number of plants.

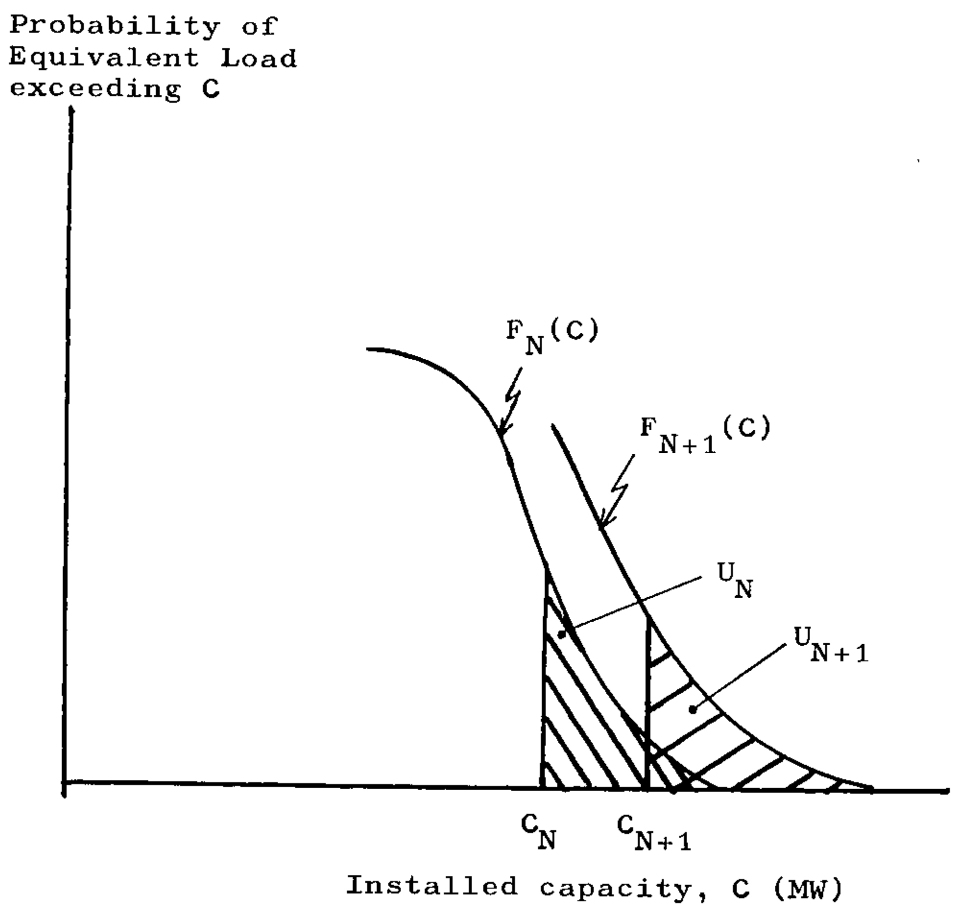


FIGURE 4.1 Equivalent Load curves and Probabilistic Simulation.

The energy demand (μ) which is not served by the system is

$$\mu = \tau \int_{C_N}^{\infty} F_N(x)\, dx \qquad 4.7$$

where τ is the time period modelled.

Equations 4.6 and 4.7 thus can be used to determine whether the particular expansion option being studied meets predetermined reliability constraints and thus deserves further study.

As shown in figure 4.1, the expected energy production (E) of plant n=N is

$$E = \tau(1-\text{FOR}) \int_{C_{N-1}}^{C_N} F_{N-1}(x)\, dx \qquad 4.8$$

$$= \tau \left\{ \int_{C_{N-1}}^{\infty} F_{N-1}(x)\, dx - \int_{C_N}^{\infty} F_N(x)\, dx \right\} \qquad 4.9$$

By combining equations 4.8 and 4.9 with dummy plants N+1, N+2 ..., of arbitrary capacity but perfect reliability, penalties for failing to meet demand can be added to the system, and probabilistic simulation can be used in "reliability cost" optimisation work.

This form of probabilistic simulation relies on deconvolution because it calculates the expected energy production of high running cost plant first and removes through deconvolution the effect of random failure of this plant before calculating expected energy production of higher merit plant. The deconvolution, to move from F_N to F_{N-1}, proceeds as in equation 4.10

$$F_{N-1}(x) = \frac{F_N(x) - F_{N-1}(x-C)(FOR_n)}{1 - FOR_n} \qquad 4.10$$

To minimise the costs of energy production, plants must be "deconvolved" from the equivalent load curve in reverse merit order. The initial convolution itself can be done in any order. The form of the deconvolution equation means that numerical instability may be encountered because of rounding error (Sager et al, 1971). As well the method's accuracy is sensitive to the step size (relative to the unit size) chosen for the calculations, though this problem is easily avoided if larger execution times and memory requirements are acceptable. To skirt some of these problems, other methods have been suggested.

4.2.2 The Forward Convolution Method

A second method used for the probabilistic uses a forward convolution process using equation 4.5. The instabilities caused by deconvolution can be avoided. During the convolution, equation 4.8 is used to calculate expected energy production by each unit. Units must be brought into the calculation in merit order if costs for energy production are to be minimised. The method has the advantage of requiring less computing time than the deconvolution method for establishing unit energy production and system reliability indices, but suffers the disadvantage that reliability indices are only available after the main body of calculations are done. It thus does not lend itself to exploratory reliability calculations.

4.2.3 The Unit Dispatch Method

The third method, labelled by Sager et al (1972) as the unit dispatch method, uses a different approach to probabilistic simulation and offers a different perspective for viewing the calculations. The method avoids the complicating notion of equivalent load.

The total expected cost E(COST), of the energy production for a given time interval, τ, for the N.th unit may be expressed as

$$E(COST) = \tau\,(1-FOR_n) \left\{ \left[\sum_{L=0}^{L<C_{N-1}} \sum_{x=L-C_n}^{x=L} \Delta L\; P(L)\; P_N(x) COST_n(L-x) \right] + \sum_{L=C_{N-1}}^{L=L_{max}} \Delta L\; P(L)\; COST_n(C_n) \right\} \qquad 4.11$$

where $COST_n(\ )$ is the energy production cost of unit n at various part loadings

$P(L)$ is the probability of load L

C_n is the capacity of the nth unit

C_N is the total of the capacities of the first N units

$P_N(x)$ is the probability of less than x MW being available from the first N units

ΔL is the step size for the calculation.

$P_N(x)$ can be calculated using a recursive equation similar in form to equation 4.5.

$$P_N(x) = P_{N-1}(x)\; FOR_n + P_{N-1}(x-c)(1-FOR_n) \qquad 4.11\ b$$

Though equation 4.11 is a daunting collection of functions, its evaluation is simplified by the use of such recursive relationships.

4.2.4 The Expected Cost Method

The fourth method, introduced by Sager et al (1972) has been labelled the expected cost method, and again does not require the notion of equivalent load. For any combination of plant, the probability of having different amounts of plant available can be calculated using equation 4.5. Again assuming that calculations are done plant by plant in merit order, the expected production cost for each increment of load ($EKST_N(L)$) can be calculated as follows

$$EKST_N(L) = EKST_{N-1}(L) + P_{N-1}(L) \cdot COST_n (1-FOR_n) \qquad 4.12$$

The total system operating costs, TC, can then be calculated since.

$$TC = \tau \sum_{L=0}^{L=L_{MAX}} \left[P(L) \sum_{l=0}^{l=L} EKST_N(l) \; \Delta L \right] \qquad 4.13\ a$$

It has proven useful to develop this formulation further

$$TC = \tau \sum_{L=0}^{L=L^*} \Delta L \; EKST_N(L) + \tau \sum_{L=L^*}^{L=L_{MAX}} \frac{dP(L)}{dL} \cdot EKST_N(L) \; \Delta L \qquad 4.13\ b$$

where L^* is the lowest predicted load during that period. In this form, the second term in 4.13 b is the expected marginal cost during that interval. This formulation has been used in this thesis to undertake sensitivity analysis of the marginal production cost due to randomness from a variety of sources, (see section 4.4), and marginal analysis of the economics of new plant, (see Chapters 5 and 6). In other research (Holmes, 1980) it has been used to calculate possible tariffs for the exchange of electricity between industrialists, using combined heat and power schemes, and the Electricity Supply Authority.

4.3 The Effect of Statistical Variation on Production Costs

During the early development of probabilistic simulation, several authors have noted trends which were becoming firmly established in power systems and which would increase the need for the replacement of deterministic simulation with a more accurate production costing model. To summarise these trends, they include:

(i) Increasing uncertainty about future loads levels (Sager et al, 1972).

(ii) Higher plant failure rates and increased uncertainty about these rates (Booth, 1971).

(iii) Larger plant sizes (Balereaux et al, 1967, Booth, 1971).

(iv) A wider range of plant operating costs (Booth, 1971).

(v) Increased use of pumped storage plant (Balereaux et al, 1967).

(vi) Increased use of hydro-electric schemes with variable inflows (Booth, 1971).

(vii) Increased uncertainty about construction load times (Sager et al, 1972).

Little effort has been devoted to tracing the common link in these trends.

To study these links, and to determine why probabilistic simulation models are more accurate than deterministic models, tests have been carried out as part of the authors research to estimate the production cost predicted in a simple system using a probabilistic simulation model (the Expected Cost Method) and to compare these results with those from a simple deterministic production cost model.

In a deterministic production cost model the total production costs are obtained as the weighted integration of the load experienced using plant whose capacities have been derated by their expected availabilities, but otherwise, are perfectly reliable and which are loaded in merit order. Relevant costs in determistic production cost models are thus expressed by equations 4.14 and 4.15

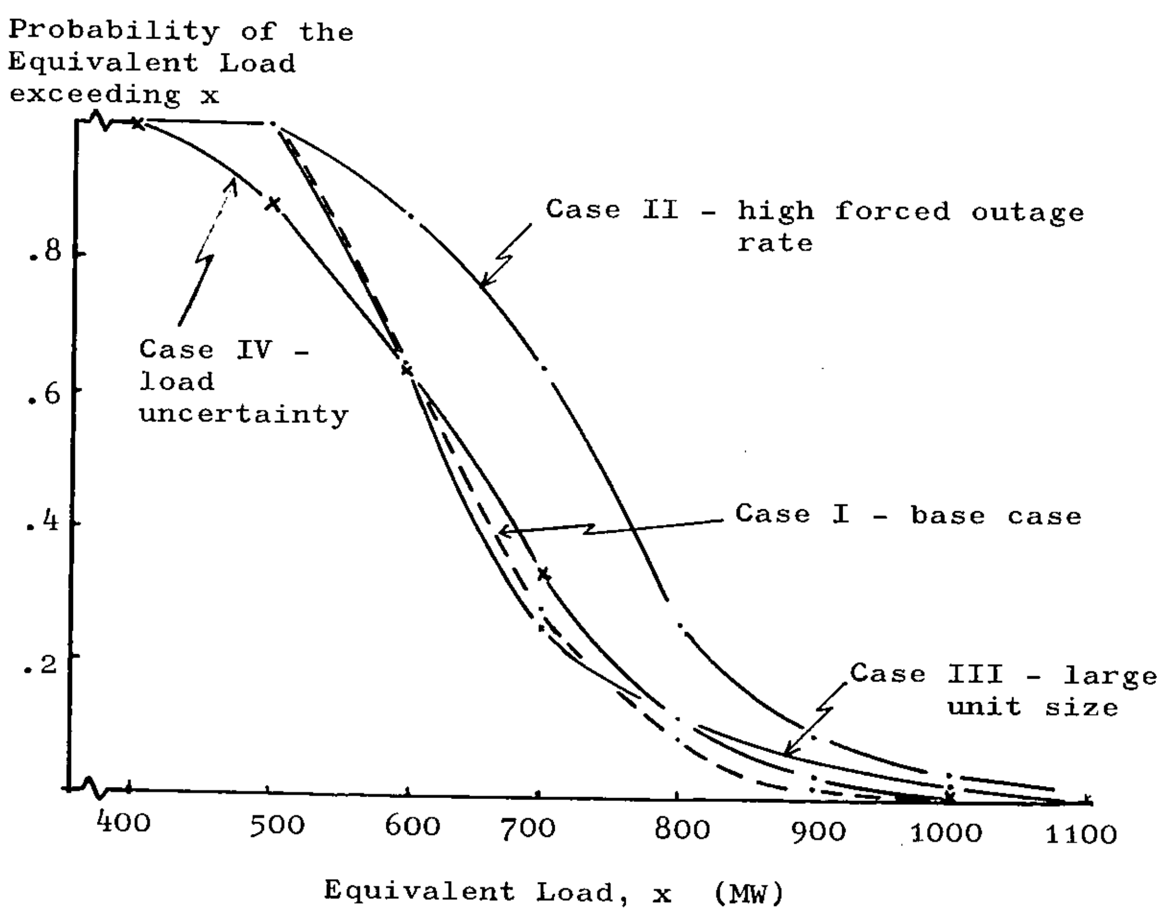


FIGURE 4.2 Equivalent Load curves for a simple system (see Table 4.1 for details)

$$TC = \tau \sum_{n=1}^{N} C_n \cdot (1-FOR_n) \cdot COST_n$$

$$+ \left(L - \sum_{n=1}^{N} C_n \right) COST_{N+1} \qquad 4.14$$

$$MC = COST_{N+1} \qquad 4.15$$

where $\sum_{n=1}^{N} C_n \; (1-FOR_n) < L$

and $\sum_{n=1}^{N+1} C_n \cdot (1-FOR_n) > L$

and where

TC - the total cost per unit time of meeting the load L

MC - the marginal cost when a load L is met

n - an index describing the plant considered

N - an identifier describing the last plant to be loaded whose capacity is used fully

C_n - the capacity of the nth plant

$COST_n$ - the energy production cost of the nth plant

L - the load level

As a base case for the analysis a system defined in Table 1 was used to meet a load of 500 MW. Subsequently, cases were tested using slight changes to the system and the load which are described below. Each change has an effect on the equivalent load duration curve which, as will be seen, can have an effect on the accuracy of the production costing models. These effects will be reflected in the marginal cost at given loads. Figure 4.2 shows the resultant equivalent load duration curve for the 4 cases studied. (Note that

Table 4.1 - PLANT CHARACTERISTICS FOR A SIMPLE SYSTEM

COLUMN	(1)					(2)	(3)		(4)	
CASE	BASE-LINEAR					BASE-EXP	RELIABILITY		PLANT SIZE	
	PLANT LABEL	UNIT CAPACITY (MW)	FOR	FUEL COST (P/kWh)	NUMBER OF UNITS	FUEL COST (P/kWh)	FORCED OUTAGE RATE a	FORCED OUTAGE RATE b	UNIT CAPACITY (MW)	FUEL COST (P/kWh)
	1	100	.1	1.0	1	1.0	.05	.2	300	2.2
	2	100	.1	1.5	1	1.25	.05	.2	300	3.8
	3	100	.1	2.0	1	1.5	.05	.2	300	7.6
	4	100	.1	2.5	1	2.25	.05	.2	300	15.0
	5	100	.1	3.0	1	3.25	.05	.2		
	6	100	.1	3.5	1	4.75	.05	.2		
	7	100	.1	4.0	1	6.75	.05	.2		
	8	100	.1	4.5	1	9.25	.05	.2		
	9	100	.1	5.0	1	12.00	.05	.2		
		2000	.0	5.5	1	15.00	.05	.2		

Table 4.2 - A COMPARISON OF EXPECTED SYSTEM MARGINAL COSTS FROM DETERMINISTIC AND PROBABILISTIC MODELS

Case	Resulting Marginal Cost at L = 500 MW Deterministic Model (A)	 Probabilistic Model (B)	Percentage Diff. $\left(\frac{A-B}{B}\right)$
	(p/kWh)		
Base Case-Linear	3.277	3.277	0
Base Case-Exponential	4.083	4.174	2%
Load Uncertainty	4.083	4.374	6%
Plant Reliability			
FOR = .05	3.644	3.665	0.5%
FOR = .2	5.250	5.534	5.1%
Unit Size*	3.800	4.431	14.2%

* Not directly comparable with base case since it was necessary to charge more than 1 parameter.

where the load is specified at a single point, the equivalent load density function has the shape of the plant availability density function; where each plant is perfectly reliable, the equivalent load duration curve has the same shape as the LDC.)

Table 2 shows the results of the four cases studied which are explained below.

4.3.1 Cost/Load Curve

To test the effect of the shape of load cost curve (which reflects the rising production cost of plant in the merit order schedule) two load cost curves were used in the analysis (see Table 1 column 1 and column 2). Plant sizes and availabilities as well as the load characteristics were identical. In the first case, the load cost curve had a constant slope; in the second case the load vs cost curve is characterised by costs that rise slowly initially and much more rapidly later thus approximating exponential growth in costs. This latter form is much closer to actual utility experience (Peddie, 1975) than the linear cost curve. Table 4.2 shows that the predicted marginal costs when servicing a load of 500 MW, and when using the non-linear cost curve, are different depending upon the method used for the prediction. The derated method underestimates costs by approximately 2%.

4.3.2 Load Forcast Error

In power systems loads must be predicted well in advance; error is possible and uncertainty is introduced. To test the effect that this uncertainty may have an expected production costs, a case was assessed in which there was an equal probability of the load being 400 MW, 500 MW and 600 MW. This uncertainty can have no effect if mean values are used in a deterministic model, but, where a non-linear cost curve is used, it raises the expected margin cost significantly and this result is shown in the probabilistic simulation.

4.3.3 Unit Availability

To illustrate the effect of increased forced outage rates calculations were done assuming that the forced outage rates (see Table 4.1) were changed from .1 to .2 and from .1 to .05. Using the linear cost/load curve, the two models produced identical estimates of marginal costs. When the non-linear curve was used, the differences between predictions using the derated method and probabilistic simulation were 5% and 0.5% respectively.

4.3.4 Unit Size

To illustrate the effect of increased unit sizes, and therefore a decrease in the required number of units, calculations were done assuming base case characteristics for the system, but replacing the 10 x 100 MW units with 4 x 300 MW units. Using the non-linear cost/load curve the estimated marginal costs at the 500 MW load level from the deterministic and the probabilistic models differed by 14%.

4.3.5 System Size

If unit size is important in determining the accuracy of production cost models, it would seem that system size may also be important. Small systems may be able to make use of the same range of plant types as those used in larger systems (i.e. nuclear, coal, oil, gas turbine, hydro), but may choose to use different unit sizes (or similar sizes but fewer units). In fact since the size of a unit can only be measured relative to the total system, system size and unit size cannot be measured independantly. Therefore results pertaining to changes in unit size are relevant here. In large systems many units are used so that each unit can be described as small, and so cost estimates from probabilistic and deterministic models converge.

4.3.6 Summary

Two hypotheses can now be offered:

(1) Probability simulation becomes a better predictor of systems operations costs as the variance of the equivalent load curve increases, relative to the curvature in the cost/load curve. As can be seen by the definition of equivalent load, the variance would increase as unit size increases, as forced outage rates increase, or as load uncertainty increases.

Probabilistic simulation thus is more important in small systems employing plant with a wide range of operating costs, than for larger systems employing a larger number of plants but which have a range of operating costs similar to those in the small system.

(2) Total system costs will rise for systems facing a concave-up load/cost curve as the variance of the equivalent load increases.

Both hypotheses follow from an understanding that, for an arbitrary function f(x), generally it is true that $f(\overline{x}) \neq \overline{f(x)}$, where the bar indicates an average value. Deterministic simulation is analogous to $f(\overline{x})$, probabilistic simulation is analogous to $\overline{f(x)}$.

When modelling complex systems it is difficult to isolate the effects of statisical variation on total system production costs. However, for the system described in Appendix A-2, the omission of load forcast uncertainty from the load description reduces marginal production costs by up to 15%. Estimates of marginal production costs using the expected capacity of each plant differ from those using the full availability density function by less than 2%. In systems where only a few plant types exist (see for instance the optimised system described in Appendix 2) the use of deterministic production cost models lead to unstable marginal system production costs.

4.5 Probabilistic Simulation and New Energy Sources

New energy sources will, because of the intermittent nature of their output, increase the variance of the equivalent load curves which characterise a system. Because the new energy sources which are being considered generally are high capital cost low operating cost plant, they will increase the range of operating costs embodied in a system's generating plant. As shown in the previous section both are considerations that increase the need for probabilistic production cost routines.

4.4.1 Load/Plant Representations

As noted in section 3.3 the load duration curve can be defined as a cumulative distribution curve. Usually it is constructed from chronological load curves taken over a large time period, but it can also be derived from probabilistic chronological load curves. For the analysis in this thesis probabilistic chronological load curves have been constructed based on the load recorded by the CEGB National Grid Control during 1977-1978. These data can be manipulated in a number of ways some of which are described in Chapter 3 to form appropriate load density functions. Figure 4.3 shows a notional probabilistic chronological load curve.

More detailed curves are discussed in Appendix A-Z and are shown in figure A2.1.

Probabilistic chronological load curves simply show the probability of different demand levels as a function of the time of day. This extension is in principle an improvement on the concept of

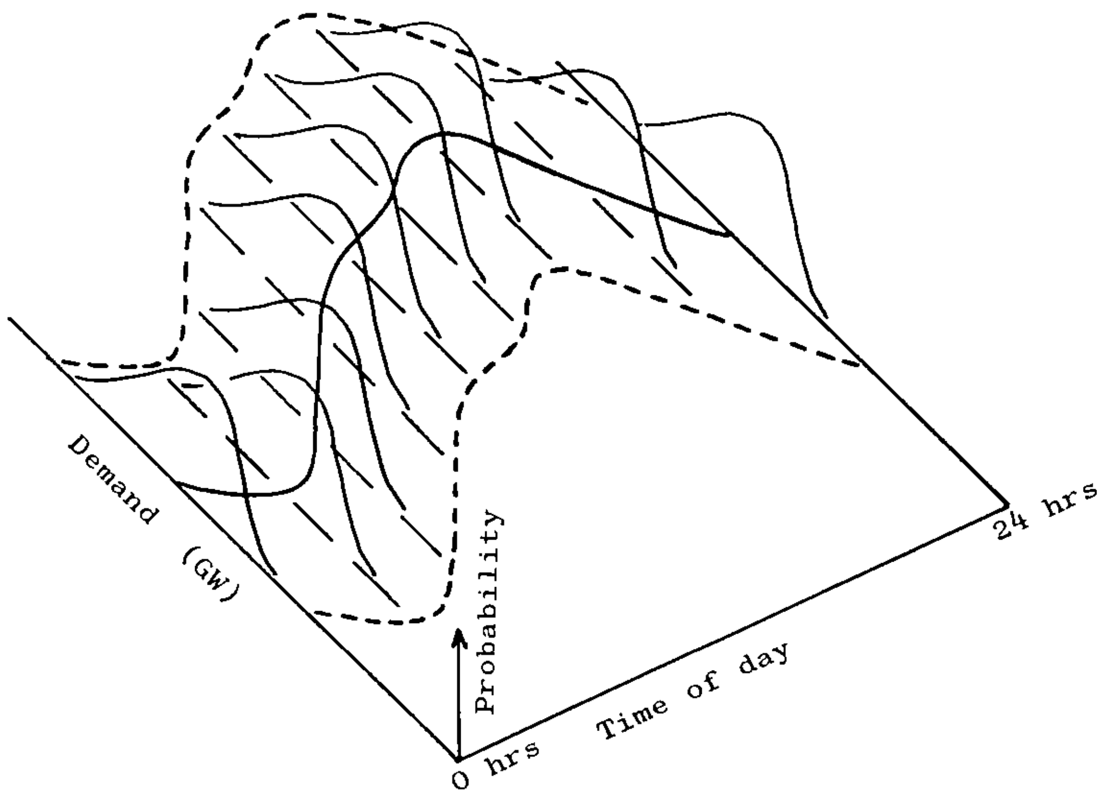


FIGURE 4.3 Probabilistic Chronological Load Curve.

an LDC constructed on the assumption that the load is a known function of time; it is also necessary in practice to deal with certain characteristics of some new energy sources (particularly the fact that the plant output density functions show important diurnal and seasonal fluctuations).

In dealing with energy sources which are characterised by very low running costs it is convenient to redefine the equivalent load equation slightly and break it into two parts. Because energy availability from renewable energy sources, though predictable over the long term, tends to have random elements in the short term, it is appropriately represented by a probabilistic chronological power curve analogous to the probabilistic chronological demand curve discussed earlier. Further details of the suitability of various density functions for describing the output of plant such as windmills are described in Chapter 5.

The concept of the equivalent load can now be extended by combining the positive load (customer load) with the negative load (from the new energy source). In mathematical terms we define

$$L_I = L_D - L_W \qquad 4.16$$

$$L_E = L_I + L_0 \qquad 4.17$$

where L_I is an intermediate equivalent load

L_W is the output from the new energy source.

At each point on the time axis of the chronological load duration curve, the probabilistic representations of L_D and L_W are combined by convolution to give a resultant probabilistic chronological representation of L_I which can then be reduced to a probabilistic load duration curve. The probabilistic simulation now proceeds in the manner described earlier.

System reliability levels before and after the addition of these new energy sources can thus be calculated conveniently. From this, capacity displacements or load carrying capabilities for new energy sources can be calculated easily. Additionally the true worth of the energy produced from new energy sources can be calculated, and the uncertainty associated with new energy sources placed in its proper perspective. The calculation of total cost vs load, and marginal cost versus load curves (merit order cost curves) has been found to be especially useful in light of the smoothing nature of the convolution operation (see figures 4.4, 4.5).

4.4.2 Computer Aided Analysis

Two suites of computer programmes were developed to supplement analytical methods of studying the systems economics of new energy sources. Programme RENEW3 is designed to analyse the effective load carrying capability of new plant and their effect in terms of other reliability measures, the influence of new plant on the operation of conventional plant already existing in the system, and the energy production value of new energy sources. It has also been designed to provide statistical information about the output of the new plant, the availability of conventional plant, and characteristics of the load. Probabalistic simulation is carried out using the deconvolution method described in section 4.2.1.

Programme PRICE3 is designed to make use of the Expected Cost Method of probabilistic simulation and calculates system cost functions (expected order of merit schedule, see figure 4.4),

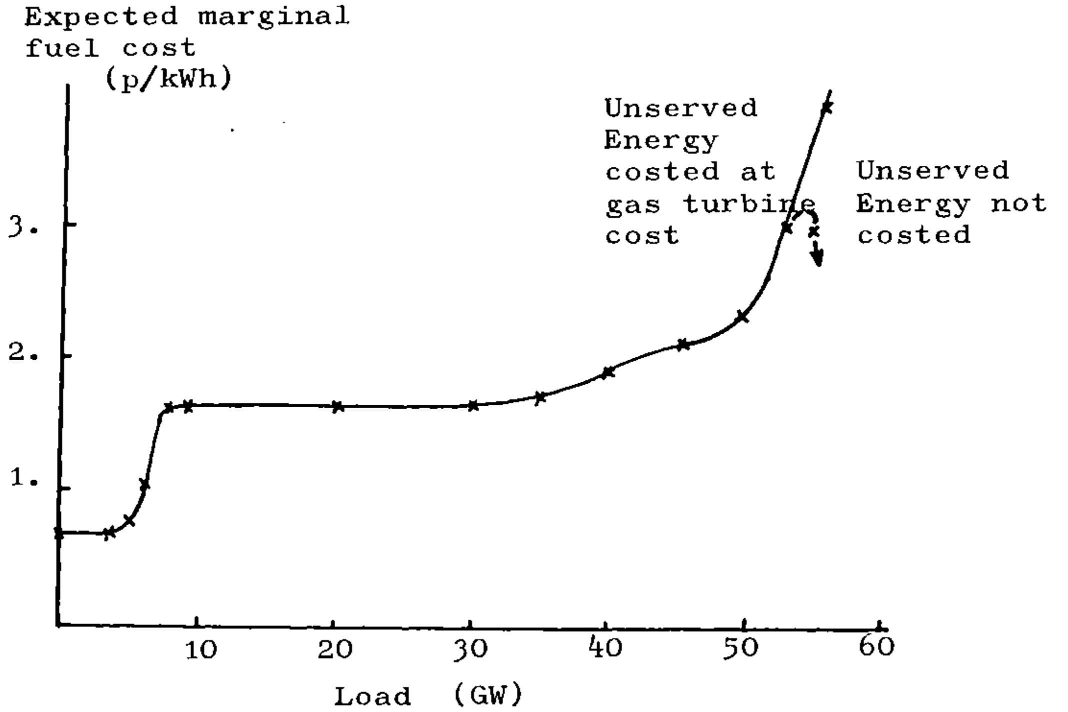


FIGURE 4.4 System marginal fuel cost curve (merit order cost curve) for 1985 system (BAU scenario), peak season.

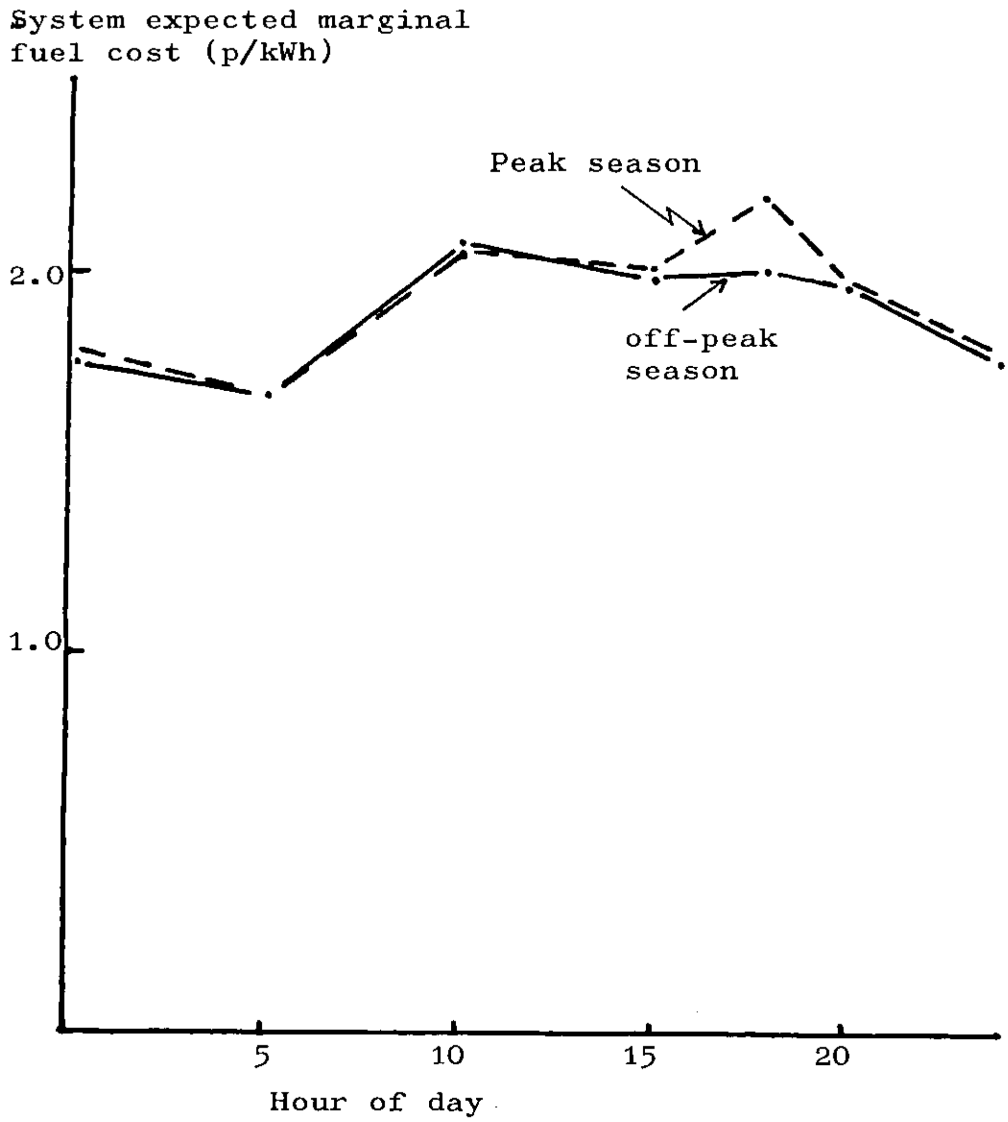


FIGURE 4.5 System expected marginal fuel costs, 1985 system, base case (BAU scenario)

expected marginal costs (see figure 4.5), and hourly, seasonal and annual system reliability. Further details of both programmes are presented in Appendix A.

4.5 Conclusions

The background to probabilistic simulation has been presented and it has been shown that an efficient method exists which can include the effect of random plant outage on the annual operating costs for power systems. A variety of useful formulations for probabilistic simulation have been presented, and used in exploring the effect on total expected system operating costs of variations in the random nature of a number of parameters. An extension to probabilistic simulation has been presented which can be used for detailed studies of the economics of intermittent energy sources.

Chapter 5 - A Framework for the Evaluation of New Energy Sources

5.0 Introduction

The systems economics of any plant can be described as a function of its cost and its worth. The worth of a plant is the net savings that can be achieved in the system as the result of the existence of that plant. If models can be used that capture all of the effects on the system that result from the integration of new energy sources into that system, then the problem of quantifying the worth of these sources is only to feed the correct input into models and to analyse the results. It was shown in chapter 2, however, that a variety of models have been used in the past to analyse the economics of intermittent energy sources, that a variety of models exist even when purely conventional plant are being analysed and that many of these models can provide conflicting results. Furthermore the models often provide little information indicating how the economics of plant might change in different circumstances.

The philosophy adopted in this chapter is to utilise the simplest possible models that are capable of capturing the important features in power system planning, operation, and analysis, relevant to wind driven plant and to use these models to explain how the worth of new plant is derived. Numerical examples are presented where these are useful: the data for these are drawn from the data sets described in Appendix A.2. More detailed and comprehensive results are presented in chapter 6. It is the simple models that provide a means of understanding of how plant worth changes as parameters in the model are varied.

In this chapter the system economics of new plant are analysed by dividing problems into the two areas in which plant can affect costs in a power system; production costs and capital costs. Section 5.1 examines the important considerations in the former area including the value of the fuel savings, the operating penalty that may be associated with intermittent energy sources, and how these change as more and more of these sources are used in the system. Section 5.2 deals with savings in capital expenditures and discusses the value of capacity to a system, capacity credits, and other capital savings that may occur. Section 5.3 describes the implications of the preceding sections for the economics of intermittent energy sources. Section 5.4 touches on other issues of importance that have not been quantified in the analysis. Conclusions are summarised in section 5.5.

5.1 Production Cost Savings

Electricity generated by new energy sources will, in most situations where these sources have low operating costs, be used in preference to other plant. The effect will be to displace the energy production of those plants in use by the utility which have the highest production costs. Thus in a simplistic analysis, the energy production of new energy sources can be valued at the marginal system energy cost. Two provisos are necessary:

(1) Account must be taken of the size of the "slice" of electricity introduced into the system. As the size of the slice increases, the average production cost savings decrease. This idea has been widely recognised in the literature (for examples see Johanson, 1978, and Jarass et al 1979) and is a feature which is common to economic evaluation for conventional plant. It will not be discussed further in this section. Detailed numerical analysis is undertaken in chapter 6 when the economics of specific machines are examined.

(2) The effects of intermittent generation on the efficiency of operation of conventional plant must be fully taken into

account. Two points in this regard have been raised. It has been suggested (Harris, 1980, Lee and Yamayee, 1980) that a large portion of the value of wind driven plant will be negated by the need to run other plant in inefficient modes to counter the variability and unpredictability of the wind. The cost of the resultant system inefficiency has been referred to as an operating penalty. It has also been suggested (Jarass et al, 1979) that, at times, some intermittent energy will have zero economic value because of the inability of the system to use that energy. This energy will, in effect, be spilled from the system. Both points are discussed below.

5.1.1 Operating Penalties Associated with WECS

To consider the magnitude of operating penalties associated with intermittent energy source, it is useful to review quickly some aspects of the operation of power systems. Because of the size and complexity of large modern thermal plant it is undesirable and often impossible to follow rapid and frequent changes in the load by stopping and starting large units. Yet rapid changes in the load occur. Demand changes because of both highly predictable events (for example sunset) or less predictable events (for example the popularity of television programmes). The effective load that the system must meet can also change rapidly because of transmission or generation failure which may decrease the amount of low fuel cost plant in use. Current policy in most utilities is to cover unpredictable generation demand mismatch using pumped storage plant in spinning mode, and marginal part-loaded plant. Additionally, gas turbines, capable of picking up load from standstill within minutes are held in reserve. Therefore, though the system can operate successfully in the presence of unpredictable variability in demand, this variability does incur added cost. Operation of part-loaded plant incurs a cost penalty because of loss in efficiency and out-of-merit running; the output from storage could be used to displace low merit plant at times of high demand thus its premature use incurs a penalty; gas turbines must use expensive fuel.

At present little reliable data is available to describe either the variability of most intermittent energy sources or their predictability. It is difficult therefore to calculate exactly the increased operating costs that will be associated with the integration of intermittent energy sources into the grid. It is, however, possible to place a bound on these increased costs, by considering the options available for responding to variable energy sources.

The most conservative credible scenario for dealing with intermittency would be to provide sufficient additional spinning reserves through the use of marginal part-loaded plant to completely cover total failure of such generation. The cost of this additional spinning reserve will, to a first approximation, represent a limit to the maximum credible system penalty that can be ascribed to plant with highly variable and unpredictable output.

