INVESTMENT APPRAISAL IN A DEREGULATED ELECTRICITY MARKET

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Investment Appraisal in a Deregulated Electricity Market

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This thesis analyses the impact of deregulation on the theory and practice of investment decision making in the electricity sector and appraises the likely effects on its long term future inefficiency.

Part 1 describes the market and its shortcomings in promoting an optimal generation margin and plant mix and in reducing prices through competition . A full size operational model is developed to simulate hour by hour operation of the market and analyse its features. A relationship is established between the SMP and plant mix and between the LOLP and plant margin and it is shown how a theoretical optimum can be derived when the combined LOLP payments and the capital costs of additional generation reach a minimum. A comparison of prices against an idealised bulk supply tariff is used to show how energy prices have risen some 12% in excess of what might have occured under the CEGB regime. This part concludes with proposals to improve the market and in particular advocates a new approach to encourage optimal capacity planning using lagrangian techniques to indicate needs without loss of data confidentiality.

Part 2 demonstrates that the classical approach to generation investment appraisal is no longer valid and develops a new approach. It is shown how an individual generator can predict his utilisation and income to establish the worth of investment and demonstrates the validity of the operational model proposed. An empirical relationship is developed between profit and capacity and this is used to develop the theory to illustrate how companies interact. Three different economic models are developed to represent different market conditions and these are tested against the actual investment decisions since deregulation to demonstrate their appropriateness. It is shown that the current market mechanisms could lead to suboptimal investment.

Part 3 discusses the essential role of transmission in enabling competition and reviews worldwide practices illustrating little consensus on charging for its use. Basic costing principles are described and a new model is developed to demonstrate how a generator may strike supply agreements either side of an interconnector to influence prices so as to maximise his income. The optimal pricing strategy for the transmitter is also derived and consumer response is simulated .The concept of transmission uplift is developed and the operational model is extended to include transmission constraints and then used to establish monthly incremental transmission constraint cost functions. It is shown how these can be used to appraise investment options and optimally plan outages.

Part 4 concludes by discussing the regulatory framework and its limitations in improving efficiency or encouraging the optimum levels of investment. The principal findings of the thesis are reviewed and potential market improvement are described. This part concludes with a discussion of alternative market structures and likely future developments.

Key words:- Power Systems,Generation,Transmission, Energy Markets,Marginal Pricing.

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Glossary of Terms

BST = bulk supply tariff for the sale of electricity from the CEGB to the distribution companies

CCGT's = combined cycle gas turbine using gas turbines with a back-end steam turbine

Constrained-on = generation that has to be run to out of MO to avoid violating a transmission constraint

Constrained-off = generation that cannot be run in MO without violating a transmission constarint

HC = generator heat cost indicating the cost of thermal energy

Interconnection = transmission links between separately owned systems

HR = generator heat rate indicating the relation between thermal and electrica energy

Incremental cost = the cost of an additional MW of generation output

Lagrangian= a parameter introduced to represent a coupling constraint

LDC = load duration curve showing the no. of hours during a year that demand is within band

LOLP = loss of load probability being a function of generation availability and demand

Margin = the percentage by which the installed generation capacity exceeds the average cold spell maximum demand

Merit Order MO = a list of generators ordered in terms of their Table 'A' or 'B' price

n-1 and n-2 = the number of circuits less the nuber of outages against which the system is secure

OCGT's = open cycle gas turbine generation

OP = operational outturn

Plant Mix = the proportion of each different generation fuel type

PPP = pool purchase price being a function of SMP and LOLP

PSP = pool selling price made up of PPP plus uplift

Redeclarations = a redefined generator parameter following the original declaration used in the price setting schedule

SDD = settlement day duration currently 48 half hours

SMP = system marginal price as set by the incremental price of the most expensive operating generator

SPD = settlement period duration currently equals one half hour

Start up Cost = the cost of starting up a generating unit

Supplier = a company engaged in wholesale trading of electricity from generators to consumers

SYS = the seven year statement by NGC showing expected system and plant conditions

Table 'B'= the incremental cost of an additional MW of output

Table 'A'= the cheapest total unit price of a generator which includes the no-load costs

TAU = table 'A' uplift in costs resulting from the inclusion of start up and ancilliary service costs

TCA = total cost as actually incurred based on metered energy

TCW = total cost as would be realised from the implementation of an ideal schedule

TLF = transmission loss factor indicates the per unit impact on system losses of additional MW

Uplift = the additional costs incurred in actual system operation over the idealised unconstrained

List of Symbols

Avail = availability

Beta = LOLP lagrangian multiplier

C= capital cost

CCOS = accumulated energy output of generator

CST = generator cold start

D = demand

DNC = declared net capability

FLX = state variable indicating whether generator is flexible or not

Exp = transmission export limit

FC = fixed cost

G = generator

Ginc = generator incremental price

H= hours

HST = generator hot start

I = interest rate

Imp = transmission import limit

In = income

INCU = unconstrained incremental price

L = generator lower output limit

Lambda= demand lagrangian multiplier

LOLP = loss of load probability

MGEN = minimum stable generation

MOC = generator merit order cost

MOFLT = generator minimum off time

MONLT = generator minimum on time

MW = load

Mt = maximum allowable charge in year 't'

ON = variable indicating generating unit is on

OP = genset metered payments

P = price

Po = per unit availability

PPP = pool purchase price

PRP = pool reserve price

Pt = price /kw in year 't'

Q = consumer consumption

RPI = retail price index

SD = variable indicating generatig unit is shut down

SDD = settlement day duration

SMP = system marginal price

SPD = settlement period duration

STC = startup cost

TAU = table 'A' uplift

TCA = total actual cost of metered energy

TCW = total scheduled unconstrained energy

TGD = total gross consumer demand

TGRP = total generation reserve payments

u = utilisation

U = uplift

UL = generator upper output limit

VARCOST = average cost of production based on heat rates and fuel prices

VC = variable cost

VLL = value of lost load

Part 1

Market Mechanisms

Chapter 1

Introduction

1.1 Objectives

On the first of April 1990 the government of the day restructured the electricity supply industry of England and Wales to introduce competition in a way that was expected to reduce prices. The privatisation process was also planned to raise revenue for the government, increase share ownership and reduce ministerial interference.This thesis examines pre and post privatised performance to assess the impact of the changes and develops models to simulate market operation to enable the longer term effects to be assessed. It examines in particular the process of investment appraisal as the most significant factor affecting prices. It explores the weaknesses of the current market mechanisms and suggests improvements.

1.2 Stucture

From 1957 the industry was structured with the CEGB managing generation and transmission development and operation, and the twelve distribution companies supplying direct to customers over lower voltage local networks. The new structure separated generation from transmission and also established several smaller generation companies operating in competition, ie independant generators, National Power, Power Gen.,and Nuclear Electric. A transmission company was also established as the National Grid initially owned by the twelve regional electricity companies. The new structure was designed to give the distribution companies

-the incentive to promote competition in generation

-the ability to connect competing generators to the system

-a wide choice of generation

They were expected to continue to contract for sufficient generation to maintain supplies to their 22 million customers. (1 White paper cm 322 feb 1988)

1.3 Commercial Arrangements

In the absence of direct competition the state owned CEGB and distribution companies were set targets by the Secretary of State to promote efficiency. The most recent targets for the CEGB were for a 4.75% return on assets employed and cost reductions of 6.1%. It was also set negative external finance limits meaning that it had to be better than self funding in providing for investment. The targets and limits would be varied from time to time by the government to suite overall fiscal needs.

In restructuring the industry it was considered that transmission and distribution were natural monopolies and that it would not make sense to encourage replication of these systems. These businesses would therefore continue to be strongly regulated. In the case of generation, a monoply was not desirable and it was proposed that competition should be encouraged with prices being market driven as descibed in chapter 3. Both existing and new generators would have open access to the transmission system for charges which would be made public.

It was also proposed that the business of supplying customers should be progressively opened up to competition removing the local REC franchise for supply. Initially the limit was set at 1MW reducing to 100kw in1994 and being removed in 1998 giving all customers the right to choose their supplier. The new 'Second Tier Suppliers' would have open access to the distribution systems for defined charges in a manner similar to the generators open access to transmission. (Dept.of Energy Licences 90)

1.4 Implications

The job of the CEGB was to predict future energy and demand needs and access the need for new generation and transmission to maintain economic and secure operation to published standards. It therefore determined both the location and type of generation to best meet the overall needs of the system to maintain optimum performance. It planned the closure of older generating units and maintained an integrated planning process for the development of the complete system .

In the new regime the individual generators and the transmission company have to make their investment descisions independently with little knowledge of the plans of their competitors. The normal industry practice is to establish capacity expansion plans based on global studies of a wide range of options and plant types to minimise the total cost of production and capital costs. In the new regime marginal prices determine the costs to consumers and there is no mechanism to reach agreement on overall expansion plans. The results therefore are unlikely to be optimum as a whole.

The electricity industry is very capital intensive and prices are dominated by previous investment decisions and fuel costs tempered by the ability to switch between primary energy sources. The interest and fuel costs can constitute 75 % of the price on the day made up of 57 % fuel and 18 % interest and depreciation (ref 2 CEGB report 87/88) .

The Sunday Times 28 Feb 88 quoted Cecil Parkinson as saying:-

'The CEGB is preoccupied with power station construction and long term investment rather than about the immediate interests of consumers concerned about what it costs to heat their homes and factories'.

The CEGB placed great emphasis on optimising operation on the day with the introduction of scheduling and dispatch routines and procedures but it recognised that prices were dominated by long term investment decisions. It is contested therefore that this is precisely what an efficient utility should emphasise and this thesis therefore concentrates on the process of investment appraisal in the new market.

A proper outcome for the privatisation could be supposed to be:

- cheaper electricity resulting from competition in generation
- evidence of consumer choice in supply influencing the market
- the maintenance of the existing quality of supply

The last requirement was in part embodied in the transmission licence which called for existing operating standards to be manitained.

1.5 The Study

The approach to the problem has been to analyse actual performance since privatisation and develop models to predict future performance. By starting the study period immediately prior to privatisation using data available at that time, it has been possible to test the veracity of the chosen models. Whereas techniques have been developed to plan investment in integrated utilities there are no known publications describing the approach to be adopted in the newly deregulated industry. These developments represent the original part of the thesis and in an area that will be critical to the emerging industries. The thesis is presented in four parts:-

Part 1 describes the new market mechanisms and their shortcomings.

Part 2 develops the approach to generation investment appraisal in the new markets.

Part 3 describes the theory and approach to transmission investment appraisal.

Part 4 discusses other influencing factors and draws conclusions from the findings.

It also reviews alternative approaches to managing an electricity supply industry.

In the sixties we had the 'dash for oil' which compares to todays 'dash for gas'. In the past energy policy was dominated by the need to secure supply whereas we now believe that we have emerged from the shadow of energy shortage and can indulge in market economics. The next decade will see the truth and impact of these decisions on the industry and the nations infrastucture. This thesis attempts to provide a basis for predicting some of the effects.

Chapter 2

Market Structure

2.1 Introduction

This chapter provides an overview of the market mechanisms that have been established to realise competition in generation and supply.

In the UK model the market price is predicted in advance rather than being based on outturn. This approach is preferred in enabling full consumer participation but does suffer in that the outturn is different from the prediction and some mechanism is needed to manage this.

2.2 The daily Market

(a)The Unconstrained Schedule

The generators submit offer prices and plant details each day before 10.00hrs. This is fed into a unit commitment algorithm to establish the cheapest mix of generation to meet the expected demand (see 2.8 and appendix 1). At this stage transmission constraints are ignored as being outside the control of the generator. The results are processed to identify the marginal price of generation distinguishing between those periods when capacity is available on part loaded units (table'B') and when additional capacity has to be started typically to meet the peaks of the day ('A' periods). The table 'B' prices are based on incremental rates whereas the table 'A' include start up prices spread

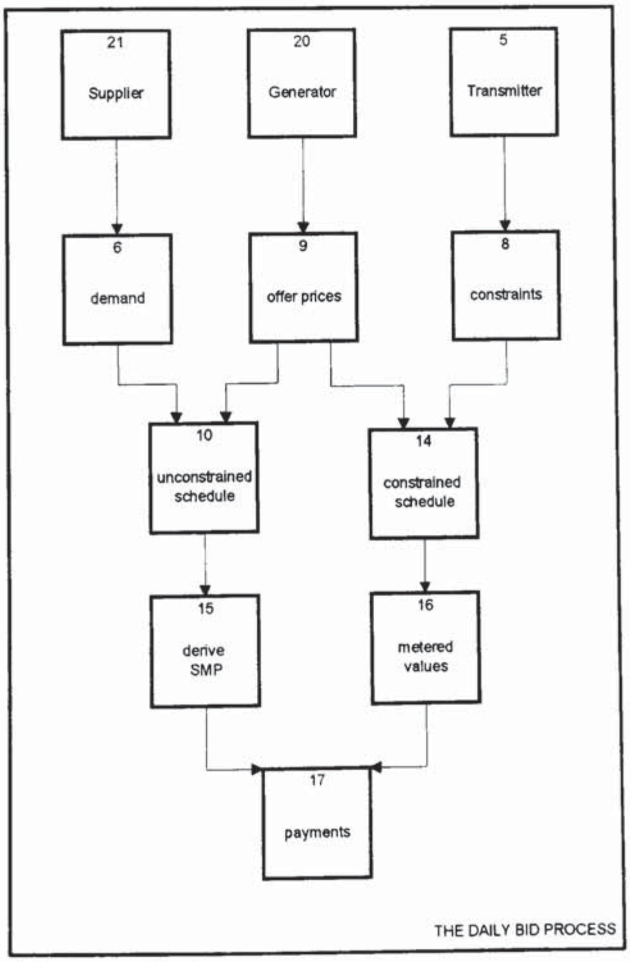


figure 2.1

over the running period. The system marginal price (SMP) is calculated for each half hour for the schedule day ahead. For operational convenience this was chosen to be from 05.00hrs day 1 to 05.00hrs day 2 to coincide with a trough when generation price induced changes would be minimised.

(b) The Constrained Schedule

The above idealised generation schedule could not be used in practice because transmission constraints are ignored, so a separate operational run is used to establish the likely generation utilisation. Further refinements to this are made during the short-term dispatch phase of operation as unit availability and demand changes become apparent. The difference in cost between the idealised schedule and the outturn is defined as the 'uplift'.

2.3 LOLP

As there is no explicit requirement for a generator to declare units available, an incentive is neccessary to ensure that sufficient capacity exists to meet demand. This is achieved by the introduction of additional payments based on the loss of load probability (LOLP). This is calculated for each half hour taking account of recently recorded statistics of the likely loss of the individual units selected to run and potential demand prediction errors.

2.4 Generator Payments

A generator gets paid for the unconstrained energy supplied at SMP, inflated in proportion to the loss of load probability for the appropriate half hour times the value assigned to lost load, ie. the Pool Purchase Price 'PPP' where:-

$$PPP_j = SMP_j + LOLP_j * (VLL - SMP_j) \qquad 2.1$$

where the 'VLL' is the value of lost load as agreed for the year in question and inflated annually. The pool reserve price 'PRP'is given by:-

$$PRP_{i,j} = PPP_i - INCU_{i,j} \qquad 2.2$$

where 'INCU' is the unconstrained incremental price of the generator holding the reserve.

These values are corrected to take account of the changes in availability subsequent to the offer and payments may be reduced if the instructed output is not reached and is within the declaration.

Where the energy is different to that calculated by the unconstrained schedule then the generator will be paid his offer price if greater than the PPP. If a generator was selected to run in the unconstrained schedule but is constrained-off due to transmission limitations then he will receive compensation for lost profit.ie he will be paid the difference between his offer price and SMP for the units that would have been supplied.

In general the genset metered payments 'OP', which embody uplift due to constraints, are given by the difference between the actual cost of metered energy 'TCA' (genset total metered cost) and that in the unconstrained schedule, ie.'TCW' (genset total revised unconstrained cost).

$$OP_j = (TCA_i - TCW_i) * \frac{SPD}{SDD} \qquad 2.3$$

where 'SPD' is the settlement period duration and 'SDD' the settlement day duration, ie the costs are spread.

The generator also receives availability payments if LOLP is positive based on the product of the availability in excess of that scheduled in the unconstrained run multiplied by the LOLP and VLL, minus the greater of bid price or SMP.

The payments for ancilliary services to support frequency and voltage control are based on bilateral contracts and those services recorded as having been called-off. Other special payments cover maximum generation conditions and payments for generators only running in table 'B' periods who would not otherwise have their start up payments covered.

2.5 Consumer Payments

The payments for energy at the pool purchase price would not cover all the payments to generators because the outturn is inflated by the need to run out of merit generation due to transmission constraints ,demand prediction errors and ancilliary service costs. These additional costs are levied on Table 'A' periods with table 'B' periods based on the marginal purchase price ie. in table 'B' periods the pool selling price is the same as the pool purchase price.

$$Table'B' \quad PSP_j = PPP_j \tag{2.4}$$

Whereas during table 'A' periods the pool selling price is increased to cover the start up costs and uplift:

$$PSP_j = PPP_j + TA\ U + (TGRP_j / TGD_j) \tag{2.5}$$

where 'TAU' is the table 'A' non reserve uplift being a function of out of merit costs and ancilliary costs, and 'TGRP' is the total generator reserve payments apportioned by total gross consumer demand 'TGD'.

The uplift is defined as the difference between the actual and idealised costs ie:

$$U = TCA - TCW \tag{2.6}$$

The calculations undertaken by settlement for the pool are described in more detail in appendix 2 (reference the Pool Rules), and appendix 3 describes the uplift element.

2.6 Hedging Contracts

Although all energy is traded through the Pool the generators and suppliers enter into bilateral contracts to provide longer term price stability and reduce the impact of random pool price variation. Two way contracts will fix the selling price and the generator will recompense the supplier if marginal prices are higher, or vice-versa if prices are lower than the strike price.

The generating companies will in turn establish contracts for long term fuel supply.

2.7 Implementation

To ensure error free data handling, most of the processes are implemented electronically and largely automatically. The generator offer data is submitted to the Grid Operator via kilostream links and serves both the constrained and unconstrained unit commitment studies. The actual outturn is recorded by high accuracy tariff meters with the results collected by dial up from central data collector stations. The generator redeclarations of changed parameters are also submitted electronically. The data captured during the operational phase is passed once per day to the settlement system which calculates and publishes SMP and retrospectively calculates the appropriate payments.

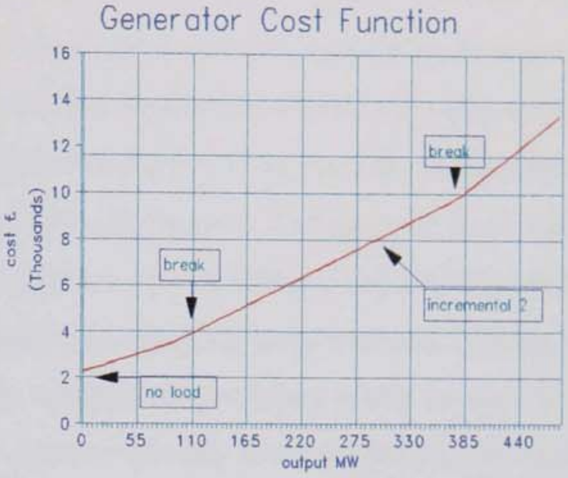


Figure 2.2

2.8 Unit Commitment

The problem of unit commitment is to minimise the cost of producing electricity to meet the expected demand whilst satisfying generation and transmission plant constraints. The generation constraints modelled are; run up and run down rates ; minimum on and shut down times as well as inflexibilities due to plant difficulties. The prices consist of a start up price, a no load price and typically up to three incremental prices as shown in figure 2.2. The transmission constraints will restrict import or export from zones of the system and may overlap or be nested. The problem solution is made more difficult due to the interaction of the following factors :

- units may not be used in merit order where differences in start up price outweigh differences in running costs for short on times.
- generator dynamic constraints, like run up rates and minimum on time, may prevent the use of units in strict MO where they are unable to track the demend.
- coupling constraints like transmission cause the use of one generator to interact with another and may force the use of units out of merit and some units off.
- the selection of units to meet peaks involves a trade off between start up and running costs.
- trough run through requires a balance between out of merit running to avoid subsequent high start up costs.
- the pattern of time varying availability may not match the demand profile

neccessitating additional starts and stops.

A variety of techniques have been applied to solve the problem including heuristic, linear and dynamic programming (Bellman 94) and lagrangian relaxation (Cohen 87 Oliveira 92) and genetic programming and synthetic annealing (Hartl 89) and probabalistic techniques (Wang 95). I consider that lagrangian relaxation is most appropriate for serving the needs of the privatised market because it replicates the process by which a generator would review his schedule against the published SMP and is therefore most easily defendable. I have initiated the development of an algorithm to replace the GOAL algorithm currently used by the UK pool. It builds on a basic algorithm (Cohen 88)to meet the special needs of the UK system and its formulation is descibed in appendix 1. The approach is to establish a lagrangian for each of the coupling constraints such as demand and also transmission constraints to enable each generator's utilisation to be independantly assessed. Starting with an estimate of the system lambda profile, dynamic programming would be used to test whether or not it would be economic to operate the unit. The total generation resulting from all the units is compared to the demand and the lagrangian is adjusted iteratively until the demand is met within a defined tolerance. The approach is capable of providing close to optimum results which are repeatable and auditable.

2.9 Conclusion

This chapter, and appendices 1 to 3, provide a basic description of the operation of a deregulated market and the processes used to establish market prices and settlement. In particular, the unit commitment problem is described to provide an insight into those physical factors affecting market prices.

Chapter 3

The Market in Operation

3.1 Introduction

This chapter shows some of the results of pool operation and analyses in some detail for Jan 92. A number of graphs are plotted to illustrate the relationship between the various elements and some of the market's apparent shortcomings are discussed.

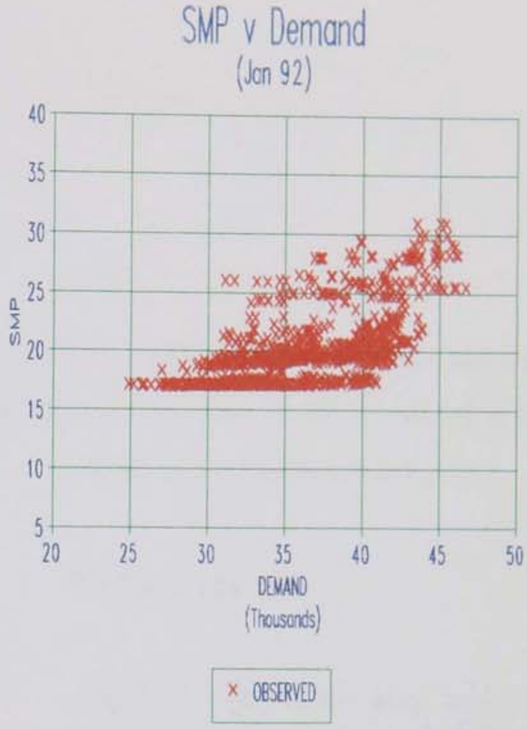


Figure 3.1

3.2 SMP v Demand

Figure 3.1 shows the variation in SMP in £/MWh as recorded for all half hrs in Jan 92, plotted against demand in GW. It can be seen that there is some correlation between the two, and that there is a marked lower minimum to SMP. The results for individual days show a similar pattern and reflect the overall system price/demand profile.

3.3 LOLP v Capacity

Figure 3.2 shows the variation in recorded LOLP through Jan 92 plotted against the apparent excess capacity, at the day ahead stage, in GW. Positive LOLP's occur for quite high generation surpluses. This reflects the finite probability of loss of generation sufficient to reduce the capacity to the highest probable demand level.The graph shows only the significant positive

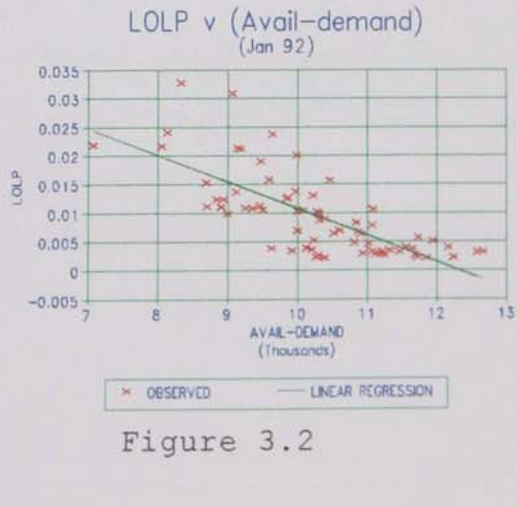


Figure 3.2

values. The linear regression line shows some discontinuity in the function.

Figure 3.3 shows the LOLP v the day ahead margin for three months of 92. It can be seen that the LOLP is around zero for a large part of the period but shows a positive sudden increase as the nett surplus drops below some 12 GW. This suggests that a simple representation is possible using a linear fit to the positive values and zero when the surplus exceeds some 12 GW. The theoretical derivation of the relationship between LOLP and margin is dveloped in chapter 7.

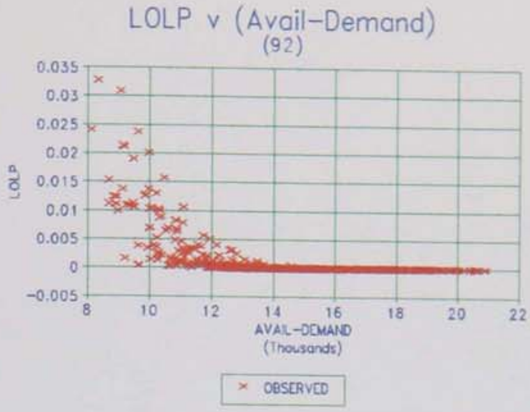


Figure 3.3

3.4 Plant Margin

Figure 3.4 shows the plant margin expected for future years if all the planned capacity is built and no further closures are announced. The margin is defined as the percentage by which the registered planned plus existing capacity exceeds the expected demand as defined and published by NGC in the Seven Year Statement.

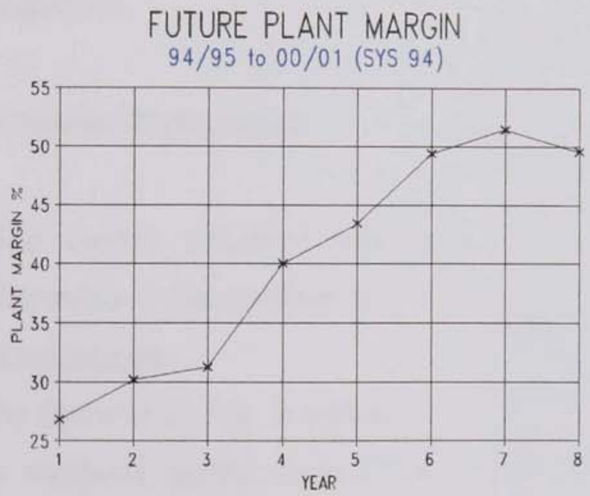


Figure 3.4

Given that the optimal is around 22.5%, it can be seen that some excessively high values are predicted resulting from the entry into the market of a number of new players building gas fired plant while existing generators continue to expand.

In practice, faced with reducing prices and profit margins existing generators may well close a proportion of their older units to maintain lower short term plant margins and SMP and LOLP payments .

3.5 Price Trends

Figure 3.5 shows the trend in pool selling price (PSP) since privatisation up to Feb 94. It can be seen that the price has continued to increase and exhibits wide fluctuations in excess of what might be expected due to demand variation. Figure 3.6 shows the increasing variation in prices during each month since privatisation.

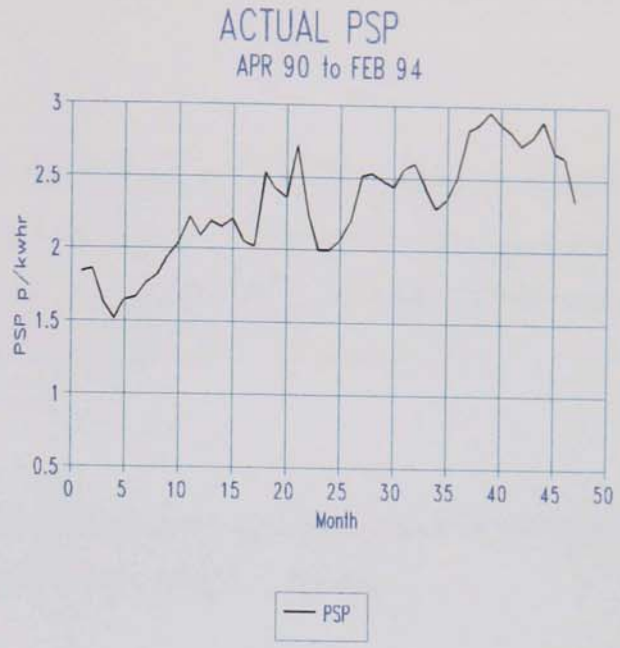


Figure 3.5

3.6 Market Performance

The current perceived market performance is discussed below:-

a. Plant Margin

The figure of 22.5% is typical of the standards applied around the world. Its derivation and construction are discussed further in chapter 7. It can be seen from figure 3.4 that significantly higher values are expected through the 4 to 8 year ahead period. This results from uncoordinated investment decisions by generators and is likely to lead to large scale premature closure programmes and reductions in coal burn in favour of cheaper gas used in combined cycle generation modules. The increasing use of gas will make future electricity prices sensitive to the availability and price of gas. It is concluded

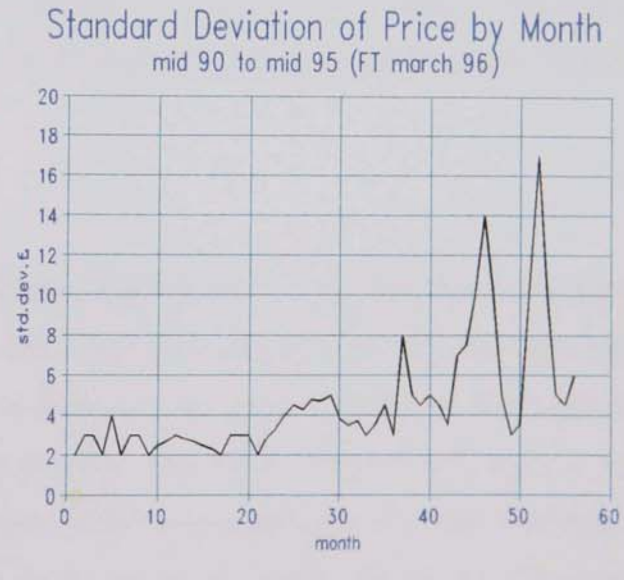


Figure 3.6

that the current day LOLP signal is an unsuitable mechanism for influencing long term plant margins.

b Plant Mix

The CEGB selected generation additions to meet future demand taking account of the expected operating regime. A plant mix was chosen to minimise the overall operating and capital costs. The current market mechanisms do not provide any incentive to build or retain peak lopping generation as is evidenced by the closure of existing OCGTs

c. Price Levels

The graph of PSP (figure 3.5)shows that the market has not been effective in driving down electricity prices which are shown to have risen in excess of inflation.

d. Optimal Outage Planning

Within the CEGB generation and transmission outage planning was undertaken on a national basis to maintain the required operating margin throughout the year. Since privatisation the short term plant margin has varied significantly from the ideal and is not being correctly influenced by the daily term loss of load probability signals. This leads to adverse margins and highly volatile prices to consumers as shown in figure 3.6 which complicate investment appraisal.

e. Transmission Constraints

Currently the SMP is set using a scheduling algorithm based on generation cost but does not include transmission constraints or losses. This presents generators with the opportunity to exploit their knowlegde of the system when they are within a constraint. They can raise prices in the certain knowlegde, that in practice, they will be called on to operate to meet the constraint and will be paid at bid price. Whereas arrangements have been proposed to include transmission losses indirectly, as yet they have not been introduced. The cost of wheeling through interconnectors will also become more important as international trading develops.

f. Use of System Charging

The current charging arrangements for Use of System are zonally based to encourage Generators to locate to areas of demand with generation shortfall. In practice it has not worked and generators have chosen to locate near to industrial connurbations, partly because a market exists for waste heat. It would be preferable to devise a charging arrangement related to the benefits of the Grid rather than its constraints.

There is also a need for an incentive to encourage the transmitter to return circuits to service as quickly as possible to minimise uplift costs.

Chapter 4

The Changing Problem

4.1 Introduction

This chapter discusses an approach to modelling the market in operation to enable an analysis and prediction of its performance against the government objectives. It descibes a set of three models that may be used to appraise the worth of generation and transmission investment within a deregulated market.

4.2 Problem Formulation

The objective function for an integrated or nationalised utility is to minimise total cost. The income function is now different for each of the players and will depend on the financial exchanges with other players as determined by the pooling arrangements and use of system charges. The variables of the problem include demand expectations, fuel price movement, interest rate, construction delays and the actions of other players on the pool prices. The object of each player will be to maximise profit and establish a robust development strategy taking account of all the uncertainties. This thesis concentrates on developing methodologies to assess income and investment return and to predict the effect of the action of other market players.

4.3 Solution Process

The problem is considered to be too complex to formulate as a single model and a suite of three interacting models is proposed todecompose the problem into manageable proportions. The decomposition is analogous to that in the real market with coupling via the market mechanisms as in the real world and they cover :

- generation investment appraisal
- transmission investment appraisal
- company interaction

These are outlined below and developed through the thesis.

4.4 Model 1 Generation

The generation model is shown in outline in figure 4.1 and is made up of three paths. The first develops the cost of constructing and operating the generation including the cost of finance. The central limb derives an assessment of the income by simulating the operation of the pool and derivation of marginal costs. The right hand limb covers the

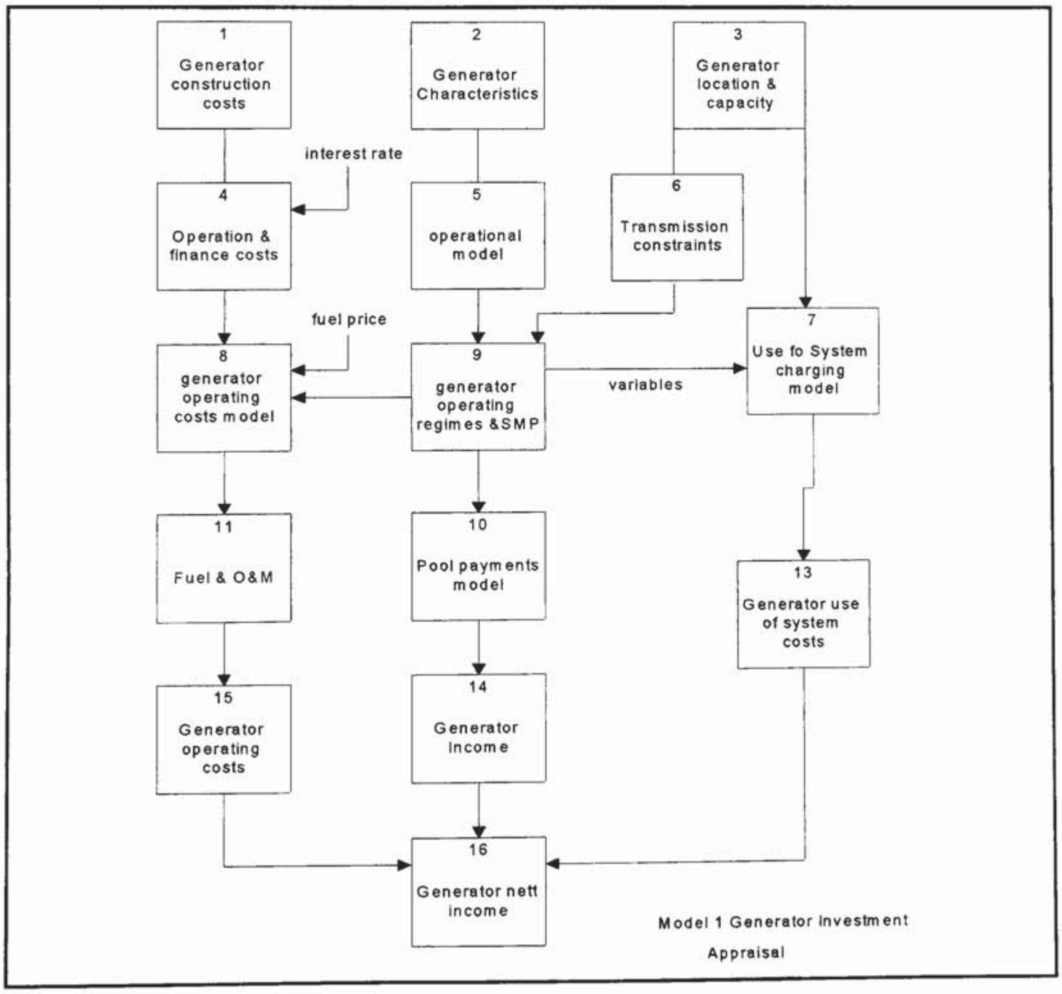


figure 4.1

interaction with transmission and its charges.

The key feature is the central operational simulation which has to replicate the pool processes that determine the operating regimes of generators and their payments. This is discussed in more detail in chapter 5.

4.5 Model 2 Transmission

The income derives from three principle sources: connections,infrastructure and interconnections. The connection charges are prescribed as being a reasonable rate of return on the assets employed in connecting a new customer. The infrastructure charges are covered in part by use of system charges and uplift payments resulting from transmission limitations. It is the latter that creates investment opportunities. The payments for interconnection are the subject of bilateral agreements based on the perceived worth .

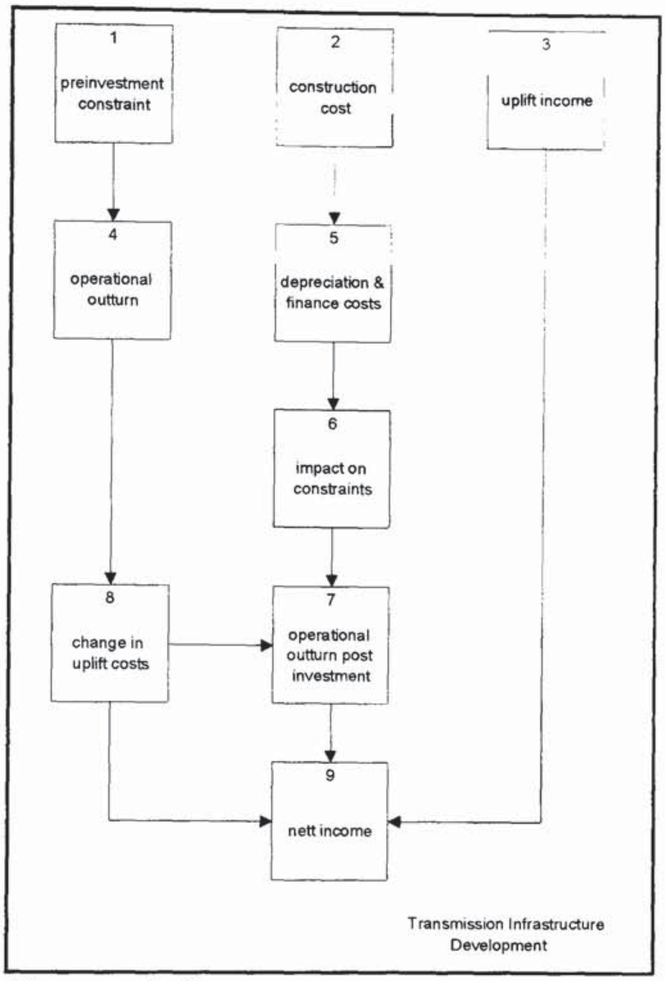


figure 4.2

The main problem in the new environment is to predict the costs associated with active transmission constraints for some future period. The unknowns are future generation prices and outages of generation and transmission. The requirement is to model the effect of transmission additions on the cost of operation as shown in figure 4.2.

The approach adopted is to use group transmission constraints to represent the network limitations within the scheduling algorithm with a dispatch solution to load generation at selected time points. This is considered preferable to the use of DC network models with a single time step dispatch which would not provide the neccessary SMP profiles and spikes resulting from the generation dynamic constraints.

4.6 Model 3 Interaction

In a deregulated environment the individual players are expected to participate in the market unilaterally and without collusion. It is therefore neccessary to establish models to show how interaction may occur through the market and how optimal investment strategies can be determined year on year,(see figure 4.3).

It is desirable to establish the sensitivity of the outturn to the variation in the inputs to enable a strategy of least regret to be adopted. Statistical techniques are of value when the variables may be expected to assume the full range of values but in this case it is proposed that scenarios are established based on key events.

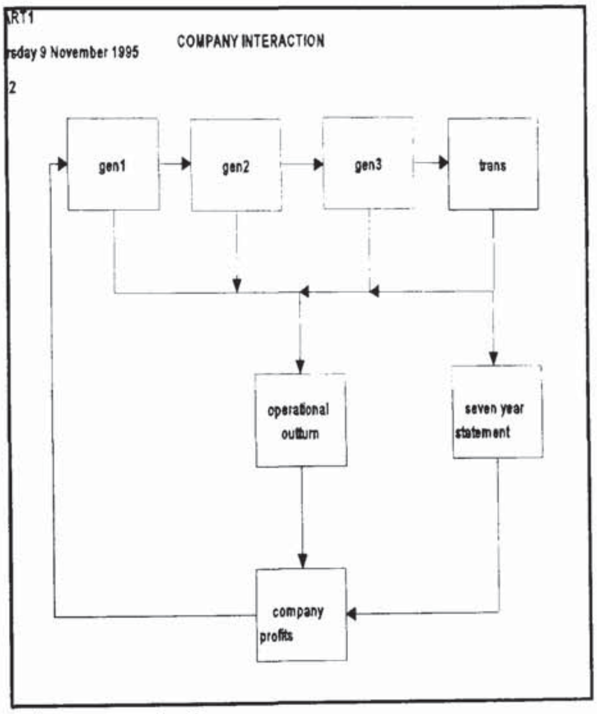


Figure 4.3

The process needs to assess the strategic options and their implementation in different circumstances. It may be preferable to accept a less than optimum strategy against the mean expected outturn if it reduces the adverse consequences of other possible outturns.

4.7 Conclusions

It is proposed to investigate generation and transmission investment strategy against the uncoordinated action of the various players through simulation of the market mechanisms. The strategy should identify the benefits to generators, consumers and the transmitter of alternative development paths, with modelling of likely decision making processes at each stage . The market interactions are:

- generators will react to pool selling price variations and zonal use of system charges in their investment decisions.
- suppliers/consumers will react to higher pool purchase price charges by demand management.
- the transmitter will react to changing consumer and generator decisions by varying prices or investment.

The first phase will be to establish a model of the operational process. Subsequenent phases will address the development of models to simulate the interaction through the market. It is proposed that a form of dynamic programming will be used to link solutions at different timesteps to establish the optimal decisions at each point in time.

Chapter 5

Development of Operational Model

5.1 Objective

This chapter describes the core algorithm which has been built to simulate system operation for upto a two year period. The model schedules generation to meet a pre-defined demand and to calculate overall production cost and generation utilization as well as marginal prices. The model is designed to accommodate heat rates and fuel prices as, applied pre-privatisation, as well as offer prices applying post-privatisation. The model can therefore be used to make a comparison of the relative costs of production by comparing the out-turn prices for a post-privatisation period against those that would have applied had fuel prices and heat rates continued to be used to calculate prices as applied pre-privatisation. The model has been made as simple as possible to enable multiple studies to address the uncertainty, but produces marginal prices in line with those recorded in practice.

5.2 Options

Full unit commitment modelling is extremely time consuming and for predictive studies is not justified in the light of the inherent inaccuracy of the data available.(see Appendix 1) However, certain aspects of the process must be modelled to derive the realistic marginal prices we require in this case. Of these, planned generation and forced outages must be modelled and the dynamic constraints encountered by generation while tracking changing demand. A number of alternative techniques have been applied and reported (Jacobs 95 Gronheit 95).

In the Equivalent Load Method all the units are committed and the cumulative probability that the available capacity will meet the demand is calculated and hence the likely average marginal price . The technique does not attempt to model the dynamics of the unit commitment process.

Several methods employ Monte Carlo techniques to simulate random outage decisions and then use a merit order to stack units until demand is met, with the last unit setting the marginal price (Billington 94). The average of several iterations would normally be used.

In practice, very large numbers of iterations have been found to be neccessary and approximations using control variate sampling or parametric techniques have been tried.

Direct methods based on orthogonal polynomials have been tested where the load price function is represented by a combination of polynomials.

An indirect approximation method has all the units committed and adjusts the load by an amount that results in its intersection with the price function coinciding with those values recorded in practice. Interpolation techniques like Chebyshev are then used to establish the total function.

