ELECTRICITY MARKETS

Investment Performance and Analysis

Barrie Murray

WILEY

ELECTRICITY MARKETS

INVESTMENT, PERFORMANCE AND ANALYSIS

BARRIE MURRAY

ELECTRICITY MARKET SERVICES LIMITED,
WOKING, UK

JOHN WILEY & SONS
Chichester · New York · Weinheim · Brisbane · Singapore · Toronto

Baffins Lane, Chichester,
West Sussex PO19 1UD England

National 01243 779777
International (+44) 1243 779777

e-mail (for orders and customer service enquiries): cs-books@wiley.co.uk
Visit our Home Page on http://www./wiley.co.uk or http://www.wiley.com

Other Wiley Editorial Offices

John Wiley & Sons, Inc., 605 Third Avenue,
New York, NY 10158–0012, USA

WILEY-VCH Verlag GmbH, Pappelallee 3,
D-69469 Weinheim, Germany

Jacaranda Wiley Ltd, 33 Park Road, Milton,
Queensland 4064, Australia

John Wiley & Sons (Asia) Pte Ltd, 2 Clementi Loop #02–01,
Jin Xing Distripark, Singapore 129809

John Wiley & Sons (Canada) Ltd, 22 Worcester Road,
Rexdale, Ontario M9W 1L1, Canada

Library of Congress Cataloging-in-Publication Data
Murray, Barrie.
Electricity markets : investment, performance and analysis / Barrie Murray.
p. cm.
Includes bibliographical references and index.
ISBN 0-471-98507-4 (alk. paper)
1. Electric utilities—Great Britain. 2. Deregulation—Great Britain. I. Title.
HD9685.G7M87 1998
333.793′2′0941—dc21 98–26912
CIP

British Library Cataloguing in Publication Data

A catalogue record for this book is available from the British Library

ISBN 0-471-98507-4

Typeset from the author's disks in Melior by The Florence Group, Stoodleigh
Printed and bound in Great Britain by Bookcraft Ltd, Midsomer Norton

This book is printed on acid-free paper responsibly manufactured from sustainable forestry in which at least two trees are planted for each one used for paper production.

To my grandchildren Ella and Harris

SYMBOLS

Avail	availability
β	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
G_{inc}	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
λ	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
M_{t}	maximum allowable charge in year t
ON	variable indicating generating unit is on
OP	genset metered payments
P	price
P_o	per unit availability
PPP	pool purchase price
PRP	pool reserve price
P_t	price/kw in year t

Q	consumer consumption
RPI	retail price index
SD	variable indicating generating 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

PREFACE

The introduction of market disciplines into the operation and structure of utilities represents a very bold experiment in a key part of the infrastructure of developed countries. The change has not been without its opponents and some countries are choosing not to follow the UK example. Some see the need to maintain strategic control as overriding the benefits of full competition. They see a degree of central coordination as essential while others believe the market will solve all. Those countries that are actively pursuing the introduction of competition are not all choosing the same model and there is a wide spectrum of opinion on the best approach. At the time of drafting this text the market in England and Wales is some eight years into operation and it is considered timely to review what the experiment has delivered and what will lie ahead.

I am fortunate in having worked in the area of power system economics both with a state utility and in a deregulated environment and am therefore able to make a detailed comparison of the two approaches. I have also closely followed developments in other countries to draw out the differences and their significance. I have tried to take a neutral position and be as objective and factual as possible with, hopefully, not too much rhetoric and I apologise if this does not appear the case.

The book is intended to be of value to all those associated with the industry, including investors, facility and service suppliers, the new market players and academics involved in teaching and research. It focuses on the analysis of markets and their mechanisms to help develop understanding and in particular on the approach to investment appraisal as being a key determinant of future prices.

The industry has in the past always maintained a public service culture with the focus of keeping the lights on albeit sometimes at the expense of what might be considered economic. In the new environment shareholders are a dominant force and it remains to be seen how well this serves the general public interest. For my part I would like to see the industry succeed and hope this book helps.

Barrie Murray
Barriemurray.Ems@btinternet.com

CONTENTS

PART ONE

A Review of Market Structures and Mechanisms

Part 1 describes alternative market structures and their benefits and shortcomings in promoting an optimal generation margin and mix and in reducing prices through competition. It discusses how the choice of structure will be influenced by the inherent topology of the network and the state of evolution of the system. The development of a suite of models to appraise investments is described and the essential features of production costing models are highlighted. These are used to simulate hour by hour operation of the market and analyse some of its features. Market mechanisms are discussed and a relationship is established between the System Marginal Price (SMP) and generation plant mix to illustrate SMP volatility. The theory behind the Loss of Load Probability (LOLP) payment is introduced and it is shown how a theoretical optimum can be derived when the combined consumer LOLP payments and the capital costs of additional generation reach a minimum. This is used to illustrate the arrangements necessary to realise the optimum generation margin in practice. Basic tariff theory is introduced and a comparison is made of actual prices against an idealised bulk supply tariff to show how energy prices in England and Wales may have risen in excess of what might have occurred under the previous cost based regime. This part concludes with proposals for improving the market and in particular advocates a new approach to encourage optimal capacity planning using Lagrangian techniques to indicate market needs without loss of data confidentiality.

CHAPTER ONE

Introduction

Objectives

Restructuring of electricity supply is sweeping through the world and transforming the industry and its suppliers, yet there appears to be no universal agreement on the optimal arrangements that should be put in place. The expectations are that competition will be introduced in a way that will lead to efficiency savings and reduce prices. Other motives are to raise revenues for governments and to widen share ownership. A number of questions need to be addressed to ensure a successful outcome:

- What new structures should be put in place to foster competition and who should own and control the assets?
- How many separate owners are necessary to realise competition?
- How should the costs of the natural monopolies in transmission and distribution be recovered?
- What market conditions and mechanisms need to be put in place to support the new structure?
- How will the security of the power system and supplies be maintained?
- How will optimum levels of investment be encouraged and financed?
- How will the manufacturers and service providers to the utilities be affected?
- Is there a universally applicable model or should the implementation be tailored to meet local circumstances?

This book discusses international developments and examines post-restructured performance to assess the impact of the changes that have been made. It develops an approach to the simulation of market operation to enable the longer-term effects to be predicted. It aims to develop a theory which is applicable internationally and validated against actual market results. It examines in particular the process of investment appraisal in generation and transmission as the most significant factor affecting longer-term prices. It explores the performance of the current market mechanisms and suggests improvements. It looks at the impact on the utilities and their organisations and examines the significant changes and prospects for their suppliers. It aims to increase understanding of the issues that confront the players in the market. It concludes with speculation about the future and the prospect of global utilities and suppliers with perhaps less competition than we started with in some areas.

International Perspectives

Other countries have tracked the restructuring process in England and Wales but have developed their own approach to meet their particular needs. This book discusses these alternatives and their strengths and weaknesses to help develop a better understanding of the options.

England and Wales

Prior to restructuring many utilities were in the control of the state with most of the generation and transmission managed as a single entity. The industry in England and Wales was typical 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 structures were designed to give the distribution companies

- the incentive to promote competition in generation
- the ability to connect competing generators to the system exploiting open transmission access
- a wider choice of generation and energy sources

They were expected to continue to contract for sufficient generation to maintain supplies to their 22 million customers. (White paper cm 322, February 1988). The new structure adopted for England and Wales separated generation from transmission and also established several smaller independent generation companies operating in competition with National Power, PowerGen, and Nuclear Electric. A transmission company was also established as the National Grid, initially owned by the twelve regional electricity companies.

In England and Wales the removal of the franchise for local distribution customers is almost complete and similar arrangements are being progressed in Australia and the US leading to the introduction of the concept of ‘suppliers’ buying energy wholesale in competition for resale to their customer base.

USA

In the US great emphasis has been placed on realising open transmission access which is seen as the key to enabling generation competition. The US Federal Energy Regulatory Commission (US FERC, 1992) made it mandatory for transmission owners to post rates for access and use of their network using a system called OASIS (Open Access Same Time Information System). The initial conditions were not the same as in England and Wales with its 100% state ownership and limited trading capability. The US industry is dominated by some 200 investor-owned utilities covering 72% of the market. In California, for example, three investor-owned utilities serve 70% of the state's needs and trade wholesale with neighbours to cut costs by buying and selling electricity. The coal industry was protected in the UK and it operated with high staff levels – some twice as high as in the US. The view from the US was that any change would produce benefits in England but that the English system would not lower customer bills in the US. There is also a strong element in favour of enabling bilateral trading between generators and suppliers/consumers as opposed to trading all energy through a pool as in the British system. There appears to be general support for the development of Independent System Operators (ISO) to coordinate operation on the day and provide fair governance but opinion on the role of pools swings between 'tight pools' dispatching generation and transmission and 'loose pools' where only security is coordinated. Utilities like Duke have been preparing for change by unbundling internally.

Norway and Sweden

Unlike England and Wales where all energy is traded through the pool, Norway opted for a system that enabled bilateral trading with a coordinating framework to balance supply and demand in the event and maintain security. The approach is less centralised with prices determined where bids and offers balance, rather than with ex-ante prices based on a generation schedule. When transmission is likely to restrict free economic operation, separate bidding areas are identified with price differentials so as to restrict the flow between areas to the transmission capacity. The day ahead trading is for physical delivery with a regulating market to provide fine tune control. The Nordpool covering Norway and Sweden also supports futures trading with a financial market used for hedging. The Norwegian system provides a useful contrast to the England and Wales approach.

New Zealand and Australia

In New Zealand the approach is different with the use of zonal energy pricing to manage transmission constraints and highlight the need for new developments.

In Australia it is intended to establish a national market supporting trading on three levels; long-term private bilateral contracts; a short-term two day ahead forward market; and a spot market. A generation and transmission split is being implemented with open access for new generation. A market management company will be responsible for facilitating the market and maintaining security. The approach in Victoria is also different in adopting ex-poste pricing based on the actual marginal generator (unconstrained) that is used in practices rather than a predictive schedule.

Europe

In the Ell the Commission proposed in 1992 that there should be a gradual introduction of competition and customer choice. The principal objectives were to:

- liberalise the generation sector
- enable third party access
- unbundle the accounts of integrated utilities to give transparency

Opinions on how competition should be realised differed widely between those favouring the free market approach and those believing in the need for central coordination and there was deadlock and no agreement. The French have always been opposed to third-party access and because of limited internal fuel supplies have maintained a vigorous nuclear programme. In 1994 they proposed the 'single buyer model' as an alternative, with some competition in generation but with a monopoly on the supply side. To break the deadlock it was accepted that the 'single buyer model' could co-exist alongside other options and it was incorporated into the Directive. An agreement was finally reached in June 1996 and it required that the state utilities enable up to 22% of energy demand to be met from non-utility sources. All sites consuming up to 100 GWh/year were immediately able to choose their supplier with this reducing to 20 GWh as of 1 January 2000. It also called for the vertically integrated companies to be 'unbundled' in accounting and management terms.

In Italy ENEL is being restructured into three separate operating divisions covering generation, transmission and distribution. They are reported to favour restructuring based on managed competition through a single buyer to enable a national strategy to reduce dependence on imported power. In Belgium and some other countries with small undertakings, mergers of generation have taken place to create more efficient units able to compete in the emerging markets. In Germany it is planned to introduce national legislation in 1999 in line with the 1997 European Directive. They aim to remove the local franchise to supply and unbundle generation transmission and distribution and enable third-party access. They hope to encourage competition, improve efficiency and lower prices. The scope to wheel power is being increased with the connection of the East European area Centrel to the UCPTE system and the development of the Baltic ring connecting all the States bordering the Baltic.

Argentina

Wholesale trading was introduced in 1992 with some 40 generators participating in the market but restricted to no more than a 10% share. The trading is on the basis of ex-ante prices but is based on an algorithm designed to minimise costs rather than bids. Transmission limitations are managed by nodal pricing with centralised scheduling and dispatch. Bilateral trading is enabled and accommodated in the central dispatch. The approach is interesting in that it seeks to introduce competition but retain the ability to minimise the real costs of production by using real costs and fuel prices in the scheduling and dispatch process.

Commercial Arrangements

In England and Wales in the absence of direct competition the state-owned utilities like the CEGB and distribution companies were set targets by the Secretary of State to promote efficiency. The last targets for the CEGB were to achieve 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 suit overall fiscal needs.

In restructuring the industry it is generally accepted that transmission and distribution are natural monopolies and that it does not make sense to encourage replication of these systems. These businesses therefore need to be strongly regulated. In the case of generation, a monopoly is not desirable and it is proposed that competition should be encouraged with prices being market driven. Both existing and new generators should have open access to the transmission system for charges which should be made public.

It is also proposed that the business of supplying customers should be progressively opened up to competition by removing the local distribution companies' franchise for supply. In England and Wales the limit was initially set at 1 MW reducing to 100 kw in 1994 and being removed entirely in 1998 giving all customers the right to choose their supplier. Other countries are following suit with a progressive approach to the removal of the local franchise to supply. The new, so-called , 'Second Tier Suppliers' have open access to the distribution systems for defined charges in a manner similar to the generators' open access to transmission (UK Department of Energy, 1990).

Implications

The task of integrated utilities 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. They therefore determined both the location and type of generation that best met the overall needs of the system to maintain optimum performance. They planned the timely 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 companies have to make their investment decisions independently with little knowledge of the commercial plans of their competitors. The normal industry practice was to establish capacity expansion plans based on global studies of a wide range of options and plant types to minimise the total system cost of production and capital costs. It would also maintain a measure of diversity to hedge against sudden fuel price movements. In the new regime marginal prices determine the costs to consumers and there is no mechanism for reaching agreement on overall expansion plans. It is arguable that central planning failed to deliver an efficient outcome, although the outturn was often strongly influenced by overriding government strategic objectives. This book analyses the likely impact of market mechanisms on overall performance to draw a comparison.

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 wholesale price on the day made up of some 57% fuel and 18% interest and depreciation (CEGB, 1988). The Sunday Times of 28 Febuary 1988 quoted the Right Honourable Cecil Parkinson MP 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 like many other integrated utilities placed great emphasis on optimising operation on the day with the introduction of sophisticated scheduling and dispatch algorithms but it recognised that prices were dominated by previous investment decisions. It is proposed therefore that realising the optimal levels of investment is critical to the development of an efficient industry and this book therefore concentrates on the process of investment appraisal in the new market environment.

A proper outcome for privatisation could be supposed to be:

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

These requirements are in part embodied in the licences and regulations issued by governments in their attempt to regulate the new industries.

The Analysis

This book discusses the results of analysing actual market performance since restructuring and uses this to develop models to predict future performance. It has been possible to test the veracity of the chosen approach using data recorded since restructuring. Whereas techniques have been available for many years to plan investment in integrated utilities, little has been written describing the approach to be adopted in the newly deregulated industries. These developments represent an original part of this book in an area that will be critical to the emerging industries. The analysis is presented in six parts:

Part 1 describes the new market mechanisms and their performance
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 outlines the impact on utilities and their organisation
Part 5 discusses the changing market for goods and services from the electricity sector
Part 6 discusses other influencing factors and future prospects

In the sixties we had the ‘dash for oil’ which compares to today’s ‘dash for gas’. In the past energy policy was dominated by the need to secure supply whereas we now believe that we can indulge in market economics. The next decade will see the true and impact of these decisions on the industry and the national infrastructures. This book attempts to provide a basis for understanding and predicting some of these effects to help those involved in planning for the future.

CHAPTER TWO

Alternative Market Structures

This chapter provides an overview of the alternative market structures and mechanisms that have been established or are being considered to realise competition in generation and supply. The recurrent theme is that of encouraging competition in generation and supply with open transmission and distribution access to enable it. There is no universal ideal solution and the approach adopted needs to reflect local circumstances and government strategic objectives. The stage of development of the industry, the security of fuel supplies and the geographic distribution of demand will be key determinants. The different models are outlined and their key advantages and disadvantages are discussed. The practical implementation issues are also highlighted. The terminology used is known to be in general use but there is no universal definition.

The Gross Pool

This is the model applied in England and Wales where all energy is traded between generators and suppliers through the pool. The market clearing price is set in advance based on a unit commitment study with the objective of minimising the total cost of production. In the UK model transmission constraints are ignored as not being the responsibility of generators or suppliers and the same energy price applies irrespective of physical location. A separate operational study is used to determine the actual generation utilisation and the effect of constraints as shown schematically in Figure 2.1. The additional generation costs incurred are shared between all suppliers. Most players hedge against the volatility of pool prices by striking two-way hedging contracts to adjust pool payments to a preagreed contract price as illustrated in Figure 2.2.

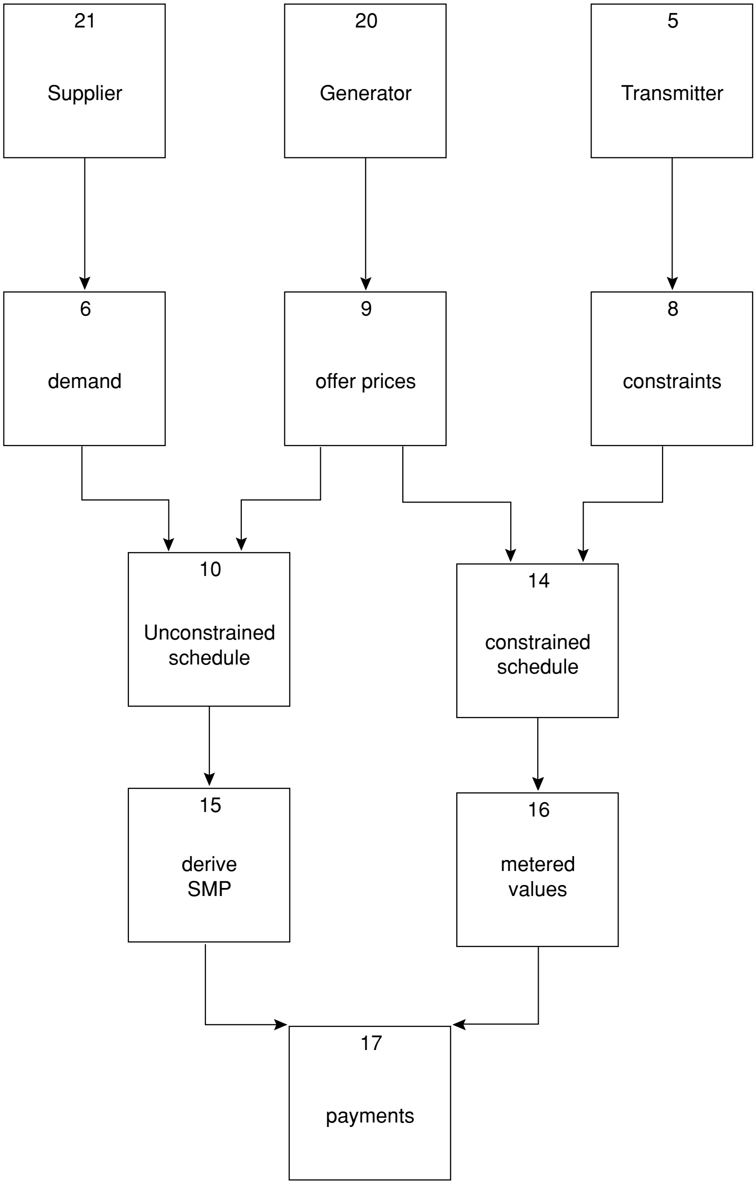

Figure 2.1 The daily bid process.

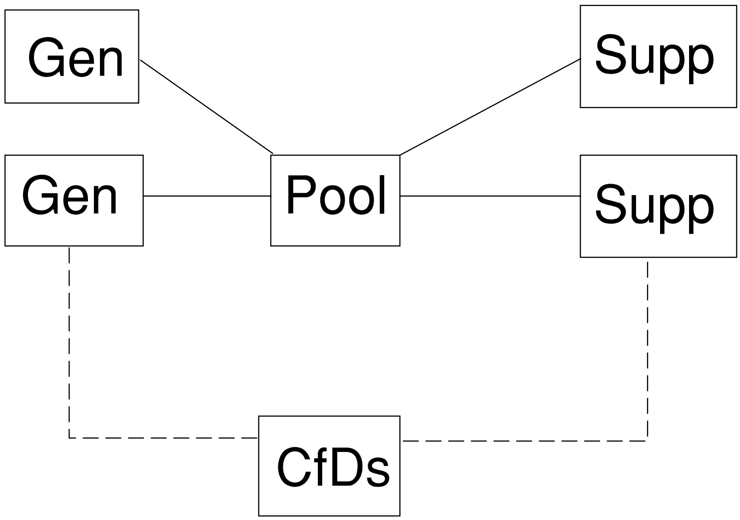

Figure 2.2 The gross pool.

The supply side of the business has also been liberalised with the franchise of the local distribution companies being progressively removed, enabling consumers to have a free choice of supplier. The free choice was initially given to those consumers with a demand greater than 1 MW followed by an extension to those with a demand greater than 100 kW in 1994, extending to all consumers during 1998.

Bilateral Trading – The Net Pool

In the model applied in Norway most of the energy is traded directly between generators and suppliers through bilateral contracts. Since in practice the level of demand and the availability of generation cannot be accurately predicted, a net pool is used to clear the residual energy and any uncontracted demand as illustrated in Figure 2.3. It has been argued that full competition is not realised through this process as the bilateral contracts are not publicly open. In the Norwegian model this is addressed by the Nordpool which facilitates trading both for day ahead contracts for delivery and futures trading for hedging. The process may be suboptimal in that although an individual generator is able to optimise his particular running arrangements the opportunity to establish a national optimum is lost and overall costs may generally be higher.

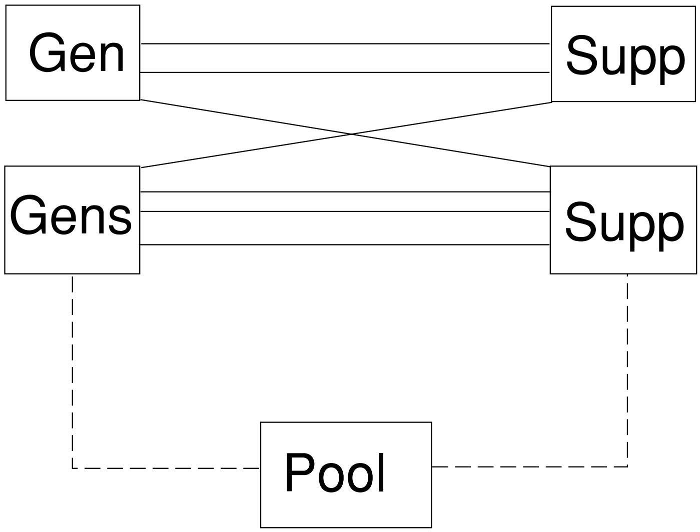

Figure 2.3 The net pool.

The Single Buyer

With this approach a nominated authority acts on behalf of all registered consumers to collate demand predictions and negotiate with generators to buy energy and services as indicated in Figure 2.4. Agreements may include the purchase of existing station outputs or contracting for the output of future stations. The arrangement has been criticised in that the authority represents a monopoly which is not itself subject to market forces but it does realise competition in generation and consumers should be able to buy at an optimal price. It also enables the development of generation and transmission to be coordinated and optimised in both planning and operational time-scales. A progressive introduction of the single buyer model is possible with a mixture of state and independent generation in varying proportions. The buyer should not own generation to avoid a conflict of interest and to maintain impartiality.

This approach has support in Italy and France where there is opposition to third-party access and there are strong national interests. Where adjacent countries adopt a different market approach it needs to be established how interconnection will be managed and who will undertake trading across it. It is arguable that EdF benefit from being able to trade into the England and Wales pool without a reciprocal arrangement being in place.

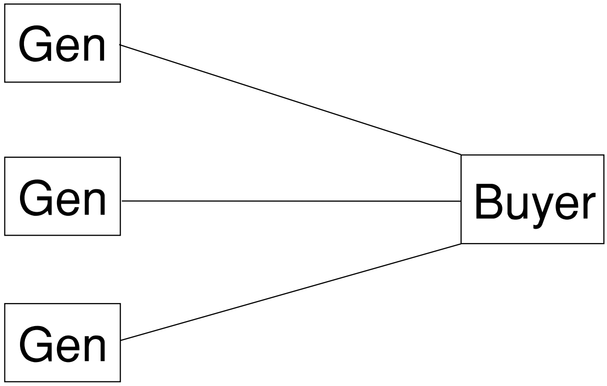

Figure 2.4 The single buyer model.

Zonal Pools

It is not economic to develop transmission systems which are entirely constraint free and from time to time they will restrict the use of generation in strict merit order incurring higher operating costs. The level of system losses resulting from changes in generation injection will also vary around the system. One way of dealing with these spatial differences is to have different energy prices in different areas of the system. With this arrangement the price of energy is set for defined geographical zones which are tightly coupled by transmission with other zones having different energy prices. In the Norwegian model separate 'bid' zones are established from time to time when transmission constraints may become active. This means that generation within a zone can usually be freely used without limitations due to transmission. Trading between zones, however, depends on the level of interconnection capacity and price differentials.

This approach introduces additional complexity but highlights the importance of transmission and creates an incentive to invest to remove constraints, or to choose a more appropriate location for generation. It is therefore appropriate where the existing network is weak and the introduction of more interzonal trading capacity might bring consumer benefit. The capacity of interconnecting transmission can be traded and can be bought by parties either side of the link, as shown in Figure 2.5. The trading could be between the pool authorities or directly between generators who have bought capacity to enable them to bid into adjacent pools as happens with the Scottish and French generation which bids into the England and Wales pool. In the US interutility trading has always been a feature of operation aimed at realising mutual benefit from price differentials.

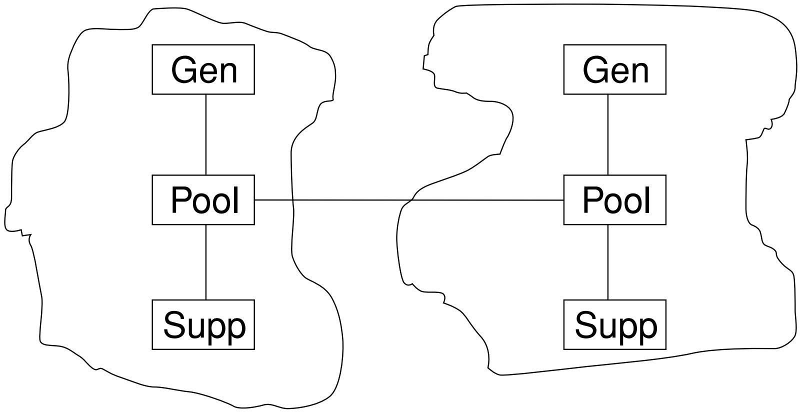

Figure 2.5 The Zonal pool. (Siemens Nixdorf)

Mixed Generation

With this arrangement the vertically integrated utility is retained but is required to enable the entry into the market of a proportion of non-utility generation (NUGs). The benefits or integrated planning are retained and a measure of competition is introduced into utility generation. The system provides a useful intermediate step towards introducing full competition in generation but it is claimed that the utility always favours its own generation and true competition is not realised while the buyer owns generation. This approach is being adopted in Europe and as an initial step state utilities will be required to enable up to 25% of the energy in their area to be met from non-utility sources

State Utility

The fully integrated utility where all the generation is in state ownership together with transmission and sometimes distribution. The absence of competition may lead to inefficiencies and overinvestment and government interference for fiscal reasons may disrupt development and induce cycling in investment. The main advantage is that it enables integrated generation and transmission planning and can create a relatively stable environment in which to encourage investment. For a developing country it has many advantages and allows the state to adopt a tariff policy which encourages the development of the infrastructure of the country as well as supporting the financing of major projects like hydro schemes.

Transmission Issues

Whereas most of the emphasis is correctly focused on realising competition in generation it is also necessary to consider transmission ownership and development. It is generally not economic to develop a transmission system which is completely free of constraints and it is accepted that from time to time the use of generation in strict merit order will be restricted. The optimum is reached when the additional costs of transmission less any savings in losses balance the increase in generation costs. This provides a test of the optimal level of investment but short-run marginal price differentials would not alone fund the development of an infrastructure. Where the demand density is high, as in the England and Wales, the network will be highly integrated as opposed to say Australia and the USA where the long distances between demand centres lead to the development of network zones which are loosely coupled with comparatively high losses. This may restrict trading between zones and justify transmission reinforcement to create more open access for generation. This objective may be better served by a system of zonal energy pricing which highlights the potential savings to market players.

A useful analogy can be drawn between funding for roads and funding for transmission.

- the main infrastructure of roads is covered by a road tax levied on all vehicles, often according to size
- major interconnecting highways are often funded by tolls paid by users
- local feeder roads and drives on estates and industrial parks are for the developers and owners to finance directly

It can be argued that the main transmission system should also be in common ownership with costs shared on the basis of nodal MW transfer without geographical differences. Any other arrangement with divided ownership would introduce difficulties as the network develops, with the retention of rights which would not enable the full exploitation of the assets. A recent example in the UK occurred with a dispute over the use of an interconnector where it was claimed that ownership of rights restricted use even though the proposed flow would be in the reverse direction and actually reduce the net line flow.

To encourage the development of main interconnectors then, it is surely reasonable for those players who will gain most benefit to pay according to use and to support the financing of the development either directly or through a transmission company. The incentive arises when different zonal energy charges apply between the zones to be coupled. There will also be losers in this situation and investors need to be aware of this.

Local connection costs should be borne entirely by the new market entrant either directly or through a transmission company. The recovery might be on a linear basis or profiled to give early returns to the transmitter. Some consideration needs to be given to the sharing of any assets off the immediate site that link into the main system and may have the potential to be shared by other users in future.

Supply Issues

Traditionally the local distribution company has maintained the right to supply the customers in its area. Several countries including England and Wales are progressively removing this restriction and allowing any licensed supplier to contract directly with customers and to pay the local distributer a use of system charge. This gives more power to the customer and avoids a distributer exploiting its captive demand. The use of system prices charged by the monopoly distributer continue to be the subject of regulation. It is difficult to see where much benefit can be derived over a system where generation is already open to competition. Any savings in the provision of a more efficient customer supply service are likely to be offset by the high costs of setting up and administering the system for recording customer/supplier arrangements and meter operations and margins are expected to be tight.

Stranded Assets

Stranded assets are often a major obstacle to restructuring a utility and special arrangements need to be devised to maintain financial viability. They occur when the present worth of the expected net revenue earnings in a deregulated environment falls short of the current book value. In England and Wales this applied to nuclear generation because of the potential high cost of decommissioning and led to the introduction of the nuclear levy. There was also a significant write-off of the value of fossil generation by the government at flotation. In the US it has been suggested (Moody) that stranded assets could amount to $300 billion including fixed price power purchase agreements which in the new market would be uncompetitive but were necessary at the time to finance a large tranche of nuclear generation.

The same may apply to transmission and distribution assets where overinvestment has resulted in excess capacity over and above that necessary to enable integrated operation and the maintenance of security. Currently this is less of a problem but it may become an issue if the result of deregulation causes a significant shift in generation location and hence in flows. The transmitter can contain this by introducing zonally varying use of system charges to encourage location in generation – deficient areas but in practice these may be overshadowed by other financial considerations like combined heat and power options.

Market Comparisons

There is no universally correct choice of market structure and the preferred arrangements at a particular time will be influenced by the stage of development of the system and its operating performance. For developing countries it is important to provide the stability necessary to fund major schemes for new generation and transmission and to ensure that the basic infrastructure is established. These needs may be better served by a high proportion of state involvement in control of the utility so that it is able to underwrite contracts and returns. For a more developed utility emphasis may be placed on realising improvements in operating efficiency through competition. Where new transmission is required to enable full open access then zonal pools may be the medium to encourage investment. Table 2.1 is designed to illustrate some of the key features and shows a qualitative relationship between cost, investment rating and security.

The cost comparison attempts to indicate how three key factors affecting cost may interact. It is assumed to illustrate that:

Table 2.1 Comparison of Structures

Structure	Generation Competition	Integrated planning	Monopoly inefficiency	Cost rating	Investment rating	Security rating
Gross pool	100%	20%	0%	+12	Low	Low
Net pool	100%	10%	0%	+11	Low	Low
Single buyer	100%	100%	50%	+15	Med	Med
Zonal pool	70%	50%	30%	+9	Med	Med
Mixed generation	60%	60%	50%	+7	High	High
State utility	10%	100%	100%	0	High	High

- Competition in generation gives 10% cost saving through the use of more efficient combined cycle systems, reducing the fuel bill
- Integrated Planning saves 10% in avoidable interest by ensuring the ideal plant margin and generation mix
- A monopoly results in inefficiency and additional costs of 10% resulting from higher staff levels and a reluctance to use standard equipment

It can be seen that the single buyer model scores favourably because competition in generation is enabled without loss of the benefits of integrated planning. However, the weighting attributed to these parameters will vary from utility and utility and the degree to which the basic premise is accepted. For example in England and Wales the key changes since privatisation have been:

- The ‘dash for gas’ resulting in an increasing proportion of CCGT generation at the expense of coal and oil. It could be argued that the CEGB would have pursued the same strategy if it had been given the freedom to reduce coal burn.
- Evidence of generation not being sited in the ideal location from a system standpoint and an apparently higher than optimal plant margin projected for future years.
- a reduction in staff levels of up to 50% coupled with an increased willingness to use proprietary systems and to out source. As staff costs across the industry were typically 10% of total costs then this results in a saving in operating costs of 5% with further savings of the order of say 5% by using standard equipment.