The penalty per unit output associated with running a plant at part-load rather than full load is due to the drop in overall efficiency which occurs at part-load. A typical plot of plant efficiency as a function of the plant output is shown in figure 1a (taken from Moore and Nixon, 1981). The same information can be shown using a Willans Line as shown in figure 1b. The efficiency is the inverse of the slope of the line connecting points on the Willans Line to the origin.

From figure 1b it can be seen that if a plant is taken off-line completely, and the boiler allowed to cool, the per unit fuel savings are C_1 where

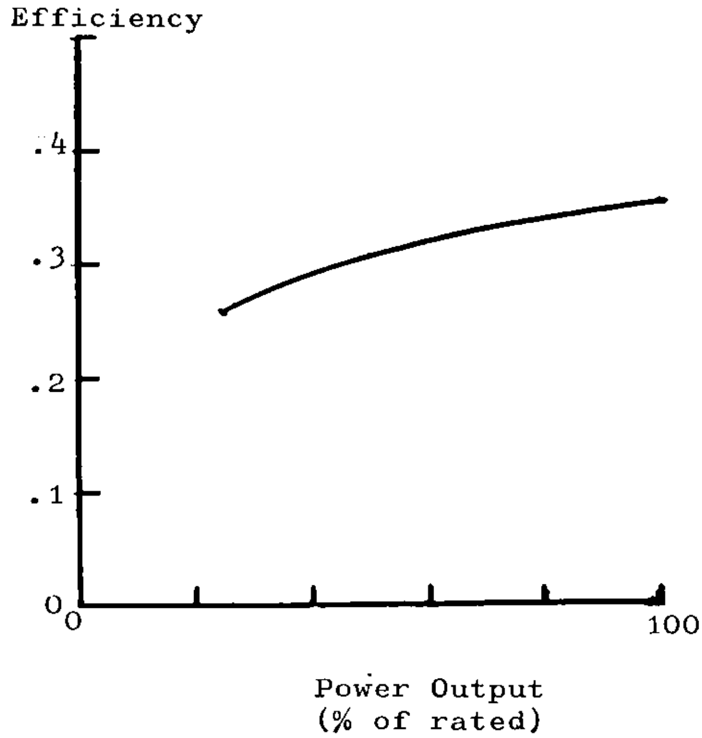


FIGURE 5.1a - Typical Part-load Efficiencies for a large fossil-fuelled power station

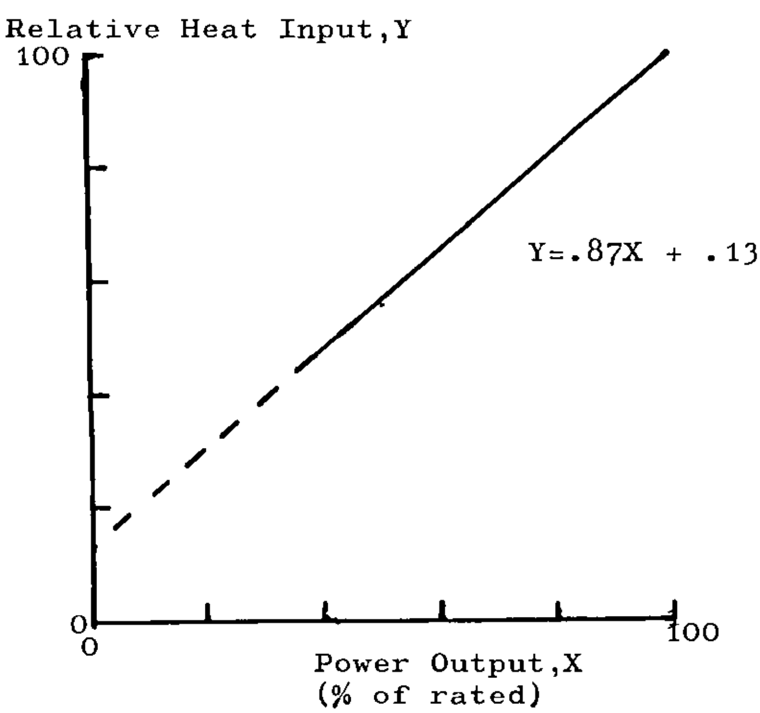


Figure 5.1b - The Willans Line for a large fossil-fuelled power station

$$C_1 = h(x)/x \tag{5.1a}$$

where h(x) is the heat consumption at load x

If the output from the plant is reduced, but the plant itself is kept "on line" (i.e. the boiler is not allowed to cool) the savings are C_2 where

$$C_2 = (h(x)-H)/x \tag{5.1b}$$

where H is the y-intercept of the Willans line

It has been suggested (CEGB, 1971) that large modern plant can be represented by a single slope Willans line. In this case the difference between C_1, and C_2 will be constant and will be determined by the intercept of the Willans line. For large power plant used in the CEGB system this is typically 13% (Rockingham, 1980). Thus in this notional system where plant could be part-loaded to zero-output, an upper limit to the penalty that could credibly be associated with intermittent energy sources would be 13% of the gross fuel saving value of the energy.

In practice large power plants cannot be part-loaded to a zero output state. Part-loading limits on each plant will mean that more marginal plant will be affected by the variability of the net load. This increased out-of-merit operation of plant will increase the system operating costs slightly. The effect can be quantified as follows. In the notional system where plant can be part-loaded to zero output, the value of intermittent sources can be calculated according to equation 5.2a.

$$\text{Value}_1 = \int_{t=0}^{T} \int_{L(t)-W(t)}^{L(t)} C_1(x)\, dx\, dt \tag{5.2a}$$

where T is the number in the period considered.

$C_1(x)$ is the system marginal cost of production at load x as defined by the order of merit schedule.

L(t) is the system load at time t.

W(t) is the level of production, at time t, of the new energy source.

Savings which have been reduced to include the effect of the system penalty due to variability can be calculated as follows:

$$\text{Value}_2 = \int_{t=0}^{T} p \int_{x = L(t) - \frac{W(t)}{p}}^{L(t)} C_2(x)\, dx\, dt \qquad 5.2b$$

where p is the proportion of a plant's capacity that can be used as spinning reserve.

$C_2(x)$ is the incremental production cost of the last plant in use at load level x.

The sensitivity of the value of wind driven plant to changes in the part-loading limit of conventional plant has been reported (Rockingham and Taylor, 1981). The total value of the fuel displaced appears to be largely insensitive to small changes in the part-loading limit of the conventional plant. The part-loading factor is however important for another reason. It will affect the amount of wind driven plant capacity which can be integrated into the grid if a part-loading only strategy is used to accommodate the variability of the wind.

Of course it is unlikely that even when such sources make a significant contribution to meeting electricity demands that it will be necessary to cover their entire production with spinning reserves from part-loaded conventional plant. It is more likely that the increased uncertainty of the generation-demand mismatch will be met in the present manner (using part-loaded plant, pumped-storage in the spinning mode, and standby gas turbines). Since the failure of such new plant, the failure of conventional plant, and unpredictable changes in demand are likely all to be largely uncorrelated, the uncertainty that results from the 3 sources together will be significantly less than the sum of the uncertainties from each source. Studies in the United States (Johanson, 1979) and in Germany (Jarass et al, 1979) have estimated that the operating penalty for wind driven plant is in the order of 5%. More comprehensive analysis (Farmer et al, 1980) carried out for conditions in the United Kingdom, considering dispersed siting, but use of very poor wind forecasts, suggest very small increases in necessary spinning reserves, and thus suggest low operating penalties.

5.1.2 Limits to the Utilisation of Intermittent Energy Sources

It is clear that unless some form of storage is available, energy produced by intermittent energy sources which is in excess of demand cannot be used. For very small amounts of new plant in the system this problem need not be of concern. However when substantial amounts are notionally to be used, it is important to appreciate, as several studies (Gibbons et al, 1979, Jarass et al, 1980) have pointed out, that significant amounts of energy that could potentially be generated might be impossible or uneconomic to use. In a simple analysis it might be assumed that all of the potential generation would be used as long as the demand exceeds the output from these sources. These sources could then penetrate the system until the installed capacity exceeded the lowest level of demand recorded during the year. In systems such as the CEGB the lowest demand is typically about 25% of the peak demand. After this point, using the simple analysis, the economic value of incremental machines would decrease significantly.

This type of analysis ignores two factors; the effects of correlation between electricity demand and the availability of energy from some energy sources; and the effects of operating constraints associated with conventional plant. In the UK there are, for

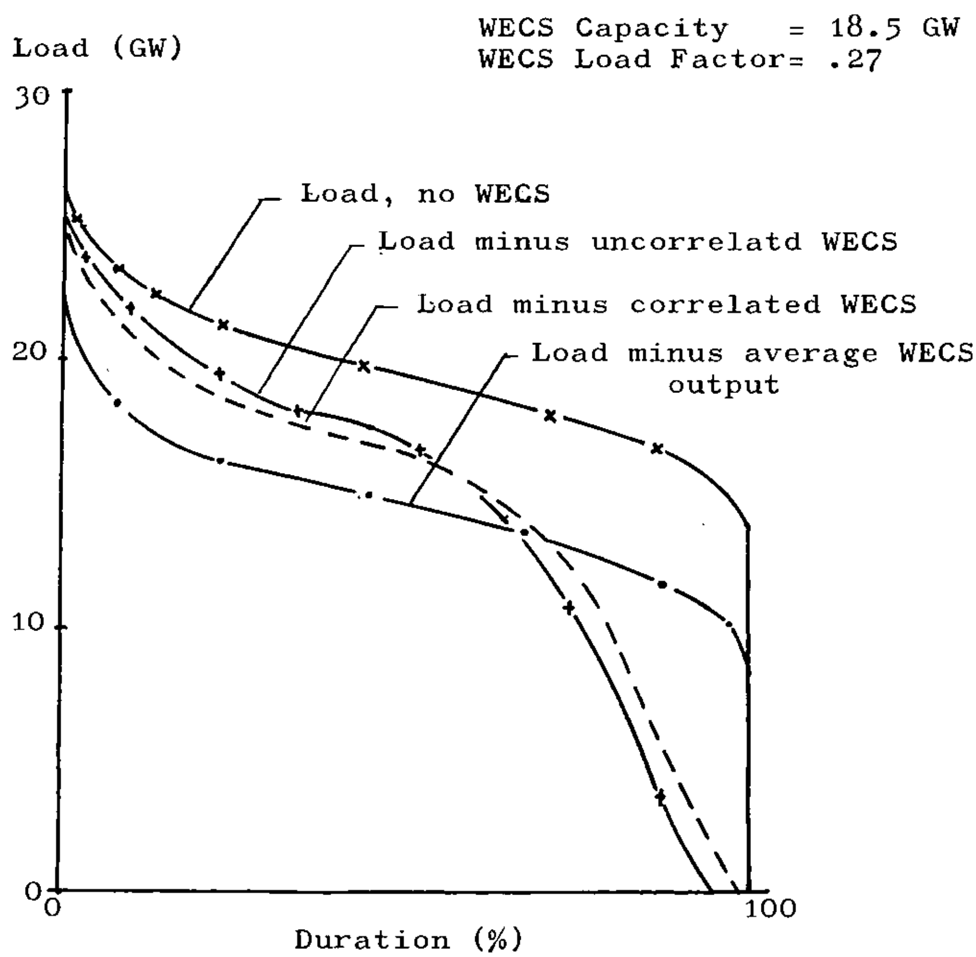


FIGURE 5.2 Net Load Duration Curves and the effect of wind turbines.

example, positive correlations on a seasonal basis between average windspeed and average electricity demand (see figure 6.4). On average one would not expect high windspeeds to occur at times of low demand. However, the variability of both electricity demand and windspeed moderates this effect since on occasion significant wind powered generation is likely to occur at times of lower than average electricity demand. Figure 5.2 illustrates the effect of a large tranche of wind turbines on a load duration curve assuming (a) only average values of the wind generation are considered, (b) actual values of wind generation are considered, (c) no correlation exists between the wind power generation and the electricity demand. A significant difference exists between the effects of the actual, versus the average values; less is visible between the correlated and uncorrelated cases.

As pointed out in section 5.2.1, because of the variability of output from wind driven plant it may be necessary to part-load conventional plant to provide spinning reserves against sudden failure of the wind turbine output. If stringent part-loading limits exist on large proportions of the plant and if only limited amounts of quick response plant is available, then system operating constraints will limit the amount of intermittent energy that can be accepted by the grid. It is also true that a variety of operating strategies could be pursued: each of which would result in the displacement of different plant types (see Sorenson, 1978, Whittle, 1980, Diesendorf and Martin, 1980).

One study (Gibbons et al, 1979) done in the context of the Irish electricity supply system has suggested that energy spillage in one scenario will possibly occur at penetrations as low as 10%. In other scenarios the same effect would not be felt until more significant penetration was achieved. The study provides a valuable illustration of the importance of the plant mix of the future system in affecting the limit to the level that wind driven plant could economically penetrate the system. It highlights the need to increase the depth of planning studies which consider such plant. The first scenario referred to above involves a large proportion of nuclear power operating in an inflexible mode, and treats wind driven plant as a fuel saver only. The economics of the intermittent energy source have been calculated without fully integrating wind plant into the future plans of the utility. It can be expected that such a study will provide a pessmistic view of penetration effects.

A more optimistic view, and in fact a more realistic view of the economics of new energy sources, can only be gained if capital cost saving, as well as production cost savings are included as part of the analysis.

5.2 Capital Cost Savings

The effect of new energy sources on the future requirements for conventional generating plant can be described in terms of capital cost savings. Notionally these savings will have two parts. If capacity credits can be assigned to intermittent energy sources, then these will have a value dependent on the value of capacity to the system and will form one source of capital savings. In addition, the energy produced by such plant may mean that the optimal mix of other plant used in the system may involve less capital intensive plant. This will be a second source of capital savings. These two aspects of capital cost savings are described in separated sections below.

5.2.1 The Value of Capacity

As discussed in chapter 2 cost polygons present a convenient method of illustrating the tradeoffs between capital expenditure and operating cost in a power system. They have been used in chapter 2 to present prima facie evidence that a mix of generator types is generally needed to minimise the cost of meeting annual electricity demands and they will be used later in this chapter to examine the effect of wind driven plant on the optional mix of plant in the system. They are also useful in defining the value of capacity to a system.

A hypothetical cost polygon for a two plant system is shown in figure 5.3a. The costs of operating plant throughout a year is represented as follows:

$$TC_i = \phi_i + \gamma_i t \tag{5.3}$$

where TC_i is the total annual cost of plant i if the plant operates for a proportion of time t.

ϕ_i is the annualised capital cost of plant type i.

γ_i is the annualised running costs of plant type i.

t is the proportion of the year during which plant type i runs.

Referring to figure 5.3a it can be seen that plants with low capital costs, but high operating costs (plant type 1) are cheaper to include in a system than plant with higher cost and lower operating cost (plant type 2), as long as the plant is expected to operate less than some proportion of the year, x. If the system mix is optimised, plant type 2 will operate with load factors greater than x and plant type 1 will operate with load factors less than x. At load factor x the cost lines of the two plant types will intersect, indicating that the costs incurred annually by each plant are equal. This is summarised in equation 5.4.

$$\phi_1 + \gamma_1 x = \phi_2 + \gamma_2 x \tag{5.4}$$

Re-arranging this we can see that

$$\phi_2 - \phi_1 = x (\gamma_1 - \gamma_2) \tag{5.5}$$

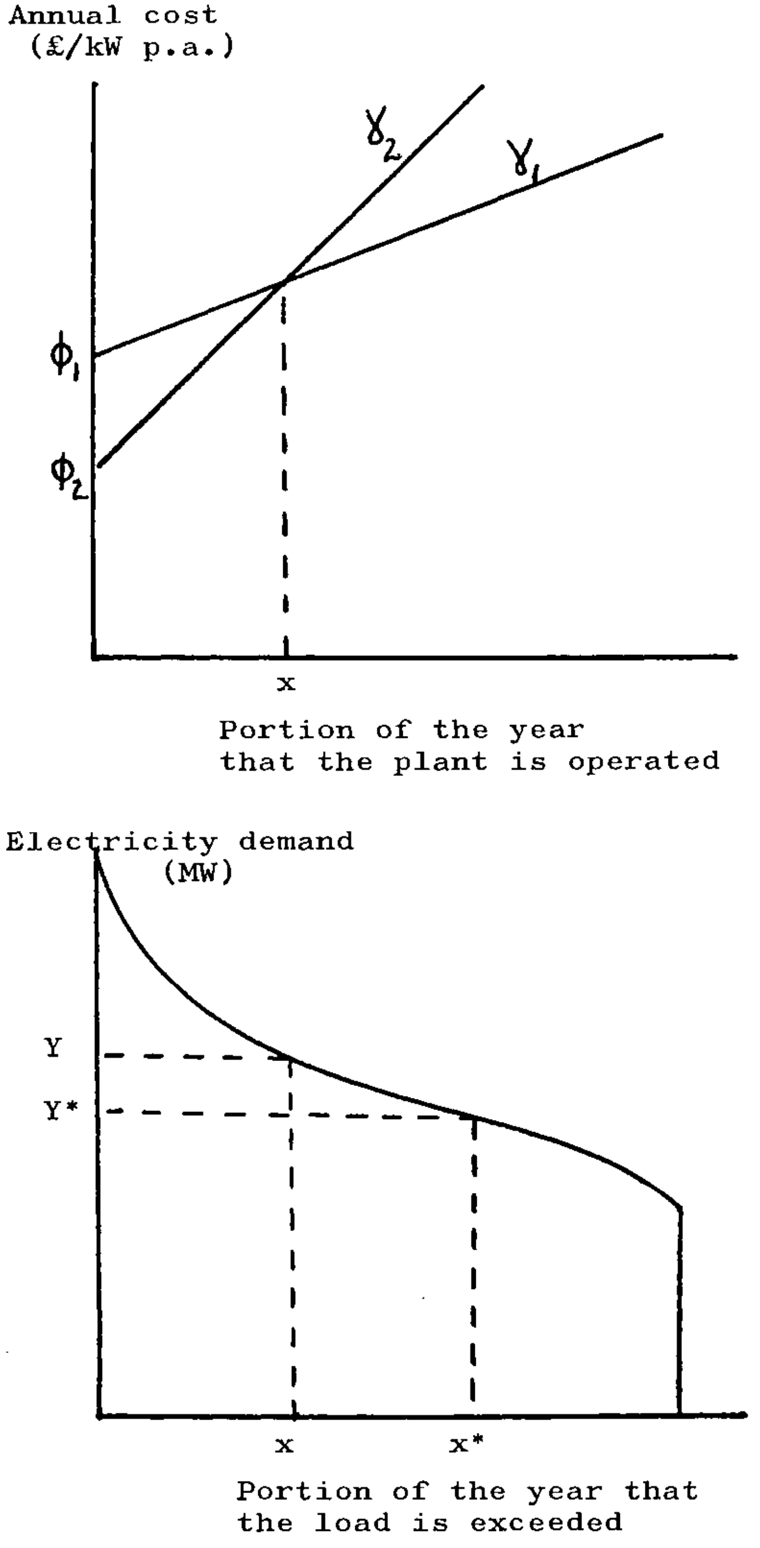


FIGURE 5.3 Optimizing the plant mix

If expansion in the system is driven by the need to meet peak demands, and if plants are perfectly reliable, then the value of capacity, can be established by studying the costs of expanding the system to meet growth in demand. If extra demand must be met at peak, in the notional system described above, two options for expanding the system exist. As one option, plant type 1 could be added to the system. The annual cost of this is the annualised capital cost of that plant plus the production cost of the added energy required. The other option is to add plant type 2 capacity to the system. Because the system mix is optimised, the net cost of the two options are the same. By installing plant type 2 an added capital cost $(\phi_2 - \phi_1)$ is incurred. However, since this plant is cheaper to run than plant type 1, it will displace some energy production of plant type 1 and will save an amount x $(\gamma_1 - \gamma_2)$. This saving exactly balances the added capital cost of this option (equation 5.5). In this situation the cost of providing an increment of capacity, and thus the value of added capacity, is equal to the capital cost of plant type 1.

In a system that is served by a mix of plant that is not optimal, an increment of firm power will have a different value. In figure 1b a non-optimal mix is shown: plant type 1 capacity is Y* instead of Y. If plant type 1 is installed to meet extra demand at the time of peak, the cost is as in the previous example. However, if plant type 2 is installed instead of plant type 1, although the added capital cost is still $(\phi_2 - \phi_1)$ the savings are $x^*(\gamma_1 - \gamma_2)$. Since $x < x^*$, the savings are greater than in the previous example and so the net cost of providing the necessary capacity is less than the capital cost of plant type 1. This net cost is the net effective cost (NEC) of plant type 2 (see section 2.3.2 or Hawkes, 1978). The minimum cost of meeting an increment of demand at peak hours is the lowest NEC of the plant available to the system. In a marginal type analysis it is this NEC which, if it is non-negative, determines the cost and thus the value of capacity to the system.

This analysis depends on the assumptions that are made in undertaking Net Effective Cost calculations. At the heart of these lies the assumption that, although the system is expanded and operated to achieve minimum electricity costs subject to due regard for safety, the environment and the need for reliable electricity supplies, there is no competition for scarce resources, or no exogenous constraints.

It is recognised that in the real world there is competition for scarce resources, and therefore the value to the system of capacity is less easily defined. If expansion of capacity is allowed only to meet reliability constraints then it is possible that a plant's effective capability would have a value less than zero. This would be true if competing plant options were available which had negative net effective costs. The addition of a unit with some finite effective capability would therefore mean that potential savings would be foregone because of the constraint on total effective capability. Similar arguments apply if a constraint exists to directly limit total system capacity.

In the real world there is generally competition for capital. A constant TDR can be set only if an effectively infinite supply of capital is available (Rozali et al, 1980). Otherwise the comparative desirability of plant would be chosen on the basis of some other criteria such as the Internal Rate of Return.

These concerns are, however, well understood by financial analysts (Grant and Ireson, 1965) and power system planners (Jenkin, 1981) and will not be discussed further here. Since the most suitable bases for comparison may vary over time and from utility to utility, a decision has been made to value capacity, where this is relevant, by using the lowest NEC of plant which can be added to the system, and to assume that the desired total capacity of the system is determined by the need for "firm" power.

5.2.2 The Capacity Displacement of New Energy Sources

Having made these assumptions, and having shown how capacity credits can be calculated (see chapter 3) it remains to explore the characteristics of the effective capability of intermittent energy sources. This is done using the analytic expression derived in chapter 2 and the numerical methods outlined in chapters 3 and 4.

Data is taken from the data base described in Appendix A2. Where numerical results are shown, output characteristics used to define the new energy source are those of wind powered generators. Trends that have been identified will relate to a number of intermittent energy sources.

5.2.2.1 Capacity Displacement of Intermittent Energy Sources at Low Penetration Levels

It was argued in chapter 2 that any energy source with a finite probability of producing power at time of peak demand could be assigned a capacity displacement figure. Equation 3.45 (repeated below) was suggested as a means of approximating the incremental capacity displacement.

$$-\frac{\partial \bar{a}P}{\partial Z} \simeq + \bar{v} - \Theta\delta_v{}^2\ \bar{v}^2 Z/\sigma_* \qquad 5.6$$

where P is the installed capacity of conventional plant (MW).

$\bar{a}$ is the expected availability of the conventional plant at the time of peak demand (%).

$\bar{v}$ is the expected availability of the new plant at the time of peak demand (%).

Z is the installed capacity of the new plant (MW).

Θ is a "security" constant.

δ_v is the coefficient of variation of the availability of the new plant (%).

σ_* is the standard deviation of the "system uncertainty" (MW).

From this equation it can be seen that, to a first approximation, the per unit capacity displacement that any plant receives is related to the expected availability of that plant at the time of system peak. For conventional plant this is likely to be (1 -FOR) where FOR is the forced outage rate defined in chapter 3. For plant such as wind turbines where seasonal and diurnal patterns exist in the wind regimes this expected availability will depend strongly on both the characteristics of the wind generator and the time period relevant to the model of demand used in the reliability calculations. In figures 5.4 through 5.6 which follow, the expected availability, at peak hours, of the windmills are plotted as solid lines beside the curve showing total capacity credit.

It is useful to note here that the term availability can lead to some confusion in discussions of conventional and unconventional power sources. For conventional power sources availability is associated largely to the mechanical reliability of the plant. Fuel shortages rarely dominate the ability of the plant to meet peak demands. For plant such as wind powered generators a lack of wind, rather than any mechanical failure, tends to have the strongest influence on the ability to contribute to meeting peak demands. In this thesis the term expected availability when applied to new energy sources will be equivalent to the term expected per unit output.

In UK conditions and for most demand models the expected availability can conservatively be estimated to be the winter load

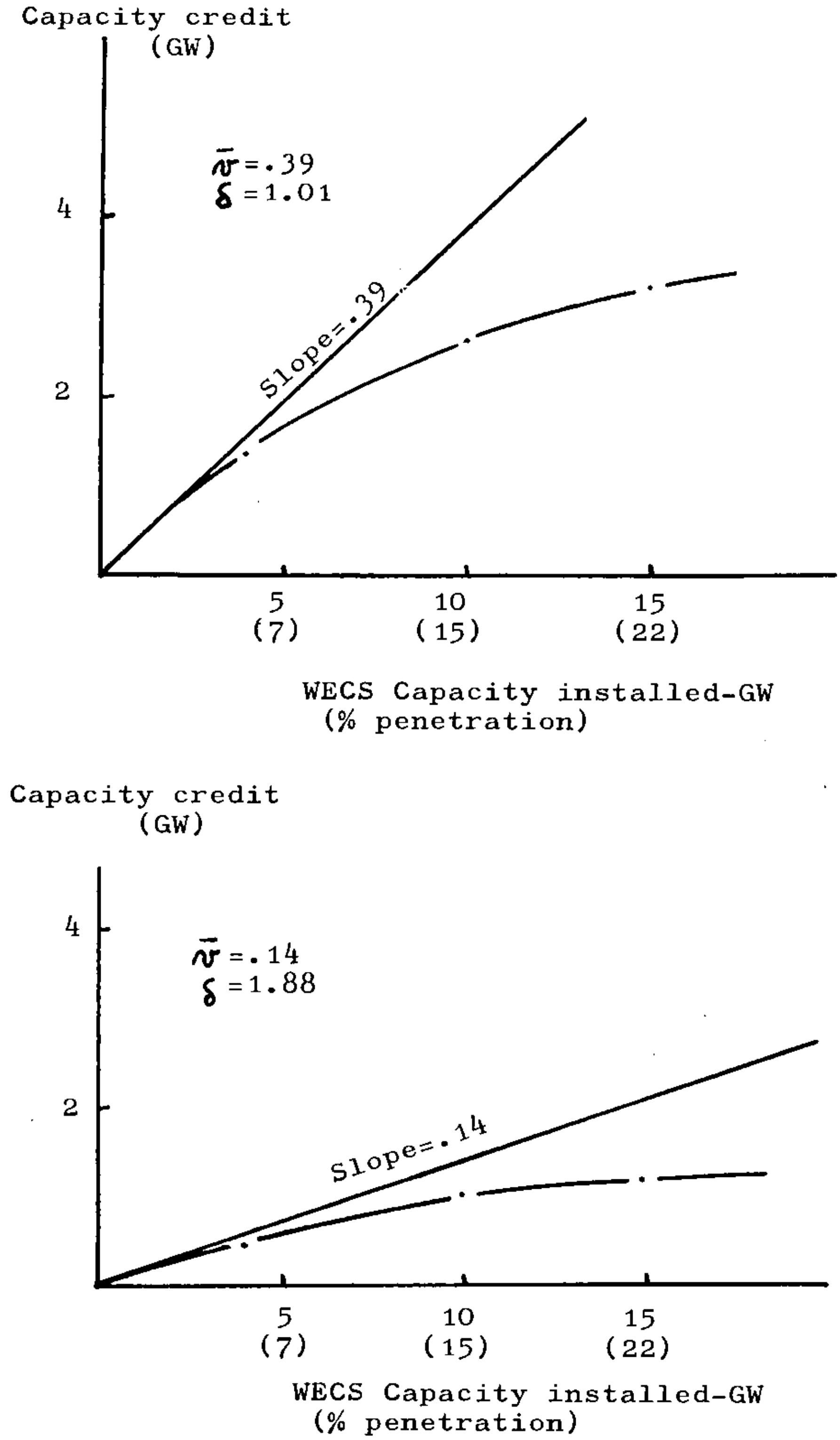


FIGURE 5.4 Capacity credits with increasing penetration.

factor of the machines. This ignores correlations between wind speed and demand. Since these are likely to be positive (Davies, 1958) the real expected output of the machine at times of peak can be expected to be higher.

5.2.2.2 The Capacity Displacement of Intermittent Energy Sources at High Penetration Levels

As discussed in chapter 2 the effective load carrying capability and the capacity displacement of a unit, is affected by the size of the unit relative to the total size of the system. In equation 5.6 this is illustrated by the second term which is a function of the plant capacity, Z. An important distinction must be made here between conventional plant and the intermittent energy sources being discussed. Whereas conventional plant are assumed to operate (or to fail) independently of each other, it is generally true that new energy sources can only be modelled as having correlated output. Each element in any notional array can be affected by single weather patterns. In the case of wind turbines, even dispersed units must be treated as combining to form one unit whose capacity is the arithmetic sum of the individual units. In contrast, the capacity displacement of a second new conventional plant is largely independent of the capacity of the first new unit. Correlated energy sources suffer major penetration effects in terms of their capacity displacement; conventional plant do not.

Figure 5.4 shows the total capacity credit of new plant as a function of their penetration into the system. The changing slope of the plot of total capacity credit can be explained in physical terms. Consider a new energy source which acts independently of the failure of conventional plant and the demand for electricity. Under these conditions there is an equal probability that output from such plant will enter the grid at times of high risk as there is that it will enter the grid during periods of low risk. Electricity production during the high risk periods reduces the overall annual system risk more than production during periods of low risk. For small amounts of generation the capacity credit will be the average contribution to the grid during periods of high risk. When a large tranche of new plant is considered, its electricity production during what were originally high risk periods may eliminate that risk entirely. A further increment of such capacity however has little effect since the overall system risk is now determined largely by those periods when there is no output from the new plant. The capacity credit of the incremental capacity is thus much less than the capacity credit of the initial capacity.

5.2.2.3 The Effect of the Target Level of System Reliability

Equation 5.6 can be used to investigate how the target system reliability level can affect the capacity displacement of new plant. Large values of Θ, the system security constant, reflect stringent reliability targets; lower levels of reliability are defined by low values of Θ. (The current CEGB target reliability of allowing voltage reductions 23 years in 100 corresponds to a security constant of .73. To reduce this reliability target to 10 years in 100 a security constant of 1.2 is needed.) Several authors (Van Kuiken et al, 1980, Marsh, 1979) have suggested that the level of the system reliability target will not affect the economics of new energy sources. The form of equation 5.6 shows this suggestion to be in error.

It can be seen that at very low penetration levels the capacity displacement of new plant is dominated by $\bar{v}$ and therefore is unaffected by the magnitude of Θ. However when significant amounts of new plant are considered the capacity displacement is inversely related to the value of Θ.

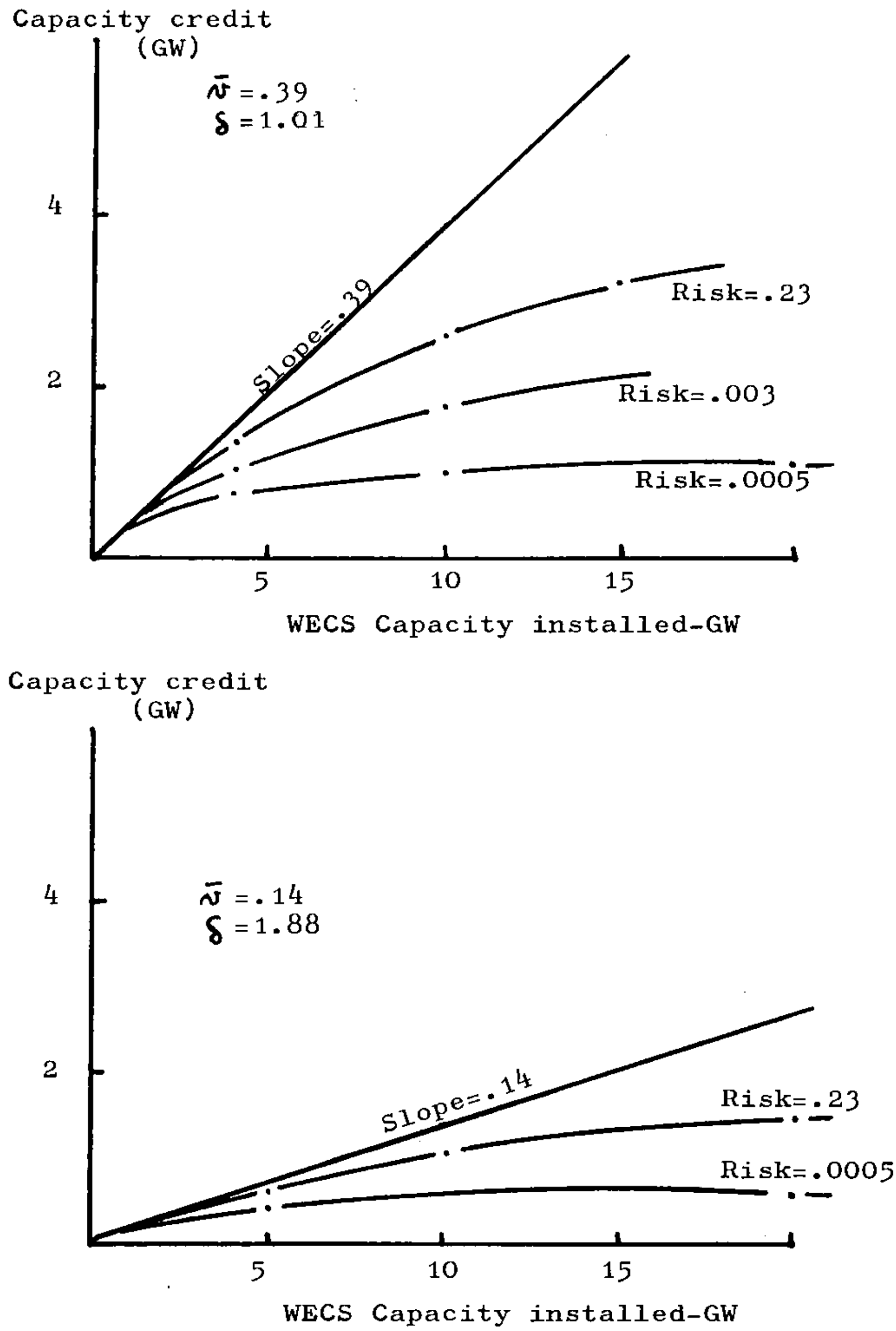


FIGURE 5.5 The effect of the system reliability (risk) target on capacity credits for WECS.

Figure 5.5 shows how capacity credits are affected by the choice of the system risk target. At penetrations of 10 GW (15%) a change from a risk of 23/100 to 1/2400 reduces the capacity credit which a low variance WECS would receive by more than 60%. Table 5.1 shows that in contrast the capacity credit which conventional plant receive is affected very little by the same change.

In view of the uncertainty about appropriate levels of reliability for power systems (as discussed in section 2.4) this result is especially interesting. If present target reliability levels are judged to be too high, the economics of large penetrations of new energy sources will improve. A similar hypothesis is offered by Kahn (1979).

5.2.2.4 The Effect of Dispersed Siting

As noted in chapter 2 many analysts in the past have argued that single wind turbines would have no capacity displacement, but that a series of machines, sited in widely separated sites, would be capable of some capacity displacement. This notion persists in detailed evaluation of the prospects of new energy sources (Khalsa and Stannets, 1980) in spite of its fundamental inconsistency (see section 2.3.1).

Early work by Justus (1975) and Molly (1976) is especially significant in attempting to quantify the effect of dispersed siting. More recently methods for modelling the effects of diversity have been presented by Justus (1978), Justus and Mikhail (1978) and Justus and Hargraves (1975) and used by Kahn (1978b). A more transparent analysis is possible using equation 5.6.

In figures 5.4 and 5.5 it has been an implicit assumption that as the capacity Z increases, the coefficient of variation δ_v, has remained constant. This is equivalent to assuming a point array of wind turbines - that the output of the additional machine is

Table 5.1: The Effect of the Target System Risk on Capacity Credits for Conventional Plant

		Small Units	Large Units
Number Size (GW) FOR (%) Total Capacity		33.3 .3 .1 10 GW	10 1.0 .2 10 GW
Standard Deviation of Plant Outage Function		.269 GW	1.6 GW
Capacity Credit GW (% of derated capacity)	$R = .23^{(1)}$	8.98 (99.7)	7.83 (97.8)
	$R = .0004^{(2)}$	8.92 (99.1)	7.26 (90.7)

(1) $\Theta = .74$
(2) $\Theta = 3.3$

perfectly correlated to the previous machine. Where a dispersed array of machines are considered, diversity between the machine outputs is likely and thus the coefficient of variation will change.