All these approaches to modelling varying availability do not reflect the practicalities whereby outage opportunities are taken at low demand levels and are not randomly distributed. It is also unrealistic to write all generator availabilities down as this fails to replicate the range of variations that occur in practice, due to random forced outages. Few techniques attempt to model the dynamics, whereas in practice dynamic constraints can lead to extended part load operation and a bias to the use of flexible units. There is also a requirement to model individual generators to assess their worth. For these reasons the model developed uses representative outage data, based on recorded plans for the time of year and includes dynamic parameters with a chronological simulation. The interval between schedules is chosen to be two hours as being sufficient to capture most of the dynamics related to unit minimum on and off times but not to lead to an oversized problem.

5.3 Scope

The model as developed is capable of handling some 250 discrete generators and calculating merit orders based on heat rates and heat costs. It will also model transmission loss factors related to generation location. The model is dynamic in that it schedules generation successively for each two hour period taking account of generator constraints related to minimum on time, minimum shut-down time and also definitions of inflexibility. By this process, start-up costs are accumulated as well as the number of both cold and hot starts on generation. The break point between cold and hot starts is currently set at 26 hours. The model is also designed to simulate manually entered transfers from both Scotland and EDF. Pump storage is also simulated externally and linked to the model. Time varying generator availability is modelled as well as regional categorisation of generation.

5.4 Data Input

Data input is by files which can be interactively edited and includes for each generator: the set name, fuel, minimum on and off times, minimum generation, flexibility markers, heat rates, heat costs, TLF and merit order data. Demand for each half year is established in a separate file for each two hour interval. The programme allows selection of merit order data and computation of merit orders based on modifications of basic data. External transfers are defined interactively for each period from a predefined set. Generator availability is defined for each period enabling outage patterns to be simulated.

5.5 Output Data

This is selectable by menu and includes a summary with the Giga-watt hours by plant type: hot and cold starts, total generation, demand and an overall error value to indicate the degree to which generation and demand are in balance. The cost of production by plant type is also available as well as individual set duty cycle details and details of coal station and oil station burn by region of the country. Typical output data is shown in Appendix 1.

5.6 Program Sequence

Step 1. Read in set name, fuel type, minimum on and off times, minimum stable generation and flexibility.

Step 2.Select merit order data, either standard or modified, and read in set name, heat rate, heat cost and TLF (Transmission Loss Factors).

Step 3. Select merit order and cost of production data either standard or modified.

Step 4. Compute merit order of sets and the merit order costs for the option chosen. This step enables heat rates, heat costs and TLF's to be edited and a new cost of production to be calculated based on:

HR * HC* TLF (ie heat rate times heat cost times TLF) subsequently the data is resorted into the new merit order.

Step 5 selects the period of study interactively by defining the start week, start year and the finishing week and year.

Step 6 enables external transfers to be modified by selection from pre-defined blocks for specific weeks through each half year.

Step 7 defines the input menu enabling the editing of merit order or execution of the program preliminary or final pass.

Step 8 - Preliminary Pass. This selects and loads generators according to pre-defined availability data for the half year. It also enables editing of availability followed by execution of the loader routine to load generation to meet demand and finally sum the unit and station data to establish the statistics for the period.

Step 9 - Final Pass. This enables the original MO to be adjusted by the inclusion of a start up cost spread over the average running hours.

Step 10 - The Output Menu. This enables selection of either a summary, a cost of production, individual set details or coal or oil details by region.

5.7 Program Details

The program is written in standard Fortran with flat file data input and is designed to run on a standard IBM compatible PC. Sub routines are established to sort the merit order using a multiple bubble technique (SORTER), to check generation against demand (CHECK), following completion of the run to establish an estimate of the error, sub routine HRCEDT enables selection of external transfer data for the period, sub routine LOADER loads generation to meet demand taking account of the dynamic constraints, and sub routine INITIATE initiates various data fields.(see app.5)

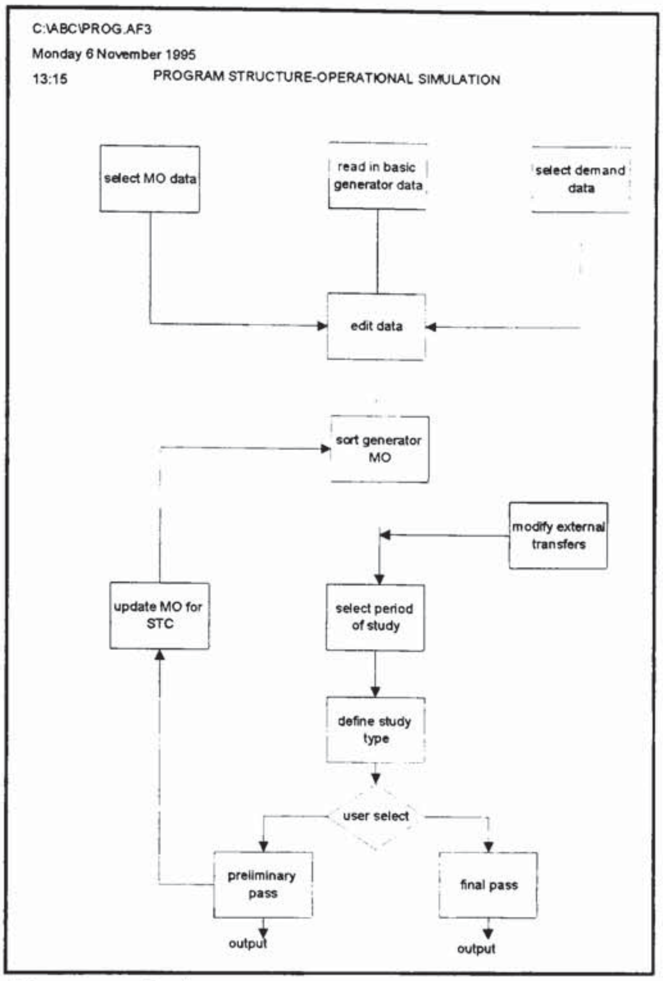


figure 5.1

5.8 Data

The data used for simulation is as applied pre privatisation for the generation available at that time. The heat rates and Generator constraints were therefore based on test data or and recorded dynamic performance. Typical Generator availability patterns are included taking account of outage plans and forced losses. Any new generators are added at the appropriate time with estimated parameters.

The EdeF and Scottish transfers are set manually to values and prices that applied during the appropriate study period. The demand profiles are based on actual values for the base year (1987/8)scaled to be consistent with the predicted monthly energy figures for the period.

5.9 Model Validation

The algorithm includes a check routine to confirm that generation is scheduled to meet demand at each time point. A record of any shortfall is maintained as well as the total error to enable any significant errors to be investigated. This may occur when, because of changing availabilities, insufficient generation is available to meet demand. Each program module has been tested separately.

The analysis of the model and some actual results are compared below:

i) Actual

The actual results for the period January'92 were derived by processing the daily results of SMP, LOLP for each half hour period, to establish the PPP (Pool Purchase Price). The product of PPP and the associated actual demand was calculated to establish the total purchase cost. The results were as follows:

SMP COST = £525m

LOLP COST = £34 m

aver SMP = £19.75

aver LOLP = £1.36

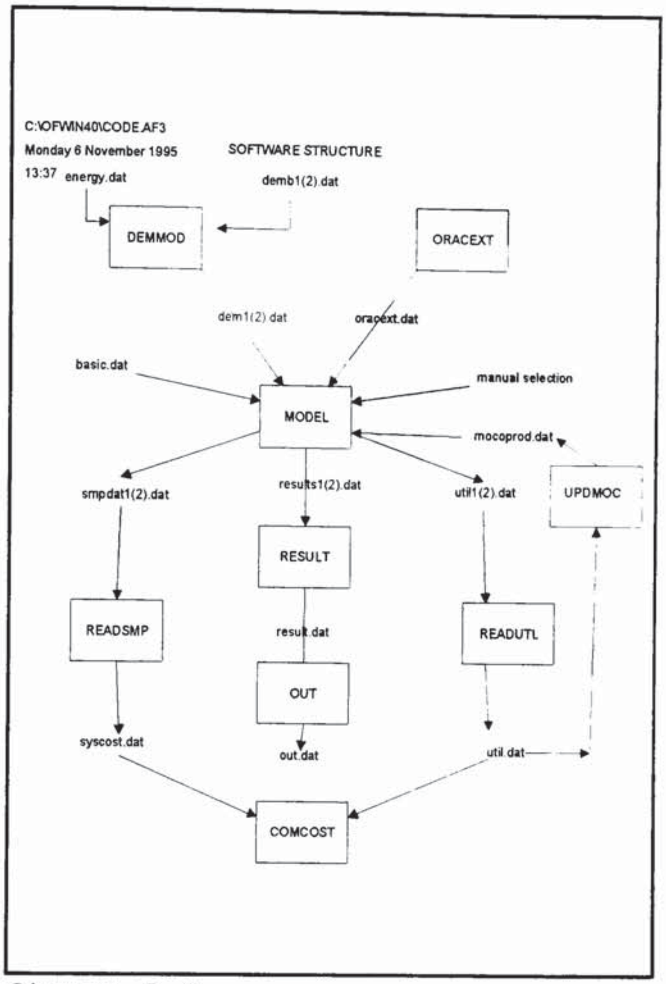


figure 5.2

ii) Model

The model was run with the the same demand for the same period amd with the generation available prior to privatisation for which heat rate data was available. Normal patterns of availability were included with new generation added. The inflation rate for the period from which the data applied to Jan 92 was assumed to be 1.105. The marginal price for each period was derived from the incremental price of the marginal generator. The results were as follows:

SMP COST = £534m

LOLP COST = £32.3m

aver SMP = £21.1

aver LOLP = £1.25

The actual cost of production for the period based on individual unit heat rates and fuel prices was calculated at £354, ie some 33 % less than the payments for all energy at marginal price.

iii) Fuel Prices

A comparison of fuel prices in January'92 shows:

COAL UK	£1.31/GJ	24 GJ/T
COAL IMPORTED	£1.0 /GJ	26/27 GJ/T
OIL	Heavy Fuel Oil	£1.4/GJ
OIL IMPORTED	Heavy Fuel Oil	£0.9/GJ

This is consistent with the heat costs used in the model and it is therefore concluded that electricity prices are some 50% higher than the base production cost. This is in part justified

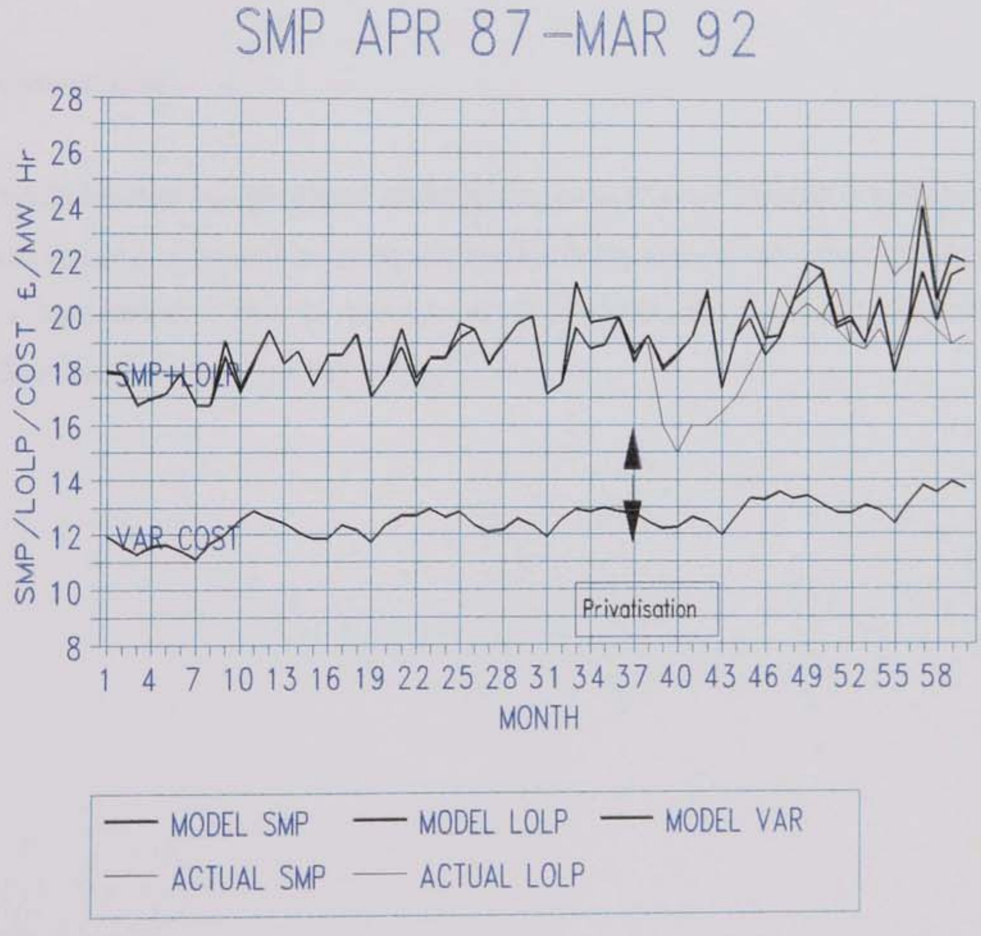


Figure 5.3

by the inclusion of capital costs and compares with independently derived data on Pool price trends.

The model was used to simulate operation for each month in turn to establish a profile of SMP and LOLP through the six years from 87/88 to 92/93. The results are shown in figure 5.3 having corrected for inflation. The graph also show the average cost of production (VAR COST) derived from the total cost of production calculated using heat rates and fuel prices and the actual outturn prices since deregulation. In these studies the demand and availability were not corrected to match outturn, but even so a reasonable correlation exists which is considered sufficient to enable evaluation of market principles. The high values immediately prior to privatisation was the result of high demand and immediately afterwards there was known to be a period of aggressive bidding which settled down after a few months to reflect actual marginal prices.

5.10 Conclusions

It is concluded that the operational model results are sufficiently similar in behaviour to the actual to enable it to be used to analyse the market behaviour and calculate generator profits from a knowledge of income based on pool payments and the costs calculated from generator heat rate data and fuel costs.

Chapter 6

SMP Theory and Plant mix

6.1 Introduction

The system marginal price (SMP) is defined as the incremental price of supplying an additional MW of power .A value is currently derived for each half hour period. The marginal incremental price is derived from a scheduling study with the objective function of minimising the total cost of production. The SMP is then the incremental price of the marginal or most expensive generator. There are two exceptions to this -

- A generator that is inflexible and cannot realise extra output is not allowed to set SMP
- A generator that is ramp rate limited is not allowed to set SMP

6.2 Table A/B Periods

Where synchronised generation has spare capacity then the SMP is set by the incremental price of that marginal generator. i.e. -

$$table\ B\ SMP_j = G_i inc$$

Where spare capacity is not available and additional generators have to be synchronised then this is defined as a table 'A' period and start up costs are included and spread over the period for which the units are selected to run ie. (Ref pooling and settlement agreement96)

$$table\ A\ SMP_j = G_i inc + \frac{STC_i}{T} \qquad 6.1$$

The effect of start up costs is shown in a separate section to be minimal and generally less than 1% with realistic values.

6.3 **Derivation of Plant Mix and SMP**

The following sections describe two approaches to predict a representative plant mix and SMP when data will not be available for full production simulations. The intention is to establish a technique that can be used in wide ranging scenario studies. The techniques also demonstrate the relationship between the plant mix and SMP.

6.3.1 **Graphical**

In an existing operational system the SMP can be estimated by full scheduling studies using actual demand and generation availability. In a future possible system the idealised optimal SMP would be a function of the demand profile and optimal plant mix. Given indicative capital, fixed and running costs for the different generation types then a function total cost/utilisation function can be established for each as shown in Fig 6.1 where:

$$G_i = I * c_i + FC_i + VC_i * h_i$$

where G = total cost in £/kW/yr and C=capital cost
I=interest rate
FC=fixed cost
VC=running cost
H=running hrs

The intersection of these functions shows the point at which it becomes more attractive to use a different type of generator because the operating and distributed capital costs become cheaper.

Given a demand profile a load duration curve(LDC) can be derived showing demand level and the number of hours for which it applies. The intersection of the generation break points with the LDC curve gives the optimal utilisation period for the different tranches of generation and their size .The results in this example were approximately:

OCGT 23%; oil 9%; coal 17%; nuclear 51%.

6.3.2 **LP Formulation**

The optimal plant mix problem can also be formulated as an LP with the objective function of minimising capital, fixed and running costs whilst meeting demand i.e.minimise

$$\sum FC_j * DNC_j + \sum^{J_{j=1}} \sum^{T_{t=1}} VC_j * MW_{j,t} * Avail_j \qquad 6.3$$

subject to

$$\sum^{J_{j=1}} MW_{j,t} = D_t$$

and

$$MW_j \leq DNC_j$$

solve for MWjt and DNCj where CC=fixed cost

DNC=capacity

VC=variable running cost

MW=load

Avail=mean availability

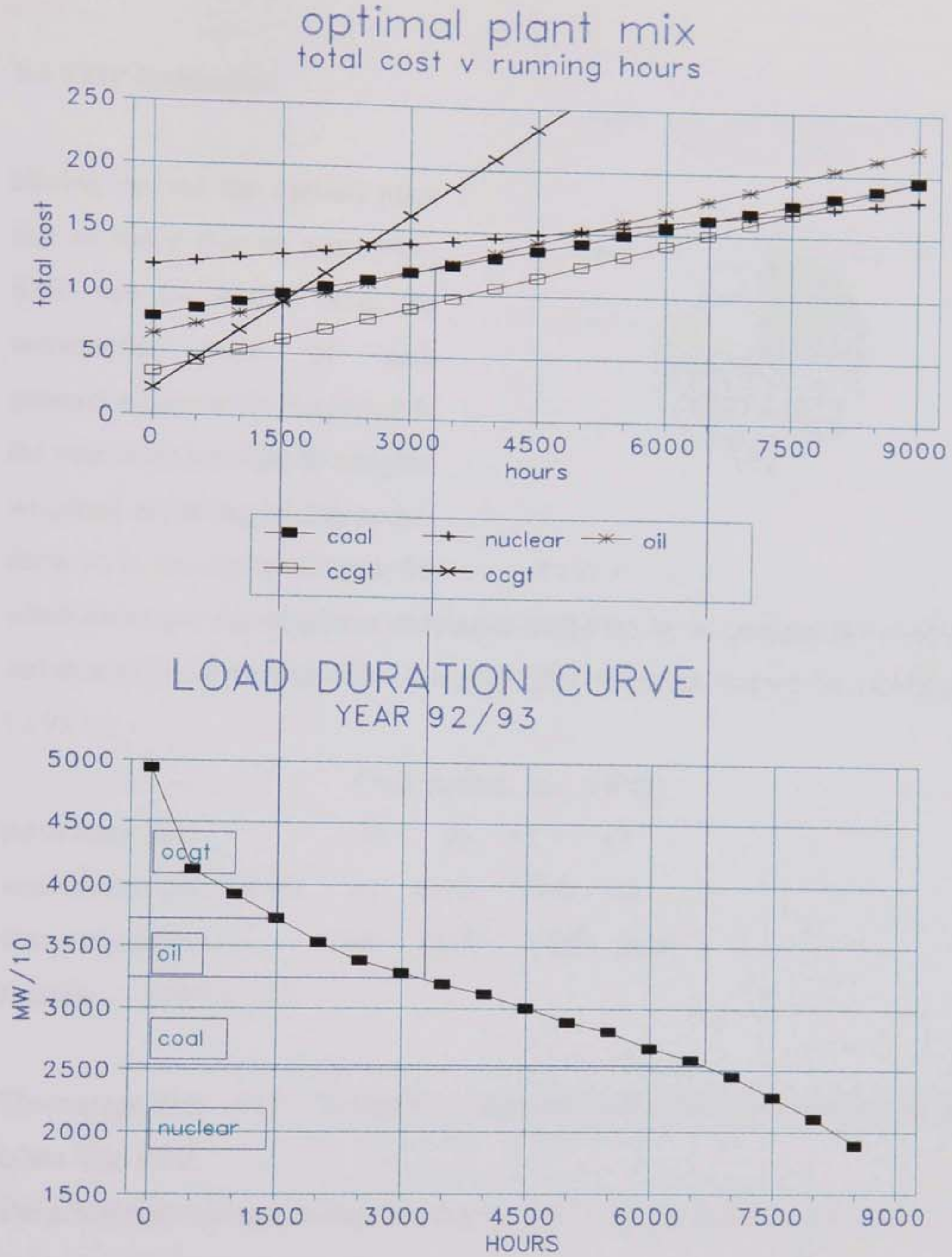


Figure 6.1

The studies were undertaken ignoring initial conditions and with and without the CCGT option. If the availability of cheap gas and the CCGT option is discounted then the result is as shown in figure 6.2. A substantial proportion of nuclear appears cost effective as would be expected.The amount is artificial in that the initial installed plant mix is ignored(This is included in chap.13)

The result is similar to that derived from the approximate graphical technique.

6.4 SMP Estimation

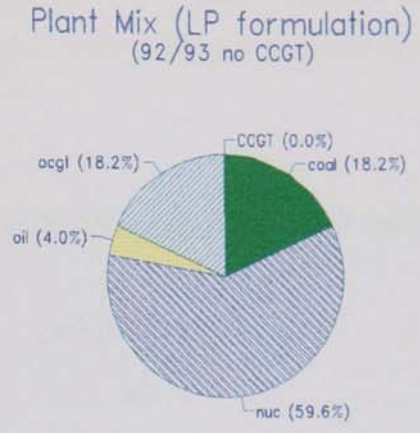


Figure 6.2

Having derived the optimal plant mix as above then an appropriate SMP can be derived from the incremental price of each generation tranche for the period of the year when it would be marginal weighted according to the period duration. ie. the number of hours for which each type of generation is marginal is multiplied by its marginal price and summated and divided by the number of hrs in a year. The LP results without the CCGT option for 92/93 are -

	Coal	nuclear	oil	OCGT
percentage mix	18	59	3.7	18
incremental cost £/MWh	13	6.75	17.5	47
marginal running hrs	3500	2000	1860	1400
average £/MWh 17.7				

The average SMP of £17.7/MWh is considerably below the actual because the actual mix is less than ideal .

The actual plant mix and average incremental prices for the different tranches of generation and marginal running hours are:-

	Coal	nuclear	oil	OCGT
percentage mix	59	17	21	2
incremental costs £/Mwh	17.75	7.0	20.25	48
marginal hrs	6260	-	2250	250
average £18.89/MWh				

These reflect the support for the indigenous coal industry and restrictions on the use of gas. Insufficient nuclear power is available for it to ever be marginal. The average SMP for the period is £18.89/MWh against a full operational simulation result of £18.32/MWh .ie the simplified estimate is within 3%. This compares to the idealised value of £17.7 without CCGT,s and with a full nuclear contribution .

The result if the CCGT option is included is as shown in the table below and figure 6.3.

	Coal	nuclear	oil	OCGT	CCGT
percentage mix	0	55	0	0	44
incremental costs £/Mwh	0	7.5	0	0	18
marginal hrs	0	1260	0	0	7500
average £16.45 MWh					

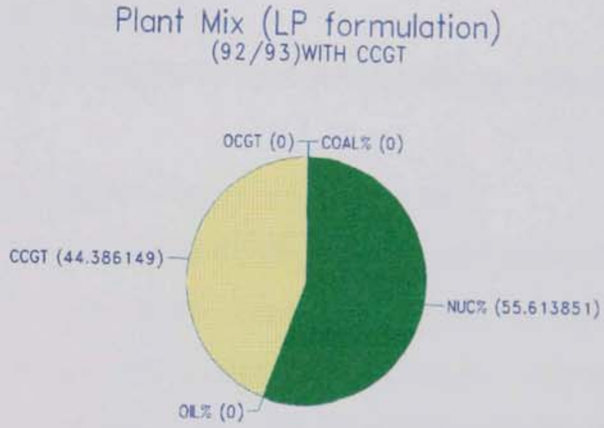


Figure 6.3

These results support the 'dash for gas' and demonstrate the viability of a significant tranch of nuclear generation as evidenced by cheap imports from EdF.

The approach of minimising total operating and interest costs using an LP formulation is the classical technique used in planning generation investment. The objective function now ,however, is for each player in the market to maximise his own income against the marginal price, which is very different. All generators will wish to build the type of generation likely to give the best overall return and will assume that they will operate as base load. In practice this will eventually be impossible and some generators may become uneconomic and fail. The generation investor now needs to predict the behaviour of his competitors and consumers and model the impact on his own decisions.

6.5 **Conclusions**

A simple theoretical framework has been established to derive a representative SMP in a green-field situation from a knowledge of the demand profile and the cost of plant options. This has been compared with full scale simulation results to demonstrate the order of accuracy. A comparison between the full production simulation value of £18.32/MWh and the value of £18.89/MWh derived from the actual plant mix and average prices shows acceptable accuracy for global simulations.

A number of conclusions can be drawn from the analysis:

- there is a direct relationship between the load shape,the optimal plant mix and the average SMP.
- the current plant mix is less than ideal and current fuel and capital costs will lead to increasing amounts of CCGT's and nuclear.
- the profits of base load generation are inflated by those periods when peaking plant sets the SMP.
- the classical approach to determining investment is no longer valid.

The current market arrangements provide no incentive to build peaking plant as the SMP is unlikely to be high enough to ever cover capital costs. This is evidenced by the wholescale closure of OCGT generation since privatisation as uneconomic. Currently, however, base-load units rely on the high marginal prices set by peaking capacity for a major proportion of their profits. The current LOLP payments go to all generators, including baseload, whereas they need to be directed to cover the costs of low utilisation peaking capacity.

Chapter 7
LOLP Theory

7.1 Introduction

This chapter describes the derivation of LOLP from basic principles and demonstrates how it relates to levels of investment and consumer LOLP payments. It is shown that the optimum level of investment is realised when the sum of the consumer LOLP payments together with the additional generator capital costs reaches a minimum. The results are tested against full operational simulations.

7.2 Theory

Loss of load probability (LOLP) is a function of time varying demand and generation availability. From statistical theory (Keeping) the availability of a number of generators 'n' is given by -

$$P_o^T = \frac{n!}{r!\ (n-r)!} \cdot P_0^{(n-r)} \cdot (1-P_0)^r \qquad 7.1$$

where P_0=availability

r= number of generators unavailable

Using actual demand profiles, a Load probability distribution curve can be established, which shows the period of time for which the demand is within a certain band, Dt

Then a measure of the probability of there being insufficient generation to meet the demand is established by comparing for each, generation availability, the number of demand period hours during which a shortfall would occur. The summated LOLP is given by:

$$\sum LOLP = \sum_{1,1}^{T,N} (H_{nt}(D_t > G_n)) \qquad 7.2$$

H_{nt} = number of hours when demand D^t > generation

Figure 7.1 shows the principle graphically where the demand probability curve is superimposed on the generation availability function. The area of overlap indicates where a shortfall would occur. The results are obtained by a computer simulation of the above theory. (see appendix 5 program LOLPCALC)

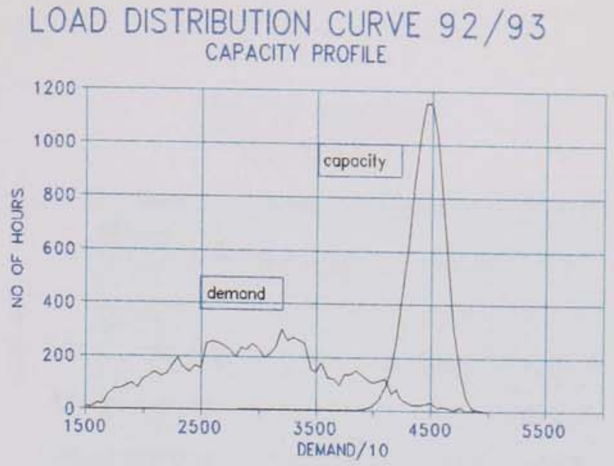


Figure 7.1

7.3 LOLP 'v' Margin

The theory has been applied to demonstrate the variation of LOLP with plant margin. The unit size was varied to represent a varying effective plant margin. Figure 2 shows the results for the 92/93 demand profile with two average values of generation availability levels ie 0.9 and 0.85. It can be seen that with the typical levels assumed of 85% that little change in LOLP occurs beyond the preferred 22.5% plant margin with the value falling to zero at 25%. Given a maximum demand of 48GW LOLP is effectively zero for margins above 12 GW (.25*48). This was the value derived from the regression fit to recorded values derived in section 3.4 and provides the basis for the simulation used in the model. It can also be seen however that if the average availability could be increased to 90%, then a 16% margin would be adequate. This then gives a direct means of comparing investment in improving availability with that for capacity to maintain security, i.e. -

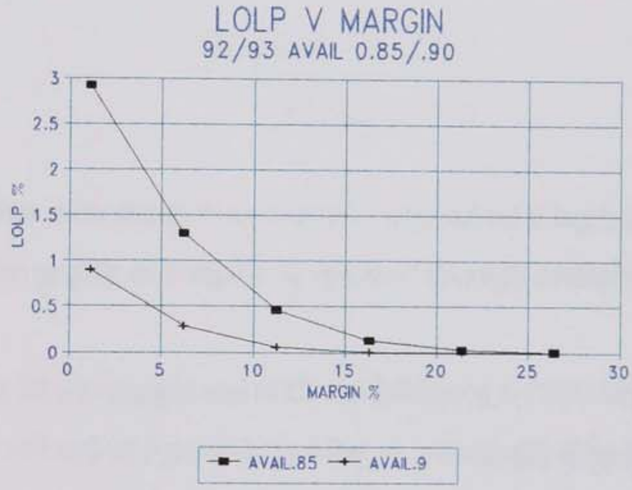


Figure 7.2

5% availability = 6.5% capacity

i.e. approximately 1:1 as would be expected.

A regression fit of LOLP to margin shows that :-

LOLP% = 0.04648-0.00173* MARGIN %

7.4 Comparison of Theory with Model and Actual

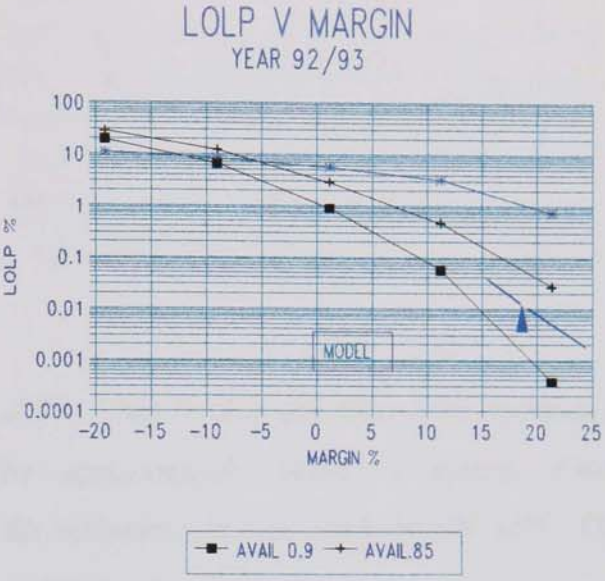


Figure 7.3

The time series model is designed to make an assessment of LOLP at each two hour sub-interval based on the plant margin at that particular time. The estimates are made using a function derived from regression analysis of actual recorded values of LOLP and margin.

Figure 7.3 shows the results from the time series model for the data available during the years 87-92 together with those from figure 2 plotted on a log scale. It can be seen that the model fits a similar profile and implies a value of average availability of approximately 87%.

It can also be seen that the LOLP with a 22.5% margin and 0.85 availability is 0.03% which would result in the probability of a loss of load of 3 periods in 100, as is normally assumed confirming the validity of the theoretical approach.

A comparison was also made of the time series model results with the actual recorded values for the January 1992 data. Although the actual demand and generation availability were not the same, a good comparison was achieved having corrected the results for inflation and the overall difference in availability.

ACTUAL		MODEL
SMP COST	£525 M	£534 M
LOLP COST	£34 M	£32.3 M
AVGE SMP	£19.75	£21.1
AVGE LOLP	£1.36	£1.25
PAYMENT		

7.5 LOLP 'v' Number of Units

Figure 7.4 shows the variation in LOLP derived from theory with the number of units whilst maintaining the same margin. It can be seen that little further improvement in LOLP results beyond the number of 100 units. Decreasing the number of units to 25 ,however, causes a rise in LOLP from .025% to 0.27%, ie. .245%. This implies that there is an optimum unit size to realise maximum availability approximately equal to system installed capacity/100.eg. For a 50 GW system the optimum unit size would be 500 MW. Other factors like economies of scale will also influence the choice.

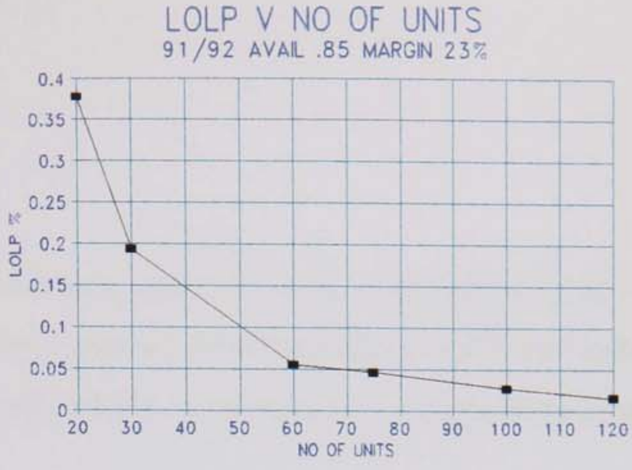


Figure 7.4

7.6 Benefits of Pooling

The implications of section 7.5 are that pooling generation using transmission enables an increase in security. Figure 7.5 shows a regression fit to the LOLP payments for varying LOLP derived from the full model run for the period 87-92. The function is -

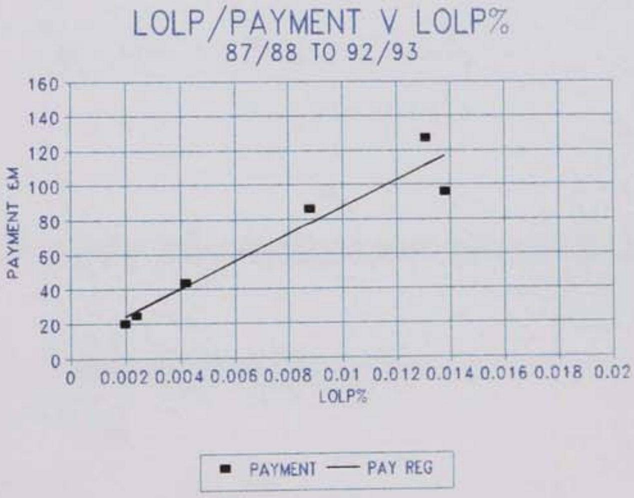


Figure 7.5

PAYMENT = 8.68 + 7828 * LOLP% £M

where LOLP is in %

and payment in millions

This provides a means of assessing the impact on LOLP payments of the change in LOLP from pooling generation. The change derived above of 0.245% is equivalent to an additional payment by consumers of -

PAYMENT = 7828 LOLP%

= £1910 M/yr

i.e. using transmission to pool 4 blocks of area generation each of 25 generators into one larger pool of 100 generators benefits the consumers in reduced annual LOLP payments by £1910 M. In practice the alternative option is for the generators to install additional units in each zone to raise the LOLP to an acceptable value of 22.5%. The benefit of pooling then reduces to approximately £455M. This then provides a direct means of comparing the relative worth of transmission versus additional generation capacity for improving security.

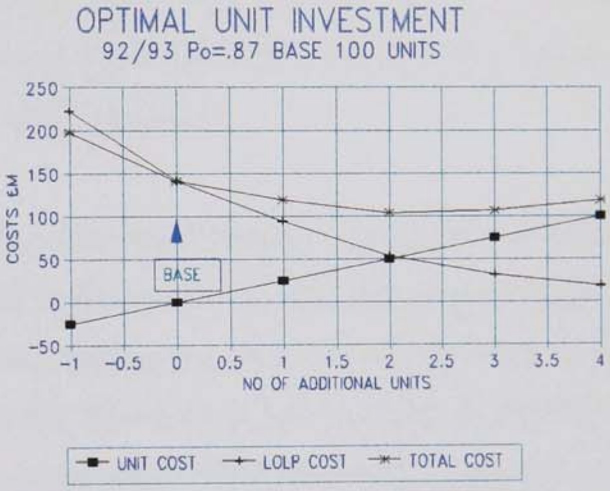


Figure 7.6

7.7 Optimum Investment Level

It is now possible to establish a function of the new investment cost plus the LOLP payments ie. the total societal cost.

The fixed capital and operating costs for an additional 500MW unit are:-

coal	nuclear	oil	ccgt
£30M	£43M	£25.5M	£13.6M
£120M	£172M	£102M	£44.4M (one unit in each area)

Assuming an average value of £100M a graph was drawn showing the cost of investment in additional units together with the LOLP payments derived from the formulation above of the impact of adding additional units on LOLP and its relationship to payments. Figure 7.6 shows this to reach a minimum to society when the additional generation costs equal the LOLP payments.This coincides with a value of 0.005% which is equivalent to a typical margin of 22.0% at the implied actual average availability of 87%.

7.8 Conclusion

We have derived an empirical relationship between LOLP and margins and also LOLP payment and LOLP which can be used to model and evaluate a large range of scenarios.

It has also been shown how the number of generators affects the LOLP, and this has been used to evaluate one of the benefits of pooling where coupling a four area system produces a saving in generation capital and LOLP costs of £455M. (Further savings will accrue from enabling a national as opposed to area MO optimisation)

Lastly it has been shown how the costs to society are minimised when the cost of additional generation equals the LOLP payments by consumers. In the base case shown in figure 7.6 it can be seen that,in this case, insufficient generation had been installed and commissioned by 92/3 to reach this optimum. However, this theoretical analysis provides a valid basis for assessing new plant needs equating to customer value . The current LOLP payments system is unlikely to realise this optimum as LOLP payments accrue to all generators rather than being focussed on encouraging just the new generation . Within an integrated utility accumulated LOLP payments would fund the capacity charge of new generation and would not be paid to existing generators who have already committed capacity. Other authors (Bunn 92) have also concluded that the current system is unstable and likely to lead to investment cycling. An alternative approach is advanced in chapter 10.

Chapter 8 TARIFFS

8.1 Introduction

Consumers buy electricity against a predefined tariff with a structure which depends on the size and nature of the load. The Suppliers in turn take supplies from generating companies against a bulk supply tariff. The determination of the tariff structures has traditionally been based on cost recovery and was fixed for periods of months but in a privatised environment other considerations apply. This chapter discusses the basic criteria involved in setting the ideal tariff and compares this with the current post privatised situation.

2.2 Basic Principle

The most efficient tariff should be one where the overall cost to society is minimised, taking account of both supplier costs and customer value

- the marginal price should reflect the prevailing marginal cost of meeting an increment in demand

- at peak times additionally the tariff should be set to reflect the cost of providing additional capacity

- the price should include operation and maintenance of transmission and distribution and losses

The consumers, for their part, should be able:

- to have a mechanism to react to the marginal prices by changing their demand curve and the price.
- to put a value on potential loss of load and the extent to which extra capacity should be provided to maintain security.

The situation will be in equilibrium when the value placed by consumers on energy and security equates with the cost to the supplier of their provision.

Post privatisation prices are set, based on what the market will bear irrespective of costs. They may be higher than costs with only competition from other suppliers acting as a cap. The importance of facilitating competition and enabling demand side participation is therefore paramount.

8.3 Price Derivation

To set tariffs, we need to predict marginal prices rather than use historic accounting costs. Short term plant changes will cause step changes in prices which would be unacceptable if they were reflected in tariffs. It is therefore preferable to establish long run marginal prices offering tariff stability.

The actual cost will be a function of marginal plant fuel costs and variable operating costs.

Capacity payments need to take account of all kW related components including generation and transmission. Typical figures are -

Generation 66%
Transmission 16%
Operation 6%
Maintenance 6%
Administration 6%

These in turn, need to be inflated to take account of transmission losses (typically 3%) and provision of a margin for security (typically 22%).

8.4 **Tariff Derivation**

The marginal prices on a half hour basis, have to be translated to a price for a quarterly tariff period where only simple kWh metering is available. The weighting for the individual half hour values will be optimal where the change in customer benefit equates with the change in costs for all periods.

$$)(dQ/dP+...dQ_n/dP)=m_1 dQ_1/dP_1+m_2 dQ_2/dP_2.. \qquad 8.1$$

where dQ/dP is the change in consumption with price
m is the period marginal cost
P is the price

The weights applied to derive the optimal P are then a function of the effect on kWh consumption of the change in price in each period. In the absence of specific information it might be assumed that the sensitivity to price is related to the consumption in the period i.e. -

$$P=\frac{m_1 Q_1+...m_{nQ_n}}{Q_1+....Q_n} \qquad 8.2$$

ie. the ideal tariff charge is the average of the marginal price in each half hour weighted according to the demand in the half hour. The model results are processed to produce this figure.

Similarly the capacity charge will be optimal when the value of lost load to the comsumer equates with the cost of providing additional capacity as discussed in chapter 7. (ref. Electricity Economics. TT Turvey and Anderson, World Bank).

8.5 **Actual Prices**

8.5.1 **Average SMP**

Given that the pool publishes prices in advance, and consumers can bid into the schedule, then in theory, customer value and cost will equate. This presumes ,however, that generators bid into the schedule at their marginal costs and in practice bids may be higher, particularly where generators are constrained by transmission limitations.

The average SMP is equivalent to the weighted marginal price as shown in equation 8.2 .The model result for 92/93 is £18.32/MWh, with an LOLP increment of 0.64 giving a PSP of £18.96/MWh. Adding additional capacity of 1000 MW in line with system expansion plans reduces this to £17.9/MWh. This is at base case fuel prices and correcting these for average fuel price inflation gives a value of £20.17/ MWh.

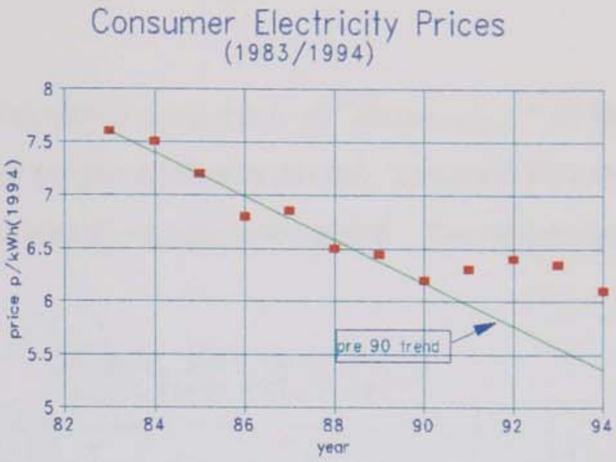


Figure 8.1

The published actual values for this period are £22.63 /MWh, i.e. some 12% higher than the true marginal value indicating an inflated price as suggested in press reports. Figure 8.1 shows statistics derived from the Digest of UK Energy (95). It can be seen that had the pre-privatisation trend continued prices would have fallen to 5.17 p/kWh instead of the actual level of 6.05 p/kWh. (These prices to end consumers include transmission and distribution prices)

8.5.2 **LOLP**

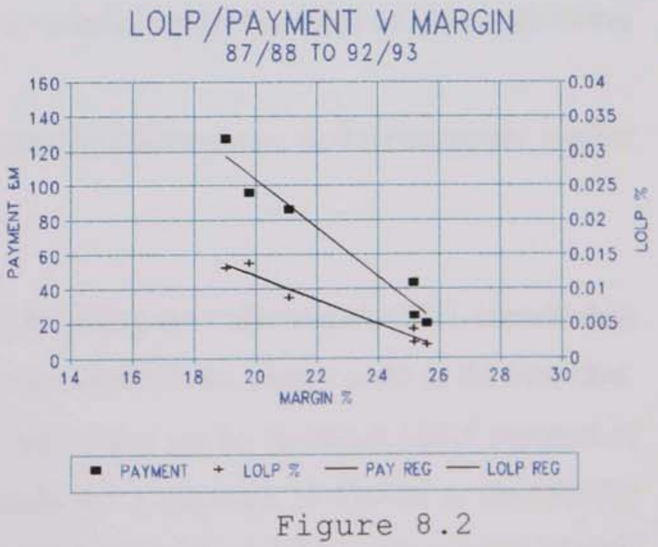


Figure 8.2

The LOLP payments for the year indicate the notional amount that consumers are required to pay to encourage additional plant availability at peak. The optimal value would be reached where it equates to the cost of providing the additional capacity. If it rises significantly above that value then the consumer is paying too much for capacity i.e.

above the market value. Conversely, significant smaller payments imply a system with over-capacity.

The annual LOLP payments have been calculated using the model simulation for all the periods in the years shown in Fig 8.2. They progressively rise through the period with the value for 92/93 being £127.3 M, if no additional capacity were added. The straight line regressions shows how the payment varies with plant margin.