The present trend towards mergers and takeovers seems to question some of the basic premises and suggest that there are benefits to be derived from vertical and horizontal integration. The longer-term effect of these developments is yet to emerge but it should be possible to quantify them for comparison with the assumptions above.

CHAPTER THREE

Market Mechanisms

Irrespective of the market structure adopted in operation on a day to day basis, a number of basic functions have to be performed. These are reviewed in this chapter to illustrate the options and how they affect the market and the settlement process. The functions discussed are:

- setting market clearing prices
- securing generation availability
- accommodating transmission constraints
- enabling demand side participation
- capturing data for settlement
- calculating payments

Price Setting

Ex-ante Pricing

This is where the price is set in advance of the event and usually a day ahead. Traditionally the optimum utilisation of generation on the day has been facilitated by the use of unit commitment algorithms. The objective is to selectively choose that generation which minimises the production costs while meeting the station and generator constraints on dynamic performance and any transmission limitations. The algorithms were originally designed to work with fuel prices and heat rates but could be adapted to work with generation bid prices. This was the case with the algorithm used by the CEGB at the time of privatisation, called GOAL, for which the author was responsible. This is now used to minimise the cost of production based on bid prices and to determine the marginal generator during each half-hour and hence the marginal incremental price. It is arguable what is now actually being optimised given that bid prices may not reflect costs. The cost to consumers is not necessarily being minimised on the basis of the marginal price. A disadvantage of this approach is that the outturn will be different from the conditions expected in the predictive schedule and a process is necessary to reconcile the differences.

Ex-poste Pricing

This is where the price is based on the incremental price of that generator recorded as being marginal in the event. In a practical implementation it would be necessary to exclude constrained inflexible generation from setting the price. In advance of the event an indicative price may be provided by a scheduling study as above. This has the advantage that the price paid fully reflects actual conditions on the day and does not leave a requirement to settle the residual.

Bid Pricing

With this arrangement generators are paid at their bid price irrespective of the marginal price. Generators would all tend to bid a little below the expected marginal price to secure running without loss of income. The clustering of prices around the margin would make the scheduling process volatile with frequent changes of units. In the Nordpool implementation the groups of bids and offers are used to establish offer and demand curves with the actual trades being set by the point of intersection. This approach does not enable a global cost minimisation.

Securing Availability

LOLP

In a competitive market there is no explicit requirement for a generator to declare units available and an incentive is necessary to ensure that sufficient capacity exists to meet demand on the day. In the England and Wales model 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. By attributing a value to consumer lost load it is possible to calculate an increment to the basic marginal price designed to encourage generators to declare maximum availability. Whilst this may address the need on the day it does not cover the planning time-scales when outages are taken for maintenance nor does it cover investment time-scales. Although data is exchanged in these time-scales there is no commitment to fix plans and in practice they are subject to short-term changes. In a single buyer market or an integrated utility the outage planning would be coordinated to ensure adequate margins are available at all times. This also applies to managing transmission constraints where it is possible to link them to generation outages to avoid constraining high merit generation.

Accommodating Transmission Constraints

It is generally not economic to design transmission networks to be constraint free and some periods will occur when the use of the cheapest generation will be restricted. This did not present a problem within an integrated utility and the constraints would be modelled and managed as part of normal operation. Within a market, however, it is likely that demands for open access will increase the frequency of periods of constrained operation and some arrangements are necessary to manage them. Three approaches have been used or proposed:

1. Post Market Settlement – the market prices are initially set ignoring transmission constraints, then the additional costs incurred in practice are added to the pool selling price and shared by all users. The transmitter may be incentivised to minimise the so called 'uplift costs'.
2. Market Settlement – With this arrangement the constraints are modelled in the pricesetting algorithms or mechanisms, resulting in different clearing prices for energy in the different zones of the network, i.e. zonal pricing. In exporting zones the price is reduced to cut back generation and in importing zones it is increased to encourage more generation or less demand until the flow falls within the capacity of transmission.
3. Price Settlement – With this scheme the use of the limiting transmission route is apportioned to users and charged for explicitly with the price adjusted so as to balance use to available capacity. Congestion management in some form will be required down to the event to take account of changing circumstances and may be based on schedule bidding for increments and decrements.

An advantage of the first arrangement is that the market dealings are managed a day ahead and on the day the system operator is left to manage the network and maintain security. A disadvantage is that the incentives to invest are less apparent. The use of zonal pricing, on the other hand, points up the benefits of investment to the players directly affected by the constraints but at the cost of introducing additional complexity. The use of transmission pricing adjustments in the short term to manage congestion is likely to put system security in jeopardy. It will undermine the ability to plan operation which in the past has been the key to maintaining security on the day.

The ideal arrangement would be one that encourages the optimal level of investment so as to minimise the overall production cost. It is difficult to see how the above mechanisms will realise this in the absence of a joint authority. Both in the US and the UK the concept of transmission user groups has been introduced but it remains to be seen whether they can operate in the common interest. In practice there will be winners and losers from new investment and some generators may oppose new lines as has occurred in the UK.

Enabling Demand Side Participation

For a market to be fully competitive it is essential that full demand side participation is enabled. In practice this is difficult to realise and attempts made in England and Wales have not been very successful. Large consumers can bid blocks of demand into the day ahead schedule together with the price at which they are prepared to reduce demand. If the expected system marginal price exceeds their bid then their demand is reduced containing the price and they receive unscheduled availability payments. Those consumers who have participated did not consider the savings worthwhile and some have withdrawn.

An alternative proposal called ‘Bidding Against Known Prices’ (BAKP) enabled consumers to bid against known prices derived from an initial scheduling study. Subsequently, a second study would be run with consumer bids to enable the reduction in costs to be calculated. The savings would be shared pro rata amongst the bidders. The proposal did not gain favour and is still the subject of discussion.

Hope is currently pinned on the complete removal of the RECs, local franchise scheduled for March 1998 when all consumers will be able to choose their supplier. This should create sufficient uncertainty to discourage suppliers from entering into long-term contracts with generators and open up the short-term market to true competition. In practice no player in the industry has an interest in reducing its income, including the RECs who want to expand their generation base.

If consumers are able to participate fully, with investment in demand management and energy-saving plant, then they need to be able to participate in planning time-scales. They need to be able to seek bids for blocks of demand so that they can exercise the option to take or pay against the total system marginal price rather than just operating through a bilateral contract. The Nordpool arrangements require a full set of bids from consumers or their agents to realise a balance with generation for each hour of the day ahead.

In practice the small supplier margins mean that the savings to consumers are less significant than those realisable through energy conservation. The effect of deregulation has been to raise the profile of energy management and encourage consideration of local generation options combined with heat production and waste disposal.

Capturing Data for Settlement

Whatever process is in place it is necessary to capture data for retrospective settlement. This will consist of bid data, the results of price setting studies and also instructions given by the Grid Operator on target output or ancillary services. Because of the very large sums of money involved accuracy and auditability are essential requirements. It is also necessary to maintain strict data confidentiality to protect commercial interests and to manage the market without bias and with transparency.

In England and Wales it was decided that the Grid Operator of the National Grid Company would manage the bid process as well as operation because the same data was required for both purposes and the National Control Centre was always operational. In the US an Independent System Operator (ISO) appears to be the preferred option with the market being managed through a separate Power Exchange (PX). The interface arrangements between the two agencies are not entirely clear but it is expected that the operator will be given a schedule and left to manage it in the event. It is yet to be proven that this will result in satisfactory system security.

Calculating Payments

Spot Contract Market

In a spot contract market each of the participants provides a list of potential sales and purchases stating the times the price and the MW block being traded. These are grouped and plotted as curves as shown in Figure 3.1 for each trading period. The intersection of the sales and purchases curves gives the point of confirmed trading. All purchase bids to the left of the intersection and sales bids to the right are invoked and become commitments. The settlement of these is at the clearing price. If transmission restrictions prevent this solution from being implemented then several bid areas will be defined with a different price in each in order to adjust the purchases and sales to balance

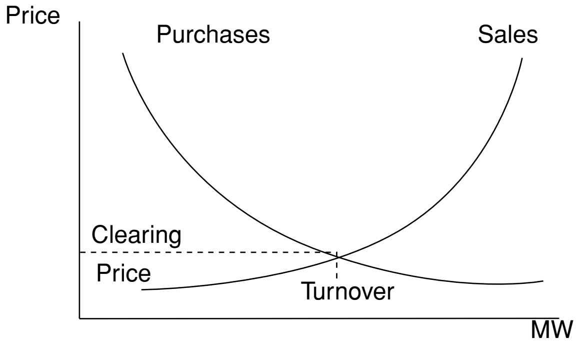

Figure 3.1 Spot market.

the capacity available. Where bilateral trading is enabled then the agreed transfers also have to be entered into the system where they may affect inter-area flows so that their effect on limits is also assessed.

The Unconstrained Schedule Model

In this approach a unit commitment algorithm is used to minimise the overall cost of production based on bid data to meet an estimated demand. In the England and Wales model the generators submit offer prices and plant details each day before 10.00. This is fed into a unit commitment algorithm to establish the cheapest mix of generation to meet the expected demand. 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 (table 'A'). The table 'B' prices are based on incremental rates whereas the table 'A' include start-up prices spread 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 05.00 day 1 to 05.00 day 2 to coincide with a trough when generation price induced changes would be minimised.

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'.

Generator Payments

In the England and Wales model a generator gets paid for the unconstrained energy supplied at the SMP, inflated in proportion to the loss of load probability for the appropriate half-hour, i.e. the Pool Purchase Price PPP is given by:

$$\mathrm{PPP}_j = \mathrm{SMP}_j + \mathrm{LOLP}_j \times (\mathrm{VLL} - \mathrm{SMP}_j) \tag{3.1}$$

where '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:-

$$\mathrm{PRP}_{i,j} = \mathrm{PPP}_i - \mathrm{INCU}_{i,j} \tag{3.2}$$

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 owing to transmission limitations then he will receive compensation for lost profit; i.e. 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, i.e. 'TCW' (genset total revised unconstrained cost).

$$\mathrm{OP}_j = (\mathrm{TCA}_i - \mathrm{TCW}_i) \times \frac{\mathrm{SPD}}{\mathrm{SDD}} \tag{3.3}$$

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

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

Consumer Payments

The payments for energy in England and Wales are at the calculated pool purchase price but this does 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 ancillary service costs. These additional costs are levied on table 'A' periods with table 'B' periods based on the marginal purchase price, i.e. in table 'B' periods the pool selling price is the same as the pool purchase price, i.e.

$$\textit{table 'B' DDD}\ \mathrm{PSP}_j = \mathrm{PPP}_j \tag{3.4}$$

Whereas during table 'A' periods the pool selling price is increased to cover the start up costs and uplift, i.e.

$$\textit{table 'A' DDD}\ \mathrm{PSP}_j = \mathrm{PPP}_j + \mathrm{TAU} + (\mathrm{TGRP}_j/\mathrm{TGD}_j) \tag{3.5}$$

where 'TAU' is the table 'A' non-reserve uplift being the difference between the actual and idealised costs and a function of out of merit costs and ancillary costs. 'TGRP' is the total generator reserve payments apportioned by total gross consumer demand 'TGD'.

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.

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

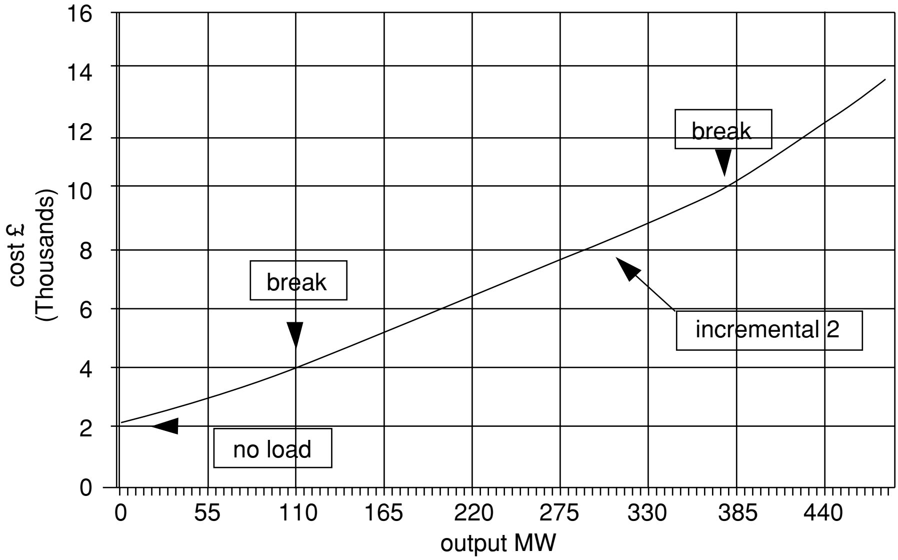

Figure 3.2 Generator cost function.

are also submitted electronically. The data captured during the operational phase is passed once per day to the settlement system which calculates and publishes the SMP and retrospectively calculates the appropriate payments.

Unit Commitment

It is worth describing some of the features of the unit commitment algorithms which are used in operation to determine which generation to use to meet demand at minimum cost. They are also sometimes used to set market price and it serves to illustrate why the process is sometimes the subject of gaming when plant parameters are adjusted to effect its outcome.

The problem of course is minimising 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 shutdown times, as well as inflexibilities due to plant difficulties. The prices may consist of a start-up price, a no-load price and typically up to three incremental prices as shown in Figure 3.2.

The transmission constraints will restrict import or export from zones of the system and may overlap or be nested. The solution of the problem is made more difficult owing 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, such as run-up rates and minimum on time, may prevent the use of units in strict MO where they are unable to track the demand.
- Coupling constraints such as transmission cause the use of one generator to interact with that of another and may force the use of some units out of merit and force other units off.
- the selection of units to meet peaks involves a trade-off between start-up and running costs.
- run-through requires a balance between running through and incurring out of merit running costs, and avoiding subsequent high start-up costs or shutting down and paying for start up.
- The pattern of time-varying availability may not match the demand profile necessitating additional starts and stops.

A variety of techniques have been applied to solve the problem, including heuristic, linear and dynamic programming (Bellman and Dreyfus, 1994), Lagrangian relaxation (Cohen and Sherkat, 1987; Oliveira, 1992), genetic programming and synthetic annealing (Hartl, 1989), and probabilistic techniques (Wang and Shahidepour, 1995). Lagrangian relaxation is attractive for serving the needs of the privatised market because it replicates the process by which a generator would review its schedule against the published SMP and is therefore most easily defendable. The development of an algorithm to replace the GOAL algorithm currently used by the England and Wales pool builds on a basic algorithm (Cohen and Sherbat, 1988) which uses Lagrangian techniques. The approach is to establish a Lagrangian for each of the coupling constraints, such as demand, and also for the transmission constraints, to enable each generator's utilisation to be independently assessed. Starting with an estimate of the system λ 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.

Conclusion

This chapter provides a basic description of the features required to operate a deregulated market and the processes used to establish market prices and settlement. Alternative mechanisms for determining the clearing price have been described including ex-ante, ex-poste and as-bid. It was explained how the ex-ante approach requires a clearing mechanism. The mechanisms to secure sufficient capacity through the LOLP premium to price was introduced. Three approaches to managing transmission constraints were outlined including post market settlement, market settlement and price settlement. The limited facilities for demand side participation were described including bids as negative generation and bidding against known price. The stringent requirements for data capture and processing were presented using the England and Wales system to illustrate the potential complexity. In particular, the unit commitment problem is described to provide an insight into those physical factors affecting system operation and market prices.

Whatever mechanisms are put in place they should be transparent and should not favour any particular sector. They should not be overly complex and should be capable of interpretation by all players including the customers as well as the large generators. The policy on who should undertake the various activities should be designed to establish clear accountabilities and simple interfaces. In practice political factors are likely to exert a major influence.

CHAPTER FOUR

Markets in Operation

This chapter discusses the impact of restructuring on the performance of utilities, particularly on reliability and price. It also highlights some of the market's apparent shortcomings. Neither the expected nor the required performance of the new markets has been defined but rather hopes are pinned on the belief that the market will resolve all. The state-owned utility industries were set financial targets and were expected to provide secure and economic supplies to agreed standards. In practice this meant that the system was developed to meet generally accepted international standards of performance. It is desirable to define what would be a good measure of performance for electricity markets and to examine how that might be delivered through the chosen structure and mechanisms.

The following issues are discussed:

- are standards of reliability likely to be maintained or to deteriorate?
- what are the requirements to realise effective competition?
- how will market prices behave?
- will optimal levels and types of investment be realised?
- how will restructuring affect operating efficiency?

The intention is to highlight those factors that must be considered in reviewing overall performance to ensure an accurate assessment.

Reliability

One of the major concerns at the time of restructuring in England and Wales was the potential impact on the security of supplies. In practice major losses of supply have not been experienced by the public but that is not to say that difficulties have not occurred in system operation. The availability of generation has been less predictable owing to the generators declaring patterns of availability for commercial reasons which did not align with the profile of demand. This resulted in the need to hold larger amounts of reserve to avoid shortfalls and increased operating costs. The increase in the amount of gas fired combined cycle generation has resulted in questions being raised about the ability of the gas network to support the requirements of regulation at times of system stress. Some problems have been experienced owing to gas interrupt contract terms with generators being invoked at times of system peak electricity demand, leading to generation capacity shortfalls. Operational planning has become much more difficult owing to the variations in price of generation and short notice changes to planned outages for maintenance. Despite the use of system charges tailored to encourage optimal generation siting, in practice stations have been built in surplus areas, aggravating transmission restrictions. This has led to the need for an extensive programme of investment in compensation equipment to prop up the system. The ability to effect long-term planning is limited by the widening uncertainty in future generation. The utility engineers have reacted to address these new problems and have met the challenge but at some expense in operating costs and investment.

The system in England and Wales has AC interconnection with Scotland and DC interconnection with France. In general the transfers are controllable and predictable. In the USA and Europe there is much more scope for wheeling through utility areas with less control over the physical paths. The blackouts that occurred in the Western States Coordinating Commission WSCC area were in part attributed to the new competitive measures introduced by regulators. Much tighter planning and control will be necessary if the increased number of transactions are not to put system security in jeopardy.

In the England and Wales pool the price of energy is incremented by a Loss of Load Probability term (LOLP). This was designed to encourage availability of generation on the day and supplement payments to generators not called through an availability payment. Figure 4.1 shows the variation in recorded Loss of Load Probability (LOLP) through three typical months plotted against the apparent excess generation capacity, at the day ahead stage, in GW. It can be seen that positive LOLPs occur for quite high generation surpluses. This reflects the finite probability of a loss of generation sufficient to reduce the overall capacity to within the range of the highest probable demand level. The graph shows only the significant positive values.

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 net 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 developed in Chapter 7.

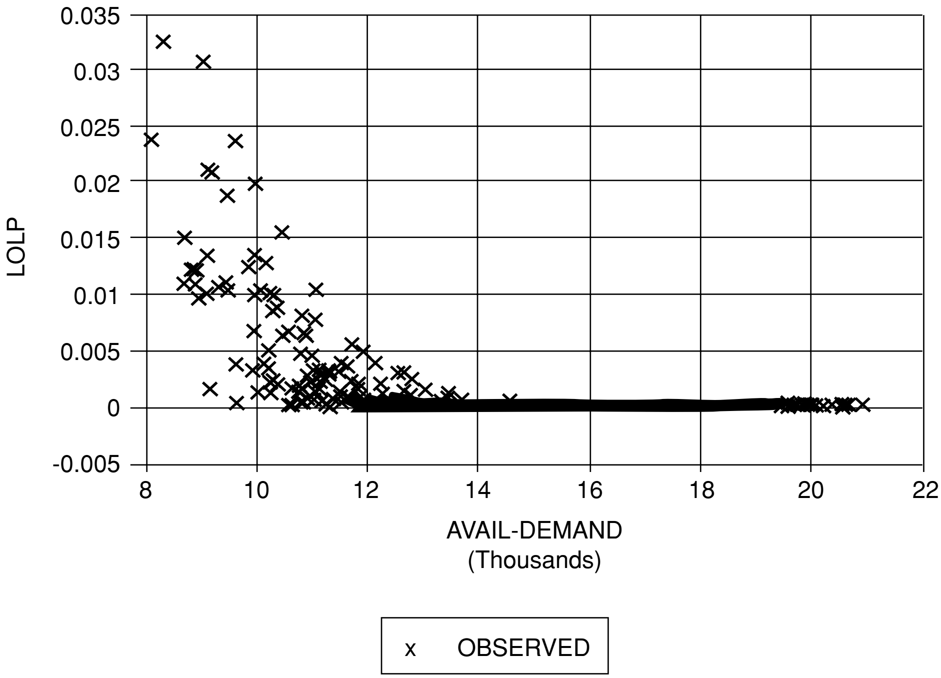

Figure 4.1 LOLP v Avail-Demand.

Competition

The expectation was that competition would result in a reduction in prices and it is claimed that they have fallen in England and Wales by some 20%. This needs to be analysed against the change in costs and particularly fuel during the same period. Electricity prices in almost all nations declined by 10% to 30% and would probably have continued to fall under the old regime. The relaxation of the requirement to burn some 70 million tons of UK coal is the most significant change affecting costs. A large tranche of gas generation has been added to the system with some 22 GW expected by 1998–1999 but this has been at the expense of the advanced closure of some 17GW of coal and oil generation as shown in Figure 4.2. The effect has been a gradual reduction in the total cost of fuel as shown in Figure 4.3 This has been estimated on the basis of typical heat rates and the price of fuel which has generally reduced for both gas and coal according to figures published by the UK Office for National Statistics.

The age of the closed generation is shown chronologically since privatisation in Figure 4.4 Against a forty-year life many units have been closed

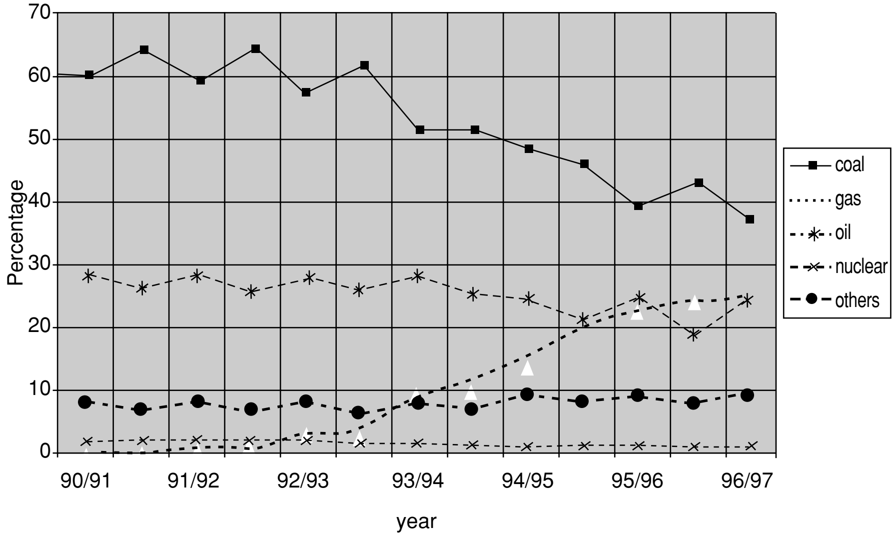

Figure 4.2 Percentage energy by fuel type (estimate).

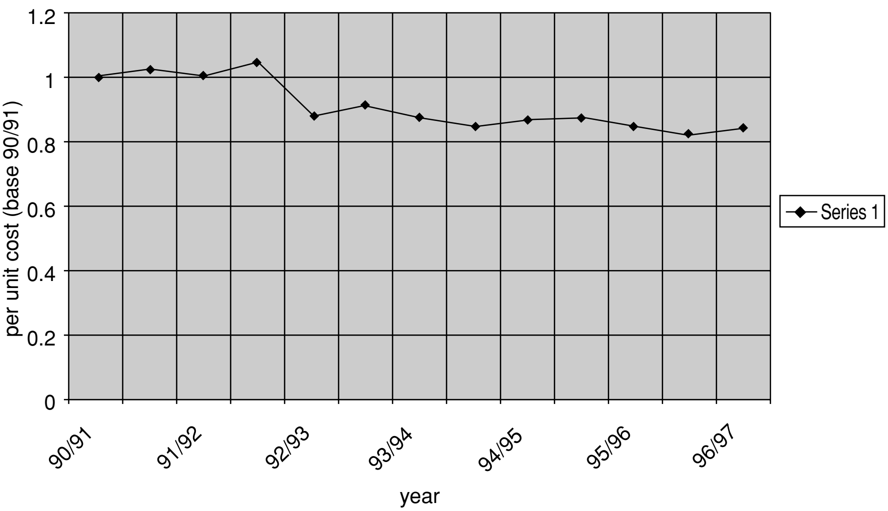

Figure 4.3 Total fuel costs.

early, particularly oil plant. Most of the new generation was expected to operate at base load and left much of the marginal generation in the hands of a few large generators enabling them to control price in the absence of effective demand side participation. The regulator has attempted to change

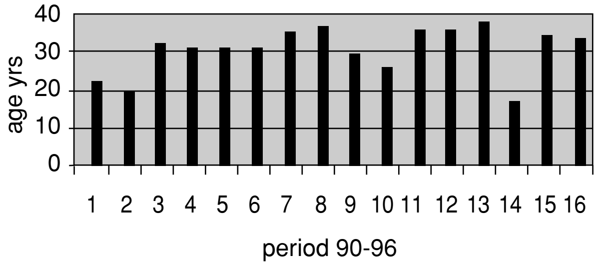

Figure 4.4 Age at closure.

this situation by requiring National Power and PowerGen to sell off a proportion of their generation to Eastern Generation Limited. In practice no private generator is interested in reducing prices and hopes are now pinned on the removal of the franchise to supply to small consumers and an increase in demand side participation. The lessons to be learnt are that certain conditions are necessary for effective competition to be realised including:

- There should be a number of generators owning generation at the margin throughout the demand cycle
- There should be an effective mechanism for consumers to influence the market
- There should be a margin of spare capacity in different ownership with limited ability to manage it by closures

In situations such as that in New Zealand, where the plant margin is already high, prices may be driven down to marginal costs and this results correctly in there being no immediate economic incentive to build new generation. When it does become economic to invest there is likely to be a rush followed by a further lull leading to investment cycling. The Norwegian approach does appear to offer a means whereby the demand side can effectively participate in the market and prices have been reduced. The single buyer model would potentially offer more effective realisation of consumer power through the process of inviting and appraising generator bids.

In Australia the England and Wales system was modelled using a paper exercise and it was reported that it confirmed their view of its shortcomings, i.e.

- The centralised scheduling and dispatch process produced counter-intuitive pools prices
- It was an unsatisfactory physical market and did not provide a basis for trading financial instruments

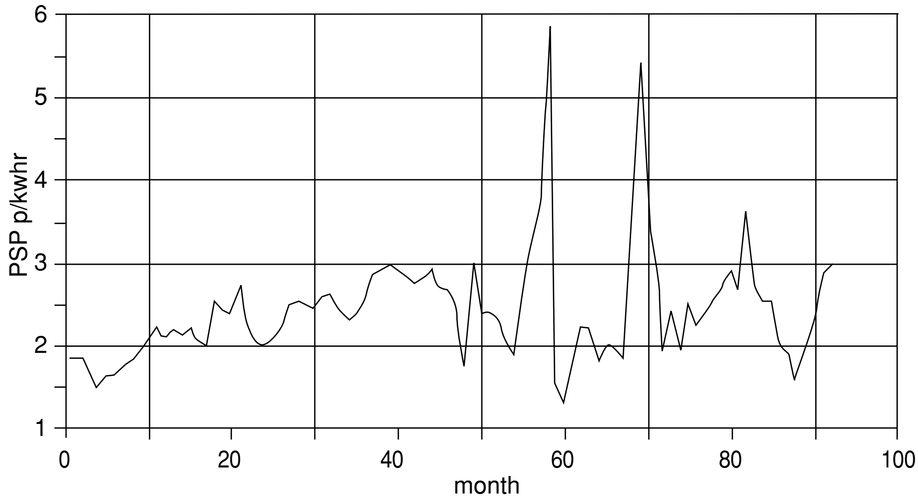

Figure 4.5 Actual PSP, April 1990 to November 1997.Siemens Nixdorf)

- The demand side bidding options were inadequate
- The provision for managing network constraints was inadequate.

Price Trends

Figure 4.5 shows the trend in the average monthly price at which energy is sold wholesale by the pool, i.e. the Pool Selling Price (PSP) since privatisation up to November 1997. It can be seen that the average monthly price has continued to increase and exhibits wide fluctuations in excess of what might be expected due to demand variation. The first extreme spike was due to nuclear outages and high uplift costs and the second was associated with strikes in France. Figure 4.6 shows the increasing volatility of prices during each month since privatisation. It has been suggested that price increases in excess of costs have resulted from the ability of the large portfolio generators to control the marginal price. The volatility in prices may result in part because of operation on a steep part of the overall system price/capacity function where relatively small changes in demand will produce large changes in price. These price movements do not provide a stable basis on which to assess investment for either generators or consumers.

The graph of PSP (Figure 4.5) shows that the market has not been effective in driving down electricity prices, which appear to have risen in excess of inflation suggesting that a true market is not in operation and that prices

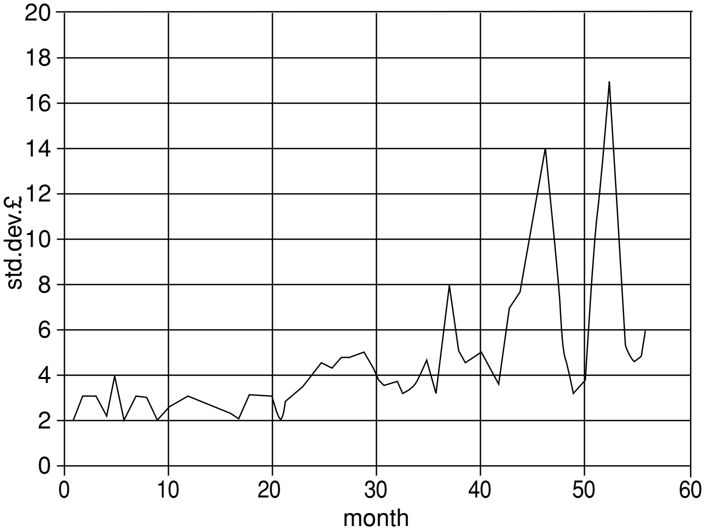

Figure 4.6 Standard deviation of price, mid-1990 to mid-1995. Reproduced by permission of Financial Times Business.

are being managed. This can be confirmed by modelling the cost of operation using generation with typical heat rates and current fuel prices. In practice prices are set by the generators that own the marginal tranche of generation which in England and Wales were the successor portfolio generators. Until such time as that marginal generation is displayed competition will not occur in large parts of the system price function. Even then, in the absence of an effective mechanism for consumer participation, no generator is likely to pull down prices.

SMP v Demand

The System Marginal Price is based on the incremental price of the most expensive generator running in each half-hour period. Figure 4.7 shows the variation in the SMP in £/MWh as published for all half-hours during January 1992, showing no apparent relationship between price and demand as might be expected in a true market. There is a marked lower minimum to the SMP, with the values above that tending to be stratified. The results for individual days show a similar pattern and reflect the overall system price/demand profile, which results in a type of similarly priced generation setting the marginal price over a wide demand range. Short-term changes in availability

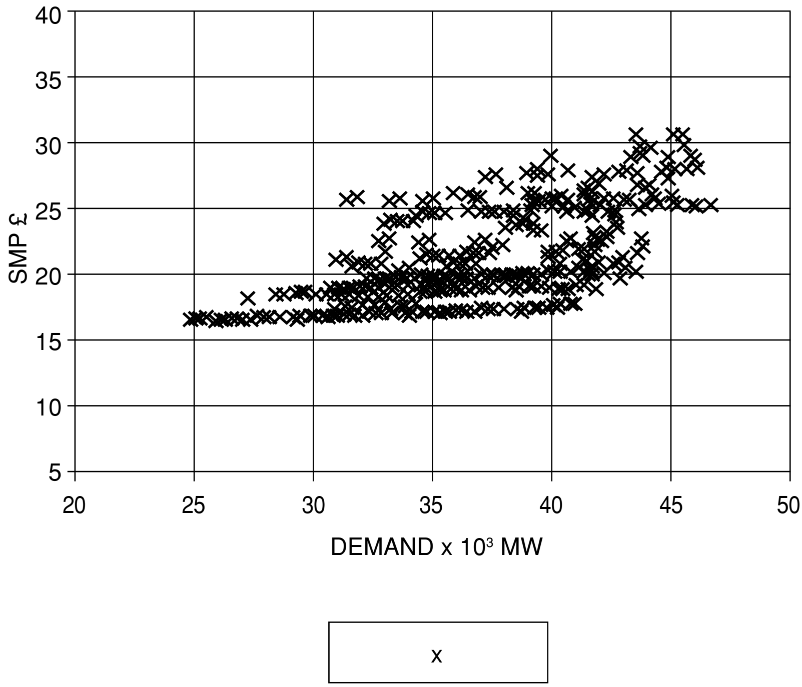

Figure 4.7 SMP v Demand, January 1992.

will cause a switch to other generation types at different demand levels, resulting in similar price levels over a wide range of demand.

Investment

The following factors can have a significant effect on the overall cost of operating the industry, which in turn will affect prices. In an ideal world it would be possible to maintain the competitive elements of the market whilst encouraging optimal development and this is discussed further in Chapter 10.