In the case of two "point arrays" of equal energy output, equal capacities, and equal dispersion, σ, in the output, the following will be true.

$$Z = Z_1 + Z_2 \qquad 5.7a$$

$$v = \bar{v}_1 = \bar{v}_2 \qquad 5.7b$$

$$\sigma^2{}_1 = \sigma^2{}_2 \qquad 5.7c$$

$$\sigma^2 = \sigma^2{}_1 + \sigma^2{}_2 + 2\,\sigma_{12} \qquad 5.8$$

The correlation coefficient ρ can be introduced as follows:

$$\rho = E\left[\frac{(X_1 - \bar{X}_1)(X_2 - \bar{X}_2)}{\sigma_1 \cdot \sigma_2}\right] = \frac{\sigma_{12}}{\sigma_1 . \sigma_2} \qquad 5.9a$$

then $\sigma^2 = 2\sigma_1^2\ (1 + \rho)$ if equal capacities are installed at each site.

Where n sites are considered to represent a single array it can be shown (Kahn, 1978) that this can be extended.

$$\sigma = \{\sigma_1^2\ [1 + \bar{\rho}(n - 1)]/n\}^{\frac{1}{2}} \qquad 5.9b$$

where the sites are identified by numerical subscripts and where

σ_{12} is the cross-correlation coefficient

X_i is an instantaneous output from the site

ρ is the correlation coefficient of the wind turbine outputs at two sites

By combining equation 5.7a, 5.7b with equation 5.6 it can be seen that at low penetration levels dispersed siting of wind turbines has little effect on their capacity displacement. However since the coefficient of variation for the total array, capacity Z, has been reduced, the rate of decay of capacity displacement as a function of penetration will be lower. Initial analysis of data from 4 sites in

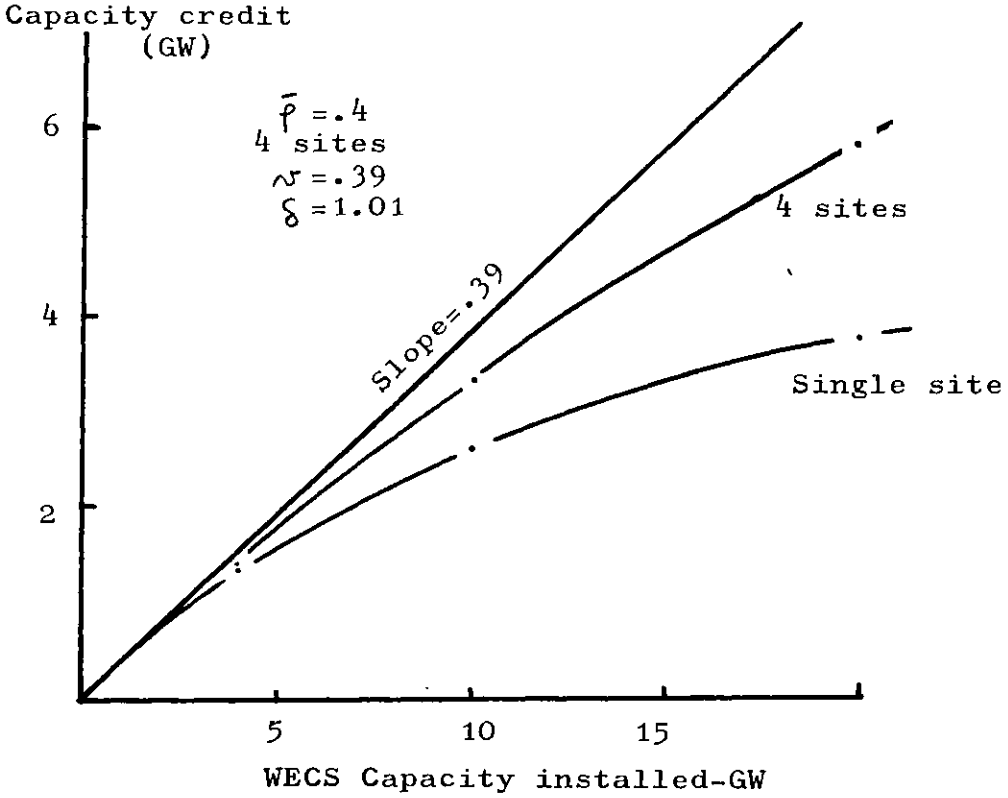


FIGURE 5.6 The effect of site diversity on capacity credits for WECS

the UK indicates that the correlation coefficient of output from wind turbines in the UK is approximately 0.4 (Rockingham and Taylor, 1981). Using this figure, the effect of geographical separation of WECS on their capacity credit can be shown (figure 5.6). These results for the UK are in agreement with those which can be extracted from studies done in other countries (see Taylor and Rockingham, 1980).

5.2.2.5 Limits to Capacity Displacement

In the case of intermittent energy sources for the UK where there is a significant probability of single weather patterns covering the entire country, intuitively one would expect that, provided present reliability standards are to be maintained, a limit would exist to the amount of conventional capacity that could be displaced by WECS.

Using the model represented by equation 5.6 a limit to the capacity displacement of new energy sources will exist when $\frac{\partial a\bar{P}}{\partial Z} = 0$.

At this point

$$\bar{v} = \Theta\delta_v^2\bar{v}^2 Z/\sigma_* \qquad 5.10a$$

Since for large Z, and typical values of $\sigma_v^2\bar{v}^2$, Z/σ_* approaches 1, a limit to the capacity displacement that can be achieved will occur if

$$\bar{v} = \Theta\delta^2\bar{v}^2 \qquad 5.10b$$

i.e. if $\Theta\delta_v^2 v > 1$

This implies that either alone or in combination, the need to maintain a low risk level, or the existence of a high coefficient of variation may place a limit on the capacity displacement of a new energy source. This suggestion is reinforced by the results shown in figure 5.5. It is useful to explore this phenomena further using the numerical models developed in chapter 3.

It was noted that for certain notional systems, capacity displacement and load carrying capability were compatible measures of a unit's contribution to meeting demand. Equation 3.29, repeated below, was presented for the calculation of a units load carrying capability Q.

$$Q = G_{N+1}^{-1}(R) - G_N^{-1}(R) \qquad 5.11$$

where $G_N(x)$ is the probability that the available capacity from the N units which compose the system exceeds the demand x.

$G_N^{-1}(y)$ is the inverse of the above function.

R is the acceptable risk level in the system.

If the system risk function is defined for a fixed load forecast in terms of surplus plant, and if the system capacity is at the target level

$$G_N\ (0) = R \qquad 5.12$$

For simplicity consider a wind turbine array of infinite capacity whose output is represented by a 2 state function (i.e. output is either zero or infinite). The affect on the system risk function is as follows

$$G_{N+1}(S) = G_N(S)FOR + G_N(S - C_n)(1 - FOR) \qquad 5.13a$$

where FOR is the forced outage rate of the plant.

C_n is the plant capacity (in this case $C_n \to \infty$).

Now since $G_N(S - C_n) = G_N(-C_n) = 0$

$$G_{N+1}(S) = G_N(S)FOR \qquad 5.13b$$

It follows from equation 5.12 that

$$G_N(S_c) = R/FOR \quad \text{and} \quad G_N^{-1}(R/FOR) = S_c \qquad 5.14$$

where S_c is the load carrying capability of the new unit.

Though a 2 state model is unrealistic for a large array of wind turbines which would be most likely to be widely dispersed

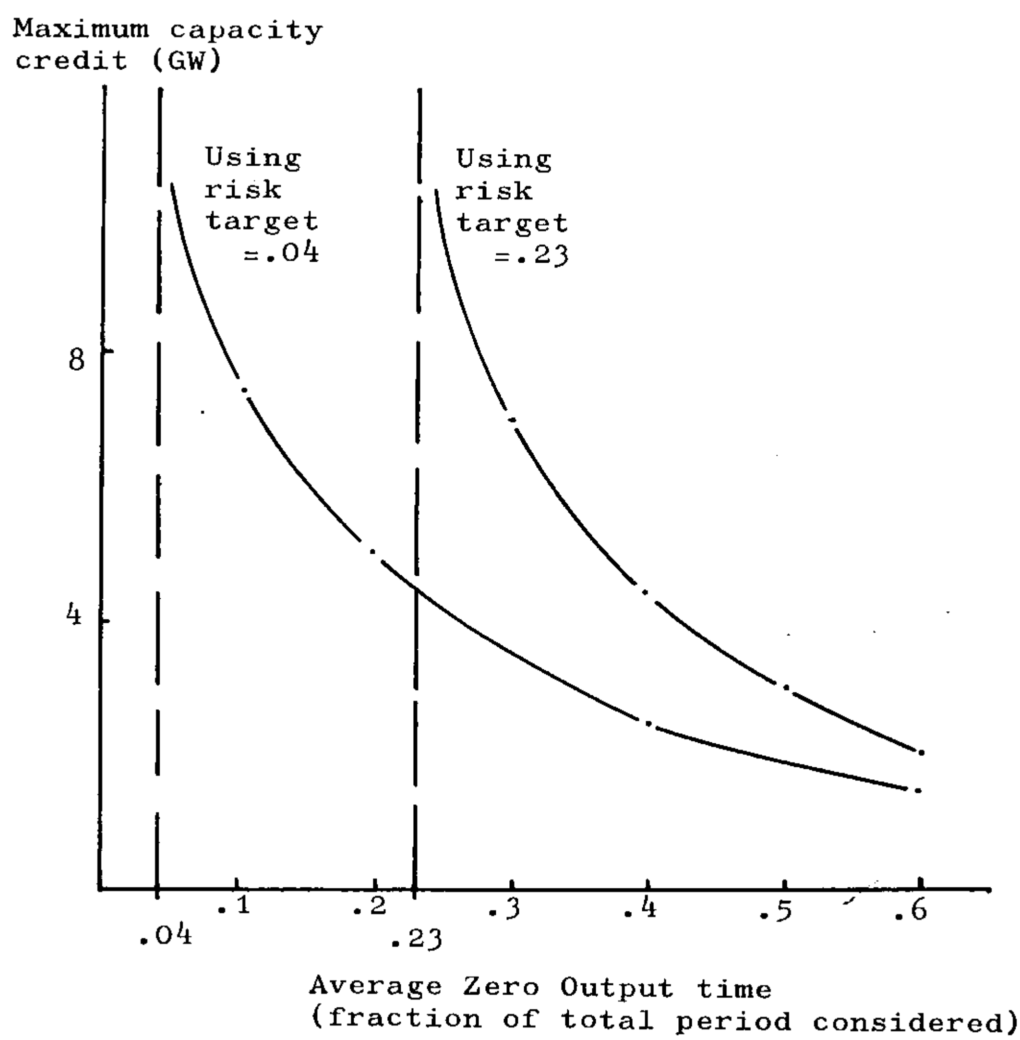


FIGURE 5.7 Capacity credits for infinitely large two-state plant.

geographically this sort of model may be used accurately in describing tidal schemes. The numerical model illustrates the importance of zero, and low output states, and supports results shown in fig. 5.5. The results shown in figure 5.8 indicate the effect of the risk level and outage time on limits to load carrying capability for plant, modelled by 2 state models, when interacting with the large system described in Appendix A.2.

5.2.3 Reoptimisation Savings

In section 5.3 it was stated that capital cost savings associated with new plant could be divided into two parts; savings possible because of a reduced need for conventional plant, and savings possible through reoptimisation of the system mix. Johanson (1979) in his analysis of the economics of wind turbines has labelled these latter savings fixed cost savings, they are better described as reoptimisation savings.

In attempting to quantify reoptimisation savings, it is important to recognise that it is impossible entirely to divorce fixed cost savings from other system effects. Up to this point in the chapter fuel cost savings and capacity displacements have been analysed separately. To analyse reoptimisation savings this separation is more difficult since a shift in the desired mix of plant in the system will only lead to capital cost savings at the expense of increased fuel costs at the margin. A net savings will result if capital cost savings exceed added fuel costs.

The task of calculating reoptimisation savings can be difficult. It has been beyond the scope of several "detailed" investigations of the economics of WECS (Van Kuiken et al 1980, Jarass et al, 1979, Kinloch et al, 1980) yet in those studies (Marsh, 1979, Johanson, 1979) that have considered in detail how future expansion plans would change if WECS were added to the system, the effect appears to be important. These latter studies have employed global cost optimisation techniques to calculate the total savings associated with the use of wind turbines. In this thesis more transparent methods based on the use of cost polygons have been used. They are more restrictive than the optimisation methods referred to above and inherit the shortfalls of the cost polygon approach (see section 2.2.2), but are useful as an aid in understanding the problem.

As stated earlier, it is often true that electricity from intermittent energy sources will be used in the grid in preference to electricity production from conventional plant and therefore can be subtracted from the existing load curve to form a "new" load. An illustration of this, and a familiar cost polygon is shown in figure 5.8. In considering the best mix of conventional plant to serve demand, it is the new load which is relevant.

Figure 5.8 shows that the optimal mix of conventional plant in a utility system will normally include less (Y_2 compared with Y_1 megawatts) capital intensive conventional plant as the amount of WECS in that system increases. From this it follows that capital savings may be possible, independently of reductions in the total capacity of conventional plant. Two approaches are taken in quantifying these savings.

Referring to figure 5.8, the reduction in total system capital cost (C) in a system re-optimised after the addition of new plant can be calculated simply.

$$C = (Y_1 - Y_2)(\phi_1 - \phi_2) \qquad 5.15$$

This is an over estimate of the net system savings attributable to the re-optimisation since it ignores the difference in running costs between the two plant types and thus the extra fuel costs incurred in the re-optimised system.

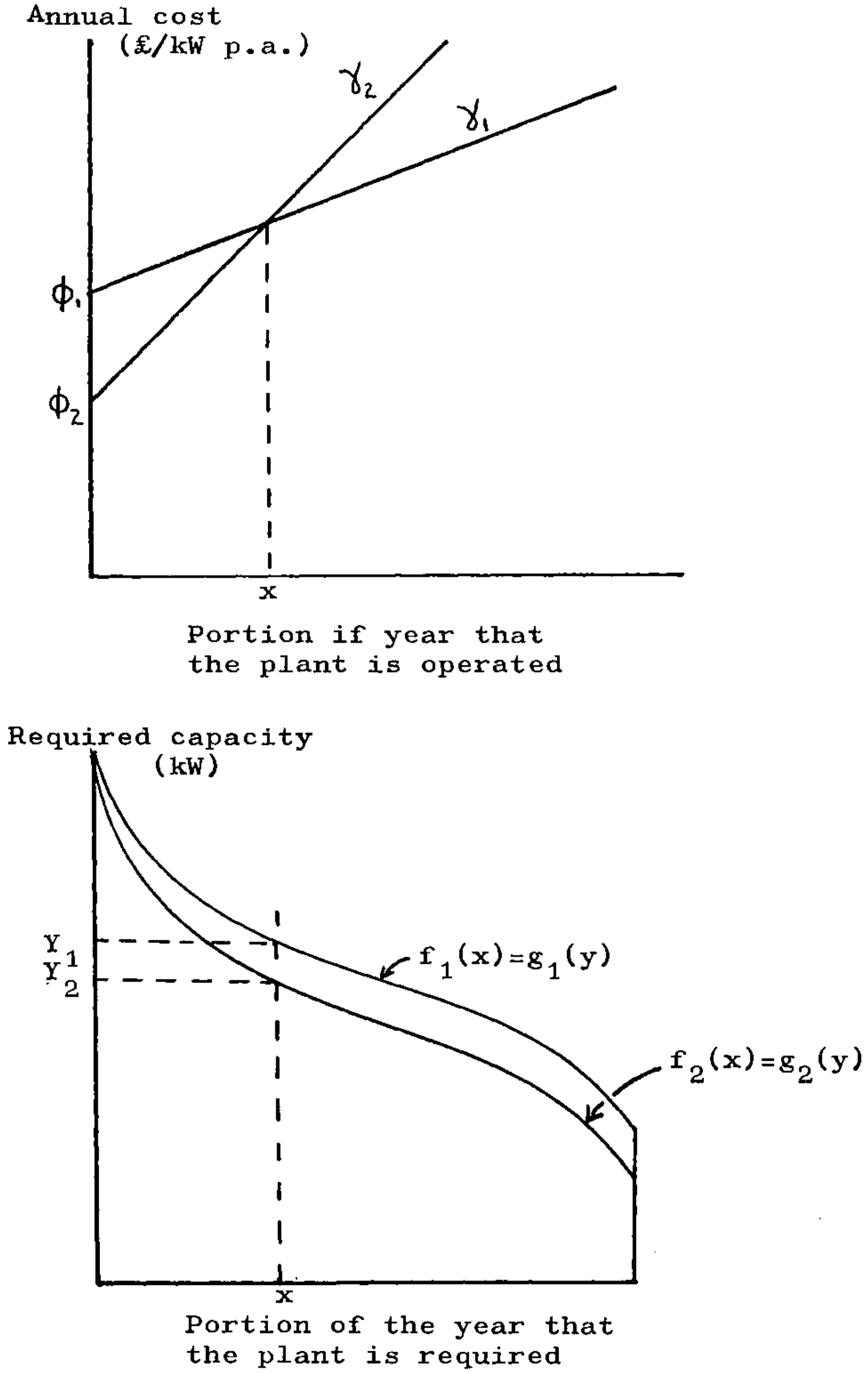


FIGURE 5.8 Cost Polygon Representation for the calculation of Re-optimization Savings

The penalty (P) due to the increased use of high running cost plant can be calculated as follows:

$$P = (\gamma_2 - \gamma_1) \int_{Y_2}^{Y_1} g_2(y)dy \qquad 5.16$$

If XCC is the excess of the capital savings over the extra fuel costs incurred

$$XCC = C - P \qquad 5.17a$$

$$= (Y_1 - Y_2)(\phi_1 - \phi_2) - (\gamma_2 - \gamma_1) \int_{Y_2}^{Y_1} g_2(y)dy \qquad 5.17b$$

By using equation 5.5 this can be re-written as

$$XCC = (\gamma_2 - \gamma_1) \left\{ (Y_1 - Y_2)\ g_1(Y_1) - \int_{Y_1}^{Y_2} g_2(y)dy \right\} \qquad 5.17c$$

For most conditions, where it is true that $[g_1(y) - g_2(y)]$ is constant over the range $Y_1 < y < Y_2$, then a simple approximation to this fixed cost saving can be made by calculating the value from the intermittent energy source in the system optimised before the consideration of the effect of that energy, and the value of that energy on the system after re-optimisation has taken place. The re-optimisation savings are equal to one-half of the difference between these values.

A more lucid analysis is possible if the savings for many small increments of new energy sources are summed and reoptimisation of the mix is carried out continuously. As long as the system mix is optimised and a net demand for electricity exists over the period under study, then the system marginal energy costs will remain stationary, indicating that the sum of the incremental fuel cost savings plus the reoptimisation savings will remain nearly constant.

Using figure 5.8, the system data shown in table 5.2, and the approximations developed thus far, the relative magnitudes of the value of wind turbines due to production cost savings (minus the operating penalty), the capital savings due to capacity displacement and the reoptimisation savings can now be calculated. It can be shown that for the sample system, by far the largest component of the value of a new energy source such as a wind turbine is due to its production cost savings. Even for a machine with a 40% load factor at a penetration level of 5,000 MW, the capacity value, the fixed cost savings and the operating penalty are all small compared to production cost savings. As the penetration of the new energy source into the system increases the incremental fuel saving value and incremental capacity credit will decrease while the incremental reoptimisation savings will increase. Detailed evaluation of reoptimisation savings is considered unnecessary since the importance of these savings, especially in the case of systems with unbalanced system mixes, will be reduced by discounted cash flow analysis since savings are only realised some distance in the future.

5.3 Discussion

5.3.1 Overall Value

The above analysis has concentrated on individual aspects of the economics of new energy sources. This was done in the context of an analysis that has separated energy value, capacity value and a value due to reoptimisation. Other analysts have chosen a global cost analysis in which these components are not easily separated. The methods used are thus quite different and it is important to make a comparison of results using these different approaches.

One of the most obvious areas of controversy relates to the proportion of the overall value which is dependent on the

Table 5.2 - Components of the Total Value of WECS

System Costs

ϕ_1 = 1000 £/kW = 80 £/kW pa
γ_1 = .7 p/kWh = 61 £/kW pa

ϕ_2 = 500 £/kW = 40 £/kW pa
γ_2 = 2.0 p/kWh = 175 £/kW pa

ϕ_3 = 190 £/kW = 15 £/kW pa
γ_3 = 6.0 p/kWh = 525 £/kW pa

Wind Plant

$\underline{Z}$ = 5000 MW
$\bar{v}$ = .4
δ = 1.0

System Mix: Plant types 1 and 2 cross-over at t = .36 YR

Fuel Cost Savings	204×10^6 £/YR
Operating Penalty	24×10^6 £/YR
Capacity Credit	30×10^6 £/YR
Reoptimisation Savings	6×10^6 £/YR

"firmness" of the power. Cottrill (1979) has claimed that if large amounts of renewable energy are used in the system then any capacity credit which intermittent energy sources might have should be valued at the Net Effective Cost of coal plant. Thus though the value of any firm power is high, Cottrill by the choice of figures in his examples indicates that new energy sources are likely to have only a small proportion of their capacity considered firm. As noted previously Marsh (1979) and Johanson and Goldenblatt (1979) have valued wind turbines by claiming production cost savings and capital cost savings that result from global system optimisation. Results presented by Marsh imply that the total value of wind very sensitive to its firmness. The presentation by Johanson and Goldenblatt is more useful since it separates capacity credits, fixed cost savings and fuel savings. Rockingham and Taylor (1981) have ignored the effect of fixed cost savings, but have dealt only with small tranches of wind turbines. The component breakdown of costs in these analyses cannot be compared rigorously since different wind regimes and different power systems are appraised, but the comparisons (shown in figure 5.10) seemingly indicate a major difference between results which could have important implications for WECS designs. The following section examines the disparities.

Using the marginal analysis presented in this chapter, the value of new energy sources can be calculated using equation 5.20.

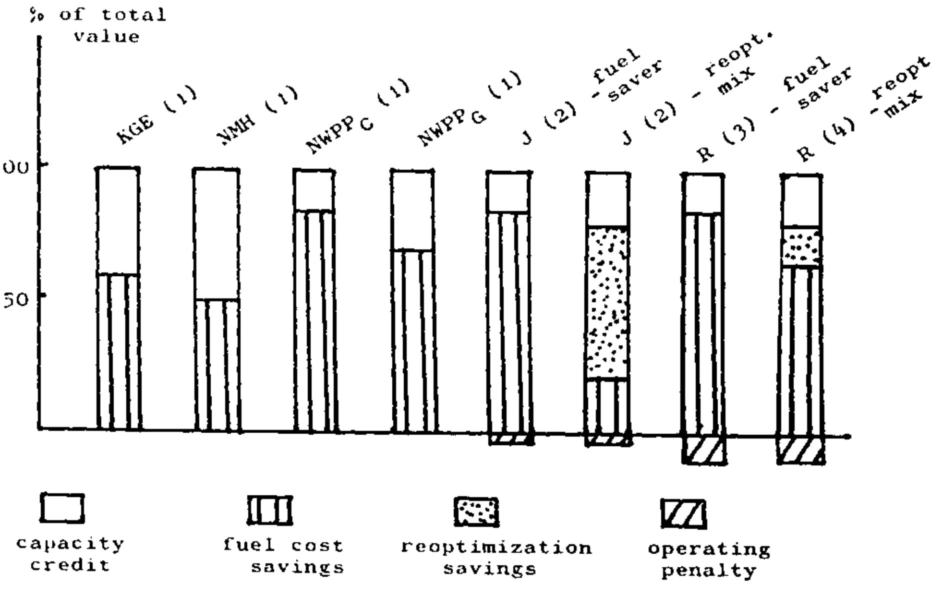
$$V = K + E \qquad 5.20$$

where V is the total value.

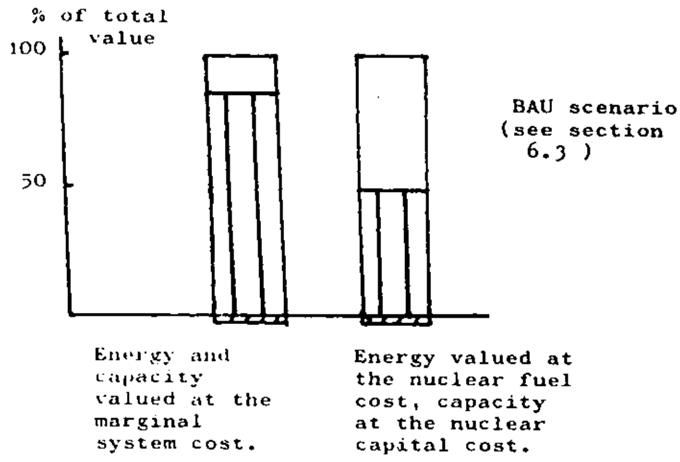
K is the capital cost saving. For small tranches, these occur as the result of the reduction in the capacity of conventional plant needed in future years.

E is the production cost savings. For small tranches the operating penalty is ignored.

a)



b)



(1) Marsh, 1979
(2) Johanson, 1979
(3) Rockingham and Taylor, 1980
(4) based on Rockingham and Taylor, 1980

FIGURE 5. 9 A comparison of the components of total WECS value.

a) Other studies
b) "Marginal" versus "plant" systems of evaluation.

In the hypothetical case where the output from the plant is statistically not correlated with electricity demand, as a first approximation the value of the capacity component of equation 5.20 is as follows

$$K = LF \times NEC_j \qquad 5.21$$

where LF is the machine's annual load factor.

NEC_j is the net effective cost of plant type j

and
$$NEC_j = \frac{\phi_j}{A_j} + \gamma_j - MC \qquad 5.22$$

where ϕ_j is the annualised capital cost of plant j.

γ_j is the annual running cost of plant j.

A_j is the availability of plant j.

MC is the annual average marginal energy cost of the system.

The value of the energy is:

$$E = LF \times MC \qquad 5.23$$

Combining equations 5.20, 5.21, 5.22, 5.23 (and ignoring extra capacity credits associated with changes in optimal system mix, see section 5.3.3):

$$V = LF \times MC + LF\left(\frac{\phi_j}{A_j} + \gamma_j - MC\right)$$

$$= LF\left\{\frac{\phi_j}{A_j} + \gamma_j\right\} \qquad 5.24$$

It is clear then that valuing capacity credits at the capital cost of nuclear plant, and valuing energy at the production cost of nuclear plant is equivalent to the marginalist approach adopted earlier. Using results from the simulations reported in chapter 6 the two systems of valuation are applied to a single tranche of windpower. The results shown in figure 5.9b show that the results of Marsh (1979) and Rockingham and Taylor (1981) could be compatible.

For the power system planner global analysis may be more satisfactory and transparent. For the design of plant and analysis of tariff policy, marginalist analysis is more useful.

A further point of interest can be noted here. It is clear that the part of the reason for the increased interest in new energy sources is the expectations of future rises in fossil fuel prices. Yet equations 5.20 through 5.24 show that where nuclear power is the preferred baseload plant option, the value of intermittent energy sources is determined by the costs of nuclear power and not by the costs and fuel price escalation for fossil fired plant. Furthermore, including the re-optimisation savings as a component in the total value of intermittent energy sources implies that these sources displace baseload plant from the future plant mix. In the utility situation considered in this thesis, intermittent energy sources and nuclear power are in direct competition for a place in future power systems.

5.3.2 Figures of Merit for WECS

Chapter 1 reviewed expansion planning models in use by utilities and indicated the figure of merit that are in common use. It was observed that expansion options should be chosen, all else being equal, on the basis of global cost reduction. Alternatives should be weighed using the chosen decision criteria on the basis of overall system costs and overall system savings. Other figures of merit are in use however, so it is interesting to examine how they can be used now that a more thorough understanding of WECS system economics is possible.

The net effective cost, NEC, is one of the figures used by the CEGB to define the comparative economic worth of alternative power station projects. The formulation as described by Hawkes (1978) and reviewed in chapter 2 does not explicitly quantify the reliability value of each option. It cannot be expected to serve as a useful figure of merit for comparing plants which, on a per kilowatt basis, contribute different amounts of load carrying capability. One suggestion to include such a contribution to a figure of merit based on Net Effective Cost has been argued (Rockingham, 1980) and has been illustrated in the preceding discussion. Problem are noted, especially when negative net costs occur, but these are related more to the assumptions associated with a fixed test discount rate (see section 5.2.1) rather than the technology.

A further basis for decision making is the "bus-bar" energy cost. As in the case of NEC it does not include any explicit quantification of contribution to overall system reliability. As it can now be argued, in some circumstances, this is not a serious problem.

In section 5.3.1 it was noted that for small increments of plant and to first order, the expected output of a plant at time of system peak is a measure of the load carrying capability of the plant. Thus in simple models where the expected power output of a plant is constant throughout the period of concern, the energy production of a plant is a good measure of the contribution of that plant to system reliability. Thus bus-bar energy costs can, in a variety of circumstances, provide a useful measure by which to compare the economic merit of different plant.

This is important to recognise since as described in chapter 2 the tendency in the past has been to compare the bus-bar energy cost of conventional plant with the sum of bus-bar energy cost of WECS and some extra cost added as an estimate of the cost of providing an equal "firm power package". It can be seen now that this unfairly discriminates against WECS.

5.4.3 Plant Economics in Dynamic Systems

As discussed in the literature review in chapter two, much of the research effort in operations research for power system planning has been devoted to developing models that can be used for economic analysis in systems that change over time. In this thesis a decision was made to simplify the analysis by dealing initially with static systems. Annuitised costs and benefits were treated and these typically were calculated after analysis of a representative year. Real systems of course change over time; plant is added, capital costs and fuel costs change, and load levels and patterns shift. As a result analysis for a single year can give a misleading view of the economics of plant; it is accepted that accurate lifetime costing is needed for detailed study.

A further point to note is that capacity credits only have a value (and in fact only really have a meaning) if capacity related costs can be saved elsewhere in the system. Over the long term these savings will reflect construction costs. In the short term, or where load growth is zero or very low, these savings will reflect annual maintenance or staffing costs. In other settings the value of capacity credits may relate to the cost of station refurbishment.

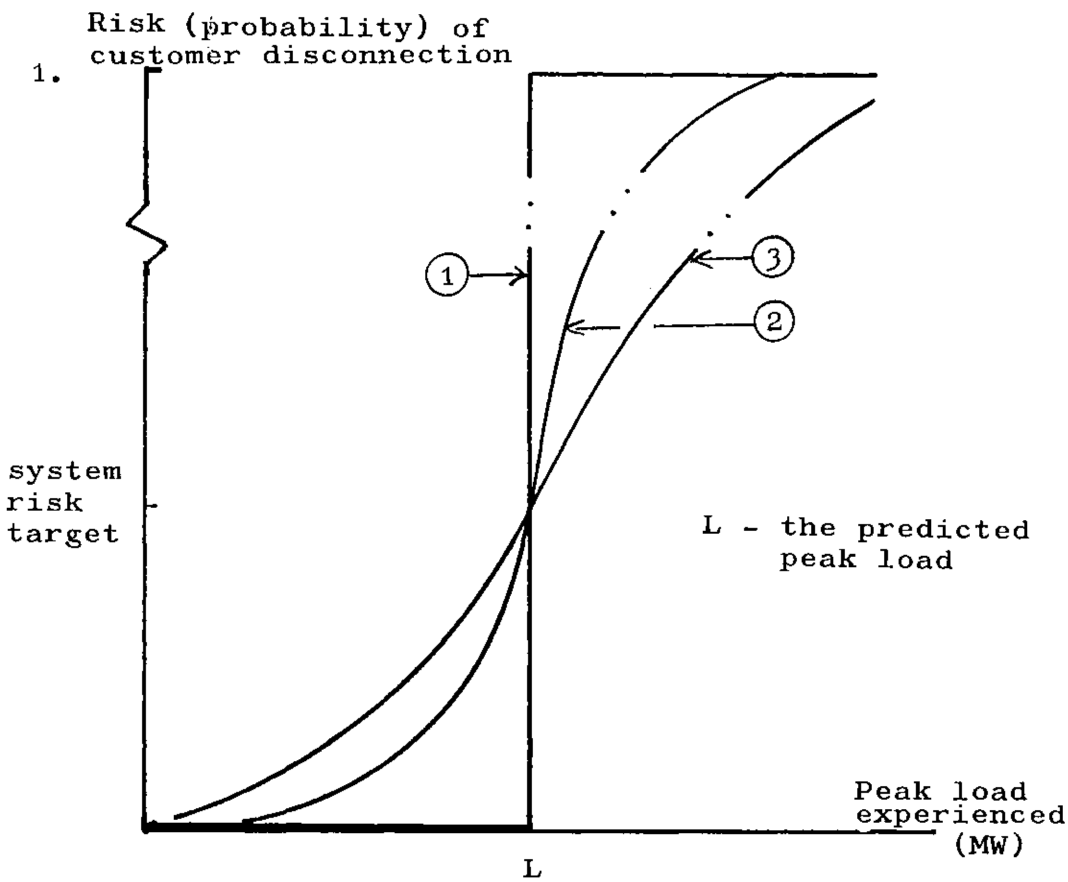
5.5 Other Planning Considerations

One of the constraints on present power system planning is that it must be done in an uncertain environment. Analysts of system planning had, in the past, been able to start planning studies with several assumptions that today seem untenable. Berrie (1967) was able to assume that electrical power systems were in equilibriums of growth (that is to say, although yearly growth in the demand for electricity varied, it tended to fluctuate about a predictable mean) and that plant failure though a stochastic event, over the short term, had a long run average that was easily predictable. Recent growth rates must force a reconsideration of the "equilibrium of growth"; the introduction of new technologies means that data on plant operation is limited and that long run forced outage rates are now difficult to predict. Furthermore as a better understanding of risks and impacts associated with particular plants have evolved, the regulations affecting the operation of new plant have changed and as a result expectations about future plant availabilities must have associated with them a great deal of uncertainty. Because of these types of uncertainties, it may no longer be adequate to deal with risk and uncertainty by the regulation of plant margins using the retirement of aging plant or the addition of low capital cost peaking plant. The assumptions upon which plant margins are calculated are no longer valid. Instead it may be better to have as a goal the establishment of a system which because of its nature is able to deal with long run uncertainty (Holling, 1978). In system planning terms, new types of uncertainty have placed a premium on resiliency, stability and flexibility.

The establishment of diversity in the supply options available to electricity power systems is widely seen as a desirable goal yet its value is rarely qualified. The result is that its benefits are rarely considered in long range planning studies. Diversity contributes to the operating flexibility of a system in the face of fuel supply constraints, and acts as a stabilising influence during fuel price fluctuations. The overall effect is to increase the resilience of the system. New energy sources can clearly contribute to the diversity within power systems, since generally, both the fuel base and the technologies themselves are different from conventional power plants. Diverse technologies are unlikely to suffer setbacks or upsets simultaneously.

New energy sources can contribute to the stability of the quality of service that a utility can offer its customers. In this context a system is stable if the change in the quality provided to customers is relatively insensitive to change in either the system parameters, the demands on the system, or exogenous constraints. Using LOLP as a measure of the quality of service provided by a grid, the quality of service can be plotted as a function of expected load. The plot is similar to that shown in a previous chapter as figure 3.2. When new energy sources are incorporated on a large scale into conventional systems, the shape of the LOLP vs load function will, because of the type of variability associated with new energy sources (Kahn, 1978), tend to change as shown in figure 5.10. If changes in total system capacity are made so that the LOLP of each system is equal, the system incorporating the new energy source will be more resilient to uncertainty due to load forecasting error. A more thorough analysis of this phenomena has been made by Kahn (1978a, 1979).

New energy sources, and the small scale technologies normally associated with them are often assumed to be modular and to have shorter lead times than conventional power plant. If this is true then this characteristic can be used in response to high levels of uncertainty about the future. If lead times for the power system can be reduced generally then uncertainty associated with load forecasts can be reduced as a result of the possibility of more accurate tracking of demand fluctuations. This aspect has been examined in some detail by Ford and Flaim (1979) who have modelled the feedback between the changes in load growth trends, the value of projects and the price of electricity. The value of smaller scale projects has been recognised by the CEGB in its recent announcements about wind power (CEGB, 1980). As well other aspects of small size,



1 - risk function with perfectly reliable plant

2 - risk function with plant having low forced outage rates

3 - risk function with plant having high forced outage rates

FIGURE 5.10 Resilience with respect to load forecast errors.

short lead times can contribute to improved service by the system but it should be remembered that these benefits need not be uniquely associated with new energy sources. Other authors (Lovins, 1977) have compiled a list of these potential benefits. Shorter lead times and smaller plant size can reduce:

(a) the likelihood of cost escalation during construction;

(b) interest charges during construction;

(c) scheduling uncertainty;

(d) the chances of changes in regulating requirements during construction;

(e) the chances of project disruption due to materials or labour shortages.

In addition to benefits that can be described by engineering criteria, or financial analysis it is possible the new technologies will have socially desirable effects that are important and should be included in any planning analysis. Their discussion is beyond the scope of this thesis, but a wide variety of literature is available in the area (Schumacher, 1973; Dickson, 1974; Illich, 1973).

5.6 Conclusions

A method has been presented of analysing the economics of new energy sources with intermittent output. The value of these sources can in principle be divided between their value due to fuel saving and their value due to capital savings. Methods have been presented by which approximation of these values can be made.