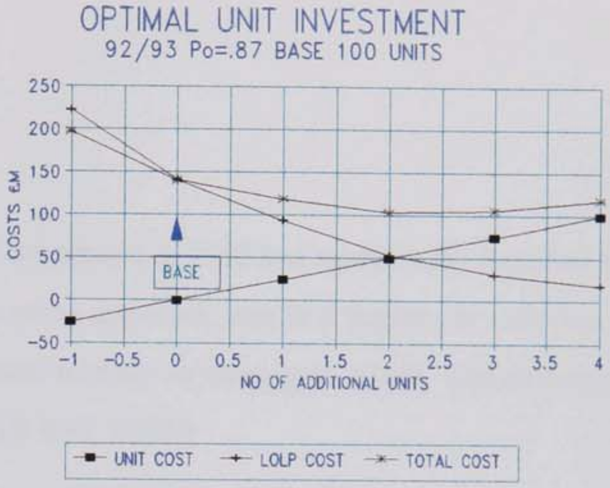


Figure 8.3

LOLP payment=385-14.089*(MARGIN %) 8.3

The graph also shows a regression fit of LOLP % against margin

LOLP% = 0.046482 - 0.00173*(MARGIN %) 8.4

8.6 **Optimal Investment**

To establish the optimal investment level we need to model the effect of adding additional units.

In chapter 7 on LOLP theory we showed that the full simulation model parameters implied an average availability of generation Po of 0.87. Using this value with the 92/3 demand data and a unit size of 583 MW and 100 units we replicate the plant margin in the base case. The results obtained from this full model simulation are for an annual LOLP payment of £127m. Using the LOLP payment formula 8.3 a payment of £140M is derived.The calculated results are sufficiently close to enable the impact of changing the number of units to be assessed using the simple formula. This is demonstrated in Fig 8.3

(LOLPOPT2.WQ1) where the consumer payments are shown together with the the additional costs of new generation capacity. The optimal occurs when an additional 2 units are added to the base case reducing the payments to £44m.In practice some additional capacity has now been added leaving the actual recorded LOLP payments at approximately £42.7M.This in part resulted from the plans laid by the CEGB.

In practice LOLP is the subject of gaming by the large generators. They can forsake availability payments on a few units and drive up LOLP which increases the income on all units sold.

8.7 **BST**

The Bulk Supply Tariff (BST) was first introduced in 1949 and traditionally included a kW and kWh component. The marginal costing approach was first applied in 1968 but was distorted by the need to provide additional revenue to meet govt. needs. The structure for 1988/89 was as shown below(ref CEGB BST 88/89)

Capacity Charges £/kW		
	Peak	23.5 (average 3 1/2 hrs-Triad)
	Basic	20.0 (average 300 ½ hrs)
Unit Rates p/kWh		
	night	1.57 (2400-0800 hrs)
	day	2.16 (0800-2400 hrs)
	surcharge	1.0 (peak)

(The Triad refers to the three non consecutive half hrs of maximum demand during the year separated by more than 10 days.)

The calculated payments for the base year are:-

Basic capacity payments	£861M
Triad	£1102 M
Energy payments night	£1100 M
Energy payments day	£3911 M

Comparing these with the model costs it is neccessary to add in uplift costs to take account of active transmission constraints and inflation.

	BST	MODEL
ENERGY PAYMENTS	£5011 M	£4628 M
CAPACITY PAYMENTS	£1963 M	£24 M
TRANSMISSION		£1000 M
AVAILABILITY	______	___5 M
1988/9	£6974 M	£5657 M
EQUIVALENT SMP	£19.9	£18.36

It can be seen that the BST recovers slightly more than the base case cost estimated with the model. The most striking difference, however, is the high capacity element included in the BST. This may reflect the Government policy of the time related to negative external finance limits requiring debt repayment from the ESI.

8.8 Comparison of Actual PSP with BST

The recorded pool selling price (PSP) includes both capacity and uplift costs and is equivalent to the energy charges to the RECs contained in the BST. The structure quoted in 88/89 BST has been assumed to apply in future years with prices increased in line with fuel prices. The comparison with the published PSP shown in Fig 8.4 confirms that the PSP has risen in excess of inflation.(The fall towards the end of the period coincided with threats from the Regulator at the time of the generator price review.) The graph also shows

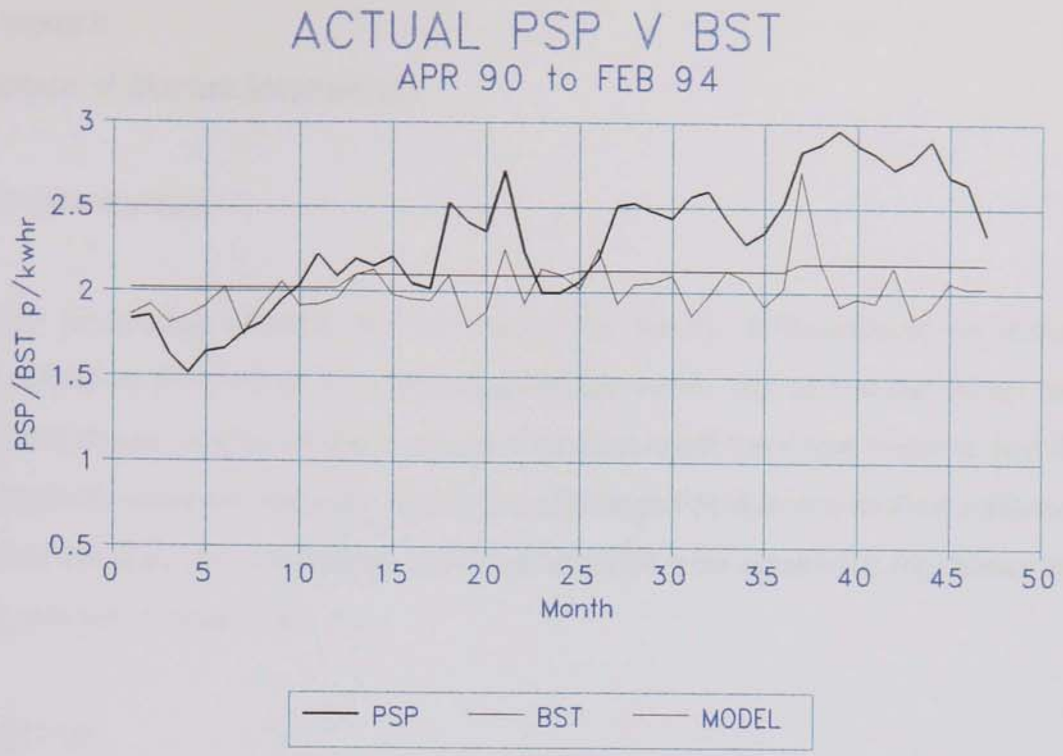


Figure 8.4

those values derived using the model with known heat rates and fuel prices. These results align approximately with the BST profile confirming this to be a a reasonable estimate.

8.9 **Conclusions**

This section has shown the derivation of idealised marginal capacity and energy charges which equate to consumer value. Analysis of actual results against the full production simulation shows energy rates at some 12% above marginal costs. However, the expansion plans, laid in part by the CEGB, have resulted in the LOLP capacity payments being close to optimal and consistent with a plant margin of 22.5%.

A comparison was made between the BST and Pool charges as would have applied in 88/89 and the most striking difference is in the large BST capacity payments which reflect govt. financing policy of the time.

The graph comparing published PSP with extrapolated BST energy charges comfirms the view that energy prices have risen in excess of normal inflation and underlying costs by some 12%.

Chapter 9

Review of Market Mechanisms

9.1 Introduction

The preceeding chapters have developed the theory under-pinning the market and reviewed its perfomance by analysing published results. An operational model has been developed and used to compare out-turn with what might have been expected had the pre-privatisation regime continued. Theory was developed to illustrate an ideal solution which would minimise costs to society. This chapter reviews the results and the shortcomings of the current arrangements.

9.2 SMP

Chapter two described the derivation of SMP and how, during table 'A' periods, the marginal unit, which may only be part loaded for a short period, will have to bear the full start up costs. This integer effect inevitably leads to spikes in the half-hour pool price.

In the medium term it can be seen from figure 3.6 that there is an increasing standard deviation in prices. This may result from the absence of coordinated outage planning. Figures 8.1 and 8.4 show prices continuing to rise in excess of what would be predicted based on costs.

There appears to be no effective mechanism to enable the demand side to bid into the market against known prices to constrain rises either on the day or in the medium term. There is also no apparent mechanism to encourage optimal outage planning. It is therefore expected that prices will continue at a high level and exhibit volatility which will exacerbate the problem of investment appraisal for both generators and those wishing to invest in demand management facilities.

9.3 Plant Mix

Chapter 6 described the relationship between SMP and plant mix. It was shown that the profits of base load generators are greatly influenced by the periods of high marginal price set by peaking capacity. The market mechanisms do not differentiate so as to encouage investment in peaking capacity.

In the classical approach to investment appraisal peaking capacity becomes attractive when the summated operating and capital costs spread over the expected running period fall below the costs of more capital intensive base load plant. The market does not explicitly cover capital costs which are expected to be financed by the LOLP increment to prices. However, the LOLP payments are distributed to all generators according to energy produced rather than to encourage the retention of peaking units. It was suggested that special ancilliary service contracts should apply but in their absence the consequence has been the whole scale closure of OCGT's.(ref NGC Seven Year Statement)

In the absence of market signals to encourage an optimal plant mix all new entrants are likely to expect to operate base load and in time either prices will rise to cover the sub-optimality or some generators will suffer losses when operating at part load and may go into liquidation.

9.4 Margins

In chapter 7 an empirical relationship was established between LOLP and plant margin and LOLP and LOLP payments. It was shown how the optimal for society would occur when the value of LOLP payments equated to the fixed costs of additional generation at a margin close to the normally assumed ideal of 22.5%. This formulation only applies, however, if there is only one new generating company receiving all the benifit of LOLP payments. As in practice the payments are distributed amongst all generators there is inadequate incentive for an individual generator to retain marginal capacity. The distributed LOLP payments also artificially inflate prices for base load units and may encourage the over capacity shown in figure 3.4.

Short term LOLP payments provide no indication of future capacity needs and are just as likely to reflect inadequate coordination of outage planning. They are also not sustained in that any new generation will cause an immediate reduction.

The current mechanism appears subject to gaming by the large generators who could forego availability payments on some generators, not likely to be selected to run, to inflate LOLP and more than recover their losses on the LOLP payments on all the energy supplied during the period.

9.5 Transmission Uplift Costs

In chapter 7 the benefits of pooling generation were derived. The current Transmission Services scheme is not based on the benefit provided by transmission but rather the cost of its constraints. While the Transmission company is incentivised to contain uplift cost there is no direct incentive to encourage investment in new transmission, with its regulated returns, if more profit can be earned through managing uplift. The removal of constraints would remove this business opportunity.

There is no commercial mechanism to encourage the ideal level of transmission investment where costs are in balance with benefit.

The outturn SMP will be different to the predicted unconstrained value because-

- transmission constraints will be active and some generation will be forced on and others forced off
- generation will be lost or subject to reduced availability between the time of bid and the event
- the demand prediction will be in error

The price consumers pay has to cover all the above costs in the event but they are only advised in advance of the day ahead prices. Their opportunity to react to actual prices is therefore limited.

The current price setting mechanisms ignore transmission constraints but in practice generator are aware of constraints and their bids can take account of this with no competitive zonal market price signal to contain this. Consumers have no prior knowledge of constrained zones and are not therefore able to engage in this market.

9.6 Conclusions

This chapter has shown that the current market and payment systems based on SMP and LOLP has significant shortcomings. The pool SMP is volatile and does not take account of zonal variations due to transmission constraints or reflect outturn. It does not therefore enable consumers to plan there reaction. The LOLP system may provide an indication of total system need for new capacity but does not cover a particular generators capital costs or encourage the optimal plant mix. The current Transmission Services scheme will not encourage the optimal levels of investment in transmission if the transmitter can realise more profit by managing constraints when only cost recovery would be allowed on new investment to remove the constraint.

Chapter 10

A Medium Term Market based on Lagrangian Relaxation

10.1 Introduction

In chapter 10 it was shown that the current market mechanisms do not provide a sound basis for future investment planning. A short run marginal cost approach (SRMC) is not appropriate to capital investment with long lead times and is unstable . A long run marginal cost technique (LRMC) is proposed based on lagrangian relaxation techniques. It is suggested that this will provide a more stable basis for both investment appraisal and setting tariffs and lead to a an out-turn delivering maximum benefit to society.

10.2 The Requirement

Investors need to have an estimate of future payments to support decision making.

The market should operate competitively without bias and enable generators and suppliers/consumers to participate equally.

There is a need for data confidentiality to protect commercial interests.

The system operator needs to be able to influence the plant margin and its mix and manage outages to secure the power system.

In an attempt to circumvent the uncertainty in the market many players have chosen to set up hedging contracts for differences. The energy sale price is fixed by prior agreement and any over or under-payments through the pool against SMP are settled separately. This effectively undermines full competition through the market and does not therefore meet all the criteria.

The requirements can be met with competition by all players agreeing to submit plan data to enable a simulation of operation through future years using a production model. The derived hour by hour system marginal price then equates to the Lagrangian multiplier for demand and enables an individual generator or consumer to assess his worth or costs without a knowledge of competitors data.(see appendix 4) Each proposal for outages, new generation or closures would be added to the simulation by a pool administrator in much the same way as NGC operate the day ahead market.

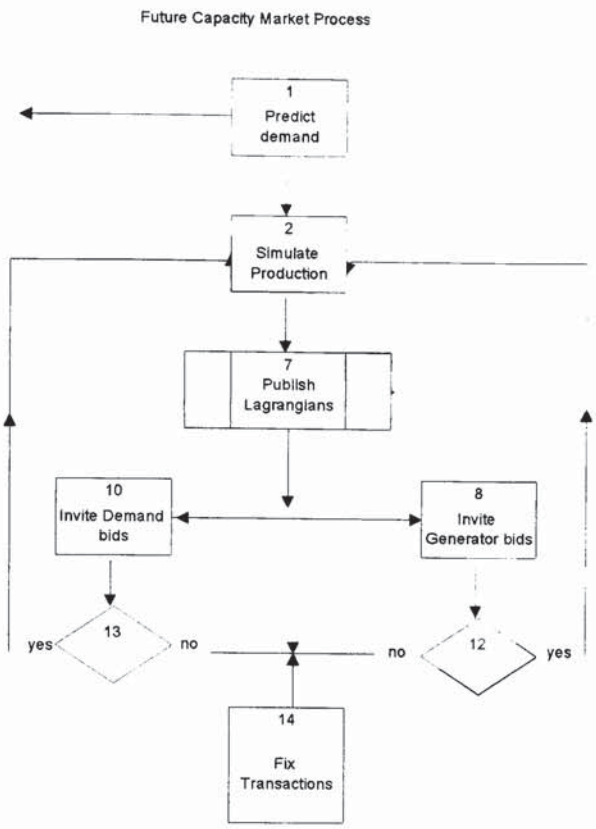


Figure 10.1

10.3 The Process

The overall process is shown in figure 10.1 and would consist of the following steps.

-The initial demand prediction would be based on suppliers estimates.

- Given the starting generation available an initial production simulation would provide the system marginal prices and security index ie. the demand and security lagrangian multipliers.

-Individual generators would assess the profitability of existing and new generation and either bid in new capacity or closures. Demand side bidders would also have the opportunity to bid in reductions or increases.

-Given the new bids the production simulation would be rerun and the new lagrangian multipliers published.

-The process would be repeated until the demand generation mismatch was within a defined tolerance when transactions would be fixed.

10.4 **The Theory**

The system objective function is to establish that multiplier 'lambda' that results in total generation offers 'G'and demand bids 'D' for energy equating and capacity bids equating to the security level 'beta' required by customers ie.find

$$f(\lambda_t)\ sothat\ \ G_t = D_t \qquad 10.1$$

$$f(\beta_t)\ so\ that\ A_t - D_t \geq f(lolp) \qquad 10.2$$

Individual generators will seek to maximise their profits, the difference between income and costs which may be assessed independently making use of the lagrangian multipliers to calculate energy and availability payments.ie.

$$P = \sum \lambda_t * g_{i,t} + \sum \beta_t * A_{i,t} - \sum [g_{i,t} * vc_i + STC_i] \qquad 10.3$$

where 'g' is the individual generator output and 'A' its availability and

$$\beta_t = lolp(vll - smp)$$

The consumers will respond to the multipliers so as to minimise their costs.

$$\sum (\lambda_t * d_t + \beta_t * d_t) \qquad 10.4$$

The overall process will be to adjust the multipliers for each period so as to realise convergence .The subgradient method is a technique that may be used where

$$\lambda_t = \lambda_{(n-1)t} + \alpha(R_t - A_t) \qquad 10.5$$

where R=required and A=actual, 'a' and 'b' are constants and

$$\alpha = \frac{1}{a + k * b} \qquad 10.6$$

To enable decisions to be made in planning timescales figures would need to be published for 1-5 yrs ahead.

The process will lead to a balance being reached between what consumers are prepared to pay and generator prices. The appropriate plant margin should result with a generator covering the cost of retaining spare capacity to cover his commitment and a supplier paying for spare capacity to cover any demand under-estimation on his part. In both cases the responsible party makes the assessment. It should also produce a solution close to the overall optimum, when prices equate to costs, in that any generator bidding in in excess of costs is likely to be under-cut by a competitor.

The objective function of the market administrator would be to minimise the total generation operating cost over the period of the schedule ie., running and start-up costs based on the submissions.ie minimise

$$\sum_{1}^{t}\sum_{1}^{i} VC_i(G_i(t)) + STC_i \qquad 10.7$$

Subject to:

$$\sum_{1}^{i} G_i(t) = D(t) \qquad 10.8$$

ie the generation requirement being met and the generator operating between upper and lower limits ie .

$$UL_i(t) \leq G_i(t) \leq L_i(t) \qquad 10.9$$

and satisfying the minimum up and down times

$$\begin{aligned} U_i(t) &= 1 \quad if\ 0 \leq X_i(t) \leq MNUP_i \\ U_i(t) &= 0 \quad if\ -MNDN_i \leq X_i(t) \leq 0 \end{aligned}$$

where Xi(t) is the cumulative time of the unit. The time resolution of the model would not warrant the inclusion of run up and down rates which in practice would have little impact on the overall energy market.

The reserve requirement must be met ie.

$$\sum_{1}^{i} U_i(t) \times RES_{i,j}(t) > RESR_j(t) \qquad 10.10$$

Where the reserve function is maximum at the defined optimal load point. Where network constraints exist a full network solution at each time step would be impractical so it is proposed that these constraints are represented by group limits around key import and export areas. The unit must then also obey the group limits between exporting and importing constraints ie.

$$\sum_{1}^{i} G_i(t) + RES_{i,j}(t) < EXP_a(t) \qquad 10.11$$

ie the net capability of the zone to export generation together with local demand.

Similarly for import constraints

$$IMP_a(t) < \sum G_i(t) \qquad 10.12$$

the sum of the generation must be such as to contain imports to meet local demand.

The problem can be made tractable by decomposing it to individual unit solutions by including the coupling constraints in the cost function ie., generation requirement, reserve and transmission limits using the Lagrange multipliers. The solution of the primal problem with multiplier fixed can then proceed.

The dual variables are:

lambda (t)	generation
alpha (t)	reserve
gamma (t)	export area a
epsilon (t)	import area a

and the object function is now to minimise

$$
\begin{gathered}
\sum_t \sum VC_i \; (G_i(t)) \\
+STC_i(X_i \; (t), U_i \; (t)) \\
-\lambda(t) \times G_i(t) \\
-\sum_j \alpha_j(t) \times RESj(G_i(t), OHL_i(t))_1 U_i(t) \\
+\sum_a \gamma_a(t) \times \sum G_i(t) \\
-\sum_a \epsilon_a(t) \times \sum G_i(t)
\end{gathered} \qquad 10.12
$$

where lambda is the shadow cost of the demand constraint and will equal the system marginal price at the solution.

Combining and re-defining the multiplier as GAM_n in the above reduces to

$$
\begin{gathered}
MIN\sum_t \; (VC_i(G_i(t) \times U_i(t) + STC(X_i(t) \times U_i(t) \\
-\sum_1^n GAM_n(t) \times Q_{n,i}(t) \times U_i(t))
\end{gathered} \qquad 10.13
$$

where $Q_{n,i}(t)$ is the amount unit (i) contribute to constraint n

Starting with an initial set of multipliers the primal problem could be solved by varying the primal decision variables ie generation. This solution would then be used to check the constraints and update the multipliers by the subgradient method ie.,

$$
\begin{gathered}
GAM_n(t) = GAM_n(t-1) + ALPH_k \times (REQ_{n,t} - \sum_i Q_{n,i}(t) \\
ALPH_k = \frac{1}{(a2 + k \times b2)}
\end{gathered} \qquad 10.14
$$

To make the problem manageable it would be neccessary to represent each year by a group of representative days and aggregate the results. Each player would receive details of his utilisation and the resulting system multipliers and be invited to revise or add new bids. Price variations would be enabled for each of the chosen representative periods.

10.5 **Commercial Arrangements**

Capacity payments could be derived from a pool paid into by suppliers interested in securing future supplies and withdrawn by prospective future generators. Individual generators would contract to supply future capacity against a market capacity price that would be met by suppliers and indirectly related to the published security index. The capacity payments would be made by the supplier annually enabling generators to cover interest payments. The future price would vary annually depending on the margin and what suppliers were prepared to pay to secure future supplies. Any energy required not covered by prior contracts would be traded in the day-ahead market.

It would be neccessary to ensure that, having participated in the process, players implement their proposals or incur penalties. One option would be for shortfalling generators to pay into the pool the difference between his bid and outturn and the prevailing value of lost load. Consumers with reduced demand would make up the lost profit. Some flexibility would be neccessary to meet the changing circumstances that may occur during long costruction periods. This could be met by enabling capacity trades between generators or swaps where both a generator and consumer agree to change their bids equally.

10.6 **Other Improvements**

The derivation of SMP could be improved by basing it on a block of say 100 MW related to a generator module rather than a single MW increment. This would remove some of the extreme volatility seen in prices.

Another concern is the high cost of unpredicted uplift and a better relation to outturn charges could be achieved by using a probabalistic prediction of outturn generation availability for the schedule. The predictor would reduce average availabilities in line with normal expectations and cause additional marginal plant to be scheduled as would occur in practice.

The uplift in out-turn prices due to transmission constraints could alternatively be derived from the shadow prices of a transmission constrained schedule. These zonal prices would then enable a more meaningful predictive market and minimise gaming by generators.

10.7 **Benefits**

10.7.1 SMP

The opportunity for suppliers to fully participate in the future market should provide a means of containing price escalation. The ability of the market to coordinate outage planning would ameliorate price volatility.

10.7.2 Plant Mix

The production model will provide a profile of the margin and price throughout the year and enable generators to offer the optimal type of plant to complement any shortfalls in the profile of the margin. Equally suppliers could offer to shed blocks of demand and receive compensation accordingly.

10.7.3 Margins

The data available from the five year ahead planning process provides a means of coordinating investment to avoid over-capacity in excess of what suppliers are prepared to pay.

10.7.4 Uplift

The use of a constrained schedules and zonal prices should provide an indication of the impact of uplift and enable suppliers and generators to trade within constrained zones.

10.8 **Conclusion**

The proposal would enable the benefits of integrated planning to be realised without destroying the market concepts. The process of decomposition also maintains the neccessary data confidentiality and avoids placing commercial responsibility on the pool administrator. It offers the opportunity for full demand side participation. The pool would need to agree the model and process.

Part 2

Generation Investment Appraisal

Chapter 11

BASIC PRINCIPLES

11.1 Classical Approach

The CEGB approach to generation investment appraisal was aimed at meeting demand at total minimum cost. Predictions were made of future demand and prospective plant closures and new generation would be planned to maintain a plant margin of some 22.5%. The type of plant chosen would be that which progressed towards the optimal mix and maintenance of diversity. The costs in meeting the additional demand would be recovered by increments to the BST. The problem was formulated as an LP with the objective function of minimising the total production and capital costs. The program used by the CEGB was called Lpmix, other programs like EGEAS (EPRI) and WASP have also been developed to address this requirement. The final descision on plant type would often be influenced by national considerations related to the security of fuel supplies or the preservation of indigenous fuel industries. Various other authors (Gorestin 93) have proposed multi-stage decision techniques using dynamic programming to address uncertainty in the data. The objective functions are then to minimise the 'regret' that could occur by maintaining flexibility with plant with short construction times. This enables a change in capacity as actual future load and conditions become clear. Other approaches (Tanahe 93) seek to manage the uncertainty by identifying the probability functions of the key variables and applying statistical techniques. Multiple trade-off analysis has also been proposed as an aid to decision makers (Huber 93). Several authors discuss the application and shortcomings of current techniques (Bunn 92, Merril, Head 90). Other authors (Caramanis, Sherali 90) have addressed the impact of non-dispatchable and non-utility generation (Siddiqi 94) but not a fully deregulated competitive generation market. This chapter demonstrates that the classical approach will not model the behaviour of deregulated generators and introduces a new approach.

11.2 Pre privatisation Approach

The problem was formulated as an LP with the objective function of minimising capital and running costs while meeting demand and generation constraints .

ie.. Minimise:

$$\sum C*I_j \cdot DNC_j + \sum_{j=1}^{J} \sum_{t=1}^{T} VC_j \cdot MW_{j,t} \cdot A_j \qquad 11.1$$

Subject to:

$$\sum_{j=1}^{J} MW_{j,t} = DEM_t$$

and:

$$MW_j \leq DNC_j$$

solve for:

$$DNC_j$$
$$MW_{j,t}$$

where:

$C*I$=fixed capital costs
DNC=capacity
VC=running costs
MW=load
A=mean availability
t=period of one month

Table 1 Existing and Planned Capacity by Plant Type at Privatisation

PLANT TYPE	AVAIL	NP	PG	NE	FIXED +CAP £/kW yr	VAR £/MW Hr	VAR £K/ month
small coal	.77	1432	-	-	70	22	16
med coal	.77	2362	1944	-	65	17.75	12.9
large coal	.77	13168	9823	-	60	15.0	10.9
oil	.8	4484	4005	-	51	20.25	14.7

occgt	.8	1417	521	-	17	48	35
magnox	.72	-		3250	90	7	4.9
agr	.72	-		6195	88	6.75	4.85
pwr	.72	-		1198	56	6.5	4.8
ccgt	.8	-		-	30	14	10.2
							*.73

In a mature situation it is neccessary to model the existing generation capacity by plant type as well as new generation options. As the capital cost of the existing generation is already commited it is omitted from the formulation. For new generation both capital and running costs are included. In the case of nuclear generation an upper bound is placed on new generation reflecting enviromental constraints. For existing generation of older type which would be uneconomic to build today it is included without capital costs and an upper bound is included representing the installed capacity to avoid utilisation above capacity.

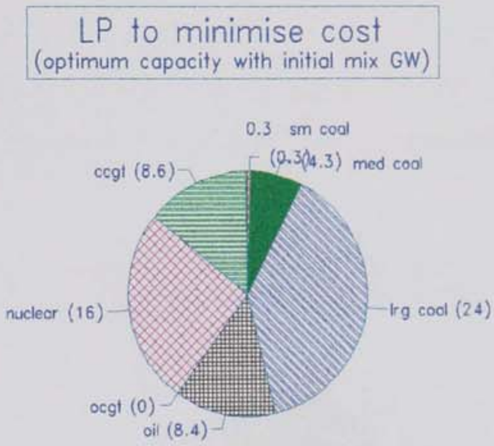


Figure 11.1

The demand is represented by a load duration curve with values chosen to represent each 1/12 of the period. The variable costs are scaled up to equate to the cost of running for 1/12 of the year i.e. 730 hrs.

The results are shown in figure 11.1 where the optimal capacity of new and retained generation is shown in GW. It can be seen, by comparison with the initial generation shown in the table, that the existing capacities of medium and large coal plant are retained but at reduced utilisation but the tranche of small coal is reduced from 1.432 to 0.3 GW . Oil is similarly retained at reduced utilisation but open cycle gas turbines are unused and therefore a candidate for closure as has occured in practice. Nuclear shows some increase confirming the case for Sizewell B. The largest increase is in the tranche of CCGT's shown to be economic at 8.6 GW. This is the optimal addition based on cost but lesser amounts will be shown to produce more profit when operating in a pool at marginal prices.

11.3 Post Privatisation

The above approach does not address the post privatisation needs where individual generators now seek to maximise their return on investment against market marginal prices. The new objective function for the generators is to maximise their profit and if they were to act in unison this could be formulated as an LP with the income based on the marginal incremental price during the period. The complication is that the choice of generation affects the marginal price which in turn affects the income. The problem therefore requires an iterative approach to determine the marginal plant type and price in each period. This is then used to calculate the profit per unit of each type of generation for inclusion in the objective function which is set to perform a maximisation. Any changes to the marginal prices in any period requires a change to the profit per unit in the objective function and the process then has to be repeated. As an initial starting point for the new LP the previous cost minimisation solution provides a suitable base.

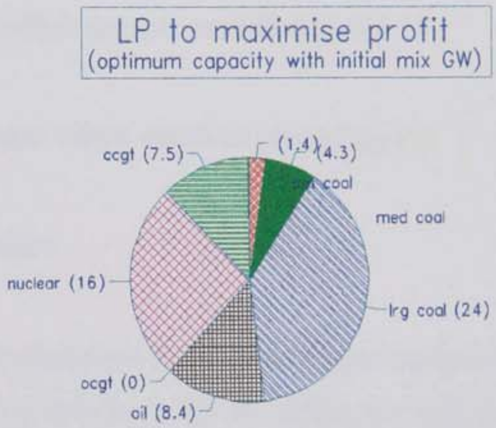


Figure 11.2

The new LP formulation is to maximise the income at SMP less the capital and operating costs ie.:

$$\sum_{j=1}^{J}\sum_{t=1}^{T} SMP_t * MW_{j,t} - \sum C*I*DNC_j + \sum_{j=1}^{J}\sum_{t=1}^{T} RC_j * MW_{j,t} * A_j \qquad 11.2$$

where SMP is the period marginal cost during the period 't'. A spread sheet function was used to derive the maximum incremental price in each period and this was used to set the SMP profile. The objective function was then expressed as a function of the period SMP less the incremental price of the particular generation type.

The new formulation will favour base load units which now receive all income at marginal prices. It will also tend to reduce the benefit of replacement of high priced units because of their disproportinate effect on total income through marginal prices . The results demonstrate this with the maximum profit is now realised with a higher proportion of small coal being retained (1.4 GW) and a correspondingly lower level of investment in new CCGT generation (7.5 GW) as shown in figure 11.2.

11.4 Shortcomings

Whilst the above approach provides a global indicator of the total need for new capacity the LP approach is unsuitable because of its coarse time resolution and the absence of dynamic modelling. The time varying SMP function is the fundamental factor affecting profit and more detailed models are therefore neccessary to establish a more robust assessment including the following.

- the time varying SMP profile
- the inclusion of LOLP
- the different dynamic characteristics which are not modelled in the LP formulation.
- the likely market share of each generator which involves predicting the behaviour of competitors.

These issues are addressed in subsequent chapters

11.5 **Conclusion**

This chapter has shown that the classical LP formulation of the generation expansion problem, based on cost minimisation, is not a suitable basis for modelling the behaviour of generators, seeking to maximise profit, in a deregulated market. This arises because, when the income is assumed to be based on the marginal cost, it may be more beneficial to retain higher priced units to continue to set SMP high and hence total income rather than replace the unit with a cheaper one which would drive down SMP. If the generators continue to add capacity so as to displace the need to use relatively expensive units at the margin then this result shows that it will have a significant effect on their overall profit.

An alternative LP formulation based on profit maximisation has been developed but it provides only a coarse representation of marginal prices and optimal capacity additions. To model the income function based on marginal prices with any accuracy a dynamic representation based on hourly periods is neccessary as well as prediction of market share. The next chapter discusses the use of the full operational simulation for this purpose.

Chapter 12

Predicting SMP and Income

12.1 **Introduction**

The previous chapter demonstrated how a global assessment could be made of the amount and type of generation it would be profitable for generators to add to the system. This chapter shows how a detailed appraisal can be made to estimate the profit for a particular generator incuding the effect of dynamics. To enable individual generators to predict the likely income from the pool and contracts for differences outside the pool they need to be able to predict SMP and LOLP. The assessment of operating costs will need to be based on the estimated utilisation and operating regimes. Generators with existing capacity will additionally have to take account of the impact of new generation on the utilisation of their existing capacity.This chapter describes an approach to calculate income and profit and how to predict the SMP/LOLP profile on which it is based.

12.2 **Estimation of Income**

A generators income is primarily fixed by the energy payments at pool selling price where

$$PSP=SMP+LOLP(VLL-SMP) \qquad 12.1$$

as set by the unconstrained schedule. An exception is where the generator is forced on or off by active transmission constraints when payments are made at bid price. Additional payments for availability and other ancillary services are usually small in comparison.

The utilisation of a prospective generator can be established by the intersection of its bid price with the system marginal price function. If the number of periods when the bid is less than or equal to the PSP is defined as 'n' then the income is the sum of the energy generated in the prevailing half hour multiplied by the associated marginal price ie

$$Income I=\sum^{t=n} MWAV_t * PSP_t \qquad 12.2$$

where MWAV is availability for the period

This is calculated by establishing an annual SMP profile using the full operational model coupled to a separate computer program (COMCOST) developed as part of this thesis to calculate the intersections when bid equals SMP and hence utilisation and income.(see appendix 5)

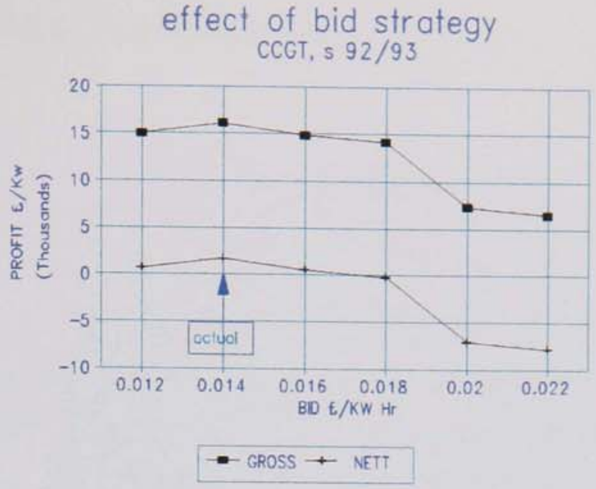


Figure 12.1

12.3 **Bidding Strategy**

In the long run, generators will tend to bid at the real incremental price of their generator if a true market is in operation. It can be shown that this will realise the maximum running hours and hence maximum contribution to their fixed costs. Higher prices will result in less running hours, lower prices will incur a loss if the bid price is set lower than the actual cost. Generators when operating close to the margin will therefore tend to bid in at actual incremental cost as would be expected in a perfect market .The operational model was used to simulate operation for a year to assess the effect on utilisation and profit of varying bid prices. The submissions were assummed to be based on the lowest slope intersection with the cost curve ie. the table 'A' value. Figure 12.1 shows the effect on the annual profit of a CCGT generator and it can be seen that the optimal return occurs when bid price equals the actual marginal price assumed in this example to be £.014/kWh. When the generator is not marginal its bid has no effect on its income unless it is constrained on or off. The above analysis will not apply ,however, where a duopoly or cartel is in operation when prices and income can be raised in unison without fear of loss of market share.

12.4 **Generator Costs**

The generator costs are made up of fixed capital and operating costs and varying fuel related and other operating costs. The effective average price is given by

$$P_e=(I*C+FC+A*U*VC*365*24)/(A*U*365*24) \qquad 12.3$$

where I=interest rate

C=capital cost

FC=fixed cost

VC=variable cost

A=average availability

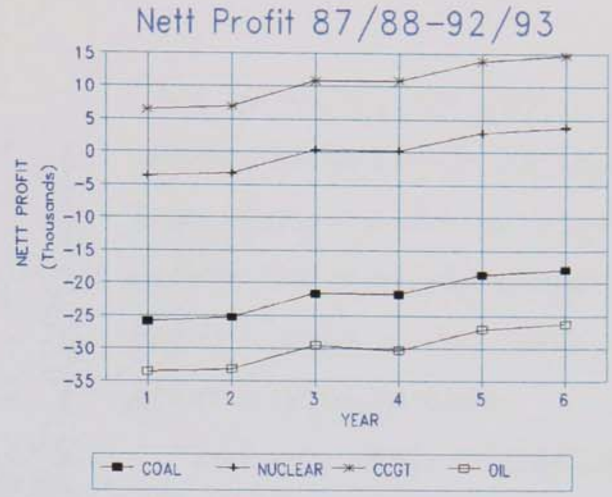


Figure 12.2

12.5 **Profit Forecast**

Using the full operational model to simulate operation for each year I calculated the SMP profile, income and costs as described above in 12.2 and 12.4. The profit/kW has been calculated on both a gross and net basis. The gross includes fixed operating costs but excludes capital costs, the net includes capital. A calculation for each of the years of operation is necessary to establish an overall return on capital employed. It is also neccessary to take account of the construction period when costs will be incurred without income and any decommissioning costs. In practice prediction beyond the first few years would be very speculative in a competitive market where the plans of other players are unknown. The net and gross profit for typical generation types are shown in figures 12.2 and 12.3 through a six year period when no new generation is added. It shows how the profit increases in line with demand,system marginal price, and LOLP. CCGTs and nuclear are shown to be expected to move into profitability, with the assumed costs, towards the end of the period. The results will change as new generation is commissioned which reduces the marginal price and income.

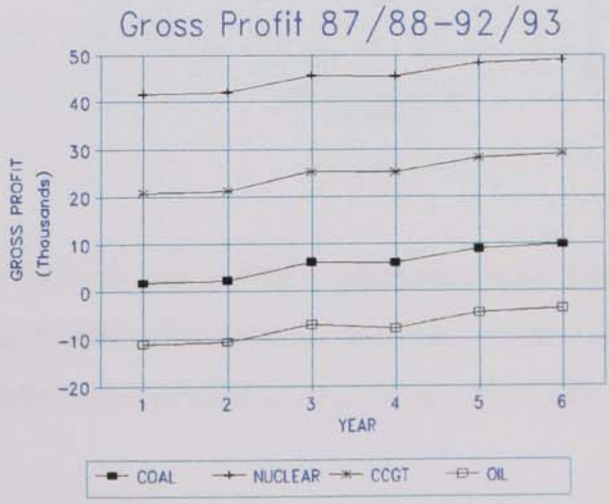


Figure 12.3

12.6 **Predicting Utilisation**

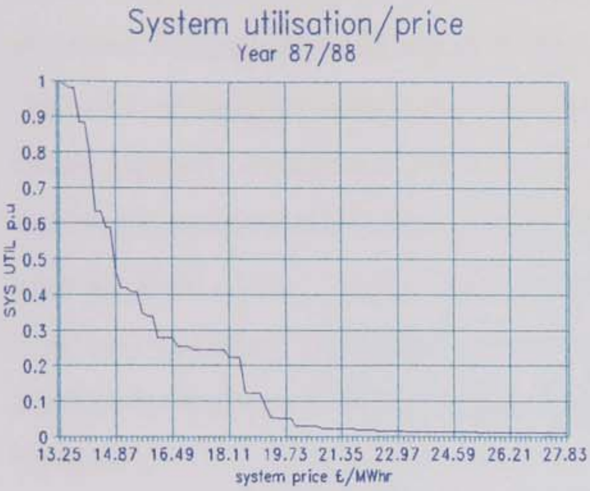


Figure 12.4

The key parameters affecting future utilisation are normally the rate of growth in demand and its profile; the incentives to maintain optimal margins and mix; and relative changes in fuel prices .These factors are discussed below.

Figure 12.4 shows a typical system utilisation/price curve derived using the operational model. The discontinuities reflect differing plant dynamic characteristics.

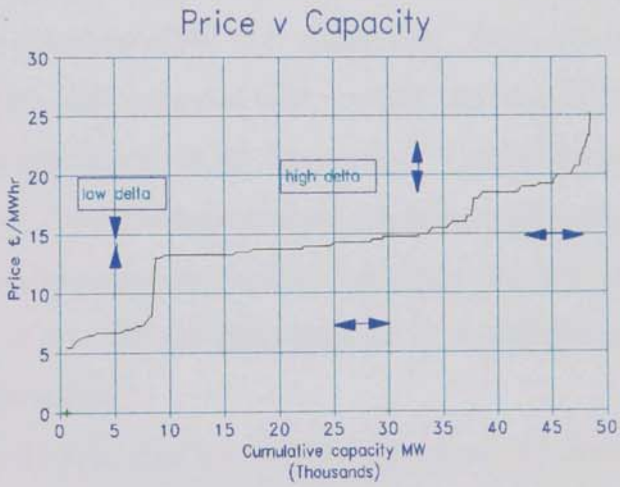


Figure 12.5

Whilst total demand growth may be known ,in the post-privatised situation it will be very difficult for individual generators to predict their share of the market because of the influence of other players. Consumer and supplier reaction to prices can also be expected to affect the daily demand profile and generator utilisation. These issues are discussed in chapter 14. A rapidly expanding demand will tend to lead to generation being sustained at full utilisation for longer periods. Large daily and annual variations in demand will tend to result in less plant being built for base load operation and continued use of older plant two shifting to meet peaks.

An assessment of the volatility of prices can be derived from an analysis of the profile of the total system price / capacity function.

A system with a typical plant margin and steep system price/demand curve would give higher and more variable pool prices than a utility operating with a high plant margin which would have a very flat SMP profile. Figure 12.5 shows that for equal demand changes that the change in price (delta) is very dependant on the margin and operating point on the curve. Any overcapacity would therefore have a disproportionate impact on SMP and generator income and could lead to business failures.

The effect of fuel price variations will be constrained by the existing plant mix which is not readily changed. An appraisal of the impact of price changes is therefore relatively straight foreward but normal utility planning would take account of the security and diversity of fuel supplies in the choice of generation. No mechanism now exists to encourage this global view and increasing dependance in the security of the gas grid may put the security of supplies in jeopardy at times of stress as has already occured in practice most recently on 19 Jan 96.

12.7 **Predicting SMP**

This section compares the results obtained from a full simulation model with the actual outturn Pool Selling Price (PSP) through the period since privatisation from April 1990 through to February 1994. The actual monthly PSP values were derived from published data. The model demand profiles used were derived by scaling the basic 87/88 profile to match the published monthly energy values for the future years. The availability profile for generation was constructed by creating outage periods consistent with known overall availability percentages. The actual generation was modified yearly to take account of new plant additions and station closures. The resulting patterns of availability are considered typical but not the same as the actual.

The operational model (version 7) was used to simulate operation and derive marginal prices assuming actual incremental generation prices are offered. The program DEMMOD was used to build the demand data files. The generation availability files were edited manually to add new generators and reduce the availability of closed generation to zero. The following files were created:(see appendix 5)

	1st half year	2nd half year
90/91	GENAV 1B.DAT	GENAV 2B.DAT
91/92	GENAV 191.DAT	GENAV 291.DAT
92/93	GENAV 192.DAT	GENAV 292.DAT
93/94	GENAV 193.DAT	GENAV 293.DAT

12.8. **Results**

The results of the simulation are shown in figure 12.6 and provide a comparison of the actual monthly PSP and the model simulation without initially allowing for inflation.The model and actual start to follow a similar trend ignoring the initial few months of known aggressive bidding policy but subsequently diverge in line with the popular view that prices have risen above inflation.