Plant Margin

The maintenance of a suitable plant margin is essential to the efficient use of capital and the maintenance of security. Figure 4.8 shows the England and Wales 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

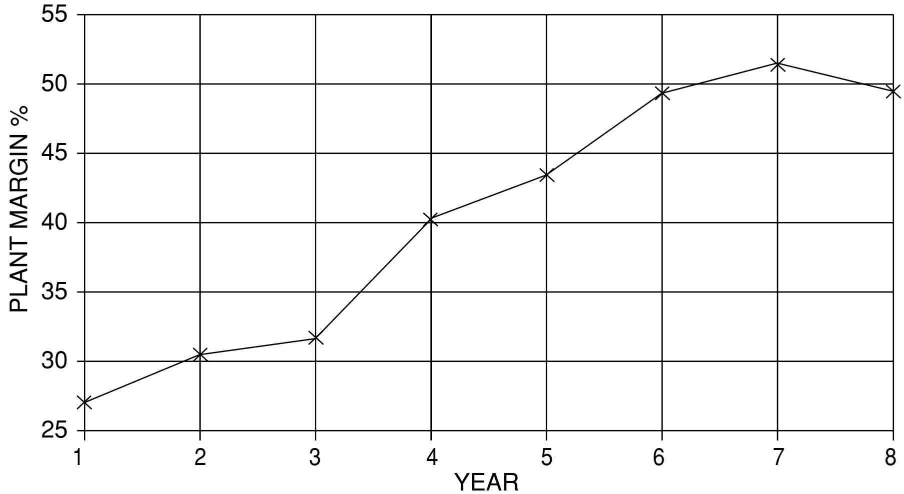

Figure 4.8 Future plant margin, 1994–95 to 2000–01 (SYS 94).

percentage by which the registered planned new generation plus existing capacity exceeds the expected demand as defined and published by NGC in the Seven Year Statement.

Given that the optimum can be shown to be found 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. 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.

The figure of 22.5% is typical of the standard applied around the world and it is shown in Chapter 7 that this results in the minimum overall societal cost. A higher plant margin will result in underutilisation and higher capital interest charges, whereas a low margin will cause more frequent costly interruptions of supply to consumers. Uncoordinated investment decisions by generators are 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. If overcapacity is developed then the impact on returns may cause generators to overreact leading to undesirable cycling in capacity levels. The gross pool current day LOLP signal relates only to short-term availability and is an unsuitable mechanism for influencing long term plant margins. The single buyer model and to a lesser extent the mixed generation approach enable integrated planning and management of the margin.

Plant Mix

Integrated utilities select generation additions to meet future demand taking account of the expected operating regime. A plant mix is chosen to minimise the overall operating and capital costs as illustrated in Chapter 6. The current pool market mechanisms do not provide any incentive to build or retain peak lopping generation as is evidenced by the closure of existing OCGTs. Since all generation cannot operate base load, eventually some generation will have to operate in regimes in which they are less economic and may not produce the expected revenues. Since all generation gets paid at marginal price it is much more attractive to operate base load at high prices set by peaking plant than to build peaking plant that only recovers its operating cost. The ideal generation mix is unlikely to be realised through market mechanisms and some other mechanism is desirable to enable integrated planning and recognition of the different operating regimes required in practice to track demand.

Transmission Constraints

In the England and Wales model the SMP is set using a scheduling algorithm based on generation cost but does not include transmission constraints or losses. This presents the generators with the opportunity to exploit their knowledge of the system when they are within a constraint. They can raise prices in the certain knowledge 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 introduced to incentivise the grid company to contain the costs due to constraints, the opportunity to game still exists. The ideal arrangement would be where the increase in operating cost due to the constraint is in balance with the incremental cost of the additional transmission to alleviate it. In practice a planned reinforcement will disadvantage some generators causing an objection to a new line as occurred in the UK. It is difficult to see what market process will realise the optimum in the absence of some authority or group being given overall responsibility for development, as in the single buyer model.

Use of Transmission Charging

The current charging arrangements for use of the transmission system in England and Wales are zonally based to encourage generators to locate to areas of the system where demand exceeds generation. In practice this has not worked and generators have chosen to locate near to industrial conurbations, partly because a market exists for waste heat. Figure 4.9 shows a steady increase in generation in the North exceeding that in the South with the new capacity in the Midlands being offset by closures. This is despite infrastructure charges of up to £7.80/kW in the North while those in the Midlands are around £1–2/kW and in the South negative at –£6.50/kW. These changes result in higher power transfers, exceeding transfer capacity, and the need for compensation equipment to maintain secure system operation. In a single buyer model or with a mixed generation arrangement it is possible to invite tenders for new generation in preferred areas and so effect better management of the overall transmission/generation system.

Efficiency in Operation

Staffing

Staffing levels have been drastically reduced across all sectors of the industry following restructuring to cut costs and to satisfy the expectation of shareholders. In some areas the savings have resulted from re-engineering processes and the application of automation through IT. In other areas it has been at the expense of research and development and maintaining the highest standards of security and quality. Some of the savings have been offset by higher salaries, particularly at senior level, and the widespread use of consultants, contract staff and outsourcing. An increased commercial awareness has been established resulting in the exposure of the full cost of some of the peripheral activities, bringing their need into question.

Scheduling and Dispatch

Integrated utilities pay great attention to the development and use of generation scheduling and dispatch algorithms designed to optimise the use of assets and minimise the cost of production. Although in England and Wales the same algorithm is used in operation as well as in identifying marginal generation, it is doubtful whether any useful purpose is served as the data submitted is no longer necessarily based on costs but on generator commercial prices.

Optimal Outage Planning

Integrated utilities undertake generation and transmission outage planning for maintenance based on a national optimisation in order 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 significantly influenced by the daily short-term Loss of Load Probability signals. Although a mechanism is in place to enable data exchange, in practice many changes to plans occur in the short term for commercial reasons. This leads to adverse margins and highly volatile prices to consumers, as shown in Figure 4.5, which complicate investment appraisal for both generators and consumers. To effectively manage outages requires either a structure that supports central direction or a system of penalties for short-term changes.

Financial Restructuring

In addition to the planned restructuring there has been an unparalleled level of activity in take-overs and mergers. It is not apparent that these changes have resulted in any improvements in performance, and dissatisfaction with regulatory interference has caused a number of new owners to consider divesting their international business. The privatised industries were not burdened with debt at flotation and many observers believed that the assets were sold off below value. Interest charges have not since been high but for new investment the credit rating of the new organisations will be adversely affected by future uncertainty and this will add to the cost base.

Market Costs

Additional costs which were not a feature of integrated utilities arise as a result of restructuring to support market operation. There is a need for additional tariff metering at the new ownership boundaries. In particular this will be required between generation and transmission as well as to support time of day metering for large consumers, with dial-up capability to facilitate data collection. There is also a need for data capture and settlement system to calculate payments.

Conclusions

There have been difficulties introduced into system operation and planning as a result of the changes brought about by competitive markets but the industry has digested these and there have not been widespread losses of supply.

It has proved difficult to establish real competition in England and Wales because of the control of two large generators over the marginal plant. Other countries have chosen to break up generation into smaller modules and restrict market share using legislation and this may create a better climate for competition.

Prices have risen despite a reduction in the fuel bill and the opportunity to burn gas in more efficient stations with a relaxation of the coal burn requirement. Prices have also been very volatile and continue to be so. This may reflect underlying difficulties in managing the plant margin through the main-

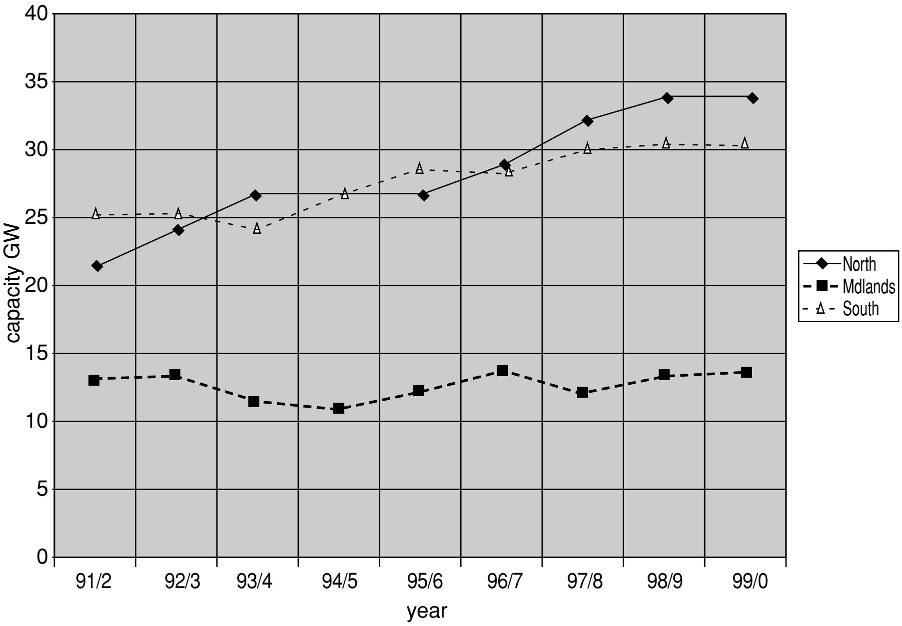

Figure 4.9 Generation location.

tenance outage programme as well as gaming. Initially the relation between price and demand was weak but this has improved somewhat in recent years.

New generation investment has occurred with the option to burn gas and favourable REC take contracts. This has, however been balanced by a closure programme of generation that may have otherwise been kept running for a few years. There is also concern about the plant mix and the ability of the system to operate with a large tranche of gas generation.

The zonal transmission use of system charging adopted to encourage optimal generation siting has generally failed to influence the location of new plant.

Although operational costs have been reduced the effectiveness of the operational process in minimising the cost of production has probably declined.

CHAPTER FIVE

Market Modelling

This chapter discusses an approach to modelling the market in operation, to enable an analysis and prediction of outturn to support investment decisions, and to appraise its performance. It describes a set of three models that could be used to appraise the worth of generation and transmission investment within a deregulated market and how companies may interact. In particular it identifies production costing simulation as the central facility and discusses the key modelling features.

The objective function for an integrated or nationalised utility is to minimise the total cost made up of capital charges and operating costs. In a deregulated environment the income level is now not tied to costs but will depend on the market exchanges with other players as determined by the pooling arrangements and use of system charges. The variables of the problem include expected demand, fuel price movement, interest rate, construction delays and the effect of the action of other players on the pool or on selling prices. The object of each player will be to maximise profit and establish a robust development strategy taking account of all the uncertainties. This book concentrates on developing methodologies to assess income and investment return and to predict the effect of the action of other market players. The management of risk through bilateral hedging contracts is discussed separately.

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 to decompose 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. These cover:

- generation investment appraisal
- transmission investment appraisal
- company interaction

These are outlined below and developed through the book.

Model 1 – Generation

The generation model is shown in outline in Figure 5.1 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 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 later in this chapter.

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 by use of system charges, and uplift payments resulting from transmission limitations are covered by an incentive scheme to encourage efficient operation. The payments for interconnection are the subject of bilateral agreements based on the perceived worth.

The main problem in the new environment is to predict future transmission needs against the costs associated with active constraints. The unknowns are future demand, generation and 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 5.2.

One approach adopted is to use group transmission constraints to represent the network limitations within a 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 necessary SMP profiles and spikes resulting from the effect of generation dynamic constraints.

Model 3 – Interaction

In a deregulated environment the individual players are expected to participate in the market unilaterally and without collusion. It is therefore necessary

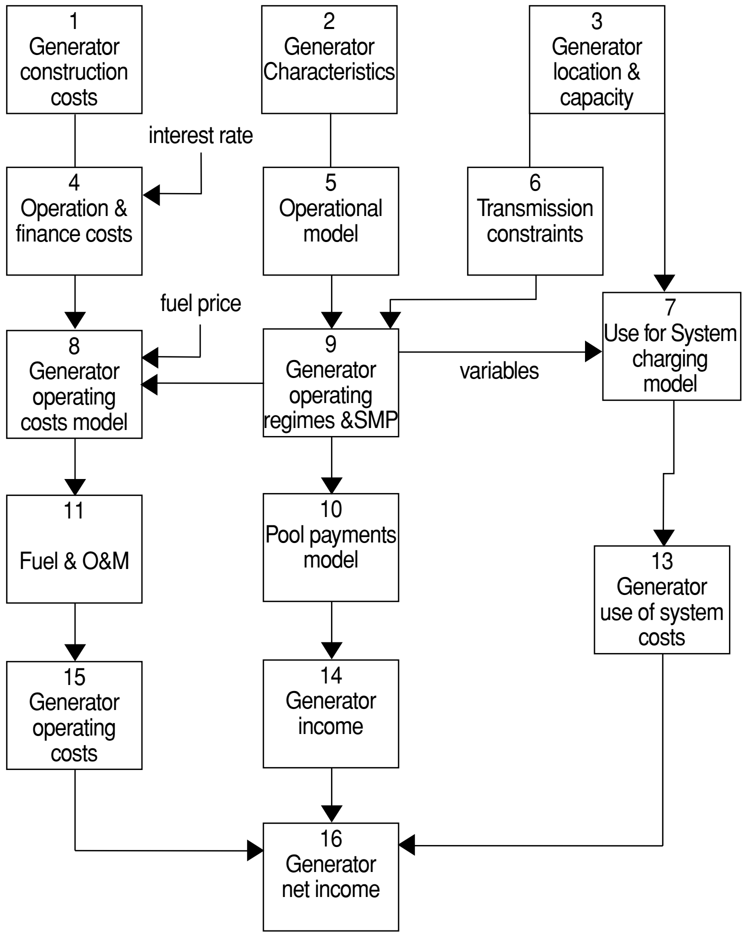

Figure 5.1 Model 1 – generator investment appraisal.

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 5.3).

The model should identify the benefits to generators, consumers and the transmitter of alternative development paths, with modelling of likely decision-making processes at each stage.

Market interactions are expected to be based around the following theoretical concepts:

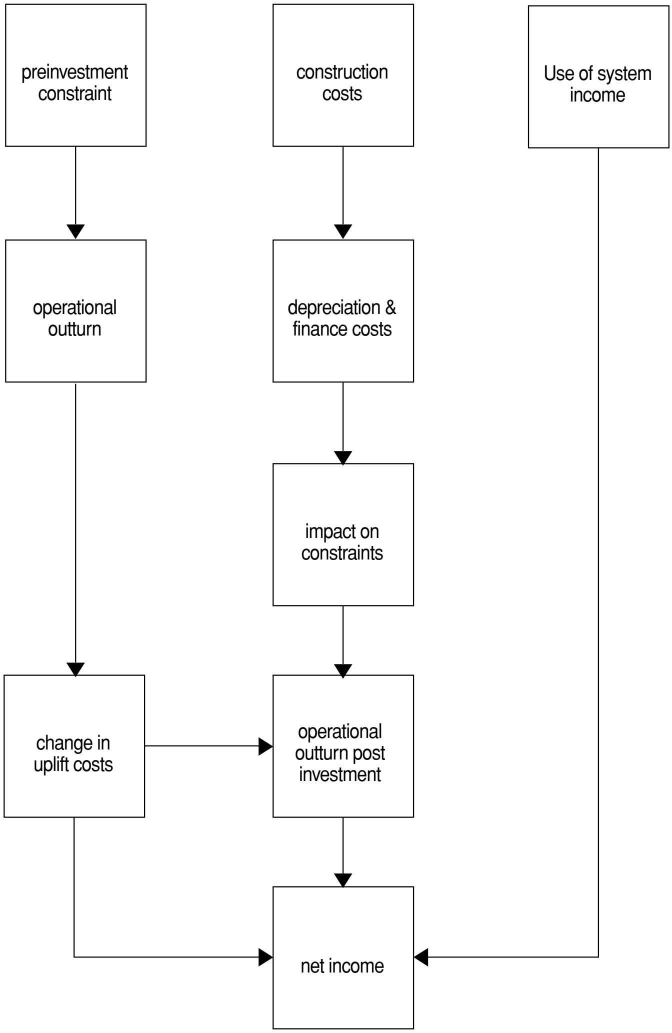

Figure 5.2 Model 2 – Transmission infrastructure development.

- 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 new investment

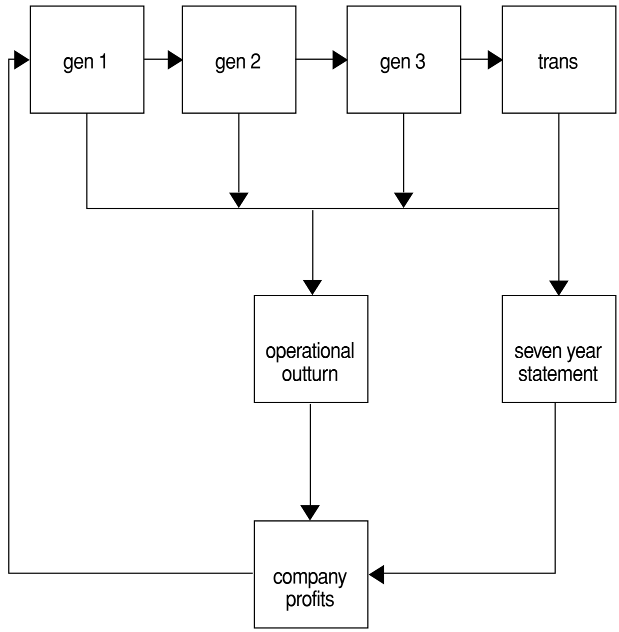

Figure 5.3 Model 3 – Company interaction.

Each player will aim to establish the sensitivity of the outturn to the variation in the inputs to assess risk and 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 based on key events are more appropriate. 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.

The first step is to establish a model of the operational process. Subsequent chapters will address the development of models to simulate the interaction throughout the market.

Production Modelling

This section describes the features of an algorithm to simulate system operation over several years. The model is required to schedule generation to meet a predefined demand and to calculate overall production cost and generation utilisation as well as marginal prices. The model can be designed to accommodate heat rates and fuel prices as applied pre-privatisation, as well as offer prices applying post-privatisation. It can then be used to make a comparison of the relative costs of production by comparing the outturn 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 needs to be as simple as possible to enable multiple studies to address the uncertainty, whilst still producing marginal prices in line with those recorded in practice.

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. However, certain aspects of the process must be modelled to derive the realistic marginal prices required in this case. Of these, generation planned and forced outages need to be modelled as well as the dynamic constraints encountered by generation while tracking changing demand.

A number of alternative techniques have been applied and reported. 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. This 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. The average of several iterations would normally be used. In practice, very large numbers of iterations have been found to be necessary 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's are then used to establish the total function.

All these approaches to modelling varying availability do not reflect the practicalities outage opportunities being taken at low demand levels and not being 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 in favour of more flexible units. There is also a requirement to model individual generators to assess their worth. For these reasons the model developed should use representative outage data, based on recorded plans for the time of year and include dynamic parameters with a chronological simulation. The interval between schedules can be as high as two hours and still be sufficient to capture most of the dynamics related to unit minimum on and off times without leading to an oversized problem.

Typical Model

A typical model has been developed by the author and illustrates how the requirement can be met. It is capable of handling some 250 discrete generators and calculating merit orders based on typical heat rates and heat costs. It will also model transmission constraints and 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 shutdown 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 breakpoint between cold and hot starts can be varied and is typically set at 26 hours. The model is also designed to simulate manually entered external transfers which in this case are from 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.

Input Data

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 program 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.

Output Data

This is selectable by menu and includes a summary with the GWh 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.

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 TLFs to be edited and a new cost of production to be calculated based on:

$$\mathrm{HR} \times \mathrm{HC} \times \mathrm{TLF} \qquad \text{(i.e. heat rate times heat cost times TLF)}$$

subsequently the data is resorted into the new merit order.

Step 5:

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

Step 6:

This enables external transfers to be modified by selection from predefined blocks for specific weeks through each half-year.

Step 7:

This defines the input menu enabling the editing of merit order or execution of the program first or second pass.

Step 8: First pass

This selects and loads generators according to predefined 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: Second 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.

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, to enable any significant errors to be investigated. This may occur when, because of changing availabilities, insufficient generation is available to meet demand. The model results have been compared with those actually recorded and a reasonable comparison obtained for the total cost based on the SMP as well as for the LOLP cost and the average SMP.

The model was used to simulate operation for each month in turn to establish a profile of the SMP and LOLP through the six years from 1987–88 to 1992–93. 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 EdF and Scottish transfers are set manually to values and prices typical of those that applied during the study period. The demand profiles are based on typical values scaled to be consistent with the monthly energy figures for the period. The results are shown in Figure 5.4, having corrected for inflation. The marginal cost and prices follow a similar trend during this period but it will be shown how they subsequently deviated. The graph also shows 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 were 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. It is worth noting that the marginal cost is some 150% of the average variable cost of production representing a considerable premium. Allowing some 20% for interest and depreciation and other fixed costs, the ratio would drop to 1.3. This is relatively high for a thermal system and more typical figures are in the range of 1.2 . This is a function of the plant mix and margin at that time which resulted in relatively expensive generation being used at the margin. In other situations where there is initially spare capacity resulting from a high margin then a much lower premium would be expected.

Conclusions

It is concluded that an operational model can be constructed which gives results sufficiently similar in behaviour to the actual to enable it to be used

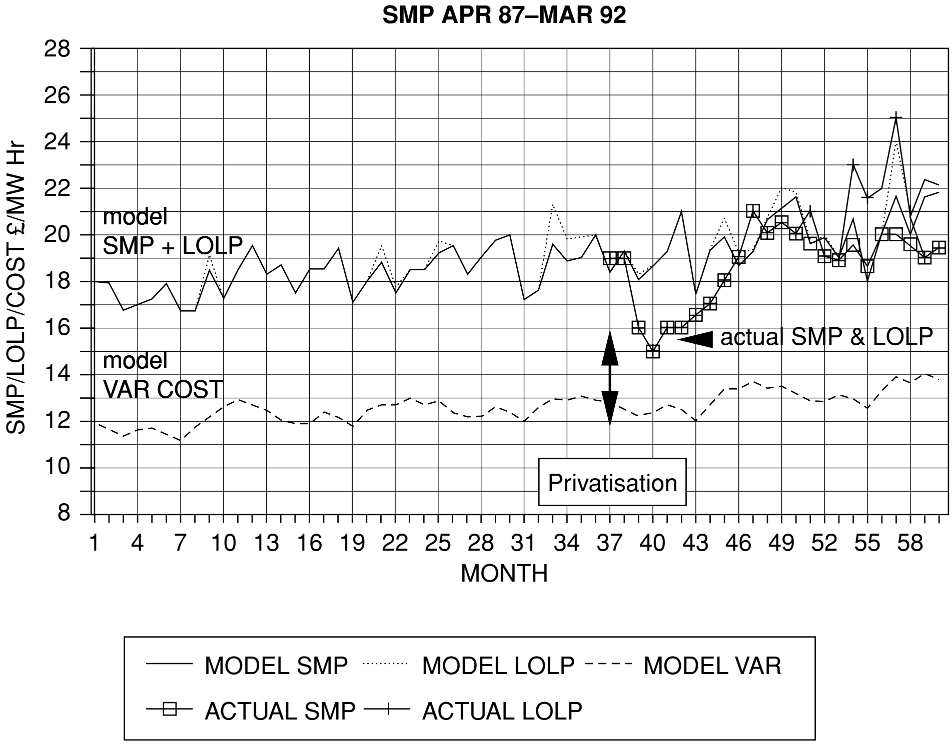

Figure 5.4 SMP, April 87-March 1992.

to analyse the market behaviour and calculate generator profits from a knowledge of income based on pool payments with the costs calculated from typical generator heat rate data and fuel costs. The results show that the income derived from marginal pricing is significantly above the average cost of production resulting in the so-called 'energy credit'. The model can also be used to derive the true marginal incremental costs as would apply in a perfect market and it is shown in Chapter 8 how the actual increased above this value.

CHAPTER SIX

SMP Theory and Optimal Plant Mix

SMP Derivation

The marginal cost of production has always been a key parameter in the economics of utility operation. Vertically integrated utilities will analyse its profile in setting bulk supply tariffs. In the new markets it often sets the price for trading. In order to be able to predict the SMP and assess the effect of new generation it is necessary to understand its derivation and its relationship to the generation plant mix. The SMP is defined as the incremental price of supplying an additional MW of power. A value is currently derived for each half-hour or sometimes hourly period. The marginal generator 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 exceptions to this:

- A generator that is inflexible and cannot realise extra output should not set SMP
- A generator that is ramp rate limited should not set SMP
- A generator constrained by transmission may not be able to set SMP in some systems

In general the intention is to ensure that incremental output is really possible. Further complication results in those periods when the incremental power has to be met by starting up more generation.

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.

$$\text{table 'B' SMP}_j = G_i \text{ inc}$$

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, i.e.

$$\text{table 'A' SMP}_j = G_i \text{ inc} + \frac{\text{STC}_i}{\text{T}} \tag{6.1}$$

The effect of start up costs is overall minimal and generally less than 1% of total costs with realistic values. However, at narrow peaks the SMP may exhibit 'spikes' with high values occurring particularly during table A periods owing to the addition of start-up prices to what may be a small number of MW on the marginal unit. The objective function of the scheduling process is to minimise the total production cost and not the marginal price and it may therefore be correct to run a high priced peaking unit. A less volatile SMP can be established by basing it on the incremental price of a tranche of say the last 100 MW of generation which would be less subject to the distorting effects due to adding in start-up prices.

Derivation of Optimal Plant Mix

In an ideal situation the introduction of new generation would progressively lead to the establishment of that mixture of generation types that has minimum capital and running costs when following the demand curve. This usually means a proportion of generation with low operating costs but relatively high capital costs that will run base load and a tranche of lower capital but higher operating cost generation run to meet peaks. In integrated utilities techniques are used to identify the optimal mix and these are usually based on LP formulations. The extent to which an optimal generation mix will emerge in a free market remains an open question.

The following sections describe two approaches to derive an optimal plant mix and to illustrate its relationship to the SMP. The intention is to establish a technique that could be used in wide-ranging scenario studies when full data sets are not available to predict trends in SMP.

Graphical Approach

Although not an accurate method the graphical approach illustrates the principles and can be used to make estimates for systems for which full data sets are not immediately available. Given indicative capital, fixed and running costs for the different generation types, a total cost/utilisation function can be established for each as shown in Figure 6.1 where:

$$G_i = I \times c_i + \mathrm{FC}_i + \mathrm{VC}_i \times h_i$$

where G = total cost in £/kW/year; c = capital cost; i = interest rate; FC = fixed cost; VC = running cost; h = running hours 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 at that utilisation level.

Given a demand profile a load duration curve (LDC) can be derived showing the demand level and the number of hours for which it applies. The intersection of the generation breakpoints with the LDC curve gives the optimal utilisation for the different tranches of generation and their size. The results in this example were approximately: OCGT 23%; oil 9%; coal 17%; nuclear 51%; without the CCGT option.

It can be seen that where the CCGT option is to be introduced it would displace a whole tranche of coal and oil fired generation. This in turn would have a significant effect on the SMP and in a truly competitive market would cause it to be much flatter with a significant reduction in the energy credit resulting from the high SMPs set by marginal plant.

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

$$\sum \mathrm{FC}_j \times \mathrm{DNC}_j + \sum^{J_{j=1}} \sum^{T_{t=1}} \mathrm{VC}_j \times \mathrm{MW}_{j,t} \times \mathrm{Avail}_j \qquad (6.3)$$

subject to

$$\sum^{J_{j=1}} \mathrm{MW}_{j,t} = D_t$$

and

$$\mathrm{MW}j \leq \mathrm{DNC}j$$

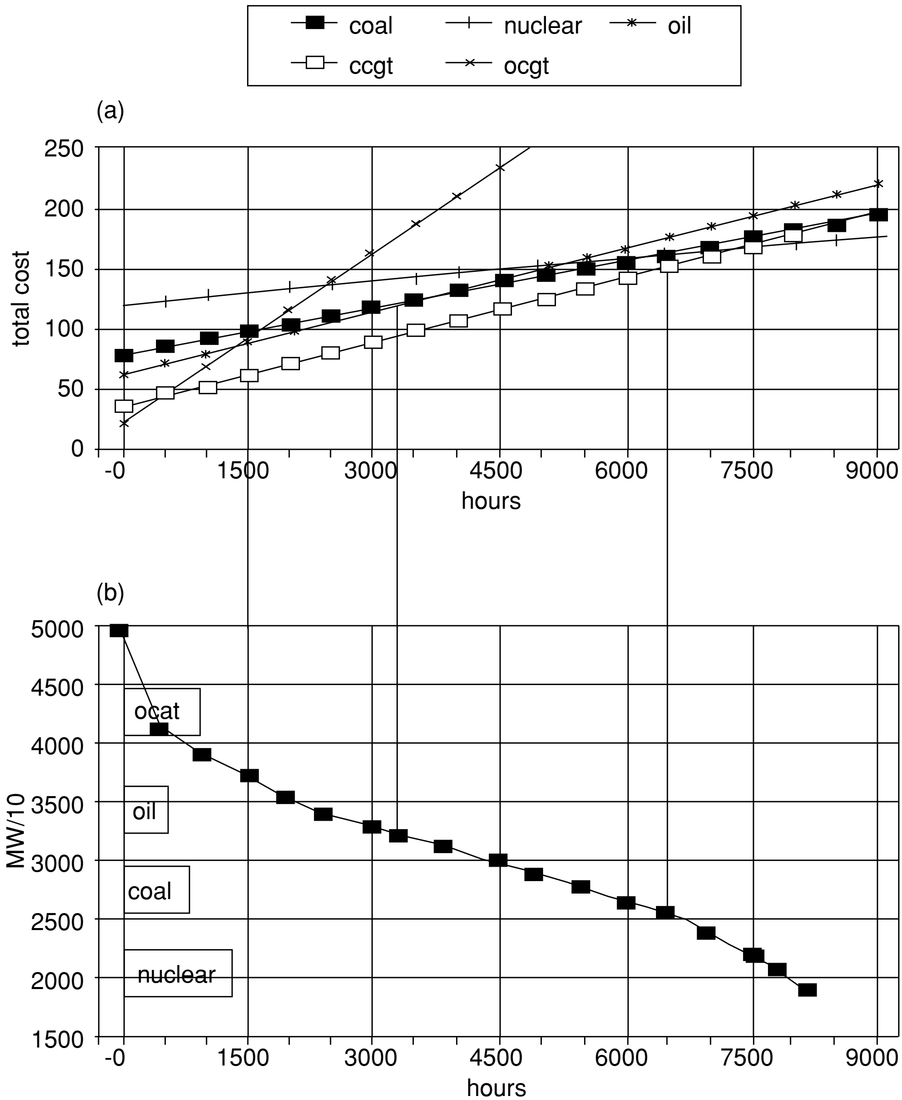

Figure 6.1 Optimal Plant Mix; (b) load duration curve.

solve for $MW_{j,t}$ and DNC_j where FC = fixed cost; DNC = capacity; VC = variable running cost; MW = load. Avail = mean availability. In practice the formulation would be more complicated and include the effect of construction costs and the existing generation as well as risk appraisal.

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 and is similar to that derived graphically. It also shows a substantial proportion of nuclear as cost-effective as was believed to be the case prior to privatisation, ignoring decommissioning costs. The same techniques can be used to estimate the utilisation of different types of generation while taking account of existing generation.

SMP Estimation

Having estimated the future plant mix 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, i.e. 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 hours in a year to derive an annual average SMP. Using the typical plant mix and incremental prices as applied at the time of privatisation for the different tranches of generation the results would be:

	coal	nuclear	oil	OCGT
percentage mix	59	17	21	2
av. incremental costs £/Mwh	17.75	7.0	20.25	48
marginal hours	6260 – 2250	250		
weighted average	£18.89/MWh			

The figure reflects 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 of £18.89/MWh compares well with that derived from a full operational simulation result of £18.32/MWh. i.e. the simplified estimate is within 3%.

The result with maximum use of the CCGT option would be as shown in the table below and Figure 6.3, i.e.

	coal	nuclear	oil	OCGT	CCGT
percentage mix	0	55	0	0	44
incremental costs £/MWh	0	7.5	0	0	13
marginal hrs	0	1260	0	0	7500
average	£12.2/MWh				

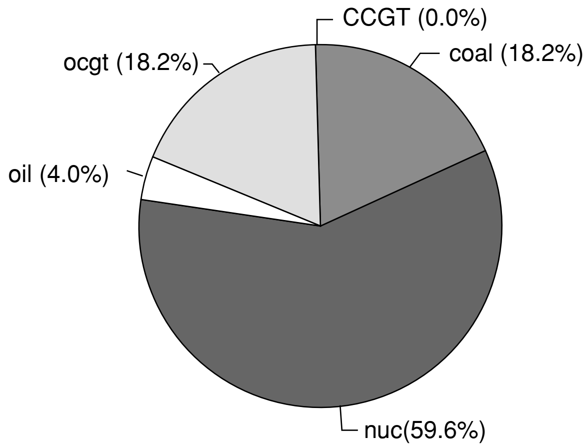

Figure 6.2 Plant mix (LP formulation). 1992–93, no CCGT.

These simplified results support the 'dash for gas' and demonstrate the viability of a significant tranche of nuclear generation in operation as evidenced by cheap imports from EdF. In practice this solution would not be viable, taking account of decommissioning costs.

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 its own income against the marginal price, which will give different results. 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 forced to close with financial failure. The generation investor now needs to be able to predict the behaviour of his competitors and consumers and model the impact on his decisions and these aspects will be addressed in Part 2.