An analysis of each of these components in a notional system and an analysis of power system planning studies involving wind turbines show that the fuel savings value of wind turbines accounts for the majority of their worth. Analysis has also shown that as the penetration into the system increases the incremental value of extra capacity decreases.

The concern expressed in earlier studies (see section 2.4) about intermittent energy sources being non-firm capacity has shown to be illusory at least until major penetrations into the system are made, and it has been shown that a useful measure of the economic merit of intermittent energy source for penetration levels of perhaps 5% can be made by comparing the total cost of electricity from these sources directly to the similar figure for conventional power plant. At higher penetration levels more sophisticated figures of merit for plant comparisons must be made.

These findings lead one to believe that past analyses of the economics of new energy sources might have produced unnecessarily strict breakeven cost targets for these sources.

CHAPTER 6

The Economics of Wind Power in the UK

6.0 Introduction

Proper economic analysis of new energy sources is important to power system planners, energy policy makers, and those involved in the design of technology for harnessing new energy sources. If the value of new energy sources is grossly understated then it is likely that the potential role of that energy source will be misjudged. This could have important policy implications. Proper economic analysis is important in balancing the performance/cost trade-offs which are possible in the design of plant to tap new energy sources and incorrect analysis could lead to poor machine design. In this chapter analysis is presented of the economics of wind turbines and of the optimal wind turbine design.

Section 6.1 in this chapter deals with wind characteristics, wind data and the assumptions that are commonly made in modelling the behaviour of the wind. Section 6.2 describes the operating characteristics of wind turbines. Section 6.3 presents the breakeven costs for such plant, and presents the results of sensitivity analysis on these breakeven costs. Section 6.4 presents an analysis of optimal windmill design.

6.1 Wind Data

Accurately characterising the winds that occur at a given location over a long period is difficult. This is true even if high quality historical data is available. The difficulty is due to the variations that occur in the wind and the varying timescales that these occur over. Gusts and turbulence will cause variation over periods of less than a second. Global climatic patterns will produce variations that are measured over seasons and years. The former timescales are referred to as micro-scale, the latter macro-scale. Between these two extremes other variations occur caused by weather patterns, or by the diurnal cycle. It is the meso- and macro-scale variations that are of greatest interest here. The micro-scale variations have an important effect on aerodynamic, structural and electrical design, on the efficiency of energy capture, and on the quality of electricity produced; but a discussion of them is beyond the scope of this thesis.

Wind conditions at a given site are often described using velocity duration curves such as those in figures 6.1 and 6.2. Though these curves hide diurnal and monthly trends, they usefully focus attention on the spread in the velocity of winds which are likely to be encountered. As discussed later, diurnal and monthly trends can be described in other ways.

A significant amount of work has been carried out to characterise velocity duration curves simply. Golding (1976) summarised attempts during the 1940s and 1950s to find useful analytical descriptions of these curves and concluded that such descriptions were of limited value "since the determination of site constants appeared to involve almost as much work as actually plotting the curve itself" (page 27, Golding, 1976). It is possible that the need for standardised descriptions of the wind for use in international collaborations and information exchanges was not perceived. More recently Rayment (1976) has argued that sophisticated analytical descriptions are not required since his analysis suggests that the distribution of wind speeds around the mean is similar, at least for all sites in the UK, if the data has been properly normalised. A similar view is expressed by Harder (1977) using a more international data set and is implicit in the analysis undertaken by Allan and Bird (1977). Other work, see section 6.4.1, suggests these models are weak, and that the essentially single parameter model suggested by Rayment is too coarse for design studies.

Detailed consideration has been given to Rayleigh, Pearson Type III and Weibull curves (Justus et al, 1976, Hennessey, 1977) as useful analytical representations of velocity duration curves. The latter apparently being the most useful (Swift-Hook, 1978, Justus and Makhail, 1978, Hennessey, 1978). Weibull curves are of the form

$$F(x) = 1 - ae^{-ax^c} \qquad 6.1$$

or $$f(x) = ac\, x^{c-1}\, e^{-ax^c} \quad \text{where } a>o,\ c>o,\ x>o$$

where x is the instantaneous wind speed.

The parameter a is normally called the characterstic wind speed, and c is called the shape factor. In the USA shape factors in the range 1.5 to 2.5 have been calculated, (Justus et al 1976, Hennessey, 1978); in Australia 2.0 has been cited (Diesendorf and Fulford, 1979); in England a range between 1.7 to 2.0 has been suggested (Bossanyi et al, 1979, Caton, 1976).

In the UK, long term wind measurements are available from a number of sites (Collingbourne, 1978). Wind data used in this thesis was taken from analysis published in 1968 (Shellard, 1968). Data from two sites, Elmdon, and Stornoway, has been analysed in detail. Elmdon is an inland site with a low annual mean wind speed, a strong diurnal change in average wind speeds, but only a slight seasonal variation. Stornoway provides an example of a coastal site with a high annual mean wind speed, a strong seasonal variation and a less pronounced diurnal variation. Data for these sites is shown in figures 6.1 to 6.4. These sites will be referred to during this thesis as inland and coastal sites respectively.

As discussed in chapter 4 it is possible to form probabilistic chronological windspeed curves which incorporate much of the information about diurnal and seasonal variation and which are compatible with the technique of probabalistic simulation which is used in power system

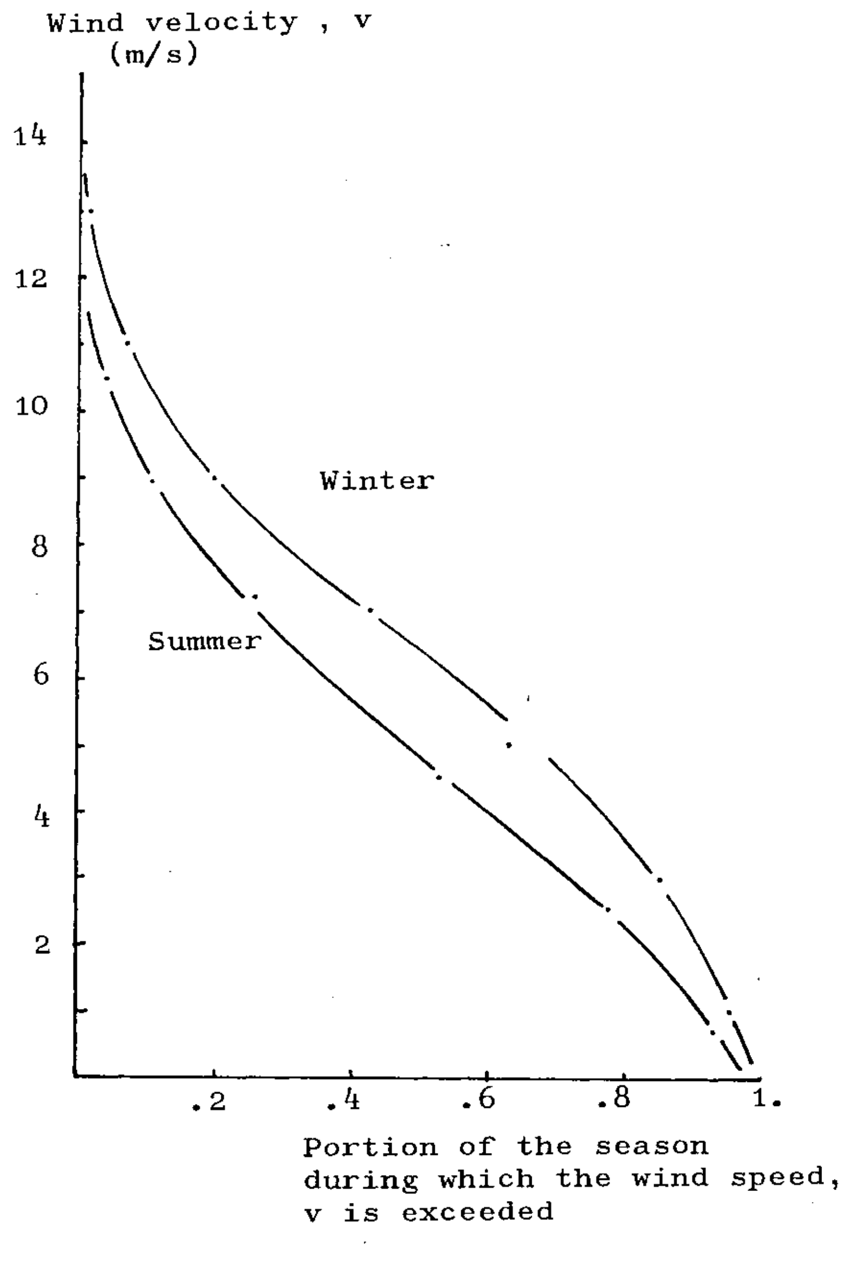


FIGURE 6.1 Velocity duration curves for the inland site.

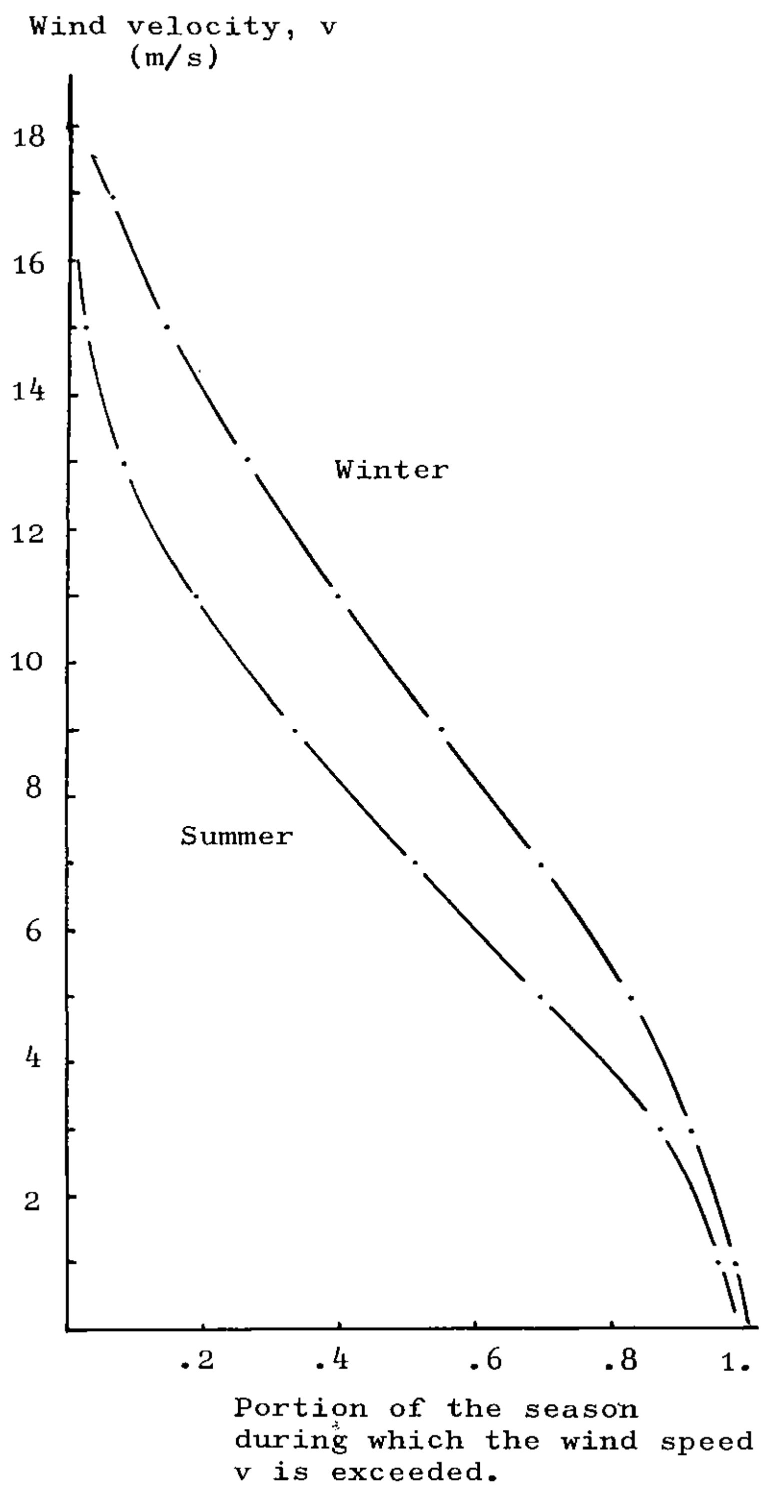


FIGURE 6.2 Velocity duration curves for the coastal site.

planning studies. Three major features of the wind that cannot be captured by such models include:

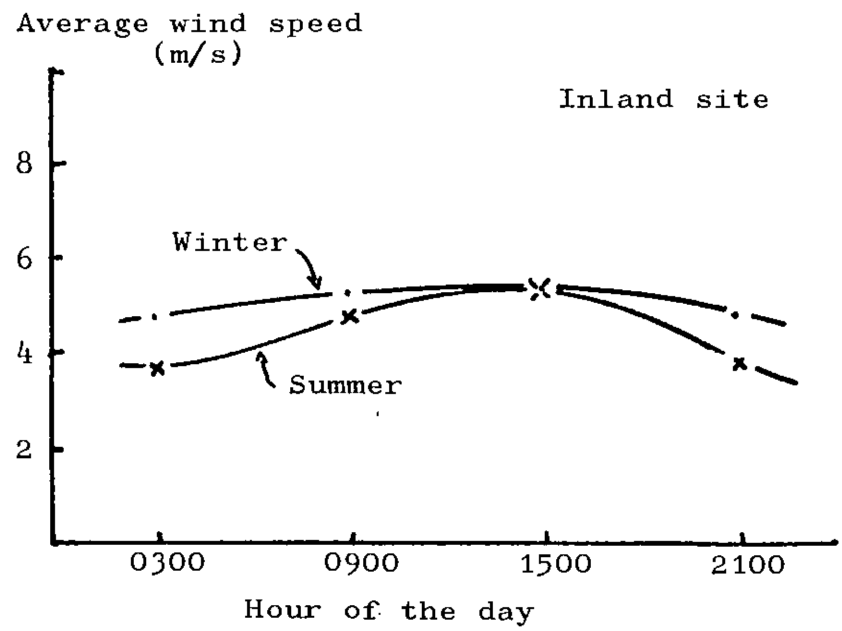
1. the hour to hour variability, or serial correlation of winds;
2. the predictability of the wind;
3. the short-tern correlation between the wind and the demand for electricity.

These shortcomings are discussed below.

Various measures of the serial correlation of wind speeds have been described elsewhere (Corotis et al., 1977, Corotis et al., 1978). It was shown in chapter 5 that the hour to hour variability of the output from WECS, and thus the need for a degree of standby, quick response plant is not of major importance in calculating the fuel saving value of WECS. As shown in section 3.3 the speed of the variation of the load or of plant failure does not feature in any part of analysis of a system's Loss of Load Probability and so any capacity credit based on this measure is unaffected by the use of models which omit this variability.

The predictability of the wind has been analysed both in connection with wind powered electricity generation (Justus, 1979 Bossanyi et al 1980, Taylor et al 1979) and more generally elsewhere (Morris, 1981). As with the speed of variation of the wind it has been found that, for reasons discussed in chapter 5, cost penalties associated with even complete unpredictability do not dominate the value of the WECS at low penetration levels. Furthermore, at higher penetration levels if increased predictability becomes important large numbers of anemometry stations could be deployed to provide the required data.

It is evident from figure 6.4 that at a gross level there is some correlation between load levels on the electricity supply system and wind speeds. Using appropriate levels of disaggregation in the



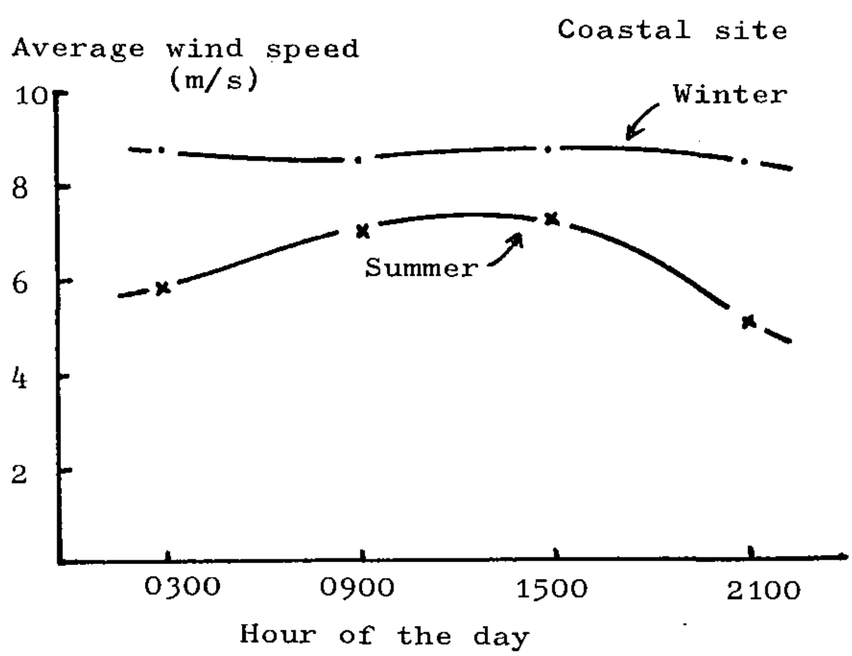


FIGURE 6.3a Diurnal variation of the wind; average wind speed at selected hours of the day

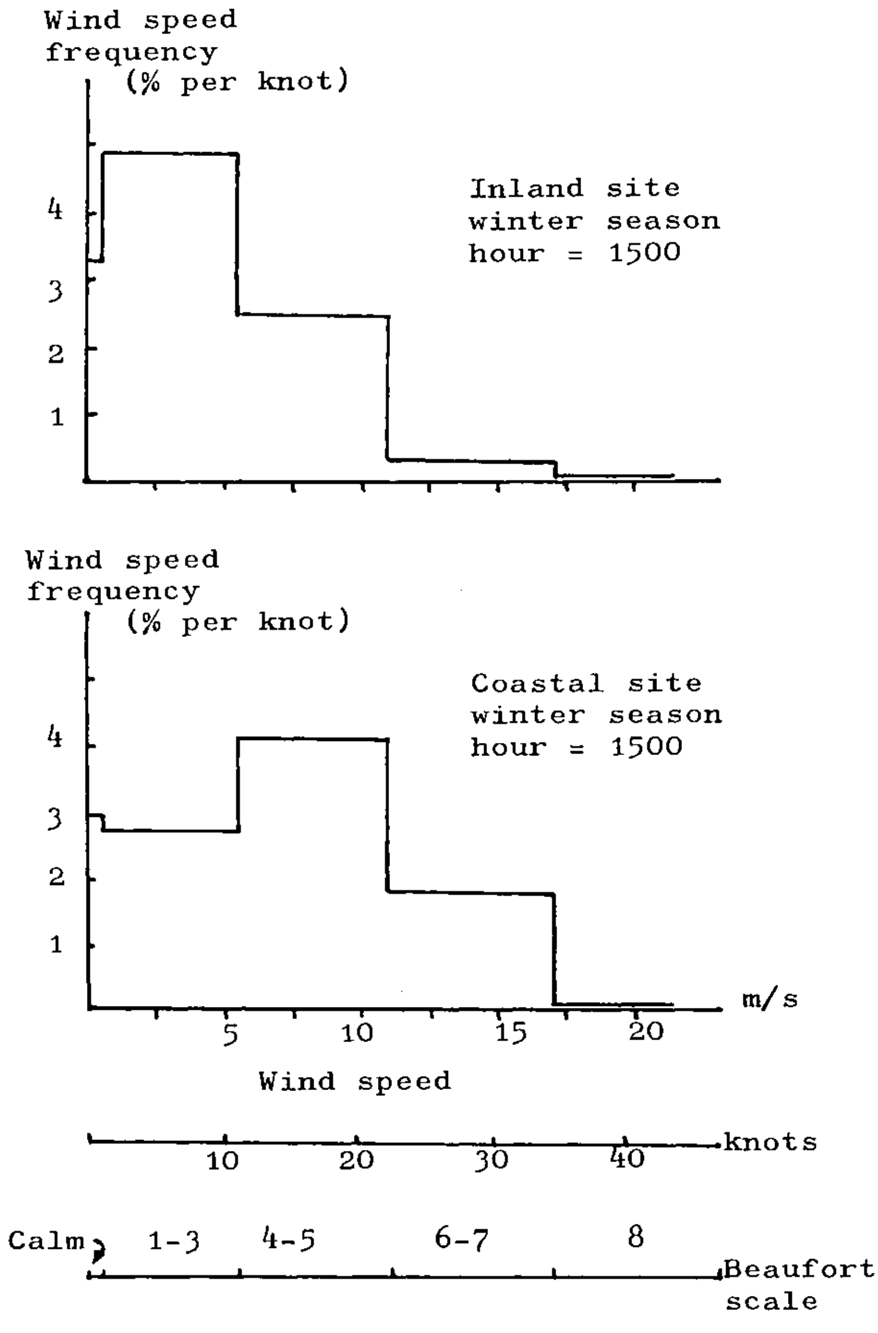


FIGURE 6.3b Average frequency of winds at selected hours.

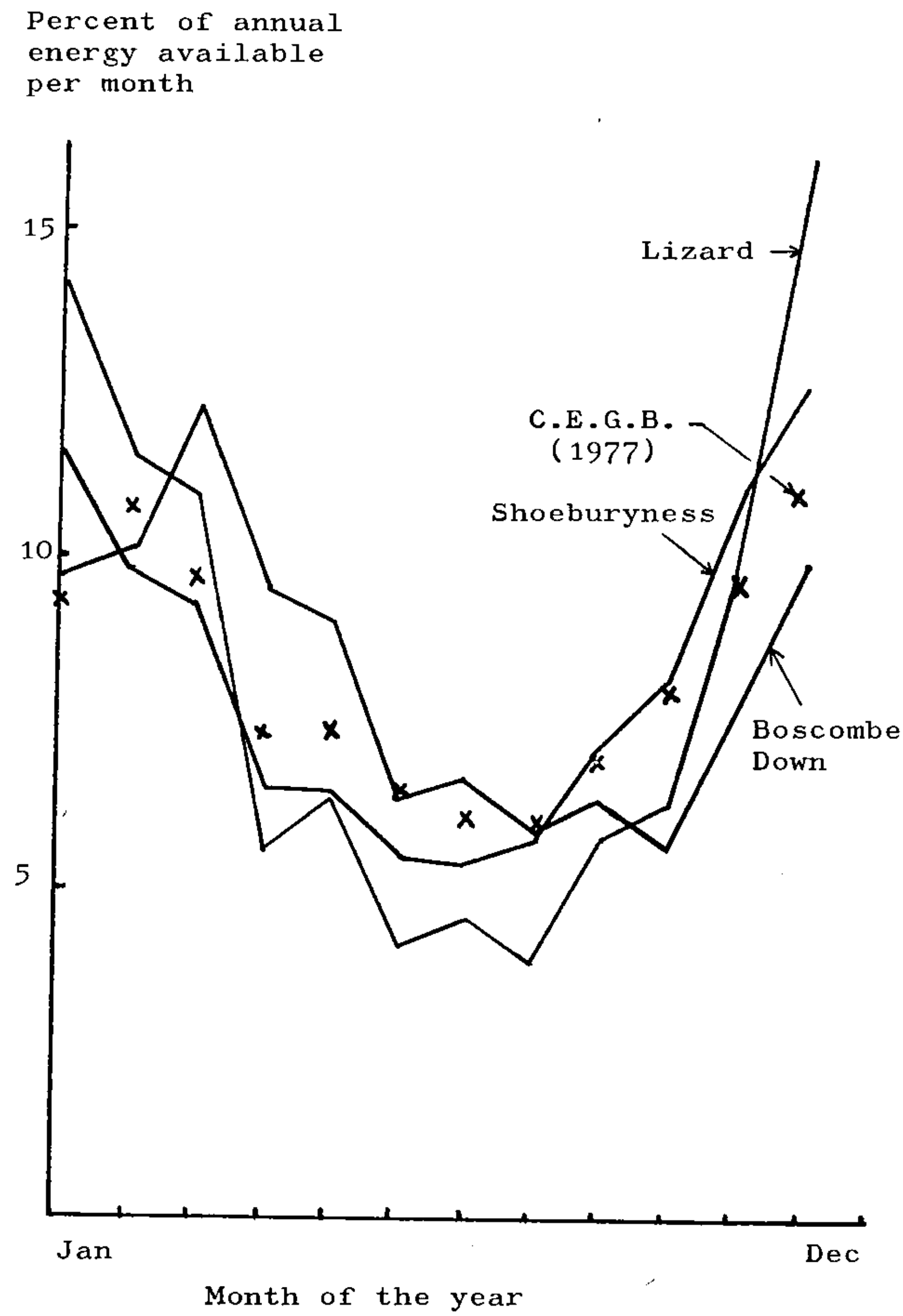


FIGURE 6.4 Monthly variability of wind energy and CEGB demand.

model this gross correlation can be captured by probabilistic chronological wind speed curves. However further correlations because of, for example, the "cooling power of the wind", will not be captured in such models. For the UK it has been estimated (Davies, 1958) that strong winds over the major population centres can add as much as 2000 MW to electricity demands. The use of probabilistic chronological windspeed curves may therefore underestimate the economic value of WECS though, as will be shown later, the distortion will not be severe.

6.2 Wind Turbine Response

The instantaneous power density $P_t(v)$ collected by a windmill can be represented by equation 6.2

$$P_t\ (v) = Cp(v) \cdot \eta(P)\ \tfrac{1}{2}\ \rho\ v^3 \qquad 6.2$$

where

Cp (v) is the aerodynamic efficiency of the turbine at velocity v

$\eta(P)$ is the efficiency of the power train and the generator

ρ is the density of the air

v is the windspeed

The aerodynamic efficiency of the blade is a function of the wind speed, and the characteristics and rotational speed of the blade: the mechanical/electrical efficiency is a function of the power output (or more directly of the torque on the input shaft). Figure 6.5a shows examples of these efficiencies using the system performance for the MOD-2 windmill.

Controversy continues about best designs for WECS. Options for the design of WECS include:

(1) one, two, three, or many blades;

(2) induction, synchronous or direct current generators;

(3) variable rotational vs fixed rotational speed operation;

(4) fixed pitch vs variable pitch (full blade or tip) blade control;

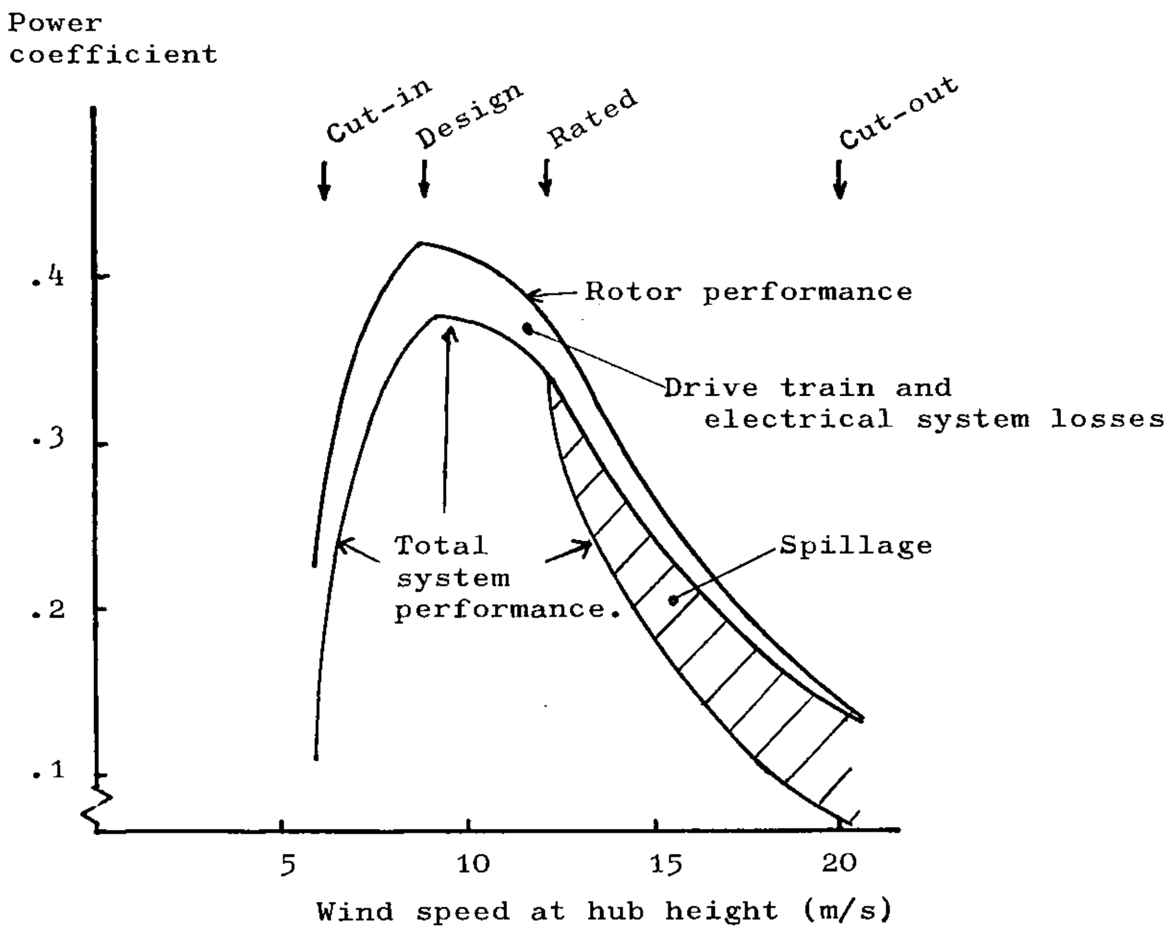


FIGURE 6.5a MOD-2 System performance
(Lowe and Engle, 1979)

(5) up wind or down wind blade positions;

(6) compliant vs rigid tower designs;

Choices in each of these options will affect the output characteristics of the resultant WECS. To the system planner interested in long term generation studies most of the information required to describe the WECS can be included in the power output characteristics curve shown in figure 6.5b.

As changes occur in WECS technology, power output curves will change in a variety of ways. The use of two speed operation will mean increased efficiency in light winds. Partial, rather than full span, pitch control may reduce efficiencies over a range of wind speed, but may be used because of major cost savings. Variable speed operation using hydraulic transmission or asynchronous generation would also have a major effect on efficiencies. Clearly a variety of power curves are possible.

Four different curves have been suggested (Haslett and Kelledy, 1981) as representative of power output curves, and thus machine characteristics, and these are described below. Each curve has the following common features;

$$
\begin{aligned}
P(v) &= o & & v < V_o \\
&= Pr & & V_R < v > V_2 \\
&= o & & v > V_2
\end{aligned}
$$

where v_o is the cut-in wind speed

V_R is the rated wind speed

V_2 is the cut-out wind speed

Their difference lies in the description of their behaviour between the cut-in and rated speeds. The performance in this region for each model is as follows:

$$P(v) = d + b\,v \qquad \text{I} \qquad 6.4$$

$$P(v) = d + b\,v + e\,v^2 \qquad \text{II}$$

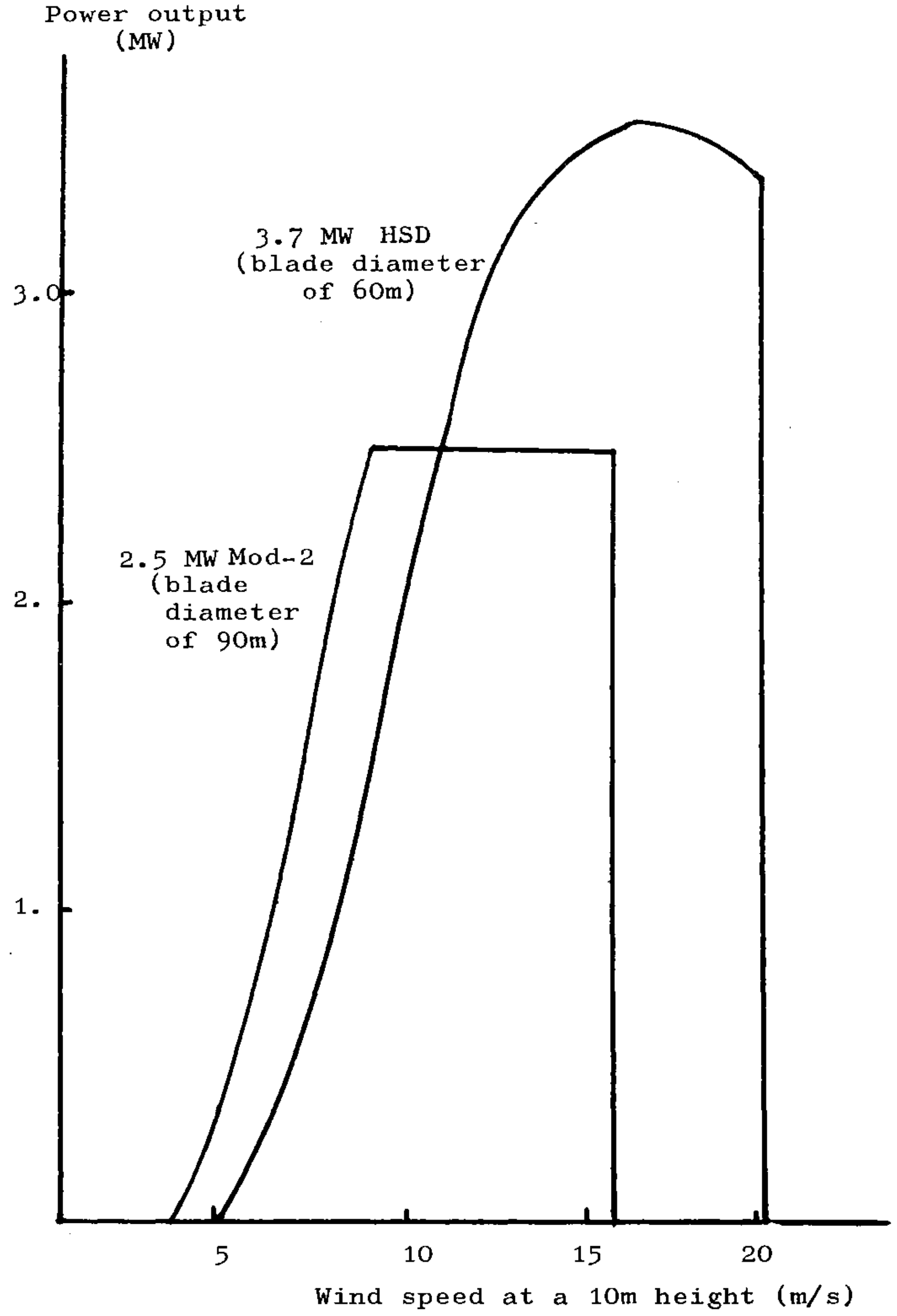


FIGURE 6.5b Power Output Characteristic for Mod-2 and HSD 3.7MW design.

$P(v) = d\ v^3$ III

$P(v) = d\ v^3 + b$ IV

Reference to these models is made later in section 6.4 and for convenience they will be labelled Type I, II, III, and IV models as indicated.

During design studies, the power rating, the cut-in speed, the rated speed and the furling speed can be varied to match particular wind conditions. This leads to the particular type of optimisation undertaken in section 6.4.3. The choice of hardware that leads to output curves described using one of equations 6.4 leads to more subtle differences which are reviewed in section 6.4.1.

For the base case economic assessment presented in the next section, the MOD-2 power output characteristic (see figure 6.5b) has been used in conjunction with the standard wind conditions adopted in the USA for their detailed competative design studies (see for example Department of Energy, US, 1979).

6.3 Breakeven Costs for WECS

It is convenient to analyse the economics of WECS using breakeven capital costs for single machines. A breakeven cost represents the maximum allowable cost of a machine for the investment to be attractive to the purchaser. It is independant of the actual cost of producing the machine but must incorporate assumptions about machine performance, machine life, test discount rate, and maintenance costs. Breakeven costs for machines will be sensitive to a wide range of factors which include; wind conditions at the site, daily and seasonal correlations between machine output and electricity load, the mix of plant in use in the grid, and economic assumptions about the future. Each of these factors is examined in turn in this section.

6.3.1 Base Case Analysis

A machine such as MOD-2 is expected to produce 9.9 GWh p.a. when sited at a location where the annual mean wind speed at a 10 metre height is 6.3 m/s (Lowe and Engle, 1979) and the velocity duration curve is described by a Weibull distribution with shape factor 2.29 (Department of Energy, US, 1979). As argued in chapter 5 it is possible to estimate breakeven costs for small tranches of these machines using a simple system model based on the average marginal system costs and the net effective costs for the plant in the base system.

For the following analysis the mix of plant used in the system, and with which the windmill must compete is described fully in appendix 2. Details have been presented in earlier chapters (see figure 4.5). The system marginal costs are dominated by fossil fuelled plant and average 1.95 p/kWh over the year.

Five cases can usefully be identified in examining the economics of WECS. These are shown in table 6.1. Case 1 represents the simpliest case; WECS are used only as fuel savers, they have no maintenance costs, the life of the machine is known (here it is 20 years) and the test discount rate is set (here at 5%). There is assumed to be no fuel price escalation during the life of the plant, and the conventional generating plant in the system and the annual load does not change from year to year.