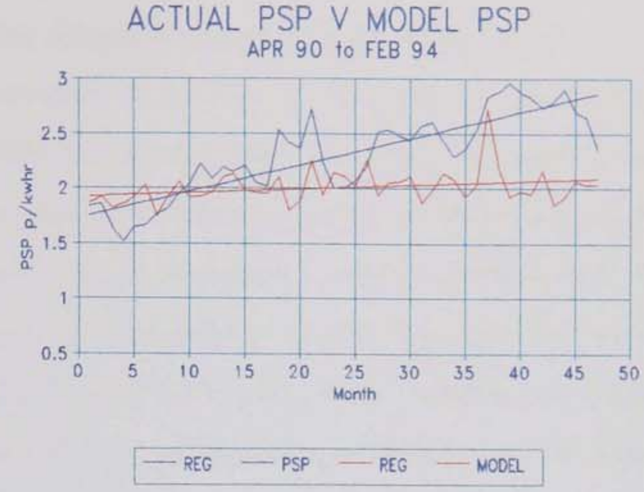


Figure 12.6

The model prices show more stability which reflects the impact of new cheap plant on containing price rises. The actual price trends show more volatility and tend to stay at high values once they rise. They also show a tendency to fall at the end of the financial year reflecting regulatory pressure. A linear regression fit shows the model results to be essentially flat as would be expected in the absence of inflation while the actual results rise according to the function

$$PSP = 1.728 + 0.024 * Month$$

with the total rise over the period being 49%. Of this the expected rise in costs due to the demand rise is 8%, with inflation and uplift covering a further 27% leaving an unexplained price escalation of some 14%. This is consistent with the popular belief that a duopoly operates. During the period the market share of NP had dropped from 45-35% and PG from 29-24% ie a combined reduction of some 15% This aligns with the price increase of 14% that would be

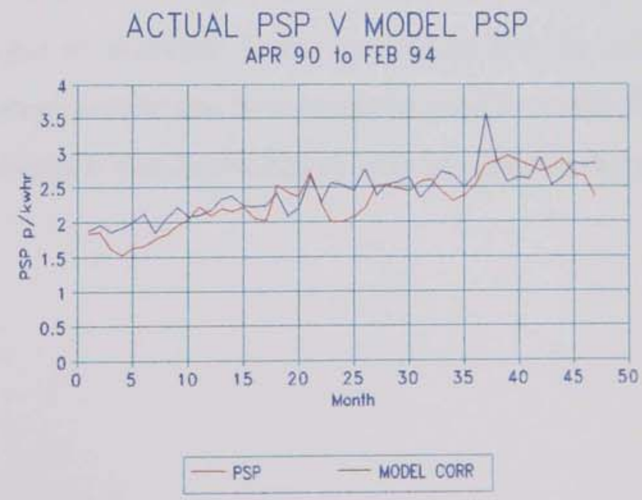


Figure 12.7

neccessary to maintain the income of the large generators despite the reduced market share. Adjusting the model results for both inflation and escalation produces the result shown in figure 12.7 which indicates a reasonable comparison given the assumptions made.

The actual prices are influenced more by commercial and financial considerations and less by cost and these results confirm the popular belief that energy prices have risen more than necessary by some 14%. Any assessment based on current market prices has to take account of the type of market perceived to be in operation and alternative models are discussed in the next chapter. It is also essential to analyse the system price profile and the plant margin to be able to judge the likely trend in marginal prices.These factors indicate whether the prices are artificially inflated and how volatile they are likely to be. The impact of capacity additions on prices is discussed in the next two chapters.

12.9 Conclusions

An approach has been developed to establish a generators prospective utilisation and income and hence profit in a post-privatised situation. The operational model is first used to derive an annual SMP profile. The utilisation is then derived using a post processing algorithm to calculate those periods when the offered price is less than the system SMP and the generator will be selected to run. It has been shown that the optimal bidding strategy to maximise income is to bid in at the true marginal cost. The results obtained from the model show both CCGT's and nuclear as profitable. It was also shown how the system price function affects the range of variation of SMP and how it may be used to assess likely future price variations and utilisation. Finally it was demonstrated how an apparent duopoly may affect future prices.

Chapter 13

Market share and Appraisal Process

13.1 Introduction

The previous chapter demonstrated how an individual generator could assess the likely income and profit against an SMP profile derived from an operational simulation. This chapter discusses how an assessment can be made of the likely investment decisions of the other market players and the impact on prices and market share.

13.2 The Profit Function

The LP formulation can only provide a coarse estimate of the additional capacity that would be profitable because its time periods are inevitably too coarse to model hour to hour SMP and hence profit variations. It is necessary to simulate the operation of the system in detail using the full simulation model with all the existing generation represented and planned new generation added with representative costs. The output of the model includes an annual SMP/LOLP profile which in turn was used to calculate the profit from new generation.

The profit calculation was performed using the algorithm COMCOST(see appendix 5) which identifies the period of time when the marginal cost of new generation puts it in merit. The income was then determined by the product of the MW and PSP during the in merit periods as described in the previous chapter ie

$$\sum_{t=1}^{t=n} MW_{i,t} * PSP_t \quad where \quad Inc_i \le PSP_t \qquad 13.1$$

where MW=unit output at time t

PSP=pool selling price

INC=incremental cost of unit i

The profit was then calculated by subtracting the fixed and variable cost elements ie

$$\sum_{t=1}^{t=n} MW_{i,t} * var_i + fix_i \quad where \quad INC_i \le PSP_t \qquad 13.2$$

where var=unit variable cost

fix=unit fixed costs

By progessively adding additional generating capacity it is possible to calculate an incremental profit at each point and hence the system overall profit function for changing levels of new capacity.

The base case results are shown in figure 13.1 with a linear regression fit to establish the function of net profit per year per MW of generation against total additional capacity. The results for the most likely case are

$$P = 18.20 - 2.71*C$$

where P = £k profit/MW/yr

and C = capacity in GW

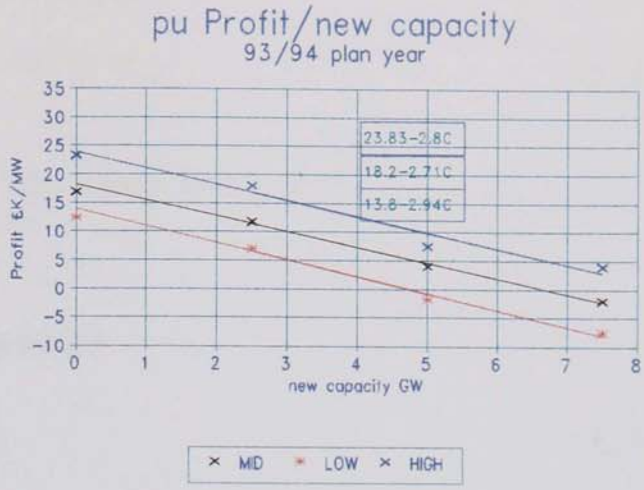


Figure 13.1

The graph also shows the range of probable outturn due to different fuel prices, interest rates and demand levels as discussed in a later section

The impact of the additional capacity is to gradually decrease the system marginal cost profile until the return does not cover the fixed operating and capital costs. This occurs in this example when approximately 7.0GW of additional capacity is added compared to the 7.5 GW in the new LP formulation. The comparison with the profit maximisation formulation of section 11.3 is close given the simplifying assumptions made in the representation. In practice a private utility required to maintain a high return to shareholders may not invest up to the limit of marginal profitability but may choose to maximise returns as discussed below.

13.3 Calculating Total Profit

Given the function of unit profit versus additional capacity derived above the function of total profit against additional capacity can now be calculated as the product of price and new capacity. This exhibits a maximum as shown by the full solid line in figure 13.2 when further additions depress the unit price so as to reduce the overall profit. As shown above the per unit price profit function can be represented by a straight line of form

$$P_{(y)} = a-b*c \tag{13.3}$$

If we assume two key market players each building capacity C1 and C2 then total profit is given by the product of price and capacity ie.

$$P_{(y_1+y_2)}(C_1+C_2)=a(C_1+C_2)-b(C_1+C_2)^2 \tag{13.4}$$

$$if \quad C_t=C_1+C_2 \quad then\ P=aC_t-bC_t^2$$

Differentiating to obtain Pmax we get

$$\frac{\partial P}{\partial C_t}=a-2b*C_t \tag{13.5}$$

$$ie. \quad Pmax=a/2b \quad =18.2/5.42 \quad =3.36GW$$

ie the total nett profit is maximised if 3.36 GW of new capacity is built. This is considerably less than the 7.0 GW derived in section 13.2 which would result in only marginal profitability as shown in fig 13.2.

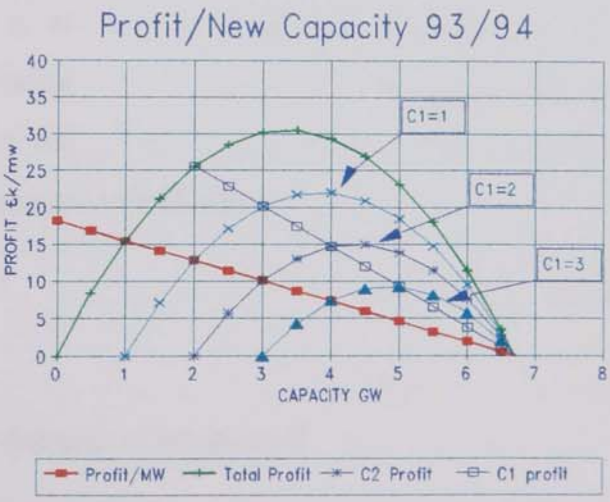


Figure 13.2

The potential impact of uncertainty will give a range of values from 4.25 GW to 2.34 GW based on the data in figure 13.1.

It is now possible to model the interaction of two market players each seeking to maximise their profit.If we assume company A chooses to build capacity C1 then a function can be calculated to show the range of profits that company two can realise with different investment strategies. Company B profit is given by

$$P_{(C_1+C_2)} * C_2 = (a-b(C_1+C_2)) * C_2 \qquad 13.6$$

Differentiating to obtain the maximum we get

$$\frac{\partial P}{\partial t} = a-b*C_1-2bC_2=0 \quad ie. \quad C_2=\frac{a-bC_1}{2b} \qquad 13.7$$

These functions of company B profit are also shown in figure 13.2 for the different choices of company A expressed in units of £m. The full solid line shows the p.u. profit versus total capacity and the bold curve the corresponding total profit. The dotted lines show the total profit when company A chooses to build 2GW of CCGT's with a variable amount built by company B. It can be seen how the same total profit is now shared between the two companies. Similar curves exist for other choices of company A as shown. Each curve shows an optimum choice for company B given a knowledge of the decision of company one. This is the function derived above

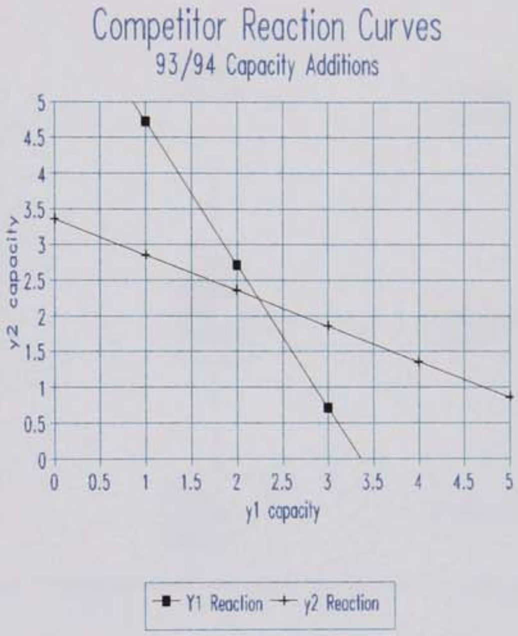


Figure 13.3

$$C_2=\frac{a-bC_1}{2b} \qquad 13.8$$

and similarly for company A given the decision of company B

$$C_1=\frac{a-bC_2}{2b} \qquad 13.9$$

These reaction curves are plotted in figure 13.3 and show the two functions ie

$$C_1 = \frac{18.2 - 2.71\ C_2}{5.42} \quad ; \quad C_2 = \frac{18.2 - 2.71\ C_1}{5.42} \qquad 13.10$$

This approach enables a generating company to determine its optimum strategy given a prior knowledge of the proposed capacity additions of its competitors. Other models where this is not the case are discussed in section 13.6.

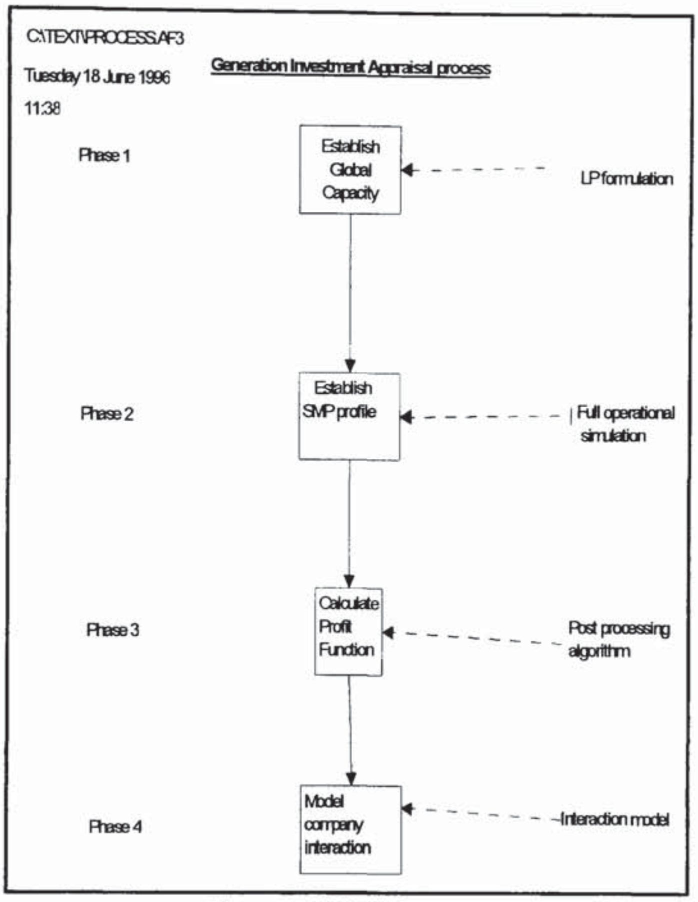


Chart 13.1

13.4 Overview

It is now possible to describe the overall assessment process based on the analysis described in the preceeding chapters.

A multistage approach is proposed with the objective of establishing the optimal investment strategy for an individual generating company. The phases are outlined below and shown schematically in flow chart 13.1.

Phase 1 Total Capacity Requirement

This uses the LP formulation described in chapter 11 to estimate the total system additional capacity that would provide a positive return to the group of generators. The formulation takes into account the existing capacity, its type and cost and assess's the optimal additional capacity by plant type to maximise the total generators profits. From the results a set of proposals for varying capacity additions up to the maximum can be defined.

Phase 2 Simulate Pool Operation and Profit

For each of the proposed scenarios a full system production simulation is run to calculate the expected hour by hour SMP profile. This can then be used to make an estimate of the utilisation and profit to be expected from individual generation additions.

Phase 3 Calculating Total Profit Function

As the profit varies with the amount of additional generation added a function can be derived showing the p.u. profit against added capacity. This function is the classic economic price quantity function where price,in this case, is profit per unit of new capacity. The total profit function exhibits a maximum when the income from further capacity additions are offset by the resulting price reduction.

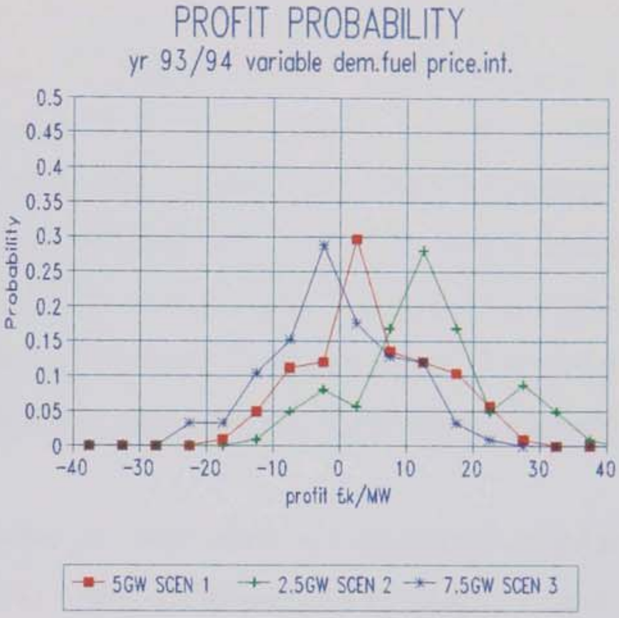


Figure 13.4

Phase 4 Company Interaction

The sharing of profit within the overall envelope is calculated depending on the interaction model in operation i.e. a duopoly; one company leads the other; or both companies act in isolation double guessing the action of the other.(see section 13.6)

For each scenario the impact on profits can be calculated for varying demand; fuel price; and interest rates. This provides a statistical distribution function around each basic scenario and enables uncertainty to be quantified to aid in decision making.

13.5 **Modelling Uncertainty**

The above profit estimates are based on the central predictions of demand, fuel price and interest rates. To establish the impact of uncertainty a range of values were assumed for each of the variables with an assigned probability as shown in table 2

Variable	Fuel Price £/kWh	Demand GW	Interest Rates	Probabil-ity
High	0.014	51	0.09	0.2
Central	0.012	50	0.07	0.6
Low	0.010	49	0.05	0.2

The results of the demand changes were simulated by changing the external imports. The effect of fuel price and interest rate changes were assessed using the COMCOST algorithm. The results are shown in fig 13.4 as the probability of different profit outturns for each of the three scenarios. It can be seen that the chosen variables have as much impact on the results as the choice of scenario. Given that the range of the variables is realistic then the graphs can be used to assess the statistics of likely out-turn for a chosen plant addition. Figure 13.1 was construced assuming that the out-turn is bounded by the 0.15 probability level for each capacity scenario. The band between upper and lower values would then capture some 50% of likely out-turns.

Various authors have addressed the issue of uncertainty in conventional expansion planning for an integrated utility and some of these techniques may be applied to the new problem. Generally the approach has been to establish the course of least regret (Gorenstin 93, Merril 95) by analysing the trade-offs using regression techniques (Aperjis 82) or decision tree analysis.

13.6 **Alternative Company Interaction Models**

There are several ways in which two companies can interact depending on cicumstances.

-A **duopoly** where both companies collude to maximise their joint profit.

-**Stackelburg equilibrium** where one company assumes quantity leadership and the other follows.(Varian-Intermediate Microeconomics)

-**Cournot** model where both companies simultaneously set quantities predicting and reacting to the expected choice of the other.

In all cases the generators fix the quantity of new capacity to build and hope that the outturn price will be right to realise adequate returns.From the above theory the result of the three approaches can be calculated.

13.6.1 **Duopoly**

In this case both companies will agree to jointly build that amount of capacity that realises maximum profit which in this case is 3.36 GW of CCGT's shared in some agreed proportion.

13.6.2 **Stackelburg Equilibrium**

In this case if company 1 fixes its capacity first at say 2 GW then it will be optimum for company 2 to build 2.33 GW making 4.23 GW in total. For the three curves shown in figure 13.2 the results are

Stackelburg Model results

Company 1	**Company 2**	**Total**
1 GW	2.75	3.75 GW
2 GW	2.23	4.23 GW
3 GW	1.79	4.79 GW

In general this model leads to more than the optimal capacity being built i.e. 3.36 GW.

13.6.3 **Cournot Equilibrium**

In this model each company simultaneously makes a decision on quantity whilst predicting the action of the other and equilibrium will, following successive interactions, eventually occur when both companies achieve their optimal response. This occurs when the two reaction curves predicting the response intersect which in this case is when each company builds 2.25 GW of capacity or 4.5 GW in total as shown in fig 13.3.

13.7 **Comparison with Actual**

In reality by 93/94 the CCGT's commissioned amounted to some 6.3 GW with PG contributing 1.7 GW and NP 1.3 GW .The combined NP/PG capacity would have been close to the optimum if it had not been for additional capacity added by the independents of 3.3 GW. This will result in reduced profits during the early years and forced premature closures by the major players to maintain returns.In practice 2673 MW of old plant was closed during the period made up of 360 MW OCGT's ;1453 MW oil ;860 MW of small coal. This is consistent with that derived from the formulation in section 13.3 and brings the nett capacity change of 6.3-2.6=3.7 GW. ie. very close to the optimum of 3.36. This then shows how the major players were forced to react to maintain their overall profitability as set by SMP/LOLP. A general modelling approach is developed in the next chapter to deal with the interaction of multiple companies.

13.8 **Conclusions**

This chapter has shown how a generator can identify the overall system need for additional capacity and then model competitors behaviour to determine his optimal contribution and market share. The process described enables profit margins to be calculated and the relationship between p.u. price and new capacity to be derived. This then enables the total system profit function to be derived and it's optimum and the overall process of assessment to be defined. Three competitor interaction models have been described and models developed to predict inter-company reaction depending on the type of market operating.

The results confirm that the objective function of minimising cost is not the same as maximising profit when the income is a function of the price of the marginal unit. It would not be in the interests of the generators to displace all their high cost old plant which will, while plant margins are low, be used from time to time to set high SMP's. Because all energy taken during these half hours is charged at SMP they will have a disproportionate effect on overall profit. On a cost minimisation basis it would be correct to displace the expensive marginal genarator as this formulation takes no account of the impact on income. It isonly if the generators controlled prices and were therefore able to fix the high marginal prices despite the new lower costs would total replacement appear attractive. The chapter concludes with a desciption of how in practice the market has reacted to maintain revenues.

Chapter 14

Predicting Multiple Company Interaction

14.1 Quantitative Analysis

The previous chapter discussed how two companies may interact in the market place in a variety of ways. The theory is now expanded to model the behaviour of several companies interacting including the following effects:.

-the closure of generation by existing companies when the level of utilisation and associated income cease to cover the fixed operating costs.

- the impact of new generation on market price and hence the change in income for existing generators.

-the reaction of generators according to their perception of the p.u. profit/capacity function so as to maximise their profit.

As new entrants are not affected by the impact of new plant on the profitability of their existing generation they will tend to enter the market first. The bigger the existing generator the more likely he is to constrain his build when plant margins are already favourable because of the impact on SMP and LOLP and the income for all their existing generation. Capacity in excess of the optimum will therefore accelerate closures by the big generators. A generalised approach is developed to model these effects within a theoretical framework which does not require full operational simulations for which the data will not generally be available.

14.2 The System Merit Order

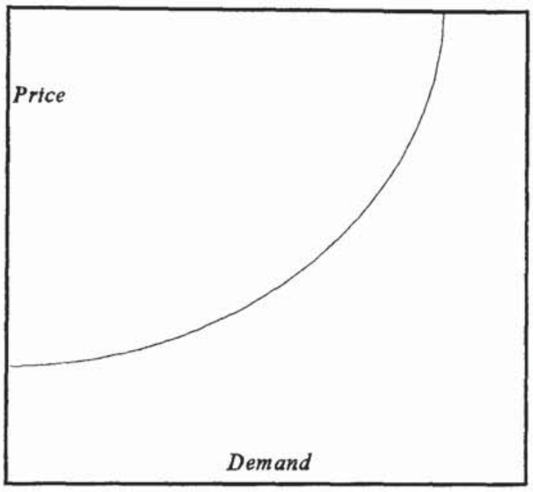
A power system with a normal distribution of demand and an optimal plant mix will exhibit a range of marginal prices consistent with the type of generation being used. Base load plant will usually have high capital costs and low operating costs with peaking plant the reverse. This leads to the total system merit order (MO) when plotted against increasing demand having an exponential form. It was shown in chapter 12(fig12.5) how the range of demand variation may be projected onto system MO function to establish the range of price variation. A system short of capacity will frequently use peaking plant having a high marginal price and will cause the profits for other generators to increase. A system with over-capacity will exhibit a flat price profile.

The impact on prices and profits of changes in demand and capacity can be seen to be essentially non-linear. Increasing demand will shift the operating envelope to the right whereas adding capacity will shift it to the left. The quantification of the variations is analysed in subsequent sections.

14.3 **Theoretical Derivation of Profit Function**

The system MO function can be approximately represented by an exponential of the form

$$P = A \exp^{B*D} \qquad 14.1$$



where P=price

D=demand

A,B are constants

The demand distribution function may be represented by a normal distribution curve of the form :-

$$H_{(D)} = \frac{K}{C\sqrt{2\pi}} \exp^{-\frac{(D/s-m_o)^2}{2c^2}} \qquad 14.2$$

where H is no of hours in the year for which a particular demand level exists ; K is a constant ; C is a constant affecting the width of the function ; mo is the mean value.

Given the demand D we can find the corresponding MO price using equation 14.1 and the number of hours for which it will persist using equation 14.2. Given the incremental price of a new generator 'Ig' we can calculate the gross income when the unit is in merit and hence the gross profit per year F i.e.

$$F^{g} = \sum_{p=1}^{p=max} H_{(D)} (P_{(d)} - I_g) \qquad for\ P_{(d)} > I_g \qquad 14.3$$

$$F^{g} = 0 \quad for \; P_{(d)} < I \qquad 14.4$$

$$F^{g} = \sum_{P=I}^{P=max} \frac{K}{C\sqrt{2\pi}} \exp^{-\frac{(D/s-m_o)^2}{2c^2}} (A\exp^{B.D} - I_g) \qquad 14.5$$

and the nett profit is the gross profit less the interest charges on the capital at the prevailing

$$F^{g} = \sum_{P=I}^{P=max} \left[\frac{K}{C\sqrt{2\pi}} \exp^{-\frac{(D/s-m_o)^2}{2c^2}} (A\exp^{B.D} - I_g) \right] - C*I \qquad 14.6$$

interest rate i.e. C*I

i.e. given the demand function we can estimate the gross annual profit.

14.4 **Results**

Figure 14.1 opposite shows a typical MO function where A=8.166 and B=.0277 i.e.

P= 8.166e .0277D

The values required to represent a typical demand duration function are

K=1729 : C=2.5 : s=2500

mo=12 for demand blocks of 500 MW .The curve then shows the number of hrs the demand is in each 500 MW range. The third curve shows the product of the two (/10) and is skewed by the exponential price curve. If the demand is expressed in GW we get the expression :-

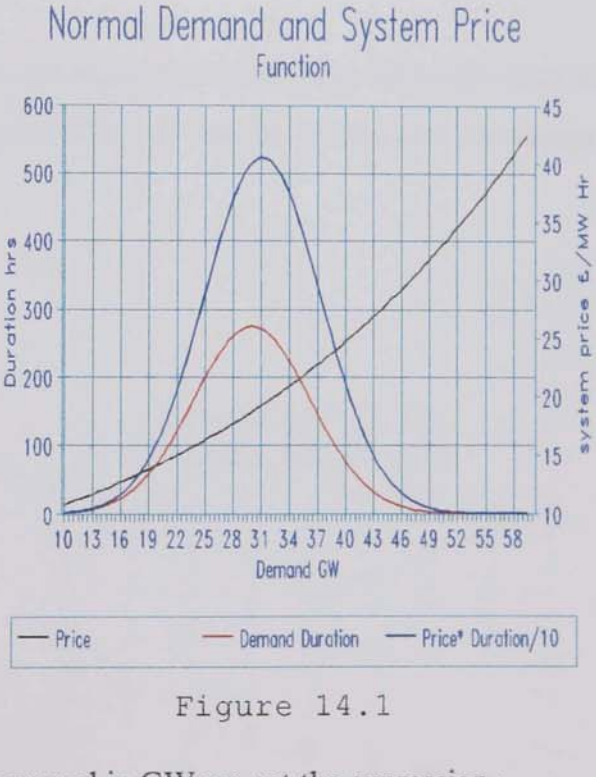


Figure 14.1

$$\int_{D=Mg}^{D=max} 275 \exp^{-(D/2.5-12)^2/12.5} [8.166 \exp^{.0277*D} - 12] \qquad 14.7$$

this gives the gross profit for a generator assuming an incremental price of £12/MWh and in this example equals £48k/MW/yr having allowed for an average availability of 80%. The nett profit is then this figure less the annual interest charges/MW ie. 288*.07 = £20k and the fixed operating costs of £4.3k/MW giving a net profit of some £23k/MW/yr (48-20-4.3). This compares with the range of results obtained from the full simulation.

14.5 **Changing Capacity and Demand**

The new representation readily enables the effect of changing capacity and demand to be assessed with a check for accuracy against the full production simulation. New generation can be expected to be high merit and will therfore shift the point at which demand intersects with the system MO curve to the right .The MO function can then be modified by the new capacity C ie.

$$P = A\ \exp^{B(D-C)} \qquad 14.8$$

An increase in demand will, assuming the profile stays the same, shifts the mean value of the distribution curve to to the right. The value of Mo will then be increased by the change in demand.

$$H_{(D)} = \frac{K}{C\sqrt{2\Pi}}\ \exp^{-(D/s-m_o-\delta D/s)^2/2C^2} \qquad 14.9$$

where delta D is the change in demand. These functions have been used to derive the graphs shown in figure 14.2. It can be seen how increasing capacity reduces the p.u. profit and that the result is very similar to that shown for the full production simulation. The theoretical increase in profit for increasing demand is at a slightly higher rate. It is concluded that this formulation is sufficiently accurate to be used to derive a new profit

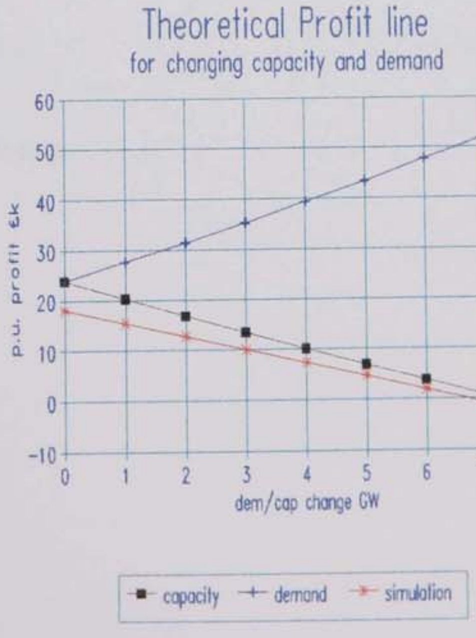


Figure 14.2

function as the capacity and demand change from year to year. The expressions derived above have been built into a subroutine of a predictive model and can be applied to any system where the price function and expected demand are known or can be estimated.

14.6 **Multiple Interaction**

It has been shown that the function of p.u.profit versus new capacity can be represented by the linear expression for a given year 't' as :-

$$P_t = a_t - b_t\ C_t \tag{14.10}$$

where 'a' and 'b' are constants , P is p.u. profit and C capacity all for the year 't'. The total additional profit is given by the product of the profit and the capacity ie.

$$P_t = (a_t - b_t\ C_t)\ C_t \tag{14.11}$$

$$C_t = \sum_{i=1}^{i=n} c_{t,i} \tag{14.12}$$

where 'Ct' is the total new capacity in the year and ci is that for each generator.

For an individual generator the total profit is given by the function :-

$$f_{i,t} = [a_t - b_t(C_t + c_{i,t})]\, c_{i,t} \tag{14.13}$$

$$f_{i,t} = c_{i,t}(a_t - b_t\ C_t) - b_t\ c_{i,t}^2 \tag{14.14}$$

differentiating we get the slope of the function ie.

$$\frac{\delta f_{i,t}}{\delta\ c_{i,t}} = (a_t - b_t\ C_t) - 2b_t\ c_{i,t} \tag{14.15}$$

which reaches a maximum when :-

$$(a_t - b_t\ C_t) = 2b_t\ c_{i,t} \tag{14.16}$$

and

$$c_i, t = \frac{(a_t - b_t\ C_t)}{2*b_t} \qquad 14.17$$

Depending on the slope of his profit line a generator will either increase or decrease his capacity.

For an existing generator it will be neccessary to take account of the price change caused by his new capacity on the income from his existing generation.ie.

$$= \delta p\ c_{i,0}\ u_{i,t} \quad \textit{where } c_{i,0}\textit{=initial genera} \qquad 14.18$$

$$\textit{where } u_i\textit{=mean utilisation}$$

but since

$$\delta p = b_t\ c_{i,t} \qquad 14.19$$

$$\delta_i = b_t\ c_{i,t}\ c_{i,0}\ u_i \qquad 14.20$$

$$f_{i,t} = c_{i,t}(a_t - b_t\ C_t) - b_t\ c_{i,t}^2 - b_t\ c_{i,t}\ c_{i,0}\ u_i \qquad 14.21$$

differentiating

$$\frac{\delta f_{i,t}}{\delta\ c_{i,t}} = (a_t - b_t\ C_t) - 2b_t\ c_{i,t} - b_t\ c_{i,0}\ u_i \qquad 14.22$$

which is maximum when

$$c_i, t = \frac{(a_t - b_t\ C_t - b_t\ c_{i,0} u_i)}{2b_t} \qquad 14.23$$

ie. given 'a' and 'b' for a future year we can identify the optimal additional capacity for a new or existing generator. The p.u. profit function will be affected each year by the changes in demand or additional capacity as shown in figure 14.2 and a subroutine has been developed to model this based on the expressions derived in section 14.5

14.7 **Modelling Interactive Expansion**

A model was built to simulate generation expansion for the group of existing and new generators using the theory described above. The pre-privatisation generation conditions were taken as the starting point and actions are modelled through the plan years.

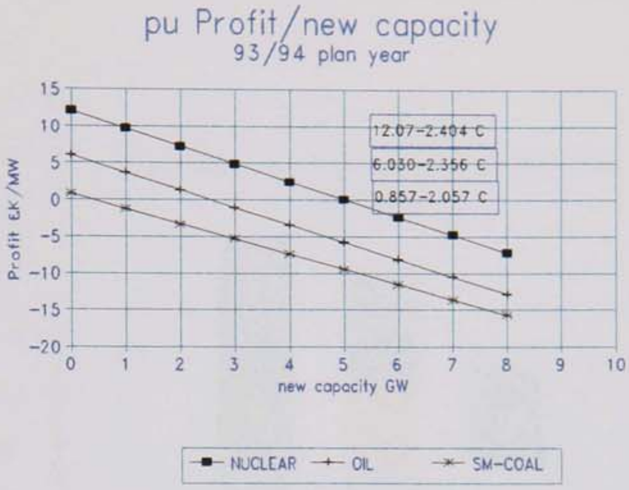


Figure 14.3

The profit function is adjusted year on year according to the change in demand or plant additions using the function derived in section 14.5.

The model processes the generator decisions in order of their size. It automatically derives the appropriate profit function depending on plant type according to functions derived internally to the model and similar to the data in figure 13.1 derived from the full simulation.

Figure 14.4 shows the actual expansion during the period modelled and figure 14.5 the model results and it can be seen that similar trends and characteristics are exhibited.

In both the model and reality the small independants see an economic case to build new generation in each of the years considered. They are less susceptable to the impact on prices of the additional generation than the larger generators. The largest generator is most exposed and therefore sees the

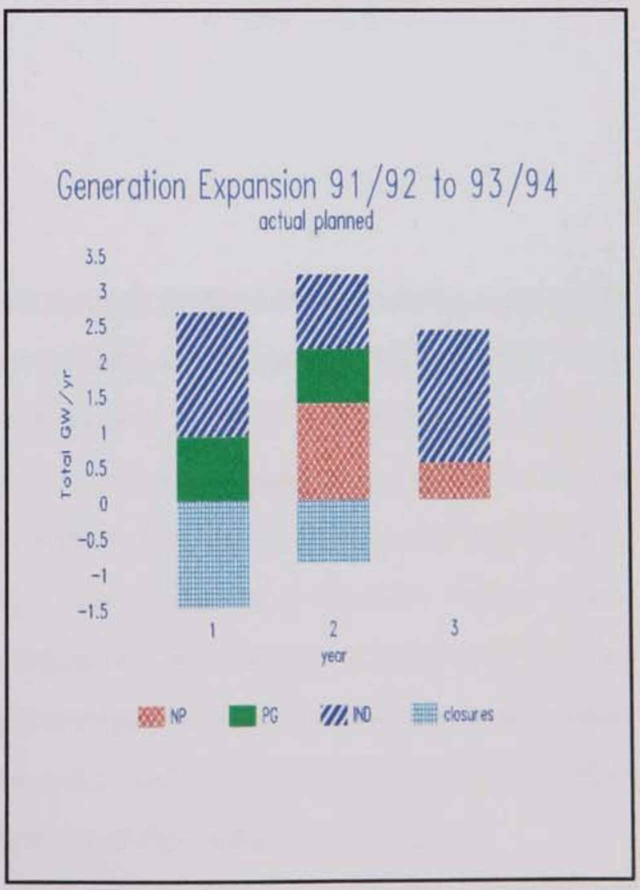


figure 14.4

need to close plant and maintain the increment on prices due to LOLP and the income on all other units before it can build new plant. The LOLP additions to marginal price applies to all energy sold during a half hour and these payments for a large generator are likely to exceed any availability payments to withdrawn generation. Equally it will be desirable to retain some marginal generators to set SMP high. Both the model and reality confirm this effect.The middle sized generator is able to take an early opportunity to build in the initial years but then sees falling profit and a benefit in reducing capacity.

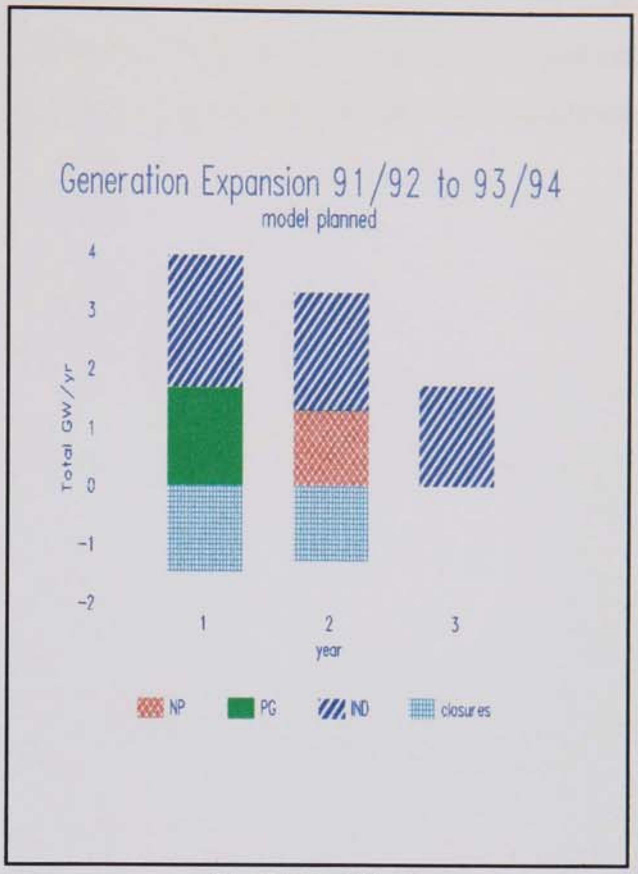


figure 14.5

14.8 **Conclusions**

This chapter has shown the development of a theoretical approach to deriving a p.u. profit function from a knowledge of the system demand profile and the system merit order function. This has then been tested by comparison with full simulations and shows a reasonable qualitative correlation . The theory has then been used to model the interaction of several companies operating in the same market. The results show similar behaviour to that which has occured in practice. The basic theory and objective functions are fundamentally different to those applied to expansion planning for a fully integrated utility and will result in a less than ideal solution for consumers. There is no apparent mechanism to encourage either the optimal plant margin or mix and the LOLP serves only as a further mechanism for generators to manipulate prices and the market in their favour.

Part 2 of this thesis has developed a new approach to investment appraisal in a deregulated market and has demonstrated that the classical approach is no longer applicable. It has shown how to predict SMP profiles and then use these to estimate income and profit . The concept of the profit/capacity function was introduced and used to establish a theoretical basis for predicting company interaction and market share and the results have been shown to compare to actual outturn.

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Part 3

Transmission Investment Appraisal

Chapter 15

Review of International Structures

15.1 The Regulated Monpoly

Transmission enables market competition in generation and supply by providing free access by consumers to all sources of generation. It also facilitates the optimum use of generation in the event to minimise operating costs and provide improved security against loss of supply. The value to the market of these transmission services has not generally been assessed because generation and transmission have traditionally been developed as an entity within an integrated utility to minimise the total costs. It would not be efficient to duplicate the transmission system and it is therefore treated as a monoply subject to regulation. The current use of system charges are therefore mainly based on the costs of the existing assets employed.This approach reflects the view that charges, in a natural monopoly, should be driven down to costs, including capital charges ,operation and maintenance costs and losses. It does not,however, provide a basis for assessing new investment or for the distribution of charges between generators and suppliers. Also, it does not provide a basis for charging for optional wheeling or to ensure optimal use of assets in the operational phase.

To encourage the optimum level of investment it is neccessary to base prices on the benefits to consumers in reduced generation costs and improved security. Equally the Transmitter should be penalised when active transmission constraints prevent the most economic use of generation. Prior to privatisation the CEGB designed the generation/transmission system as a single entity with the object of minimising total production cost. The most desirable outcome would be for the same level of benefit to be realised by appropriate price messages through the market.

15.2 Objectives of a Market Structure

The ideal market structure needs to :-

-provide unbiased open access to facilitate competition

- encourage the optimal level of investment
- encourage efficient operation
- accommodate choice in location of generators and consumers
- be simple to apply

Some of the implementation issues that need to be addressed are:-

-what should a new entrant into an existing system pay?
-how do we finance new infrastructure developments?
-how do we encourage private venture capital to build transmission?
-should we split ownership of the wires from operation of the system?
-how to distinguish between cable and overhead line charges.

. Having identified appropriate prices it has to be decided how these should be apportioned. All players benefit from enabling competition in supply and consumption .At anyone time consumers benefit most if located in a nett importing area while generators benefit if located in an exporting area.
Circumstances will of course change as new generation is built and the value of freedom to locate needs to be assessed in apportioning charges between generators and consumers.
The following sections discuss how some of these issues have been addressed by different countries

15.3 International Practice

15.3.1 United Kingdom

The approach adopted in the UK is made up of three elements

-connection charges based on the assets required to connect the generator or consumer to the system.

-use of system charges based on a zonal price with a capacity and utilisation element.

-infrastructure charges to cover the inherent development needs of the system to ensure its security and operability.

The zonal use of system charges are currently designed to encourage generation and demand to locate in areas which would minimise the use of, and need for, new transmission. Generation is encouraged to locate in the south with low charges while consumers pay a premium. Whilst these charges do reflect the current utilisation of the system they do not encourage investment in new transmission to exploit its benefit. The cost of transmission limitations are paid equally by all consumers through uplift rather than by those aggravating the constraint. If these charges were also levied zonally then those sponsoring investment would see a return through reduced operating charges. No benefit is seen with the current arrangements.

In practice the zonal price messages have not worked and generators have chosen to locate in exporting areas where the benefits of local industrial contracts for power and or heat exceed the use of system costs. The costs are apportioned between generators and consumers on a 25:75 basis as decided by agreement at privatisation.

15.3.2 Australia

Transmission charges have been implemented based on a benefit method with cost apportionment determined by a load flow and levied as demand charges. Two approaches have been considered in setting up a market

-bilateral trading with the transmission charge related directly to that part of the system used.

-a pool arrangement with foreward spot prices established on a nodal basis employing a load flow solution.

The former approach enables prices to be set directly related to the benefit realised from the bilateral trade. The nodal price approach embodies the impact of transmission constraints and the use of out of merit generation will result in the zonal price being inflated. This approach more clearly identifies who would benefit from investment to ameliorate the constraint.

Open competition is more easily realised in a tightly coupled network, which equates to an infinite bus, as opposed to a radial network where transmission constraints restrict market access. Where several zones are loosely coupled a local pool is more appropriate with opportunity trading between zones and appropriate wheeling charges.(Plowman 94)

15.3.3 USA

A wide variety of techniques have been used with varying levels of sophistication. They have been developed to cater for non-utility generation embedded within the network and for transactions that affect boundary flows between regions. (Head 90)

Of the methods used for embedded generation the first two do not use load flows.

-'rolled in method' where all the transmission costs are apportioned between generators irrespective of use.

-'contract path method' where the generator output is assumed to follow a defined contract path irrespective of actual flows and charges are based on the proportional use of the path. (Happ 94)

-'boundary flow method' which identifies the change in critical boundary flows and apportions charges accordingly.

-'line by line method' where the change in MW flows in all lines is calculated and compared to the original to apportion charges.

None of the above methods cover the impact on generation dispatch of active constraints or appraisal of any new investment that may be cost effective. They essentially apportion existing costs on the basis of proportional utilisation.

Long run incremental cost methods have also been developed based on conventional planning methods and designed to take account of new investment costs and the change in operating costs resulting from wheeling deals.

-'the $/MW method' apportions both operating and investment costs according to the connected generation MW.

-'the $/MW mile method uses load flows with and without the transfer to calculate the increase in MW-miles.(Shirmohammadi 89)

-'flow allocation by region methods' use load flows to compute the change in inter-regional flows due to the wheel. The associated investment and operating cost changes are then calculated for each region and allocated on a $/MW basis.

Recently concern has developed in the US where parallel flows occur which are not consistent with the 'contract path'. The GAPP Committee have developed a **G**eneral **A**greement on **P**arallel **P**aths which define compensation for the unathorised parallel or loop flows. A matrix is used to determine the 'pricing path' and the Transaction Participation Factor (TPF) associated with all potential exchanges. A load flow is used with all lines in service to assess the nett value of all interchanges .If the flows that occur in other than the contract path exceed the 5% threshold then compensation is due.(Happ 94)

15.3.4 Chile

Open transmission access is seen as the key to generation competition and is actively encouraged. The rates for use are derived so as to distinguish between the natural and commercial path.The charges are related to the generators local area of influence where an increase in output directly results in an increase in flow within the line. If he wishes to trade with a partner outside this area then he has to negotiate an additional tariff.(Hissey 94)

15.3.5 New Zealand

A separate transmission company has been set up called Transpower with responsibiity for providing open transmission access. Prices are based on the need to recover costs and provide a return on the assets employed.The asset value is regularly reviewed and set to an 'optimal derived value' discounting those assets that exceed the need. Customer specific costs are charged direct. Other network costs are levied according to use based on a peak load flow solution and on the distance between the load and generation. Capacity payments are based on the power consumed at peaks with losses distributed according to average TLF's.