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

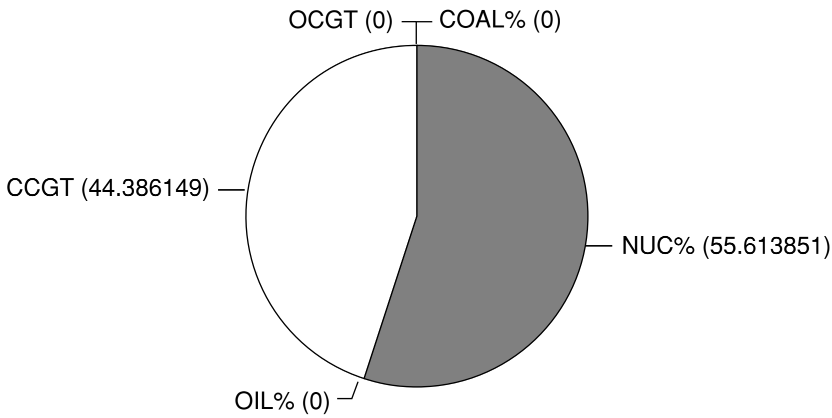

Figure 6.3 Plant Mix (LP formulation). 1992–93, with CCGT.

£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 CCGTs
- The profits of base load generation are inflated by those periods when peaking plant sets the SMP
- The classical approach to determining capacity 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 ever to cover capital costs. This is evidenced by the wholesale 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. It has been illustrated how the plant mix can have a significant effect on SMP but there appears no market mechanism to encourage the optimal.

CHAPTER SEVEN

LOLP Theory and Optimal Margin

The previous chapter discussed the price of energy, this chapter discusses the other key parameter of interest to consumers – the security of supply. This can be assessed in terms of the loss of load probability (LOLP) and the task is to determine the value that would best meet consumer needs. The derivation of LOLP from basic principles is described and it is demonstrated how this relates to plant margin and consumer LOLP payments on the basis of an ascribed value to lost load. It is shown that the optimum level of investment for society is realised when the sum of the consumer LOLP payments together with the incremental generator capital costs reaches a minimum. The results are tested against full operational simulations and used to illustrate the advantage of pooling generation. The chapter concludes with a discussion of the difficulty of realising the optimum using the current market mechanisms.

Theory

Loss of load probability (LOLP) is a function of time-varying demand and generation availability. From statistical theory the probability of *r* generators being unavailable from a population of *n* generators is given by:

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

where P_O = unit availability; r = number of generators unavailable; P_o^r = probability of r units being 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, D_t. Then a measure of the probability of there being insufficient generation to meet the demand is established by comparing for each generation availability level the number of demand period hours during which a shortfall might occur. The summated LOLP is given by:

$$\sum \text{LOLP} = \sum_{1,1}^{T,N} (H_{nt}\,(D > G_n^t)) \tag{7.2}$$

where H_{nt} = number of hours when demand D^t > generation; D_t = demand at time t; G_n = output of generator n at time t.

Figure 7.1 shows the principle graphically. The demand probability curve is superimposed on the total generation availability function. The area of overlap indicates where a shortfall would occur. The results can be obtained by a computer simulation of the above theory. The actual simulation used in the England and Wales pool is calculated daily and takes account of most recent performance but the above approach can be used to estimate annual averages.

LOLP v Margin

The theory can be used to demonstrate the variation of LOLP with plant margin. Figure 7.2 shows the results for the 92/93 demand profile with two typical average values of individual generator availability i.e. 0.9 and 0.85. It can be seen that with the assumed level of 0.85 little change in LOLP occurs beyond the generally preferred 22.5% plant margin, with the value falling to zero at 25%. Given a maximum demand of 48 GW, LOLP will then be effectively zero for margins above 12 GW (0.25×48). This was the value derived from the regression fit to recorded values derived in Chapter 4 and provides the basis for a simulation that can be used in a detailed model. It can also be seen however that if the average generation availability could be increased to 90%, then a 16% margin would be adequate. This then gives a direct means of comparing investment in improving the availability of existing generation with that for adding new generation capacity to maintain security, i.e. 5% availability = 6.5% capacity, i.e. approximately 1:1 as would be expected. A regression fit of LOLP to margin shows for this data set that average LOLP is given by:

$$\text{LOLP\%} = 0.04648 - 0.00173 \times \text{MARGIN\%}.$$

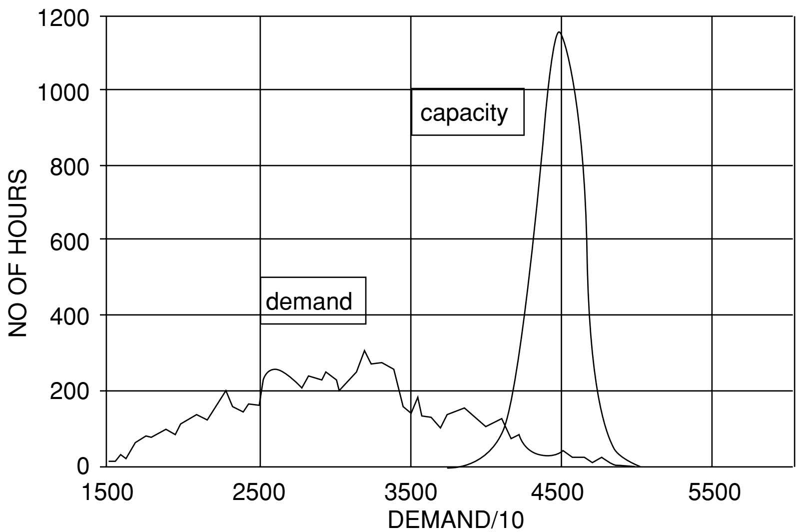

Figure 7.1 Load distribution curve, 1992–1993. Capacity profile.

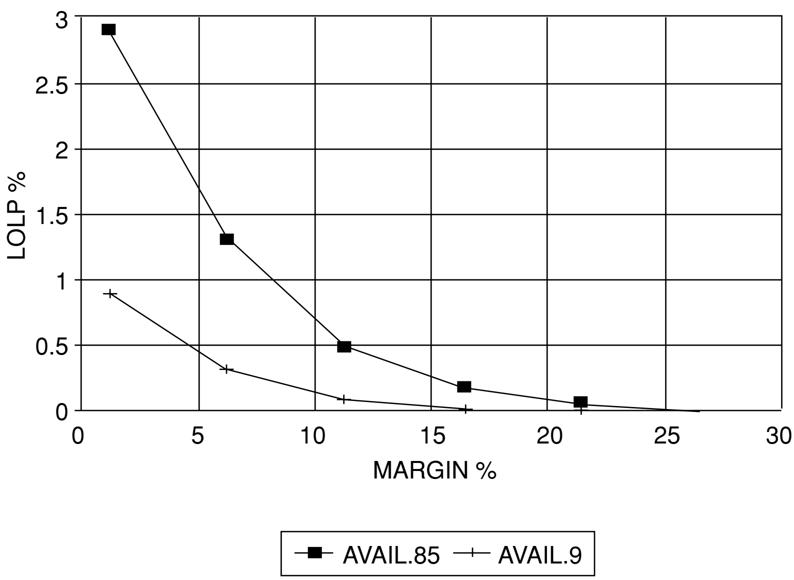

Figure 7.2 LOLP v margin, 1992–93.

Comparison of Theory with Model and Actual

A time series model can be used to make an assessment of LOLP at each two-hour subinterval based on the plant margin with the generation available at each time interval. The estimates can be 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 (arrowed) for the data available during the years 1987–92 for which different margins existed, together with the theoretical results from Figure 7.2 plotted on a log scale for the 1992–3 demand profile. It can be seen that the time series model fits a similar profile and implies a value of average annual availability of approximately 87% for the generators in service at that time. 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 three years in 100 which was typical of the target value assumed by the CEGB.

A comparison was also made of time series model results with the actual recorded values for the January 1992 data and although the actual spot demand and generation availability were not the same, a reasonable comparison was achieved, having corrected the results for inflation and the overall difference in availability. The actual LOLP cost was £34 M against the model £32.3 M.

The model can be used then to assess the impact of new generation on LOLP and the payments resulting from it and also the impact of changing mean generation availability. It can be seen that the value of LOLP is very sensitive to the margin and a 5% change in margin can produce a tenfold change in the value of LOLP and the associated payments. It also shows that if the high future margins currently predicted were realised in practice then LOLP payments would theoretically reduce to zero.

LOLP and Pooling

In an integrated planning environment it would be normal to establish the most appropriate unit size consistent with the size of the system. If the unit size is too large then there is an increased chance of outages resulting in loss of load. Figure 7.4 shows the variation in LOLP derived from theory when the unit size and corresponding number of units are varied whilst maintaining the same overall margin. It can be seen that little further reduction in LOLP results from increasing the number of units beyond the number of 100. However, as the number of units is decreased the chance of outages causing a failure to meet demand increases. Decreasing the number of units to 50 causes a rise in LOLP to 0.10%. This implies that there is a maximum unit size to realise maximum overall availability which is approximately

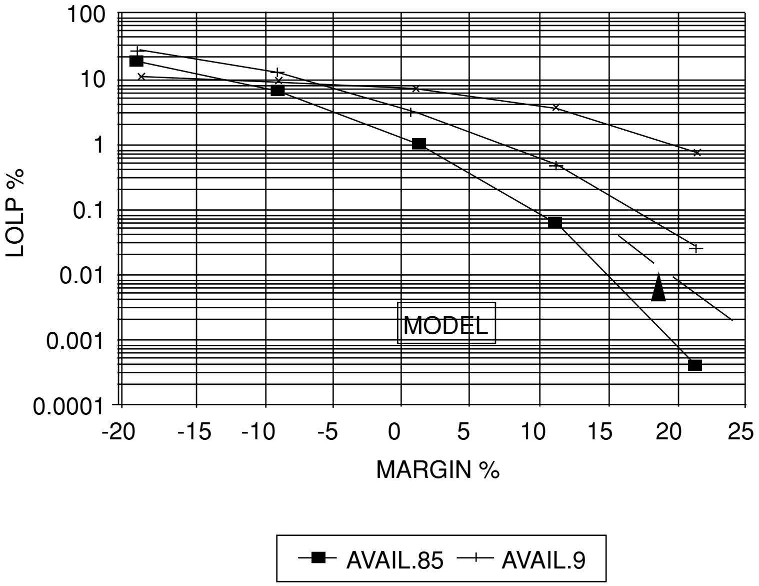

Figure 7.3 LOLP v margin, 1992–93.

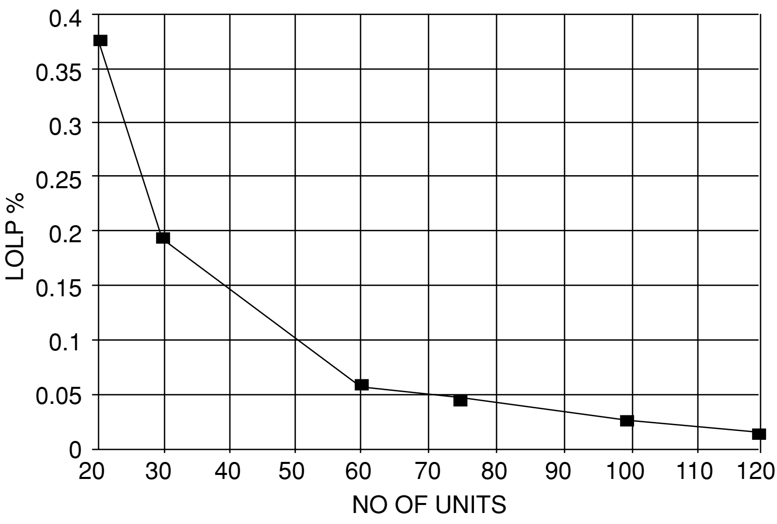

Figure 7.4 LOLP v margin, 1991–92.

equal to system installed capacity/100. For example, for this 50 GW system the maximum size would be 500 MW. Other factors like economies of scale and spinning reserve policy will also influence the choice. Typically utilities will hold sufficient spinning reserve to cover the loss of the largest unit and if disproportionally large units are used on a small system the generation reserve costs in operation will be proportionally high as will LOLP and consumer payments. There is a balance when the cost of providing more spare capacity equates to the LOLP payments.

The principles can be used to illustrate the benefit of pooling generation through transmission to improve security and reduce consumer LOLP payments. Figure 7.5 shows a regression fit to the LOLP payments for varying LOLP derived from a full time series model simulation for the period 1987–92. The function for this system is

$$\text{LOLP Payment} = 8.68 + 7828 \times \text{LOLP\%} \;\; \text{£M}$$

where LOLP is in % and payment in millions of pounds. This provides a means of assessing the impact on costs and LOLP payments of the change in LOLP realised from pooling generation using transmission, e.g. pooling four blocks of area generation each of 50 generators into one larger pool of 200 generators. This benefits the system, which requires less overall reserve, and consumers, through reduced annual LOLP payments. With 200 units LOLP would be about 0.015% with payments of some £125 M whereas for the 50-unit areas LOLP would be 0.1% with payments of £790 M i.e. an additional cost of £665 M. In practice the alternative option is for the generators to install additional units in each zone to raise the LOLP to a more acceptable value. In this case the saving would be less. This approach provides a direct means of comparing the relative worth of transmission and additional generation capacity for improving security.

Optimum Investment Level

It is now possible to establish a function of both the new generation investment cost plus the consumer LOLP payments, i.e. the total societal cost.

Assuming a typical annual capital and fixed operating cost of £25 M for an additional 500 MW unit a graph can be drawn showing the cost of investment in additional units and the consumer LOLP payments derived from the above formulation. Figure 7.5 shows the impact of adding additional units on LOLP payments and the total cost to society of both. It can be seen that this reaches a minimum when the additional generation costs equal the LOLP payments. This coincides with a LOLP value of 0.005% which is equivalent to a typical margin of 22.0% at the implied actual average availability of 87%.

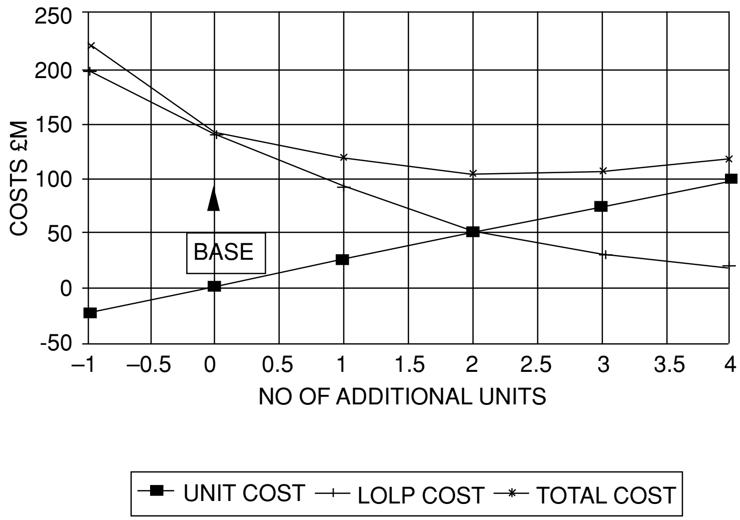

Figure 7.5 Optimal unit investment, 1992-93. $P_o = 0.87$, base 100 units.

Conclusion

An empirical relationship has been established between LOLP and margins and also LOLP payments 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 LOLP payments by consumers of some £665 M. Operating costs are also reduced with fewer reserve holding requirements, and savings from enabling a national as opposed to an area MO optimisation.

Lastly it has been shown how the costs to society are minimised when the fixed cost of additional generation equals the LOLP payments by consumers. In the base case shown in Figure 7.6 it can be seen that insufficient generation had been installed and commissioned by 1992–1993 to reach this optimum. The current England and Wales LOLP payments system is unlikely to realise this optimum as LOLP payments accrue to all generators rather than being focused on encouraging just the new generation. In a market situation where integrated planning were possible the accumulated LOLP payments would fund the capacity charge of new generation and would not be paid to existing generators who might already have committed capacity. It is also concluded that LOLP is very sensitive to margin and that generator overreaction could lead to instability and investment cycling. An alternative approach that ameliorates these problems is advanced in Chapter 10.

CHAPTER EIGHT

Idealised Tariffs

The discussion has so far concentrated on developing the theory and models of production costing and marginal pricing, this chapter looks at the mechanisms for charging consumers. Vertically integrated utilities will supply their local distribution companies against a Bulk Supply Tariff, apart from a few large or special direct consumers. The determination of the tariff structures is based on cost recovery with the inclusion of 'cost messages' reflecting the variation in cost with time of day/season and particularly at peak. They are generally fixed for periods of a year or a quarter and provide some stability against which consumers can make energy-saving investment decisions. The tariff can sometimes be used by government to influence regional or business sector development, particularly in developing countries. In a privatised environment prices can vary from half-hour to half-hour and the removal of the local distributors franchise will result in a wider range of suppliers and tariff options confronting the customer. This chapter discusses the basic criteria involved in setting the ideal tariff that would maximise societal benefit and compares this with what is likely to happen in the post-privatised situation.

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, and should exhibit the following:

- 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 allow for operation and maintenance of transmission and distribution and network losses

The consumers, for their part, should be able to:

- have a mechanism to react to the marginal prices by changing their demand level and shape.
- 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 marginal cost to the supplier of their provision.

Post-privatisation prices are set on the basis of what the market will bear irrespective of costs. They may be higher than costs with only competition from other suppliers acting as a cap. There is also explicitly no requirement to maintain consistency or equality and the larger consumers with most bargaining power will fair best. The importance of facilitating competition and enabling demand side participation is therefore paramount.

Ideal 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 but these would not normally be 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. A typical breakdown would be

Generation 66%

Transmission 20%

Operation 5%

Maintenance 4%

Administration 4%

These in turn, need to be inflated to take account of transmission losses (typically 2–3%) and the provision of a margin for security (typically 22%).

The marginal prices on a half-hour basis, have to be averaged to a price for a quarterly tariff period where only simple integrating kWh metering is available without time of day recording. 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.

$$P_o\,(\mathrm{d}Q/\mathrm{d}P + \ldots \mathrm{d}Q_n/\mathrm{d}P = m_1\mathrm{d}Q_1/\mathrm{d}P_1 + m_2\mathrm{d}Q_2/\mathrm{d}P_2 \ldots \tag{8.1}$$

where $\mathrm{d}Q/\mathrm{d}P$ 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.

$$P = \frac{m_1Q_1 + \ldots\ m_{nQ_n}}{Q_1 + \ldots .\ \mathrm{Q_n}} \tag{8.2}$$

i.e. the ideal tariff charge is the average of the marginal price in each half-hour weighted according to the demand in the half-hour. A model can be used to simulate operation and predict the outturn to produce this figure. Similarly the capacity charge will be optimal when the value of lost load to the consumer equates with the cost of providing additional capacity as discussed in Chapter 7.

Actual SMP Prices

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 but in practice bids may be higher, particularly where generators are constrained by transmission limitations. It also assumes that consumers can fully participate in the market which currently they cannot in England and Wales although the Norwegian model does enable full bidding by purchaser and strikes a balance.

It is possible to model operation of the system to derive the average SMP which is equivalent to the weighted marginal price as shown in equation (8.2). It can be shown that on this basis that the result for 1992–1993 would have been a pool energy price of £20.17/MWh, having added LOLP and corrected for average fuel price inflation and new generation.

The published actual value for this period was £22.63/MWh, i.e. some 12% higher than the true marginal incremental cost indicating an inflated

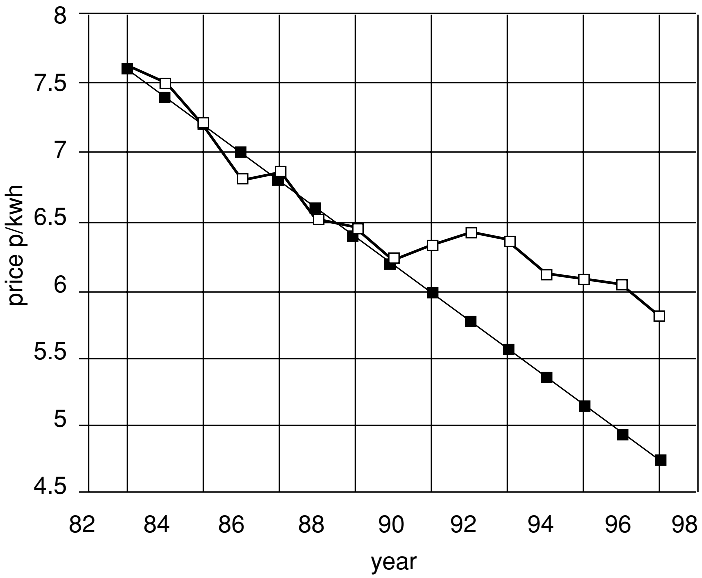

Figure 8.1 Small consumer electricity prices, 1983–97.

price as suggested in press reports. Figure 8.1 shows statistics derived from the Digest of UK Energy '97 where it can be seen that had the pre-privatisation trend continued prices to end consumers would have fallen to below 5p/kWh instead of the actual level of 5.8p/kWh. (These prices to end consumers include transmission and distribution prices.)

LOLP and Capacity Charge

For larger consumers where maximum demand metering is justified the tariffs normally include a capacity charge. Since privatisation the LOLP payments for the year have indicated the notional amount that consumers are required to pay to encourage additional plant availability at peak, which equates to the tariff capacity charge. The optimal value will be reached where it equates to the cost of providing the additional capacity as described in the previous chapter. If it rises significantly above that value then the consumer is paying too much for capacity, i.e. above the market value. Conversely, significantly smaller payments imply a system with overcapacity.

The annual LOLP payments can be calculated using a model simulation for all the periods in the years shown in Fig 8.2. They progressively rise

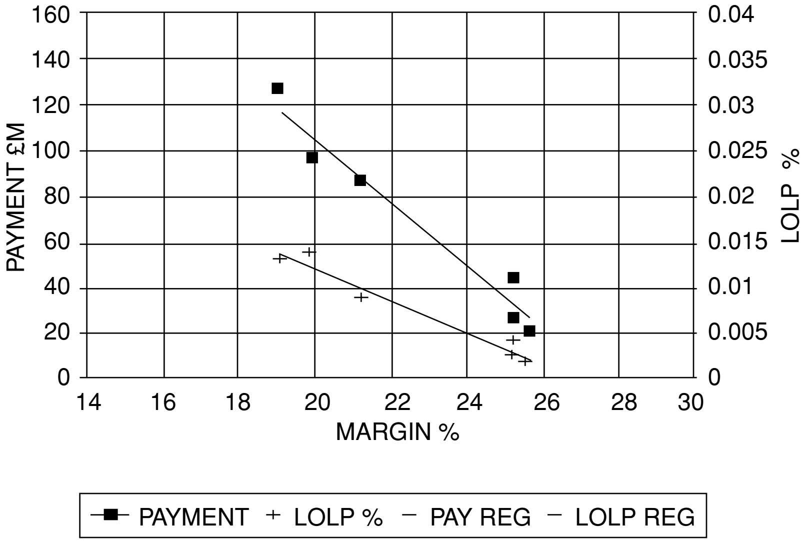

Figure 8.2 LOLP and payment v margin. 1987–88 to 1992–93.

through the period with the value for 1992–1993 being £127.3 M, if no additional capacity were added. The straight line regressions show how the payment varies with plant margin:

$$\text{LOLP payment} = 385 - 14.089 \times (\text{MARGIN\%}) \tag{8.3}$$

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

$$\text{LOLP\%} = 0.046482 - 0.00173 \times (\text{MARGIN\%}) \tag{8.4}$$

To establish the optimal investment level it is necessary 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 P_0 of 0.87. Using this value with the 1992–1993 demand data and a unit size of 583 MW and 100 units the plant margin in the base case can be replicated. The results obtained from this full model simulation are for an annual LOLP payment of £127 M. Using the LOLP payment formula (8.3) a payment of £140 M is derived. The calculated results are sufficiently close to enable the impact of changing the number of units to be estimated using the simple formula. This is demonstrated in Fig 8.3 where the consumer payments are shown together with the additional costs of new generation capacity. The optimal occurs when an additional two units are added to the base case

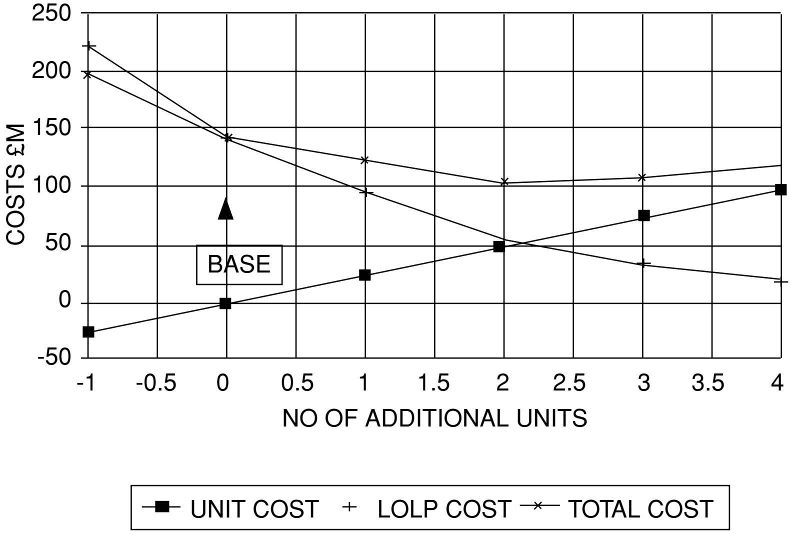

Figure 8.3 Optimal unit investment, 1992-93. $P_o = 0.87$, base 100 units.

reducing the payments to £44 M. In practice some additional capacity was subsequently added leaving the actual recorded LOLP payments at approximately £42.7 M.

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. There is no direct link between LOLP payments and funding the entrant of a new independent generator. It is the larger portfolio generators that will receive the bulk of the LOLP payments.

BST

The Bulk Supply Tariff (BST) was first introduced in England and Wales 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 government needs. The structure for 1988–1989 was as shown below (ref. CEGB BST 88/89)

Capacity Charges £/kW		
	Peak	23.5 (average 3½-h–Triad)
	Basic	20.0 (average 300½-h)

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-hours of maximum demand during the year separated by more than 10 days.)

The calculated payments for the base year are:

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

To compare these with the model simulations of the true post-privatised marginal costs it is necessary to add an uplift element to take account of active transmission constraints and inflation.

	BST	MODEL
Energy payments	£5011m	£4628m
Capacity payments	£1963m	£24m
Transmission	NA	£1000m
Availability 1988/9	NA	£5m
	£6974m	£5657m
Equivalent SMP	£19.9m	£18.36m

It can be seen that the BST recovers slightly more than the base case cost estimated with the model but that there is a reasonable agreement in energy payments. 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.

Comparison of Actual PSP with BST

The actual PSP did not compare favourably and was significantly above what would have been expected under the 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 the 1988–1989 BST has been assumed to apply in future years with prices increased in line with fuel price changes. The comparison with the published PSP shown in Fig 8.4 confirms that the PSP has risen in excess of inflation. (The

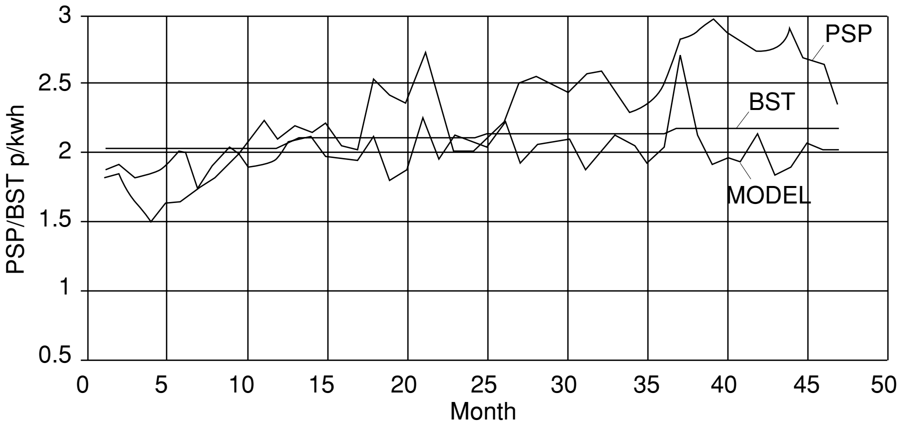

Figure 8.4 Actual PSP v BST, April 1990 to February 1994.

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

The Open Supply Market

Since deregulation the local franchise has been progressively removed enabling consumers to choose their supplier. This first applied to those with a peak demand of 1 MW or more and they initially benefited from a government stipulation that price changes should not exceed inflation. To choose an alternative (Second Tier) supplier the customers have to have meters that record energy in each half-hour and can be remotely interrogated. This is to align with the pool's half-hourly pricing. The price for special metering and its maintenance ranged from £1000 to £5000 and has been the subject of complaint. Of some 5000 eligible approximately half are estimated to have changed supplier and opted for a tailored contract rather than a tariff.

From 1994 those with a demand of 100 kW followed suit and of some 30 000 registered two-thirds have chosen second tier suppliers. They also are required to have meters able to record half hour consumption and be remotely interrogated. This enables the use of tariffs or contracts with time of day pricing as well as maximum demand charges. Difficulties were experienced in introducing the settlement facilities and correctly registering details and this is estimated to have cost £20 M to correct.

Sometime during 1998 the smaller consumers will be able to choose their supplier but they will not be required to fit expensive meters. Instead they will assume a predefined profile to enable settlement reconciliation. In their case the tariff options will be more limited and probably restricted to a general-purpose tariff with perhaps the option for cheap overnight energy.

In a deregulated environment the larger consumers are likely to have more options and be able to strike better terms than the small individual consumer. This has led to a number of organisations with an existing infrastructure and organised membership looking to negotiate collectively on behalf of their members. The small isolated consumers at the end of the supply line are likely to fair worst.

Conclusions

This section has shown the derivation of ideal tariffs so that marginal capacity and energy charges equate to consumer marginal value. A comparison with actual results against the full production simulations shows energy rates at some 12% above marginal costs for the period to 1994 after allowing for fuel price changes and inflation. In the absence of consumer participation it is difficult to see this situation changing. There is no guarantee that the option to change supplier will produce any benefit and the regulator as recently as July 1997 was prompted to call for price reductions by the generators to show some benefit from the planned removal of local franchise in 1998.

Although overall LOLP payments may be of the correct order there appears to be no mechanism for this to be used to support the entry of new competition, with most of the payments going to the larger generators.

A graph comparing published PSP with extrapolated BST energy charges confirms the view that energy prices have risen in excess of normal inflation and underlying costs. The liberalisation of the supply market is likely to benefit the larger consumers at the expense of smaller consumers. The emphasis in tariff design will be to reflect the Pool half-hour by half-hour price variations using meters capable of recording half-hour data and also using remote dial-up for interrogation.

CHAPTER NINE

Review of Market Shortcomings

The preceding chapters have developed the theory underpinning electricity markets and reviewed their performance by analysing published results. The theory was used to illustrate an ideal system development strategy which would minimise costs to society by achieving the optimal plant mix and margin.

A proper outcome for privatisation could be supposed to be:

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

This chapter reviews some of the shortcomings in meeting these objectives within the existing market structures.

Marginal Pricing

It is inevitable in an instantaneous market like electricity that the price will be volatile, reflecting the sudden changes in consumer demand. This is somewhat exacerbated, however, when the method of derivation is based on a scheduling algorithm designed to minimise cost. Chapter 6 described the derivation of SMP and how, during table 'A' periods, the marginal unit which may only operate at low load for a short period will have to bear the full start-up costs. This integer effect of the scheduling process inevitably leads to spikes in the half-hour pool price. It may be preferable to use a system based on matching bids and offers, which will offer more stability if at the expense of tracking true marginal costs. In practice the ability of consumers to respond to half-hourly cost messages is very limited and some averaging over longer periods is desirable to enable consumers to plan energy conservation investment.

In the medium term it can be seen from Figure 4.6 that there is an increasing standard deviation in prices which may result from the absence of coordinated outage planning or the inherent volatility due to the steep slope of the overall system price function. Figures 8.1 and 8.4 show prices in England and Wales continuing to rise in excess of what would be predicted based on costs. The generators are in a better position to control marginal prices and currently there appears to be no effective mechanism to enable the demand side to bid into the market on the day 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.

In practice most of the energy is traded against bilateral contracts for differences outside the pool which makes the pool price less relevant. The contracts are not, however, public or necessarily conducive to open competition but rather based on protecting market share and maintaining price levels. In the single buyer model one authority acts on behalf of all consumers to establish bilateral contracts with all prospective generators or demand managers. The advantage is that the process could be open and designed to enable full demand side participation and provide more stable prices. An alternative is to promote a mechanism that supports future-trading in an open market against standard formats and developments in the Nordpool and New Zealand have shown this to be possible.

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. Whereas tariffs have traditionally included a capacity charge the market mechanisms do not differentiate so as to encourage investment in peaking capacity as all generators get the same LOLP payment.

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 England and Wales 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 directly encourage the retention of peaking units. It has been suggested that special ancillary service contracts should apply but in their absence the consequence has been the whole scale closure of OCGTs which were installed for peak lopping and emergency use.

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 either rise to cover the suboptimality or some generators will suffer losses when operating at part load and may go into liquidation.

In a single buyer model the plant mix would be managed by calling for generation bids against a specified operating regime. This would enable the generator to optimise the design and staffing levels to minimise the costs. An active futures market would also enable bids against contracts for specific operating regimes to be invited in open tender.