Case 2 is similar to case 1 except that an annual maintenance cost equal to 1% of the total capital cost of the machine is assumed. This is in line with estimetes made by Seltzer (1981). In Case 3 an operating penalty (see section 5.1.1) equal to 5% of the fuel saving value of the WECS is included in the calculation. In case 4 and 5 a value is assigned to the capacity credit that the WECS should receive. In case 4 the value for the capacity credit is 28 £/kW p.a. and represents

Table 6.1 - Breakeven Costs for WECS - Base Case

	Sensitivity					
	Base	Maintenance 3%	Plant Life 25 years	TDR 10%	$\overline{V}$=5.5 m/s	$\overline{V}$=5.0 m/s
Fuel Saver, No System Penalty, No Maintenance	2.4	-	2.7	1.6	1.6	1.2
Fuel Saver, No Maintenance	2.3	-	2.6	1.6	1.6	1.2
Fuel Saver	2.0	1.4	2.2	1.4	1.4	1.0
Good Investment	2.4	1.7	2.7	1.8	1.6	1.2
Best Investment	1.7	1.2	1.9	1.5	1.2	.8

(Breakeven costs for MOD-2 design £ x 10^6)

the annual capital charge on gas turbines, or the annual cost of foregoing the scrapping of very low merit plant. In case 5 the value of the capacity credit is -30 £/kW p.a. which is the NEC of the preferred plant expansion option. In the base system nuclear power would have this NEC if the total capital cost including interest during construction is 700 £/kW.

It is important to review the significance of these cases. The figure calculated in case 3 shows the breakeven cost of a machine that is used purely as a fuel saver. At the breakeven cost, the utility's discounted savings over the life of the machine would exactly balance the capital and maintenance costs incurred. A comparison of results in case 3 with the earlier cases shows the importance of the maintenance cost and the system operating penalty. Case 4 identifies the breakeven cost of a machine, where the utility reduces plant margins after calculating the windmills capacity credit, and where the utilities savings over the life of the machine would exactly balance the capital and maintenance costs incurred. Note that at costs below this breakeven prices the purchase of the WECS becomes a good investment; it is not necessarily the best investment. This is a distinction which has not been drawn in previous analysis (Johanson, 1979), but which the author believes deserves more consideration.

The case 5 breakeven cost shows the cost at which the utility would be indifferent to the purchase of the WECS, or the next best option, in this case nuclear power. For this example if machines could be purchased at prices less than £1.71 x 10^6 then the utilities optimal investment strategy considering the data presented calls for the purchase of WECS. Both this plant and the next best option would have similar benefit cost ratios and busbar energy cost: their net effective cost, see section 2.3 would not necessarily be equal.

Table 6.2 - Breakeven Costs for WECS - System Changes

	Site Windspeed (Average)		
	6.3 m/s	5.5 m/s	5.0 m/s
Base Case			
Fuel Saver	2.0	1.4	1.0
Good Investment	2.4	1.6	1.2
Best Investment	1.7	1.2	.8
Fuel Cost Escalation			
Fuel Saver	2.6	1.8	1.3
Good Investment	3.1	2.1	1.6
Best Investment	1.9	1.4	.9
Optimal System Mix			
Fuel Saver	1.3	.9	.7
Best Investment	1.7	1.2	.8

(Breakeven costs for MOD-2 design £ x 10^6)

It has been estimated (Low and Engle, 1979) that when a production run of more than 100 units is made the cost of MOD-2 is £1.1 $\times 10^6$ (1978 money - based on 10% inflation p.a. from 1977 to 1978, 1.8 \$US = £1 sterling). On this basis the economics of WECS look very encouraging.

Each of cases 1 through 5 can be used to examine the sensitivity of the breakeven price to changes in maintenance costs, plant life and test discount rate results are shown in table 6.1. For these three parameters the breakeven cost is shown to be very sensitive to the maintenance costs and the test discount rates assumed.

6.3.2 <u>Sensitivity to Average Annual Wind Speed</u>

The power in the wind varies as the cube in the wind speed and so it is clear that the energy available is very sensitive to the site annual average wind speed. In section 6.2 a variety of mathematical descriptions of the wind were reviewed and it was suggested that for design optimisation or where precise calculation of the energy capture is required one must specify more than the mean wind speed at a given site. It is possible that for simple sensitivity analysis that less rigour is demanded.

The total energy available in the wind divided by the energy calculated by cubing the mean wind is called the energy pattern factor, Ke, and is often used during preliminary analyses to circumvent the need for detailed description of the wind variation.

$$Ke = \frac{\int_o^T v^3 \, dt}{T \left(\frac{\int_o^T v \, dt}{T} \right)^3} \qquad 6.5$$

where v = the wind speed at any time

T = the total time

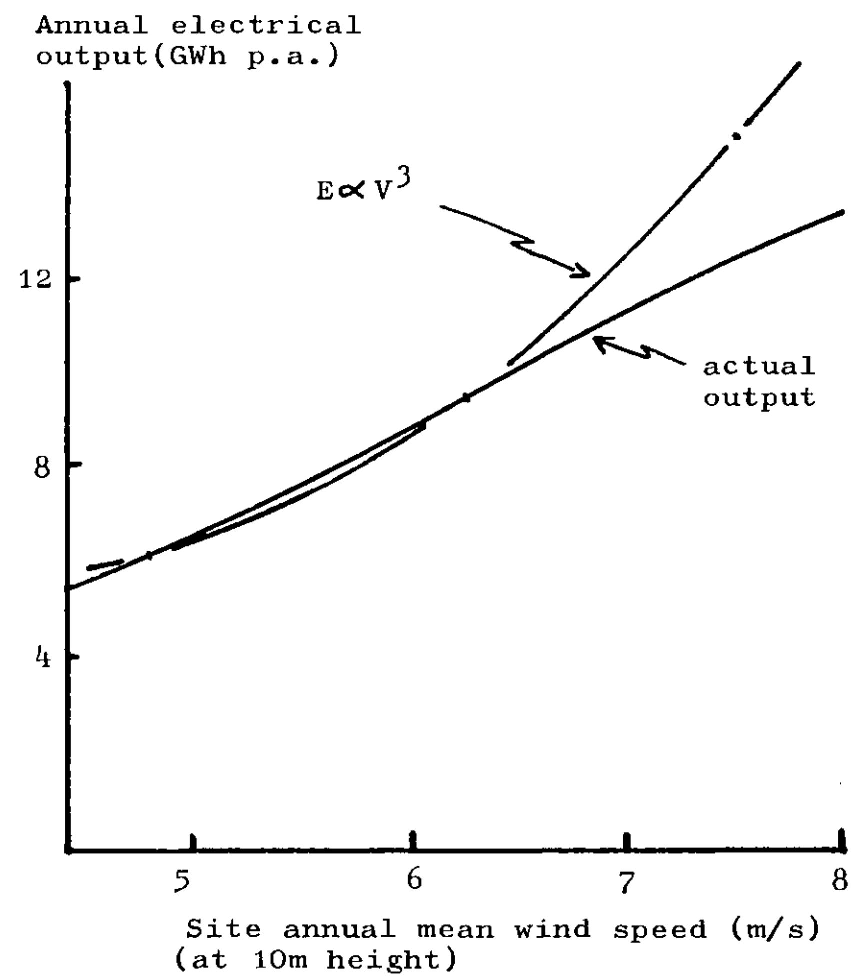


FIGURE 6.6 Predicted output for Mod-2
(system availability of .9)

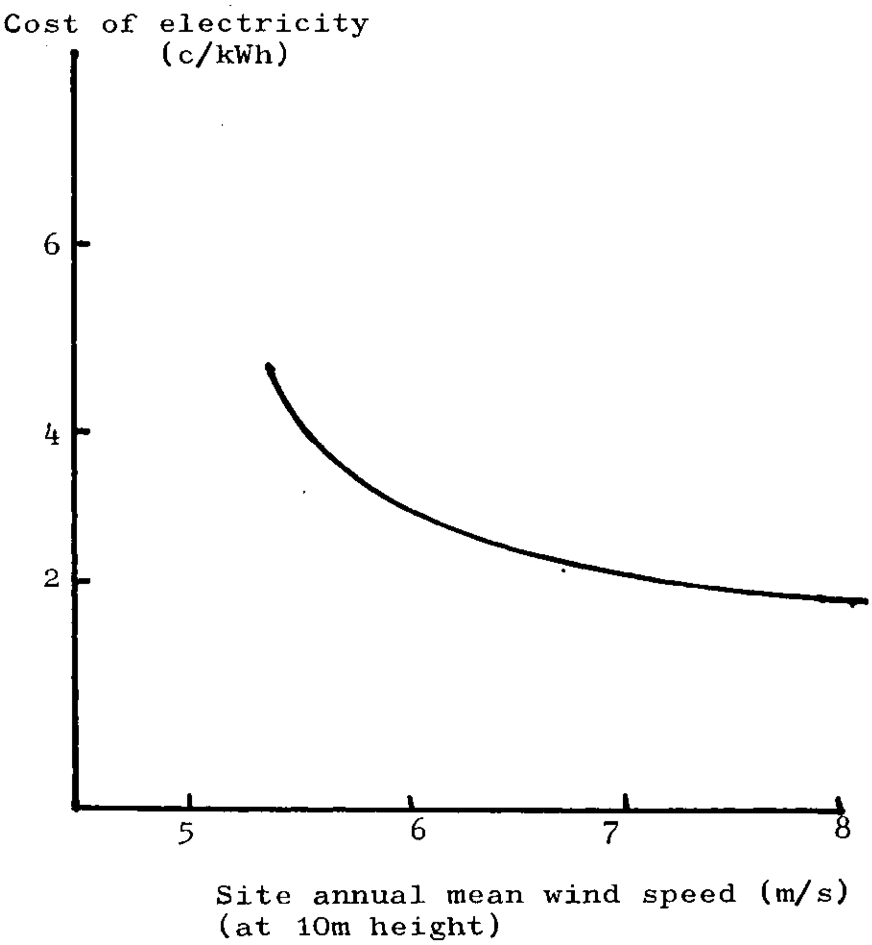


FIGURE 6.7 Predicted cost of electricity for Mod-2 (mature product)

Golding (1956) reported energy pattern factors for the UK between 1.5 and 4. Diesendorf and Fulford (1981) have reported this factor being more constant at about 1.9.

If the energy pattern factor is constant then the energy output for a machine whose design is continuously optimised would vary as the cube of the mean windspeed. If the energy pattern factor varies then the relationship between the site mean windspeed and the machine output may be more complicated and detailed calculations are needed.

For a fixed design it is likely that a cubic relationship between site mean windspeed and machine output will not hold. The output of MOD-2 for different wind speed sites is shown in figure 6.6 (from Thomas and Robbins 1979) and the implications for the machine breakeven cost are shown in table 6.1. The sensitivity of breakeven cost to mean windspeed is mirrored by the estimates shown in figure 6.7 (taken from Lowe and Engle,1979) of how the site mean windspeed affects the cost of electricity. Both table 6.1 and figure 6.7 show how important the estimate of the site annual mean windspeed is to the economic of WECS.

6.3.3 Daily and Seasonal Variations in the Wind and in Electricity Demand

Farmer et al (1979) have reported that the composite wind, calculated by summing readings from a number of sites around the UK, and the electricity demand show a slight daily correlation. They further report that a correlation coefficient of .23 has been calculated for the aggregate WECS output from these sites and electricity demand. It was shown in chapter 4 that the expected marginal energy cost over a winter day and a summer day varies from 2.2 to 1.7 p/kWh for a system representing the mix of plant currently suggested for the 1985 CEGB system. Together these statistics indicate that for the base case system and for small penetrations the diurnal variation in wind and load does not have a major influence on the economics of WECS. This was confirmed using PRICE (see chapter 4 and appendix 3) in correlated and uncorrelated modes. The former produced average fuel savings for a 1000 MW of capacity (3 TWh p.a.) at the Elmdon site of 2.0 p/kWh while the latter case produced average fuel savings of 1.9 p/kWh.

The breakeven costs for machines therefore vary by only 10% in what for the UK seem to be extreme variations in duirnal wind patterns.

The importance of seasonal variations is more difficult to assess. Figure 4.5 has shown that with reasonable maintenance scheduling the expected marginal production costs for the winter and summer day are similar. Scheduling patterns were established with objective of minimising system risk over the year. Maintenance patterns are, within limits, in principle very flexible and can be manipulated to suit the plant characteristics. It is likely that the variability of WECS output will increase the difficulty of scheduling maintenance, but the penalty associated with this cannot, at the moment, be quantified. The seasonal variation of the wind does have important implications for capacity credits since for the sites studied summer and winter load factors can vary considerably (see figure A-2.8b). However for most system penetrations that are realistic in the medium term capacity credit does not dominate the economics of WECS and thus seasonal variation is unlikely to be a major factor to be considered in the overall system economics. At larger penetrations seasonal variations in wind conditions are likely to be more important.

6.3.4 <u>Fuel Cost Escalation</u>

Recent assessments by the Central Electricity Generating Board, (1980) show that fuel price escalation for nuclear, coal and oil burning power station is expected to occur at rates of 2%, 3% and 3½% per year averaged over the life of plant now under construction.

If these escalation rates are included in the economic analyses of WECS, the breakeven costs for windpower increase as shown in table 6.2. (The calculations assume that the marginal plants in the system are coal-fired). The effects of fuel cost escalation are shown to be substantial in some cases; raising the breakeven costs by as much as 30%. It was, however, argued in chapter 5 that a "Best Investment" analysis is the most appropriate type for calculation the economics of WECS and with this analysis fuel cost escalation of nuclear fuel changes the allowable breakeven cost of WECS by less than 5%.

6.3.5 Changes in the System Mix

As mentioned in section 5.4 decisions for investment that are made in power systems planning must recognise the dynamic nature of the system mix. The present CEGB planning calls for a major shift to nuclear power. If this shift occurs to the extent that nuclear power moves out of its base load role two effects need to be noted: the marginal costs of energy on the system would decrease dramatically, and as a result, the net effective costs of the best alternative plant (nuclear) would start to rise. To study this effect an additional case has been studied in which the system mix used in simulations was optimised with regard to the balance of coal and nuclear power capacity. Cases using this new optimised mix has been referred to in the thesis as OPT scenarios. Cases using the base mix are referred to as BAU scenarios.

Program PRICE3 was used to estimate marginal system costs in the OPT scenario where the lowest merit nuclear plant is operating at its breakeven point - a load factor of .35. Marginal costs over the winter day are shown in figure A2.5 (Appendix 2). Breakeven costs for WECS are shown in table 6.2. If the breakeven costs for the machine are calculated solely on the basis of the fuel savings value, there is a dramatic decrease in that cost. However if more proper analysis is done and Best Investment analysis is carried out the breakeven costs for small penetrations of the machine are independent of the postulated system mix. A further point is worth noting: in the optimised system mix the net effective costs of a small increment of all plant options in the system are equal and so it is now impossible to differentiate between the "good investments" and the "best investment" described earlier.

6.3.6 Penetration Level

In chapter 5 the reasons for the decreasing incremental worth of WECS as a function of penetration were described. The reasons included:

(i) the increasing operating penalties because of the difficulties of integrating intermittent energy sources with the grid;

(ii) the increasing energy spillage which occurs when WECS energy is available but cannot be integrated into this grid;

(iii) the decreasing fuelling cost of higher merit plant;

(iv) the decreasing incremental capacity credit;

Only the last two aspects can at the moment be quantified with any accuracy using the models discussed in this thesis.

It was shown in chapter 3 (section 3.2.3) that at low penetrations it is possible to predict capacity credits using a simple analytical formulation. At significant penetrations this formulation is less accurate for a number of reasons which are described in that chapter. Numerical models can be used to increase the accuracy of predictions regarding capacity credits, but must, at very large penetrations, be suspect because of the system risk model in use (see section 3.2.3). The numerical models incorporated in programme

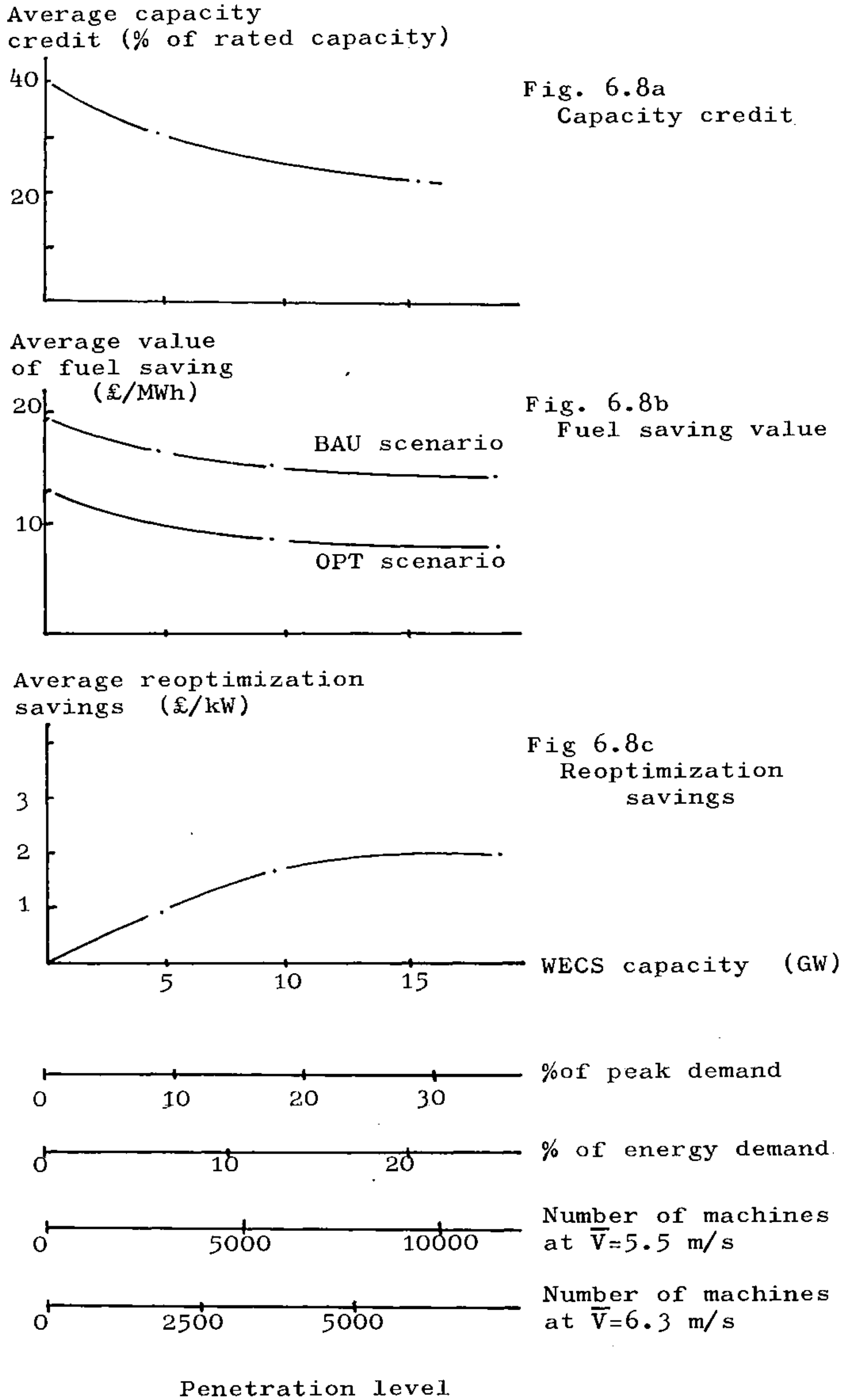


FIGURE 6.8 The components of WECS value versus penetration into the system. (Mod-2 characteristic, $V_R/\overline{V}=1.5$)

RENEW were used to calculate the capacity credit of WECS, but until utilities themselves study the problems of system reliability imposed by large penetrations of WECS, capacity credits at large penetration level must be used with caution. Results from RENEW are shown in figure 6.8a.

In analysing the effect of WECS on the system Johanson (1979) has noted a second sort of capacity credit which can be attributed to WECS. He notes that when a large tranche of WECS are considered, and the system is re-optimised to accommodate these WECS, peaking plant will replace a certain amount of other types of plant. Since this peaking plant generally is more reliable than the plant it replaces, a reduction in overall reserve capacity can take place. He attributes this reduction to WECS and counts it, in addition to the original capacity credit, as a benefit of WECS. These calculations are not possible with the models developed in this thesis and this effect has not been quantified. In small systems such as those analysed by Johanson it is also true that the capacity credit of WECS is strongly affected by the mix of plant considered since this mix affects the standard deviation of the total system uncertainty (see equation 3.37). For the base case, and optimised mix case considered here the total system uncertainty for the two cases was similar and thus the behaviour of the capacity credit in the two systems must likewise be similar.

Fuel cost savings also vary as a function of penetration. Results for the two system mixes studied are shown in figure 6.8b. Note that both the absolute value of the fuel savings and the rate of decrease in the incremental savings are dependant on the initial system mix.

In Section 5.3.3 the magnitude of the reoptimisation savings component of total capital savings that can be associated with WECS were analysed. It was shown that at high penetration levels, reoptimisation savings can be significant (especially if low discount rates are in use - figure 6.8c shows estimates of reoptimisation savings as a function of the WECS capacity considered; a zero test discount rate is assumed).

The three parts of figure 6.8 are brought together in figure 6.9 where the breakeven costs, as judged by a number of criteria and in the two system mixes, are displayed. Penetration effects are evident; these agree broadly with results from other studies (Marsh, 1979, Johansen, 1979, Van Kuiken et al, 1980). Again breakeven costs vary according to the criteria used in the analysis (good investment versus best investment) and according to the system mix considered.

6.3.6 Summary

Having examined the breakeven costs for WECS for a number of situations several points emerge.

(1) the economics of WECS look encouraging. For the data used to represent UK conditions, breakeven costs for WECS appear to be well in excess of predicted costs when series produced machines using existing designs are sites in moderate windspeed regimes.

(2) the economics of WECS are very sensitive to annual operating and maintenance costs, to the site mean windspeed, and to both the capital and fuel costs of competing plant options.

(3) the economics of WECS appear to be relatively insensitive to the pattern of daily electricity demand and wind conditions, and to the actual mix of plant used in the system. The validity of this last point rests with the assumption that system reoptimisation savings are possible through flexibility in future system development and that the economics of WECS must be judged against the costs of other planting options.

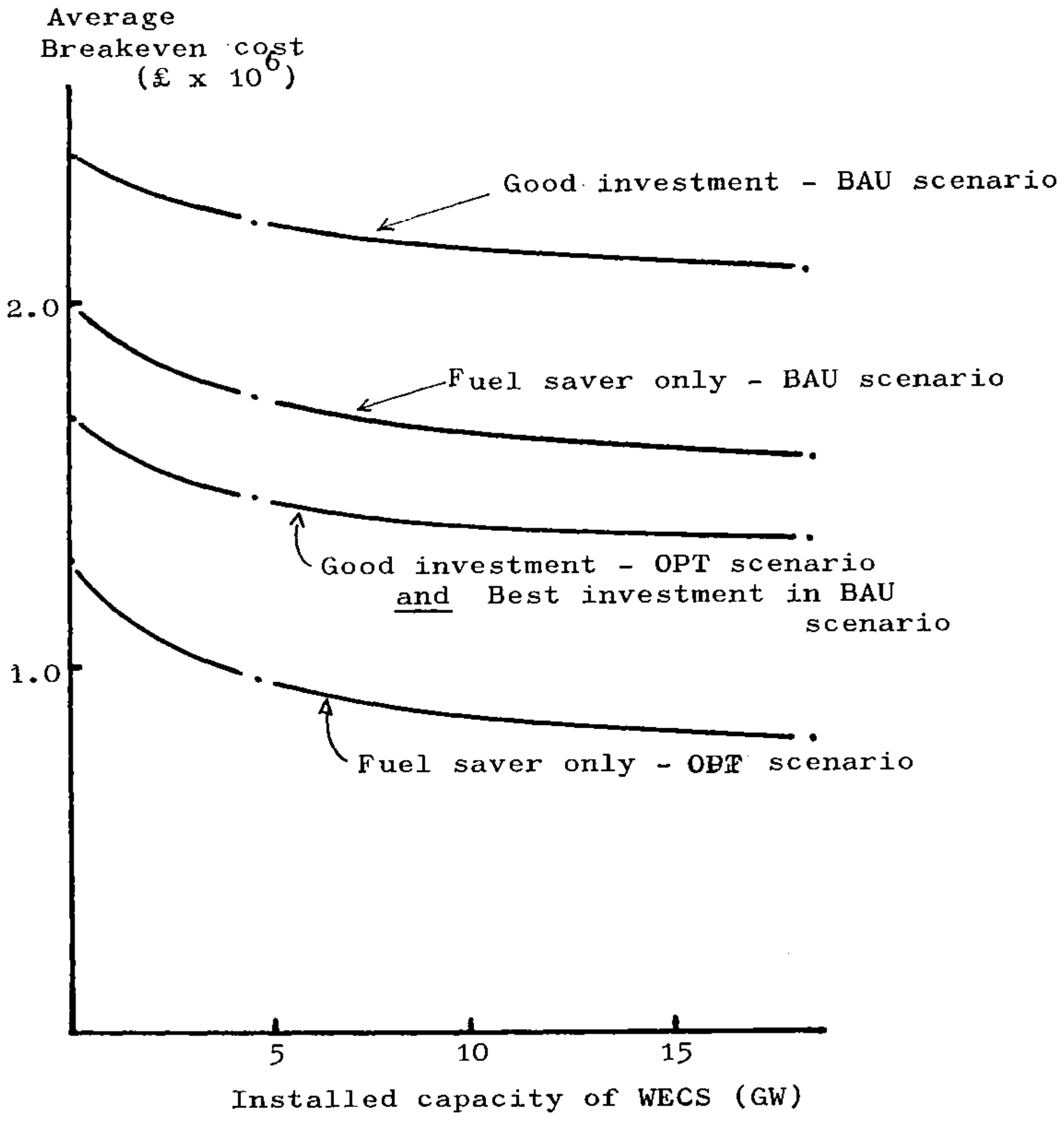


FIGURE 6.9 Breakeven costs and penetration effects for wind turbines.

6.4 Optimisation of WECS Rating

To fully optimise WECS design requires a complex series of trade-offs between parameters such as blade size (diameter, solidity), rotation speed, cut-in speeds, rated speeds, furling speeds, tower heights and a host of other considerations. Analyses of all of these parameters would be important in civil, mechanical or aerodynamic studies: they are beyond the scope of this thesis. A partial or constrained optimisation can however be carried out for machine rating. The problem can be framed as follows: given the diametral size of an aerogenerator wind rotor and the wind regime and system data for the chosen site, what is the best size of electrical machine to be coupled to the wind rotor. Trade-offs are possible to control overall efficiency across the spectrum of wind speeds that occur. The efficiency in different winds affect the speed of variation of the WECS output, and the overall continuity of that output; both will affect the value of the output from WECS.

Past optimisation (Taylor et al 1979, Bossanyi et al 1979) has focussed on maximising the energy output, or minimising the per unit energy cost (Taylor 1979). To a large degree this type of optimisation can be done independantly of any consideration of conditions in the electricity system of which the WECS will be part. However, as argued throughout the thesis, system conditions affect the value of WECS and thus may affect optimal WECS design. Section 6.4 has shown that the value of WECS change as their penetration into the system increases, again optimal designs may be influenced.

6.4.1 Maximum Energy Output

By fixing the machine efficiency curve relative to the rated wind speed, it is possible to show the effect on the total energy capture of the rating ratio $V_R/\overline{V}$ (the rated wind speed divided by the site annual mean wind speed). Figure 6.10 shows the annual energy capture of a machine whose cutin speed is one half the rated wind speed, whose furling speed is twice the rated wind speed, whose overall efficiency at the rated wind speed is .35 and which fits a type I model described in equation 6.4. (Characteristics for 3 machines each having this characteristic are shown in figure 6.11.) The wind regime used for the analysis is based on the velocity duration curve shape calculated for the inland site described in section 6.2. It is clear that an optimal rating ratio exists. For this example the maximum energy capture per machine occurs at a rating ratio of 2.0.

Other analysts have shown similar results with slight differences reflecting different wind conditions or machine efficiency curves. Diesendorf and Fulford (1979) have examined data from Australia which is best described with a Weibull shape factor of 2. They have used a type IV WECS model (see equation 6.4) and calculate the maximum energy capture to occur at rating ratio of 2.0. They also note that the maximum in energy capture occurs at a rating ratio of 2.3 if the constant term in that WECS model is neglected (i.e. type III model is used). This result is interesting in view of the analysis of Allen and Bird (1977) which also shows the optimal rating ratio to equal 2.3 and which uses the type III WECS model. Bossanyi et al (1979) have done similar analyses and as well have shown the effect on optimal ratings that result from the consideration of different wind regimes. Those results show that the optimal values of the rating ratio lie between 2.0 and 3.0 depending on the WECS model used. Similarly Taylor (1979) using a type III model has found energy capture maxima at rating ratios between 2.1 and 2.4 depending on the shape factor of the Weibull distribution wind regime and Taylor et al (1979) using data from a number of sites in the UK in combination with a type I WECS model show optimal rating ratios of between 2.0 and 2.3. Haslett and Kelledy's

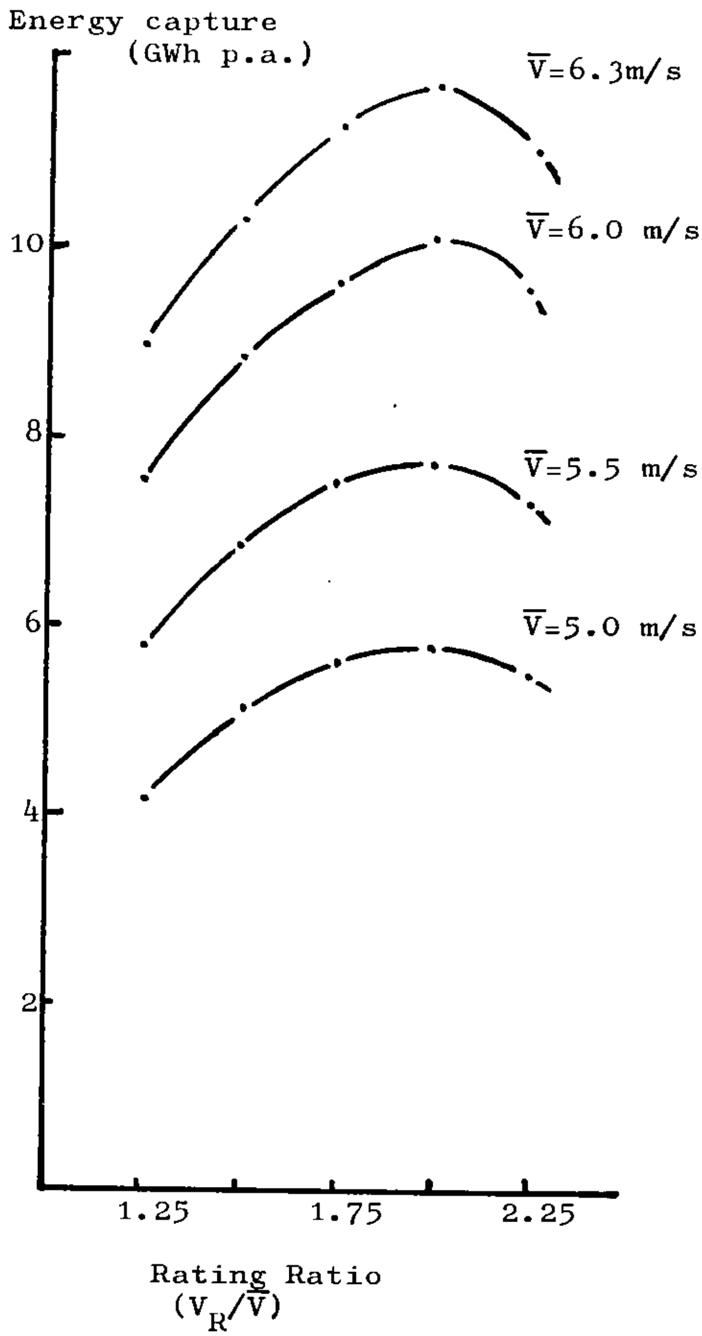


FIGURE 6.1C The effect of site annual mean wind speed and machine rating on energy capture.

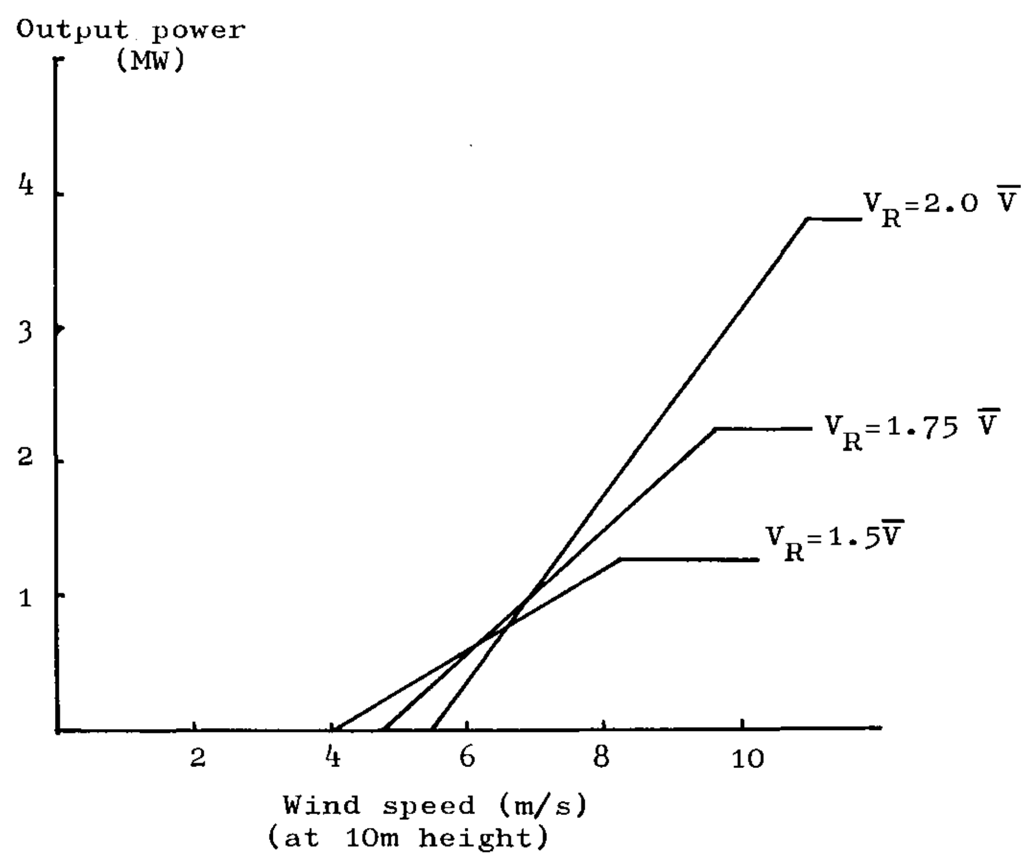


FIGURE 6.11 Power output curves and machine rating at a site with an annual mean wind speed of 5.5 m/s.

study of the four WECS models (1981) shows the optimal rating ratio to lie between 1.9 and 2.1 if a Rayleigh wind speed model is used. One can conclude that the rating of the machine which maximises energy output is sensitive to both the machine characteristics and the wind conditions, but over a range of conditions lies near a rating ratio of 2.

Before moving on to an examination of the optimal ratings for machines which minimise energy costs it is important to make a number of points. Firstly if optimisation is carried out,based on the distribution of winds aggregated over the year,then the implication is that output from WECS can be valued independantly of when or in what quantities it is produced. Clearly this is a heroic assumption which although adequate for the type of analysis carried out in section 6.3 may be inappropriate for more refined analysis such as that in section 6.4. Secondly the machine characteristics described in the section have assumed a constant power output between rated and cut-out speeds. In some cases the control system needed for this is more costly than can be justified. For machines such as the 3.7 MW HSD machine (British Aerospace, 1979), or the Boeing Mod 5B (Wind Energy Report, 1981) analysis such as that done by Haslett and Kelledy (1981) is misleading and the work of Bossanyi et al (1979) is more informative. Thirdly these optimisations ignore penalties associated with uncertainty. Jarass (1979) has analysed the variation of output from a given wind turbine using data collected over 10 years and has found a coefficient of variation of 10%. It is possible that machines with lower rating ratios would have lower coefficients of variation associated with their total annual output and this decrease in variance may be of some value.

6.4.2 Minimum Energy Cost

Maximising the energy capture of a given machine does not ensure that unit energy costs will be minimised. For a given blade geometry an increase in the rated wind speed increases the power output and thus the generator rating; the turning moment on the tower; and arguably the weight at top of the tower. The minimum energy costs will be achieved when the changes in costs due to the changes in the rating are balanced by the changes in the energy capture. If maximum energy capture is achieved at rating ratios of between 1.9 and 2.3 minimum energy costs will occur at lower ratings. Golding has estimate optimal rating ratios in the range 1.4 to 2.0. Putnam implies a rating ratio of 1.3. More recent designs (Thomas, 1979 and Wind Energy Report, 1980) suggest rating ratios of 1.5. Taylor (1979) estimates it to be 1.7.