15.3.6 Argentina and Peru

The transmission business is regulated to encourage efficiency with costs recovered through global allocation to all consumers at a standard rate. The administration of the transmission service is managed separately from ownership of the wires.

Specific customer prices are based on depreciation costs against self or regulated valuations of the assets employed plus operation and maintenance costs within the area of influence as determined from peak power flows.

The main network costs are shared with

-losses based on TLF's with respect to a pivotal node

-the capacity element based on connection charges.

(Hissey 94)

15.3.7 Sweden

A separate grid company has been established to secure open access and provide technical operation of the network.Charges are only made at the connection point with complete freedom to trade with any other agent irrespective of location. Since the transmission costs are a relatively small proportion of the total (ie. some 4%) they are readily recovered through an increment to the charges to the generator or regional electricity company.
The transmission charges include an element for capacity, which is some 60% of the total, varying with the maximum power level and location. They are profiled from a maximum in the north to zero in the south reflecting the zonal imbalance with most of the cheap hydro in the north and the population and load in the south. The remaining 40% energy related charges are based on nodal marginal loss factors. The grid maintains short term power balance by calling up regulation from generation according to bid prices.

15.4 Discussion

There are a number of common themes that appear in the international practices applied to date -

-open access is seen as the key to generation competition and is best realised through a commercially separate transmission company.

-charges are directly related to costs rather than benefit in the belief that a monopoly applies.

-apportionment arrangements vary from global to being based on utilisation according to zones of influence and load flows.

-commercial arrangements do not neccessarily align with physical flows and arrangements are proposed to compensate for this.

None of the techniques provide a basis for appraising new investment which has to be established based on the potential benefit to sponsors rather than historic cost. No rational criteria have been developed to apportion charges between generators, suppliers and consumers so as to encourage competition and maintain a level playing field. Other authors have concluded that there is no simple solution to ensure equitable trading together with value added to society (Schweppe 88). The costs and impact on the scheduling and dispatch process are not generally discussed and some mechanism is essential to encourage optimal maintenance outage planning. The following chapters address these issues and propose new theories and techniques.

Chapter 16

Cost Apportionment and Benefit

16.1 Introduction

This chapter discusses the apportionment of costs in a way that aligns with the benefit so as to encourage the optimal levels of investment. There are three production cost levels depending on the level of transmission investment as shown in figure 16.1.

-the absolute minimum assuming an infinite transmission bus

-the actual costs with a partially constrained solution

-the local costs assuming no bulk transmission

The optimal solution for an integrated utility is when the total generation and transmission operating and capital charges are minimised. This will not neccessarily result in the establishment of an infinite transmission bus but that level of investment when the savings in operating costs no longer exceed the cost of investment. This solution does not apply in a deregulated environment and it is neccessary to apportion charges for transmission to where the benefit is realised so as to encourage this optimal level of investment and to equitably distribute costs. Without this transmission investment is unlikely to be sponsored and may even be opposed as was the case recently with PG opposing a proposed transmission line in Yorkshire.

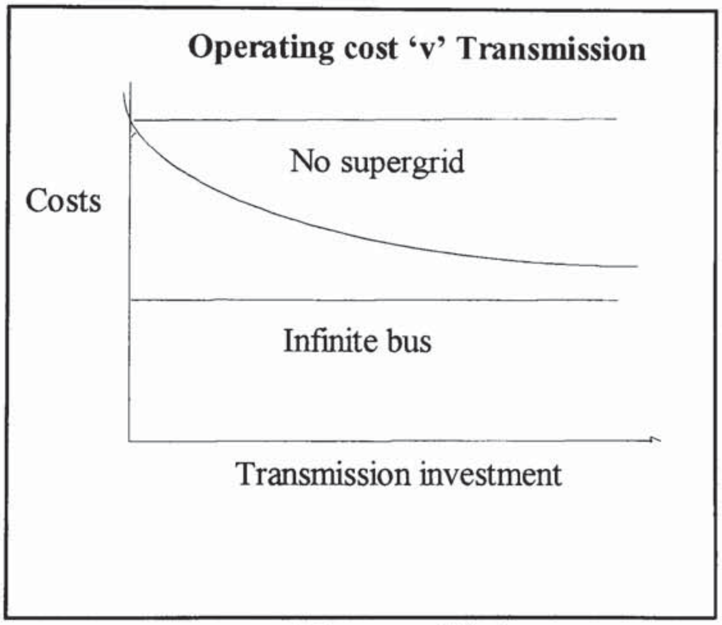

Figure 16.1

The benefits from transmission are realised through -

-minimising the cost of production by enabling full merit order operation

-minimising the unserved energy and consumer LOLP payments by enabling generation pooling and so reducing the probability of available generation falling below demand

-improvements in the security and quality of supply by providing resilience against outages

The pre-privatisation approach to appraising proposed transmission investment within an integrated utility was to simulate operation with and without the new lines using a cost based model. Investments would be authorised if the savings in generation out of merit costs and losses exceeded the capital and operating costs of the reinforcement.

Since privatisation the transmission company as a monopoly is regulated and only allowed to make charges to realise an agreed rate of return on the existing sunk assests employed. Connection charges are the subject of bilateral agreement and although new connections are subject to open competition in practice these charges are also the subject of appeal to the Regulator and defined rates of return.

The position is less clear for infrastructure developments. It is possible to assess the global benefit but there is no general agreement on who should sponsor the investment or how the costs should be apportioned between the market players. In the UK model transmission charges are set to encourage generator siting that would eventually minimise the use and need for transmission rather than exploit its potential to provide benefit. The treatment of sunk costs needs to be handled differently to new investment which needs to be based on its potential to provide benefit. It is also unclear how the optimal levels of investment will be encouraged. The present transmission services scheme provides significant profit opportunities to the transmitter who receives payments for minimising uplift charges. This therefore encourages the perpetuation of constraints, rather than there removal. These issues are discussed in the remaining part of this chapter.

16.2 Cost Apportionment of Existing System

Various techniques for apportioning existing transmission costs between users have been proposed. One approach (Calviou 93) formulated the problem as a classical transportation algorithm using a route cost for tranmission in £/MW/km and ignoring the physical laws of electricity . A slack node was arbitrarily chosen to give a split in costs between generators and consumers of 25:75 .The results showed an over utilisation of short lines and a significant under recovery of the required revenue.

It has been proposed that wheeling rates should be based on differential nodal marginal prices but studies have shown this to be overly sensitive to network conditions (Merril 89). It is also only applicable for a small transfer before the changes in generator output cause changes in prices. A more recent proposal (Farmer et al 95) proposed an optimal pricing strategy where the consumer benefit is maximised by minimising the total cost of production including generation and transmission costs. The benefit deriving from the use of transmission is in enabling a global optimisation as opposed to local zonal sub-optimal solutions. The gross benefit is given by the reduced zonal generation production costs in enabling full MO operation and the nett benefit less the transmission costs.

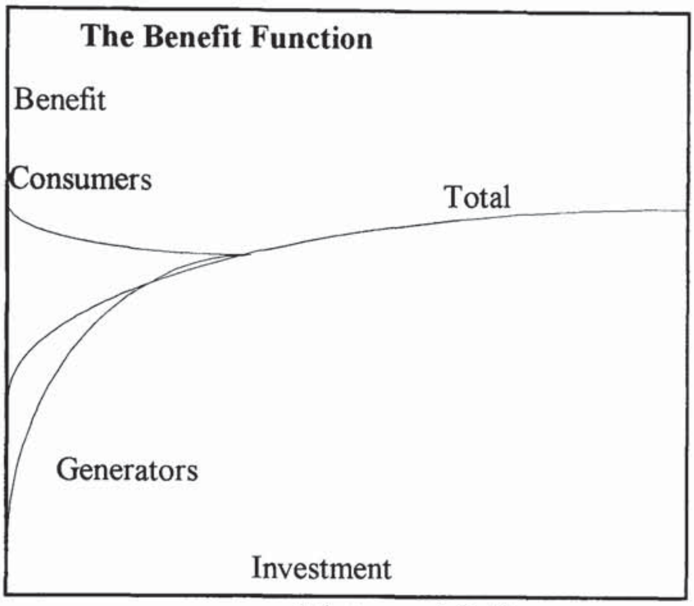

Figure 16.2

The above methods focus on an assessment of generation operating costs together with transmission costs. In practice prevailing generation bid prices in a market will reflect constraint activity rather than basic costs. Where prices are inflated in constraints this approach could lead to an overestimate of the worth of reinforcement. It is also invalid to assume that generation siting would have been the same without bulk transmission.

One approach to apportioning the costs of an existing system is on the basis of incremental and decremental costs and benefits which provide a more realistic basis for assessing new investment. The recovery of sunk costs in the existing system should not be allowed to distort cost messages by loading them with costs that relate to historic decisions.

The form of the benefit function could be established by progressively incrementing the system transmission capacity from a base system of decoupled zones. As the zones are coupled by new investment the additional benefit will gradually reduce with the optimum being reached when it just covers costs. If over investment exists then the slope would become negative. Where a system wide SMP applies, as opposed to zonal pricing the function describing benefit wil be different for consumers and generators depending on whether they are in exporting or importing zones.ie.

(A) Exporting zone

New transmission will benefit the generators within the zone in opening up a larger market but at the expense of local consumers who will loose the benefit of captive cheap capacity as shown in figure 16.2.

(B) Importing zone

New transmission will benefit local consumers in opening their market to more generators who may displace more expensive local generation .

Whilst on a global basis there may be economic advantage in introducing new transmission it may disadvantage some players and the apportionment of the costs of investment should reflect this.(eg. Power Gens opposition to Yorkshire line) The UK use of system charging principles aligns with this approach for sunk costs in the that those that make most use of the system ie generators in the north and consumers in the south pay most. In operation, however, in the absence of zonal pricing all consumers contribute to the impact of constraints through uplift and there is no direct incentive to those that would benefit most from investment to sponsor it. There are at least two ways to create the correct price signals and incentives.

(A) to establish zonal pricing for energy when consumers in import constraints would see a direct benefit from sponsoring reinforcement.

(B) to establish a <u>long term</u> arrangement with the transmitter to bear the cost of uplift to encourage investment to that level which minimises the overall cost. This could be coupled to agreements to share any resulting benefit with those customers sponsoring the incentive scheme.

Both approaches lead to a position where the benefit to the participants will eventually tend to equalise.

Hunt and Shuttleworth 96 discuss the problem of apportionment particularly in relation to recovery of the fixed elements of any investment to cover (n-2) security needs and the overheads of any development. They recognised that several lines need to be installed to provide firm capacity. Various economic techniques of apportionment are discussed including; joint venture agreements; Ramsey pricing where costs are set in proportion to the inverse of the demand elasticity ; non-linear incremental pricing and simple average pricing. These could be negotiated having established the global benefit.There is also a need to ensure that the contractual arrangments provide for recovery of the fixed sunk element of the costs with long term contracts or termination payments. These would need to be associated with transfer rights to the owner. Non- linear charging can also be used with high prices to provide recovery in the early years and reducing ones in later years. A joint transmission user forum is a possible mechanism to establish a mutually acceptable apportionment of costs.

16.3 Assessment of Global Benefit

(a)Operating costs

The assessment of the worth of a single line as part of a system is difficult and would require full security constrained generation schedules for the whole period with and without the line. No algorithm is currently available which combines a full network model with a generation scheduling algorithm capable of solving practical sized problems. It is also difficult to dissociate the benefit of one line from another because of their non-linear impact on operating costs. It is practical to assess the benefit of an increment or decrement in transmission along bulk transfer routes which can be represented by group constraints in scheduling studies. The variation in the benefit function can be established by changing the group limit to simulate the removal of lines from the network. If applied progressively this approach would eventualy reduce the system to a series of zones to which the local running costs would apply. In practice it is unrealistic to make calculations assuming that no transmission exists as the generation siting would then have been chosen differently. Only the incremental value is valid as a guide to benefit but the approach could provide a guide to the apportionment of infrastrucure costs.

(b) **Improved Security**

The increased number of generators resulting from pooling has a direct effect on the probability of the available generation being less than that required to meet the prevailing demand as shown in chapter 7. From an empirical relationship between the margins and

LOLP payments the benefit of coupling four areas was derived. This basic theory enables the benefit of coupling several systems to be calculated. The theory was extended to show the optimal plant margin by comparing the cost of addition units with the customer benefit in reduced LOLP payments. It is implicit that the transmission benefit is then affected by the prevailing plant margins in the systems being coupled . If these are high then the benefit will not be seen in the short term.

Transmission networks have to be designed with redundancy to cater for maintenance and forced outages. The problem cannot be linearised but requires integer decisions involving alternative routing.The security function needs to take account of the likelihood of occurnce of an outage, the volume of load that could be lost and its duration, a value can then be attributed to avoiding the contingency using the same value of lost load applied to generation shortfalls.ie. The optimal level of redundancy in a market occurs when the marginal price for increasing security equates to the consumer benefit in reduced loss of supply probability as with generation. It could be argued that the consumer should pay more for electricity, in the short term, when the probability of loss of interconnection is high to discourage use of the route, as with generation LOLP payments.Equally it could be argued that as the consumer has less transmission supporting his service he should pay less. Prepayment via the equivalent of LOLP makes more sense if it is added to an accumulating fund ,which, when it covers the cost of additional transmission could be used to finance investment and reduce future charges for those users paying into the fund. Then only if the consumer indicates a need to improve security,through the value of lost load, is there a basis for investment.

On the day the Grid Operator could be given incentives to manage security if he were payed a predefined sum to bear the insecurity costs that may occur due to transmission outages.This would also create an incentive to return transmission equipment to service. The generator also derives benefit in ensuring that its ouput can be delivered at all times.

(c) **Quality of Supply**

Economies of scale result form a pool in sharing reserve holding costs ; in maintaining regulating capacity to control frequency and in maintaining dynamic reactive capability to control voltage. Because the simultaneous loss of generation in each area of a system is unlikely reserve to cover the loss of a single generator will cover for all areas. Reserve holding costs are therefor saved in all other areas. Consumers realise benefit in having stable supplies to drive their equipment and generators from being able to maintain smooth operation.

(d) **Losses**

Investment in additional transmission will reduce overall losses. Similar questions arise as to who should manage losses and how the costs should be apportioned between generators and suppliers and whether or not zonal charging should apply reflecting the impact of incremental changes on total losses. The non-linear nature of losses adds to the problem of apportionment and it is neccessary to decide if generator selection should be influenced by their relative impact on losses. It is practical to apply transmission loss factors to bias the price for generation in scheduling studies according to their impact on system losses which may typically vary between 0.95 and 1.05. The resulting schedule will then minimise the overal cost of generation and lossses. The difficulty with this approach is that the loss factors continually change as a result of demand and generation changes.

16.4 **New Investment Types**

(a) Non Optional

This is the investment required to directly connect a generator or consumer to the system. The charges are directly attributable to the user on the basis of an agreed percentage return on assets employed. Investment will be covered by a bilateral arrangement where costs will be determined depending on whether a firm or non firm connection is required. The charges will be influenced by what is thought to be a reasonable rate of return by the regulator or capital market. The arrangements are covered by a master connection agreement and are relatively straight foreward and not discussed further.

(b) Optional Interconnection

This is additional investment in transmission between two systems to enable opportunity trading or wheeling when marginal prices are different. In the past marginal prices differentials would have been predictable given demand profiles and plant mix. A common commercial arrangement would be for the benefit from trading to be shared. In a deregulated environment prices will be more volatile and the benefit of investment less predictable.The implications of Third Party Access are that the links will enable external generators to participate in the pool and strike supply deals direct with customers in each system. In these circumstances interconnection capacity becomes a commodity to be traded between the external parties wishing to export into the pool and influence prices and its potential value needs to be assessed based on the impact on income to the users.

Given the long term nature of the investment it is neccessary to take account of the expansion plans of the interconnecting utilities. As well as the benefits derived from energy trading it is common to maintain a shared reserve agreement to provide post incident support. Potential variations in prices will make it neccessary to test the benefit within a probable range.

(c) Optional Infrastructure

Where an active transmission constraint exists then the benefit of reinforcement can be assessed from operational simulation studies with increasing levels of reinforcement. Usually the constraint will only become active in practice following a contingency. It is also neccessary to consider alternative strategies like post incident generator intertripping .

To establish the worth of new transmission infrastructure investment we need to simulate operation with changing levels of investment. The production model developed in part 1 simulates realistic patterns of generation availability but it is also essential to model transmission outages. This is particularly important because many constraints only become active and increase production costs when the network is depleted. Whereas in the past the generation and transmission outages were cordinated to minimise costs this is now much more difficult and random and the model has been enhanced to facilitate this.

It is also neccessary to consider the impact on system losses particularly in the vicinity of high merit generation.To produce realistic results the model also needs to simulate post incident operator actions including redispatch or automatic generator intertripping. In the latter case the probability and cost of the generator outage will influence the result particularly where nuclear stations are involved which loose output due to reactor poisoning. Finally the robustness of the result will need to be tested against the probable range of price variations. The apportionment of new infrastructure development costs is more difficult, depending on the arrangements for transmission services, and is discussed in chapter 18.

16.5 **Conclusions**

The discussion has shown that different principles may apply to the apportionment of costs for an existing system as opposed to new investment which depends on the principal beneficiaries. There is also the point that existing assets may bear relatively little dept charge. It was also proposed that different models should apply to the evaluation of benefit and distribution of costs respectively for connection, interconnection and infrastructure developments. It is suggested that zonal transmission pricing or a long term incentive scheme with the transmitter is a neccessary condition to create the correct cost messages to encourage optimal investment. Finally the techniques to assess the benefit of the different categories of investment are discussed. The following chapters discuss the evaluation of benefit for the different investment types and how the optimal levels can be identified and encouraged through market mechanisms and the apportionment of charges.

Chapter 17

Interconnection Evaluation

17.1 Introduction

This chapter discusses the evaluation of wheeling opportunities between two systems when a generator has investment interests in both parts of the interconnected systems and the opportunity to strike supply agreements with consumers in each. This is the situation emerging with full open access in the British Isles to generators and suppliers in Scotland. The object is to estimate the gross total profit of the generator and to show how it varies with different levels of interconnection transfer. Given a price for transmission and the worth of the interconnection to the trader the overall optimum transfer for the generator is established. The transmission company can they assess its optimum price to realise maximum profit. Finally the reaction of consumers to price changes is modelled. It is proposed that most investment decisions will be made against medium term contracts rather than the spot daily market which will support opportunity trading.

17.2 Income and Costs

In chapter 13 a process was developed to estimate a generator's profit from a knowledge of the system MO function and an annual demand profile represented by a normal distribution function. The same basic formulation is now used to establish an estimate of total generator costs and prices to consumers. The prices are derived by determing the intersection of the demand function with the system MO curve and the costs by an accumulation of all the generation costs that are used to meet that demand level.The generator price is given by

$$P=A\ \exp^{B*D} \qquad 17.1$$

Where P=price, D=demand and A and B are constants.The demand duration function is given by

$$H_{(D)} = \frac{K}{C\sqrt{2\Pi}} \exp^{\frac{-(D/s-m_o)^2}{2c^2}} \qquad 17.2$$

where H is the number of hrs in the year for which a particular demand band exists; K is a constant ; C is a constant affecting the width of the function and mo is the mean value.The total income is derived from the product of the price the demand and its duration for all periods of the year.i.e

$$I_t = \sum_{t=0}^{t=8760} P_t \, H_t \, D_t \qquad 17.3$$

At each demand level the cost is given by the sum of all the generator prices that are used to meet that demand level i.e

$$c_t = \sum_{D=\min}^{D_t} P_t \qquad 17.4$$

and the total system cost 'Ct' is given by the sum for all periods i.e

$$C_t = \sum_{t=0}^{t=8760} c_t \, D_t \, H_t$$

17.5

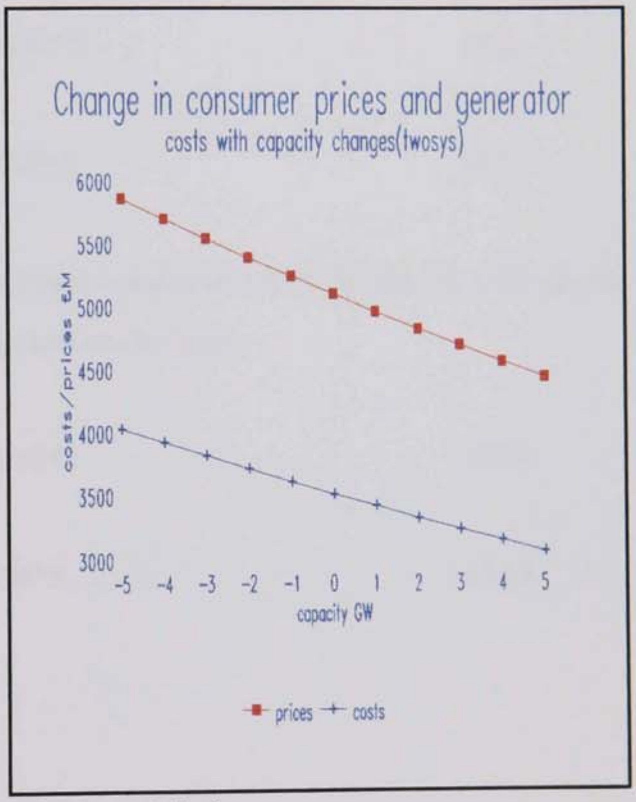

figure 17.1

17.3 Effect of Interconnection

The effect of changes in the interconnection level on the total costs and income can be estimated using the above formulation and adjusting the MO function for the change in import or export as if new generation had been added or old plant closed. The summated consumer prices and generator costs are derived for varying levels of transfer using equations 17.3 and 17.5.The resulting functions are shown in figure 17.1 for the system characteristics used in chapter 13 . It can be seen that they are substantialy linear and a regression fit was made giving equations of the form.

$$P=Ap+Bp*I \qquad 17.6$$

and

$$C=Ac+Bc*I \qquad 17.7$$

where **I** is the interconnection in GW and A and B are constants, 'P' is the price and 'C' the cost

In this case the results were

$$P=5115-141*I \qquad 17.8$$

and

$$C=3526-97.5*I \qquad 17.9$$

where the price and costs are expressed in £million and **I** is in GW for this 50 GW system. For each GW of installed capacity the expressions become :-

$$P=102.3-2.82*I \qquad 17.10$$

and

$$C=70.5-1.95*I \qquad 17.11$$

17.4 The Optimal Wheel

It is now possible to establish the optimal wheel for a generator using the formulation above to assess the impact of changing levels of transfer on prices and costs and hence net income.

In the general case assume that a generator 'i' has generation investments in two interconnected systems 'A' and 'B' expressed as a p.u of the total capacity and is in a position to negotiate supply contracts with consumers in both systems so that.

$$\sum G_i^A+G_i^B=\sum D_i^A+D_i^B \qquad 17.12$$

The gross profit for generator 'I' 'Fi' in each system is given by the difference between the total income based on prices and the generator costs. For a particular generator **'i'** the profit will be a function of the generation in each system and the associated supply contracts i.e

$$F_i=D_i^A.P^A+D_i^B.P^B-G_i^A.C^A-G_i^B.C^B \qquad 17.13$$

substituting for **'P'** and **'C'** from above we get- 17.14

$$F_i=D_i^A(A_p+B_p.I)+D_i^B(A_p-B_p.I)-G_i^A(A_c+B_c.I)-G_i^B(A_c-B_c.I)$$

rearranging we get- 17.15

$$F_i=A_p(D_i^A+D_i^B)+I.B_p(D_i^A-D_i^B)-A_c(G_i^A+G_i^B)-B_c.I(G_i^A-G_i^B)$$

but **'I'** the interconnection transfer contracted by generator **'i'** will be given by the difference between the generation and transfer in each system. Defining the transfer from system **'A'** to **'B'** is positive then-

$$D_i^A=G_i^A-I \quad , \quad D_i^B=G_i^B+I \qquad 17.16$$

where **'I'** is expressed in GW and is converted to p.u of the total capacity in this example by dividing by 50 GW. Substituting for the demand terms **'D'** and rearranging we get-17.17

$$F_i=(A_p-A_c)(G_i^A+G_i^B)+I(B_p-B_c)(G_i^A-G_i^B)-2\ I^2B_p \quad £M$$

and differentiating to obtain the maximum we get:-

$$\delta\frac{F_i}{\delta I}=(B_p-B_c)(G_i^A-G_i^B)-4IB_p \qquad 17.18$$

equating to zero we get:-

$$I^{opt}=(B_p-B_c)(G_i^A-G_i^B)/4B_p \quad GW \qquad 17.19$$

If we now add in a cost for the use of the transmission we get:- 17.20

$$F_i=(A_p-A_c)(G_i^A+G_i^B)+I(B_p-B_c)(G_i^A-G_i^B)-2I^2B_p-IC_i$$

and differentiating we get :-

$$\delta\frac{F_i}{\delta I}=(B_p-B_c)(G_i^A-G_i^B)-C_i-4IB_p \qquad 17.21$$

which equals a maximum when :-

$$I_{opt}=[(B_p-B_c)(G_i^A-G_i^B)-C_i]/4B_p \qquad 17.22$$

17.5 Example

Using the above theory and the data from section 17.3 an example has been calculated to illustrate the effects. Let a particular generating company have 30% of the capacity in system '**A**' and 10% of the capacity in system '**B**' then we can derive the optimal transfer and associated supply contracts from the above formulation and price /cost functions.

In this example using the functions derived from the model shown in equations 17.10 and 17.11 and figure 17.1 we have

Ap=102.3 ; Ac=70.52 ; Gi(A)=15 GW

Bp=2.82 ; Bc=1.95 ; Gi(B)= 5 GW

Substituting in equation 17.17 we get :-

$$F_i=636.4+8.7*I-5.64*I^2$$

and

$$\delta\frac{F_i}{\delta I}=8.7-11.28*I \quad , \quad I_{max}=0.7712$$

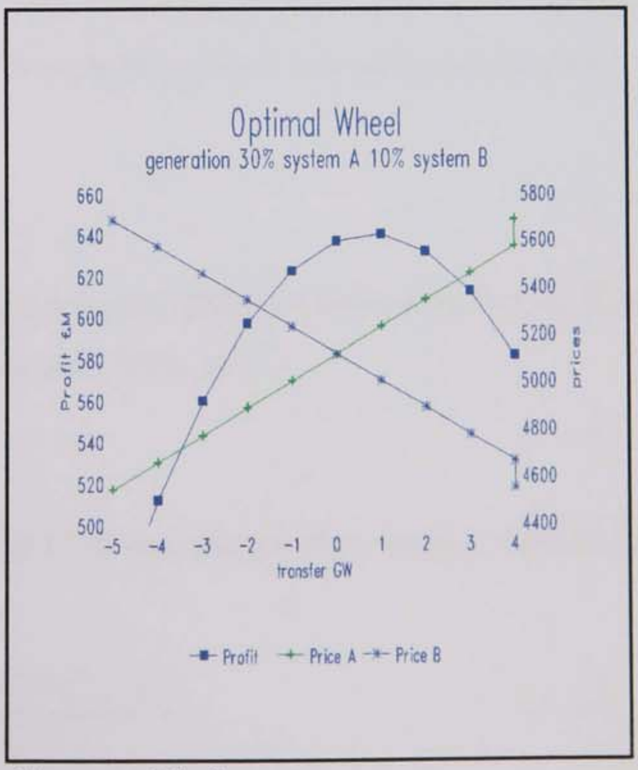

figure 17.2

ie the optimum transfer for this generator is 0.77 GW between the two systems. The transfer from system **'A'** to **'B'** raises the prices in the system where the generator has most of his generation and therefore increases income at the expense of some reduction in income from the customers in system **'B'**. The generator would then seek to establish supply contracts in the two systems consistent with the optimal transfer.The increased profit is £3.35M and if we include a transmission charge of £1.5M/GW/yr then using equation 17.20 to 17.22 it can be calculated that the profit reduces to £2.3M with a transfer of 0.638GW. The profit function and the impact on consumers prices is shown in figure 17.2. It can be seen that as the transfer increases so the prices in the exporting system will rise while those in the importing system will fall. The transfer has the effect of moving generation from system 'A' to system 'B'. The benefit to a particular generator will then be realised by the impact on prices and market share. Since Scotland has over-capacity it is obviously attractive to strike supply agreements in England which would have the effect of raising prices in Scotland and depressing those in England. The attraction of buying into a REC is that it has an established supply business.

Figure 17.2 shows that even though the systems in this case are similar an individual generator may still have a case to establish supply agreements in an adjacent system to optimise his total income. The optimisation at the dispatch phase will seek to equalise marginal prices and may offset some of the proposed transfer depending on bid prices.

17.6 **Transmission Profit**

The transmission company's profit is given by the difference between its income from generator **'I'** and the operating and capital costs of the line. i.e

$$F_t = C_i . I_i - S . I_i \qquad 17.23$$

but we have shown previously in equation 17.22 how the generator reacts to the price of transmission according to the function -

$$I_{opt} = \frac{[(B_p - B_c)(G_i^A - G_i^B) - C_i]}{4B_p} \qquad 17.24$$

we can simplify this to

$$I_{opt}=(K-C_i)/4.B_p \quad where\ K=(B_p-B_c)(G_i^A-G_i^B) \tag{17.25}$$

substituting for 'I' in the profit function we get:-

$$F_t=(C_i-S_i)(K-C_i) \tag{17.26}$$

rearranging

$$F_t=-\frac{S.K}{4B_p}+\frac{(K+S)}{4B_p}C_i-\frac{C_i^2}{4B_p} \tag{17.27}$$

and differentiating to obtain the maximum we get:-

$$\frac{\delta F_t}{\delta C_i}=\frac{(K+S)}{4B_p}-\frac{2C_i}{4B_p} \tag{17.28}$$

equating to zero the optimal price for transmission to obtain most revenue is given by :-

$$C_{opt}=\frac{K+S}{2} \tag{17.29}$$

ie. This is the highest product of price and capacity. At lower prices more transfer would be attractive to the generator but less overall income would accrue to the transmitter. As an example using the figures above then K=8.7 and assume that the cost of transmission S=1.0 £m/GW/yr then

$$F_t=-0.771+0.8594*C_i-0.0886*C_i^2$$

$$C_{opt}=4.85 \quad when \quad I_{opt}=0.34$$

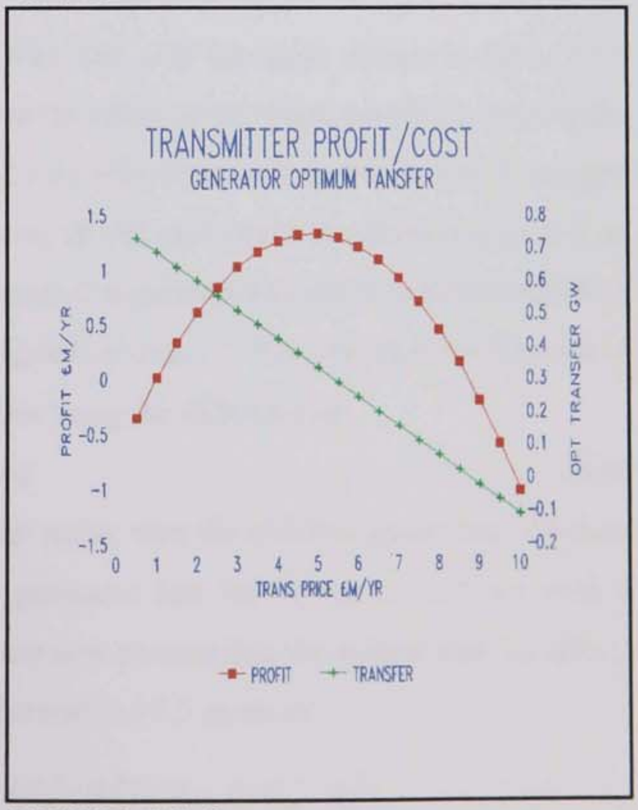

FIGURE 17.3

This is somewhat less than the optimum transfer of 0.77GW when transmission was assumed at zero cost. Figure 17.3 shows the variation in the profit for the transmitter as price varies and the reaction of the generator in changing his transfer.

It has been shown how a transmitter can assess the worth of transmission to a generator and the likely impact of prices on the benefit function. It has also been shown that there is an optimal price which maximises the profit to the transmitter which occurs at somewhat less than the generator maximum posiible investment with a positive return. Investment plans would be formulated having reached agreement with the potential users on funding arrangements to recover the fixed and variable costs. In this circumstance the benefit is shared through a process that results in the transmitters price with profit equating to the worth to the generator. It is less clear how consumers could effectively participate prior to 1998 when the franchise of local REC's is completely removed and supplier's will be able to trade on their behalf across inter-connectors to counteract price movement.

17.7 **System Wheeling**

The difference in slope between the price and cost functions shown in figure 17.1 represents the increasing profit resulting from the effect of low plant margins increasing the marginal prices. This will encourage overall a transfer which will create the lowest margins in proportion to the generation in each zone. In this case whilst the demand in each zone has to be met the generation assigned to meet it is optional and can be accommodated by changing the transfer. The generation assigned to area 'A' **'Ga'** will be some function of the installed generation **'Gi'**with the transfer being the difference.ie

$$\mathbf{Ga=Gi+or-I} \qquad \mathbf{17.30}$$

The price in each zone is determined by **'Ga'** rather than the installed generation. Whereas in the previous example the individual generator had the option to contract with a proportion of the consumers in each zone we now assume that the independant variable is the assigned generation. The profit is as derived in 17.5 given by :-

$$F=A_p(D^A+D^B)+I,B_p(D^A-D^B)-A_c(G_A^A+G_A^B)-B_c,I(G_A^A-G_A^B) \qquad 17.31$$

where '**D**' and '**G**' are the demand and assigned generations in zones '**A**' and '**B**'.Since the generation assigned must equal the demand we gat:-

$$F=(D^A+D^B)(A_p-A_c)+I(D^A-D^B)(B_p-B_c) \qquad 17.32$$

which using the above figures and assumming '**Da'=40GW** and '**Db' =20 GW** reduces to the straight line expression

F=1906+I*17.4

ie. the profit continues to increase as the export increases the prices in the largest generating zone. In practice this will be constrained by the available margin for export whilst continuing to meet demand and consumer reaction to prices.

17.8 **Consumer Reaction**

We assume that consumers have the option to strike supply agreements with generators in either system and will counteract the price rises in system '**A**' by trading with generators in system '**B**'.Their demand sensitivity to a price change is given by the constant '**r**' so that :-

$$D_A^A=D_A(1-\delta p_A r_A) \quad ; \quad D_A^B=D^B(1-\delta p_A r_A) \qquad 17.33$$

and

$$D_A^A=D^A(1-B_p I r^A) \quad ; \quad D_A^B=D^B(1+B_p I r^B) \qquad 17.34$$

But the slope of the price function is given by '**Bp*I**' and
since the change in price is given by the slope of the price function, substituting in the equation above we get :- 17.35

$$F=D^A(1-r^A B_p I)(A_p-A_c+B_p I-B_c I)+D^B(1+r^B B_p I)(A_p-A_c-B_p I+B_c I)$$

which rearranges to :- 17.36

$$F=(D^A+D^B)(A_p-A_c)$$
$$+I[D^A(B_p-B_c-r^A A_p B_p+r^A B_p A_c)+D^B(-B_p+B_c+r^B A_p B_p-r^B B_p A_c$$
$$+I^2[D^A(-r^A B_p^2+r^A B_p B_c)+D^B(-r^B B_p^2+r^B B_p B_c)]$$

substituting the figures above and rearranging we get :- 17.37

$$F=1906+I(17.4-r^A 3585+r^B 1792)+I^2(-r^A 99-r^B 50)$$

This reduces to the straight line function above when '**r**' equals zero and has a maximum value when '**I**' equals.

$$I_{opt}=\frac{(17.4-r^A 3585-r^B 1792)}{2(r^A 99+r^B 50)} \qquad 17.38$$

The variation of optimal transfer with varying consumer price sensitivities is shown graphically in figure 17.4. In this example the response is assumed to be the same in both systems.

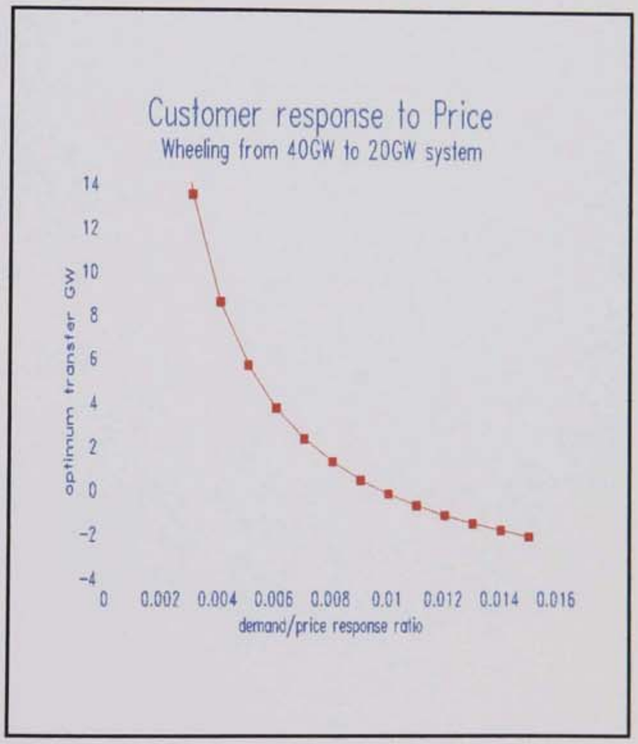

figure 17.4

It can be seen that a relatively small response to price changes is sufficient to reduce the generators optimal transfer to zero. At this point the generators attempt to raise prices through external supply agreements are balanced by customers seeking supply agreements in the reverse direction. In practice there is little evidence of consumer reaction to prices in terms of reduced demand but a significant number of the larger consumers have chosen other than their 'native' supplier and this may increase post 1998 when all consumers will have the option.

17.9 **Discussion**

This chapter has described and formulated the market interaction of generators, suppliers, consumers and the transmitter and illustrated this with examples. It has been shown how an individual generator can affect his profit through striking supply agreements that favourably affect the marginal prices in the two systems in which he is trading. The theory would equally apply to a system using zonal pricing. The effect of the price of transmission interconnection is examined and it is shown how the transmission company could optimise its price so as to establish that level of investment which realises maximum profit. Finally the part played by consumers is examined at the system level and it is shown how their reaction to price affects the optimal transfer in this deregulated market and the importance of their participation to offset price manipulation.

Chapter 18

The Uplift Incentive Scheme

18.1 **Introduction**

The minimum requirement for transmission is to connect generation to the system and to couple it to the local load .With this arrangement the generation output is fully assigned to the local load and has to be varied to track it's changes. Further interconnection of generation and demand to enable pooling is defined as infrastructure development. The level of investment is optional and prior to privatisation was influenced primarily by the needs of system security. Planning standards were used which defined the security to be provided against planned and forced outages. The levels of demand to be met following outages varied with the size of the importing group. This approach did not remove all constraints and at certain times of the year merit order operation could be resticted.

Post privatisation market mechanisms have been established to create incentives for the transmitter to minimise the impact of the transmission constraints on the cost of production by improved operating practices or investment. This chapter discusses how this commercial process may be modelled.

18.2 **Constraint Costs**

If the optimal use of generation is restricted by an active transmission constraint then the increase in costs is defined as the contraint cost.It may result from thermal limitations on line loading or as a consequence of post contingency voltage or stability limits being exceeded. The duration of constraint activity will usually be a function of associated network outages. The traditional approach to assessing the costs has been to undertake scheduling studies with and without the constraint. One modelling approach is to identify groups of generators and associated demand within a zone and to fix the group import and export limits. The effect is to force generation on out of merit in import constrained zones and to force merit generation off in export limited zones.ie.

For an export limited zone:-

$$\sum_{i}^{n} G_i^A - D^A \ngtr E^A \qquad 18.1$$

For an import limited zone:-

$$D^B - \sum_{i}^{n} G_i^B \ngtr I^B \qquad 18.2$$

The cost implications of all the constraints in a complex network are not easily dissociated because they may be nested or overlap. It is however possible to assess the impact of investment in a new line using a generation scheduling study with transmission group constraints.The group constraint is adjusted to take account of the new line on the transfer capability enabling assessment of the change in annual production costs with and without the investment.

Since deregulation generators are allowed to set prices on a commercial basis making an assessment of constraint costs more difficult. Knowing that they may be forced on to meet the constraint their prices may be inflated and any assessment requires some simulation of this commercial behaviour.

18.3 **Uplift Definition**

The total uplift costs are defined as the difference between the outturn costs and the idealised costs. It includes the cost of the constraints as well as extra costs due to generation shortfalls and demand prediction errors. Anciliary service costs to enable management of voltage and frequency are also included.The uplift 'U' is given by :-

$$U = TCA - TCW \qquad 18.3$$

where the Total Cost Actually incurred 'TCA' is given by :-

$$TCA = \sum_{1}^{n} (G_i^W . P_i^W + (G_i^A - G_i^W) . P_i^o + NLC_i . T_i^A + SUC_i . N_i^A \qquad 18.4$$

and the Total Cost idealised Without transmission constraints 'TCW' is given by :-

$$TCW=\sum_{1}^{n} (G_i^W . p_i^W+NLC_i . T_i^W+SUC_i . N_i^W) \qquad 18.5$$

where 'NLC' is the no load cost, 'T' the time on load, 'SUC' the start up cost, 'N' the number of starts and the superscript 'A' refers to metered values and 'W' unconstrained values.

The dissociation of uplift into its various components can be achieved by using actual demand and proven outturn availability in the calculation of TCW.

In practice the transmitter has no control over the actual energy supplied and this is removed from the incentive scheme leaving the residual operational outturn 'OO' where :-

$$OO=TCA-TCW+(W-A) . PPP \qquad 18.6$$

The term (W-A) is negative if 'A' is greater than 'W' meaning that more energy has been supplied than predicted in the idealised study and this serves to reduce the transmitter costs 'OO'.

18.4 **Commercial Incentive Scheme**

There are at least two approaches to managing the impact of transmission constraints either using outturn ex-post prices or predictive ex-ante pricing. Ex-post prices are based on the actual outturn on a near to the event dispatch solution including transmission constraints. The effect of the constraints results in different zonal prices. As the prices are not known until after the event consumer response is effectively disabled. The dispatch is also constrained by the unit commitment solution which will be less than optimal and there is no incentive to minimise the impact of transmission constraints. These shortcomings could be partially overcome by a predictive day ahead constrained study.

The alternative ex-ante pricing uses a predictive full unit commitment solution to derive idealised marginal prices without transmission constraints. The energy supplied according to this schedule is paid at the market SMP. Extra generation forced on in the event is paid at offer price and constrained off generation is paid lost profit. The additional costs are included in 'Uplift' and the transmission company may be incentivised to manage them. Consumers are also given advanced notice of prices and are able to respond by reducing demand. It is this model that has been applied in the UK.

Based on the uplift costs in previous years the suppliers buy in bulk on behalf of their customers and pay the transmitter an annual payment to manage and pay uplift costs. The savings or extra costs about the expected value are shared. The transmission company then has the option to pay outturn prices or to hedge its position by contracting with generation in constrained groups for energy at a predetermined price. There is also an incentive for the transmitter to return transmission to service as quickly as possible by reducing maintenance and repair times.The other option open is to the transmitter is to take post incident automatic action to alleviate the constraint by tripping generation in export constrained groups or redispatching import constrained generators. The incentive scheme applied to date in the UK has only covered one year ahead and does not therefore provide a long term income to provide a basis for independant investment by the transmitter.

18.5 **Transaction Model**

The transactions between the various players are shown schematically in figure 18.1.The consumers pay the suppliers their costs plus a profit margin. The suppliers in turn pay the generators for the energy according to the unconstrained schedule and the transmitter for managing uplift. The transmitter will pay the generator for the additional energy supplied over and above the unconstrained schedule or the lost profit to constrained off generation.

The supplier may choose to contract directly with generators to fix his prices. The transmitter may also choose to contract generation or consumers in import constrained zones as a hedge against price rises.

The independent variables of the problem are the generator prices and consumers response to these in the form of changes to demand. Additionally both the suppliers and the transmitter can strike contracts for a proportion of their energy.