Plant 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 the new generator receives all the benefit of LOLP payments to cover the capital costs. 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 overcapacity in base load units. They also offer another mechanism to manipulate prices as occurred during the summer of 1996.

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 added to the system will cause an immediate reduction in LOLP. The current mechanism appears subject to gaming by the large generators who might forego availability payments on some generators, not likely to be selected to run, to inflate the LOLP and more than recover their losses on the LOLP payments on all the energy supplied during the period. In a mixed pool or single buyer model there would be opportunity to contract for generation to provide the optimal margin and mix to meet the consumer demand profile and minimise the costs and prices.

Transmission Management

In the England and Wales model transmission constraints are ignored in setting market prices and the Grid Operator is left to decide how to manage generation on the day to alleviate any constraints and to meet system needs. In an attempt to create an incentive to minimise the additional costs the Transmission Services scheme was devised where the Grid gets a share in any savings from a predefined level for the year. While the transmission company is incentivised to contain these ‘uplift costs’ 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.

In Chapter 7 the benefits of pooling generation were shown but there is no commercial mechanism to encourage the ideal level of transmission investment, where costs are in balance with the benefit derived from pooling. A zonal pool with different prices in constrained areas would create the investment incentive and the affected parties could sponsor new transmission – but who would own and control it? The prospect of ownership becoming fragmented would introduce the sort of difficulties that have been the subject of acrimonious debate in the USA related to ‘loop flows’ and ‘parallel paths’. The concept of Transmission User Groups has been proposed to coordinate developments but it is difficult to see how agreement would be reached given the fractional and diverse interests of members. There is a danger of losing the open transmission access that is considered the key to realising full generation competition. In the single buyer model, or in those market structures that enable integrated planning, the decision on transmission investment could be based on a global optimisation to minimise costs while fully taking into account the impact on existing generation contracts in the financial appraisal. This should result in the lowest price to end consumers.

Consumers

In the England and Wales market consumer influence has been limited. With ex-ante pricing the outturn costs will be different to the predicted unconstrained pool prices 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 but before the event they are only advised of the day ahead idealised prices. Their opportunity to react to actual prices is therefore limited as they have no prior knowledge of constrained zones and are not therefore able to engage in this part of the market. In contrast the generators are aware of the constraints and their bids can take advantage of the fact that they know they will be called upon to run in the event. The use of both zonal and closer to real time prices ameliorates these problems but at the expense of introducing operational risk. It remains to be seen how close to real time a market may be operated.

Where bilateral trading is enabled the prices are fixed by the contract between the supplier and consumer with only the residual spill being subject to real time market prices. The consumer then has an opportunity to seek alternative suppliers in open competition.

Security of Supply

The security of supply from the system can be affected by insufficient generation being available to meet demand or the transmission system being unable to sustain delivery of the power.

In the England and Wales market the day ahead bids that generators make into the pool are not firm and the units can be declared unavailable on the day. To avoid shortfalls the Grid Operator will schedule for 'contingent generation' over and above basic need to be available for use to make up any deficit on the day. Given the random nature of the process in practice the judgement of the level required may be wrong and the shortfall may necessitate demand shedding. The LOLP premium to day ahead prices is designed to encourage generators to maintain availability but it is known to be subject of gaming by portfolio generators who stand to gain more from LOLP payments on all their energy than they might lose on availability payments on a few units. It would also not discourage withdrawal due to interruptible gas contract clauses being invoked. It is difficult enough to manage the margin to cater for forced outages without compounding the problem with commercial manipulation and bids should be required to be firm.

The management of transmission availability is usually coordinated with generation outages via a joint planning process. This is to avoid transmission outages constraining high merit generation by taking advantage of any generation outage to work on the transmission at the same time. Whilst a process can be put in place in a market situation, generators are not bound by any declarations and will make changes in the short term for whatever commercial reason. This compounds the problem and makes it more difficult for the Grid Operator to secure the system and maintain adequate margins, and short-term changes should be penalised.

In the USA different transmission systems interact through loop and parallel flows and these appear to be accepted on a quid pro quo basis. With the advent of deregulation competition is expected to increase interzonal flows and this arrangement is not likely to remain tenable. Recent widespread system failures on the West Coast have resulted in some adverse press reports, e.g. The New York Times headline 'Blackouts may be Caution Sign on the road to De-regulation'. All commercial deals must be notified to the Grid Operator in sufficient time to enable a full network analysis to be undertaken.

Conclusions

This chapter has shown that markets and payment systems based on SMP and LOLP have significant shortcomings. The pool SMP is likely to be volatile and does not take account of zonal variations due to transmission constraints or reflect outturn. In the absence of effective demand side participation generators will continue to control the marginal prices, which can be expected to remain high and volatile. Alternative methods of setting prices based on 'balancing methods' and supported with futures trading are likely to give better stability and more open competition.

The LOLP payment system to all generators based on short-term availability will not encourage the optimal plant margin. In that all generators receive the payment there is no mechanism to cover the capital costs of peaking plant or encourage the optimal plant mix. The system should be abandoned or if it is an issue a market approach that enables some coordination should be applied like a single buyer model.

The current annual Transmission Services scheme will not directly encourage the optimal levels of investment in transmission and may encourage the perpetuation of constraints. The use of system charging has failed to influence generating siting. Zonal energy pricing may provide a better transmission prices signal to enable arbitrage between generation and transmission.

In the absence of a firm capacity market the withdrawal of generation on the day may put system security at risk and necessitate demand shedding, and bids and short-term outage plans should be made firm.

CHAPTER TEN

A Medium Term Market Based on Lagrangian Relaxation

The key to efficient and secure power system operation is a rigorous approach to system development and operational planning and the current levels of uncertainty facing planners should be of serious concern. It is not practical to restructure a network and its generation pattern on the day and maintain economic and secure operation unless the system has been designed recognising the mode of operation. The optimum arrangement of outages and contingency actions also needs to be planned and firmed up in advance. The opportunity to influence the cost of production on the day is very limited and the attention of control room staff has to be focused on managing constraints and maintaining a viable system. The key decisions affecting trading opportunities are focused on the medium to long term and this is where market participation should be enabled either through an open future-contract market or a single buyer model. This chapter illustrates that theoretically the implementation of an alternative market focused on the medium term rather than the current day ahead process should give rise to a closer to optimum outturn.

In Chapter 9 it was shown that the current market mechanisms do not provide a sound basis for future investment planning. The short run marginal cost approach (SRMC) is not considered appropriate to capital investment with long lead times and is unstable. In an attempt to circumvent the uncertainty in the market many players have chosen to set up private hedging contracts for differences where the energy sale price is fixed by prior agreement. This effectively undermines full competition through the market and does not therefore meet all the criteria of an effective market. It will also be undermined by the removal of the local franchise to supply.

It is necessary to define the objectives of the market and the requirements that it is desirable to meet and these are outlined first. It is proposed that they are best realised through a long run marginal cost approach (LRMC) 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 an outturn delivering maximum benefit to society. It also provides more opportunity for consumers to participate in the market. There will always be short-term unavoidable changes or errors in demand prediction and these can be catered for in a day ahead and on the day balancing market based on bids for incremental generation and energy.

The Requirements

The ideal market arrangement would foster competition while enabling the benefits of integrated planning to be realised. It would meet the following needs:

- operating competitively without bias and with equal participation by generators and suppliers/consumers
- providing stability to enable investors to estimate future income streams to support decision making.
- maintaining confidentiality in the process to protect commercial interests.
- enabling the system operator to influence the plant margin and its mix
- managing outages to maintain system security

These requirements could be met by all players agreeing to submit firm plan data to enable a simulation of operation through future years using a production simulation model. The generators would bid in firm capacity and consumers firm demand. The simulation would be used to derive the time-varying system marginal price which equates to the Lagrangian multiplier for demand. This then enables an individual generator or consumer to assess its worth or costs without access to any competitor's data. Each proposal for outages, new generation or closures would be added to the simulation by a pool administrator in much the same way as the current day ahead market is operated on behalf of pool members. The approach is the equivalent of the single buyer model but with control of the process vested in the market players with the 'buyer' acting only as a facilitator.

The Process

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

- Make initial demand prediction based on suppliers estimates
- Use generation capacity declared in initial production simulation run to provide the system marginal prices and security index, i.e. 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.

The Theory

It can be shown theoretically how the idealised requirements can be met through the proposed process. The system objective function is to establish the multiplier that results in total generation offers *G* and demand bids *D* for energy equating, and capacity bids equating to the security level β required by customers, i.e. find

$$f(\lambda_t) \text{ so that } G_t = D_t \tag{10.1}$$

$$f(\beta_t) \text{ so that } A_t - D_t \geq f\,(LOLP) \tag{10.2}$$

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.

$$P = \sum \lambda_t \times g_{i,t} + \sum \beta_t \times A_{i,t} - \sum [g_{i,t} \times \mathrm{VC}_i + \mathrm{STC}_i] \tag{10.3}$$

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

$$\beta_t = LOLP(VLL - SMP)$$

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

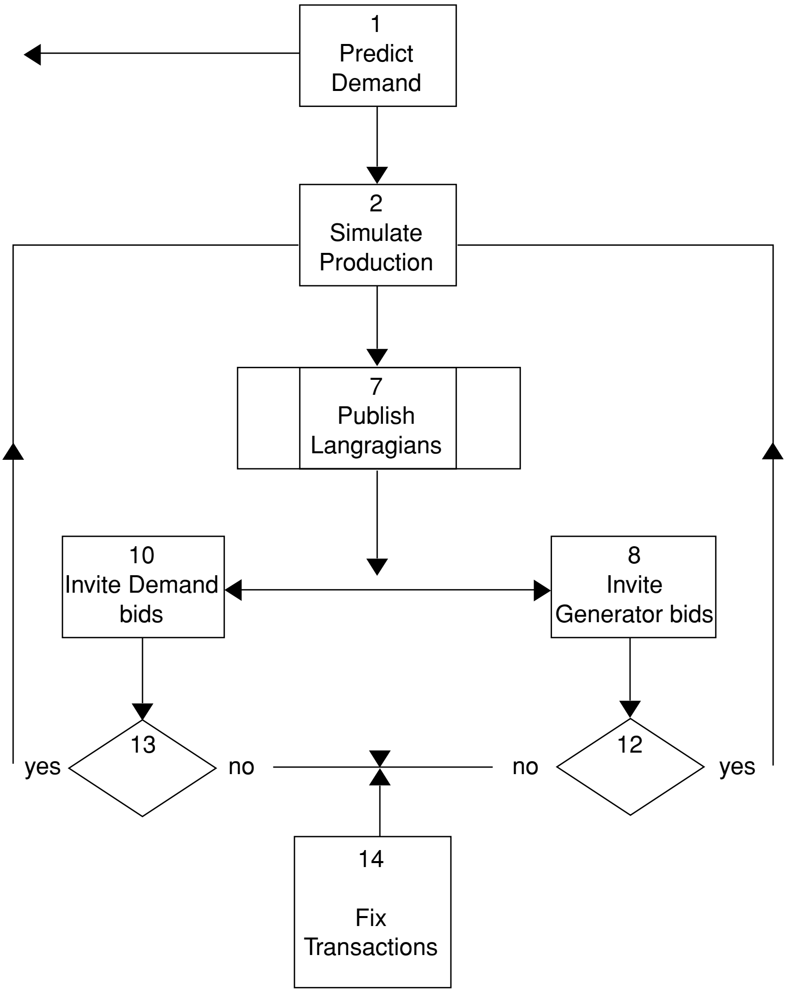

Figure 10.1 Future capacity market process.

$$\sum (\lambda_t \times d_t + \beta_t \times d_t) \tag{10.4}$$

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

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

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

$$\alpha = \frac{1}{a + k \times b} \tag{10.6}$$

To enable decisions to be made in planning time-scales figures would need to be published for 1–5 years 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 its commitment and a supplier paying for spare capacity to cover any demand underestimation on its 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 excess of costs is likely to be undercut 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, i.e., running and start-up costs based on the submissions, i.e. minimise

$$\sum_{1}^{t}\sum_{1}^{i} \mathrm{VC}_i\,(G_i(t)) + \mathrm{STC}_i \tag{10.7}$$

subject to

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

i.e. the generation requirement being met and the generator operating between upper and lower limits, i.e.

$$UL_i(t) \leq G_i(t) \leq L_i(t) \tag{10.9}$$

and satisfying the minimum up and down times

$$U_i(t) = 1 \quad \text{if } 0 \leq X_i(t) \leq \mathrm{MNUP}i$$

$$U_i(t) = 0 \quad \text{if } -\mathrm{MNDN}_i \leq X_i\,(t) \leq 0$$

where $X_i(t)$ 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, i.e.

$$\sum_{1}^{i} U_i(t) \times \mathrm{RES}_{i,j}(t) > \mathrm{RESR}_j(t) \tag{10.10}$$

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, i.e.

$$\sum_{1}^{i} G_i(t) + \mathrm{RES}_{i,j}(t) < \mathrm{EXP}_a(t) \tag{10.11}$$

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

Similarly for import constraints

$$\mathrm{IMP}_a(t) < \sum G_i(t) \tag{10.12}$$

the sum of the generation must be such that imports are contained to meet local demand.

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

To make the problem manageable it would be necessary 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.

Commercial Arrangements

The requirements could be met by a rigorous approach with a degree of central coordination or more loosely by enabling a futures contract market. It is considered important to separately identify capacity and not just energy supplies as this focuses attention on one of the most important aspects affecting economic operation, i.e. meeting peak demands. It provides a mechanism for managing the balance between generation and demand throughout the operating period with cover for outages and contingencies.

Capacity payments could be derived from a pool paid into by suppliers interested in securing future supplies and withdrawn from 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 required energy not covered by prior contracts would be traded in the day ahead market in residuals.

It would be necessary 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 bid and outturn at the prevailing value of lost load. Equally consumers with reduced demand would make up the lost profit with additional payments to the generators. Some flexibility would be necessary to meet the changing circumstances that may occur during long construction periods. It could be met by enabling capacity trades between generators or swaps where both a generator and consumer agree to change their bids equally. However, generators and suppliers would only be allowed to participate in the market on the day if they had previously bought a capacity 'ticket'.

Both Norway/Sweden and Australia have introduced futures contract trading. In Nordpool the periods stretch from weekly, to monthly, to seasonally covering periods up to three years ahead. In Australia contracts are traded on a monthly basis for up to a year ahead in 500 MWh blocks. An essential prerequisite to a viable futures market is real competition and the avoidance of complexity. This can be realised whilst retaining a close to optimal solution throughout the process described above.

Other Improvements

Even with a futures market a short-term market will be required to effect balancing owing to short-term changes. The derivation of short run 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 set by generators operating at very low loads for short periods loaded with all the start-up costs added to a few MWs.

Another concern is the high cost of unpredicted effects of generation shortfall in the events and a better relation to outturn charges could be achieved by using a probabilistic prediction of outturn generation availability for the schedule without the risks attendant on real time pricing. The predictor would reduce average availabilities in line with normal expectations and cause additional marginal plant to be scheduled as would occur in practice. Having put in place an effective prediction process it would be natural to effect settlement based on the ex-ante marginal prices.

The uplift in outturn prices due to transmission constraints could be avoided by using zonal energy prices 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.

Benefits

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 should ameliorate price volatility.

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.

Margins

The data available from the five year ahead planning process provides a means of coordinating investment to avoid overcapacity in excess of what suppliers are prepared to pay. Capacity payments to secure supplies would provide a more equitable and stable mechanism than the current LOLP price increment.

Uplift

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

Conclusion

An alternative approach has been advanced to structure a competitive market based on long run marginal costing. The proposal would enable the benefits of integrated planning to be realised without destroying the market concepts. The process enables decomposition of the problem so that each player may make an independent assessment whilst maintaining the necessary data confidentiality and avoiding placing commercial responsibility on the pool administrator. It also offers the opportunity for full demand side participation. The pool would need to agree the model and process and as a start it should be agreed that day ahead bids are made firm and not subject to *ad hoc* withdrawal.

PART TWO

Generation Investment Appraisal

The demise of the native franchise market will make it increasingly difficult for suppliers to enter into long-term agreements with prospective generators and new entrants will have to rely on an appraisal of the future market. 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 its 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 may interact. Three different economic models are developed to represent different market conditions and these are tested against the actual investment decisions since deregulation in England and Wales to demonstrate their appropriateness. It is shown how the current market mechanisms might lead to suboptimal investment.

CHAPTER ELEVEN

Basic Principles

Classical Approach

The classical approach of integrated utilities to generation investment appraisal was to develop the power system to meet the expected demand at minimum cost consistent with meeting security criteria. 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 of generation and maintained diversity in fuel sources. The costs in meeting the additional demand would be recovered by increments to the BST. The problem was usually 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 such as EGEAS (EPRI) and WASP have also been developed to address this requirement. The final decision on plant type would often be influenced by national considerations related to the security of fuel supplies or the preservation of indigenous fuel industries. Dynamic programming has also been used to address the uncertainty in the data and to minimise the 'regret' that could occur with different scenarios (Gorenstin, 1993). Flexibility would be maintained by choosing some generation options with short construction times, which enables a change in capacity as actual future load and conditions become clearer. Other approaches seek to manage the uncertainty by identifying the probability functions of the key variables and applying statistical techniques (Tanahe 1993). Multiple trade-off analysis has also been proposed as an aid to decision makers (Huber, Redmond and McDonald, 1993) . Several authors have discussed the shortcomings of current techniques (Bunn and Vlahes, 1992, Merril and Head 1990). Other authors have discussed the impact of non dispatchable (Caramis and Sherali, 1990) and non utility generation (Siddiqi and Baughman, 1994). This chapter demonstrates that the classical approach will not model the behaviour of deregulated generators and introduces a new approach.

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. i.e. minimise

$$\sum C \times I_j \,\mathrm{DNC}_j + \sum_{j=1}^{J} \sum_{t=1}^{T} \mathrm{VC}_j \cdot \mathrm{MW}_{j,t} \cdot A_j \tag{11.1}$$

subject to

$$\sum_{j=1}^{J} \mathrm{MW}_{j,t} = \mathrm{DEM}_t$$

and

$$\mathrm{MW}_j <_{\mathrm{DNC}_j} \mathrm{MW}_j \leq \mathrm{DNC}_j$$

solve for

$$\mathrm{DNC}j$$

$$\mathrm{MW}_{j,t}$$

where CI = fixed capital costs; DNC = capacity; VC = running costs; MW = load; A = mean availability; t = period; DEM = demand.

In a mature situation it is necessary to model the existing generation capacity by plant type, as well as the new generation options. As the capital cost of the existing generation is already committed it may be omitted from the formulation. For new generation both capital and running costs are included. In the case of nuclear generation an upper bound may be placed on new generation reflecting any environmental constraints.

The demand is usually represented by a load duration curve with values chosen to represent each of the chosen periods. The variable costs are scaled up to equate to the cost of running for the period of the year.

To illustrate the principles with an example a set of initial conditions are assumed as shown in Table 11.1 which are similar to those that existed at the time of deregulation in England and Wales. The results of an expansion study 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

Table 11.1 Existing and Planned Capacity at Privatisation

plant type	small coal	medium coal	large coal	oil	OCGT	nuclear	CCGT
capacity GW	1.43	4.3	23.0	8.5	2.0	10.6	0.0

initial generation shown in the table, that the existing capacities of medium and large coal plant are retained, but at reduced utilisation, and that the tranche of small coal is reduced from 1.432 GW 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 presented itself in practice. Nuclear shows some increase in this example where decommissioning costs are ignored. The largest increase is in the tranche of CCGTs shown to be economic at 8.6 GW as of Febuary 1994. 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.

Post-Privatisation Approach

The approach of the preceding section does not address the post-privatisation situation 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 individual profit, with their income based on the marginal incremental price during each period. The complication is that in a competitive market the choice of generation affects the marginal price which in turn affects the income. As more and more older units, operating at the margin, are replaced, so the marginal price will be driven down reducing the income on all units sold. It is therefore more optimal for a portfolio generator not to replace all the older units but rather to accept that these units are marginal and bid them in at marginal cost. Whilst they will not always run when they do a high marginal price will be set. The alternative of displacing all marginal units would put them into direct competition at the margin with independent power producers and result in marginal prices and profits being driven down. The solution to the problem therefore now requires an iterative approach to determine the marginal plant type and price in each period. This can then be 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.

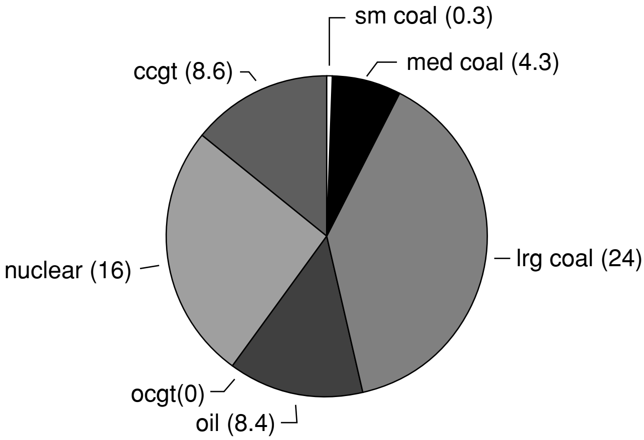

Figure 11.1 LP to minimise cost. Optimum capacity with initial mix (GW).

As an initial starting point for the new LP the previous cost minimisation solution provides a suitable base.

The new LP formulation is to maximise the income derived at SMP less the capital and operating costs, i.e.

$$\sum_{j=1}^{J}\sum_{t=1}^{T} \mathrm{SMP}_t \times \mathrm{MW}_{j,t} - \sum C \times I \times \mathrm{DNC}_j +$$
$$\sum_{j=1}^{J}\sum_{t=1}^{T} \mathrm{VC}_j \times \mathrm{MW}_{j,t} \times A_j \tag{11.2}$$

where SMP_t is the period marginal cost during the period t. A spreadsheet function can be used to derive the maximum incremental price in each period and this can be used to set the SMP profile. The objective function is then expressed as a function of the period SMP less the incremental price of the particular generation type.

This 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 disproportionate effect on total income through marginal prices. The results demonstrate this and the maximum profit is now realised with a higher proportion of small coal generation 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.

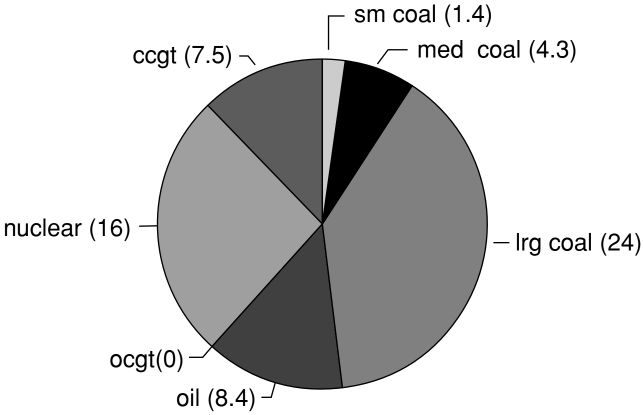

Figure 11.2 LP to maximise profit. Optimum capacity with initial mix (GW).

Shortcomings

Whilst the above approach provides a global indication of the total need for new capacity, the LP approach is unsuitable for definitive appraisals because of its coarse time resolution and the absence of dynamic modelling. In the new environment the time-varying SMP function is the fundamental factor affecting profit and more detailed models are therefore necessary to establish a more robust assessment including the following:

- the time-varying SMP profile
- the inclusion of LOLP or any other capacity element
- 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

In practice a generator will wish to secure a customer for the output of its generation through contracts but the bargain will still be struck against the expected market price and is unlikely to cover all the output. These issues are addressed in subsequent chapters.

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 for large portfolio generators to retain higher priced units to continue to set SMP high and hence increase their total income rather than replace the unit with a cheaper one which would drive down SMP. If the generators continue to add capacity 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 against which to assess the optimal capacity additions. To model the income function based on marginal prices with any accuracy a dynamic representation based on hourly periods is necessary as well as a prediction of market share. The next chapter discusses the use of a full operational simulation for this purpose.

CHAPTER TWELVE

Predicting SMP and Income

The previous chapter demonstrated how a global assessment can be made of the amount and type of generation it may be profitable for generators to add to the system. This chapter describes how to estimate the profit for a particular generator based on the income from the pool and any contracts for differences outside, and their fixed and variable operating costs. To enable individual generators to predict their utilisation and likely income they need to be able to predict SMP and LOLP and two approaches are discussed based on marginal costing and statistical analysis. The assessment of operating costs will need to be based on the estimated utilisation and operating regimes including the effect of dynamics as generation tracks demand changes. Generators with existing capacity will additionally have to take account of the impact of new generation on the utilisation of their existing generation capacity. This chapter describes an approach to calculate income and profit and to predict the SMP/LOLP profile on which it is based.

Estimation of Income

A generator's income is primarily fixed by the energy payments at the pool selling price where the Pool Selling Price (PSP) for each half hour is given by:

$$\mathrm{PSP} - \mathrm{SMP} + \mathrm{LOLP}(\mathrm{VLL} - \mathrm{SMP}) \tag{12.1}$$

Where the System Marginal Price (SMP) is as set by an unconstrained schedule or some other process and LOLP represents a capacity element which in this case is related to the loss of load probability and value of lost load VLL. An exception is where the generator is forced on or off by active transmission constraints when payments are made at the 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, i.e.

$$I = \sum^{t=n} \mathrm{MWAV}_t \times \mathrm{PSP}_t \tag{12.2}$$

where MWAV is the availability for the period and is the income. This can be calculated by establishing an annual SMP profile using a full operational simulation model with post processing to calculate the intersections when bid equals SMP and hence utilisation and income.

Bidding Strategy

In the long run, generators will tend to bid at the real incremental cost 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 fewer running hours; lower prices will incur a loss if the bid price is set lower than the actual variable 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. An operational model can be used to simulate operation for a year to assess the effect on utilisation and profit of varying bid prices. The submissions in this example were assumed to be based on the lowest slope intersection with the generators cost curve, i.e. the table ‘A’ value. Figure 12.1 shows the effect on the annual profit of a CCGT generator of different bids and it can be seen that the optimal return occurs when bid price equals the actual marginal cost, which in this example is assumed to be £0.14/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 assumes a fully competitive market and will not apply where a duopoly or cartel is in operation when prices and income can be raised in unison without fear of loss market share – profits would then be much higher.

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

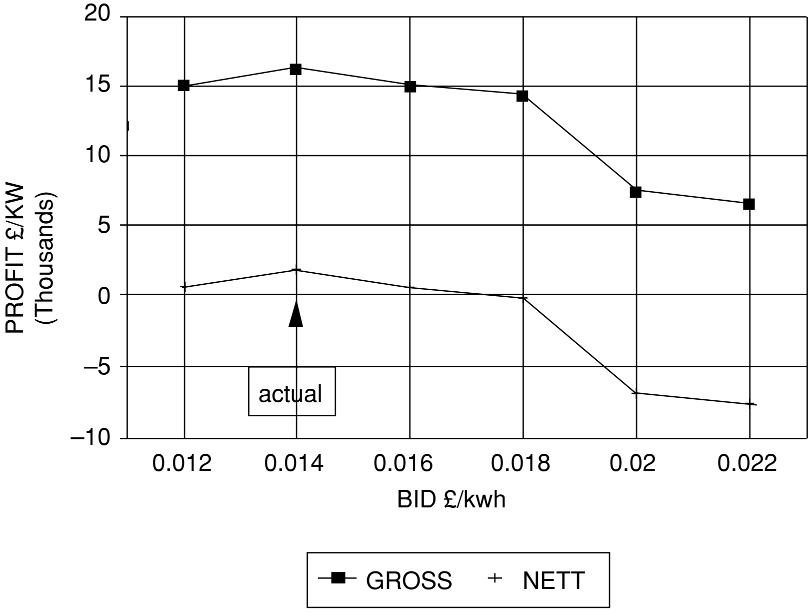

Figure 12.1 Effect of bid strategy CCGT, 1992–93.

$$P_C = (I{\times}C{+}FC{+}A{\times}U{\times}VC \times 365{\times}24)/(A{\times}U{\times}365{\times}24) \qquad (12.3)$$

where I = interest rate, C = capital cost, FC = fixed cost, VC = variable cost, A = average availability.

Profit Forecast

Using a model to simulate operation for each year it is possible to calculate an SMP and an LOLP profile for each year. The income and costs can then be calculated as described above. The profit/kW can be calculated on a gross and net basis where the gross includes fixed operating costs but excludes capital costs and 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 necessary to take account of the construction period when costs will be incurred without income and also any decommissioning costs. In practice prediction beyond the first few years would be very speculative in a competitive market where the development plans of other players were unknown. The net and gross profits for typical generation types are shown

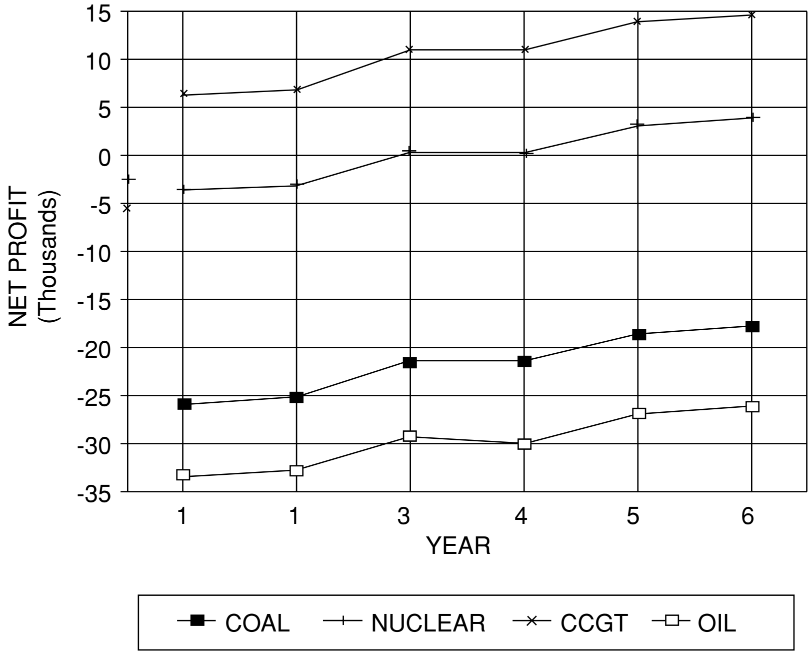

Figure 12.2 Net profit 1987–88 to 1992–93.

in Figures 12.2 and 12.3 over a six-year period. In this example it is assumed that no new generation is added during the period and that a competitive market is in operation. It shows how the profit gradually increases in line with the growth in demand, system marginal price, and LOLP. CCGTs are shown to be most profitable, with the costs as assumed in this study. The results will change as any new generation is commissioned displacing older more expensive generation and resulting in a reduction in the marginal price and income. The model would need to simulate the expected addition of the new generation through each of the study years as discussed in the next chapter.

Predicting Utilisation

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 an operational model. The discontinuities reflect differing plant dynamic

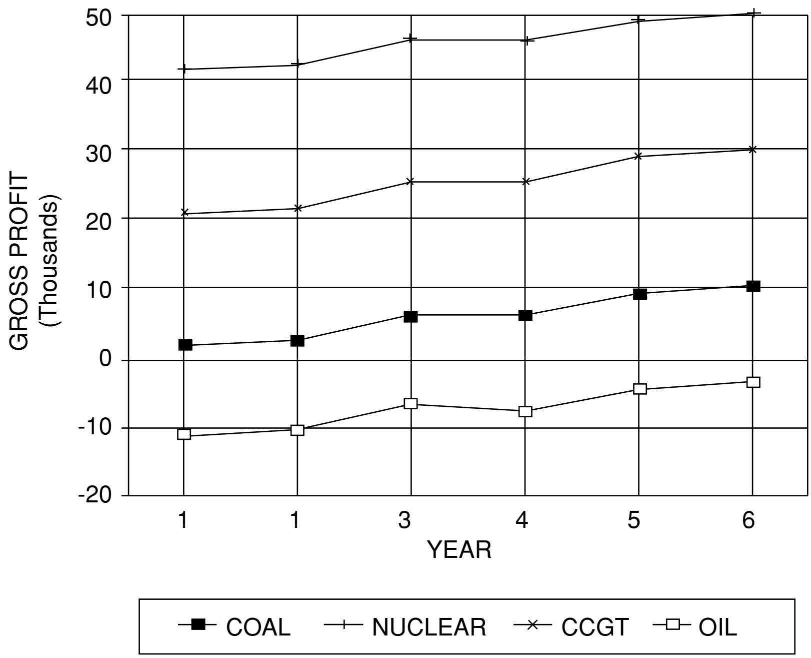

Figure 12.3 Gross profit 1987–88 to 1992–93.

characteristics and changes in fuel types. 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. 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 likely 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, the change in price δ is very dependent on the margin and the operating point on the system overall price curve. On the steep part of the curve a 5 GW change gives a corresponding price variation of some £5/MWh whereas on the middle portion of the curve the same demand change only gives a change in price of less than £1/MWh. If new

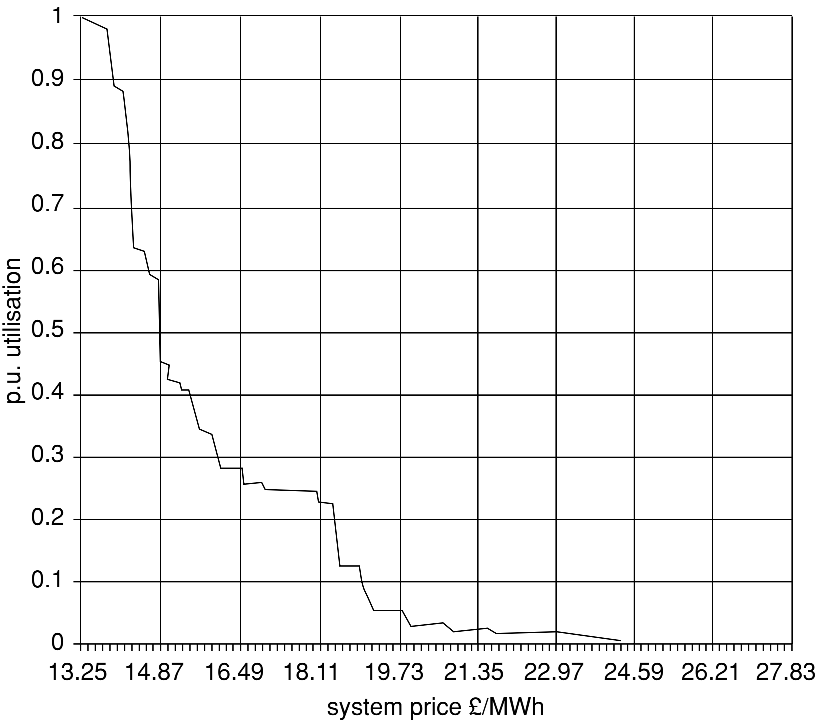

Figure 12.4 Typical generation utilisation v price.

capacity is added to the system at a rate exceeding the growth in demand and plant closures then the overcapacity could have a disproportionate impact on SMP and generator income. In this example demands above 45 GW result in the marginal price being set by units with prices up to £25/MWh whereas if some 2 GW of low merit generation were added marginal prices would not rise above £20/MWh.