Changes in the rating ratio of a machine can have dramatic effects on its characteristics. As an example, if a rating of 2.1 maximises energy capture, and a rating of 1.7 minimises per unit energy cost then at a 6.3 m/s average wind speed site,the capacity of a machine with the blade diameter and coefficient of performance of MOD-2 will have ratings of 6.7 MW and 3.6 MW, and load factors of 18% and 32% respectively. Clearly the two optimisations lead to very different machines.

To incorporate cost/efficiency trade-offs which will define optimal ratings of a given wind turbine it is necessary to be able to estimate how costs change as a function of the rating. For some components such as the generator, relationships between the cost and the rated power are well established (Hardy, 1977). For other components and for total machine cost, less is known.

The overall electricity costs will also depend on the scenario for development which is envisaged. Where machines are assumed to be sited only in remote areas on hill-top sites, transmission and maintenance costs form a major portion of overall project costs and are only slightly affected by machine rating. Where machines are sited near transmission grids and easy access, these costs form a smaller position of the total. The component breakdown of costs for several machines is shown in Table 6.3.

For this thesis the normalised cost per machine was assumed to vary with rating according to a simple power law as shown in equation 6.4. Other models have been suggested (Kirschbaum et al, 1976). Although a more refined model of machine costs would be desirable, the present model suits the purposes of this thesis.

$$C(P_R) = K_1 + (1-K_1)\ P_R^{0.6} \qquad 6.6$$

$$C(V_R) = K_1 + (1-K_1)\ V_R^{1.8}K_2$$

where C is per unit machine cost

P_R is the rated power of the machine

V_R is the rated wind speed of the machine

K_1, K_2 are constants

After considering the data presented in table 6.3, K_1 was set equal to 0.6. Where maintenance costs and transmission costs are included in the model these will be 1% p.a. and 5% of machine capital cost. These figures are suitable when large arrays of land based machines are considered (Robbins and Thomas, 1979, Seltzer, 1981).

If the per unit costs of energy are to be minimised,the function C(V)/E(V) (where E(V) is some function describing the energy capture as a function of rating, see figure 6.10) must be minimised. This occurs when the first derivative with respect to V is equal to zero.

$$\frac{\partial(C/E)}{\partial V} = 0$$

$$= \frac{E\frac{\partial C}{\partial V} - C\frac{\partial E}{\partial V}}{E2}$$

$$E(V)\ \frac{\partial C}{\partial V} = C(V)\frac{\partial E}{\partial V} \qquad 6.7$$

Table 6.3 - Normalised Costs for Large Horizontal Axis Wind Turbines

<table>
<tr><th>Machine†</th><th>A_1</th><th>A_2</th><th>B</th><th>C</th><th>D</th><th>E_1</th><th>E_2</th></tr>
<tr><td>Ref.£</td><td>1, 2</td><td>3</td><td>4</td><td>4, 5*</td><td>6</td><td>7</td><td>7</td></tr>
<tr><td>Component</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Rotor</td><td>28</td><td>38</td><td>8</td><td>11</td><td>28</td><td>25</td><td>22</td></tr>
<tr><td>Mechanical Transmission</td><td>24</td><td>18</td><td>36</td><td>50</td><td rowspan="2">25</td><td>15</td><td>26</td></tr>
<tr><td>Alternator</td><td>11</td><td>5</td><td>12</td><td>4</td><td>9</td><td>16</td></tr>
<tr><td>Orientation</td><td>4</td><td>4</td><td>5</td><td>7</td><td>12</td><td rowspan="2">10</td><td rowspan="2">16</td></tr>
<tr><td>Tower</td><td rowspan="3">20</td><td></td><td>8</td><td>8</td><td>12</td></tr>
<tr><td>Foundation</td><td>19</td><td rowspan="2">31</td><td rowspan="2">17</td><td>6</td><td rowspan="2">11</td><td rowspan="2">7</td></tr>
<tr><td>Site Work</td><td></td><td>4</td></tr>
<tr><td>Other</td><td>13</td><td>16</td><td>-</td><td>4</td><td>11</td><td>30</td><td>13</td></tr>
<tr><td>Total Machine</td><td>100</td><td>100</td><td>100</td><td>100</td><td>100</td><td>100</td><td>100</td></tr>
<tr><td>Installation+</td><td>60</td><td></td><td></td><td>15</td><td></td><td>7</td><td>9</td></tr>
<tr><td>Maintenance+</td><td>60</td><td></td><td></td><td></td><td>10</td><td>10</td><td>10</td></tr>
<tr><td>Transmission+</td><td>23</td><td></td><td></td><td>11</td><td></td><td></td><td></td></tr>
</table>

Notes for Table 6.3

* In the "Fourth Approximation" design study (see Putnam, 1948, p.152) it was estimated that between 24-50% of the machine costs would be influenced by the machine capacity. The cost estimate shown above is taken from Golding (1976) and apparently is in conflict with Putnam's estimate.

\+ Expressed as a percentage of Total Machine Cost

† A_1 46 m variable pitch machine, 1974
A_2 46 m variable pitch machine optimised for minum energy cost, 1974
B 64 m variable pitch machine, 1955
C 54 m variable pitch machine, 1946, Smith-Putnam
D 91 m variable pitch machine, 1978, MOD-2
E_1 104 m variable pitch tips, 1980, MOD-5A, 2nd machine
E_2 104 m variable pitch tips, 1980, MOD-5A, 100th machine

£ References

(1) Allen and Bird, 1974
(2) Taylor, 1979
(3) Anderson et al, 1978
(4) Golding, 1976
(5) Putnam, 1948
(6) Wind Energy Report, 1980

As a prelude to the next section it is worthwhile to note that the net worth of the machine is to be maximised, and the net worth can be defined as in equation 6.8, then the maxima can be located as in equation 6.9

$$\text{Net worth} = W(V) - C(V) \qquad 6.8$$

$$\frac{\partial\ \text{Net Worth}}{\partial V} = 0 \text{ when } \frac{\partial W(V)}{\partial V} = \frac{\partial C(V)}{\partial V} \qquad 6.9$$

6.4.3 Maximum Net Value

It has been recognised by several analysts (Hutter, 1978, Kahn, 1978) that the value of wind turbines is affected by the variability of the output that they produce and that this can be reduced, albeit at the expense of overall energy output, by changes in the machine rating. Sections 6.5.1 and 6.5.2 have shown how total output and total costs vary as a function of machine rating. Methods were developed in chapter 3 which allow the machine capacity credit to be calculated as a function of machine rating. Maximising the net value of a given machine brings these considerations together.

Figure 6.12a shows how the average capacity credit per machine varies as a function of penetration for two machine ratings. The machine characteristics and wind conditions are those described in section 6.4.1. For modest penetrations a high rating is preferred; at deeper penetrations a lower rating ratio maximises total capacity credit. This would suggest that the optimal rating will depend on the degree to which WECS are used in the system. However, as argued earlier, the capacity credit which WECS receive has little influence on its overall value, so the variation of capacity credit with rating may have little influence on optimal machine design.

A second source of value for WECS may be their reoptimisation savings. In notional systems facing static conditions these can be significant. In the real world where change is continuous and gradual

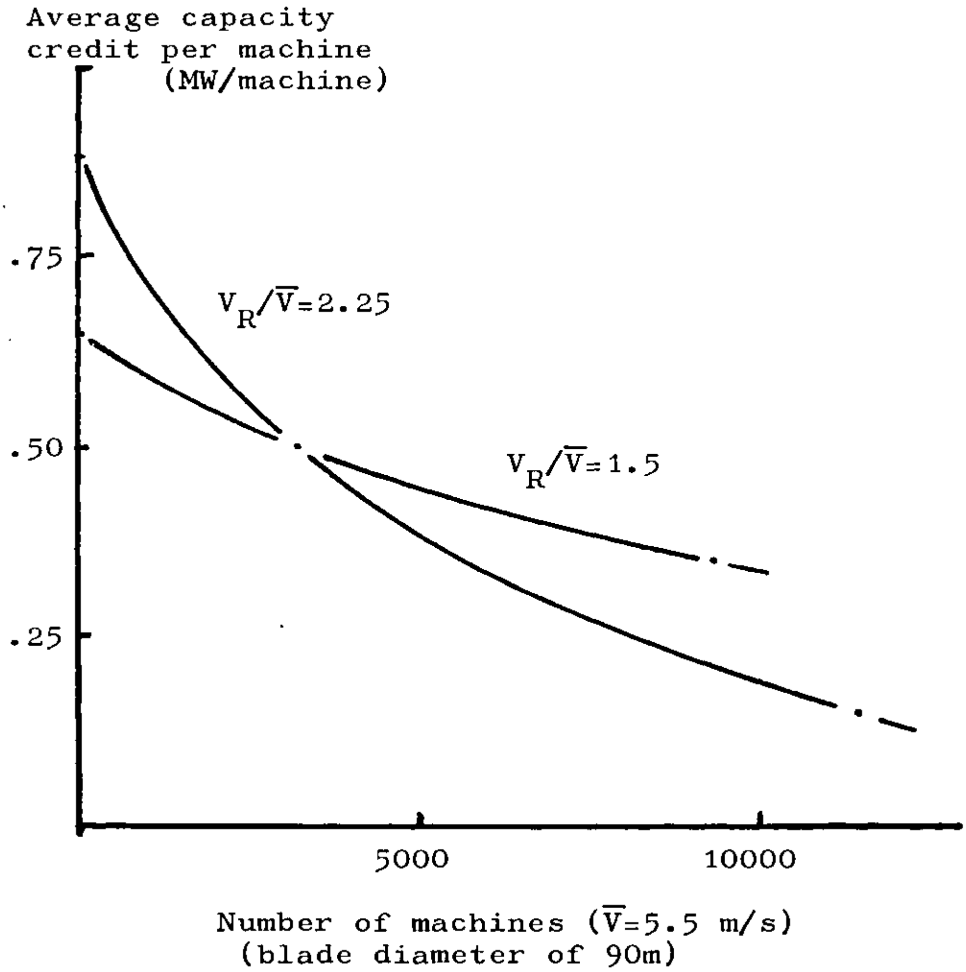


FIGURE 6.12a Average machine capacity credit, penetration effects and machine rating.

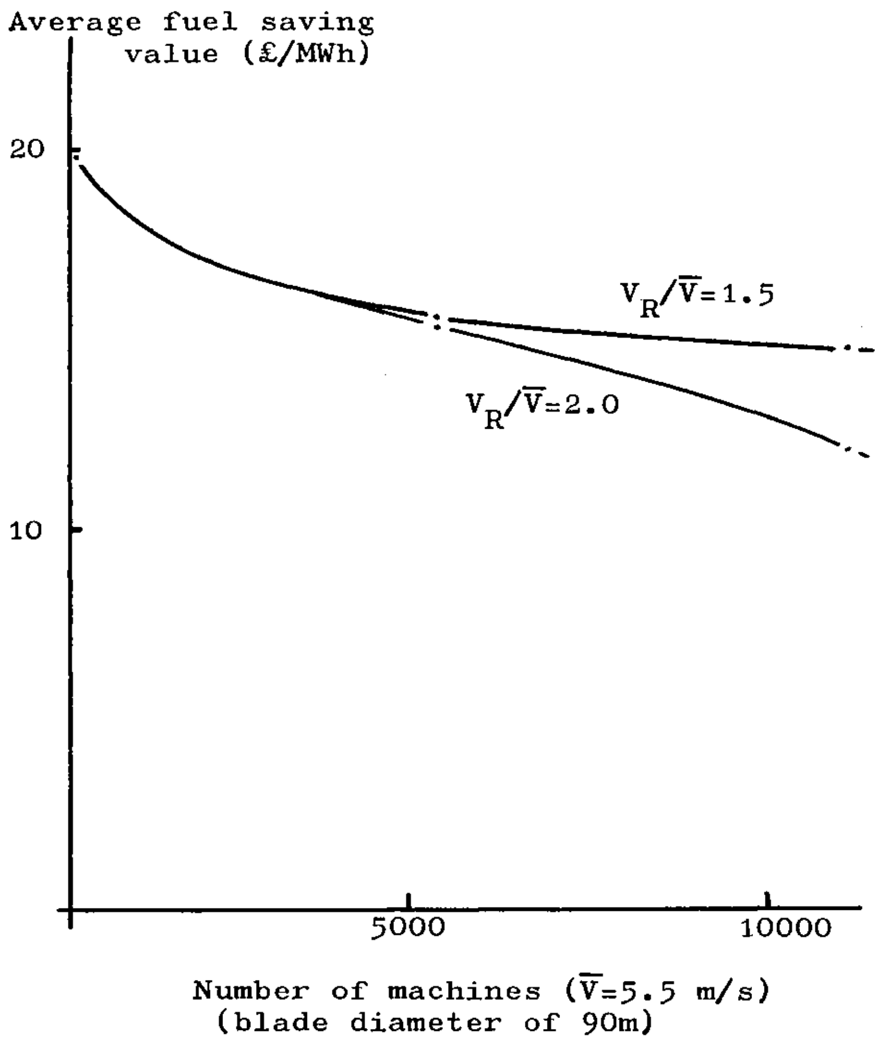


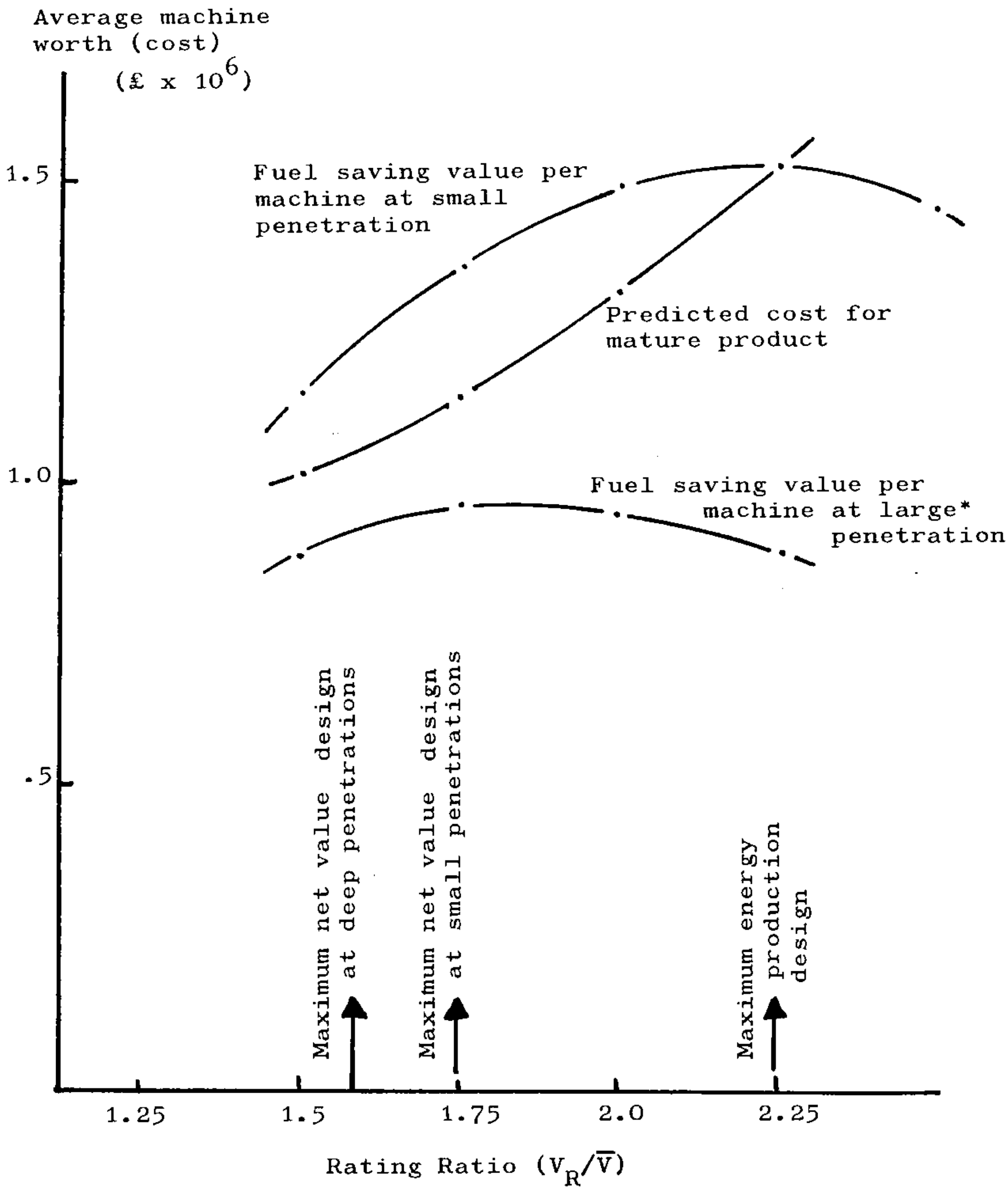
FIGURE 6.12b Average value of fuel saving, penetration and machine rating.

and where the mix of plant in the system is difficult to influence, reoptimisation savings are less important.

One is left with the question of how the fuel saving ability of WECS is affected by their rating. As shown in figure 6.10, for the data considered here, a machine rated at 2.0 the mean wind speed maximises the energy capture. At small penetrations the value of this energy is to first order not affected by the machine rating. What is generally not recognised is that at large penetrations the value, as opposed to the amount, of the electricity produced will be affected by this rating. Figure 6.12b shows the average value of the energy from two sets of machines of different ratings. At significant penetrations the value of the energy differs by as much as 15%.

The reason for this difference in value relates to the size of the slice of wind power being considered in each case. In a wind regime with an annual means of 5.5 m/s the total capacity of 5000 machines is less than 9,500 MW if a 1.5 $\overline{V}$ rating is used, and more than 20,000 MW if a 2.0 $\overline{V}$ rating is used. For equal annual energy outputs the higher capacity machines will, on average, displace more efficient conventional plant, and will generate more electricity when it cannot be used. Figure 6.12b shows these effects assuming completely flexible operation by conventional plant, and ignoring system operating penalties. More realistic assumptions about plant flexibility and system operating penalties would further reduce the average, per unit value of the machines rated at 2.0 $\overline{V}$.

Figure 6.13 shows the average value of the fuel savings as a function of the machine rating at two penetration levels. When combined with estimates of the machine cost variation, these figures can be used to predict optimal machine designs if the effects of capacity credits are ignored. To include the effect of capacity credits further



*large means greater than 10,000 machines

FIGURE 6.13 Average fuel saving value, penetration effects and machine rating.

information as shown in figure 6.14 is required. As shown in figure 6.15 when an evaluation of the capacity credit is included in the analysis, the optimal machine rating shifts to lower values. Clearly at deep penetrations lower ratings are preferred.

6.4.4 Discussion

Because of the nature of the problem, and the data available, it has been necessary to simplify the analysis to such a degree that it can be considered only illustrative rather than definitive. It seems, though, that analysis of wind turbines in the context of the utility grid rather than in isolation of the power system leads to different optimal designs. It has been impossible to include analysis of the effects of the predictability of wind power and how this relates to the machine rating. Likewise it has been impossible to look at the serial correlation, the chronological variability of WECS, and how these relate to machine rating. Both considerations are likely to add weight to the argument for lower ratings. Balanced against this is the fact that the anlaysis in this section has made use of a point cluster of machines rather than a dispersed array. The geographic separation of machines would tend to decrease the penalties associated with machines with high ratings, the effect being controlled by the correlation between the winds at the various sites.

Another facet of the problem which has not been dealt with here concerns the difference between the economics of the "average machine" versus those of the "incremental machine". Clearly the total amount of wind power which is "economic" in the system depends on which "machine" is analysed. It is not clear how the two different analyses would affect the optimum machine rating.

6.5 Conclusions

This chapter has shown how the framework developed in chapter 5 can be used in the analysis of the economics of wind power and the study of optimal machine design. A number of points

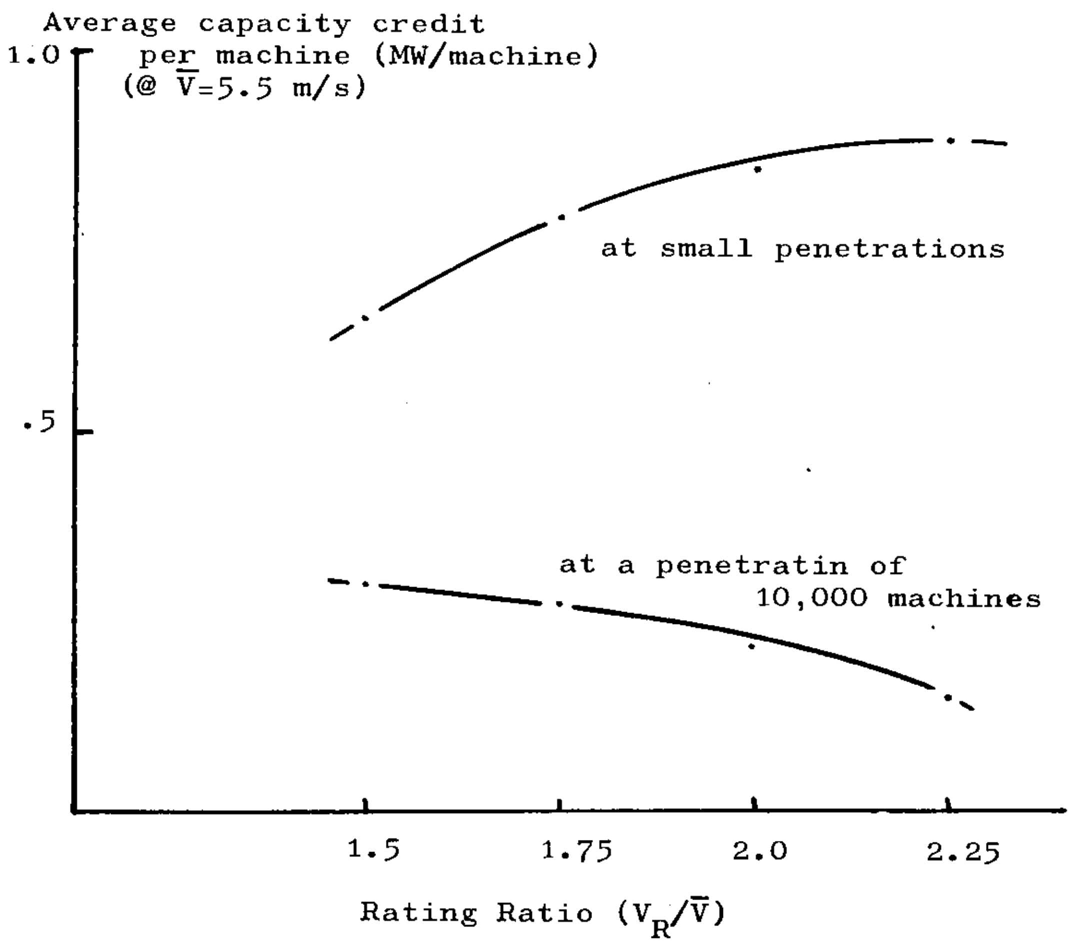


FIGURE 6.14 Capacity credit,penetration and machine rating.

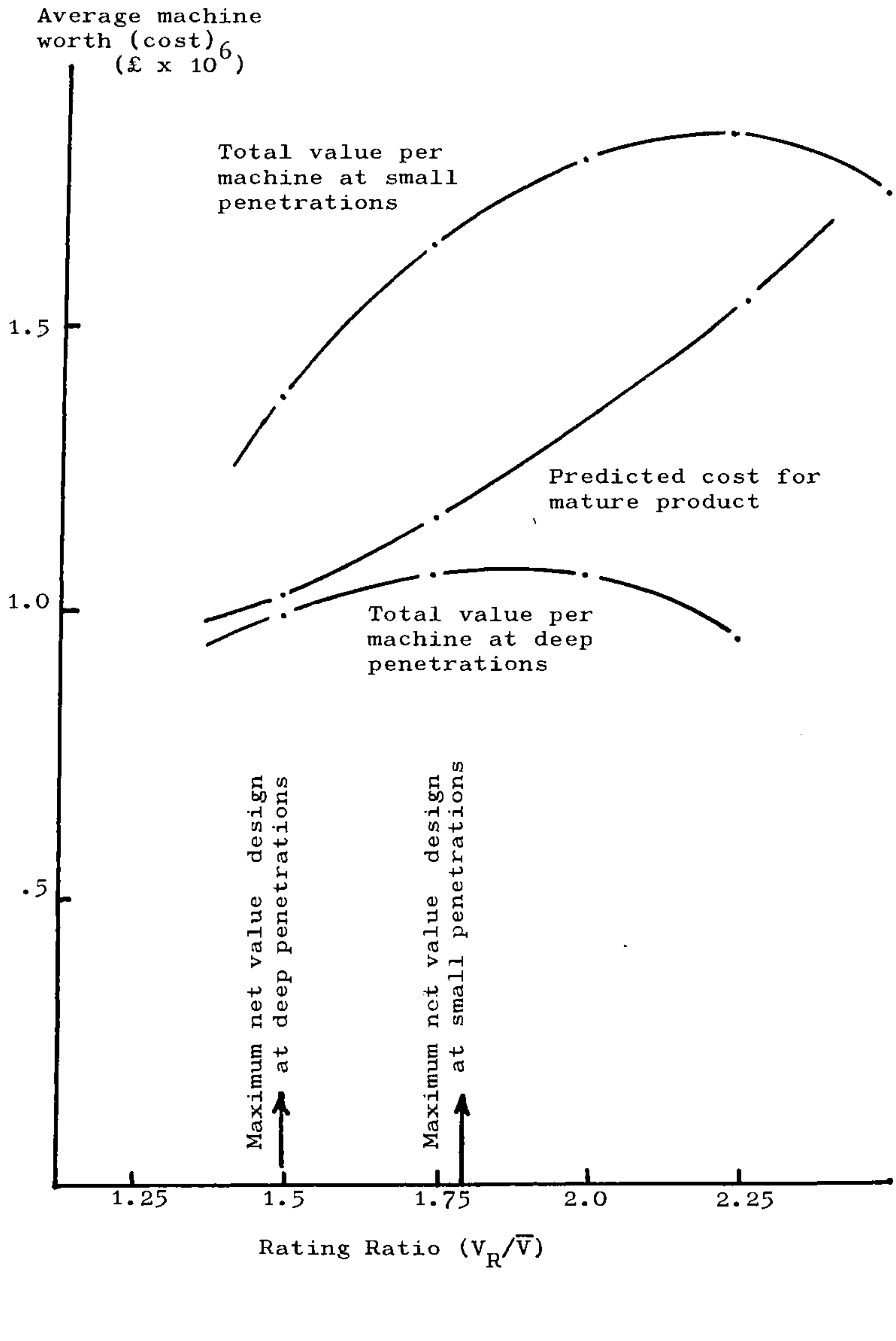


FIGURE 6.15 Optimal WECS design based on total value to the utility system.

have emerged. The sensitivity of the economics of WECS to maintenance costs, site wind speed, and the costs of conventional plant have been shown to be significant. As predicted in chapter 5 the economics case for WECS is largely insensitive to the mix of plant in use in the grid if a "best investment" type analysis is used. For initial penetrations into likely future CEGB systems the diurnal variation of wind speeds has little impact on the economics of wind power. At deeper penetrations both diurnal and seasonal variations in site wind speeds may be important.

Other recent studies have shown how the value of incremental wind powered machinery decreases as a function of penetration; this effect has been confirmed. It has also been shown that the optimal machine design is also affected by the expected penetration of wind power into the system and may be different when systems data, rather than purely machine and wind data, are considered.

Chapter 7 - Conclusions

The research described in this thesis has two parts; the analysis of the methods used in the economic appraisal of the options available for the development of the generation system in a large interconnected power system, and the detailed appraisal of the economics of using windpower to produce electricity for such a system.

Analysis of the methods used for the economic appraisal of new plant in power systems led to the conclusion that inspite of the availability of increasingly powerful computers , power system planning models must rely on major simplifications to reduce complex problems to tractable states. Common simplifications have been discussed in terms of those used in modelling system operation, those implied by the choice of optimization technique, and those at the base of figures of merit for economic appraisal. It has been shown that many past analyses of the economics of new technologies such as wind turbines have used extremely simplified models of power system operation. As a result, these analyses have assumed that such plant can only be used as fuel savers, and thus that the worth of the output is equal to the fuelling cost of the conventional plant with which they compete. It has been shown that, in a variety of circumstances, this sort of valuation does not allow a consistent appraisal of the work of intermittent energy sources. It follows from this that the basic assumption upon which this valuation is based must be questioned.

To examine the economics of wind turbines, a number of models have been introduced. Detailed numerical models have been used to study the behaviour of a specific system in the presence of a wind turbine of a given design,in given wind conditions. Analytical models have been developed to allow more generalised analyses, and to provide a better means of communicating results.

The detailed system model developed in this thesis is based on probabilistic simulation. It has been used to evaluate the effects on total system costs of statistical uncertainty relating to electricity demands, and to the availability of conventional plant. The model has been adapted to allow the evaluation of the effects on the system of the use of such intermittent generation plant as windmills, and has been used to verify the acceptability of simplifications in the analytical models which have been introduced.

An analysis of power system reliability calculations was carried out and a single equation has been developed for assessing the capacity credit of new plant when different amounts of that plant are incorporated into the system. The form of the equation makes it particularly useful for assessing the sensitivity of the capacity credit of new plant to the size of that plant, the size of other plant in the system, the level of reliability demanded of the system, the plants forced outage characteristics, and in the case of windmills, the effects of dispersed siting over the country.

Using this equation, and modelling wind conditions typical of those in the U.K., it was found that the capacity credit which wind turbines should receive is a significant part of the rated capacity of the machine when small amounts of windpowered generation are introduced to the system. This is a finding which, though now broadly accepted, was contrary to the accepted view of system planners when first argued. It was found that due to the seasonal variation of wind turbine output and electricity demand, this capacity credit, at low penetration levels, should generally be in excess of the annual average per unit output of the machine. When larger penetrations were considered it was found that the average capacity credit per machine is reduced. The decrease in the average capacity credit per machine was found to be moderated if dispersed siting of the machines was considered, but was found to be increased if the system reliability criteria for the system were changed to require stricter loss of load probability limits.

Two further generalized analyses were carried out to evaluate the magnitude of the operating penalty which might be assigned to unpredictable, intermittent energy sources, and to evaluate the savings which may be ascribed to new energy sources because of the re-optimization of the system plant mix after their introduction. It has been argued that the maximum system penalty that would result from moderate amounts of windpower in the system is about 15% of the fuel saving value of that plant. The analysis of re-optimization savings has led to the conclusion that even at significant penetrations, plant such as windmills should be compared against costs at the system margin rather than the fuel costs of competing base load plant. Many previous analyses have therefore grossly underestimated the value of windpower.

A number of economic figures of merit have been discussed, and following the findings relating to capacity credits and re-optimization savings,it has been argued that one of the simplest figures of merit, the bus bar energy cost, is perhaps more applicable than is generally realized.

The major conclusion resulting from the numerical analysis is that the economics of windmills appear to be very encouraging for countries such as the U.K. Although more detailed analysis is required to verify cost and performance claims made by windmill manufacturers, a purely economic analysis suggests that a market worth several billions of pounds exists for present designs of large wind turbines operating in moderate windspeed sites in the U.K.

Analysis of the sensitivity of these economics to a number of factors suggests that they are very sensitive to assumed capital costs of both windmills and competing generation options, maintenance costs, the site annual mean wind speed and the assumed fuel cost escalation for other plant. The economics appear to be less sensitive to the daily pattern of electricity demand, the diurnal fluctuations of the wind, or the actual mix of conventional plant in the system.

Using the methods developed in the thesis a prediction has been made of the optimal ratings of machines in given wind conditions and considering the effects on plant output of the choice of machine rating. It is concluded that lower ratings than those currently favoured could increase the net value of windmills, especially if large numbers of such machines are to be used in the system.

It was also found that the introduction of intermittent energy sources could in principle have major impacts on the optimal mix of plant in the system, and thus on the economics of other capital intensive generation plant.

Several areas have been identified in this thesis where further research is needed. It has been found that the system models in current use do not deal adequately with the effects on system economics of project lead times, of generation plant unit size or of future load uncertainty. Research to develop models which have the capacity to include the effects on the system of these factors would be of value. It has also been found in this thesis that current system reliability indices may be inadequate for judging the effect on system risk of large quantities of wind, wave, or solar powered plant. Research to suggest more appropriate risk indices would thus be important. Analysis in this thesis suggests that the optimum machine design for a system is affected by characteristics of the system, and further research to explore this would be useful.

There are a variety of topics which are on the fringe of the research done in this thesis and which, though they could be very important, were not dealt with. If a major portion of the electricity needs of the U.K. are to be met using intermittent energy sources it is likely that the electricity system will make use of either load management techniques or energy storage. It is not at present clear,how, quantitatively, the presence of a large load management or energy storage capability would effect the economics of intermittent energy sources. Wider economic issues such as the importance to local communities of decentralized energy sources, as well as decentralized energy authorities, also deserve more attention but were not considered in this thesis. It may well be that such considerations are at least as important for the development of renewable energy sources as the traditional economic arguments.

Appendix 1 - Symbols

A number of acronyms are employed in this thesis where their use is common in the literature. A limited number are introduced to facilitate the readability of this thesis. Those extracted from the literature are:

CEGB - Central Electricity Generating Board

IEE - Institute of Electrical Engineers (England)

IEEE - Institute of Electrical and Electronic Engineers (US)

LDC - Load Duration Curve

NEC - Net Effective Cost, a term used by the CEGB and defined in section 2.3

TDR - Test Discount Rate, a term used to calculate present values of expenditures which occur over a number of years or some time other than the agreed datum.

WECS - Wind Energy Conversion Systems

Those assigned a meaning in this thesis are

BAU - "Business As Usual", the title of a particular scenario for fuel price increases and system development.

OPT - "Optimized", as above, the title of a particular scenario for system development

RENEW - The name given to a suite of computer programmes which undertake probabilistic simulation to estimate the value of various capacities of renewable energy sources.

PRICE - The name given to a suite of computer programmes which predict various system parameters for given load patterns and plant mixes.

The symbols used in the equations of this thesis are defined locally as they are used. Standard conventions are used for statistical work. Functions described by lower case symbols are density functions while upper case letters generally refer to cumulative distributions. A bar over a variable indicates that the reference is to the mean value of that parameter. The standard deviation, and coefficient of variation are identified using σ and δ respectively.

In dealing with individual plants, as distinct from groups of plants, the former employs lower case subscripts (i.e. C_n) while the latter an upper case subscript (i.e. C_N).

A complete list of the symbols used in this thesis is produced below.

Chapter 1

No symbols are used.

Chapter 2

γi - annual variable costs for plant i (£/KWYR)

ν - a subscript defining the plant vintage

ϕ_i - annual capital cost for plant i (£/KW pa)

A - peak hour availability of a given plant (%)

A* - peak hour availability of the total capacity of the system (%)

$b_{j\nu t}$ - annual availability of plant j, vintage ν, in period t (%)

D - annuitizing factor for plant capital costs

e_1 - system risk target for energy production (MWh p.a.)

e_2 - system risk target for peak hour operation (hr p.a.)