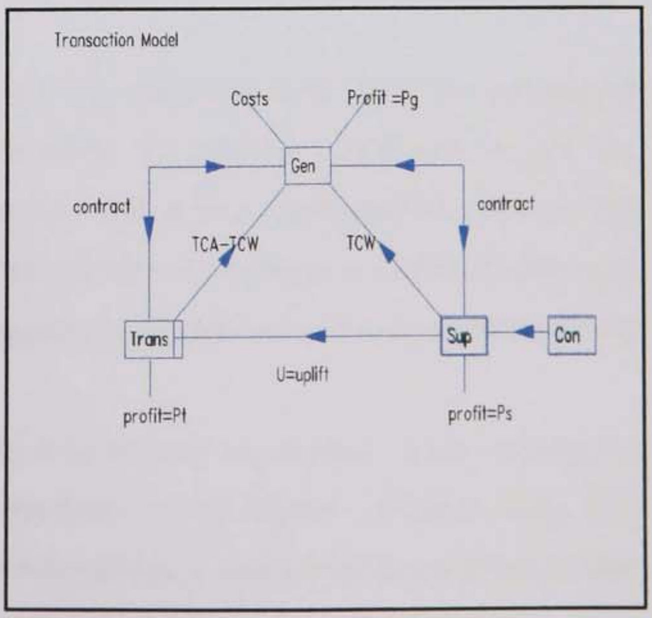

Figure 18.1

18.6 Theoretical Formulation

The generation is assumed to be made up of a potentially constrained part 'Gc' and unconstrained part 'Gu' MWh with representative offer prices 'P_o^c' and 'P_o^u' for each tranche. We assume in this global model that the unconstrained offer price sets the system marginal price and that the demand is accurately predicted.

(a) No contracts

The generator profit 'Pg' is given by the sum of the payments from the supplier and transmitter less the generation costs.

$$P_g=(G^u+G^c)P_o^u+G^c(P_o^c-P_o^u)-G^uC^u-G^cC^c \qquad 18.7$$

The suppliers profit 'Ps' is given by the difference between income from customers and the payments to the generator and transmitter plus a proportion of the transmitter's profit.

$$P_s=DT-(G^u+G^c)P_o^u-U+\alpha(P_t) \qquad 18.8$$

The consumer demand 'D' is itself a function of the tariff 'T'.

$$D=D_o(1-\delta T.r) \qquad 18.9$$

where 'r' represents the p.u change in demand for a change in the tariff.

The transmitter profit 'Pt' is given by the difference between the uplift payment 'U' and the payments to constrained generators and is shared with the supplier so that:-

$$P_t=(1-\alpha)[U-G^c(P_o^c-P_o^u)] \qquad 18.10$$

In this model the independent variable is the generator offer price for constrained generation, with the dependent variable being the consumer tariff and in turn the demand.The tariff 'T' and the uplift payment 'U' will be fixed in advance for a period. The generator ,however, can increase short term profits, at the expense of the suppliers and transmitter, by raising offer prices. Subsequntly tariffs will be increased and demand will reduce as shown in figure 18.2

It can be seen that the transmitter's profit is particularly susceptible to price rises by the generator whereas the supplier can recover his position at the expense of market share. This emphasises the need for the transmitter to strike hedging contracts with generators within constraints to secure their availability at a predefined price.

(b) Contracts

In this example the transmitter strikes contracts with the generators at the initial price for a proportion of the constrained capacity. Let the contracted generation be 'Gt' at a price 'Pt' then the generators profit becomes 18.11

$$P_g = (G^u + G^c)\,P_o^u + (G^c - G^t)\,(P_o^c - P_o^u) + G^t\,(P^t - P^u) - G^u C^u - G^c C^c$$

and the transmitters profit:-

$$P_t = (1-\alpha)\,[U - (G^c - G^t)\,(P_o^c - P_o^u) - G^t\,(P^t - P_o^u)] \qquad 18.12$$

and the supplier's profit will in turn be adjusted according to its share of the transmitter's profit.

Using the same figures as in the example above the new profit lines are as shown in figure 18.3. The generators profit is now curtailed as prices are increased and the transmitter stays in profit.There is now a point where further increase in generator prices will be counter productive.

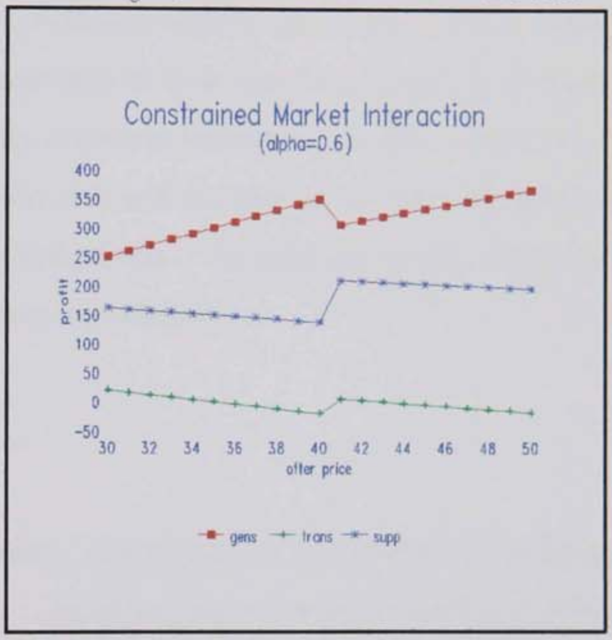

figure 18.2

18.7 Modelling in Operation

At the day ahead stage the value of uplift can be predicted using scheduling studies with known constraints and generation availability and prices explicitly represented. In the dispatch phase the active constraints can be monitored and their costs calculated and displayed by summating the group out of merit costs.

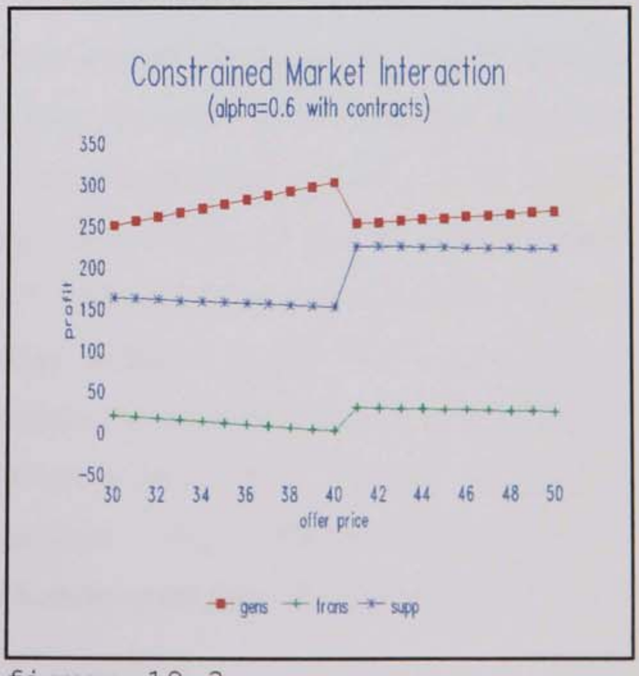

figure 18.3

Studies are also neccessary to plan outages for the 2-6 week period and this requires price and availability predictions. For longer lead times DC network models are used with a single time step dispatch. Since most of the network constraints are currently voltage or stability related this is not satisfactory. It is proposed that more accurate modelling could be achieved by using the DC model to make a quick assessment of all outages and calculating the change in system reactance losses for each outage ie.

$$\partial lossses = \sum_{i}^{n} I_t^2 X_t - \sum_{i}^{n} I_{t+1}^2 X_i \qquad 18.13$$

If this is large it gives an indication of where voltage problems may result. These outages would then be evaluated by a full AC optimal power flow and if neccessary an optimal dispatch would be computed to ameliorate any constraint violation. It is also neccessary to predict the costs and the single time step dispatch will not give an accurate estimate of generation costs or their variation with changing limits . An approach to this, using the dynamic scheduling model, is developed in the next chapter.

18.8 **Conclusion**

In this chapter an approach to the management of constraints through market mechanisms has been described. The theory of uplift has been developed and a simple model has been formulated to demonstrate its operation and the interaction of the market players. The susceptibility of the transmitter to the price rises of constrained generation was shown and how this may be ameliorated by hedging contracts. The current market mechanism does not provide a direct incentive for transmission infrastructure investment since the transmitter can probably make more money from managing the constraints in the short term than from investments with regulated rates of return. A long term transmission incentive scheme is considered neccessary to provide the income stream to support invesment but in the abscence of a knowledge of the worth other players can be expected to resist this approach. The alternative of zonal energy pricing creates a much clearer vision of the potential benefits of transmission in enabling MO operation . The next chapter discusses how the optimal level of investment can be derived from an assessment of active constraint costs.

Chapter 19

Optimal Investment andOutage Planning

19.1 Objectives

The objective is to assess the worth of an increment in transmission capacity in reducing uplift costs by simulating operation through a year taking account of the varying availability of transmission. A parallel objective is to establish the optimal periods through the year when transmission lines should be taken out of service for essential maintenance so as to minimise additional generation market costs. Where the generation is within a zone were generation exceeds demand then in-merit generation may be constrained off by an export limit and the generator will be paid constrained off, lost opportunity profit, at the difference between SMP and bid. Conversely where the demand in the zone exceeds generation then units may be forced on out of merit because of active import limits and the generator will be paid constrained on payments at bid price. Taking account of the variation in these costs through the year the ideal pattern of outages is when the additional costs are minimised and all essential outage requirements are accommodated. The incremental costs at this point indicate the true benefit of an increment in transmission capacity.

19.1 Modelling

The generation loading model was extended to include transmission group constraints (MODELT.FOR). For the import constraints 'I' the limits apply to the difference between the zonal demand and generation and for export constraints 'E' the difference between generation and demand.ie

$$D^A - \sum_1^n G_i^A \leq I_L^A \qquad 19.1$$

where D is the demand in zone A and G the generation.similarly for export constraints

$$\sum_1^n G_i^A - D^A \leq E^A \qquad 19.2$$

Each generator is allocated to a zone and the national demand in each period is apportioned to the constrained zones in accordance with predefined ratios.

19.3 Loading Programme

The procedure for loading in constrained studies is as follows:-

(a) An unconstrained study is run first to establish the SMP for the periods in question using the basic model and the results are stored in a file .(SMPDAT(1).DAT)

(b) For each period the generation within import constrained zones is loaded first in zonal merit order until the imported power is within the constraint limit for the period.

(c) For each period the merit order cost of the last generator to be used is recorded as a

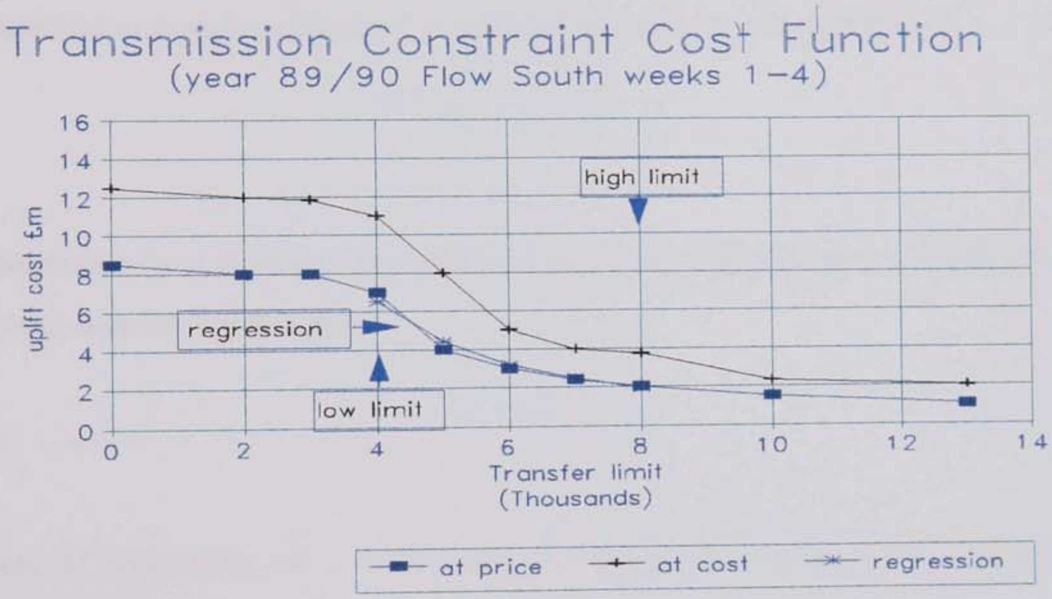

Figure 19.1

pointer to avoid its subsequent re-use.

(d) All remaining generation is now loaded in national merit order until each period demand is met unless the unit is constrained off by an export constraint.

(e) The additional costs resulting from constraint activity are calculated as the product of the energy in each period for each unit and the higher of the SMP or unit cost.

19.4 The Cost Function

Using the new constrained model it is possible to establish the variation in increased costs as the transmission limit (shown in GW) is varied. A typical cost function for a main constraint with nested sub constraints is shown in figure 19.1

The limits for the nested subconstraints are left unchanged and only the main constraint limit is varied. For very low import limits the uplift cost reaches a limit when all the available generation in the zone is in service.ie the lower active limit occurs when :-

$$L^{u}=D_1-G_1^{\max}-G_2-G_3 \qquad 19.3$$

where Gn is the generation in zone 'n' and D the demand. As the limit is increased the constrained on generation will reduce together with the uplift cost until the lower limit is reached when the generation constrained on in the nested constraints together with that generation on in merit in the zone is sufficient to meet the zonal demand. ie :-

$$L_1^{high}+G_1+G_2+G_3^{mo} \geq D_1 \qquad 19.4$$

A regression fit to the active part of the curve showed that the best fit was obtained with a power function of the form :-

$$U_i=A_iL^{B_i} \qquad 19.5$$

where 'U' is the uplift and 'L' is the limit and 'A' and 'B' are constants for the particular period with 'B' being negative. The first derivative of the function is given by :-

$$\frac{\delta U_i}{\delta L_i}=A_i*B_i*L_i^{(B_i-1)} \qquad 19.6$$

or given the derivative the limit 'L' is found for period 'I' using the expression below :-

$$L_i=(A_i*B_i/(\delta U_i/\delta L_i))^{1/(1-B_i)} \qquad 19.7$$

By using the model an uplift cost function can be derived for each period of the year. The shape of the function will be related to the incremental cost curves of the generation in the constrained zone placed in MO. It has generally been found that this can be represented by a power function for UK generation. Other functions may be more appropriate for other types of generation with different cost curves.

19.5 Derivation of Optimal Outage Pattern

The objective is to minimise the total uplift cost across all periods ie.

$$U^T=\sum_1^n (U_1+U_2+U_3...U_n) \qquad 19.8$$

Where

$$U_i=A_i*L_i^{B_i} \qquad 19.9$$

subject to meeting the outage requirement

$$\sum_1^n (L_1+L_2+L_3...+L_n)=K \qquad 19.10$$

The lagrangian function can be written as

$$Z=f(L_1)+f(L_2)...+\lambda(K-L_1-L_2...) \qquad 19.11$$

differentiating to obtain the minimum we get

$$\frac{\delta z}{\delta\lambda}=K-L_1-L_2...L_n \qquad 19.12$$

$$\frac{\delta Z}{\delta L_1} = \delta f_1-\lambda = A_1B_1L_1^{B_1-1}-\lambda \qquad 19.13$$

similar functions are derived for the other values of 'L' .Equating these to zero it can be seen that the lagrangian function will be a minimum when the differentials of the constraint cost function in each period all equal lambda. The problem then reduces to finding that value of lambda for all periods which fixes the limits in each period so that the total availability through the year meets the target and allows for the neccessary maintenance outages.

In practical terms this is what would be expected since if during a period the slope of the cost function is higher than in another then it would be advantageous to move outages to the lower incremental cost period so saving more in the higher cost period. This approach will eventually lead to the slope of the cost function being the same in all periods.

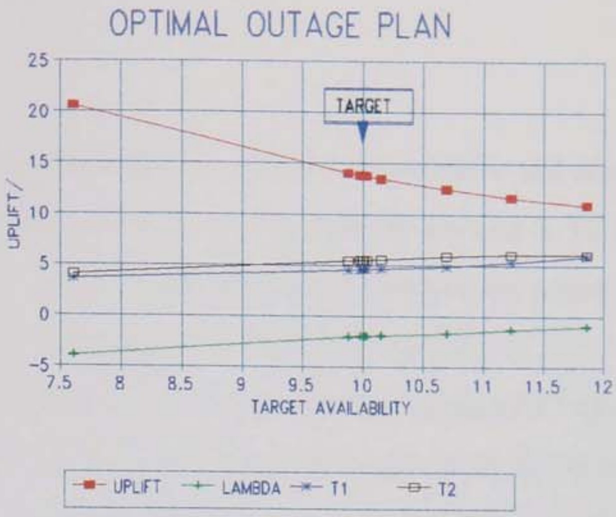

Figure 19.2

19.6 Solution Approach

A computer algorithm OPTOUT.FOR was established as the most convenient way to solve for the optimum lambda. Given a set of cost functions calculated for each period using the constrained operational model the approach is as follows :-

-choose a value for lambda

-derive for each period the value of 'L' using equation 19.7

-check the summated values of 'L' against the target availability to realise the required outages

-adjust the value of lambda, up or down, depending on whether the target is exceeded

-continue to iterate until the target is met within the required tolerance

Good convergence was obtained when lambda was updated using the function :-

$$\lambda = \lambda + 2 * \lambda('e'/'target') \qquad 19.14$$

where 'e' is the error.

19.7 Example

Figure 19.2 shows the output from the algorithm for iterations from below and above the target.In this example the target availability for the two monthly periods is 10 with a maximum for each constraint of 6.0. It can be seen that in this example the target is met when T1=4.5 and T2=5.5. where A1=75.79:B1=-1.77:A2=76.79 and B2=-1.295.

Figure 19.3 shows the total uplift costs on the 'y' axis for differing values of T1 along the 'x' axis where T2 takes a residual value (ie.10-T1) to meet the target of 10. It can be seen that the cost is minimum when T1=4.5 (and T2=10-4.5 ie. 5.5) confirming the theory above.

19.8 Full Year Assessment

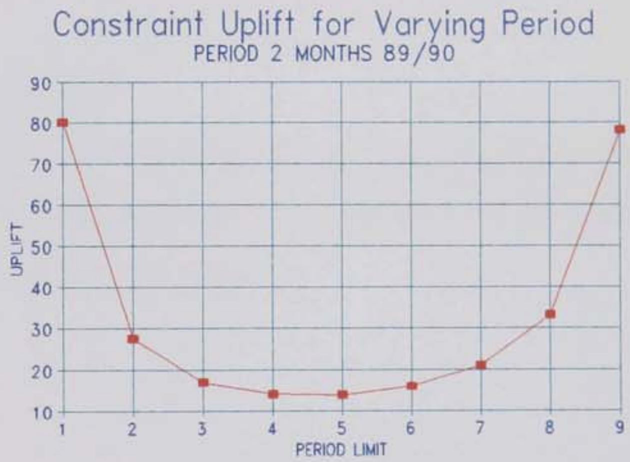

Figure 19.3

The above approach was applied to a full year with a separate function for uplift cost with varying constraint limit being derived for each month. Feeding the function parameters into the optimisation routine (optout) the least cost outage programme was derived for the year. In this example it was assumed that twelve circuits were available with a combined capacity of 6.0 GW and that it was required to take each line out once during the year for one month. The maximum route availability during each month was 6.0 GW giving an accumulated total for the year of 72 GW months with a target of 60 GW months for the year ie. Each line out for one month . The value of lambda meeting this requirement was found to be -1.504 after 7 iterations. This also gives the best estimate of the incremental benefit of additional trnsmission capacity.

For practical use the solution would need to be rounded to the nearest integer value.

It can be seen from figure 19.4 that the pattern of outages is somewhat random reflecting

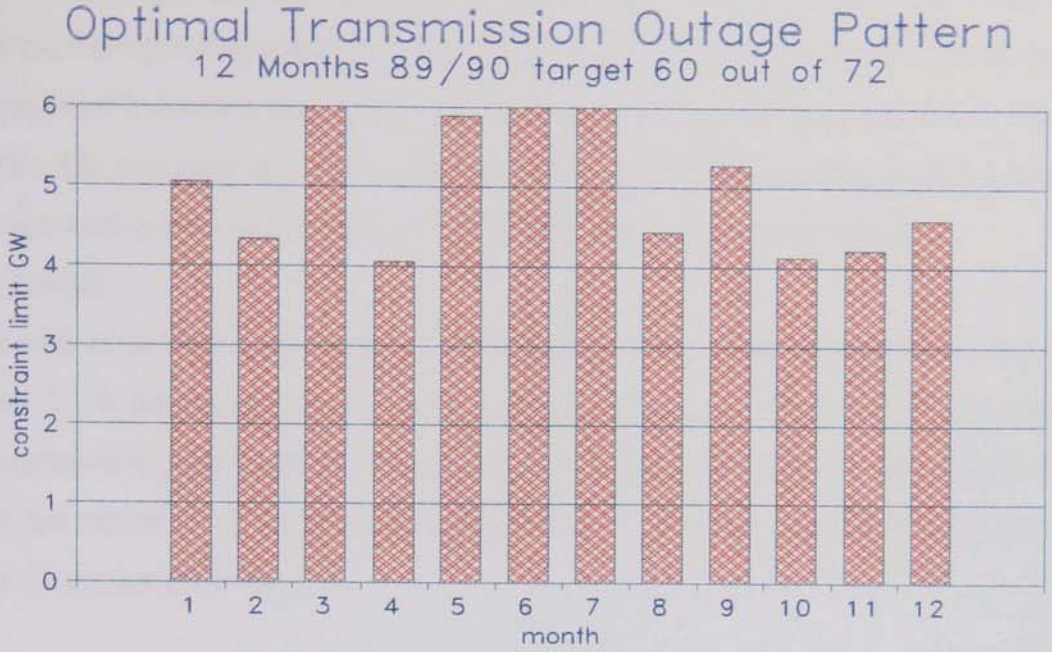

Figure 19.4

the pattern of generator outages and the in-merit generation. It is not neccessarily correlated with demand level as at some high load levels more generation may be on in merit in the constrained zone and the impact of outages would be less.

19.9 Investment Evaluation

(a) Uplift

For an active constraint it has been shown that a non-linear function exists representing the impact on the cost of production with varying constraint limits.It has further been shown that a different function exists for each month depending on generation patterns of availability and the demand profile. Using these functions a technique has been developed to establish that maintenance outage plan giving the minimum uplift cost. This was shown to occur when the incremental cost was the same for each month. This incemental cost also gives the best estimate of the worth of an increment of transmission capacity in reducing uplift costs.

The value of the slope is expressed in £m/month/GW and at -1.504 would equate to a saving of £18m/year for an extra GW of capacity. The cost of any reinforcement will depend on length and line type but the investment would be worthwhile if the annual interest and operating costs were less than £18m in this example. Since the cost function is non-linear it would be neccessary to repeat the study with the changed limit to check the results. The study period of one month was chosen to align with the typical major line route outage used in this study but shorter periods could be used if appropriate.

(b) Losses

As well as savings in transmission constraints the new line would reduce total system losses 'L'. In this example the average route loading 'I' was some 5 GW and assuming that the system was being operated to an (n-2) security criteria with 10 similar lines in service each line carries 'i'= 0.5 GW. Given a line resistance of 'r' then the general formula for the total losses are given by-

$$l = \sum_{j=1}^{n} i_j^2 r_j \qquad 19.15$$

If we assume that all lines have the same resistance and share the load equally then the change in losses is given by

$$\frac{(n+1)(I/(n+1))^2 R}{n(I/n)^2 R} = \frac{n}{n+1} \qquad 19.16$$

In this case the reduction is inthe ratio of 10/12 and given a typical resistance of 0.6 on 100MVA base and an average energy price of £25/MWhr the annual saving would be £0.3m .

Having decided that an investment in increased capacity across a boundary is worthwhile this needs to be translated into a physical line or uprating proposal. If there are a large number of options then the problem becomes a complex mixed integer non-linear programming problem. For small problems mathematical programming techniques based on binary search or Benders decomposition but for larger ones the use of simulated annealing has been advocated.(Romero et al IEEE Pas feb 96)

19.10 Commercial Arrangements

A constrained off generator will see little benefit from infrastructure reinforcement as the profit is protected. Some generators receiving constrained on payments may also lose income.

The transmitter would lose the opportunity to make money from managing constraints. Only consumers and suppliers will benefit but are not in a position to initiate the development. There is a need to establish a long term incentive scheme for the transmitter to encourage cost effective investment. The benefits from this would be shared and that proportion due to the transmitter should result in a benefit function consistent with LRMC.

19.11 Conclusion

It has been shown in this chapter how a function can be derived of transmission constraint uplift for varying constraint limits. This has been used in a lagrangian formulation and it has been demonstrated that the optimal annual line outage plan is derived when the period incremental uplift functions are equal . A routine was built to derive the optimal and this was demonstrated by example for a particular year. It is proposed that the resulting value of lambda provides the best estimate of the worth of an increment of transmission capacity. Finally the benefit of reduced losses is discussed and the overall commercial arrangements.

Part 2 of this thesis has reviewed international practice in charging for transmission services and the shortcomings in encouraging the optimal level of investment. Methods of apportioning the costs are described which take account of the benefit derived by the market players. An approach has been developed to assess the worth of transmission interconnection and to establish the optimal prices and levels of investment for the transmitter. The uplift costs resulting from constraints in the infrastructure are analysed and a technique is developed to appraise the worth of additional capacity and optimally plan outages.

It is difficult to see how the current market structure will meet all the requirements identified in section 15.2.ie.

- open transmission access is provided but with discriminatory location charges.
- there is no obvious mechanism to encourage the optimum levels of investment
- there is a mechanism to encouage efficient real time operation but no mechanism

to optimise the medium term outage plan.

- there is very little scope for consumer participation in the current market.

It has been suggested that a market based on zonal SMP's may be more conducive to encouraging the optimum level of transmission investment by providing visible evidence of the effect of constraints on day to day prices. The beneficiaries who would act as sponsors would also be clear.

In the USA open access is being enforced by federal dictate and proposals have recently been advanced to establish joint regional transmission groups to coordinate activities.(Vojdani 96) This would address some of the perceived shortcomings by ensuring fair governance, open access and joint planning. In the UK a user group is also being established to oversee the operation of the transmission services scheme. These initiatives will address some of the issues but it may then be difficult to find willing owners for transmission.

Part 4

Regulation and the Future

Chapter 20

The Role and Effect of Regulation

20.1 The Role

Where a natural monopoly exists, as in electricity transmission and distribution, regulation is applied in the form of a price cap within which the company can maximise profits by lowering costs. The alternative of allowing parallel development of these systems would clearly be an inefficient use of resources. In the case of transmission, the regulatory formula for the maximum average charge in £/kw 'M' in year 't' is:-

$$M_t = [1 + \frac{RPI_t - X_g}{100}] * P_{t-1}.G_t - K_t \qquad 20.1$$

where Pt-1 is the price/kw in year 't-1'which is in turn a function of that for previous years ie

$$P_{t-1} = P_{t-2}(1 + \frac{RPI_{t-1} - X_g}{100}) \qquad 20.2$$

and Pt-1 for 93/4 = £21.496

Gt = scaling factor based on average cold spell demand in kw weighted according to the average of the previous five years

RPI= retail price index

X=target percentage reduction in prices

For distribution the formula is-

$$M_t = [1 + \frac{RPI_t + X_d}{100}] * Pd_{t-1}.A_t - Kd_t \qquad 20.3$$

and for suppliers the initial restriction on charges was -

$$Ms_t = [1 + \frac{RPI_t - X_s}{100}] * Ps_{t-1} + Y_t - Ks_t \qquad 20.4$$

In each case the general form is that the maximum average charge is a function of the retail price index (RPI) and a target adjustment factor 'X' which is reviewed from time to time by the regulator. The charge for transmission is scaled according to the previous price and also 'G' the maximum demand factor, in the case of distribution a factor 'A' based on the losses is used. For suppliers an additional factor 'Y' is introduced which is given by-

$$Y_t = E_t + F_t + T_t + U_t + S_t \qquad 20.5$$

where 'E' is the energy, 'F' is the fossil fuel levy ,'T' is the transmission charge ,'U' is the distribution charge and 'S' the settlement charge. A correction factor 'K' is subtracted to cover for over or under recovery in previous years.

The above applies to those activities undertaken to meet the licence commitment as opposed to contracted unlicenced services.(Dept.of Energy 1990)

The various players in the market are granted licences by the Secretary of State for Energy which include an overview description of their responsibilities. The regulator is responsible for monitoring and enforcing the licence and can call for appropriate amendments in consultation with the MMC. The Director has described his role as that of a referee and will adjudicate in disputes between licensees or licensees and consumers. (Littlechild 91)

In particular, he will review the price conditions in the transmission licence every few years. In the review he will call for information from the industry and will take reports from the consultative committees and his own staff.

20.2 International Experience

Regulation of monopolies has been practiced for many years in the US and is known to suffer from a number of problems. The structure encourages protracted judicial debates creating opportunities for lawyers and lobbyists, resulting in lengthy rate setting operations. The regulator tends to be persuaded to the side of the supplier given the wealth of information that can be made available to make their case.

Where the price control is set to allow a defined return on assets employed, over-investment is encouraged. The formula proposed for the UK was designed to overcome this deficiency but has the problem that if it continues to be tightened it destroys incentive. It can also reduce investment if perceived shareholder value is reduced giving rise to less favourable borrowing terms and the need for higher returns on capital investment.

20.3 UK Experience

OFFER believe that progress in introducing competition is being made in that the market share of the two largest generators has dropped from 74% in 90/91 to 61% in 93/4, but accepts that these two players are still able to control prices. (Offer Report July 1994). Although all energy is traded through the pool , it is generally believed in the industry that some 80% is covered by bilateral contracts for differences.

On the supply side, the progressive removal of the REC franchise has enabled Second Tier Suppliers to enter the market with some 60% of customers, with demand greater than 1MW, taking supplies from other than their local REC. In the case of the emerging 100kW market, some 28% are contracted with other suppliers, although not without problems in introduction. The planned complete removal of the franchise in 1998 is in doubt because of the enormous investment required in metering and settlement systems (expected to cost some £300M).

20.4 Impact on Generation and Transmission

As the government believed that generation was not a natural monopoly, (Parkinson Sunday Times 25/2/88), price control was not neccessary as this would be affected by market forces. In practice, whilst the market is dominated by the two large players, an effective duopoly exists. Recognising this position, the regulator has, under threat of referral to the MMC, called on these generators to maintain price control to prescribed limits and also to dispose of a proportion of their generation.

In his 1996 proposals the regulator has seen the need to impose a one off reduction in NGC transmission charges of some 20-28% with a further annual reduction of RPI-4% for the following three years. This discontinuity in income levels makes investment appraisal very difficult.

The regulator also ruled on 6 August 96 that Scottish Power and Hydro Electric could use the full interconnector capacity to export to England and Wales. Prior to this decision the amount of capacity available was restricted by that contracted to generators in the south to export to Scotland even though the power flow was in the reverse direction. In contractual terms it was assumed that a proportion of the link capacity was sterilised even though in physical terms the power would flow in the reverse direction.

20.5 The Nuclear Position

The government originally planned to sell off the nuclear stations as part of National Power and was the reason why NP was established as the larger generator to be able to bear the costs. On the 9 November 1989, the government cancelled these plans as it was advised that NP would be unsaleable. It was claimed that the true cost of nuclear power was some 9p/kWh, as opposed to gas at 3p/kWh and that a levy was necessary to support nuclear power. The Non Fossil Fuel Obligation (NFFO) was proposed which required the new REC's to purchase at least 15% of their energy from non-fossil sources including wind and wave power. To cover the decommissioning costs and any excess costs arising from purchases from other non fossil energy sources, all suppliers are required to pay a nuclear levy to the regulator. The levy is expected to be phased out in 1998 when sufficient funds should have been put aside for decommissioning.

The overall impact of the levy was expected to raise the final price to customers by some 10%. As these costs are added at the supply stage they do not affect the working of the pool but the levy does distort the market. It artificially raises prices and discourages investment in electricity plant in industry. It has been proposed that VAT on the end domestic use of fuel would be preferable , rather than on industrial users, otherwise UK industry is disadvantaged. (Newbery 93). As the levy currently recovers some £1.3b/yr against the requirement for an accumulated sum of some £9b for decommissioning a VAT set at 17.5% would be necessary. A further advantage is that this would avoid having to pay benefit from the levy to EDF of £95m/yr.

20.6 Impact on Investment

The threat of referral to the MMC is seen by investors as an unpredictable influence on future returns and is likely to discourage longer term ventures in favour of investment to realise short term profits. This is evidenced by the rate at which staff have been shed to reduce costs (one of the easiest options) and gas generation has been built to take advantager of the short construction times. The proposal to break up the larger generators discounts any benefits from economies of scale and will further reduce the industries ability to finance large fossil and nuclear stations and plant development. The NFFO/ nuclear levy further distorts the operation of the market and consumer investment.

The price regulation on distribution and transmission discourages investment and development and focuses attention on presenting the best face to the regulatory review. Where prices are set to provide a reasonable return on assets employed, over-investment may be encouraged. Regulation does not provide a mechanism to establish the optimum level of investment as described in chapter 19.

It is considered that the process of regulation, as currently framed, is not likely to encourage either the right level or type of investment necessary to promote long term efficiency and price stability. At best, it introduces instability in short term markets in the interests of promoting the illusion of competition and efficiency.

Chapter 21

Principal Findings

21.1 The Market

The current arrangements for the UK electricity market were described through chapters one to three and the outturn perfomance was reviewed. Shortcomings were identified in the market mechanisms to encourage the optimal generation margin and mix and in realising stable low prices through competition. It was suggested that outage planning could only be loosely coordinated and that the generators immunity from transmission constraints provided opportunities for gaming. Transmission losses are not currently managed and the charges for use of transmission do not signal investment opportunities.

The development of models to analyse the problem was discussed in chapters four and five. The mechanisms through which market players could assess their income and expenditure were shown schematically to illustrate how they would interact in the market. A dynamic model to simulate operation was developed which included those characteristics considered essential to be representative of pool operation. The program structure was developed and its performance was demonstrated by comparison with results recorded from actual operation.

The theory of system marginal pricing and its relationship to plant mix was developed in Chapter 6. Both a graphical and an LP formulation of the optimal plant mix problem were developed and used to illustrate the relationship between load shape, plant mix and SMP. A dichotomy was shown where the current market mechanisms do not encourage the development of peaking capacity whereas the profit of base load generation is very dependent on those periods when SMP is set high by peaking units with high operating costs. Comparison of results with full simulation studies and actual values were used to validate the proposition. It was concluded that the classical approach to investment appraisal was no longer applicable.

The theory supporting the loss of load element of pool pricing was developed from first principles in Chapter 7 and used to establish a relationship between LOLP and plant margin.

It was shown how the number of generators affects the LOLP and how to derive the consumer benefit from its reduction and generator pooling. Finally it was shown how the optimal plant margin could be derived ie. when the cost of additional generation equated to the change in consumer benefit from reduced LOLP payments. It was concluded that the current distribution of LOLP payments to all generators in accordance with the energy produced is unlikely to encourage the optimal plant margin and distorts energy prices. It is suggested that the payment should be focussed on encouraging and financing additional capacity.

In Chapter 8 the theory supporting the derivation of the ideal energy and capacity prices was discussed so as to equate incremental cost to the consumer added benefit. A comparison was made against the extrapolated use of bulk supply tariff (BST) charging and actual. It was concluded that energy prices were some 12% above marginal costs and what would have been charged via the BST.

The closing chapters of part one review the market mechanisms and suggest alternatives. It is postulated that the key to containing future electricity prices lies in establishing the ideal level and type of investment in generation and in enabling full consumer participation in the market. It was argued that this requirement was unlikely to be met by a day ahead market. It is proposed that a more effective market could be established using a medium term prediction of operation rather than a day ahead market. It would be designed around an optimisation algorithm employing Lagrangian principles that would enable the predicted SMP profile to be published to support investment decisions against accurate data whilst maintaining commercial confidentiality. It should also facilitate consumer participation and lead to more stable prices. It was argued that a market developed taking account of the principles of optimisation algorithms and providing simulation in timescales more consistent with investment appraisal offers the best prospect of realising long term efficiency in the industry.

21.2 Generation Investment Appraisal

Part 2 reviewed the implications of deregulation on the approach to generator investment appraisal. The classical technique based on an LP formulation, with the objective function set to minimise costs, was described in chapter 11. A new iterative LP formulation was developed to maximise generator profits and it was used to confirm that this produced different results. It was explained that this resulted from all energy being paid for at the marginal price. The implication is that more profit can be derived by the retention of older higher cost units that will set high SMP's from time to time and result in more profit from all energy sold than would be realised from the replacement of the marginal unit. The results confirmed this by showing the retention of a higher proportion of small coal stations.

It was postulated that the high dependance of the outcome on the SMP makes it essential to predict it using a dynamic model simulating the effect of start up costs and generator dynamic constraints in tracking demand. The theory and approach were developed in chapter 12 based on the operational simulation model coupled with a post processing algorithm to derive utilisation, costs and hence profit. The model was used to demonstrate the optimal bidding strategy and to predict the profitability of CCGT's and nuclear against coal and oil.

The key factors affecting the future SMP were discussed and it was shown that marginal prices had risen in excess of inflation and fuel costs suggesting that the market was being manipulated.

In chapter 13 a function of the relationship between the overall generator per unit profit and additional capacity was derived and used to develop the theory and show how total profit varies with capacity and reaches a maximum when the product of price and capacity is higher than the effect of depressing the price by adding more capacity. The theory was used to show how two generating companies may interact through the market to establish their optimal share of profit. Three alternative economic models were described based on a duopoly, Stackelburg equilibrium and the Cournot theory. The results further highlighted the difference between maximising profit and minimising cost. It was shown that it is in the interests of generators to contain capacity and keep SMP and LOLP high. Finally the overall process of appraising investment options was developed including; the use of the new LP formulation to establish the total system capacity position; the use of the dynamic operational model to establish accurate SMP and profit estimates; and using the profit function and interaction model to estimate market share and the optimum capacity addition.

The final chapter developed a model to enable the prediction of the interaction of several generating companies through a market. It was shown how a system profit function could be estimated from the representation of the demand profile by a statistical distribution function and the system MO price by an exponential. It was shown how this could be used to support a model to simulate company interaction taking account of their existing capacity and market share. The results of studies were shown to exhibit similar effects to the actual capacity additions that have occured. It was concluded that the process is unlikely to result in optimal expansion planning.

21.3 Transmission Investment Appraisal

Part 3 reviews the impact of deregulation on the process of transmission investment sponsorship and appraisal. The different electricity market structures that have been implemented or proposed around the world are reviewed and the common themes and apparent shortcomings are identified. It is generally accepted that that transmission open access is the key to realising a competitive market in generation and supply and that it should be managed as a separate company. There is less consensus on the methods used to establish and apportion charges and none of the approaches appeared to provide a basis for the sponsorship or appraisal of transmisson investment other than where the transmission owner acts as an energy wholesaler.

A proposal for the apportionment of costs in relation to benefit was developed in chapter 16 and it was suggested that different principles may need to apply in dealing with the existing systems, built prior to deregulation, as opposed to new investment which should be sponsored by the key beneficiaries. A distinction was drawn between investment in new connections ; interconnection and and the infrastructure each requiring a different approach to the evaluation of benefit and investment.

Models were developed to illustrate the market interaction of generators, the transmitter and suppliers/consumers and the respective benefit deriving from system interconnection. The concepts would equally apply to the evaluation of interconnection between different price zones within the same system. It was shown how a generator may benefit through his supply contracts by manipulating prices in those zones by 'exporting generation' through interconnectors. The effect of the price of transmission on the optimal level of transfer for the generator was calculated and the theory was developed to establish that price giving the maximum return to the transmitter. Finally the impact of consumers response to prices was included to demonstrate their importance in containing escalation.

In chapter 18 the concept of 'uplift' was introduced to describe the increased operating costs resulting from active transmission constraints. A transaction model was used to show the impact on the various market players of the constraints and how they may interact. In particular the exposure of a transmitter, with commercial responsibility for uplift, to generators raising 'constrained on' prices makes it essential to establish hedging contracts. It was proposed that a long term transmission services incentive scheme would be necessary to encourage the transmitter to establish the optimal levels of investment as opposed to the year ahead scheme currently in place. An alternative approach would be to establish a system based on zonal marginal pricing which would more clearly illustrate the impact of constraints on particular players and the benefit to them of investment to remove them.

The original model used to simulate operation was further developed to model transmission group constraints as described in chapter 19. This was used to derive a function describing the incremental effect of changing constraint limits on production costs. Lagrangian principles were applied to establish an approach to identifying the optimal transmission outage plan when the period incremental lambda's equated to the same value. It was proposed that the resulting value of lambda provides the best estimate of the worth of an increment of transmission in reducing out of merit operating costs. The chapter concludes with an assessment of the benefit also arising from reduced losses and a discussion of the commercial conditions neccessary to sponsor and promote the optimal levels of investment.

21.4 Conclusions

The theory of the market has been developed and tested against outturn and models have been developed to enable investments to be appraised and to predict the strategy of other market players. They serve to illustrate the difficulty and uncertainty facing potential investors and it is difficult to see how the current day ahead market will help to encourage the optimal levels of investment in either generation or transmission.

A medium term market was proposed set in timescales more consistent with investment, offering the opportunity for customer participation and realising a solution closer to optimum. It was also proposed that transmission development may be better served by introducing zonal market energy prices to focus on the costs and benefits of transmission. In general it would appear more tractable to start from a model of what is needed to optimise a system and build a market around it rather than start with a simple market notion and then try to develop its price messages to encourage optimality.

Chapter 22

The Future

22.1 Is the UK Market Delivering Benefit

In chapter 1 it was suggested that a proper outcome of privatisation would be:

- to ensure that true competition is established with prices reflecting marginal costs and equating to consumer value
- to ensure that customer influence exists in the market through choice of energy use and the level of security of supply.
- to encourage those levels of generation and transmission investment that optimally meet the expected consumer need whilst recognising social and environmental issues.

It is difficult to conclude other than that the market has failed to deliver customer benefit through reduced prices. There is evidence to suggest that energy prices have risen above what would have applied under the previous regime and have certainly been more volatile. These rises have been ameliorated by savings in transmission and distribution primarily through staff cuts which may create longer term support problems. More generators have entered the market but the developing dependance on gas supplies with interruptable contract terms may put the system at risk at times of stress.

Consumer choice in suppliers is being developed and taken up but little has been done to enable consumers to participate actively in the market so as to influence prices.

In the abscence of any accountability for meeting demand there have been several near misses when generation shortfalls have put the ability to maintain supplies in jeopardy. There has also been pressure on the transmitter to adopt 'n-1' as opposed to 'n-2' circuit outage security standards in planning and operation of the system introducing further risk to supplies.

It is difficult to see how optimum planning and investment can be realised through the market mechanisms and eventually this could lead to further price rises. Some of these issues are being addressed and the UK regulator has called for the larger generators to sell off a proportion of their plant to reduce their market dominance The removal in 1998 of the REC franchise will increase customer choice. There are also proposals to review LOLP. It is doubtful if these measures alone will meet all the criteria above.

22.2 The Economic Theory

There are schools of economic thoery that private ownership and the pressure deriving from that are essential to promote efficiency. The 'property rights' theorists see take-overs as the ultimate threat to inefficiency. Government ownership is not considered effective as its directions are politically driven rather than designed to promote efficiency. There is no doubt that maintaining shareholder value motivates directors as they are most likely to loose their jobs in the event of takeover.

There is a counter view that private capital markets encourage short-termism at the expense of long term strategic investment. The threat of takeover is not neccessary to promote efficiency as evidenced by the performance of Japan and Germany where takeovers are rare. Costs in the electricity sector are more likely to be minimised by long term integrated planning rather than short term opportunism. Public ownership gives the opportunity to maintain stable prices which are essential to enable the appraisal of appropriate industrial investment.

The efficiency of the electricity industry is dominated by fuel costs and interest and depreciation charges . The CEGB annual report for 87/88 shows that of the total costs of £7.8b fuel costs were £4.5b and depreciation and interest £1.5b with other services and staff costs making up the remaining £1.8b. These costs are in turn the result of previous investment decisions and the diversity established in alternative fuel sources. In practice this was realised by creating a plant mix and the use of dual fired stations and maintaining the appropriate plant margin. It is arguable that much of the apparent benefit of privatisation in containing energy prices could have been realised if the CEGB had been allowed free choice in use of fuel to take advantage of cheap gas. The 'dash for gas' could have been managed without premature closures and loss of diversity. In the longer term the over-dependance on the gas grid may jeopardise system security. It is against this background of fundamental differences of principle that the industry is moving foreward along a number of different paths.