The plant margin and shape of the inherent system cost function are then key parameters in any risk assessment of investment of forward contracting. The effect of fuel price variations will be constrained by the existing plant mix, which is not readily changed, and an appraisal of the impact of fuel price changes is therefore relatively straightforward. Expansion planning within an integrated utility or single buyer model would normally 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 dependence on single fuel sources may create security problems in future. In England and Wales because of the rapid expansion of gas fired generation, failures or problems at the supply terminals or on the gas grid may put the

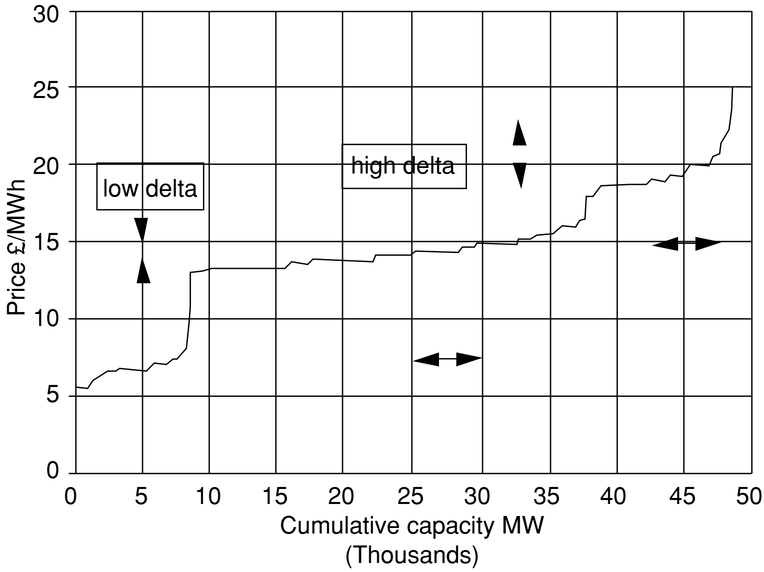

Figure 12.5 Price v capacity.

security of electricity supplies in jeopardy at times of stress as has already occurred in practice in January 1996 when interruptible terms were invoked in gas supply contracts.

Predicting SMP

This section compares the results obtained from a full simulation model with the actual outturn Pool Selling Price (PSP) in England and Wales through during the period after privatisation from April 1990 to February 1994 when the Regulator intervened. The actual monthly PSP values were derived from published data and the model was constructed on the basis of generally available data. The demand profiles used were derived by scaling historic profiles to match the published monthly energy values for each year. The availability profile for generation was constructed by creating outage periods consistent with known overall availability patterns and periods. The actual generation was modified yearly to take account of new plant additions and station closures for which data was available. The resulting patterns of availability are considered typical but not necessarily the same as the actual.

An operational model was used to simulate operation and derive marginal prices assuming full competition with actual generation incremental costs being bid. Generation availability files were edited manually to add new generators and reduce the availability of closed generation to zero. Fuel prices were adjusted on the basis of data published by the National Statistics Office.

Results

The results of this 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 outturn start by following 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 in excess of cost increases.

The cost based model results show a small rise in marginal prices to meet the increased demand, with prices being contained by the addition of new cheap gas plant combined with low fuel prices. 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 price rise to be contained to a few percent while the actual results rise according to the function:

$$\text{PSP} = 1.728 + 0.024 \times \text{Month}$$

with the total rise over the period being 49%. Of this, the expected rise in marginal costs due to the demand rise is some 8%. There is also a need to allow for transmission uplift to cover the cost of managing constraints and to cover price inflation, and this would account for a further 27%, leaving an unexplained price escalation of some 14%. This could be the result if a fully competitive market was not in operation which is consistent with the popular belief that a duopoly operated through this period. During the same period the combined market share of the large generators dropped by some 15% which aligns with the price increase of 14% that would be necessary to maintain their income level 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 wide range of data assumptions necessary to establish a representative model. The results suggest that actual prices were influenced more by commercial and financial considerations and the level of market competition and less by underlying costs, and these results confirm the popular belief that energy prices have risen by some 14% more than necessary during the period modelled and prior to the Regulator intervening. The prediction of prices then has to take account of the underlying costs as well as the level of competition. Any investment appraisal based on current market prices

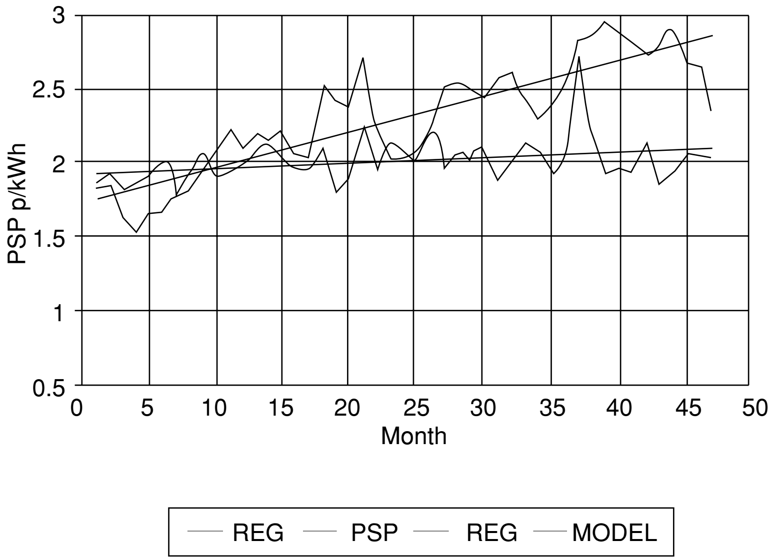

Figure 12.6 Actual PSP v model PSP, April 1990 to February 1994.

alone could prove naïvely optimistic. It is necessary to take account of the type of market perceived to be in operation and alternative models to evaluate this 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 will 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.

Forward Pricing

Forward pricing prediction is key to the assessment of the future profitability of generation and the evaluation of contract options. It has been found that energy forward curves do not comply with the classical models developed for financial markets and alternative approaches are necessary.

There are two general approaches one based on 'mark-to-cost' and the other 'mark-to-market'. The cost based approach seeks to synthesise a price based on the cost stream whereas the market approach seeks to establish a stochastic model based on actual recorded prices. The former would constitute the lower bound of profitability while the latter would reflect what the market would bear on the day and arbitrage opportunities. It is accepted that both approaches have a role to play in the management of risk.

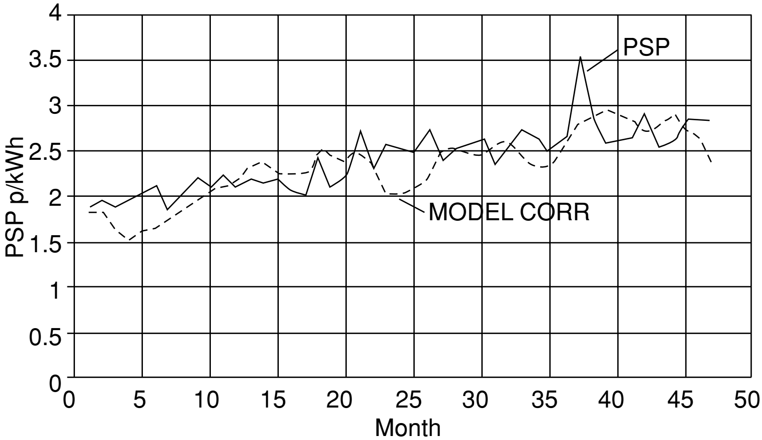

Figure 12.7 Actual PSP v model PSP, April 1990 to February 1994.

Deregulation has confounded what was always a difficult problem for utilities. Deciding where to send the next train-load of coal requires a good prediction of future operating regimes for generation. This in turn now requires a prediction of what will happen as a result of competition in the market. Understanding the process that utilities go through in bidding generation and identifying trading opportunities helps in modelling the forward price curve. Some of the factors that have to be considered are:

- the demand prediction process and price elasticity
- the unit commitment process used to optimally allocate the use of generation
- the concept of marginal prices to cover incremental and capacity costs
- predicting generation availability taking account of planned and forced outages
- the system marginal price function and the impact of plant margins on price volatility
- the impact of transmission constraints and the zonal pricing concept
- the state of development of competition in the market across the merit order curve

When all these factors are considered and modelled it is possible to make sensible projections to support the decision making of the utilities as well as those involved in trading.

The level of consumer demand is a key determinant in fixing the generation that will be used at the margin and the incremental price in a competitive market. Demand prediction techniques are based on historic daily profiles with the levels influenced by the weather and economic activity. A new factor that particularly affects the peak is price elasticity and demand side management.

Utilities have traditionally used unit commitment algorithms to select the generation to meet the demand at minimum cost and portfolio generators still use similar algorithms to choose how best to meet their commitments. In England and Wales the same algorithm as used for operation is now used to set marginal prices. These optimisation routines take account of start-up and no-load prices and the dynamic plant restrictions on the use of generation. The effect of these subtleties on the outturn price would confound any stochastic model.

The other key factor determining price is generation availability which is influenced by both planned outages for maintenance and forced outages due to failures. The decision on when to plan for maintenance will in turn be influenced by the prevailing market conditions and is not random. In the England and Wales model the recent history of generation availability directly influences price through the addition of a Loss Of Load Probability element (LOLP) to the marginal price. An assessment is made on a rolling basis of the probability of loss of sufficient generation so that demand cannot be met, and the price is incremented in proportion to this and the Value of Lost Load to consumers (VLL). The effect on price could not be easily predicted using a statistical model without taking into account the trend in LOLP directly.

The impact of demand and availability variations can be visualised by examination of the slope of the overall system price/capacity function for the period in question. This basic function needs to be modelled in any prediction process.

Another factor affecting the costs of operation is limitations in transmission capacity, which constrain the use of the cheapest generation to meet demand because of bottlenecks in the routes linking the two together. This may be reflected in the price by a global uplift element added to all energy sold through the pool, as in England and Wales, or by different zonal energy prices. The process is not entirely random and will be influenced by when transmission outages are taken, the zonal generation availability and demand, and any forced outages. The impact on operation will depend on the utility practice in managing insecurities and its capacity to take post-incident corrective action. In a deregulated environment it is almost impossible to optimally coordinate outage planning and generators can and do make many short term changes to their plans.

So far those factors affecting the cost of operation have been discussed and in a fully competitive market this should give a good indication of marginal prices. In practice, however, the market may be less than perfect and other factors need to be considered in estimating outturn prices.

Where there are a few large portfolio generators then it is likely that they will own a large proportion of the generation in a particular part of the system merit order or price function. This means that they can effectively control the marginal price when the demand falls within their controllable band and raise prices above marginal costs. The generators may choose to operate collectively as they have a common interest in maintaining prices. In England and Wales it has been alleged that a duopoly has been in effect at times. A way of predicting bidding patterns in these circumstances is to inflate prices by the rates of return normally expected by the companies for different tranches of generation. The underlying marginal cost can be assessed from a knowledge of typical heat rates for each tranche of generation and the respective prices of fuel. The bid price can then be estimated by adding in margins to provide the expected return.

It has also been found that realistic models for medium-term predictions need to include planned outages as well as Monte Carlo simulation of forced outages of generation and transmission. Transmission constraint activity can be modelled using historic seasonal profiles but it is also necessary to simulate typical post-incident operator action.

The other approach is to develop statistical models of actual price movement and the classical approach used in finance is the log-normal model in which the price change is normally distributed about a mean with the prices being log-normally distributed with a positive skew. The price at any one time is then made up of a drift term bringing the oscillating variable back to the mean and a stochastic term ie.

$$\partial p = \mu P_t \partial t + \sigma P_t \partial X_t \qquad (12.4)$$

The drift rate μ affects the rate of return and the volatility σ the random element with both being a function of the price P.

However, the log-normal model has been found not to work well for electricity which exhibits different characteristics. Energy prices stabilise more quickly following a disturbance with a narrower range of price levels and a tendency to stratification as shown in Figure 4.7. They also have different short- and medium-term behaviour with the former driven by weather and commercial activity and the latter by supply and demand changes and economic trends. These characteristics reflect the underlying physical process being modelled and are similar to those exhibited by consumer demand and built into demand prediction algorithms. Other authors (Pilipovic, 1997) have advocated the use of mean reverting models which do a better job of capturing energy prices. For electricity the mean reversion in the log of the spot price has been proposed where if a new variable is defined as the natural log of the price P:

$$\chi_t = \ln\partial\left(P_t\right) \tag{12.5}$$

then

$$\partial\chi_t = \alpha\left(b - \chi_t\right)\partial_t + \sigma\partial Z_t \tag{12.6}$$

where α equals the rate of mean reversion, b is the mean and Z the stochastic term.

Modelling system operation has always been a requirement of utilities, to enable the optimum management of fuel supplies and associated transport costs. The advent of privatisation has added a new dimension to the problem but has not changed the underlying physical process and this needs to be modelled to get results accurate enough to support the onerous financial decisions associated with investment. It is also necessary to track actual prices using statistical techniques to assess the level of competition occurring in practice.

1998 will be key year in the development of electricity markets in England and Wales when the local franchise to supply is finally fully removed. If this does lead to full competition then it is going to be increasingly difficult for suppliers to underwrite hedging contracts with generators against pool prices. If this happens then a very keen interest is going to develop in predicting pool prices and assessing risk and this is discussed in Chapter 14.

Conclusions

An approach has been developed to establish a generator's prospective utilisation and income and hence profit in a post-privatised situation. An operational simulation is first used to derive an annual SMP profile. The utilisation can then be 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 was 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 CCGTs as being most 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 the level of market competition may affect outturn and future prices with prices having risen above the cost level by some 14%. Two approaches to predicting prices were described, one based on 'mark-to-cost' and the other 'mark-to-market' and it was concluded that both will have their role in appraising options.

CHAPTER THIRTEEN

Market Share and Appraisal Process

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 this will have on prices and market share. The overall process of investment appraisal is brought together and various models are introduced to describe the interaction between companies. The theory is illustrated by comparison with actual data available from observation of developments in the England and Wales deregulated market.

The Profit Function

The iterative LP formulation of the expansion planning problem can only provide a coarse estimate of the additional capacity that would be profitable because its time periods are too coarse to model hour-to-hour SMP and hence profit variations. As described in the previous chapter it is also necessary to simulate the operation of the system in detail using a full simulation with all the existing planned new generation added with representative costs. The output of an operational simulation will provide an annual SMP/LOLP profile which can be used to calculate the profit from new generation options.

The profit calculation identifies the period of time when the marginal cost of new generation is below the market SMP when it operates in merit. The energy income can then be determined from the product of the MW and PSP during the in merit periods as described in the previous chapter, i.e.

$$\sum_{t=1}^{t=n} \mathrm{MW}_{i,t} \times \mathrm{PSP}_t \quad \text{where } \mathrm{Inc}_i \leq \mathrm{PSP}_t \tag{13.1}$$

where MW = unit output at time t PSP = pool selling price, INC = incremental cost of unit i. The profit is then calculated by subtracting the proposed generation fixed and variable cost elements. i.e.

$$\sum_{t=1}^{t=n} \mathrm{MW}_{i,t} \times \mathrm{var}_i + \mathrm{fix}_i \quad \text{where } \mathrm{Inc}_i \leq \mathrm{PSP}_t \tag{13.2}$$

where var = unit variable cost fix = unit fixed costs.

If new generation is added to the system to displace older more expensive marginal generation then the marginal prices and profits should fall. By progressively adding additional generating capacity to the simulation it is possible to calculate a new incremental profit at each point and hence the system overall profit function for changing levels of new capacity.

Typical 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 in this example are

$$P = 18.20 - 2.71 \times C$$

where P = £K profit/MW/year and C = capacity in GW. 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. All results assume that a true competitive market is in operation.

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 7.0 GW of additional capacity is added compared to the 7.5 GW in the revised LP formulation. The comparison with the profit maximisation formulation of Chapter 11 is close given the simplifying assumptions made in the representation. In practice a private utility required to maintain a high return to shareholders might not invest up to the limit of marginal profitability but may choose to maximise returns as discussed below.

Calculating Total Profit

Given the function of incremental unit profit versus additional capacity as derived above, a function of total profit against additional capacity can now be calculated from the product of price and total new capacity. This exhibits a maximum as shown by the outer semicircle shown in Figure 13.2. The total return builds up as the amount of new capacity is increased until further additions depress the unit price so as to reduce the overall profit, assuming that a fully competitive market is in operation.

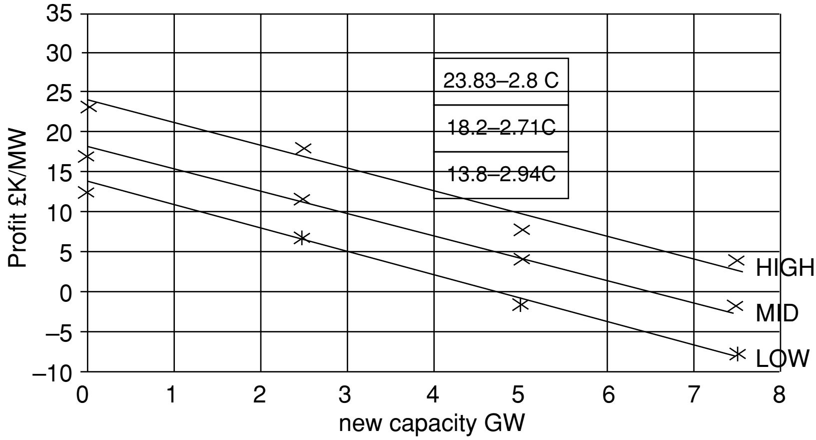

Figure 13.1 p.u. profit v new capacity, 1993–94 plan year.

As shown above the per unit price profit function can be represented by a straight line of form

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

If we assume two key market players each building capacity C_1 and C_2 then the total profit is given by the product of price and capacity, i.e.

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

This can be differentiated to obtain P_{max} which in this example occurs at 3.36 GW, i.e. the total net profit is maximised if 3.36 GW of new capacity is built. This is considerably less than the 7.0 GW derived above using an LP formulation and if built would result in only marginal profitability as shown in Figure 13.2. This confirms that the LP formulation can only provide a guide to the additional capacity that would be marginally profitable and not that which maximises profitability. In practice with typical levels of uncertainty a range of maximum profit values from 4.25 GW to 2.34 GW could occur based on the data in Figure 13.1.

It is now possible to model the interaction of market players each seeking to maximise their profit. To illustrate the concepts it is assumed that only two players interact and in the next chapter the approach is extended to multiple players. If we assume company A chooses to build capacity C_1 then a function can be calculated to show the range of profits that company B can realise with different investment strategies.

Company B profit is given by :

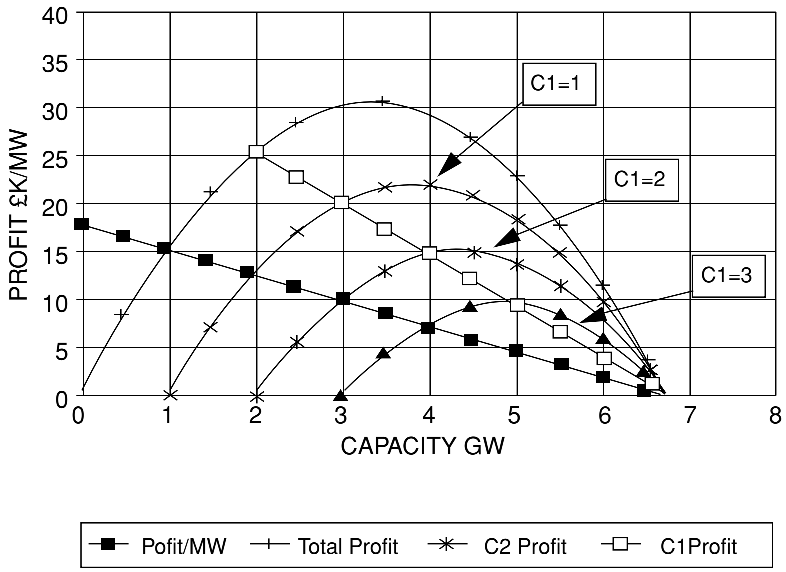

Figure 13.2 Profit v new capacity, 1993–94.

$$P_{(y_1+y_2)} \times C_2 = (a–b(C_1+C_2)) \times C_2 \tag{13.6}$$

This can be differentiated to obtain the maximum, i.e. the capacity that company B should build to maximise its profit expressed in terms of the constants of the original straight line per unit profit function. A more complex function would result from a non-linear profit function but the same principles would apply.

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 outer curve the corresponding total profit. The other lines show the total profit when company A chooses to build 2 GW of CCGTs 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 A. This is the function derived above

$$C_2 = \frac{a–bC_1}{2b} \tag{13.7}$$

and similarly for company A given the decision of company B

$$C_2 = \frac{a - bC_2}{2b} \tag{13.8}$$

These reaction curves are plotted in Figure 13.3 which shows the two functions, i.e.

$$C_1 = \frac{18.2 - 2.71C_2}{5.42}; \quad C_2 = \frac{18.2 - 2.71C_1}{5.42} \tag{13.9}$$

This approach enables a generating company to determine its optimum strategy given prior knowledge of the proposed capacity additions of its competitors. In practice this may not be the case and other models are discussed at the end of the chapter.

Overview of Process

It is now possible to outline an overall process to assess the optimal level of additional capacity that maximises profit based on the analysis described in the preceding 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 Chart 13.1.

Phase 1. Total Capacity Requirement

This uses an iterative LP formulation as 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 assesses the optimal additional capacity by plant type to maximise the generators' total profits. From the results a set of proposals for varying capacity additions up to the maximum with positive profitability 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 and type of additional generation added a function can be derived showing the p.u. profit against added capacity.

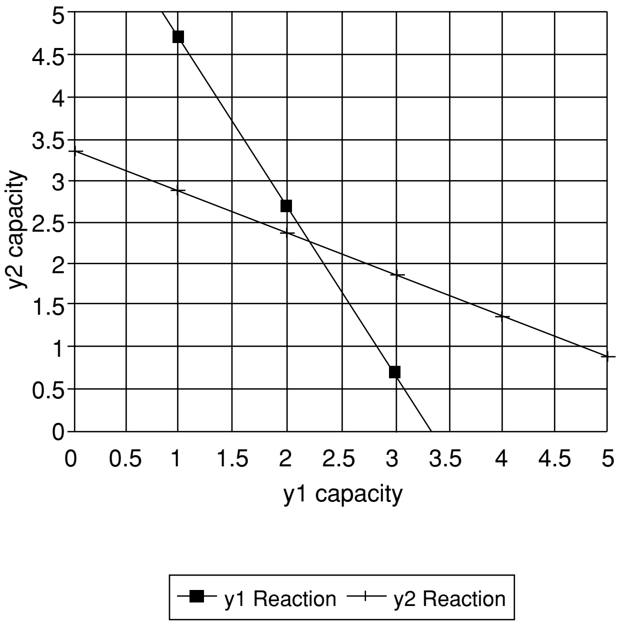

Figure 13.3 Competitor reaction curves, 1993–94 capacity additions.

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 is offset by the resulting price reduction.

Phase 4. Company Interaction

The sharing of profit within the overall envelope is calculated depending on the interaction model in operation, e.g. in a duopoly one company leads the other, or both companies act in isolation double-guessing the action of the other as described. 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.

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 typical

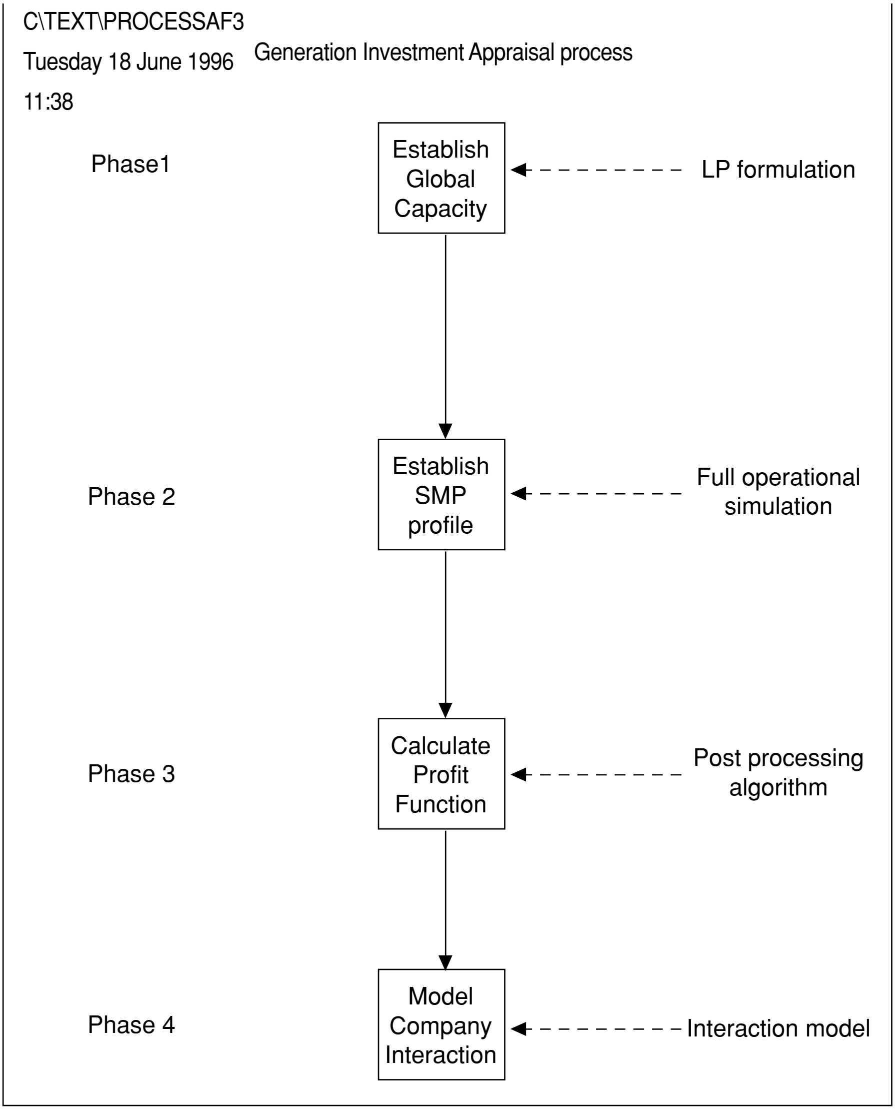

Chart 13.1 Generation investment appraisal process.

values can be used for each of the key variables with an assigned probability as illustrated in Table 13.1.

The results are shown in Figure 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

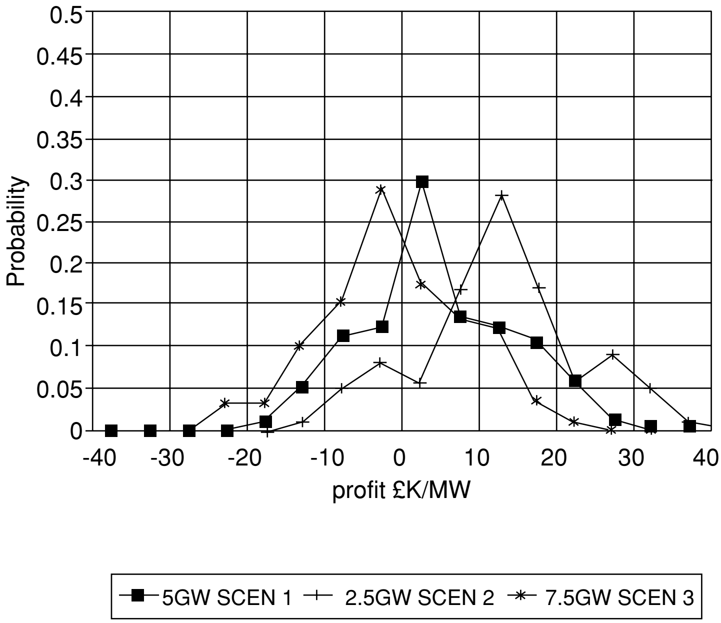

Figure 13.4 Profit probability, 1993–94.

range of the variables is realistic then the graphs can be used to assess the statistics of likely outturn for a chosen plant addition and hence the risk. Figure 13.1 was constructed assuming that the outturn is bounded by the 0.15 probability level for each capacity scenario. The band between its upper and lower values would then capture some 50% of the likely outturns.

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 by analysing the trade-offs using regression techniques or decision tree analysis.

Alternative Company Interaction Models

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

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

Table 13.1

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

- *Stackelburg equilibrium* where one company assumes quantity leadership and the other follows.
- *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 realise adequate returns. From the above theory the result of the three approaches can be calculated.

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 CCGTs shared in some agreed proportion.

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

Table 13.2 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.

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 Figure 13.3.

Comparison with Actual

In reality by 1993–1994 the CCGTs commissioned amounted to some 6.3 GW including 3.3 GW of capacity added by the independents. The potential impact on prices and profits may have prompted some forced premature closures by the major players faced with diminishing returns and in practice some 2.6 GW of old plant was closed during the period made up of 0.4 GW of OCGTs; 1.4 GW of oil and 0.8 GW of small coal. The net result is then consistent with the optimum derived from the above formulation and brings the net capacity change to $6.3 - 2.6 = 3.7$ GW, i.e. very close to the optimum of 3.36 GW. This then shows how portfolio generators may react to maintain their overall profitability as set by SMP/LOLP in a competitive market. A general modelling approach is developed in the next chapter to deal with the interaction of multiple companies.

Conclusions

This chapter has shown how a generator can identify the overall system need for additional capacity and then model a competitor's behaviour to determine its 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 its optimum and the overall process of assessment to be defined. Three competitor interaction models have been described and models developed to predict intercompany 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 SMPs. Because all energy taken during these half-hours is charged at SMP they will have a disproportionate effect on overall profit leading to the so called ‘energy premium’. On a cost minimisation basis it would be correct to displace the expensive marginal generator as this formulation takes no account of the impact on income. It is only if the generators were to control prices and were therefore able to fix the high marginal prices despite the new lower costs that more replacement would appear attractive. The theory has been developed assuming that competition does exist and in practice even if a generator can control prices for some of the time it would be a risky strategy to rely on this in making long-term investment decisions. Given the potential impact of the uncertainty in key parameters on the profit it is not surprising that generators and suppliers have sought hedging contracts and price control. The chapter concludes with a description of how in practice the market has reacted to maintain revenues.

CHAPTER FOURTEEN

Predicting Multiple Company Interaction

The previous chapter discussed how two companies might 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 it is to constrain its build when plant margins are already high because of the potential impact on SMP and LOLP and the income for all their existing generation. Capacity in excess of the optimum will therefore tend to accelerate closures by the big generators. A generalised approach is developed to model these effects within a theoretical framework which enables the initial evaluation of a full range of scenarios and risk without full simulations.

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 (Figure 12.5) how the range of demand variation may be projected onto a system MO function to establish the range of price variation. A system short of capacity will frequently use peaking plant, which will set high marginal prices and increase the profit margins for all generators. A system with overcapacity will exhibit a flat low price profile with small profit margins.

The impact on prices and hence profits resulting from changes in demand or capacity can be seen below to be essentially non-linear although it was shown in the previous chapter how it may be linearised over a small range. Increasing demand will shift the effective operating range to the right whereas adding capacity will shift it to the left.