H(t) - the present worth, per unit, of the operating cost during period t of a given plant (£/KWh)

H*(t) - as above, but for a reoptimized schedule of operation (£/KWh)

j - a subscript used to identify plant type

K - the present worth of the capital cost of a given plant (£/KW)

K_s - the system capital savings attributable to a particular plant (£)

K^+ - the capital expenditure deemed necessary to meet load growth (£)

l(t) - load at time t (kW)

l_t - load during period t (kW)

$\hat{l}_t$ - the system peak load in year t (kW)

M - net system fuel cost savings attributable to a particular plant (£)

t - the period at which, or over which plant operation is considered (yr)

T - the time horizon considered (yr)

U - the energy production of a given plant in period dt (KWh/yr)

W - the total annual cost of meeting customers demands (£ pa)

X - the total capacity of a given plant (KW)

Chapter 3

α_i - the relative frequency of peak load i

λ - unit failure rate for a given plant (events/yr)

λ_{g+} - the transition rate for a given plant from outage state g to a state with a lower g index (events/yr)

λ_1 - the transition rate from load 1 to the background load (events/yr)

μ - unit repair rate (events/yr)

μ_A - the mean valve of function A

σ - the standard deviation of the equivalent load uncertainty (MW)

σ^* - the standard deviation of the equivalent load uncertainty for the new plant mix (MW)

σ_A - the standard deviation of function A

Θ - the system secuity constant

A - the long term probability that a unit is operable

A^1 - the long term probability that a unit is unavailable for operation

a - a random variate representing the percentage of the installed system capacity which is available to meet the load

A_R - the average rate at which a deficiency state is encountered (events/yr)

A_D - the average duration of all the difficiency states (yr)

C_N - the capacity of a system containing N units (MW)

C_n - the capacity of the n^{th} unit in the system (MW)

CAP - the total capacity of the system (MW)

C_Z - the system capacity state Z (Z megawatts being available)

D - a random variate representing the system demand (MW)

e_i - the fraction of sub-period i during which the elevated load l_i is experienced

EFOR - the equivalent forced outage rate

f_g - the frequency of encountering state g plant

f(t) - the plant failure density function

$F_N(s)$ - the probability of s or more units being unavailable

FOR_i - the forced outage rate, the proportion of time spent in state i

FOR_N - the forced outage rate of plant N

$FREQ_N(x)$ - the cumulative frequency of departure from state x in system containing N units

g(y) - the weighting factor for a capacity shortfall of y

$G_N(x)$ - the system risk function, the risk of the available capacity being less than the system demand

l - load (MW)

m - the margin of available plant in excess of load (MW)

M - the "system characteristic" (see equations 3.30 and 3.31)

P - the installed capacity of the system (MW)

P* - the installed capacity of the re-optimized system (MW)

p_{l_0} - the probability of being in load state l_0

$P(V_i)$ - the probability of capacity state i occuring

P_g - the probability of g units out of n failing

p(l) - the probability of load l occuring

Q - the load carrying capability of a plant (MW)

R - the risk of the system being unable to meet demand

r - the probability of a plant surviving at time t

v - the random variate representing the portion of total capacity of the new plant which is available.

v_i^1 - the capacity state i, the portion of the plant output which is unavailable

Y - a random variable representing the difference between the load and the available plant (MW)

Z - the installed capacity of a unit (MW)

Chapter 4

μ - the energy demand which can not be served by the system (MWhr pa)

τ - the time period being modelled in the probabalistic simulation (YR)

* - signifies a convolution operation

C_N - the total capacity of a system with N units (MW)

C_n - the capacity of the n^{th} unit (MW)

$COST_n$ - the energy production cost of the n^{th} unit (£/MWh)

$COST_n(k)$ - the energy production cost of the n^{th} unit at a part load level k (£/MWh)

E - the expected energy production of a plant (MWh)

E(COST) - the expected fuel cost of the electricity produced by a specific plant (£)

$EKST_N(L)$ - the expected system fuel cost for an increment of load at point L (£/MWh)

f_D - the demand density function

f_E - the equivalent load density function

f_O - the outage density function

$f_N(x)$ - the probability of x megawatts being unavailable from the first N units

F_D - the distribution function for demand

F_E - the distribution function for the plant outage

$F_N(x)$ - the probability of the equivalent load, for a system of N units being greater than x

FOR_n - the forced outage rate for the n^{th} unit

L_D - the load on the system (customer demand) (MW)

L_E - the equivalent load on the system (MW)

L_I - the intermediate equivalent load on the system (MW)

L_O - the load imposed by the plant outage (MW)

L_W - the output from the new energy source (negative load) (MW)

MC - the system marginal energy cost (£/MWh)

P(L) - the probability of load L occuring

$P_N(x)$ - the probability of less than x megawatts of plant being available from the first N units

TC - the total system fuel cost (£/YR)

Chapter 5

γ - the annual running cost of a given plant (£/MWYR)

ϕ - the annual fixed cost for a given plant (£/MW p.a.)

Θ - the security constant

δ_v - the coefficient of variation of the output density function of plant v

σ_* - the standard deviation of the uncertainty density function of the system

σ_{12} - the cross-correlation coefficient for the output between sites 1 and 2

ρ - the correlation coefficient

a - the availability of the system at peak hours

A_j - the availability of plant j

C_1 - the fuel savings which occur when a plant is taken off line, and allowed to cool (£/MWh)

C_2 - the fuel savings which occur when a plant is operated at reduced load (£/MWh)

$C_1(x)$ - the system marginal savings when plant is off-loaded and system demand is x (£/MWh)

$C_2(x)$ - the system incremental production cost savings when plant is operated at reduced load and system demand is x (£/MWh)

E - electric energy production cost savings (£)

$g_1(y)$ - the portion of the year that the original load y is exceeded

$g_2(y)$ - the portion of the year that the net load y is exceeded

$G_N(y)$ - the probability that the available capacity from the first N plants will be less than the system demand y

$G_N^{-1}(R)$ - the load at which the risk of the available capacity being less than the demand is equal to R

h(x) - the heat consumption of a given plant at load x (BTU/hr)

H - the no load heat consumption of a given plant (the y-intercept of the Willans line) (BTU/hr)

K - capital cost savings (£)

L(t) - the total system demand at time t (MW)

L_F - the load factor of a given plant

MC - the system marginal cost averaged over the period of study (£/MWh)

NEC_i - the net effective cost of plant i (£/KW)

p - the portion of a plant's capacity that can be used as spinning reserve

P - the installed capacity of the conventional plant in the system (MW)

Q - the load carrying capacity of the plant (MW)

R - the level of risk of loss of load which is deemed acceptable

Sc - the load carrying capability of an infinitly large two state plant (MW)

t - the portion of a year that a plant is operated

TC_i - the total annual cost associated with plant i (£)

v - the load factor of the new energy source

V - the total value of a new plant (£)

$W(t)$ - the contribution to the grid at time t from the new energy source

x - the load factor of the plant at the merit order interface between two plant types

x_i - the instantaneous electrical output from site i (MW)

$\bar{x}_i$ - the average electrical output from site i (MW)

Z - the installed capacity of the new energy source (MW)

Chapter 6

$\eta(P)$ - the efficiency of the power train and generator

ρ - the density of air (kg/m^3)

a - Weibull function characteristic windspeed (m/s)

c - the Weibull function shape factor

C - Total machine cost (£)

C_p - coefficient of performance (aerodynamic efficiency of the blade)

$F(x)$ - Weibull distribution function

K_e - energy pattern factor

K_1 - coefficient for machine cost curve

P_r - rated power (MW)

$P_t(V)$ - power output at time t, velocity V (MW)

T - period of T over which the observations are taken (YR)

V - instantaneous windspeed (m/s)

V_R - windspeed at which the windmill reaches rated power (m/s)

$\bar{V}$ - site annual mean windspeed (m/s)

Appendix 2 - Data Sets

Three data sets were used in a probabilistic production cost model for the economic calculation described in this thesis. Each data set was based on descriptions of various detail of the Central Electricity Generating Board (CEGB) system. The first data set was constructed to represent the CEGB system as it existed in 1977-1978. It was used in conjunction with load data recorded in that year to examine the behaviour of probabilistic simulation models and to compare statistics generated by the model against those recorded for that year. The second data set (BAU Scenario) described the system predicted (CEGB, 1978) for the year 1985. It was used to examine the economics of WECS in the UK assuming the system developed along the lines currently envisaged. The third data set (OPT Scenario) described a system in which the mix of plant was optimized (for that single year) to minimize the total production and annuitized investment costs. This third system has a substantially larger proportion of nuclear plant than either of the earlier systems and was used to test the economics of WECS in a high nuclear scenario.

A2.1 CEGB Plant

Plant data for each of the three data sets are shown in table A2.1. Ten notional plant types were used based on the aggregation suggested in the U.K. Digest of Energy Statistics, 1979. The plant mix used in the 1977-1978 system is similar to that recorded in the CEGB Statistical Yearbook for that year (CEGB, 1978). Changes in the plant required for the first 1985 system are those suggested in the 1978-1979 annual report; the additions to the 1977-78 system total 13,060 MW, the retirements total 3480 MW. Forced outage rates have been estimated by the author - they generally appear to be lower than those implied by CEGB figures. The actual peak hour availability of the system in 1978-79 is listed as 83%, the models prediction based on the plant shown is 88%. The

Table A2.1 C.E.G.B. Plant 1977-78, 1985

PLANT TYPE	SIZE[1] (MW)	FORCED OUTAGE RATE (%)	COST (2) 1977-78 (p/kWh)	COST (2) 1985 (p/kWh)	INSTALLED CAPACITY 1977-78 (MW)	INSTALLED CAPACITY 1985-BAU (MW)	INSTALLED CAPACITY 1985-OPT (MW)	CAPITAL COST (2) (£/KW)
N	620	.2	-	.68	-	3720	46,500	700
N	460	.15	.54	.7	3688	3680		-
FS	620	.2	-	1.64	-	8060	18,600	500
FS	430	.15	1.136	1.68	24080	24080		-
FS	200	.1	1.254	1.77	6400	6400		-
FS	160	.1	1.291	1.98	3680	3680		-
FS	100	.1	1.361	2.12	5000	5000		-
FS	90	.1	1.490	2.27	5040	5040		-
FS	65	.1	1.758	2.37	2535	2535		-
FS	60	.1	1.900	-	2280	-		-
FS	60	.1	2.00	-	1200	-		-
GT	80	.05	3.5	5.0	2240	3500	3,440	225
					56043	65,715	68,540	

N - Nuclear
FS - Fossil Fired Steam Plant
GT - Gas Turbine

(1) Aggregation of certain plant was convenient. The sizes shown are those suggested by the U.K. Digest of Energy Statistics, (Department of Energy, 1979a).

(2) Cost estimates are for 1978 price level.

similar figure for the 1985 system is 86%. Costs were based on figures given by the Department of Energy (1979a) and the Energy Commission (Department of Energy 1979b). Maintenance schedules and capital costs were calculated from annual figures given by the CEGB (1978, CEGB 1980). No storage capability was included in the model; the actual 1977-1978 system contained 360 MW of pumped storage.

A2.2 CEGB Load

The load used in the 1977-1978 system data is based on a tape of the half hourly integrated load experienced during that year and recorded by the CEGB National Control Center. It covers the period April, 1977 to March 31, 1978. The peak system demand was 42,800 MW (experienced at 6 p.m. on Wednesday, January 18), the lowest load was 9,530 MW (at 6 a.m. on Sunday, July 31). The load factor was 55.96%.

For the probabilistic simulation, a number of sets of "probabilistic days" were created (see figure A2.1). The Peak Season Day represented possible loads during week days in November, December and January. The Off-Peak Day represented loads during the off-peak months and weekends during the peak months. A second set of "probabilistic days" represented the winter and summer seasons, the former making use of load data from the winter months September to March, the latter from April to August.

These were used to examine the sensitivity of the calculations to choice of load model. The forecast peak ACS demand used in the 1985 models were 51.2 GW. This represents an increase in the 1977-1978 load of 20%. Load forecast uncertainty was taken to be normally distributed and to have a standard deviation of 9%. The load growth for the 1985 model was modelled by convolving each point of the probabilistic day with a normal distribution with a mean of 20% of that load and a standard deviation of 9%. Two load duration curves are shown in figure A2.2.

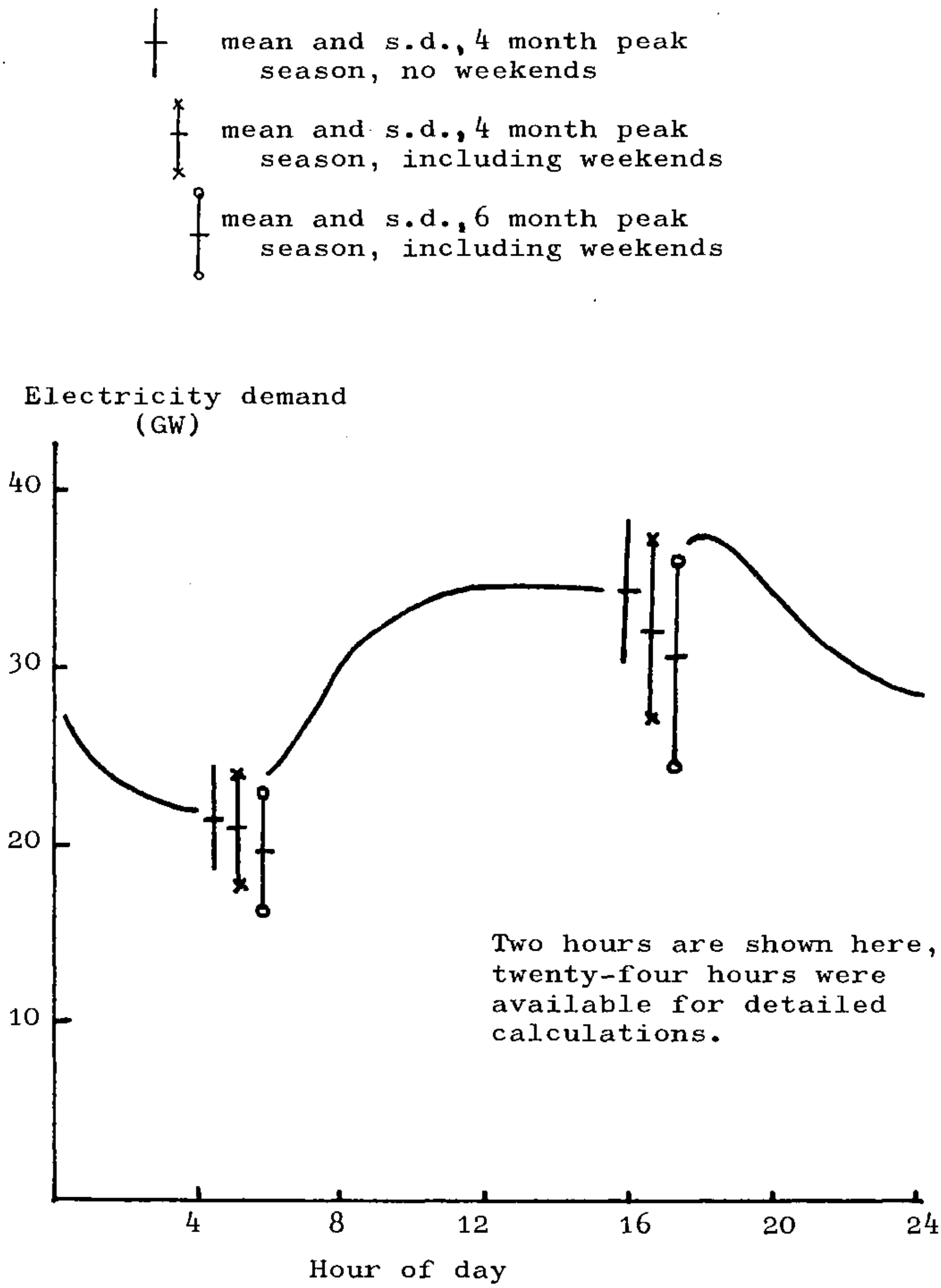


FIGURE A2.1 Probabilistic chronological load curve for "the" peak season day.

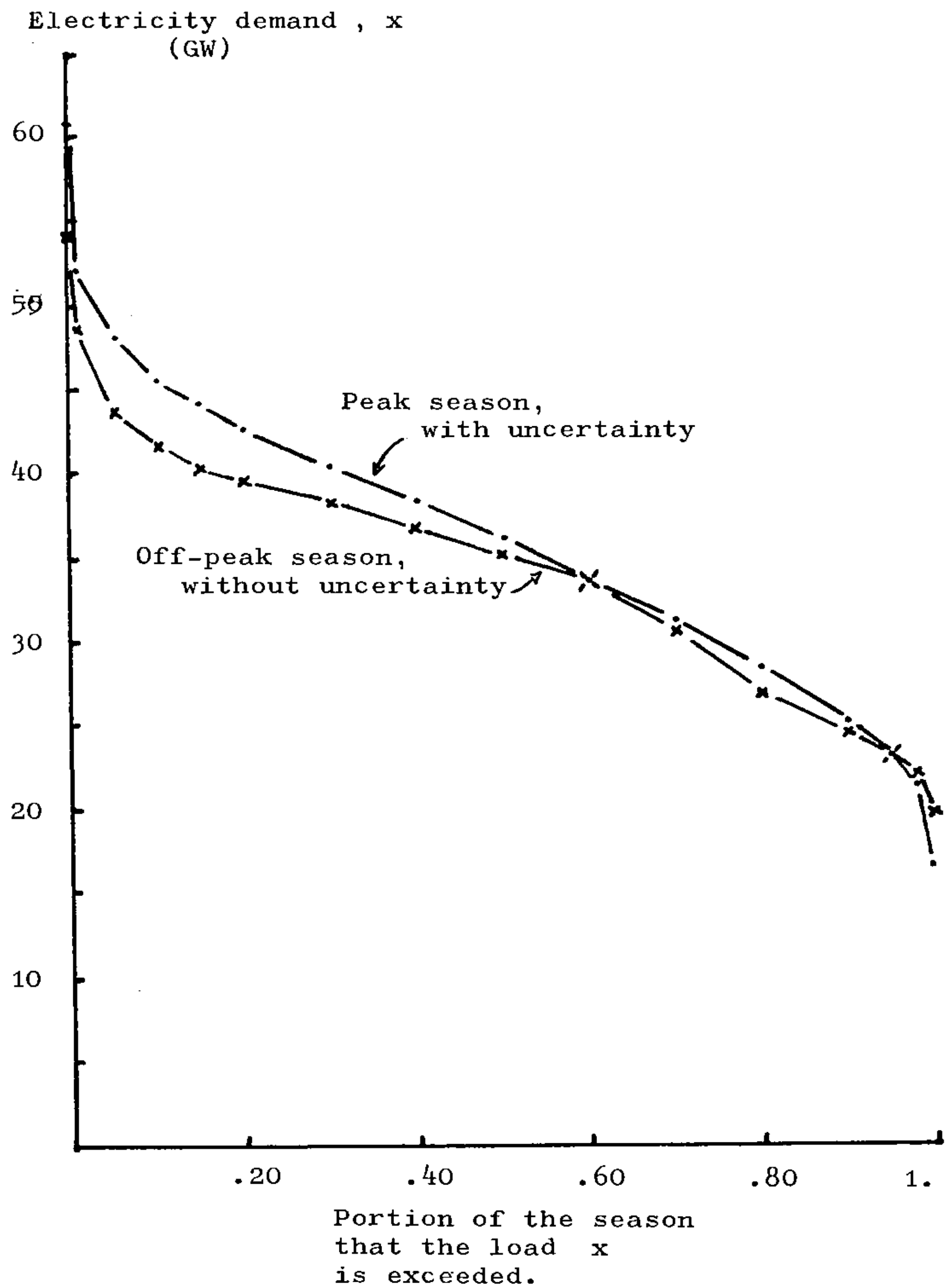


FIGURE A2.2 Load duration curves for 1985 and the effect of load forecast uncertainty.

A2.3 System Results

Sample hours from the probabilistic chronological load curves are shown in figure A2.1. The results show the impact that the definition of the peak season can have on the load. As will be shown later this then has major impacts on the reliability of the system. Figure A2.2 shows the peak season load duration curves for the 1977-78 system and the 1985 system.

The plant outage curve for the 1977-78 model is plotted in figure A2.3 and shows a good fit to a normal distribution with a mean of 12% and a standard deviation of 2.9%. Reliability calculations presently done by the CEGB assume a standard deviation for that density function of 3.75% (Jenkin, 1978).

Two sets of cost curves can be calculated. Figure A2.4 shows how the incremental production costs rises as a function of the load. Merit order cost curves are shown for each system model. These curves can be combined with the load estimates embodied in the "probabilistic day" to form the expected marginal hourly costs, or expected total system costs shown in A2.5. The effect of load forecast uncertainty and high price electricity imports are also shown.

Using the model of the 1977-78 system total production costs were estimated to be £2.537 x 10^9 and the load factor on the 3500 MW of least efficient plant was 2.2%. The total works cost actually recorded in 1977-78 was £2.5038 x 10^9. The probabilistic simulation model used in this thesis has been very coarse in its treatment of seasons. Only two seasons were used here whereas detailed models (for an example see Goodrich, 1972) often use more than 50 seasons. With this proviso results were judged acceptable for the purposes of this thesis.

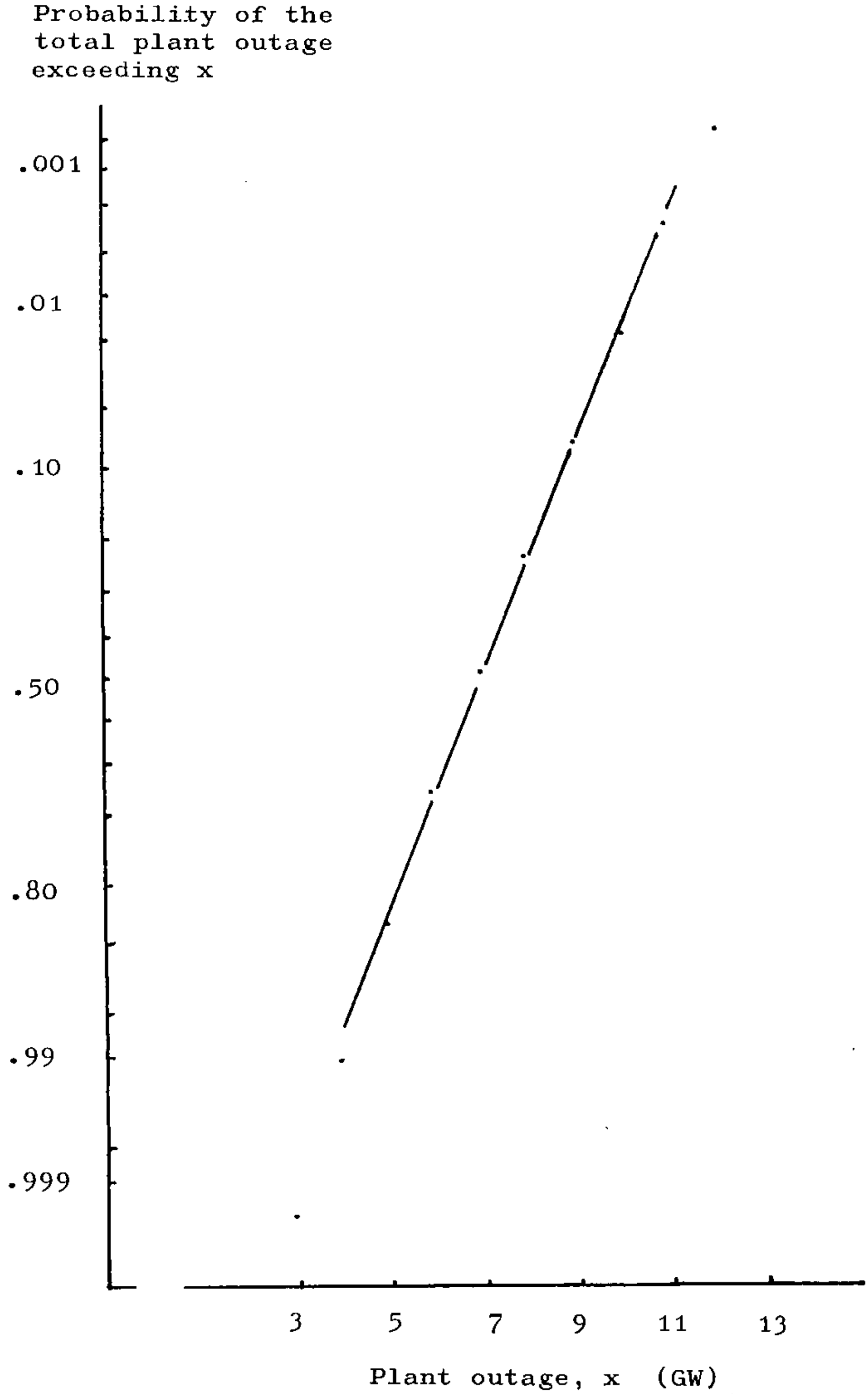
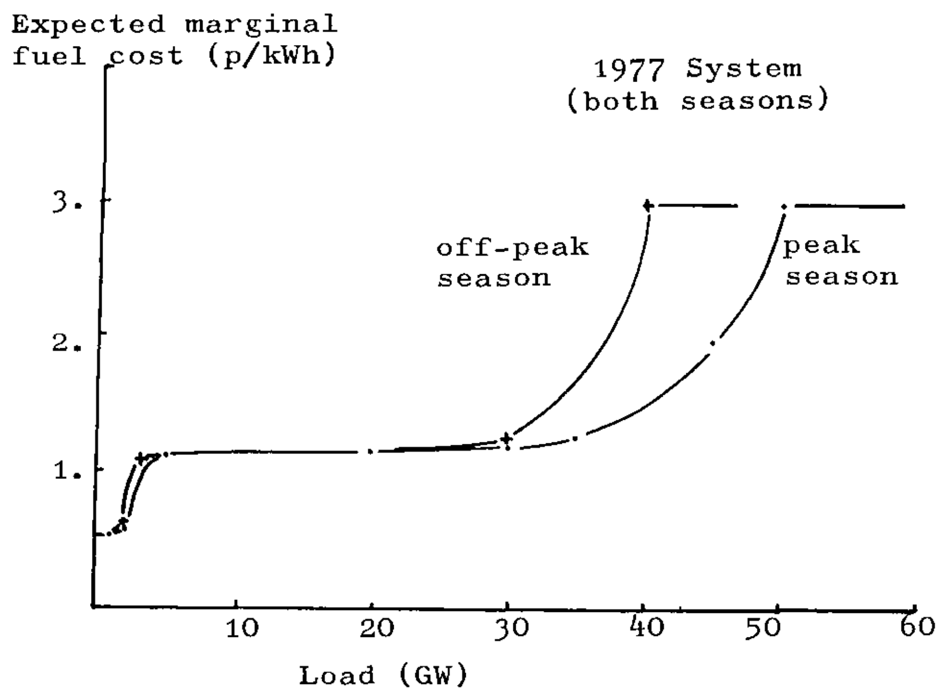


FIGURE A2.3 A plot of the plant outage curve for the 1977 system using Normal Probability paper.



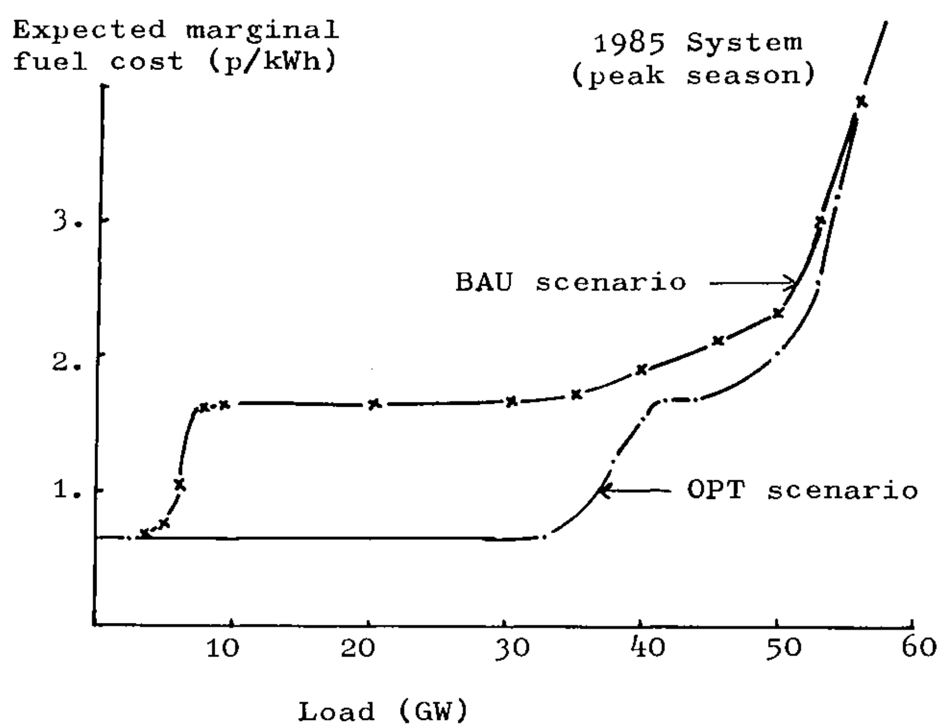


FIGURE A2.4 System expected marginal fuel cost curves (merit order cost curve)

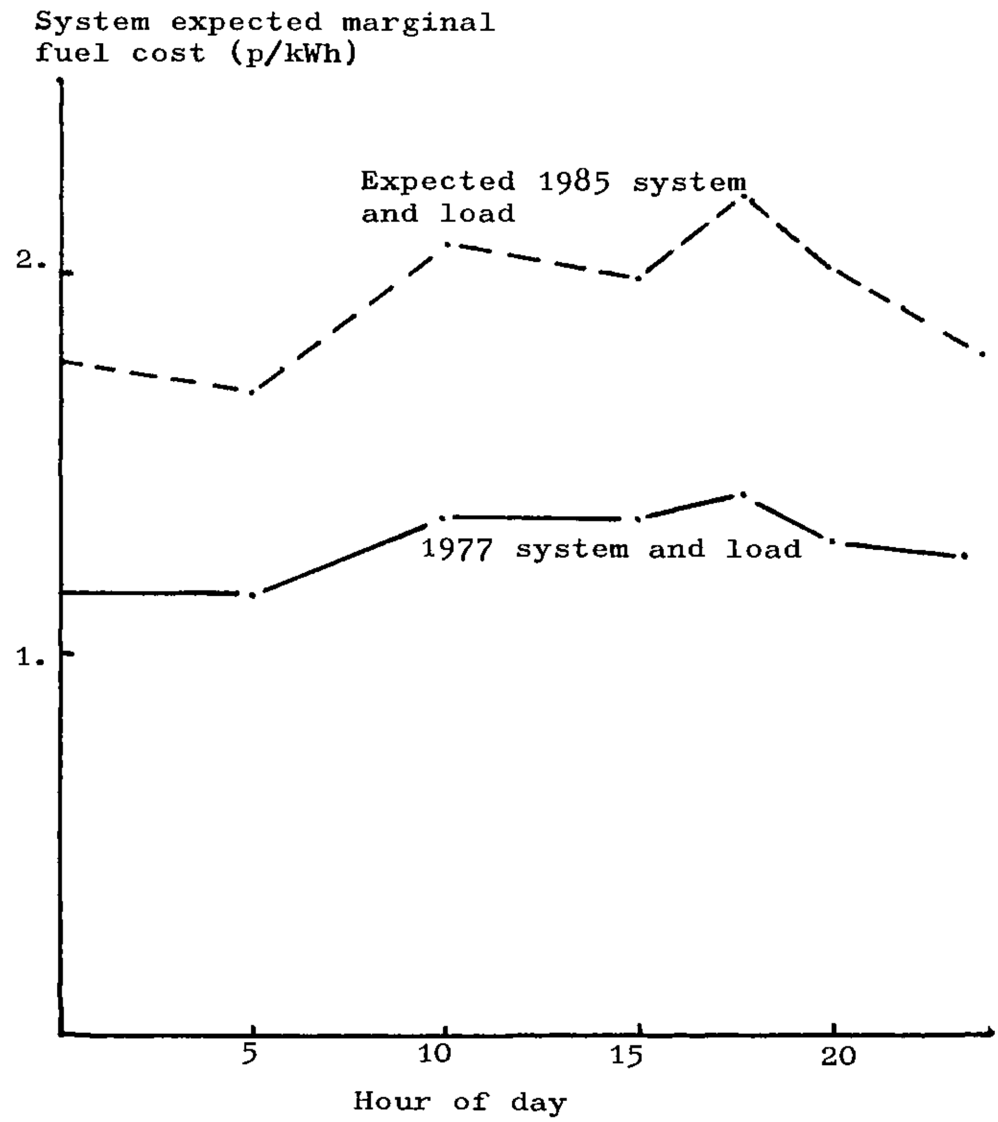


FIGURE A2.5a 1977 and 1985(BAU scenario) peak season expected marginal fuel costs

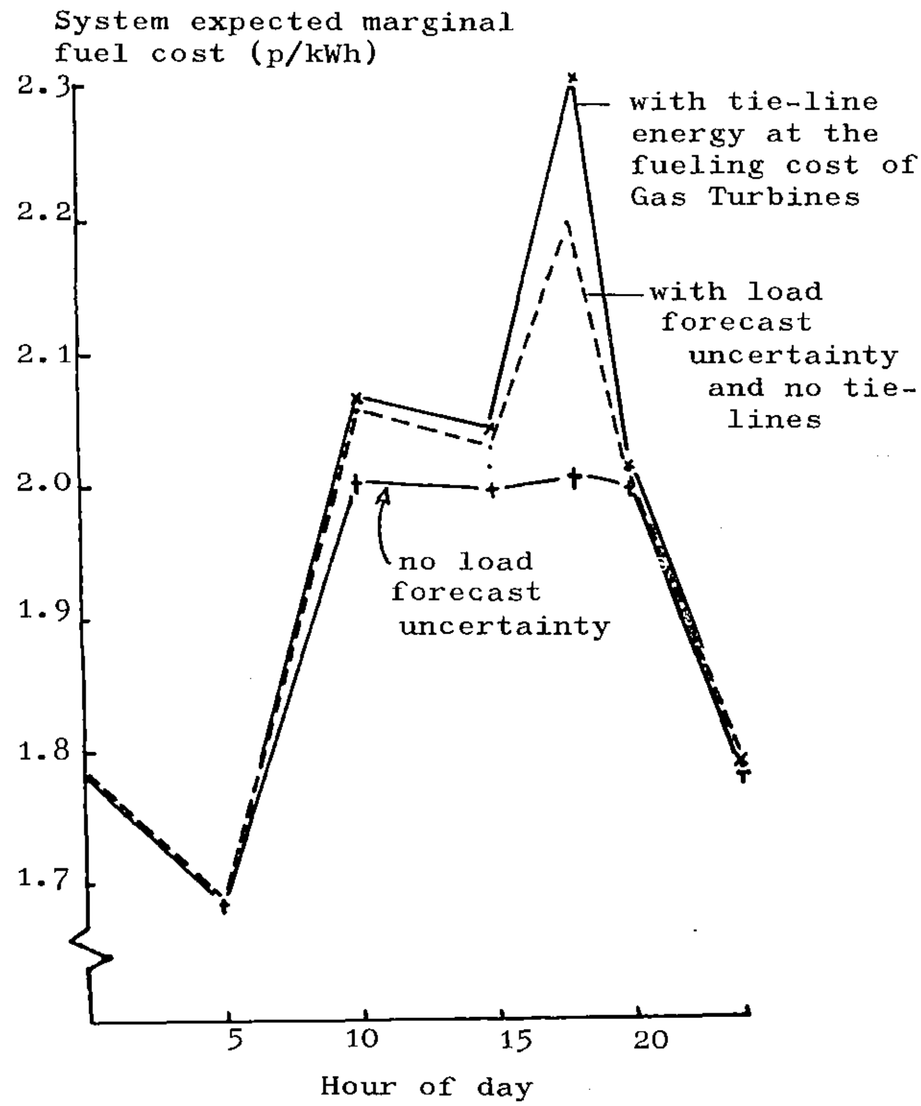


FIGURE A2.5b The effect of tie-lines and long range load forecast error on system expected marginal fuel costs. (1985 BAU scenario, peak season season)

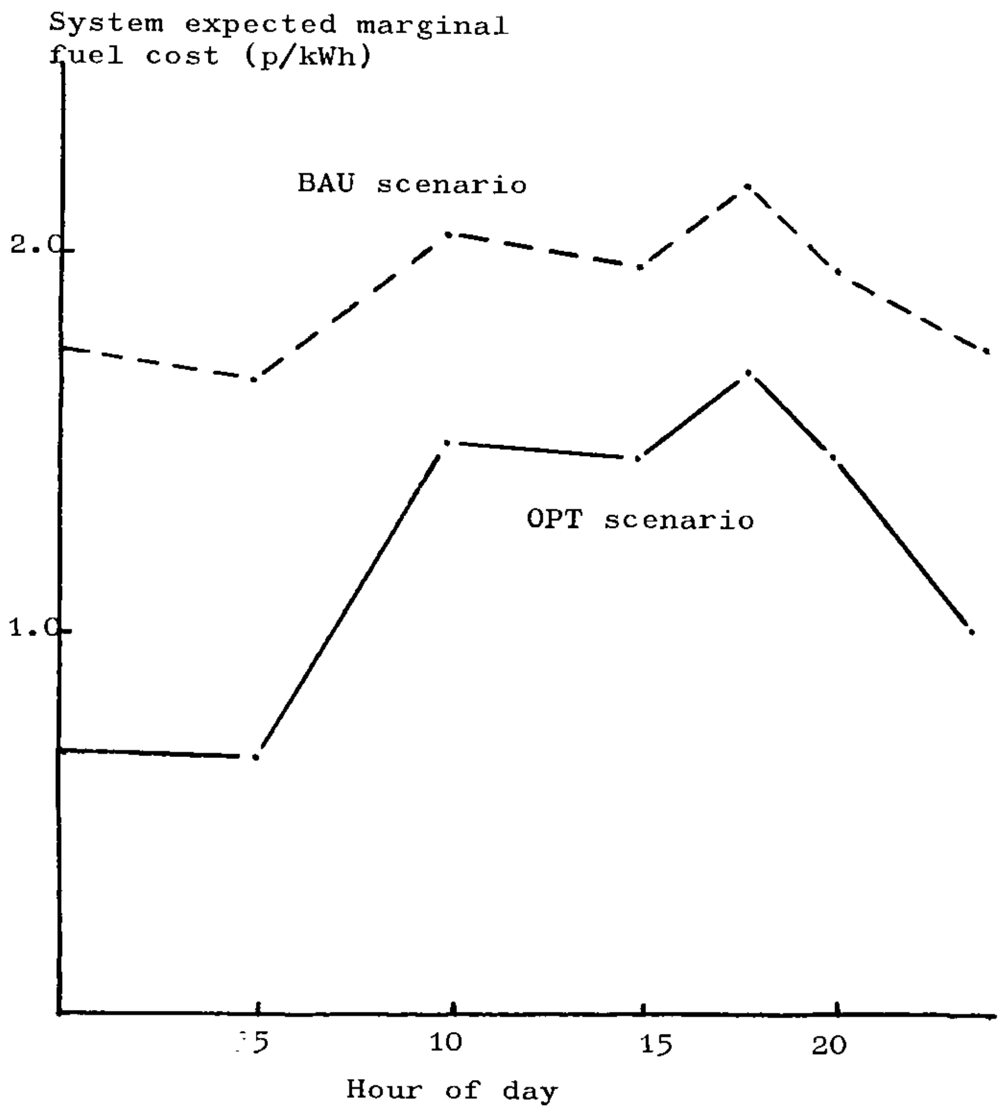


FIGURE A2.5c 1985 Peak season system expected marginal fuel costs, BAU scenario and OPT scenario.