22.3 Alternative Structures

Several structures have been proposed for managing electricity supply including:

- the vertically integrated monopoly of which there are many examples
- the generation single buyer who acts on behalf of all consumers to purchase energy in a competitive market.
- a hybrid of public ownership supplemented by private generation.
- full competition in generation and supply as is being implemented in the UK.

It is arguable that most of the benefit to be derived from electricty privatisation is realised by creating competition in generation whereas transmission and distribution are essentially monopolies with ownership vested in the public or private sector.

The advantage of public ownership of generation is in creating a base to support the development of large scale hydro or nuclear that would be difficult to finance privately and in enabling integrated planning. The disadvantage is the abscence of competition.

A mixture of public and private ownership still retains the ability to plan and support infrastructure developments whilst introducing an element of competition and is the model preferred by EdF as the european compromise. The public utility would take on responsibility for securing supplies and coordinating system development but would be required to accommodate initially some 15% of private generation. It is suggested, however, from experience in the US that fair open access is not given to non utility generation (NUG's) nor are they considered to contribute to firm capacity and plant margins.

The full private ownership implemented in the UK in theory introduces competition in supply as well as generation by progessive removal of the REC franchise.It has been suggested ,however, that in practice a duopoly exists and that the generators will act in their group interest. It also has the serious disadvantage of not enabling integrated planning which is likely to have a more adverse impact on prices.

It appears generally accepted that some level of competition in generation is desirable together with open transmission access. It is not clear how the benefits of integrated planning of generation and transmission will be retained This thesis has, amongst other proposals, advanced an alternative to address this shortcoming of the private market by establishing a forward market to support investment planning. This could be enabled as an information service or with a principal establishing contracts. The proposal also has the advantage of enabling consumer participation in the market and providing a degree of price stability. The same process should also enable the transmitter to identify investment opportunities and realise the benefit from investment. These proposals would not obviate the need for a short term day ahead market to take account of outages and demand estimation errors.

22.4 Alternative Working Arrangements

It has recently been recognised by FERC (the Federal Electricity Regulatory Commission in the USA) that operation of the power system could be managed by an independent body and not by the transmission owner as in the UK model. The Independent System Operator (ISO) would operate to rules jointly agreed with all the market players to ensure equitable treatment. It has also been advocated that the operation of the daily spot market or power exchange should also be a separate from that of system operation to ensure open access and fair treatment. The exact working arrangements have yet to be defined but it represents a considerable challenge to implement these proposals while providing sufficient controls to the ISO to maintain system security. In the UK model the problem is decomposed so as to enable the market processes at the day ahead stage with the system operator left to manage actual generation availability and transmission constraints on the day. Prices are not allowed to change on the day and only plant parameters can be redeclared. Pressure is likely to increase to enable market price changes on the day and consideration needs to be given as to how the operational problem can be decomposed to enable this.

22.5 The Way Forward

It is likely that other countries, having observed the operation of the UK market will adopt alternative arrangements which may prove more effective. New Zealand are likely to introduce zonal pricing. The US is placing most emphasis on realising open transmission access against published rates. The French authorities are adamant that public ownership best suites their needs. The future performance will be viewed with interest from around the world and all will no doubt claim a measure of success. In practice different structures will probably be applicable depending on the state of development of the system. A developing country will probably benefit from state ownership to support development of its infrastructure.

Developments are currently being driven at the political and commercial level and there is a danger of discounting and loosing the benefits of optimal planning and operation developed to support integrated utilities. This thesis has provided a basis framework from which to model and analyse performance and many of the principles would equally apply to other structures and enable a more considered and structured approach to deregulation.

22.6 Further Research

There remains considerable division of opinion on how the electricity supply industry should be structured and operated both between engineers and economists and also from one utility and country to another. To what extent these differences reflect vested interests is not clear but currently there appears little common ground and recent regulatory decisions on takeovers in the UK have not served to introduce clarity. There would be benefit in esablishing a theoretical framework ,developing the concepts introduced in this thesis, to enable a more considered view of the options. This could include :

- to establish technical/economic models of alternative industry structures and their associated markets to enable a review of their merits in relation to the state of develoment of the generation and transmission system with respect to plant mix and transmission constraints.

- to examine the alternative market signals to SMP and LOLP and the mechanism of there derivation to support both optimal planning and operation and to demonstrate their effectiveness

- consideration of alternative ways of introducing competition in generation without loss of overall optimality including the single buyer model and a balanced mixture of public and private ownership.

- to develop a basis for use of transmission and distribution charging that recognises sunk costs and encourages the ideal level of investment

- to develop techniques to support alternative modes of operation including bilateral trading and the disaggregation of the market and system operation

- to develop techniques to support combined MW and MVAR scheduling and dispatch within an active and reactive market

- to develop techniques that enable the process of generation and transmission resource allocation to be managed in an equitable open framework

- to develop the means to evaluate and balance overall generation and transmission economy with security against consumer need in both planning and operational timescales.

22.7 Conclusion

This thesis provides a basic framework of understanding and modelling to enable the evaluation of alternative commercial structures and market mechanisms. It has been used to illustrate the operation of the market and the interaction of the players. New techniques have been developed to appraise investment options in a deregulated environment and these have been evaluated against outturn. It is concluded that the current market mechanisms offer a crude alternative to realising optimum efficiency when compared to what could be achieved with a vertically integrated utility and hence will result in higher costs. Alternative market mechanisms have been proposed to enable the benefits of integrated planning and competition without loss of commercial confidentiality. The proposal also enables greater influence by consumers through suppliers on prices and the quality of supply. For transmission it is proposed that charges for 'sunk' assets should be separated from new investment and that zonal energy charging would create improved cost messages.

Appendix 1

A unit commitment algorithm based on Lagrangian multipliers and dynamic programming

1. Problem definition

Over the period of the scheduling study we wish to minimise the total generation cost consisting of running and start-up costs

$$\sum_{1}^{t}\sum_{1}^{i} MOC_i(G_i(t))+STC_i(SD_i(t),ON_i(t)) \qquad \text{A1}$$

where 'MOC' is the merit order cost in £/MWhr, 'G' is the unit output in MW, 'STC'is the start up cost and 'SD' and 'ON' are variables representing the period that the unit has been shut down or on. The minimisation is subject to the following constraints:
(a) The summated generation ouput equals the demand in each time period.

$$\sum_{1}^{i} G_i(t)=D(t) \qquad \text{A2}$$

(b) The generator if operating has an output between its upper and lower limits.

$$AVAIL_i(t)\leq G_i(t)\leq MGEN_i(t) \qquad \text{A3}$$

(c) The generator being on or off for periods which do not violate the the minimum up and down times.

$$\begin{array}{ll} 0\leq ON_i(t)\leq MONLT_i & state=on \\ MOFLT_i\geq SD_i(t)\geq 0 & state=off \end{array} \qquad \text{A4}$$

where ' ON(t)' is the cumulative time that the unit is on and 'SD(t)' the cumulative time that the unit is shut down
(d) That the run up and run down rates are not exceeded between successive schedules.

$$-RDR_i \;\leq\; (G_i\,(t+1)-G_i(t)) \;\geq\; RUR_i \qquad \text{A5}$$

where 'RDR' is the run down rate and 'RUR' the run up rate.
(e) The reserve requirement being met.

$$\sum_{1}^{i} RES_{i,j}(t) > RESR_j(t) \qquad \text{A6}$$

Where the reserve function is maximum at the effective optimal load point and is zero at outputs > 0.95. (Cohen 87,Oliveira 92)

The basic algorithm described above has been successfully applied by a number of utilities but without modelling transmission constraints. To meet the needs of the UK and possibly other utilities providing open access in the future the author proposed to extend the basic model to include these additional constraints. It was proposed that the most practical way was to represent the transmission system, not explcitly, but as zonal group constraints around a collection of generators within a common part of the network where constraints exist. Then the units must also obey the limits between exporting and importing constraints.

$$\sum_{1}^{i} G_i(t)+RES_{i,j}(t) < EXP_a(t) \qquad \text{A7}$$

ie the net capability of the zone to export generation together with local demand.

Similarly for import constraints

$$IMP_a(t) < \sum G_i(t) \qquad \text{A8}$$

the sum of the generation must be such as to contain imports to meet local demand.

2. Primal/Dual

The problem can be decomposed to individual unit solutions by including the coupling constraints in the cost function ie., generation requirement, reserve and transmission limits using Langrange multipliers. The solution of the primal problem with multiplier fixed can then proceed.

The dual variables are:

GAM1 (t)	demand
$GAM2_i$ (t)	reserve
$GAM3_a$ (t)	export area 'a'
$GAM4_a$ (t)	import area 'a'

and the object function is to minimise

$$\begin{aligned}\textstyle\sum_t \sum MOC_i\ (G_i(t))+STC_i(SD_i\ (t),ON_i\ (t))\\ -GAM1(t)\times G_i(t)\\ -\textstyle\sum_j GAM2_j(t)\times RESj\,(G_i(t)\\ +\textstyle\sum_a GAM3_a(t)\times\sum G_i(t)\\ -\textstyle\sum_a GAM4_a(t)\times\sum G_i(t)\end{aligned} \qquad \text{A9}$$

where GAM 1 is the shadow cost of the demand constraint and will equal the system marginal price at the solution.

Re-defining the multiplier generally as GAM_n in the above reduces to

$$MIN\sum_{1}^{N}\sum_{1}^{T}(MOC_i(G_i(t)+STC(SD_i(t),ON_i(t)) \\ -\sum_{1}^{n} GAM_n(t)\times Q_{n,i}(t) \qquad \text{A10}$$

where $Q_{n,i}(t)$ is the amount unit (i) contribute to constraint n

Starting with an initial set of multipliers the primal problem is solved by varying the primal decision variables ie generation. This solution is then used to check the constraints and update the multipliers by the subgradient method ie.,

$$GAM_n(t)(k+1)=GAM_N(t)(k)+ALPH_k\times(REQ_{n,t}-\sum_i Q_{n,i}(t) \\ ALPH=\frac{1}{(a2+k\times b2)} \qquad \text{A11}$$

The straightforward application of duality would require the maximal value of the primal over all multipliers and would not necessarily give a feasible solution because of the commitment decisions. In practice to get a feasible solution GAM^1n (t) is only updated when a feasible solution does not exist and by solving the economic dispatch problem at each time step.

The commitment decision must enable the coupling constraints to be met and this is achieved by processing the deficit in order, starting with total generation with others set to zero. Dynamic programming is used to solve the primal problem.

3. Solution Techniques

This involves repeatedly solving the Unit Dynamic Programming problem and then modifying the multipliers until the constraints are met. Economic dispatch is used to establish the generation levels having set the commitment. Convergence is assessed when only one generator changes state between over and under meeting the constraint.

Two variables can be used to model the unit dynamics, '$ON_i(t)$' the cumulative up and SD_i (t) the cumulative down time. The dispatch problem is made differentiable by splitting it into two parts depending on whether the unit is above or below the optimal load point. An LP is used to solve the convex economic dispatch.

The reserve is dispatched by setting up an index array indicating whether a raise in generator output will raise or lower reserve. The gensets are ordered by marginal cost. Finally a multistep economic dispatch is used to include the ramp constraints. In practice having solved the single time step dispatch problems a series of small multi step dispatches are solved with the boundaries at times of peaks and troughs.

Fine tuning of the solution is affected by examining short generator on and off periods to establish the merit of changing the decision.

4. Overall Procedure

a) Input data processing to convert data relevant to the dispatch resolution time T1 to the schedule interval T2 (typically 5 min and 30 min).

b) Check for infeasibilities using an economic dispatch at each interval with unit availability set at maximum within its constraints.

c) Estimate system Lambda based on economic dispatch at each time ignoring dynamics.

d) Solve for schedule where T2=T1 using Lagrangian relaxation.

e) Modify schedule if possible to reduce cost examining particularly those units changing state between iterations.

f) Reset T2 to original value.

g) Solve for schedule at T2 resolution using Langrangian relaxation.

h) Examine scope for schedule adjustment to save cost.

i) Reform single time step economic dispatch.

j) Perform multi time step economic dispatch, sub problems.

k) Repeat single time step economic dispatch

l) Calculate outputs.

5. Alternative Techniques

The above approach whilst rigorous leads to solution times of the order of 30 mins to 1 hr on a modern workstation for a days study making it impractical for scenario studies of years. The algorithm will be used, however, to set marginal prices for the day ahead but for longer term investment appraisal an alternative model has been developed based on the approach described.

- The generator price function is represented as a single table 'A' value as opposed to a no load cost and three incrementals. This is justified given that the table 'A' value determines selection and therefore has most impact on utilisation.

- A periodicity of 2 hrs is used as opposed to ½ hr as this will capture the effect of minimum on and off constraints and provide sufficient banding of the daily demand profile to model on/off cycles and associated start up costs.

- Both hot and cold start up costs are modelled but are not included directly in the initial optimisation. The effects can be modelled in a subsequent pass with prices adjusted according to the operating regime by apportioning costs according to running hrs.

- run up and run down rates are not modelled as they are rarely active.
- Transmission constraints are modelled as group limits around blocks of generation
- The model includes heat rate and fuel price as options to entering prices.
- Minimum up and down times are modelled.
- Generator infexibility is modelled.
- planned generation outages are modelled.

The above assumptions enable studies covering up to a year to be run in less than 5 mins. The input data and the output of a typical interactive session are described below together with output results.

Input Data

For each of up to 250 generating unit the following data is provided
General:- Station name, no of units, main fuel burn
Cost data:- merit order costs, merit order position, heat rate, heat costs
Unit Limits:- minimum on time, minimum off time, minimum generation, flexibility status
Availability:- weekly generating unit MW availability
System data:- 2hr demand, group transmission limits and associated gen. sets, loss factors

Model(7) Interactive Session & Output Data

Specify the year to prepare demand data
    93/4
Select merit order data
    S (for standard as opposed to calculated)
Select period of study
    start week 1
    end week 5
Any mods to external transfers
    no
Input Menu
    merit order listing/editor
        Nuclear 1
        Coal 2
        Oil 3
    Execution
        Prelim pass 4
        Final pass 5
Availability editor
    999
Ouput Menu
    Summary 1
    Cost of Production 2
    Set output & starts 3
    Coal details 4
    Oil details 5
    Exit 6

1- Generation summary

Coal Gwh	1173		
Hot starts	1922		
Cold starts	198		
Oil GW	1323		
Hot starts	366	Total gen	24594
Cold starts	115	Demand(gross)	26858
Nuc Gwh	6557	Demand (net)	24968

Coal summary

Area	Gwh	Burn KT
NW	1571	669
NE	6314	2660
Mid	6420	2763
SE/SW	2408	1055
Total	16714	7146

2 - Cost of production(£'000)

Coal	232719
Oil	27053
Nuc	43944
Total	303716

Marginal cost 529403 (cost of all units at marginal price)

3 - Set details

(Results of each set available by submitting ref.no)

set 23 81694 Gwh
28 hot starts
1 cold start

4 - Oil details

Station	Gwh	KT
ABEO	17	5
BEL	16	4
FAWL	120	28
GRA	334	77
INC	56	13
KINO	158	39
LIT	307	71
NOR	20	6
PADO	7	2
PEM	208	48
RIC	24	6
GT's	56	20
Tot	1323	318

The results of individual 2hr SMP and LOLP and generator utilisation are written to files to facilitate subsequent automatic processing. The program can model periods of up to 2 years in one study. The software is described in appendix 5.

Appendix 2

Settlement Processing

Data Sources

i) GOAL Data

The GOAL unconstrained schedule provides spot generator MW output and reserve

V_{ij}) for each generator $_i$ and period $_j$
VR_{ij})

These are converted to integrated MWh values for each Settlement period SPD by averaging successive values.

$$U_{ij}=(V_{ij+1}+V_{ij})\times\frac{SPD}{2}$$

$$UR_{ij}=(VR_{ij+1}+VR_{ij})\times\frac{SPD}{2}$$

The generator offered availability GOA_{ii} is processed taking account of

Genset Synchronising Load GSL_i
Genset average run up rate ARU_i
Genset average run down rate ARD_i

to establish the minute by minute profiled maximum availability AU_{ii} with the area under the curve expressed in MWh as XA_{ij} for each settlement period.

ii) SMP Data

The algorithm that calculates system maginal price using the GOAL results produces the following output.

- SMP's a single value for each settlement period
- Table A/B indicator ABI; ie whether a table A or B period
- Marginal set adjustment MSA_{ij} which qualifies generators operating below the economic output for additional payment.
- A genset inflexibility indicator GIT_{ij} if the generator is inflexible.

iii) CDCS Tariff Metering

This provides the metered output for each generator GCM_{ij} and for each grid supply point the metered demand CCD_{ij} in kw.

These are processed to give

Genset metered generation $A_{ij} = (GCM_{ij} /1000) \times SPD$
GGSP metered demand $CMD_{gj} = (CCD_{gj} /1000) \times SPD \times (-1)$

Consumer metered demand

$$ND_{c,j} = \sum_{j}^{c} CMD_{g}$$

Additional Data

The loss of load probability algorithm provides $LOLP_j$ for each settlement period

iv) NGC Operational Data

Genset re-offered availability GRA_{it}
Genset failure log GFI_{ij}
Genset maxgen instruction MII_{ij} plus maxgen price MP_i
NGC/ASB will provide a single figure for each day amounting to the ASB payment.

Settlement Calculations

i) Pre-processing

The no load and incremental prices NLT_{ij}, $INC1_j$, $INC2_{ij}$, $INC3_i$ are used to establish equivalent no load prices at the intercept with the zero MW axis. $NL1_i$, $NL2_i$ and $NL3_i$

The genset startup price SU_i become SUU_{ij} for a startup caused by the unconstrained schedule.

Pool purchase price

$$PPP_j = SMP_j + LOLP_j(VLL - SMP_j)$$

Pool reserve price (5 minute reserve)

$$PRP_{ij} = PPP_i - INCU_{ij}$$

The genset actual availability is calculated XP_{ij} taking account of the redeclared availability, actual output and any recorded failures. The genset maximum redeclared availability XMD_{ij} and the genset proven availability since it last failed XMP_{ij}.

ii) Genset revised unconstrained generation and reserve are calculated taking account of the declared availability XA_{ij} and the redeclared XD_{ij} and the realised availability Xp_{ij}. If the redeclared availability was greater than the declared then

Genset revised unconstrained generation $D_{ij} = U_{ij}$
Genset revised unconstrained reserve $DR_{ij} = UR_{ij}$

If however the output could have been constrained by the redeclared availability, then it is written down to the value. Similarly the output related to the outturn availability XP is calculated as Y_{ij} and YR_{ij}

The final revised generation and reserve W_{ij} and WR_{ij} can then be derived.

iii) Genset total revised unconstrained costs for period of scheduling day is calculated from the product of the revised incremental price 'INCW' and the unconstrained generation 'W', plus the revised no load price times the period plus the revised start up price 'SUW'.

$$TCW_i=\sum_j ((INCW_{ij}\times W_{ij})+(NLW_{ij}\times SPD)+SUW_{ij})$$

Similarly the Genset total metered costs

$$TCA_i=\sum_j ((INCA_{ij}\times \min(XD_{ij}A_{ij})+(NLA_{ij}\times SPD)+SUA_{ij})$$

where A_{ij} = metered generation, 'XD' the redeclared availability and the suffix 'A' denotes the metered values for all other variables

The genset availability cost 'CC' is given by

$$CC_{ij}=(INCXA_{ij}\times XA_{ij})+(NLXA_{ij}\times SPD)+SUXA_{ij}$$

for each period where suffix 'X' is the declared value and the total availabilty cost

$$TCC_{ij}=\sum_x^y CC_{ij}$$

where x and y define periods of declared availability

The genset bid price 'BP' is then given by

$$BP_{i,j} = \frac{TCC_{\in}}{\sum_x^y XA_{ij}}$$

ie an effective cost

iv) Payments to gensets not subject to central dispatch.

If $CDI_i = 0$ then the genset is not subject to central dispatch and its non-dispatch payment

$$GNY_{ij}=PPP_j \times A_{ij}$$

where A_{ij} is the metered generation

v) Payments to dispatched gensets

a) Unconstrained energy and reserve payment 'EP' and 'RP'

$$EP_{ij}=PPP_j \times W_{ij}$$

$$RP_{ij}=PRP_{ij} \times WR_{ij}$$

b) Availability payment 'AP'

$$AP_{ij}=\max((XP_{ij}-W_{ij}-WR_{ij},D) \times \max(LOLP_j \times VLL-\max BP_{ij},SMP_j)),0)$$

where 'BP' is the bid price

c) Transmission constraints and forecast error
Genset metered payment 'OP'

$$OP_j=(TCA_i-TCW_i) \times (\frac{SPD}{SDD})$$

ie the difference between the unconstrained study energy and the actual. This is the uplift described in appendix 3 due to system requirements and forecasting error spread over each settlement period.

d) Ancillary Services

The total payment for various categories of reserve and frequency regulation is divided amongst generators according to contracts.

e) Maxgen

The genset maxgen payment

$$GMP_{ij}=\max(MP_j\times(A_{ij}-XD_{ij}),0)$$

if the maxgen indicator flag is $MII_{ij}=1$.

f) The marginal set adjustment

MSA_{ij} is a payment derived from the SMP algorithm to compensate a generator who is required to operate below his economic output.

g) Table B startup cost addition

A payment 'TBP' that may be made to a generator that only runs in table 'B' periods when by definition it would not recover startup costs as they are loaded into Table 'A' period.

Total genset payments including those to gensets not centrally dispatched 'GNY'

In each period

$$GY_{ij}=EP_{ij}+RP_{ij}+MSA_{ij}+AP_{ij}+OP_i+GMP_{ij}+TBP_{ij}+GNY_{ij}$$

Total payment

$$TGY_i=\sum_j GY_{ij}$$

Consumer Sales

The period metered demand 'PND'

$$PND_j=\sum_c ND_{ij}$$

ie. The sum of the metered supply point demands for all consumers 'C'

The period metered generation

$$PA_j=\sum_i A_{ij}$$

The transmission losses are given by the difference between the metered generation 'PA' and metered demand 'PND'

$$TL_j = PA_j - PND_j$$

To spread the losses over all MWh taken, they are divided up in proportion to

$$TLM_j = \frac{TL_i}{PND_j}$$

Then consumer gross demand

$$GD_{cj} = ND_{cj}(1 + TLM_j)$$

Calculation of Pool selling price

In any settlement period the genset payment = Gy_{ij}

During table 'B' periods the Pool selling and purchase price are the same ie.

$$PSP_j = PPP_j$$

For table 'A' periods the Pool selling price is inflated by uplift.

For consumers, reserve is paid as directly attributable in table 'A' periods, but that in table 'B' periods is summed and also spread over table 'A' periods. As the recovery of genset reserve and availability payments are different in table 'A' periods the generator payment may be split into a reserve payment

$$GRP_{ij} = RP_{ij} + AP_{ij}$$

and non reserve

$$GNP_{ij} = GY_{ij} - GRP_{ij}$$

Then total gross demand

$$TGD_j = \sum_c GD_{cj}$$

Total genset non-reserve payment

$$TGNP_j = \sum_j GNP_{ij}$$

The genset non-reserve uplift not covered by purchase at PPP's

$$ANR = \sum_j^a (TGNP_i - (TGD_i \times PPP_j))$$

The total gensets payments in settlement period is

$$BGY_j = \sum GY_{ij}$$

Then the table 'B' period uplift not covered

$$BR = \sum_j^b (BGY_j - (TGD_j \times PPP_j))$$

The daily Ancillary Services payment = ASD

Total genset reserve payments

$$TGRP_j = \sum GRP_{ij}$$

Total number of Table 'A' MWh over which PPP uplift is calculated

$$AGD = \sum_j^a TGD_j$$

Then PPPi uplift applied to each table 'A' MWh

$$\mathrm{T} = (ANR + BR + ASD)/(AGD)$$

ie in table 'B' period $PSP_j = PPP_j$

in table 'A' period $PSP_j = PPP_j + TAU + (TGRP_j / TGD_j$

then consumer sales for consumer = in period $_j$

$$CL_{cj} = GD_{cj} \times PSP_j$$

and daily sales

$$CLD_c = \sum_j CL_{cj}$$

Appendix 3

Uplift

The Pool purchase price

PPP = SMP + LOLP (VLL - SMP)

The Pool selling price

PSP = PPP in table 'B' period
PSP = PPP + uplift in table 'A' period

ie all uplift costs are apportioned to table 'A'running periods.

Generator payments

1) Energy payments at PPP in revised unconstrained schedule

2) Reserve payment at PPP incremental price for reserve scheduled in the unconstrained schedule. They are lost profit payments.

3) Payment for availability not scheduled in unconstrained schedule. The payments are a function of LOLP and VLL - SMP or BP whichever is the greater

4) Metered payment ie difference between revised unconstrained schedule actual at offer price.

5) Maxgen payment

6) Other payments like ASB

8) Centrally dispatched payment

The uplift is defined as the difference between the total cost in the unconstrained schedule and the actual outturn - ie

unconstrained cost:

$$TCW=\sum (\lambda \frac{P_{un}}{2})+NLC\times T_{un}+SUC\times N_{un}$$

Actual cost:

$$TCA=\sum (\lambda \frac{P_{act}}{2})+ALC\times T_{act}+SUC\times N_{act}$$

$$Uplift = TCA - TCW$$

Uplift occurs because of transmission constraints, generator shortfalls and demand prediction error. Other payments include reserve and availability. ASB payments maxgen and MSA. The current breakdown of uplift is ASB 38%, gen shortfalls 33%, transmission 19%, demand forecasting 8%.

Appendix 4

Lagrange Multiplier Method

Given the problem of finding the extremum of a function which is subject to constraints then the constraints may be incorporated into the objective function to create what is called the Lagrangian function. This is achieved by the introduction of a Lagrangian multiplier lambda which is initially undetermined.eg. For a function 'Z' of two variables 'x' and 'y'subject to a constraint 'g' :

$$Z = f(x,y) \quad \textit{with constraint} \quad g(x,y) = c$$

then the lagrangian function can be written as:

$$Z = f(x,y) + \lambda[c - g(x,y)]$$

Then the first order condition for the extremum will consist of a set of simultaneous equations ie.:

$$Z_\lambda(=\frac{\partial z}{\partial \lambda}) = c - g(x,y) = 0$$

$$Z_x(=\frac{\partial z}{\partial x}) = fx - \lambda g_x = 0$$

$$Z_y(=\frac{\partial z}{\partial y}) = fy - \lambda g_y = 0$$

which can be solved to find the extremum and satisfy the constraint. The value of the second order exremum will confirm whether the extremum is a maximum or minimum. The multiplier represents the sensitivity of the function 'Z' to changes in the constraint.

In the generator dispatch problem,for example, the objective function is to minimise the cost of production of running generation. The equality constraint is that generation should equal demand and the cost is a function of generator incremental price and output.

$$Z = \sum f(inc,g) + \lambda(D-G)$$

$$\frac{\delta Z}{\delta \lambda} = D - \sum g_i = 0$$

$$\frac{\delta Z}{\delta g_i} = inc_i - \lambda = 0$$

where 'D' is demand, 'G' is total generation and 'inc' is the incremental cost of generator 'i'and 'g' its output. In this case lambda is the sensitivity of the cost function to changes in demand or the effective system marginal price. The objective is to find that value of lambda such that the generators incremental prices are equal to or below the system value and the combined output equals demand. This can be solved iteratively by varying lambda depending on the constraint mismatch to arrive at a solution when generation equals demand. The lagrangian then provides a means of decoupling the analysis to enable each generator to be analysed in turn by deriving a loading regime depending on its incremental price in relation to the system value . (Chiang 84)

Appendix 5

A software suite for simulating operation and income in a privatised environment

This appendix describes the software suite developed as part of this thesis to support the analysis and evaluation of the various theories advanced. The overall framework of the interacting modules was shown in figure 5.2 and the fortran code associated with each module is listed below.

The main program is called model(7) with version 7 excluding transmission constraints and version'T' including them. This in turn calls subroutines to initiate variables (initiat) , to sort the generator prices into a merit order (sorter), to load the generation to meet demand and meet the constraints(loader(7)) , to check any error in meeting demand and constraints (check), and to calculate LOLP (lolp).

This program is supported by other routines to prepare the demand data from stored profiles and energy data (demmod) and external transfer data (oracext). The results can be processed by programs to read and analyse SMP (readsmp)and generator utilisation data readutil). An overview of results is extracted by command procedures (result and out)

The program used to establish profit by post processing the results of 'model' is called 'comcost'. The program used to establish the optimal transmission outage pattern is called 'optout'. The data used by the programs is listed first followed by the programs in the order.

Model7,Intiate,Sorter,Loader,Check,Lolp,Demmod,Oracext,Readsmp,Readutil,Result,Out, Comcost and Optout.