Theoretical Derivation of Profit Function

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

$$P = A\mathrm{e}^{BD} \tag{14.1}$$

where P = price, D = demand, and A and B are constants. The demand distribution function may be represented by a normal distribution curve of the form

$$H_{(D)} = \frac{K}{C\sqrt{2\pi}} \exp\left(\frac{\mathrm{D/s} - \mathrm{m_c})^2}{2\mathrm{C}^2}\right) \tag{14.2}$$

where H is the number 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; m_o 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 I_g we can calculate the gross income when the unit is in merit and hence the gross profit per year F, i.e.

$$F_g = \sum_{p=1}^{p=\max} H_{(D)}\,(P_{(d)} - I_g) \quad \text{for } P_{(d) > I_g} \tag{14.3}$$

$$F_g = 0 \qquad \textit{for } P_{(d)} < I \tag{14.4}$$

$$F_g = \sum_{P=1}^{P=\max} \frac{K}{C\sqrt{2\pi}} \exp\left(\frac{(D/s - m_o)^2}{2\sigma^2}\right)(A\,e^{BD} - I_g) \tag{14.5}$$

and the net profit is the gross profit less the interest charges on the capital at the prevailing interest rate, i.e. $C \times I$. That is to say, given the demand function we can estimate the gross annual profit.

Results

Figure 14.1 shows typical functions derived from the formulation above. The normal demand curve shows the number of hours the demand is within each 500 MW range. The MO curve is shown as an exponential and the third curve shows the product of the two (÷ 10) and is skewed by the exponential price curve. It shows the price duration function as the number of hours that the marginal price is likely to be within each band. It can be used to estimate the in merit running and profit of a generator and also the likely period when it would be marginal and called on to regulate as demand varies. The results obtained from this simplified formulation compare well with the range of results obtained from full operational simulations.

Changing Capacity and Demand

The new representation readily enables the effect of changing capacity and demand to be assessed. New generation can be expected to be high merit and will therefore have the effect of shifting the point at which demand intersects with the system MO curve to the left, reducing the prices. The MO function can then be modified by the new capacity C, i.e.

$$P = Ae^{B(D-C)} \tag{14.6}$$

An increase in demand will, assuming the profile stays the same, shift the mean value of the demand distribution curve to the right and can be represented by the modified function.

$$H_{(D)} = \frac{K}{C\sqrt{2\pi}} \exp\left(\frac{-(D/s - m_o - \delta D/s)^2}{2C^2}\right) \tag{14.7}$$

where δD is the change in demand. The value of the MO will then be increased by the increase in demand.

These functions can been used to derive the graphs shown in Figure 14.2, which show the change in per unit profit from new generation for changes in the

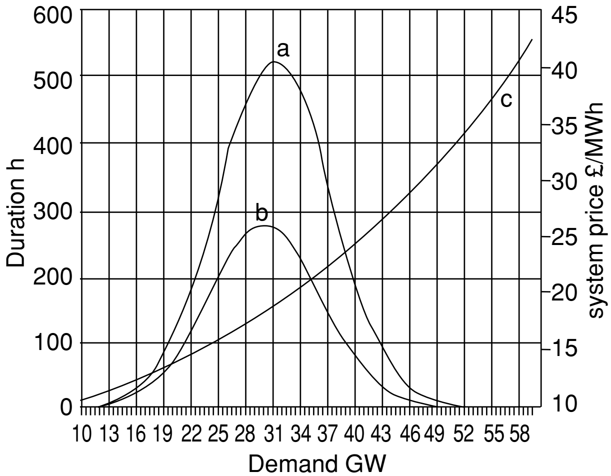

Figure 14.1 Normal demand and system price. a, price × duration/10; b, demand duration; c, price.

total capacity added or in the demand. The line labelled 'capacity' is the result from full production modelling and that labelled 'simulation' is that derived from the new functions. It can be seen how increasing capacity reduces the p.u. profit and that the results are very similar to those described in the previous chapter and are linear over the range shown. The estimated increase in profit for increasing demand is at a slightly higher rate than with the full simulation but it is concluded that this formulation is sufficiently accurate to be used to derive a new profit function as the capacity and demand change from year to year. The expressions derived above can be used to model any system for which the price function and demand can be estimated.

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

$$P_t = a_t - b_t C_t \tag{14.8}$$

where a and b are constants, P is p.u. profit and C capacity, as shown for different types of generation in Figure 14.3. The total additional profit is given by the product of the profit and the new capacity ie.

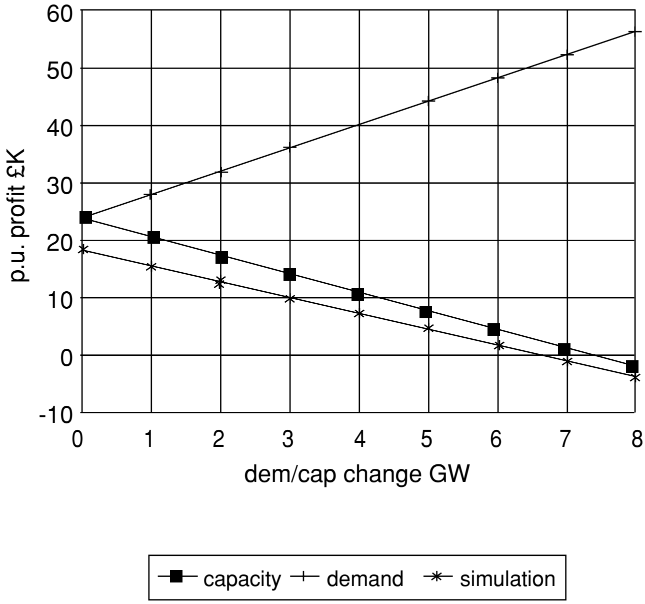

Figure 14.2 Theoretical profit line for changing capacity and demand.

$$P_t = (a_t – b_t C_t) C_t \tag{14.9}$$

$$C_t = \sum_{i=1}^{i=n} C_{t,1} \tag{14.10}$$

where C_t is the total new capacity in the near and c_I is that for each generator. Expressions can then be derived for the total profit of an individual generator and differentiated to derive the optimal strategy when profit is maximised, i.e.

$$(a – b_t C_t) = 2 b_t c_{i,t} \tag{14.11}$$

and

$$C_{i,t} = \frac{(a_t - b_t C_t)}{2 b_t}$$

Depending on the slope of its profit line a generating company will either increase or decrease capacity by building new generation or advancing closures. For an existing generator it will also be necessary to take account of

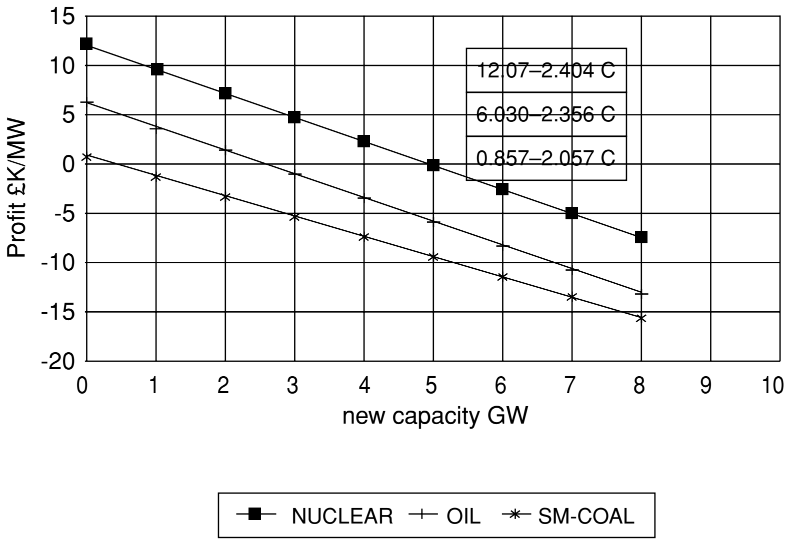

Figure 14.3 p.u. profit v new capacity, 1993–94 plan year.

the effect of the price change caused by new capacity on the income from existing generation and a similar analysis can be used to establish the optimal additional capacity addition. Having estimated the value of a and b for a future year it can be used to calculate the optimal additional capacity for all new and existing generators. The p.u. profit function will be affected each year by the changes in demand or additional capacity as shown in Figure 14.2.

Modelling Interactive Expansion

Using the above theory a model can be built to simulate generation expansion for the group of existing and new generators. The pre-privatisation generation conditions were taken as the starting point and actions are modelled through the first few years. The profit function is adjusted year on year according to the change in demand or plant changes using the functions (14.6) and (14.7).

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

Risk and Option Evaluation

The discussion so far has concentrated on the decision of weather to build generation or not but there is also the need to assess the value of options for both generators and suppliers. A classical approach used in financial markets is the Black–Scholes model which is used to estimate the worth of a call option by comparing the current price against the exercise price of the call option. Unfortunately this assumes the log-normal distribution of prices which, as discussed in Chapter 12, does not have a good fit for electricity. The approach also assumes that the volatility remains constant which is not true for electricity and in practice the model does not hold very well.

For a portfolio generator putting forward an option it is necessary to appraise the variability in production cost due to the probability of loss of some of the generation resulting in higher costs. There may also be a need to factor in potential fuel price variations. For a supplier given the option to buy the production output at some future date at an exercise price it will be necessary to establish a view of forward prices taking account of the extreme volatility and variations in demand, transmission and outages.

There are various types of option that need to be evaluated including European options with a single exercise date, American options which can have more than one exercise date and Asian options with average price settlements. The technique chosen to evaluate the option should be as simple as possible while capturing the market features. In the classic Black–Scholes model the worth of the call option C is given by:

$$C = SN(d_1) - Ee^{-rt}N(d_2) \tag{14.13}$$

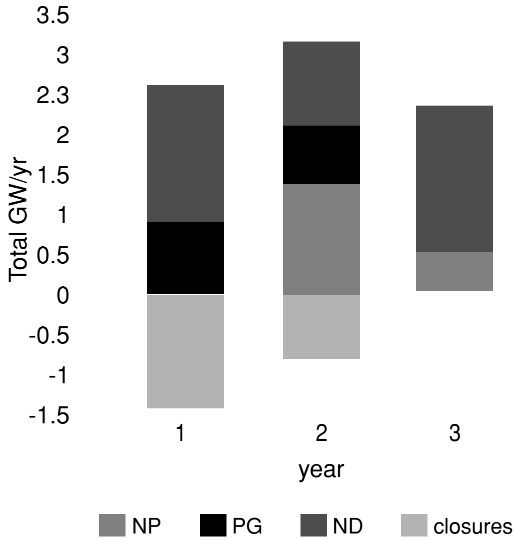

Figure 14.4 Generation expansion 1991–92 to 1993–94.

where S is the current spot price, E the exercise or strike price and $N(d_1)$ and $N(d_2)$ are the probabilities that normally distributed variables will be less than or equal to d. d_1 and d_2 are given by:

$$d_1 = \frac{\ln (S/E) + (r + \sigma^2/2)t}{\sqrt{\sigma^2 t}} \tag{14.14}$$

$$d_2 = d_1 - \sqrt{\sigma^2 t} \tag{14.15}$$

where σ is the spot price volatility, t is the time to expiration date, and r is the risk-free rate of return at which money can be borrowed from the bank. In practice simplifying assumptions are made, e.g. that prices are log-normal with constant volatility and adjustments are made to reflect actual market behaviour. There are likely to be many other factors which will affect the outturn and decision trees may be used to analyse their effect if probabilities can be assigned to their likelihood.

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

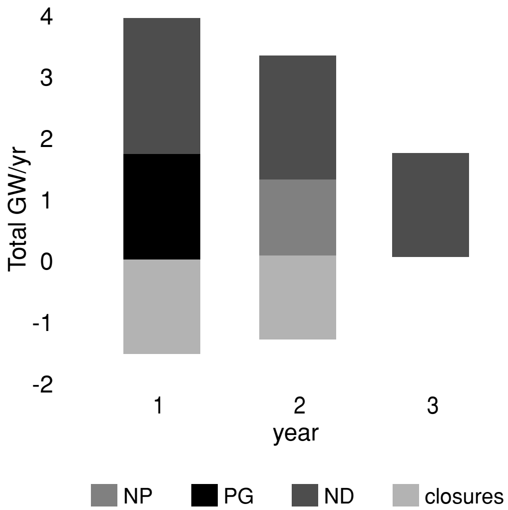

Figure 14.5 Generation expansion 1991–92 to 1993–94, model planned.

the system merit order function assuming that a fully competitive market is in force. The theory has been tested by comparison with full production simulations and the results show reasonable correlation. The theory has been used to model the interaction of several companies operating in the same market. The results show similar behaviour to that which has occurred in practice.

The basic theory and objective functions are fundamentally different to those applied to expansion planning for a fully integrated utility and are likely to 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 influence prices and the market in their favour.

Part 2 of this book has developed a new approach to investment appraisal in a deregulated market and has demonstrated that the classical approach is no longer applicable. It was 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.

PART THREE

Transmission Investment Appraisal

Part 3 discusses the essential role of transmission in enabling competition and reviews worldwide practices revealing little consensus on charging for its use. Basic costing principles are described and a new paradigm is proposed based on an analogy with road funding. A model is developed to demonstrate how a generator may strike supply agreements either side of an interconnector to influence prices so as to maximise its income. The optimal pricing strategy for the transmitter is also derived and consumer response is simulated. The alternative approaches to managing the additional costs due to transmission constraints are discussed and it is shown how they may be modelled in operation. A model is used to derive functions describing the increased costs due to transmission constraints and it is shown how these can be used to evaluate investment options and optimally plan outages.

CHAPTER FIFTEEN

Review of International Structures

The Regulated Monopoly

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 provides 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 in order to minimise the total costs. It would not be efficient to duplicate the transmission system and it is therefore treated as a monopoly subject to regulation. The current use of system charges are therfore 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 to establish the optimum level or for the distribution of charges between generators and suppliers. Nor does it 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 necessary to balance costs with the benefits to consumers in reduced generation costs and improved security. An integrated utility would design 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 optimal level of investment to be realised by appropriate price messages throughout the market with adjustments to take account of the price that consumers are prepared to pay for security.

Objectives of a Market Structure

An ideal market structure could be supposed to serve the following needs:

- provide unbiased open access to facilitate competition in generation
- encourage the optimal level of transmission investment to minimise costs
- encourage efficient operation of the integrated power system
- accommodate choice in location for 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 do we distinguish between cable and overhead line charges?

Having identified appropriate prices it has to be decided how these should be apportioned. All consumers benefit from enabling competition in generation and supply. New transmission will benefit consumers most if located in a net importing area while generators benefit if they are located in an exporting area. Circumstances will change as new generation is built and the freedom to locate needs to be tempered by singling the cost implications and apportioning charges between generators and consumers. The following section discusses how some of these issues have been addressed by different countries

International Practice

England and Wales

The method of charging adopted in the England and Wales is made up of three elements

- connection charges based on the assets required to connect the generator or consumer to the system
- generation use of system charges based on net maximum registered capacity and the connection zone
- a demand charge based on the average demand taken at times of system peak (average of three half-hour periods) and the zone

The costs are currently apportioned between generators and consumers on a 25:75 basis as decided by agreement at privatisation. The charges are not related to energy transfer but to installed capacity. They are derived using an Investment Cost Related Pricing (ICRP) transport model which calculates the marginal cost of investment in the transmission system that would be required as a consequence of an increase in generation or demand at each node. These nodal costs are aggregated for each closely coupled electrical area to give a zonal figure.

The zonal use of system charges are designed to encourage generation and demand to locate in areas that 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 since the additional costs of producing energy due to the transmission limitations are paid equally by all consumers through uplift rather than by those aggravating the constraint. If energy charges were also levied zonally then those sponsoring investment would see a return through reduced operating charges whereas no benefit is seen with the current arrangements.

In practice the zonal price messages have not worked, as shown in Chapter 4, and generators have chosen to locate in exporting areas where the benefits of local industrial contracts for gas, power and/or heat offset the use of system costs.

Australia

Paper trials confirmed the shortcomings of the England and Wales system on a number of counts and two alternative approaches were 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 forward 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 where the forced use of out of merit generation will result in the zonal price being inflated. This approach more clearly identifies who would benefit from investment in transmission to ameliorate the constraint. It uses an embedded network model to enable arbitrage against operational constraints with spot prices determined for each bus from a load flow and levied as zonally based energy prices.

Open competition is more easily realised in a tightly coupled integrated network, which equates to an infinite bus, as opposed to a radial network where transmission constraints may restrict market access. Where several zones are loosely coupled, local pools are more appropriate with opportunity trading between zones with appropriate wheeling charges. It is planned that New South Wales, Victoria and South Australia will operate as an interconnected system leading to the development of a national market called NEM. Any constraints on the interstate transmission lines will be managed using zonal energy pricing.

USA

A wide variety of techniques have been applied with varying levels of sophistication. In the past they have been influenced by the need to cater for nonutility generation embedded within the network and to accommodate transactions that affect boundary flows between regions. (Head, et al. 1990).

Of the methods described below for charging 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, 1994)
- ‘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.

The above methods do not appear to cover the impact of active constraints on generation dispatch or the appraisal of any new investment that may be cost-effective. They appear essentially aimed at apportioning 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 et al, 1989)
- ‘flow allocation by region methods’ use load flows to compute the change in interregional flows due to the wheel. The associated invest-

ment and operating cost changes are then calculated for each region and allocated on a $/MW basis.

More recently concern has been reported 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 defines compensation for the unauthorised parallel or loop flows. A matrix can be used to determine the ‘pricing path’ and the Transaction Participation Factor (TPF) associated with all potential exchanges. A load flow can then be used with all lines in service to assess the net value of all interchanges. If the flows that occur in paths other than the contract path exceed the 5% threshold then compensation is due. (Happ, 1994)

In response to Federal demands for open access a system called OASIS was set up early in 1997 to enable transmission operators to publish rates for use of their system simultaneously to all participants. A second phase of developemnt is planned for 1998 to enable energy transaction and trading. In the emerging market in California zonal energy pricing will apply when network studies indicate potentially active constraints. All users of the constraint path will pay a congestion charge based on the zonal price differential and the surplus of funds resulting will be paid to the transmission owner to reduce overall use of system charges.

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 influ-ence where an increase in output directly results in an increase in flow within the line. If it wishes to trade with a partner outside this area then it has to negotiate an additional tariff. (Hissey, 1994).

Norway

In the Nordpool implementation if transmission bottlenecks look likely then a number of separate zones are identified by the Power Exchange at the beginning of the week and each participant is advised of its zone. Energy price equilibrium points are determined for each zone and network flows are checked. If there is an excess network flow then the operator can adjust the energy clearing price by buying and selling in each zone to balance the flow. As in California the excess funds collected as a result of the adjustments are used to offset use of system charges.

New Zealand

A separate transmission company has been set up called Transpower with responsibility for providing open transmission access. Use of system charges 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.

Energy related network costs are levied according to use, based on a peak load flow solution and on the distance between the load and generation. The adoption of full nodal pricing for energy leads to a comparatively large number of prices with one for each node and half-hour. Capacity payments are based on the power consumed at peaks with losses distributed according to average TLFs.

Argentina and Peru

The transmission business is regulated to encourage efficiency with use of system 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 operating costs are shared with (Hissey, 1994)

- losses based on TLFs with respect to a pivotal node
- the capacity element based on connection charges.

If constraints become active then nodal prices will diverge with the marginal set at each node setting the price. The surplus funds are used to fund reinforcement.

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 (i.e. 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.

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 being global to being based on utilisation according to zones of influence and load flows
- commercial arrangements do not necessarily align with physical flows and arrangements are proposed to compensate for this

The techniques do not generally provide a basis for appraising new investment but rather focus on the apportionment of the historic cost of existing assets through use of system charges. Investment needs to be based on the potential benefit to sponsors rather than historic cost and this is highlighted by the application of zonal energy charging. The problem arises because the charging concept is being introduced late in the development of the network when most of the cost has already been incurred. It is not easy in retrospect or commercially acceptable to identify who benefited from and who should have sponsored each of the historic system developments. This has lead to different arrangements for recovering costs of existing systems and those incurred in operation owing to system limitations.

No rational criteria have been developed to apportion charges between generators, suppliers and consumers so as to encourage competition and create the incentives for investment. Some authors have concluded that there is no simple solution to ensuring a balance between investment and the value added to society (Schweppe, 1988).

The costs and impact in operation 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 alternative theories and techniques.

CHAPTER SIXTEEN

Cost Apportionment and Benefit

This chapter discusses the apportionment of transmission costs in a way that aligns with the benefit so as to encourage the optimal levels of investment. Three production cost levels can be identified depending on the level of transmission investment as shown in Figure 16.1.

- the absolute minimum cost assuming an infinite transmission bus
- the actual costs with a partially constrained solution
- the local costs assuming no supergrid 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 necessarily result in the establishment of an infinite transmission bus but a system with that level of investment when the additional savings in operating costs from new investment balance the incremental cost of investment. To realise this in a deregulated environment it is necessary to apportion charges for transmission to where the benefit from investment would be realised so as to encourage the optimal level of investment. Without this, transmission investment is unlikely to be sponsored and may even be opposed as was the case recently in the UK where a generator opposed a proposed transmission line which weakened its trading position. The alternative scenario is where weak regulation of the monopoly enables overinvestment in transmission.

The benefits from transmission are realised through

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

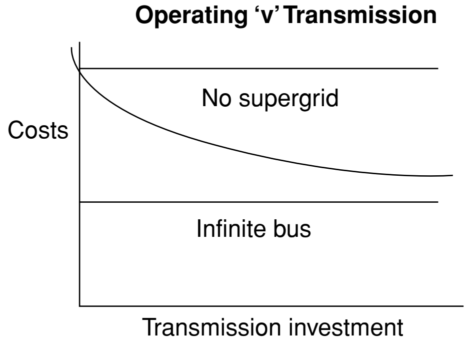

Figure 16.1 Operating cost v transmission.

- minimising the unserved energy and consumer LOLP payments by enabling generation pooling and so reducing the probability of available generation falling below demand
- improving the security and quality of supply by providing resilience against outages

Within an integrated utility the approach to appraising proposed transmission investment is 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.

Where transmission is unbundled it is regarded as a monopoly subject to regulation and only allowed to make charges which realise a reasonable rate of return on the existing sunk assets 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 must provide 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 England and Wales model the Use of System 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 may need to be handled differently to new investment, which needs to be based on its potential to provide benefit. One covers the recovery of historic costs and the other needs to be based on the potential to reduce future operating costs. The current England and Wales transmission services scheme provides significant profit opportunities to the transmitter who receives payments for minimising the ‘uplift’ charges due to constraints. This could encourage the perpetuation of constraints, rather than their removal and a longer-term incentive scheme, as opposed to the current annual scheme, may better engender the optimal level of investment.

Cost Apportionment of Existing System

Various techniques for apportioning existing transmission costs between users have been proposed. One approach (Calviou, 1993) formulated the problem as a classical transportation algorithm using a route cost for transmission 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 overutilisation of short lines and a significant underrecovery of the required revenue.

It has also been proposed that wheeling rates should be a function of differential nodal marginal prices with price differentials settled so as to constrain flows to the available transmission capacity. Studies have shown nodal pricing to be overly sensitive to network conditions and a small change in transfer changes the generator output and prices (Merril, et al, 1989). Zonal pricing is preferred where the price represents some average function of a cluster of electrically close nodes.

In England and Wales, investment cost related pricing is used where the charge is assessed on the basis of the proportional use of all lines resulting from an increase in injection at the connection node. The charge is then based on the proportion of the total investment cost. These methods are based on an apportionment of the cost of transmission rather than on its capability to add benefit and do not directly signal the value of investment.

The Benefit Function

The need to recover sunk costs should not be allowed to distort cost messages by loading them with costs that relate to historic decisions made in a different environment by different players. To establish the optimal level of investment it is necessary to base charges on the added benefit through a reduction in future operating costs.

The consumer benefit is maximised by minimising the total cost of production including generation and transmission costs. The benefit derived from the use of transmission is in enabling a global optimisation as opposed to local zonal suboptimal solutions. (Farmer, et al, 1995) The gross benefit is given by the reduced zonal generation production costs in enabling full MO operation and the net benefit of this, less the transmission costs. The method focuses on an assessment of generation operating costs together with transmission costs. In a market, prevailing generation bid prices will reflect constraint activity rather than basic costs. Where prices are artificially 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 be the same in the absence of bulk transmission.

Rather than basing charges on total costs it may be preferable to base them on the incremental costs and benefits, which should then indicate new investment opportunities. The form of the historic benefit function could be established by progressively incrementing the system transmission capacity from a base system with completely decoupled zones. As the zones are linked by new investment the additional benefit will gradually reduce with the optimum being reached when it just covers costs. If overinvestment occurs then the slope would become negative. The issue of any stranded assets should be addressed as a separate issue.

The benefit will be different for consumers and generators depending on whether they are in exporting or importing zones, ie

1. 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 lose the benefit of captive cheap capacity as shown in Figure 16.2.
2. Importing zone.
   New transmission will benefit local consumers in opening up their market to more generators who will compete with and displace some of the 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. The current England and Wales use of system charging principles aligns with this approach in that those making most use of the system, i.e. 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:

1. to establish zonal pricing for energy, by which consumers in import constraints and generators in export constraints would see a direct benefit from sponsoring reinforcement.

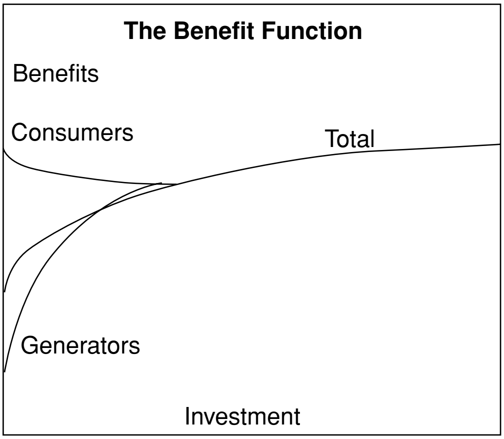

Figure 16.2 The benefit function.

2. to establish a long-term 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 net benefit to the participants will eventually tend to equalise to the costs. The first approach raises the issue of ownership and could lead to this becoming fragmented and difficult to administer. The contracts would need to be long-term and provide for full cost recovery with transfer rights. This could undermine open access. Giving the long-term responsibility to the transmitter would enable an unbiased development of the system with a global cost minimisation which should be to the long-term benefit of all players. A joint transmission user forum is a possible mechanism for agreeing on the development and establishing a mutually acceptable apportionment of costs that takes account of benefits and losses to all players. A joint venture agreement on apportionment would be established incorporating estimates of the cost and global benefits, including the impact on security (Hunt and Shuttleworth, 1996).

Assessment of Global Benefit

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 practically sized problems covering long periods. It is also difficult to dissociate the benefit of one line from another because of their non-linear impact on operating costs.

Rather than analysing total costs it is more meaningful to examine incremental 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 generation 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 eventually 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. But the incremental value is valid as a guide to benefit and the apportionment of infrastructure costs.

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 additional units with the customer benefit in reduced LOLP payments. It is implicit that the transmission benefit is affected by the prevailing plant margins in the systems being coupled. If these are initially 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 occurrence 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, i.e. 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 existing transmission supporting its service and should therefore pay less. The position is clearer if we dissociate historic costs from current operating costs as proposed. The consumer should then be paying a lower proportion of historic costs but should be bearing the current costs of constraints to encourage investment. Prepayment of these costs 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 it were paid a predefined sum to bear the insecurity costs that may occur owing to transmission outages. This would also create an incentive to return transmission equipment to service, from which the generator also derives benefit in ensuring that its output can be delivered at all times.

Quality of Supply

Economies of scale result from 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 can cover for all areas. Reserve holding costs are therefore saved in all other areas. Consumers gain benefit in having stable supplies to drive their equipment, and generators gain benefit from being able to maintain smooth operation. The benefit applies equally to interconnected systems where shared reserve agreements are common.

Losses

Investment in additional transmission will reduce overall losses. In the vicinity of large high merit stations the savings can offset the total cost of transmission. The questions that arise following the introduction of competition are who should manage losses and how should the costs be apportioned between generators and suppliers. The other issue is whether or not zonal charging should apply, reflecting the impact of incremental changes in output on total losses. The non-linear nature of losses adds to the problem of apportionment and it is necessary to decide whether 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 tend to minimise the overall cost of generation and losses. The difficulty with this approach is that the loss factors continually change as a result of demand and generation changes and some time of day averaging is necessary to make the problem tractable. Any treatment of losses should also consider generation losses, as the minimisation of transmission losses can result in an increase in generator and overall losses.

New Investment Types

There are several different types of investment which need to be distinguished as they need to be appraised and funded differently.

Non-Optional

This is the investment required to connect a generator or consumer direct to the system. The charges are directly attributable to the user on the basis of an agreed percentage return on assets employed. Investment is covered by a bilateral arrangement where costs depend on whether a firm or non-firm connection is required. The charges are influenced by what is thought to be a reasonable rate of return by the Regulator or capital market. Other annual charges of around 3% or 4% are levied to cover the operating and maintenance costs of the system. The arrangements are covered by a master connection agreement and are relatively straightforward.

Optional Interconnection

This is additional investment in transmission between two distinct systems to enable opportunity trading or wheeling when marginal price 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 and sometimes for energy to be returned during different periods with no net transfer of monies. 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 interconnectors 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 on the basis of the impact on its users' income.

Given the long-term nature of the investment it is necessary to take account of the expansion plans of each 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 necessary to test the benefit within a range of probable operating conditions.

Optional Infrastructure

Where an active transmission constraint exists then the benefit of reinforcement can be estimated from operational simulation studies with increasing levels of reinforcement. Usually constraints will only become active, in practice, following a contingency. It is also necessary to take account of alternative strategies like post-incident generator intertripping which can be used to offset the impact of the constraint and reduce the effect on operating costs.

To establish the incremental worth of new transmission infrastructure investment it is necessary to simulate operation with changing levels of investment. The production model described 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 cause an increase in production costs when the network is depleted. Whereas in the past generation and transmission outages were coordinated to minimise costs this is now much more difficult and random and needs to be modelled.

It is also necessary 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 lose 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.

Conclusions

The discussion has shown that different considerations apply to the apportionment of costs for an existing system as opposed to the apportionment of increased current operating costs due to congestion on the day. The new players have had no say in historic decisions whereas new investment needs to be sponsored by the principal beneficiaries to ameliorate current operating constraints. New investment needs to be based on the incremental benefit function to ensure that the optimal level of investment is established. The approach to the apportionment of existing costs should be based on current levels of utilisation with any shortfalls in revenue managed as stranded assets.

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 was suggested that zonal transmission pricing or a long-term incentive scheme with the transmitter is a necessary condition to create the correct cost messages to encourage optimal investment. Finally the techniques for assessing 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 SEVENTEEN

Interconnection Evaluation

The development of the use of interconnectors has traditionally been managed by bilateral agreements between the adjacent participating utilities. The arrangements would cover daily opportunity energy trading to take account of peak diversity or longer-term trading based on seasonal differences. There would sometimes be a net transfer but often a restitution agreement would apply with energy being exported in one period and imported in another resulting in a net balance. The benefits derived from the interchange would be shared. In the new deregulated environment interconnection capacity is a commodity available for individual market players to contract for its use. This chapter discusses how a generator may evaluate wheeling opportunities between two systems when it has investment interests or opportunities 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. It would apply equally to the analysis of trading between zones of a system with different energy prices as will apply in the US, Australasia and parts of Europe. 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 can be established. The transmission company or interconnector owner can then assess its optimum price to realise maximum profit. Finally the reaction of consumers to price changes is taken into account. It is proposed that most interconnector investment and contract decisions will be made against medium-term contracts rather than the daily spot market which will support opportunity trading.

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 determining 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

$$P = Ae^{BD} \tag{17.1}$$

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

$$H_{(D)} = \frac{K}{C\sqrt{2\pi}} \exp\left(\frac{-(D/s - m_o)^2}{2C^2}\right) \tag{17.2}$$

where H is the number of hours in the year for which a particular demand band exists; K is a constant; and 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.

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

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.

$$C_t = \sum_{D=\min}^{D_t} P_t \tag{17.4}$$

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

$$C_t = \sum_{t=0}^{t=8760} C_t D_t H_t \tag{17.5}$$

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). and assuming that a competitive market is in operation. The resulting functions are shown in Figure 17.1 for the system characteristics used in Chapter 13. It can be seen that they are substantially linear over the range analysed and a regression fit can be made giving equations of the form.

$$P = Ap + Bp \times I \tag{17.6}$$

and

$$C = Ac + Bc \times I \tag{17.7}$$

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

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 p.u. of the total capacity and is in a position to negotiate supply contracts with consumers in both systems so that

$$\sum G_i^A + G_i^B = \sum D_i^A + D_i^B \tag{17.8}$$

The gross profit for generator I, F_i 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.

$$F_i = D_i^A \cdot P^A + D_i^B \cdot P^B - G_i^A \cdot C^A - G_i^B \cdot C_B \tag{17.9}$$

substituting for P , C and D and rearranging we get equation 17.10 where I is expressed in GW and is converted to p.u. of the total capacity in this example by dividing by 50 GW:

$$F_i = (A_p - A_c)(G_i^A + G_i^B) + I(B_p - B_c)(G_i^A - G_i^B) - 2\ I^2 B_p \text{ £M} \tag{17.10}$$

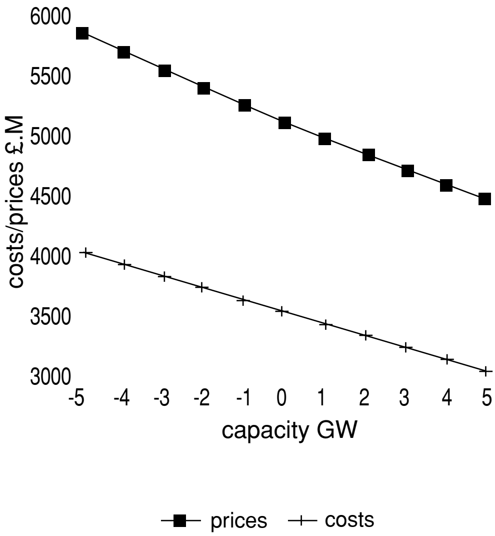

Figure 17.1 Change in consumer prices and generator costs with capacity charges (twosys).