A2.4 Wind Data

Wind data used in this thesis was taken from a summary of windspeed data produced by the Meteorological office (Shellard, 1968). Samples of this data has been compared with Weibull distribution as shown in figure A2.7. As can be seen the data produces a good fit with Weibull curves except in slow windspeeds. This may reflect the poor quality of the data rather than the inadequacy of the Weibull function.

Detailed calculations of the economics of WECS have used a type I model of the power characteristic curve. (See section 6.2.) Load factor predicted for U.K. conditions based on the U.K. meteorological data and the simple WECS model is shown in figure A2.8. A model of the output of WECS is compared against that of a conventional plant in figure A2.9. Information about the variance of such an output is shown in figure A2.10.

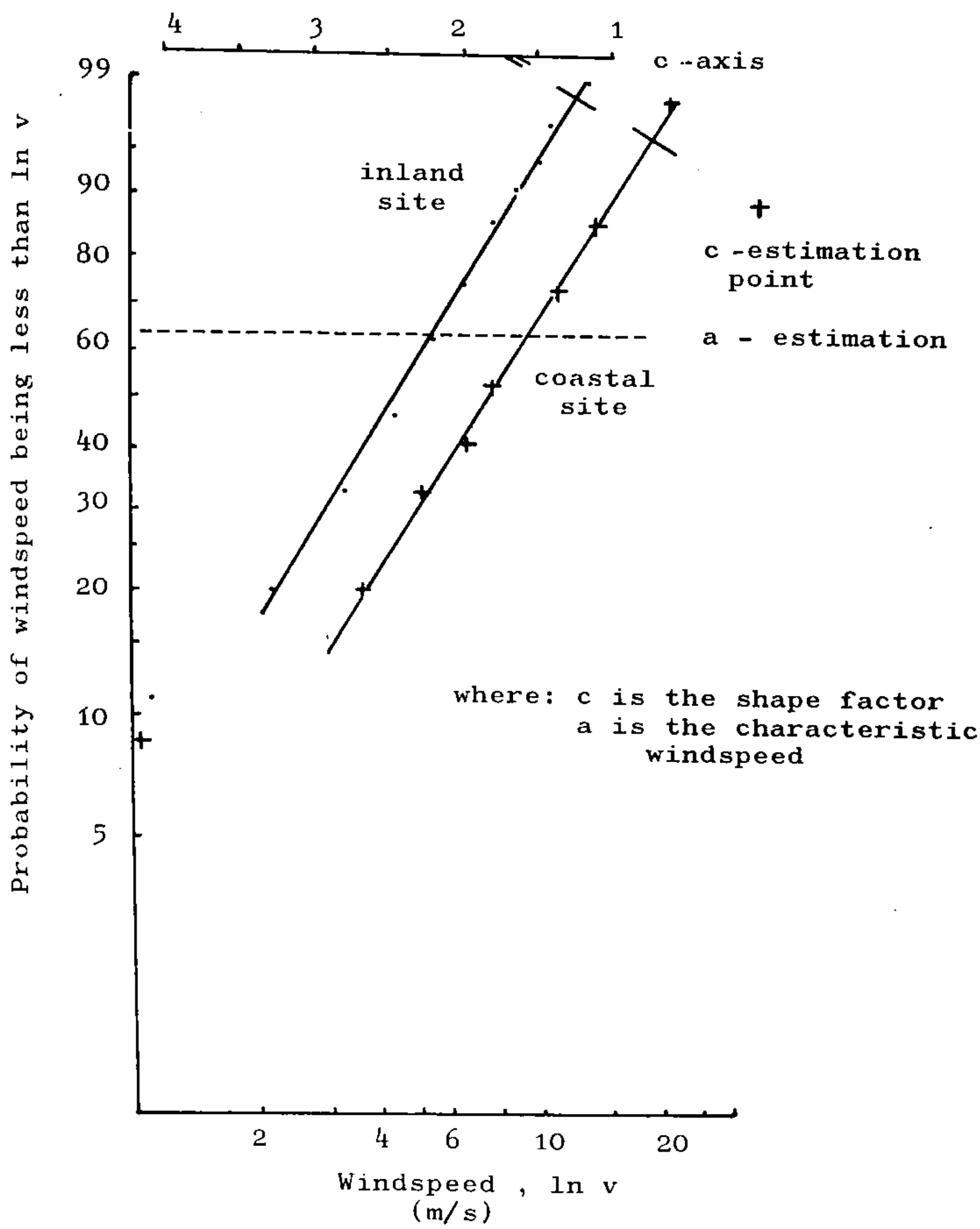


FIGURE A2.6 Weibull plots of wind speed data.

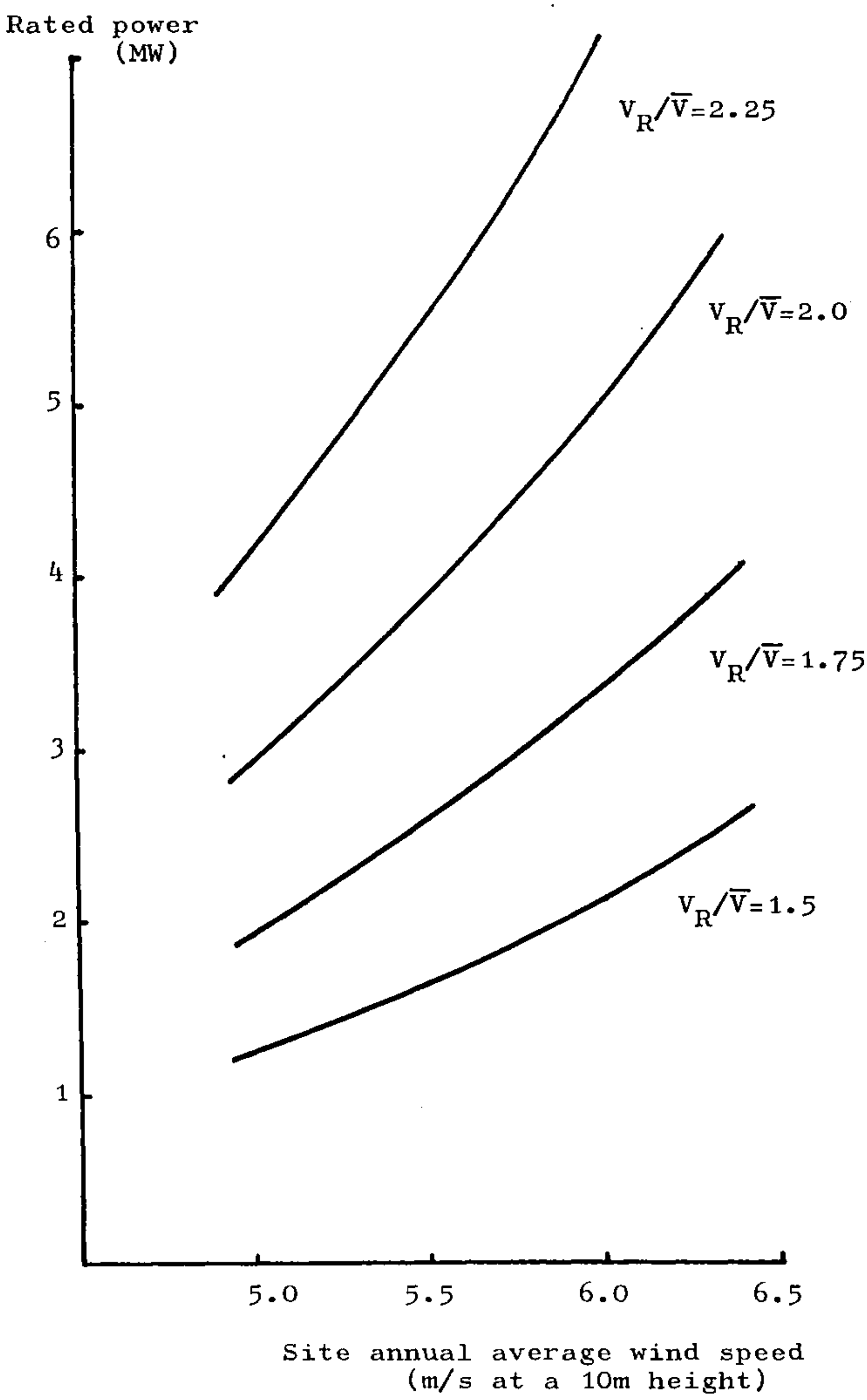


FIGURE A2.7 Rated power, site wind speed, and Rating Ratio for a windmill with Mod-2 characteristics.

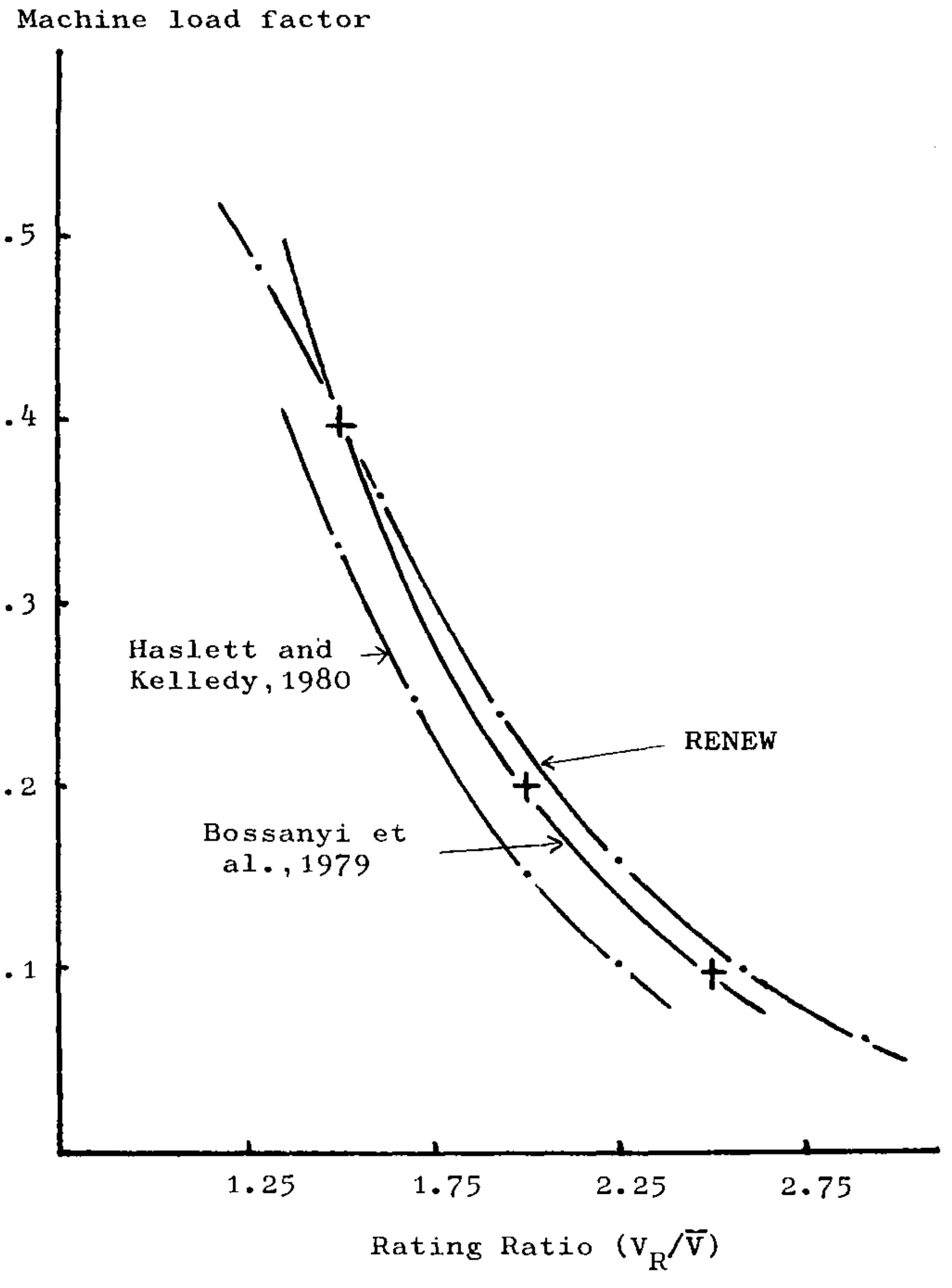


FIGURE A2.8a The effect of the Rating Ratio on the WECS load factor ; predictions from three analyses.

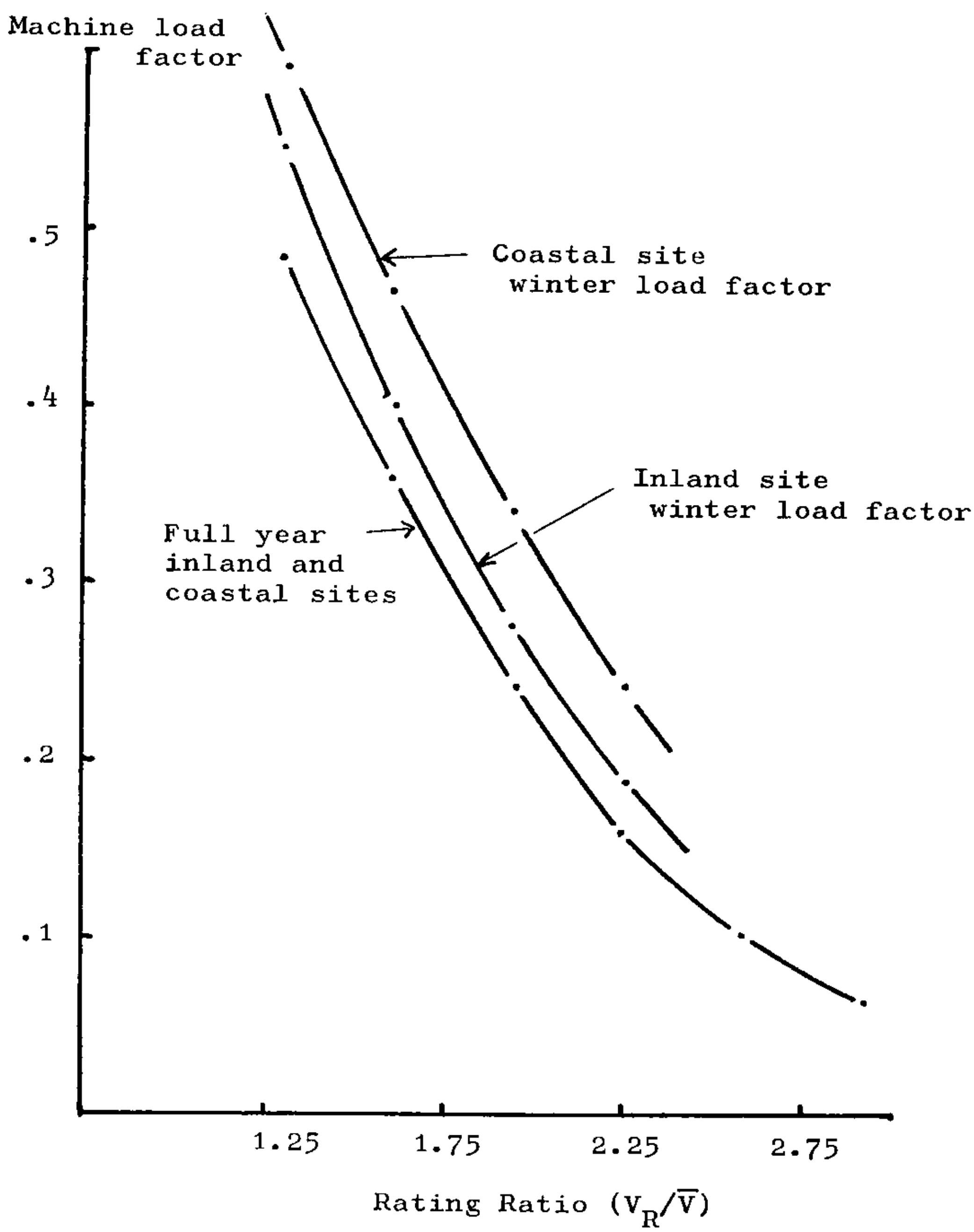


FIGURE A2.8b Season changes in WECS load factors.

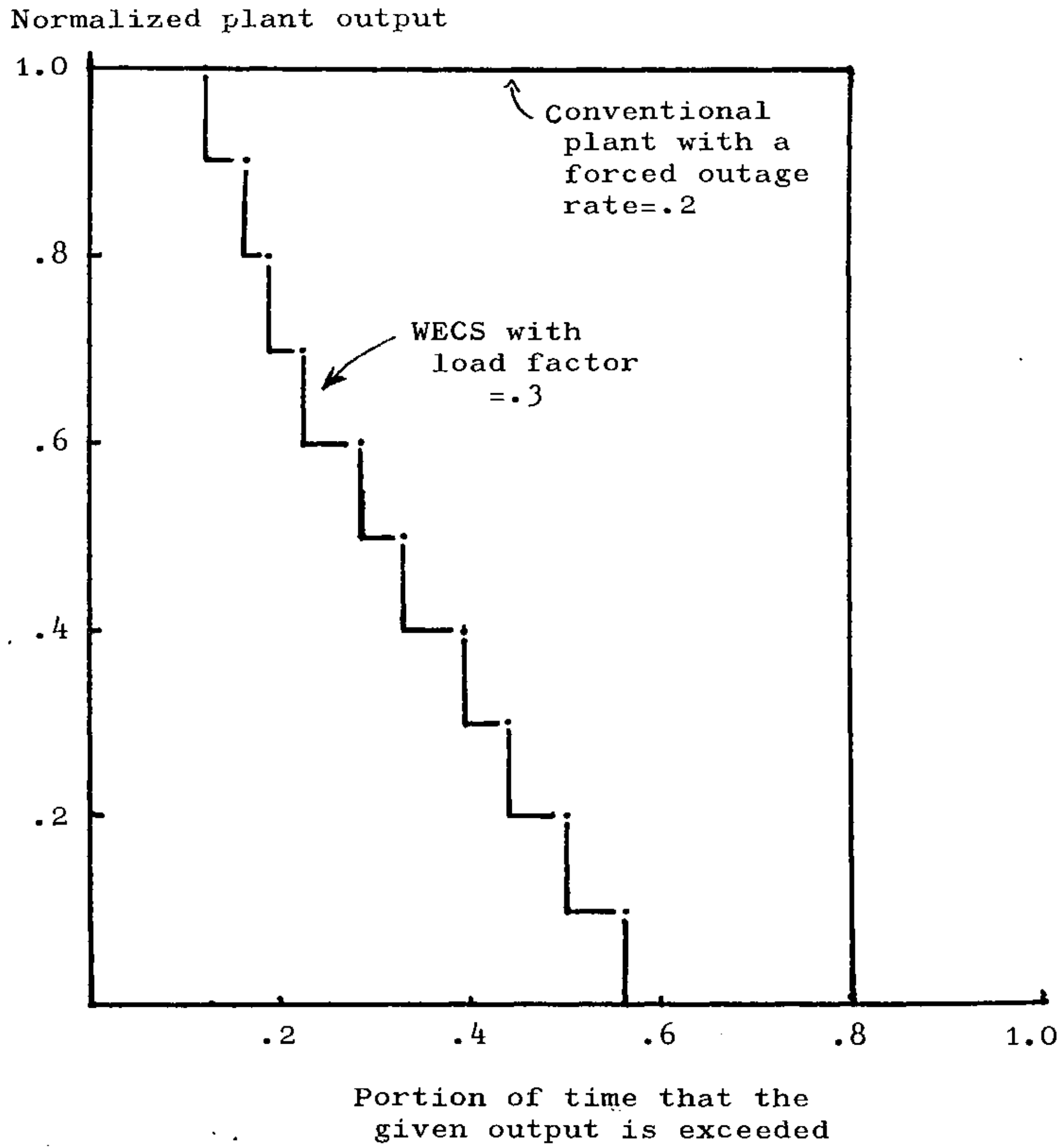


FIGURE A2.9 Plant output characteristics.

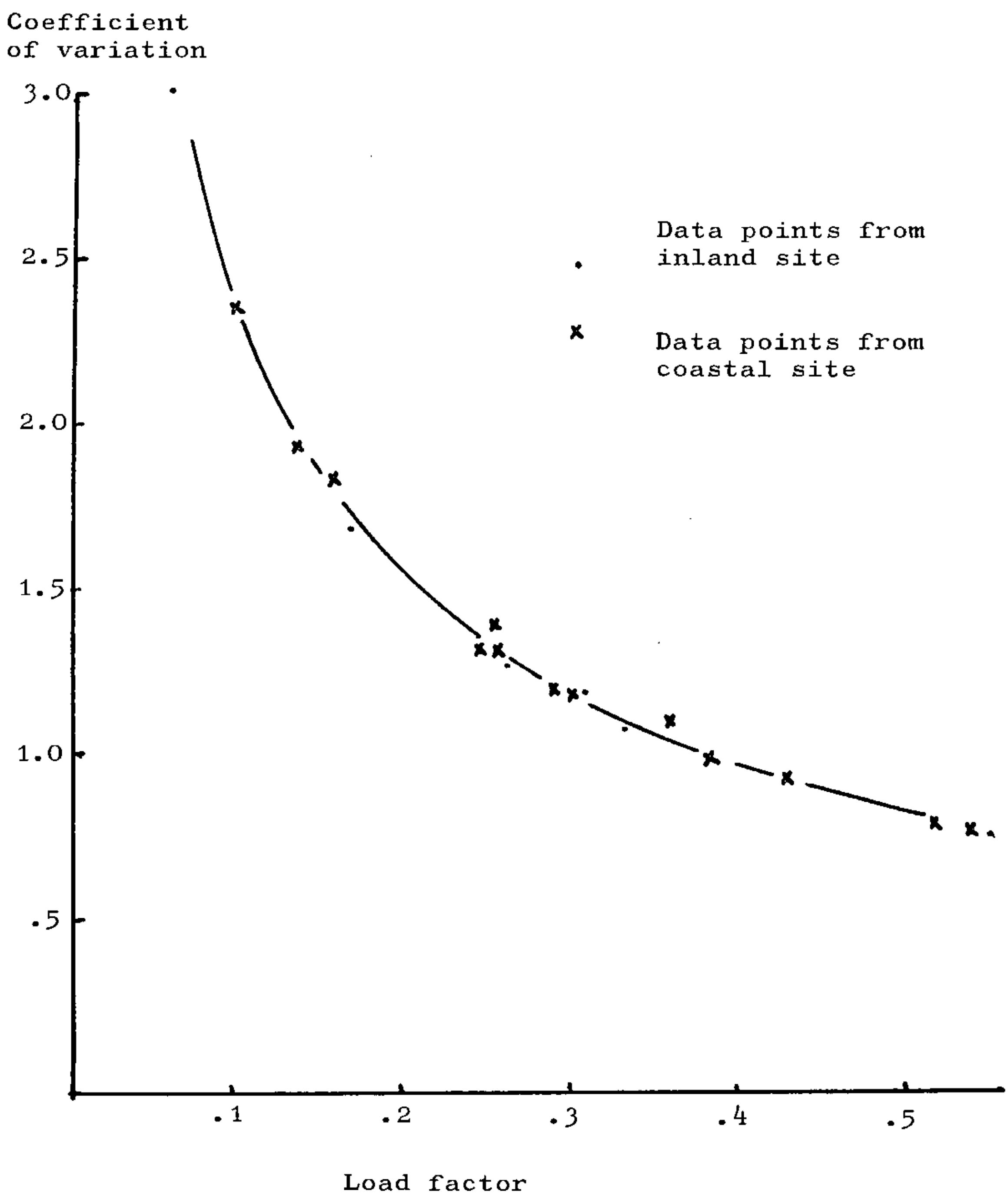


FIGURE A2.10 The load factor and coefficient of variation for WECS.

Appendix 3 - Computer Routines

Three suites of computer programmes were developed by the author and used in this thesis. Chronological wind and load data were analysed and a variety of operations and transformations were carried out on load duration curves, power output density curves, and order of merit cost curves. These curves were manipulated using discrete representations whose precision was under the control of the operator, using variable step sizes on either the ordinate or the abscissa of each curve. All programmes were written in Fortran and run on the CDC - 6600.

A3.1 CEGB Load Analysis - CEGBAN

The programme was developed to analyse load data received from the National Grid Control and to provide load representations compatible with the probabilistic simulation model developed for this thesis. A flow chart for CEGBAN is shown in figure A3.1. To analyse a tape of half hourly data for one year required 41 CP seconds.

A3.2 Systems Analysis and Marginal System Costs - PRICE

The programme takes plant and load data and calculates plant outage curves, the expected order of merit curve (which incorporates the effects of statistical uncertainty from a number of sources), the expected hourly system marginal costs, the total system fuel cost and the system reliability. The Expected Cost Method (see section 4.2.4) is used for the probabilistic simulation. A flow chart for PRICE is shown in figure A3.2. The programme requires 56 K octal words and 8.5 CPU seconds to compile. System analysis for a grid with 110 plants, a 24 period day, and a 2 season year required 33.9 CP seconds.

A3.3 System Simulation and SECS Analysis - RENEW

The programme undertakes detailed systems analysis including predictions of system operation on a plant by plant basis, and of system reliability using a number of risk indices. The effect of a number of load growth predictions, including different levels of load forecast uncertainty, can be studied. Windspeed data can be analysed and wind turbine performance predicted. Necessary input data includes load data, plant data, wind speeds and wind turbine characteristics. Programme compilation required 54 K octal words and 8 CPU seconds. For a 2 season year using 2 probabilistic days based on 1 hour blocks, 180 individual plants, and a resolution of 100 MW, the total run time was 404 CP seconds. A flow chart for RENEW is shown in figure A3.3.

A3.4 Subroutines

1. COMBINE - Analyses hourly load duration curves to produce a daily load duration curve.
2. CON - Accepts the probability function f(x) and g(y) and produces h(x+y) using probability mathematics.
3. CONPROD - Accepts the probability functions f(x) and g(y) and produces $h\{(x)(y)\}$ the product of x and y using probability mathematics.
4. CONVOLV - Accepts the probability functions f(x) and g(y) and produces h(x-y) using probability mathematics.
5. HISTO - Analyses load and wind data to produce probability density functions, for given hours or periods and to calculate the means and standard deviations for these.
6. LDCCARR - Produces the equivalent load duration curve for the system. Two major subroutines are used:

   BOOTH - produces the plant outage curve for the system

   CON - combines the plant outage curve with the load duration curve using probability mathematics.

7. LDETAIL - Increases the resolution, using linear interpolation, of a given probability distribution.

8. NORMAL - Constructs a discrete representation of appropriate resolution of a density function representing a specified level of load forecast uncertainty.

9. NOVEL - Provides a probabilistic description of the output of a wind turbine. Three major subroutines are used:

   AERO - simulates the operation of a wind turbine

   WIND - processes windspeed data to provide an input to AERO

   HISTO - analyses the output of a wind turbine.

10. OPRICE - Uses the load duration curve and the merit order schedule to produce the expected marginal energy cost.

11. RESULTS - Uses the merit order schedule and load data from OPRICE to calculate total system production costs and system risk levels.

12. RINGLEE - Uses the plant outage and cost data to produce a system merit order schedule.

13. SYSCOST - Carries out system production costing. Two major subroutines are used:

   DECONV - removes 1 plant from the equivalent load duration curve

   BTHCOST - calculates the expected energy production of the plant being considered.

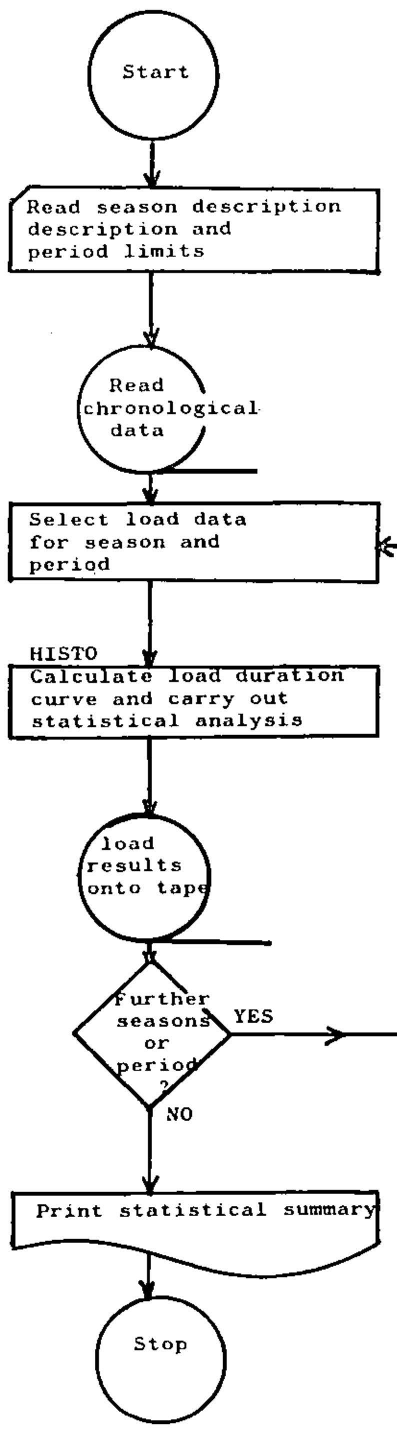
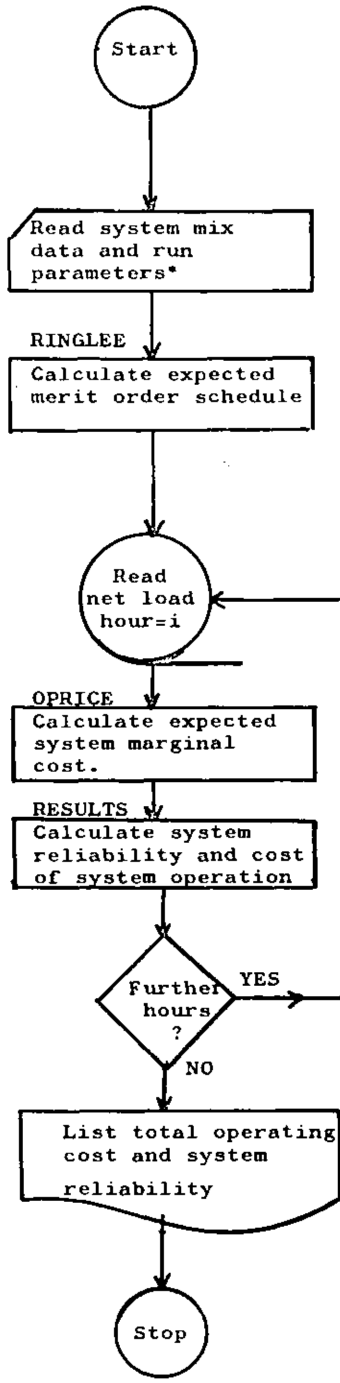


FIGURE A3.1 Flowchart for programme CEGBAN



*run parameters include
-step size for calculations.
-number of hours in each probabalistic day.

FIGURE A3.2 Flowchart for programme PRICE.

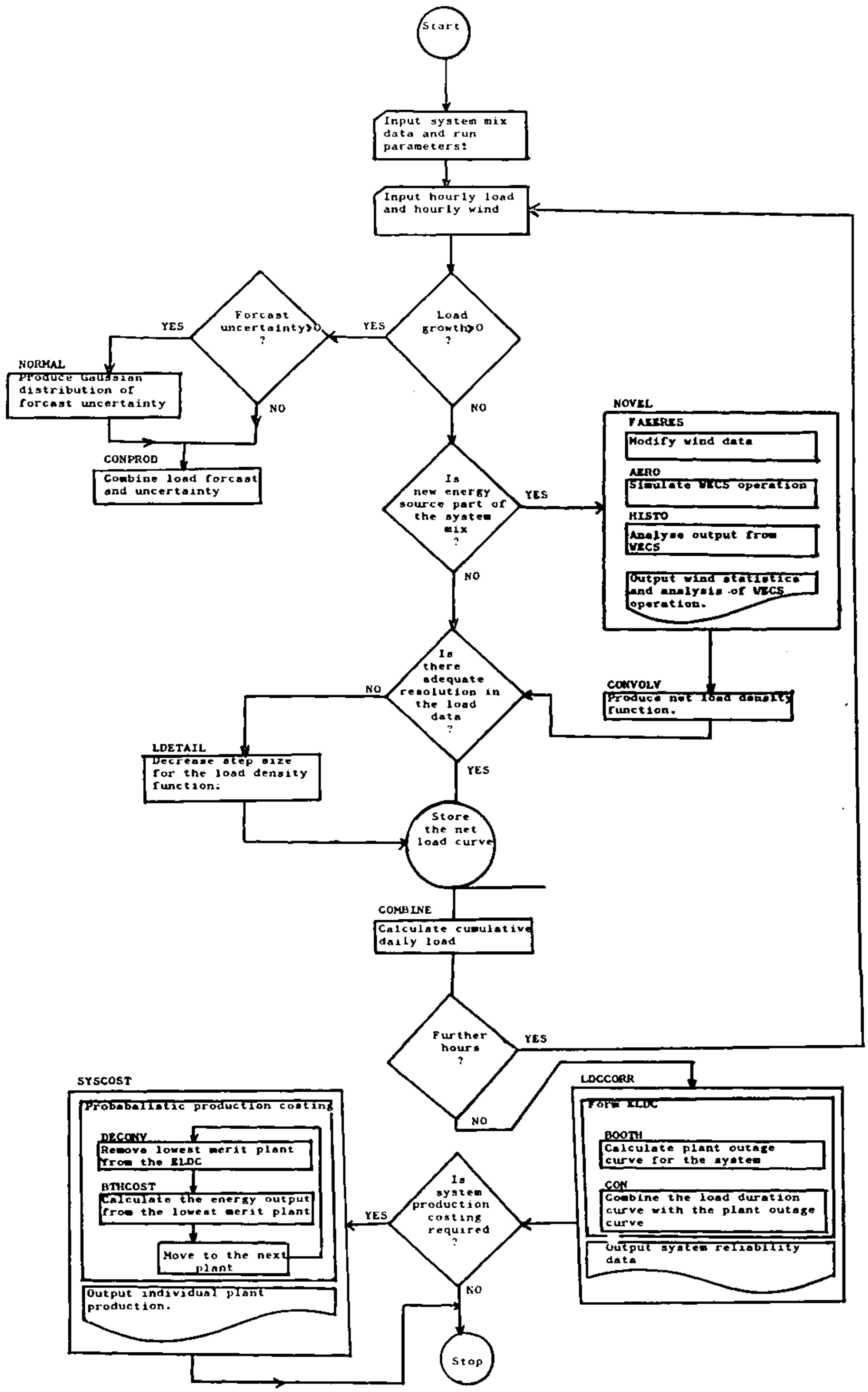


FIGURE A3.3

Flowchart for programme RENEW.

*run parameters include
- step size for the calculations
- load growth, forcast error
- WECS characteristics
- print requirements

Appendix 4 - Published Work by the Author

A5.1 Work Published while carrying out Research for this Thesis

1. Rockingham A.P. Some Aspects of Work on the Evaluation of the Worth of Renewable Energy Sources to Large Electrical Power Systems, Presented at CNRS-SRC Symposium, Toulouse, France, July 1978.
2. Rockingham A.P. A Probabilistic Simulation Model for the Calculation of the Value of Wind Energy to Electric Utilities, Proceedings of the First British Wind Energy Association Workshop, April 1979.
3. Rockingham A.P. The Impact of New Energy Sources on Electric Utilities. A Research Report for the Royal Commission on Electric Power Planning, Toronto, May 1979.
4. Rockingham A.P. Systems Economics Theory for WECS, Proceedings of the Second British Wind Energy Association Workshop, April 1980.

A5.2 Related Work

1. Rockingham A.P., Taylor R.H. The Value of Wind Turbines to Large Electricity Utilities, Institute of Electrical Engineers, Future Energy Concepts Conference, London, 1981.
2. Rockingham A.P., Taylor R.H., Walker J., Offshore Wind and Wave Power: A Preliminary Estimate of the (U.K.) Resource, Proceedings of the Third British Wind Energy Association Workshop, Cranfield, April 1980.
3. Rogers J.S., Choudrey S. and Rockingham A.P. Optimal Expansion of the Ontario Hydro East System 1980-2010: The Effects of Capital Constraints, Growth Rates, and Costing Policy, University of Toronto, December 1975.
4. Slater K., Rogers J.S., Rockingham A.P. Reliability Study Part I. A Research Paper for the Ontario Royal Commission on Electric Power Planning, Toronto, December 1976.

5. Taylor R.H., Rockingham A.P. A Comparison of Studies of WECS Economics for Utility Applications, Proceedings of the Second British Wind Energy Association Workshop, Cranfield, April 1979.

6. British Wind Energy Association Publication: Wind Power in the Eighties. Edited by Lipman and Musgrove. Chapter Five entitled Systems Integration, was edited by R.H. Taylor and A.P. Rockingham with contributions from members of the BWEA.

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