Program Data

Variable name(array size)	Data	Units
GENAV(244,26)	Generator availabiity	MW
DEM(2184)	Demands	MW
EXT(336)	External transfer	MW
MOS(244)	M.O. position of sets	Integer
MOC(244)	M.O.costs of sets	£/MWhr
OCS(1092)	2hr outputs on current set	MW
CCOS(244)	Cumulative output per set	MWhrs
TGO(2184)	2hr period summated TGO's	MWhrs
HR(244)	Unit Heat rates	KJ/Kw
HC(244)	Unit Heat costs	p/GJ
TLF(244)	Transmission loss factor	per unit
RES(244)	Calculated MO=HR*HC*TLF	£/MWhr
SETNBR(244)	Set no.	Integer
MFB(196)	Main fuel burn	Character
MOFLT(244)	Min' off-load time	Minutes
MONLT(244)	Min' on-load time	Minutes
MGEN(244)	Min' generation	MW
HST(244)	Number of hot starts	Integer
CST(244)	Number of cold starts	Integer
SMP(2184)	Merit order cost of marginal set	£/MWhr
STN(72)	Station name	Character
FIRST(72)	first set in station	Integer
LAST(72)	last set in stn	Integer
WS(4)	Week start	Integer
WF(4)	Week finish	Integer
HS(4)	Period 2hr start no.	Integer
HF(4)	Period 2hr finish no.	Integer
OW(4,4)	no. of weeks selected for 'EXT' option	Int
OB(4,4)	block no. selected for external transfer	Int
SG(72)	Summated station output	GW/hr
SF(72)	Station fuel burn	(KT)
SS	Current station name	Character
NST	Current station number	Character
YS	Year start	Integer
YF	Year finish	Integer
P1	Present M.O.position	Integer
P2	Required M.O.position	Integer
TG	Total generation	GWhr
GC	Generation total cost of production	£
FUELTP	Temporary fuel type variable	Character

```
    program MODEL7
c  Links with HRCEDT7,SORTER7,INITIAT7,LOADER7,CHECK,LOLP7
c  This version includes SMP and LOLP derivation
C  Version5 reads basic data from file BASIC.DAT
C  Version 7 extended array sizes to accommadate new gens
c    FORTRAN       Description
c
c
c
C
C
C    GENAV(244,26)   Gen' avail'
c    DEM(2184)     Demands
c    EXT(336)      Ext'
c    MOS(244)      M.O.sets
c    MOC(244)      M.O.costs
c    OCS(1092)     2hr outputs on curr. set
c    (244)     Cumulative output p/ set
c    TGO(2184)     2hr TGO's
c    HR(244)       Heat rates
c    HC(244)       Heat costs
c    TLF(244)      TLF
c    RES(244)      HR*HC*TLF
c    SETNBR(244)   Set no.
c    MFB(196)      Main fuel burn
c    MOFLT(244)    Min' off-load time
c    MONLT(244)    Min' on-load time
c    MGEN(244)     Min' generation
c    HST(244)      Hot starts
c    CST(244)      Cold starts
c    SMP(2184)     Merit order cost of marginal set
C
c    STN(72)       Station name
C    FIRST(72)     first set in station
C    LAST(72)      last set in stn
C    WS(4)         Week start
c    WF(4)         Week finish
c    HS(4)         2hr start no.
c    HF(4)         2hr finish no.
c    OW(4,4)          no. of weeks selected for 'EXT' option
c    OB(4,4)          'EXT' block no. selected for 'EXT' option
c    SG(72)        output p/ station (GW/hr)
c    SF(72)        Fuel burn p/ station (KT)
c    SS            Current station name
c    NST           Current station number
c    YS            Year start
c    YF            Year finish
```

```
c   P1          Present M.O.position
c   P2          Required M.O.position
c   TG          Total GW/hr generation
c   GC          Generation cost (total cost of production)
c   FUELTP      Temporary variable
c-------------------------------------------------------------------------
c
c
    INTEGER*2 OW(4,4),OB(4,4),HS(4),HF(4),WS(4),WF(4),MFB(244),
   1       MONLT(244),HHS(244),CCS(24),
   2       HR(244),HC(244),RES(244),FIRST(72),LAST(72),
   3       MOS(244),SFF(4),SLL(4),HST(244),
   4       CST(244),
   5       MOFLT(244),OCS(1092),FLX(244)
c
    real TLF(244),SSG,SSF,SSC,G,F,C,V,MOC(244),SMP(2184)
       REAL NG,SC(72),SG(72),SF(72),CDG,CDN,K8,K9,TEST
c
    character RESP,FILE*12,SS,SA*3,AR(4)*5,FIL(4)*2,T*15,
   1 TT*15,NAME(244)*4,WEEK(26)*7,FUEL(72)*1,STN(72)*4,
   2 FUELTP*1
    logical*2 COMPUTE,TYPE
c
    integer*4 EXT(336),SETNBR(244),DEM(2184),TGO(2184)
    INTEGER *4 ERROR,MGEN(244),GENAV(244,26)
    INTEGER *4 CCOS(244),TESTC,P
       REAL RG(4),RC(4),TG,TC,GC,NC,TF,TSMPC,TSMPCK
       C         O         M         M         O         N
/BLK1/OW,OB,DEM,GENAV,EXT,MOFLT,MONLT,FLX,MOS,SETNBR
       COMMON /BLK2/CST,HST,TGO
       COMMON /BLK3/WS,WF
       COMMON /BLK4/MOC,SMP,TSMPC
c
    data SFF,SLL,AR,FIL,T /
   1 1,8,18,31,7,17,30,37,'NW','NE','MID','SE/SW','7A','7B',
   2 '8A','8B','Fred' /
c
c
C Read in basic data on station names and sets from file BASIC.DAT
       OPEN(16,FILE='BASIC.DAT')
       READ(16,*)
       DO I=1,72
        READ(16,666)STN(I),FIRST(I),LAST(I),FUEL(I)
       END DO
       CLOSE(16)
666    FORMAT(1X,A4,2X,I3,2X,I3,3X,A1)
       WRITE(6,666)STN(1),FIRST(1),LAST(1),FUEL(1)
```

```
C Phase 1
C-Read in set name,fuel,min off time,min on time min gen,flexibility
    open (10,file='ORACSET.DAT')
    READ (10,200)
        DO 5,I=1,244
    read(10,201,end=10)NAME(I),MFB(I),MOFLT(I),MONLT(I),MGEN(I),FLX(I)
5     CONTINUE
10   close (10)
201     FORMAT(1X,A4,2X,I3,2X,I2,2X,I2,2X,I3,1X,I2)
D       PAUSE 'To write out first line of oracset press return'
D       WRITE(*,800)
800     FORMAT(1X,'NAME',1X,'MFB',1X,' MFT ',1X,'MOT',1X,'MGN',1X,'FLX')
D       DO 7,I=1,2
D        WRITE(*,201)NAME(I),MFB(I),MOFLT(I),MONLT(I),MGEN(I),FLX(I)
D7       CONTINUE
200     FORMAT(//////////)
c----------------------------------------------------------------------------
C Phase 2
C Select MO data from standard or modified file including heat rate,cost,TLF
    write (*,100) 'Select Merit order data (MODAT.OBJ file)'
100  format ('1',(A))
    write (*,*) 'Standard "MODATSTD"  (S)'
    write (*,*) 'Modified "MODATMOD"  (M)'
11   read (*,103) RESP
103  format (A)
    if (RESP.eq.'S') then
        FILE='MODATSTD.DAT'
    elseif (RESP.eq.'M') then
        FILE='MODATMOD.DAT'
    else
        write (*,102)
102     format (' Wrong choice - Try again')
        goto 11
    endif
c
    open (10,file=FILE)
        READ(10,199)
    do 12,i=1,244
        read (10,202,end=13,err=99)NAME(i),HR(i),HC(i),TLF(i)
12     SETNBR(i)=i
13   close (10)
        WRITE(*,*)SETNBR(244)
199     FORMAT(///////)
202     FORMAT(1X,A4,2X,I5,2X,I3,2X,F5.1)
801     FORMAT(1x,'NAME',1X,' HR  ',2X,' HC  ',1X,'TLF')
D       PAUSE 'To write out first line of HR data- press return'
D       WRITE(*,801)
```

```
D      WRITE(*,202)NAME(1),HR(1),HC(1),TLF(1)
c-----------------------------------------------------------------------
C-Phase 3
C Select MO standard modified or computed including order and cost
    write (*,100) 'Select Merit order & Cost of Prod" data (MOCOP.',
   1           'OBJ file)'
    write (*,*) 'Standard "MOCOPSTD"  (S)'
    write (*,*) 'Modified "MOCOPSTD"  (M)'
    write (*,*) 'Computed            (C)'
14   read (*,103) RESP
    if (RESP.eq.'S') then
         FILE='MOCOPSTD.DAT'
    elseif (RESP.eq.'M') then
         FILE='MOCOPMOD.DAT'
    elseif (RESP.eq.'C') then
         COMPUTE=.true.
         goto 16
    endif
c
    open (10,file=FILE)
         READ(10,198)
         DO 4,I=1,244
          read (10,203,end=15,err=99)NAME(I),MOC(I),MOS(I)
4      CONTINUE
15    close (10)
198    FORMAT(////////)
C
203    FORMAT(1X,A4,2X,F5.2,2X,I3)
802    FORMAT(1X,'NAME',1X,' MOC ',1X,'MOC')
D      PAUSE 'Press return to write out first MO'
D      WRITE(*,802)
          WRITE(*,203)NAME(215),MOC(215),MOS(215)
c-----------------------------------------------------------------------
16   if (.not.COMPUTE) goto 9
c--Phase 4---------------- EDIT HEAT RATES --------------------------
C edit heat rates,costs or TLF,s and calculate new costs=HR*HC*TLF
C then sort to find new MO
    RESP=' '
    write (*,100) 'Edit heat rates (Y/N) ?'
17   read (*,103) RESP
    if (RESP.eq.'N') then
         goto 18
    elseif (RESP.ne.'Y') then
         write (*,102)
         goto 17
    endif
    TYPE=.false.
```

```
      call HRCEDT7 (HR,FIRST,LAST,STN,TYPE)
c------------------ EDIT HEAT COSTS --------------------------------------
18    RESP=' '
      write (*,100) 'Edit heat cost (Y/N) ?'
19    read (*,103) RESP
      if (RESP.eq.'N') then
           goto 20
      elseif (RESP.ne.'Y') then
           write (*,102)
           goto 19
      endif
      TYPE=.true.
      call HRCEDT7 (HC,FIRST,LAST,STN,TYPE)
c------------------ EDIT TLF --------------------------------------------
20    RESP=' '
      write (*,100) 'Edit TLF (Y/N) ?'
21    read (*,103) RESP
      if (RESP.eq.'N') then
           goto 25
      elseif (RESP.ne.'Y') then
           write (*,102)
           goto 21
      endif
c
24    write (*,*) 'Input Station :'
      read (*,103) SS
      NST=0
      do 22,i=1,72
22       if (SS.eq.STN(i)) NST=i
      S1=FIRST(I)
      S2=LAST(I)
      if (NST.eq.0) goto 25
      S=S1
      V=TLF(S)
      write (*,104) 'Existing value : ',V
104   format (1X,(A),F5.1)
      write (*,*) 'Required value ?'
      read (*,*) V
      if (V.ne.0) then
           do 23,S=S1,S2
23           TLF(S)=V
      endif
      goto 24
c------------------ COMPUTING COSTS OF PRODUCTION ------------------------
25    write (*,100) 'Calculating "Costs of Prod"'
      do 26,i=1,244
26       RES(i)=(HR(i)*HC(i)*TLF(i))
```

```
      RESP=' '
      write (*,*) 'Save MODATSTD.DAT  (S)'
      write (*,*) '    MODATMOD.DAT  (M)'
27    read (*,103) RESP
      if (RESP.eq.'S') then
          FILE='MODATSTD.DAT'
      elseif (RESP.eq.'M') then
          FILE='MODATMOD.DAT'
      else
          write (*,102)
          goto 27
      endif
c
      open (20,file=FILE)
      do 28,i=1,244
          write (20,202,err=98)NAME(i),HR(i),HC(i),TLF(i)
28        MOC(i)=RES(i)
      close (20)
c------------------- SORT M.O. --------------------------------------------
9     call SORTER7(MOC,244,SETNBR)
c     MOS contains in MO the number of the set in the original list
         WRITE(*,*)MOS(215),MOS(216),SETNBR(215),SETNBR(216)
c------------------- END OF CALCULATION ----------------------------------
C Phase 5    Select period of study
      write (*,100) 'Select period of study'
      write (*,*) 'Input week start no" :'
      read (*,*) WS(1)
      write (*,*) 'Input week finish no" :'
      read (*,*) WF(1)
      K=+WS(1)
      L=+WF(1)
      TW=L-K+1
c  this sets array of week start and end through up to two year period
c  depending on how many half years are covered
      do 30,i=1,4
          if (K.gt.26.or.K.lt.1) then
            WS(i)=0
          else
            WS(i)=K
          endif
          if(WS(i).gt.0)then
           if(WF(i).le.26)WF(i)=L
           if(WF(i).gt.26)WF(i)=26
          else
           WF(i)=0
          end if
          K=K-26
```

```
      L=L-26
30    if (L.gt.0.and.K.lt.0) K=1
      WRITE(*,*)WS,WF
c-Phase 6 edit external transfers--- EXT OPTIONS ------------------------------------------
      OPEN(UNIT=15,FILE='ORACEXT.DAT')
      READ(15,901,END=99,ERR=99)(EXT(I),I=1,336)
      CLOSE(15)
      WRITE(*,*)EXT(1),EXT(336)
901   FORMAT(12(1X,I5))
   RESP=' '
   write (*,100) 'Ext. options'
   write (*,*) 'Any mods to EDF (Y/N) ?'
31  read (*,103) RESP
   if (RESP.eq.'N') then
        goto 34
   elseif (RESP.ne.'Y') then
        write (*,102)
        goto 31
   endif
C-------------------- EDF MODS ---------------------------------------------
32  write (*,*) 'Input block no" for EDF mod :'
   read (*,*) EB
   if (EB.eq.0.or.EB.gt.6) goto 34
   write (*,*) 'Input size of EDF import :'
   read (*,*) EM
   do 33,i=1,84
        EX=EXT(84*(EB-1)+i)
          EX=EX+EM
33    EXT(84*(EB-1)+i)=EX
   goto 32
c
34  do 35,i=1,4
        if (WS(i).lt.1) goto 35
        if (i.eq.1) write (*,*) '1st half year'
        if (i.eq.2) write (*,*) '2nd half year'
        if (i.eq.3) write (*,*) '1st half year'
        if (i.eq.4) write (*,*) '2nd half year'
        do 8,q=1,4
8        OW(i,q)=0
        do 36,j=1,4
          write (*,*) 'Option no" ',j,' - Input no" of weeks :'
          read (*,*) OW(i,j)
          if (OW(i,j).eq.0) goto 35
          write (*,*) 'Input block no" :'
          read (*,*) OB(i,j)
C not needed ?       SEL(8*i+j-8)=OW(i,j)
c 36        SEL(8*i+j-4)=OB(i,j)
```

```
36      continue
          if (OW(i,1)+OW(i,2)+OW(i,3)+OW(i,4).gt.26) write (*,*)
     1   'Too many wks'
35      CONTINUE
c------------------- INPUT MENU -------------------------------------------
C Either edit MO or execute preliminary study or final which reloads
37    write (*,100) 'Input menu'
      write (*,*)  '----------'
      write (*,*) 'Merit order listing/editor'
      write (*,*) '  for nuclear       - 1'
      write (*,*) '  for oil           - 2'
      write (*,*) '  for coal          - 3'
      write (*,*) 'Execution'
      write (*,*) '  - prelim" pass   - 6'
      write (*,*) '  - final pass      - 7'
c
38    read (*,*) i
      if (i.lt.1.or.i.gt.7) then
           write (*,102)
           goto 38
      endif
      if (i.eq.6) goto 45
      if (i.eq.7) goto 67
      if (i.eq.1) then
           write (*,100) 'Nuclear'
           FUELTP='N'
      elseif (i.eq.2) then
           write (*,100) 'Oil'
           FUELTP='O'
      elseif (i.eq.3) then
           write (*,100) 'High merit coal'
           FUELTP='C'
      endif
c------------------- EDIT M.O. -------------------------------------------
      DO I=1,72
       IF(FUEL(I).EQ.'FUELTP')THEN
          write (*,109) MOS(i)
       END IF
      END DO
109   format (1X,(I4,'=',I3,' '))
41    write (*,*) 'Merit order editor'
      write (*,*) 'Input set no" / station name :'
      read (*,103) SA
      read (SA,103) SS
      TYPE=.false.
      NN=ichar(SS)
      if (NN.gt.57) goto 69
```

```
      if (NN.ge.48.and.NN.le.57) read (SA,'(I3)') S
      if (S.gt.244) goto 37
      do 39,i=1,156
           if (S.eq.MOS(i)) then
             P1=i
             TYPE=.true.
           endif
 39       continue
      if (.not.TYPE) then
           write (*,'(1X,(A),I3)') 'Present M.O. position : ',P1
           write (*,*) 'Input required M.O. position :'
           read (*,*) P2
           if (P1.gt.P2) then
             do 42,i=MOS(P1-2),MOS(P2-1),-1
 42           MOS(i+1)=MOS(i)
             MOS(P2)=S
           elseif (P1.lt.P2) then
             do 43,i=MOS(P1+1),MOS(P2)
 43           MOS(i-1)=MOS(i)
             MOS(P2)=S
           endif
           goto 41
      endif
c  start of prelim pass which ends at line 44
45    TYPE=.false.
      write (*,100)
      call INITIAT7(TG,GC,K8,K9,CDN,ERROR,CCOS)
          CDG=0
c Read in all availability data
      write (*,*) '"DEAV" loading in progress'
      do 44,i=1,4
          if (WS(i).lt.1) goto 44
          IF(i.EQ.1)FILE='GENAV1.DAT'
          IF(i.EQ.2)FILE='GENAV2.DAT'
          IF(i.EQ.3)FILE='GENAV3.DAT'
          IF(i.EQ.4)FILE='GENAV4.DAT'
C        WRITE(*,'(1x,A12)') FILE
          open (10,file=FILE)
         READ(10,197)
         DO 144,K=1,244
          read (10,211,END=333,ERR=333)NAME(K),(GENAV(K,J),J=1,13)
          read (10,212)(GENAV(K,J),J=14,26)
144     CONTINUE
          close (10)
333     CONTINUE
         WRITE(*,211)NAME(1),(GENAV(1,J),J=1,13)
332     FORMAT(1X,'Generator availability file ')
```

```
197    FORMAT(////)
211    FORMAT(1X,A4,13(1X,I3))
212    FORMAT(5X,13(1X,I3))
C now read in demand data for half year
       IF(i.EQ.1)FILE='DEM1.DAT'
       IF(i.EQ.2)FILE='DEM2.DAT'
       IF(i.EQ.3)FILE='DEM3.DAT'
       IF(i.EQ.4)FILE='DEM4.DAT'
       open(unit=11,file=FILE)
       DO 145,W=1,26
       READ(11,213)WEEK(W)
       DO 146,D=1,7
       ITEM=(W-1)*84+(D-1)*12
       READ(11,214)(DEM(ITEM+Q),Q=1,12)
146    CONTINUE
145    CONTINUE
       CLOSE(11)
       DO 143,L=1,2184
        DEM(L)=DEM(L)*10
143    CONTINUE
       WRITE(*,*)(DEM(P),P=1,12)
213    FORMAT(1X,A7)
214    FORMAT(12(1X,I4))
       DO 433,WK=WS(i),WF(i)
        REFER=(WK-1)*84
        DO 434,HOUR=1,84
         CDG=CDG+2*DEM(REFER+HOUR)
434     CONTINUE
433    CONTINUE
        HS(i)=84*WS(i)-83
        HF(i)=84*WF(i)
        write (*,709) WS(i),WF(i)
709     format (1X,'Weeks ',I2,' to ',I2)
C Phase 8
C edit availability as required type 999 to continue
        write (*,*) 'Availability editor'
46     write (*,*) 'Input set no" :'
        read (*,*) S
        if (S.ne.999) then
          write (*,*) 'Input week start :'
          read (*,*) WWS
          write (*,*) 'Input week finish :'
          read (*,*) WWF
          if (WWS.gt.26) WWS=WWS-26
          if (WWF.gt.26) WWF=WWF-26
C         K=26*(S-1)+WWS /
C        L=26*(S-1)+WWF
```

```
          write (*,*) 'Input avail'' (MW) :'
          read (*,*) V
          do 47,j=WWS,WWF
47         GENAV(S,j)=V
          goto 46
        endif
C       *****
C  Phase 9 ______________________________________________
c  Now load to meet demand
        if (i.eq.1.or.i.eq.3) then
          write (*,105) 'Starting 1st half year '
105      format (1X,(A),I4)
          call LOADER7(i,PASS,MGEN,CCOS)
          write (*,105) 'Finished 1st half year '
        else if(i.eq.2.or.i.eq.4.)then
          write (*,105) 'Starting 2nd half year '
          call LOADER7(i,PASS,MGEN,CCOS)
          write (*,105) 'Finished 2nd half year '
        endif
C       if (WS(i+1).lt.1.or.i.eq.4) then
C         open (20,file='EXTMODEM.OBJ')
C         write (20,*) GENAV,DEM
C         close (20)
C       endif
        call CHECK(DEM,TGO,CDN,i,ERROR)
        RESP=char(i+48)
C       write (FILE,'(A)') 'NEWDEAV',RESP,'.OBJ'
C       open (20,file=FILE)
C       write (20,*) GENAV,DEM
C       close (20)
44  continue
c-end of loading loop-----------------------------------------------------
    if (.not.TYPE) then
        K8=CDG/1000
        K9=CDN/1000
C Summate results for stations
C      goto 37
    endif
74  write (*,'((A)\)') ' Summating Station data'' '
       TESTC=0
       DO P=1,244
        TESTC=TESTC+CCOS(P)
       END DO
       WRITE(*,*)TESTC
       TEST=0
   do 49,i=1,72
       SSG=0
```

```
        SSF=0
        SSC=0
        S1=FIRST(I)
        S2=LAST(I)
        IF(S1.EQ.0)GOTO 49
        do 48,S=S1,S2
          G=CCOS(S)
          G=G/1000
          F=G*MFB(S)/400.
          C=G*MOC(S)
          SSG=SSG+G
          SSF=SSF+F
48        SSC=SSC+C
        SG(i)=SSG
        SF(i)=SSF
        SC(i)=SSC
        TEST=TEST+SG(I)
49      continue
        WRITE(*,*)TEST
      HC4=0
      CC4=0
      HO4=0
      CO4=0
      do 50,i=1,154
          HC4=HC4+HST(i)
50        CC4=CC4+CST(i)
      do 51,i=157,196
          HO4=HO4+HST(i)
51        CO4=CO4+CST(i)
      pause 'To continue - Press RETURN'
c-----------------------------------------------------------------------
c temp mod?    open (10,file='EXTMODEM.OBJ')
c     read (10,*) EXT
c     close (10)
cPhase 10------------------ OUTPUT MENU -------------------------------
57   write (*,100) 'Output menu'
     write (*,*)  '-----------'
     write (*,*) 'For summary                - 1'
     write (*,*) 'For Cost of production     - 2'
     write (*,*) 'For Set output and starts - 3'
     write (*,*) 'For coal details           - 4'
     write (*,*) 'For oil details            - 5'
     write (*,*) 'For exit                   - 6'
     read (*,*) i
     goto (55,58,62,63,65,69) i
c-----------------------------------------------------------------------
55   write (*,100) 'Generation summary'
```

```
      TG=0
         NG=0
      do 52,i=1,72
 52    IF(FUEL(I).EQ.'C')TG=TG+SG(i)
      write (*,*) 'Coal GW.HRS : ',TG
      NG=TG
      TG=0
      write (*,*) 'Hot starts : ',HC4
      write (*,*) 'Cold starts : ',CC4
 c
      do 53,i=1,72
 53     IF(FUEL(I).EQ.'O') TG=TG+SG(i)
      write (*,*) 'Oil GW.HRS : ',TG
      NG=NG+TG
      TG=0
      write (*,*) 'Hot starts : ',HO4
      write (*,*) 'Cold starts : ',CO4
 c
      do 54,i=1,72
 54     IF(FUEL(I).EQ.'N') TG=TG+SG(i)
      write (*,*) 'Nuc" GW.HRS : ',TG
      NG=NG+TG
      write (*,*) 'Totals : Generation     : ',NG
      write (*,*) '         Demand (gross) : ',K8
      write (*,*) '                (net)   : ',K9
      pause 'To continue - Press RETURN'
 c
      write (*,100) 'Coal summary'
      write (*,106) 'Units','Burn'
 106  format (15X,(A),T27,(A))
      write (*,106) '(GW.HR)','(KT)'
      TG=0
      TC=0
      do 155,i=1,4
          RG(i)=0
          RC(i)=0
          do 56,j=SFF(i),SLL(i)
            RG(i)=RG(i)+SG(j)
56         RC(i)=RC(i)+SF(j)
          TG=TG+RG(i)
          TC=TC+RC(i)
155       write (*,107) AR(i),RG(i),RC(i)
107     format (1X,A5,T14,F7.0,T27,F9.0)
     write (*,107) 'Total',TG,TC
     pause 'To continue - Press RETURN'
     goto 57
c-------------------------------------------------------------------------
```

```
58   write (*,100) 'Cost of production'
     write (*,*) '    (£ "000)'
     GC=0
     NC=0
     do 59,i=1,72
59     IF(FUEL(I).EQ.'C') GC=GC+SC(i)
     write (*,*) 'Coal plant : ',GC
     NC=GC
     GC=0
     do 60,i=1,72
60     IF(FUEL(I).EQ.'O') GC=GC+SC(i)
     write (*,*) 'Oil plant  : ',GC
     NC=NC+GC
     GC=0
     do 61,i=1,72
61     IF(FUEL(I).EQ.'N') GC=GC+SC(i)
     write (*,*) 'Nuc" plant : ',GC
     NC=NC+GC
     write (*,*) 'Total cost : ',NC
     TSMPCK=TSMPC/1000
     WRITE (*,*) 'Marginal cost:',TSMPCK
     pause 'To continue - Press RETURN'
C write results to results file
        OPEN(UNIT=17,FILE='RESULTS1.DAT')
        WRITE(17,171)NG
        WRITE(17,172)K8
        WRITE(17,173)K9
        WRITE(17,174)NC
        WRITE(17,175)TSMPCK
        CLOSE(17)
171    FORMAT(1X,'Generation    ',F10.2,' GW Hrs')
172    FORMAT(1X,'Gross Demand  ',F10.2,' GW Hrs')
173    FORMAT(1X,'Net Demand    ',F10.2,' GW Hrs')
174    FORMAT(1X,'Total cost    ',F10.0,' K')
175    FORMAT(1X,'Marginal cost ',F10.0,' K')
     GOTO 57
62   write(*,100) 'Set output & starts'
     write (*,*) 'Input set no" :'
     read (*,*) S
     write (*,'(1X,I8,A)') CCOS(S),'GW.HRS'
     C1=CST(S)
     H1=HST(S)
     if (S.le.196) then
         write (*,*) H1,'hot starts'
         write (*,*) C1,'cold starts'
     endif
     write (*,*) 'Cont" (C) or Exit (E) ?'
```

```
      read (*,103) RESP
      if (RESP.eq.'C') then
          goto 62
      else
          goto 57
      endif
c
63    write (*,100) 'Coal details'
      write (*,*) 'NW area - 1'
      write (*,*) 'NE      - 2'
      write (*,*) 'MID     - 3'
      write (*,*) 'SE/SW   - 4'
      write (*,*) 'For exit  5'
      write (*,*) 'Name it :'
64    read (*,*) I
      if (I.lt.1.or.I.gt.5) then
          write (*,102)
          goto 64
      endif
      if (I.eq.5) goto 57
      write (*,100) 'Coal details'
      write (*,'((A)\)') 'Station'
      write (*,106) 'Units','Burn'
      write (*,106) '(GW.HR)','(KT)'
      write (*,107) (STN(j),SG(j),SF(j),j=SFF(I),SLL(I))
      pause 'To continue - Press RETURN'
      goto 63
c
65    write (*,100) 'Oil details'
      write (*,'((A)\)') 'Station'
      write (*,106) 'Units','Burn'
      TG=0
      TF=0
      write (*,106) '(GW.HR)','(KT)'
      do 66,i=1,72
        IF(FUEL(I).EQ.'O')THEN
         TG=TG+SG(i)
         TF=TF+SF(i)
         write (*,107) STN(i),SG(i),SF(i)
        END IF
66      CONTINUE
      write (*,107) 'Total',TG,TF
      pause 'To continue - Press RETURN'
      goto 57
c
67    TYPE=.true.
      write (*,100)
```

```
      call INITIAT7(TG,GC,K8,K9,CDN,ERROR,CCOS)
c     line 4820
      write (*,*) '"NEWDEAV" loading in progress'
      do 68,i=1,4
          if (WS(i).lt.1) goto 68
          write (FILE,'(A)') 'NEWDEAV',char(i+48),'.OBJ'
          open (10,file=FILE)
          read (10,*) EXT
          close (10)
          HS(i)=84*WS(i)-83
          HF(i)=84*WF(i)
          write (*,709) WS(i),WF(i)
          if (i.eq.1.or.i.eq.3) then
            write (*,105) 'Restarting 1st half year ',i/2+1987
            call LOADER7(i,PASS,MGEN,CCOS)
            write (*,105) 'Finished 1st half year ',i/2+1987
          else
            write (*,105) 'Restarting 2nd half year ',i/2+1986
            call  LOADER7(I,PASS,MGEN,CCOS)
            write (*,105) 'Finished 2nd half year ',i/2+1986
          endif
68      continue
      goto 74
c----------------------------------------------------------------------------
69    write (*,100) 'Save MOCOP (Y/N) ?'
      RESP=' '
      read (*,103) RESP
      if (RESP.eq.'Y') then
          write (*,*) 'MOCOPSTD  (S)'
          write (*,*) 'MOCOPMOD  (M)'
70        read (*,103) RESP
          if (RESP.eq.'S') then
            FILE='MOCOPSTD.DAT'
          elseif (RESP.eq.'M') then
            FILE='MOCOPMOD.DAT'
          else
            write (*,102)
            goto 70
          endif
          DO I=1,244
           MOS(SETNBR(I))=I
          END DO
          open (20,file=FILE)
          WRITE(20,198)
          DO 701,I=1,244
          write (20,203) NAME(I),MOC(I),MOS(I)
701       CONTINUE
```

```
      close (20)
   endif
c---------------------------------------------------------------------------
73  write (*,*) 'The end'
   write (*,*) '-------'
   OPEN(UNIT=17,FILE='SMP.DAT')
   write (17,*) SMP
   CLOSE(UNIT=17)
   stop
c
98  write (*,*) 'ERROR ON OUTPUT FILE'
   stop
99  write (*,*) 'ERROR ON INPUT FILE'
   end
```

```
      SUBROUTINE INITIATE(TG,GC,K8,K9,CDN,ERROR,CCOS)
C sets variables to zero
      INTEGER *4 TGO(2184),ERROR,CCOS(214)
      INTEGER *2 HST(214),CST(214)
      REAL TG,GC,K8,K9,CDN
      COMMON /BLK2/CST,HST,TGO

      DO 10,I=1,214
       CCOS(I)=0
       HST(I)=0
       CST(I)=0
10    CONTINUE
      DO 12,I=1,2184
       TGO(I)=0
12    CONTINUE
```

```
      TG=0
      GC=0
      K8=0
      K9=0
      ERROR=0
      CDN=0
      RETURN
      END→→→→→→→→→→→→→→→→→→→→→→→→→→→→
```

```
      SUBROUTINE SORTER(MOC,N,SETNBR)
C quicksort routine using multiple bubble technique
      INTEGER *2 I,I1,J,J1,T,S(20,2),E,C,P
      INTEGER *4 SETNBR(214),IND
      REAL VAR(214),W,MOC(214)
      INTEGER *2 N

C     WRITE(*,*)VAR
      DO 10,I=1,214
       VAR(I)=MOC(I)
10    CONTINUE
C     WRITE(*,*)SETNBR
```

```
      E=0
      C=0
      I1=1
      J1=N
      T1=TI
350   I=I1
      J=J1
      H=-1
360   C=C+1
      IF(VAR(I).LE.VAR(J))GOTO 410
      W=VAR(I)
      IND=SETNBR(I)
      SETNBR(I)=SETNBR(J)
      VAR(I)=VAR(J)
      VAR(J)=W
      SETNBR(J)=IND
      H=-H
410   IF(H.EQ.1)THEN
       I=I+1
       GOTO 430
      END IF
      J=J-1
430   IF(I.LT.J)GOTO 360
      IF(I+1.GT.J1)GOTO 470
      P=P+1
      IF(P.GT.20)then
       WRITE(*,*) 'stack overflow'
       STOP
      END IF
      S(P,1)=I+1
      S(P,2)=J1
470   J1=I-1
      IF(I1.LT.J1)GOTO 350
      IF(P.EQ.0)THEN
       T2=TI
C     WRITE(*,*) VAR
C     WRITE(8,*) SETNBR
       RETURN
      END IF
      I1=S(P,1)
      J1=S(P,2)
      P=P-1
      GOTO 350
      END
```
→→

```
      SUBROUTINE LOADER7(I,PASS,MGEN,CCOS)
C This version derives  SMP and links with MODEL5
C loads up generation to meet system demand in each two hr period
C modify Xdemand for nett external transfer
C version 4 calls subroutine to estimate LOLP
C version 5 creates file smpdata.dat to establish annual profile
C version 6 creates file util.dat with unit utilisation data
C avarage availability and MO cost
C restructered to simplify logic  24/4/94
C changed external transfer logic to cover all weeks 1/5/94
C added cost of external transfer 4/5//94
C added calculation of total demand in period 1/6/94
C added calculation of availability payments  29/12/94
      INTEGER *2 ON,SD,REF,G,W,H,FWEEK,LWEEK
      INTEGER *2 OW(4,4),OB(4,4),WK
      INTEGER *4 GENAV(244,26),L,AV(244),GENR
      INTEGER *2 MOFLT(244),MOS(244),MONLT(244),CST(244)
      INTEGER *2 HST(244),FLX(244)
      INTEGER *4 EXT(336),SETNBR(244),DEM(2184),TGO(2184)
      INTEGER *2 WS(4),WF(4),I,PASS
      INTEGER *4 GEN,NEED,MW,MGEN(244)
      INTEGER *4 CCOS(244),K,WEEK,HR
      REAL MOC(244),SMP(2184),SMPC,TSMPC,UTIL(244),TOTDEM
      REAL EXTCST,EXTSMP,EXTLOP,TS,TL,AVSMP,AVLOLP,AVTOT
      REAL LOLPC,TLOLPC,VLL,LOLP(2184),UNIT(2184),COST(2184),AVPAY
      CHARACTER FILE*12 ,FIL*12

      C  O  M  M  O  N       /  B  L  K  1       /
OW,OB,DEM,GENAV,EXT,MOFLT,MONLT,FLX,MOS,SETNBR
      COMMON /BLK2 / CST,HST,TGO
      COMMON /BLK3 / WS,WF
      COMMON /BLK4 /MOC,SMP,TSMPC

      VLL=2345
      IF(PASS.EQ.2)GOTO 8
C find total demand in period
      TOTDEM=0
      DO WEEK=WS(I),WF(I)
       DO HR=1,84
        TOTDEM=TOTDEM+DEM(84*(WEEK-1)+HR)
       END DO
      END DO
      TOTDEM=TOTDEM/500      ! 2 hr convert to GW hrs
C adjust demand for external transfer
      DO 10,J=1,4
      IF(OW(I,J).GT.0)THEN
```

```
C                    !OW=no of weeks
      IF(J.EQ.1)FWEEK=1
      IF(J.GT.1)FWEEK=OW(I,J-1)+1
      LWEEK=OW(I,J)+FWEEK-1
      DO WK=FWEEK,LWEEK
       DO K=1,84
        DEM(84*(WK-1)+K)=DEM(84*(WK-1)+K)-EXT((OB(I,J)-1)*84+K)
       END DO
      END DO
C              ! OB=ext. block no
      END IF
10    CONTINUE
8     CONTINUE
C call subroutine lolpest to estimate LOLP for each period
      CALL LOLP7(I,GENAV,SETNBR,DEM,WS,WF,LOLP)
C determine for each set in MO whether required or not and load up
      IF(I.EQ.1)TSMPC=0
      IF(I.EQ.1)TLOLPC=0
      IF(I.EQ.1)AVPAY=0
      DO 14,G=1,244
       MW=0
       ON=0
       SD=0
       GEN=SETNBR(G)
C                    ! choose set in MO
       DO 16,W=WS(I),WF(I)
C                    ! each week in half year
        MW=GENAV(GEN,W) ! scaling factor for availability?
        REF=(W-1)*84
        IF(MW.EQ.0)GOTO 16
        DO 18,H=1,84
C                    ! for each 2 hr period in week
         NEED=DEM(REF+H)-TGO(REF+H)
C      WRITE(*,*)H,NEED      ! now find marginal set and SMP

         IF(NEED.GT.MW)THEN
C                    !set required
          IF(W.EQ.1.OR.ON.GT.0)THEN
           TGO(REF+H)=TGO(REF+H)+MW
           ON=ON+2
           CCOS(GEN)=CCOS(GEN)+MW*2
C                              !MW hrs
           SD=0
          ELSE IF(SD.GE.MOFLT(GEN))THEN
C                              !set was off but can come on
           TGO(REF+H)=TGO(REF+H)+MW
           ON=ON+2
```

```
          CCOS(GEN)=CCOS(GEN)+MW*2
          IF(SD.GT.26)CST(GEN)=CST(GEN)+1
C                              !cold start
          IF(SD.LE.26)HST(GEN)=HST(GEN)+1
C                              !hot start
          SD=0
         ELSE IF(SD.LT.MOFLT(GEN))THEN
          SD=SD+2
         END IF
         IF(G.EQ.244)THEN      ! ie last available set then set SMP
          SMP(REF+H)=MOC(GEN)
          SMPC=SMP(REF+H)*TGO(REF+H)*2  ! cost of units at SMP
          LOLPC=LOLP(REF+H)*(VLL-SMP(REF+H))*TGO(REF+H)*2 !LOLP cost
          TSMPC=TSMPC+SMPC
          TLOLPC=TLOLPC+LOLPC
         END IF
C if need less than size of gen then set is marginal
        ELSE IF(NEED.GT.0.AND.NEED.LE.MW)THEN   ! set is marginal
         MW=NEED                        ! and is required
         IF(W.EQ.1.OR.ON.GT.0)THEN
          TGO(REF+H)=TGO(REF+H)+MW
          ON=ON+2
          CCOS(GEN)=CCOS(GEN)+MW*2
C                              !MW hrs
          SD=0
         ELSE IF(SD.GE.MOFLT(GEN))THEN
C                              !set was off but can come on
          TGO(REF+H)=TGO(REF+H)+MW
          ON=ON+2
          CCOS(GEN)=CCOS(GEN)+MW*2
          IF(SD.GT.26)CST(GEN)=CST(GEN)+1
C                              !cold start
          IF(SD.LE.26)HST(GEN)=HST(GEN)+1
C                              !hot start
          SD=0
         ELSE IF(SD.LT.MOFLT(GEN))THEN
          SD=SD+2
         END IF
C now set SMP
         SMP(REF+H)=MOC(GEN)
         SMPC=SMP(REF+H)*TGO(REF+H)*2  ! cost of units at SMP
         LOLPC=LOLP(REF+H)*(VLL-SMP(REF+H))*TGO(REF+H)*2 !LOLP cost
         TSMPC=TSMPC+SMPC
         TLOLPC=TLOLPC+LOLPC

C else if demand already met
        ELSE IF(NEED.LE.0)THEN
```

```
C                    !set not required if its not inflexible
      IF(ON.EQ.0.OR.SD.GT.0)THEN
       SD=SD+2
       ON=0          !availability payments
       AVPAY=AVPAY+LOLP(REF+H)*(VLL-SMP(REF+H))*MW
      ELSE IF(ON.GE.MONLT(GEN).AND FLX(GEN).NE.1)THEN
       SD=2
       ON=0
       AVPAY=AVPAY+LOLP(REF+H)*(VLL-SMP(REF+H))*MW
      ELSE IF(ON.LT.MONLT(GEN).OR.FLX(GEN).EQ.1)THEN
       TGO(REF+H)=TGO(REF+H)+MGEN(GEN)
       ON=ON+2
       CCOS(GEN)=CCOS(GEN)+MGEN(GEN)*2
      END IF
      END IF
18    CONTINUE
16    CONTINUE
14    CONTINUE
C write profile of costs smp,lolp,lolp cost and total to smpdat* file
      WRITE(*,*)' Availability payments ',AVPAY
      WRITE(*,*)TSMPC,TLOLPC
      IF(I.EQ.1)FILE='SMPDAT1.DAT'
      IF(I.EQ.2)FILE='SMPDAT2.DAT'
      OPEN(UNIT=12,file=FILE)
      DO L=1,2184
       UNIT(L)=LOLP(L)*(VLL-SMP(L))
       COST(L)=SMP(L)+UNIT(L)
       WRITE(12,333)SMP(L),LOLP(L),UNIT(L),COST(L)
      END DO
      CLOSE(UNIT=12)
C calculate cost of external transfer in k
      EXTCST=0    ! total cost
      EXTSMP=0    ! smp cost
      EXTLOP=0    ! lolp cost
      DO 100,J=1,4
      IF(OW(I,J).GT.0)THEN
C                    !OW=no of weeks
       IF(J.EQ.1)FWEEK=1
       IF(J.GT.1)FWEEK=OW(I,J-1)+1
       LWEEK=OW(I,J)+FWEEK-1
       DO WK=FWEEK,LWEEK
        DO K=1,84
         EXTCST=EXTCST+COST(84*(WK-1)+K)*EXT((OB(I,J)-1)*84+K)*2/1000
         EXTSMP=EXTSMP+SMP(84*(WK-1)+K)*EXT((OB(I,J)-1)*84+K)*2/1000
         EXTLOP=EXTLOP+UNIT(84*(WK-1)+K)*EXT((OB(I,J)-1)*84+K)*2/1000
        END DO
       END DO
```

```
C             ! OB=ext. block no
       END IF
100    CONTINUE
       WRITE(*,*)EXTCST,EXTSMP,EXTLOP
C now find utilisation  of each unit
       DO K=1,244
        GENR=SETNBR(K)
        AV(GENR)=0
        DO L=1,26
        AV(GENR)=AV(GENR)+GENAV(GENR,L)
        END DO
        AV(GENR)=AV(GENR)/26
        IF(AV(GENR).GT.0)THEN
         UTIL(GENR)=FLOAT(CCOS(GENR))/(365*12*AV(GENR))
        ELSE
         UTIL(GENR)=0
        END IF
       END DO        ! note only half year
C now write utilisation results to file util
       IF(I.EQ.1)FIL='UTIL1.DAT'
       IF(I.EQ.2)FIL='UTIL2.DAT'

       OPEN(UNIT=14,FILE=FIL)
       DO M=1,244
        GENR=SETNBR(M)
        WRITE(14,334)AV(GENR),UTIL(GENR),MOC(GENR)
       END DO
       CLOSE(UNIT=14)
333    FORMAT(1X,F5.2,1X,F7.5,1X,F6.2,1X,F6.2)
334    FORMAT(1X,I5,1X,F7.4,1X,F7.4)
C calculate average prices
       AVSMP=(TSMPC/1000+EXTSMP)/TOTDEM
       AVLOLP=(TLOLPC/1000+EXTLOP)/TOTDEM
       AVTOT=AVSMP+AVLOLP
       WRITE(*,*)AVSMP,AVLOLP,AVTOT
C write results to file results.dat
       TS=TSMPC/1000
       TL=TLOLPC/1000
       OPEN(UNIT=15,FILE='RESULTS.DAT')
       WRITE(15,335)TL
       WRITE(15,336)EXTCST,EXTSMP,EXTLOP
       WRITE(15,337)AVSMP,AVLOLP,AVTOT
       CLOSE(15)
335    FORMAT(1X,'LOLP cost   ',F12.0,'K')
336    FORMAT(1X,'External transfer costs  K ',/'  total       ',F10.0,
     1 /'  SMP        ',F10.0,/
     1 '  LOLP       ',F10.0)
```

```
337   FORMAT(1X,'Av SMP ',F6.2,' Av LOLP ',F6.2,' Tot ',F6.2)
      RETURN
      END



→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→
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      SUBROUTINE CHECK(DEM,TGO,CDN,I,ERROR)

      INTEGER *4 DEM(2184),TGO(2184),ERROR,CHK(2184)
      INTEGER *2 I,WS(4),WF(4),W,REF,H
      REAL CDN
      COMMON /BLK3/WS,WF

      DO 17,W=WS(I),WF(I)
       REF=(W-1)*84
       DO 18,H=1,84
        ERROR=ERROR+2*(DEM(REF+H)-TGO(REF+H))
        CDN=CDN+2*DEM(REF+H)
        CHK(REF+H)=DEM(REF+H)-TGO(REF+H)
18     CONTINUE
17    CONTINUE
      WRITE(*,*)'ERROR', ERROR
      OPEN(9,FILE='TEMP.DAT')
      WRITE(9,*)CHK
      CLOSE(9)
      WRITE(*,*)'See file TEMP.DAT for results of check'
C     WRITE(10,*)TGO
      RETURN

END→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→
→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→→



      SUBROUTINE LOLPEST(I,GENAV,SETNBR,DEM,WS,WF,LOLP)
      INTEGER*2 G,W,H,WS(4),WF(4),REF
      INTEGER*4  GENAV(214,26),SETNBR(214),DEM(2184),GEN
      INTEGER*4 AVAIL(26)
      REAL LOLP(2184),MARGIN,TAVAIL,AVAVAIL
C establish for each 2 hr period the surplus availability and hence
C LOLP for each period assuming a relationship derived from regression
```

```
C analysis of .005*margin in GW
      TAVAIL=0
      DO 20,W=WS(I),WF(I)
       AVAIL(W)=0
        DO 22,G=1,214
         GEN=SETNBR(G)
         AVAIL(W)=GENAV(GEN,W)+AVAIL(W)
22        CONTINUE
       REF=(W-1)*84
       TAVAIL=TAVAIL+AVAIL(W)
        DO 24,H=1,84
         MARGIN=1.0*(AVAIL(W)-DEM(REF+H))
         LOLP(REF+H)=((12000-MARGIN)/1000)*0.005
         IF(LOLP(REF+H).LT.0.0)LOLP(REF+H)=0.0
24        CONTINUE
20      CONTINUE
      AVAVAIL=TAVAIL/(WF(I)-WS(I)+1)
      OPEN(10,FILE='LOLP.DAT')
      WRITE(10,*)GENAV(214,1),(AVAIL(W),W=1,5),AVAVAIL
      WRITE(10,*)LOLP
      CLOSE(10)
      RETURN
      END
```

```
      PROGRAM DEMMOD
C Reads basic demand data from demb(n).dat and scales to future year
c in proportion to estimated energy
C write out year to YEAR.DAT 6/11/94
      IMPLICIT NONE
      INTEGER*4 DEM(2,2184),WKENERG(2,26),MTHENEG(8,12)
      CHARACTER NAME*12,WEEK(52)*7,FILE*12
      INTEGER*4 W,D,K,REF,I,J,Q,P,N,ITEM,Y1(8),Y2(8),YS,YF,YEAR
      REAL SCALE(12),SCALEM,INF(8),INFLATION
      DATA INF/1.0,1.053,1.063,1.063,1.105,1.126,1.15,1.175/
C   Open file and read in data for half year
      DO I=1,2
       IF(I.EQ.1)NAME='DEMB1.DAT'
       IF(I.EQ.2)NAME='DEMB2.DAT'
       OPEN(UNIT=11,FILE=NAME)
        DO W=1,26
         WKENERG(I,W)=0
         READ(11,213)WEEK(W+(I-1)*26)
         DO D=1,7
          ITEM=(W-1)*84+(D-1)*12
```

```
   READ(11,214)(DEM(I,ITEM+Q),Q=1,12)
   DO P=1,12
    WKENERG(I,W)=WKENERG(I,W)+DEM(I,ITEM+P)
   END DO
  END DO
 END DO
 CLOSE(11)
END DO
213   FORMAT(1X,A7)
214   FORMAT(12(1X,I4))
C
C Read data on annual/monthly energy
      OPEN(UNIT=15,FILE='ENERGY.DAT')
      DO K=1,8
       READ(15,216)Y1(K),Y2(K)
       READ(15,215)(MTHENEG(K,J),J=1,12)
      END DO
      CLOSE(15)
215   FORMAT(6(1X,I7))
C Write to screen to select year
      WRITE(6,*)'select year nn/nn between 87/88 and 94/95'
      READ(*,217)YS,YF
      DO I=1,8
       IF(Y1(I).EQ.YS.AND.Y2(I).EQ.YF)THEN
        YEAR=I
        INFLATION=INF(I)
       END IF
      END DO
217   FORMAT(I2,1X,I2)
216   FORMAT(6X,I2,1X,I2)
      WRITE(*,*)YS,YF
      WRITE(*,*)(MTHENEG(YEAR,J),J=1,12)
C now derive scale between base year and selected year
      DO I=1,12
       SCALE(I)=(1.0*MTHENEG(YEAR,I))/(1.0*MTHENEG(1,I))
      END DO
      WRITE(*,*)SCALE
C scale demand in each month with 5 wks in every third
      N=1
      P=0
      DO I=1,2
       DO W=1,26
        SCALEM=SCALE(N)   !ie scale value for month
        REF=(W-1)*84
        DO J=1,84
         DEM(I,REF+J)=DEM(I,REF+J)*SCALEM
        END DO
```

```
      P=P+1
      IF(P.EQ.4)THEN
       N=N+1        !note every third month has five weeks
       P=0
       IF(N.EQ.3.OR.N.EQ.6)P=-1  !ie adds extra week
       IF(N.EQ.9.OR.N.EQ.12)P=-1
      END IF
     END DO
    END DO
c
c now write new demand data file to that read by the operation model
    DO I=1,2
     IF(I.EQ.1)FILE='DEM1.DAT'
     IF(I.EQ.2)FILE='DEM2.DAT'
     OPEN(UNIT=12,FILE=FILE)
      DO W=1,26
       WRITE(12,213)WEEK(W+(I-1)*26)
       DO D=1,7
        ITEM=(W-1)*84+(D-1)*12
        WRITE(12,214)(DEM(I,ITEM+Q),Q=1,12)
       END DO
      END DO
     CLOSE(12)
    END DO
C record year
    OPEN(UNIT=14,FILE='YEAR.DAT')
    WRITE(14,219)YS,YF
    WRITE(14,218)INFLATION
    CLOSE(14)
219   FORMAT(1X,'YEAR ',I2,1X,I2)
218   FORMAT(1X,'INFLATION ',F7.4)
    STOP
    END



   program ORACEXT
c enables the model external transfers to be edited
   integer EX(84),EXT(336)
   character*1 RESP

c read existing data from file
   OPEN(UNIT=20,FILE='ORACEXT.DAT')
    READ(20,101,END=10,ERR=10)(EXT(I),I=1,336)
   CLOSE(20)
c
10   write (*,100) 'Input EXT block no 1-4 or zero to save" :'
```

```
100  format ('1',(A))
     read (*,*) K
c
     if (K.eq.0.or.K.gt.6) then
       write (*,*) 'Save EXT (Y/N) ?'
       read (*,'(A)') RESP
       if (RESP.eq.'Y') then
         open (20,file='ORACEXT.DAT')
         write (20,101)(EXT(I),I=1,336)
         close(20)
       endif
       goto 14
     endif
101   FORMAT(12(1X,I5))

     do 12,i=1,84
12   EX(i)=0
     write (*,100) 'EDF (Y/N) ?'
     call RESPSUBR(EX)
     write (*,100) 'SSEB (Y/N) ?'
     call RESPSUBR(EX)
     write (*,100) 'GT''S (Y/N) ?'
     call RESPSUBR(EX)
     write (*,100) 'HYDRO (Y/N) ?'
     call RESPSUBR(EX)
c
     do 13,i=1,84
13      EXT(84*(K-1)+i)=EX(I)
c
     pause 'Ready for full print-out ?'
     WRITE(*,101)(EX(I),I=1,84)
     goto 10
14   end
c
c
     subroutine RESPSUBR(EX)
c
     character*1 RESP
c
     integer EX(84)
c
11   read (*,'(A)') RESP
     if (RESP.eq.'Y') then
       call INSUBR(EX)
     elseif (RESP.ne.'N') then
       write (*,*) 'Wrong choice - Try again'
       goto 11
```

```
      endif
c
      end
c
c
      subroutine INSUBR(EX)
c
      integer D1,D2,X,H(80),EX(84),M(40),MOD(84)
      character*1 RESP
c
      J=0
10    if (J.eq.0) then
        write (*,*) 'Week days'
        D1=1
        D2=5
      elseif (J.eq.1) then
        write (*,*) 'Weekends'
        D1=6
        D2=7
      else
        return
      endif
       IF(J.EQ.0)THEN
        DO 18,I=1,84
18        MOD(I)=0
       END IF

      N=0
11    N=N+1
      write (*,*) 'Input first 2hr ending : eg 1200 '
      read (*,*) H(N)
      H(N)=H(N)/200
      N=N+1
      write (*,*) 'Input last 2hr ending :'
      read (*,*) H(N)
      H(N)=H(N)/200
      write (*,*) 'Input MW value :'
      read (*,*) M(N/2)
      write (*,*) 'Cont'' (C) or Exit (E) ?'
      read (*,'(A)') RESP
      if (RESP.eq.'C') goto 11
      do 12,i1=D1,D2
        X=-1
        do 12,i2=1,N/2
          X=X+2
          do 12,i3=H(X),H(X+1)
          EX((i1-1)*12+i3)=EX((i1-1)*12+i3)+M(i2)
```

```
12        MOD((I1-1)*12+I3)=M(I2)
      J=J+1
       IF(J.EQ.2)THEN
        WRITE(*,102)(MOD(I),I=1,84)
       END IF
102    FORMAT(12(1X,I5))
      goto 10
c
      end
```

Command procedures to process results 'result' and 'out'.

```
COPY YEAR.DAT+RESULTS1.DAT+RESULTS.DAT RESULT.DAT
EDIT RESULT.DAT
COPY OUT.DAT+RESULT.DAT OUT1.DAT
```

```
       PROGRAM COMCOST
C Calculates new generator profit
C reads annual system cost data from SYSCOST.DAT
C reads system generator utilisation from UTIL.DAT
C finds break point when system and gen util have same price
C modified to cover increased no of gens 20/5/94
C modified to avoid double acconting of availability 10/6/94
       INTEGER AVAIL(244),I,NCOST(400),TOTNO
       REAL UTIL(244),MOC(244),BANDCST(400),SYSUTIL(400)
       REAL CAP,FCOST,VCOST,AVAV,U,INT,INF,AVCOST
       REAL SIZE,BCOST,INCOME,UNITS,GPROFIT,NPROFIT,BUTIL

       OPEN(UNIT=11,FILE='UTIL.DAT')
       DO I=1,244
        READ(11,101)AVAIL(I),UTIL(I),MOC(I)
       END DO
       CLOSE(11)
101     FORMAT(1X,I5,1X,F7.4,1X,F7.2)
       WRITE(*,*)AVAIL(1),UTIL(1),MOC(1)
C now read in system smp profile 400 bands of cost no in band
C and utilisation below band price
       BANDS=0
       TOTNO=0
       OPEN(UNIT=12,FILE='SYSCOST.DAT')
       DO I=1,400
        READ(12,102,END=15)BANDCST(I),NCOST(I),SYSUTIL(I)
        IF(BANDCST(I).GT.0)BANDS=BANDS+1
        TOTNO=TOTNO+NCOST(I)
       END DO
15      CONTINUE
```

```
      CLOSE(12)
      WRITE(*,*)BANDS
102   FORMAT(1X,F6.2,1X,I4,1X,F6.3)
      WRITE(*,*)BANDCST(1),NCOST(1),SYSUTIL(1)
C read in generator details from screen
      WRITE(*,*)'capital cost £/kw'
      READ(6,103)CAP
103   FORMAT(F7.0)
      WRITE(*,*)'fixed cost £/kw/yr'
      READ(6,103)FCOST
      WRITE(*,*)'variable cost £/kw/hr'
      READ(6,103)VCOST
      WRITE(*,*)'average availability pu'
      READ(6,104)AVAV
      WRITE(*,*)'interest rate pu'
      READ(6,104)INT
104   FORMAT(F7.4)
      WRITE(*,*)'inflation factor'
      READ(6,104)INF
      WRITE(*,*)'unit size ?'
      READ(6,103)SIZE
C now calculate break point when unit cost intercepts system price
C at common utilisation and income ie.no in period*sys price*2
C during which unit is in merit
      INCOME=0
      UNITS=0
      DO I=1,400
       IF(SYSUTIL(I).EQ.0)GOTO 25
       U=SYSUTIL(I)
       AVCOST=1000*VCOST
       AVCOST=AVCOST*INF
       IF(AVCOST.LE.BANDCST(I))THEN
        INCOME=INCOME+2*NCOST(I)*BANDCST(I)*AVAV
        UNITS=UNITS+2*NCOST(I)*AVAV
       END IF
      END DO
25    CONTINUE
      BUTIL=UNITS/(TOTNO*2)   ! includes AVAV
      BCOST=1000*(FCOST+VCOST*365*24*BUTIL)/(24*365*BUTIL)
      BCOST=BCOST*INF     !£/MW Hr
      WRITE(6,106)BCOST,BUTIL
106   FORMAT(1X,' UNIT COST ',F7.2,' UTILISATION ',F7.3)
C above calculates income by summating no of periods in band
C times system price for all bands in which unit is in merit
C the cost of generation is based on cost and util at break point
      COST=UNITS*BCOST
      GPROFIT=INCOME-COST
```

```
      NPROFIT=GPROFIT-INT*CAP*1000
      WRITE(6,105)COST,INCOME,GPROFIT,NPROFIT
105   FORMAT(1X,'COST',F7.0,'INCOME ',F7.0,'GROSS',F7.0,'NET',F7.0)
      STOP
      END

COPY OUT1.DAT OUT.DAT


C Programme optout
C Programme to calculate optimum outage plan given period uplift
C cost functions.Uses lagrangian principles with gradient update
C of lambda. Function assumed to be of the form U=A.t power B

      REAL A(12),B(12),T(12),TARGET,LAMBDA,TMAX,POWER,POW
      INTEGER I,ITER
      DATA A/75.69,51.0,76.67,29.77,146.46,
     1 77.55,75.86,36.7,38.0,23.88,24.9,29.1/
      DATA B/-1.77,-1.8,-1.29,-1.34,-1.96,
     1 -1.36,-1.34,-1.34,-0.82,-0.73,-0.73,-0.76/

      WRITE(*,*) 'Specify initial Lambda  (negative)'
      READ(6,101)LAMBDA
      WRITE(*,*)LAMBDA
101   FORMAT(F7.2)
      TMAX=6.0
      TARGET=60.0
C given initial lambda adjust until target is met at minimum cost
      OPEN(UNIT=12,FILE='OPTOUT.DAT')
      WRITE(12,*)' Uplift   Lambda    sum T   T1    T2'
      ITER=0
89    UPLIFT=0
      SUMT=0
      DO I=1,12
       POW=1/(1-B(I))
       T(I)=(A(I)*B(I)/LAMBDA)**POW
       IF(T(I).GT.TMAX)T(I)=TMAX
       SUMT=SUMT+T(I)
       IF(B(I).LT.0)THEN
        POWER=-B(I)
        UPLIFT=UPLIFT+A(I)/(T(I)**POWER)
       ELSE
        UPLIFT=UPLIFT+A(I)*T(I)**B(I)
       END IF
      END DO
      ITER=ITER+1
      WRITE(12,121)UPLIFT,LAMBDA,SUMT,T(1),T(2)
```

```
      IF(ITER.GT.10)GOTO 99
121    FORMAT(5(1X,F7.2))
C now update lagrangian to meet target
      IF(ABS(SUMT-TARGET).LT..001*TARGET)THEN
       GOTO 99
      ELSE IF(SUMT.GT.TARGET)THEN
       LAMBDA=LAMBDA+2*LAMBDA*(SUMT-TARGET)/TARGET
       GOTO 89
      ELSE IF(SUMT.LT.TARGET)THEN
       LAMBDA=LAMBDA-2*LAMBDA*(TARGET-SUMT)/TARGET
       GOTO 89
      END IF
99     CONTINUE
      WRITE(12,*)'  TARGET,    SUMT,    LAMBDA,    UPLIFT'
      WRITE(12,*)TARGET,SUMT,LAMBDA,UPLIFT
      WRITE(*,*)'    T1          T2 '
      WRITE(12,*)T
      CLOSE(12)
      STOP
      END
```

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