This can be differentiated with respect to the transfer to obtain the maximum and equated to zero to get:-

$$I^{\mathrm{opt}} = (B_p – B_c)(G_i^A – G_i^B)/4B_p \text{ GW} \tag{17.11}$$

or with the inclusion of a cost for transmission :

$$I^{\mathrm{opt}} = [(B_p – B_c)(G_i^A – G_i^B) - C_i]/4B_p \tag{17.12}$$

Example

Using the above theory and the data from the preceding section, an example has been calculated to illustrate the effects. Given a particular generating company having 30% of the capacity in system A and 10% of the capacity in system B 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 and shown in Figure 17.1 and substituting in the above equations Figure 17.2 is derived where the optimum transfer for this generator is 0.77 GW between the two

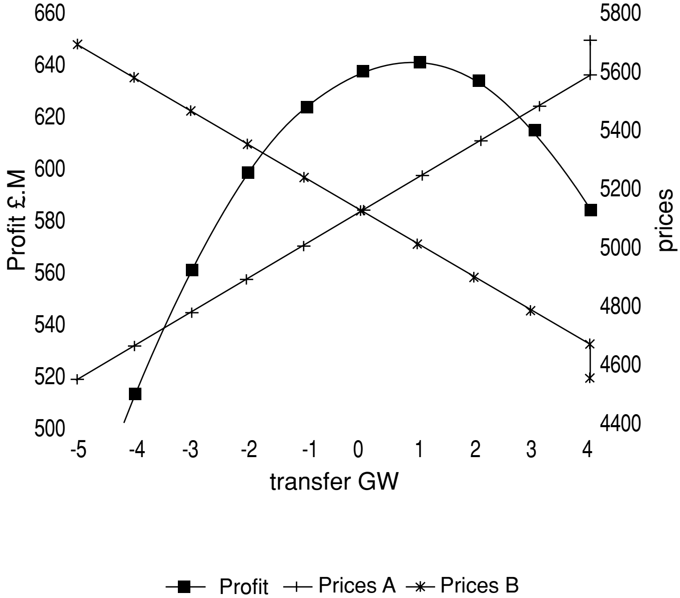

Figure 17.2 Optimal wheel generation; 30% system *A*, 10% system *B*.

systems. It shows how changing the transfer affects the total prices in each of the two systems. It can be seen that transfer from system *A* to *B* raises the prices in the system where the generator has most of its 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 in this example is £3.35 M and if we include a transmission charge of £1.5 M/GW/year then it can be calculated that the profit reduces to £2.3 M with a transfer of 0.638 GW. The profit function and the impact on consumers prices are also 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 in each system.

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. If one utility has overcapacity it is obviously attractive to strike supply agreements in an adjacent utility, which would have the effect of raising prices in the exporting pool and depressing them in the importing pool. The attraction of buying into an

REC in the adjacent pool is that it has an established supply business which can be contracted to the exporting generator.

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. It has been shown previously how a generator may react to the price of transmission according to the function

$$I_{\text{opt}} = \frac{[(B_p - B_c)(G_i^A - G_i^B) - C_i]}{4B_p} \tag{17.13}$$

we can simplify this to

$$I_{\text{opt}} = (K–C_i)/4 \cdot B_p \quad \text{where } K = (B_p–B_c)(G_i^A–G_i^B) \tag{17.14}$$

substituting for I in the profit function F we get

$$F_t = (C_i–S_i)(K–C_i) \tag{17.15}$$

This can be rearranged and differentiated with respect to the cost of transmission to obtain the maximum:

$$\frac{\delta F_t}{\delta C_i} = \frac{(K + S)}{4B_p} - \frac{2C_i}{4B_p} \tag{17.16}$$

This can be equated to zero to find that price for transmission which will obtain most revenue, i.e. 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. This maximum revenue transfer is somewhat less than the generator's optimum transfer of 0.77 GW when transmission was assumed at zero cost. Figure 17.3 shows the reaction of the generator in changing its transfer to transmission price increases and how this affects the the profit for the transmitter.

It can be seen how a transmitter can assess the worth of interconnection to a generator and the likely impact of its charges on the benefit to the generator from the transfer. There is an optimal price which maximises the profit to the transmitter and occurs at a transfer less than the ideal maximum for the generator. In this circumstance the benefit is shared through a process that results in the transmitter's price with profit equating to the worth to the generator. It is less clear how consumers could effectively participate prior

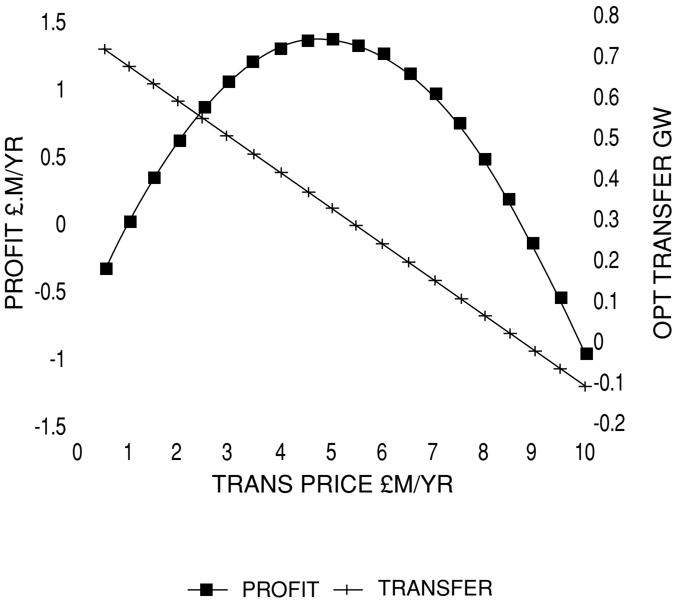

Figure 17.3 Generator optimum transfer and transmitter profit against cost.

to 1998 when the franchise of local RECs was completely removed and suppliers became able to trade on their own behalf across interconnectors to counteract system price movement.

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 trading 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 and effectively exporting generation. The generation assigned to area A, *Ga*, will be some function of the installed generation *Gi* with the transfer being the difference, i.e.

$$G_a = G_i \pm I \tag{17.17}$$

The price in each zone is now determined by 'G_a' rather than the installed generation. In the previous example the individual generator had the option to contract with a proportion of the consumers in each zone. However, if it is assumed that the independent variable is the assigned generation then it can be shown that in theory prices and profits can be continually driven up, i.e. 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 generation margin for export whilst continuing to meet demand and competitor and consumer reaction to prices.

Consumer Reaction

If consumers have the option to strike supply agreements with generators in either system they will be able to counteract the price rises in system A by trading with generators in system B. If their demand sensitivity to a price change is given by the constant r so that :-

$$D_A^A = D_A(1-\delta p_A r_A);\ D_A^B = D^B(1-\delta p_A r_A) \tag{17.18}$$

and

$$D_A^A = D^A(1-B_p I r^A);\ D_A^B = D^B(1+B_p I r^B) \tag{17.19}$$

Since the slope of the price function is given by $B_p \times I$ and since the change in price is given by the slope of the price function, a new profit function can be established :-

$$F = D^A(1-r^A BI)\ (A_p-A_c+B_pI-B_cI)+D^B(1+r^B B_pI) \\ (A_p-A_c-B_pI+B_cI) \tag{17.20}$$

which rearranges to

$$F = (D^A+D^B)(A_p-A_c)+\mathrm{I}[D^A(B_p-B_c-r^A A_p+r^A B_p A_c)+ \\ D^B(-B_p+B_c+r^B A_p B_p-r^B B_p A_c+I^2[D^A(-r^A B_p^2+r^A B_p B_c)+ \\ D^B(-r^B B_p^2+r^B B_p B_c)] \tag{17.21}$$

This enables an assessment of the impact of consumer demand sensitivity on the optimal transfer and is shown graphically in Figure 17.4. In this example the response is assumed to be the same in both systems. 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 any attempts by the generators to raise local prices through external supply agreements are balanced by customers reducing demand in response to price or seeking supply agreements in the

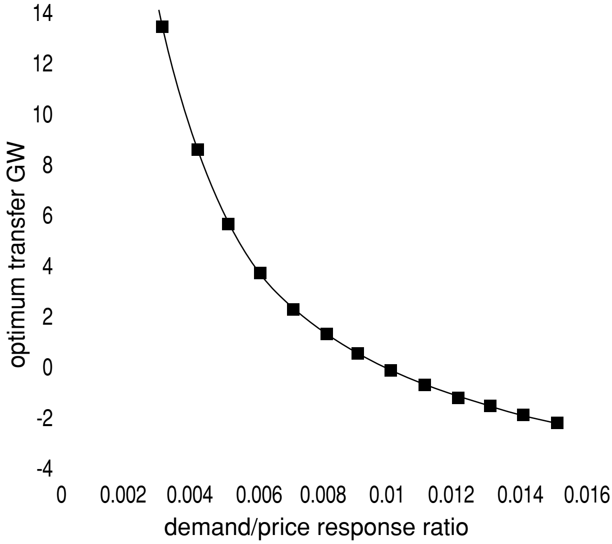

Figure 17.4 Customer response to price; wheeling from 40 GW to 20 GW system.

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 this option. The same consumer option needs to be available across interconnectors.

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 a generator with investments across two systems could affect its profit by striking supply agreements that favourably affect the marginal prices in the two systems in which it 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 a relatively small reaction to price affects the optimal transfer. This illustrates in a deregulated market the importance of consumer participation to offset price manipulation. There appears no reason why interconnection should not be traded as a commodity and be financed by joint venture agreements. To enable consumers to react it is important that their suppliers are also able to buy energy from remote generators across the link to exert a balancing influence.

CHAPTER EIGHTEEN

Managing Constraints

The minimum transmission requirement is that which enables connection of generation to the system and enables it to be coupled to the local load. With this arrangement the generation output is fully assigned to the local load and its output has to be varied to track the demand changes. Further interconnection of generation and demand to enable pooling can be defined as infrastructure development and the level of investment is influenced primarily by generation location and the need to maintain system security. In an integrated utility planning standards were often used which defined the security to be provided against planned and forced outages. They defined the level of demand to be met following outages which varied with the size of the importing group. This approach did not remove all constraints nor would it have been cost-effective to do so and at certain times of the year merit order operation of generation could be expected to be restricted. In an integrated utility the constraints are identified and generation is scheduled and dispatched to avoid their infringement. Post-privatisation market mechanisms have to be established to manage congestion on the network and to create incentives for the transmitter to minimise the impact of these transmission constraints on the cost of production on the day by improvements in operating practices.

Three approaches have been used or proposed-

1. Post Market Settlement
   The market prices are set initially ignoring transmission constraints, then the additional costs incurred in practice are added to the pool selling price and shared by all users. The transmitter may be incentivised to minimise the so-called ‘uplift costs’. This is the approach adopted in the England and Wales model.

2. Market Settlement
   With this arrangement the constraints are modelled in the price-setting algorithms or mechanisms, resulting in different clearing prices for energy in the different zones of the network, i.e. zonal pricing. In exporting zones the price is reduced to cut back generation and in importing zones it increases to encourage more generation or less demand until the flow falls within the capacity of transmission. This is the approach adopted in the Nordpool model.

3. Arbitrage Price Settlement
   With this scheme the use of the limiting transmission route is apportioned to users and charged for explicitly with the price adjusted to balance demand to available capacity. Congestion management in some form will be required down to the event to take account of changing circumstances and may be based on schedule bidding. This approach has been proposed in the US.

Constraint Costs

If the optimal use of generation is restricted by an active transmission constraint then the increase in costs is defined as the constraint 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 often be the result of other local circuit outages and will then be influenced by the return to service times. The approach of integrated utilities to assessing the increase in costs is to undertake scheduling studies with and without the active constraint. To avoid the complication of a full network model in the scheduling algorithm the constraints may be modelled by group transfer limits. With this approach the network is separately analysed to identify groups of generators and their associated demand which fall within natural zones. The transfer capability between zones is then calculated to fix the group import and export limits. The effect of the constraint is to force out of merit generation on in import constrained zones and to force merit generation off in export limited zones, i.e. for an export limited zone

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

and for an import limited zone

$$D_B - \sum_{i}^{n} G^B \ngtr I^B \tag{18.2}$$

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

Since deregulation generators have been 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 estimation of this commercial behaviour and the use of assessments based on cost.

Where market mechanisms are used to manage the constraint flows, by buying and selling energy in the interconnected zones, then the cost of the constraint is explicitly the cost of the market intervention. Where transmission itself has increased the price to reduce the flow to the capacity then the price of arbitrage between generation and transmission is realised for the particular route. This would signal the potential for new investment to the transmitter.

Post-Market Settlement – Uplift Definition

In the England and Wales approach the impact, of all constraints on operating costs are lumped into what is called uplift which is defined as the difference between the outturn costs and the idealised costs assuming an infinite transmission system. They include the cost of the constraints as well as extra costs due to generation shortfalls and demand prediction errors. Ancillary service costs to enable management of voltage and frequency are also included. The uplift U is given by

$$U = \mathrm{TCA} – \mathrm{TCW} \tag{18.3}$$

where the Total Cost Actually incurred TCA is given by

$$\mathrm{TCA} = \sum_{1}^{n} (G_i^A \cdot P_i^W + (G_i^A - G_i^W) \cdot P_i^o + \mathrm{NLC}_i \cdot Y_i^A + \mathrm{SUC}^i \cdot N_i^A \tag{18.4}$$

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

$$\mathrm{TCW} = \sum_{1}^{n} (G_i^W \cdot P_i^W + \mathrm{NLC}_i \cdot T_i^W + \mathrm{SUC}_i \cdot N_i^W \tag{18.5}$$

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

$$\mathrm{OO} = \mathrm{TCA} - \mathrm{TCW} + (W - A) \cdot \mathrm{PPP} \tag{18.6}$$

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'.

Commercial Arrangements

The effect of transmission constraints is to produce different zonal energy prices and there are at least two approaches to their derivation using either outturn ex-post prices or predictive ex-ante pricing. Ex-post prices are based on the actual outturn of a dispatch solution including transmission constraints undertaken near to the event. As the exact prices are not known until after the event consumer response is limited. 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 approach of managing constraints by varying the price for use of the transmission is close to that of ex-ante pricing and is likely to give a result closest to outturn. There is, however, a potential risk to system security by making short-term changes which undermine the capability to maintain plans.

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. In practice constraints and generation shortfalls will result in extra generation being forced on in the event, which is paid at offer price, and constrained off generation, which is paid at lost profit. These additional costs are included in what is termed uplift and the transmission company may be incentivised to manage them on behalf of consumers. There is no advanced notice of prices and the consumers ability to respond by reducing demand is very limited. This is the model that has been applied in England & Wales.

Based on the uplift costs in previous years the suppliers pay the transmitter an annual payment to manage and pay uplift costs into the pool. The savings or extra costs resulting from the outturn, which may be more or less than the expected value, are shared. The transmission company then has the option to pay outturn prices to generators or to hedge its position by contracting with those within 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 to the transmitter is to take post-incident automatic or manual action to alleviate the constraint by tripping generation in export constrained groups or redispatching import constrained generators. The incentive scheme applied to date in England and Wales has only covered one year ahead and does not therefore provide a long-term income to provide a basis for independent investment by the transmitter.

The third approach is to intervene in the market by buying and selling energy in the market to effect a new zonal balance where constraints are not violated. In the Nordpool model notice is provided a week ahead if network bottlenecks are likely to be a problem and each participant is advised of their bid area. If in the event interarea flows look like exceeding capacity then the operator will adjust the price and balance point between sell and purchase offers in each area to establish a new balance point as shown in Figure 18.1. This process is repeated in each area, reducing prices in exporting areas with a surplus of generation to increase the local demand take, and increasing them in importing areas to reduce demand until the net imbalance is such that flow is contained to capacity. Market participants bear the cost through a capacity fee in a spot market settlement.

Transaction Model

The exact type of model will depend on the method chosen to manage constraints but the following serves to illustrate the interaction of the various players through the market. The transactions between the various players are shown schematically in Figure 18.2. 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 transmission services or managing uplift. The incentivised 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 its 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 the 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.

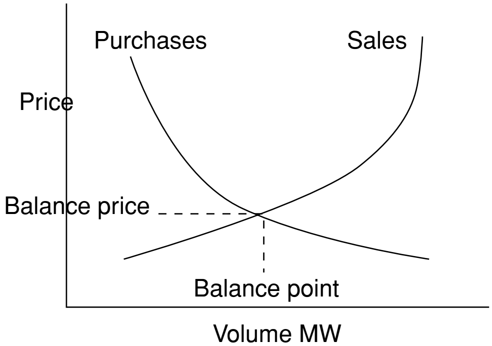

Figure 18.1 Zonal balance.

Theoretical Formulation

The generation is assumed to be made up of a potentially constrained part G^c and unconstrained part G^u 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. The profits can be estimated for each player and for the transmitter both with and without hedging contracts

No Contracts

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

$$P_g = (G^u+G^c)\ P_o^u + G^c\ (P_o^c - P_o^u) - G^u C^u - G^c C^c \tag{18.7}$$

The suppliers profit P_s 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.

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

The consumer demand D is itself a function of the tariff T

$$D = D_o(1 - \delta T \cdot r) \tag{18.9}$$

where r represents the p.u. change in demand for a change in the tariff, i.e. The demand price elasticity.

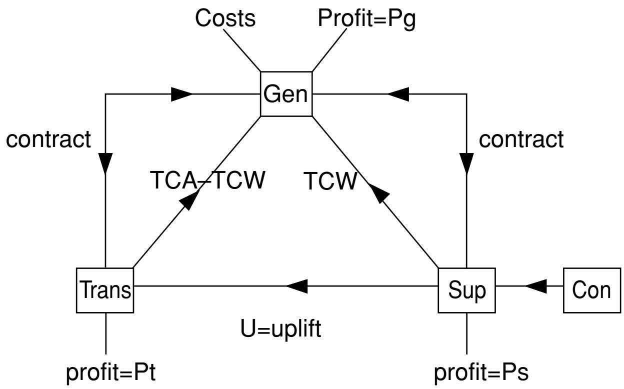

Figure 18.2 Transaction model.

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

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

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. Subsequently suppliers will react and tariffs will be increased and demand will reduce as shown in Figure 18.3

It can be seen that the transmitter's profit from uplift management 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.

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 G_t at a price P_t then the generators' profit becomes

$$P_g = (G^u + G^c)\,P_o^u + (G^c - G^t)\,(P_o^c - P_o^u) + G^t(P^t - P^u) - G^uC^u - G^cC^c \tag{18.11}$$

and the transmitters profit

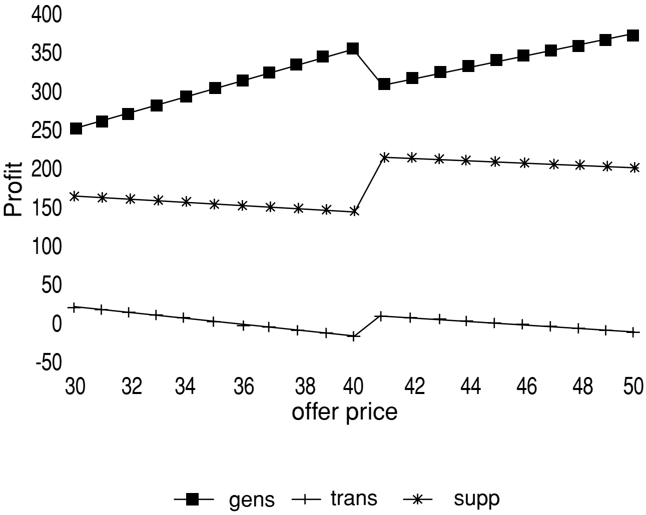

Figure 18.3 Constrained market interaction; $\alpha = 0.6$.

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

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 18.4. 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 is counter productive.

Modelling in Operation

The role of system operation has always been to minimise the cost of production while avoiding insecurities and the development of market operation has added new emphasis to this and the need to model it to take account of the complications introduced by privatisation.

Studies are necessary to plan outages for the 2–6 week period and beyond and this now requires predictions of prices and availability. For longer lead times DC network models can be used with a single time-step dispatch. Since many of the network constraints will be voltage or stability related this is of limited accuracy and more accurate modelling can 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.

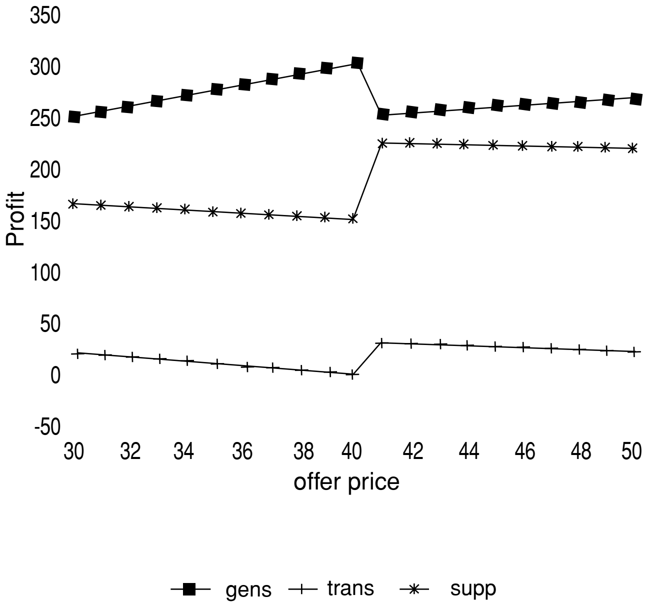

Figure 18.4 Constrained market interaction; α = 0.6 with contracts.

$$\partial \text{losses} = \sum_i^n I_t^2 X_t - \sum_i^n I_{t+1}^2 X_i \tag{18.13}$$

If this is large it gives an indication of where voltage problems may result. These outages could then be evaluated by a full AC optimal power flow and if necessary an optimal dispatch would be computed to ameliorate any constraint violation. It is also necessary 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.

At the day ahead stage the cost of constraints can be predicted using scheduling studies with constraints, generation availability and prices explicitly represented and some outages may be moved or cancelled to minimise costs. In the dispatch phase the active constraints can be directly monitored and their costs calculated and displayed by summating the out of merit running costs of the generation within each group. Whichever method of managing constraints is chosen the Grid Operator will need to be given the plant flexibility and incentives to minimise outturn costs and maintain security. The balance between the two will also need to be defined and this may prove difficult in practice.

Conclusion

In this chapter an approach to the management of constraints through market mechanisms has been described using three different approaches:

- where constraints are ignored and the transmitter is incentivised to minimise the outturn costs
- where market mechanisms are used to influence the prices in each area and establish a new balance
- where transmission pricing is used to constrain flows

An advantage of the first arrangement is that the market dealings are managed a day ahead and on the day the system operator is left to manage the network and maintain security. The current England and Wales market mechanism does not, however, 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 necessary to provide the income stream to support investment but in the absence of a knowledge of the worth of investment other players can be expected to resist this approach. The alternative of zonal energy pricing, on the other hand, points up the benefits of investment to the players directly affected by the constraints but at the cost of introducing additional complexity. The use of transmission pricing adjustments in the short term to manage congestion is likely to put system security in jeopardy. It will undermine the ability to plan operation, which in the past has been the key to maintaining security on the day.

The ideal arrangement would be one that encourages the optimal level of investment in order to minimise the overall production cost. It is difficult to see how the above mechanisms will realise this in the absence of a joint authority. The current incentive schemes adopted in England and Wales only cover one year and do not span investment time-scales. Both in the US and UK the concept of transmission user groups has been introduced but it remains to be seen whether they can operate in the common interest. In practice there will be winners and losers from new investment and some generators may oppose new lines as has occurred in the UK.

CHAPTER NINETEEN

Optimal Investment and Outage Planning

This chapter describes an approach to establishing the benefit of an increment in transmission infrastructure capacity in reducing the overall system operating cost. Whatever commercial arrangement is in place it is in all participants' interests that real operating costs are minimised. The problem is made difficult because of the wide range of system conditions that may prevail, against which the assessment should be made. In many instances transmission constraints only become active as a result of outages. The problem is addressed by simulating operation over one year to assess the change in operating costs while taking account of the varying generation prices and the changing availability of transmission. A parallel interdependent objective is to establish the optimal periods through the year when transmission lines should be taken out of service for essential maintenance in order to minimise additional generation market costs. Where the generation is within a zone where generation exceeds demand then in merit generation may be constrained off by an export limit and have to be replaced by more expensive generation. This may result in different zonal energy prices as apply in Norway, Australia and California or the generator may be paid constrained off, lost opportunity profit, at the difference between SMP and bid as applies in England and Wales. Conversely where the demand in the zone exceeds generation then units out of merit may be forced on because of active import limits. The generator may be paid constrained on payments at bid price as applies in England and Wales or no payment as applies in Norway. Irrespective of the commercial arrangements in place the transmitter should seek to minimise the increase in operating costs due to network restrictions through the management of maintenance outages. Taking account of the variation in these costs over 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 also indicate the true benefit of an increment in transmission capacity.

Modelling

The simulation needs to model the generation loading process as well as the transmission constraints which would be derived from off-line network analysis studies. In the New Zealand market individual nodal energy pricing is applied whereas in Norway, California and Australia zonal pricing is applied where generators in a tightly coupled electrical part of the system are grouped together and have a common marginal price for energy.

For the import constraints I the limits apply to the difference between the zonal demand and generation, and for export constraints E to the difference between generation and demand, i.e.

$$D^A - \sum_{1}^{n} G_i^A \leq I_L^A \tag{19.1}$$

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

$$\sum_{1}^{n} G_i^A - D_A \leq E^A \tag{19.2}$$

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.

Loading Programme

The procedure for loading generation in a transmission constrained study has to ensure that generation is used in merit without violating export constraints, when it would be recorded as constrained off. In importing zones the generation will be used in merit but if this results in an import limit being violated then generation within the zone will be forced out of merit.

The procedure will need to establish the SMP first from an unconstrained run. It will then be necessary to satisfy import constraints and finally export limits. 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.

The Cost Function

Using a 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 is shown in Figure 19.1 for variation in a main constraint limit (1) with two nested subconstraints (1, 2). In this example there is a constraint nested within a constraint. The limits for the nested subconstraints are left unchanged and only the main constraint limit is varied. It can be seen that to satisfy very low import levels the uplift cost tends to a maximum limit when all the available generation in the zone is in service, i.e. the lower active limit occurs when :-

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

where G_n 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 cost 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, i.e.

$$L1^{\text{high}} + G_1^{\text{MO}} + G_2 + G_3^{\text{MO}} \geq D_1 \tag{19.4}$$

The constraint will normally be in the range from inactive to active and a regression fit to this part of the curve showed that the best fit was obtained with a power function of the form:-

$$U_i = A_i L^{B_i} \tag{19.5}$$

where U is the increase in cost or 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

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

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

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

By using the model an uplift cost function can be derived for each constraint for each period of the year. The shape of each 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 England and Wales generation. Other functions may be more appropriate for other types of generation with different cost curves.

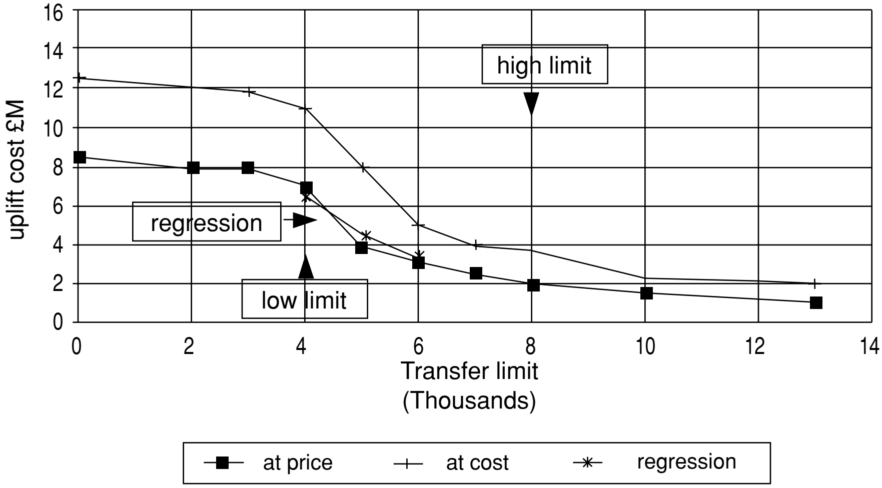

Figure 19.1 Transmission constraint cost function, 1989–90. Flow south weeks 1–4.

Derivation of Optimal Outage Pattern

Transmission outages will be required throughout the year to enable maintenance work and these will often cause a constraint to become active. The objective is to minimise the total increase in costs or uplift resulting from these across all periods, i.e. minimise:

$$U^T = \sum_1^n (U_1 + U_2 + U_3 \ldots U_n) \tag{19.8}$$

where

$$U_i = A_i L_i^{B_i} \tag{19.9}$$

subject to meeting the requirement for outages defined in this example as:

$$\sum_1^n (L_1 + L_2 + L_3 \ldots + L_n) = K \tag{19.10}$$

The Lagrangian function can be written as

$$Z = f(L_1)+f(L_2) \ldots + \lambda(K–L_1–L_2 \ldots) \tag{19.11}$$

which can be differentiated with respect to λ and L to obtain the minimum. Similar functions can be derived for all 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 λ. The problem then reduces to that of finding that value of λ for all periods which fixes the limits in each period so that the total availability throughout the year meets the target and allows for the necessary 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.

Given a set of cost functions calculated for each period derived using a constrained operational model an iterative procedure can be used to find the value of λ that realises the required outages for the period and minimises cost. Good convergence was obtained when λ was updated using a function of the error from target as a proportion of the target.

It is now possible to analyse the combined problem of minimising the cost of taking outages which in turn will minimise uplift in generation costs due to constraints. The results of the analysis give a realistic estimate of the incremental worth of additional transmission capacity across key boundaries in that critical outages are explicitly modelled. The period of study may cover several years giving a long run marginal cost suitable for appraising investment. The incremental cost function based on regression will be less subject to the discontinuities inherent in the selection of integer generators that arise with single studies. The problem is made tractable by effectively decoupling it into three parts: generation scheduling studies to establish the cost function associated with limits, outage simulation to establish the optimal limit profile, and full network studies to identify limits.

Example

The first simple example demonstrates the principle using a full system simulation covering just two monthly periods. In this example the target availability for the two monthly periods is 10 GW with a maximum for each constraint of 6.0 GW. It can be seen that in this example the target is met when the availabilities in the two months are $T_1 = 4.5$ GW and $T_2 = 5.5$ GW, where $A_1 = 75.79$; $B_1 = -1.77$, $A_2 = 76.79$ and $B_2 = -1.295$.

Figure 19.2 shows the total uplift costs on the y-axis for differing values of T_1 along the x axis where T_2 takes a residual value (i.e.$10-T_1$) to meet the target of 10. It can be seen that the cost is minimum when $T_1 = 4.5$ GW (and $T_2 = 10-4.5$, i.e. 5.5 GW) confirming the theoretical approach.

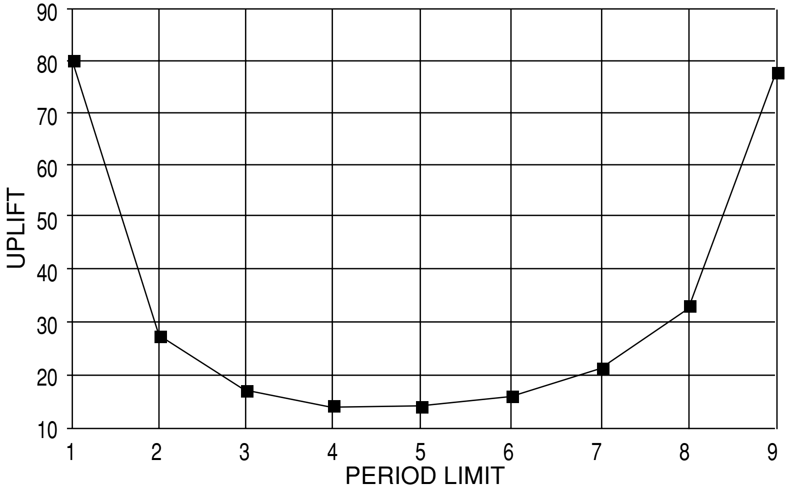

Figure 19.2 Constraint uplift for varying period; two-monthly periods, 1989–90.

Full Year Assessment

The above approach can be applied to a full year with a separate function for uplift cost against varying constraint limit being derived for each month. By feeding the function parameters into an optimisation routine the least cost outage program can be derived for the year. In this example it was assumed that 12 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 and the target was to realise an accumulated total of 60 GW months for the year, i.e. each line was required to be out for one month. The value of λ meeting this requirement was found to be -1.504 after seven iterations. This also gives the best estimate of the incremental benefit of additional transmission capacity.

Figure 19.3 shows the constraint limits for each month that realised an equal incremental cost function and indicates in which month the outages may be best placed. It can be seen that the pattern of outages is somewhat random reflecting the pattern of generator outages and the in merit generation. It is not necessarily correlated with demand level as at some high load levels more in merit generation may be on in the constrained zone and the impact of outages would be less. For practical use the solution would need to be rounded to the nearest integer value consistent with a discrete number of lines.

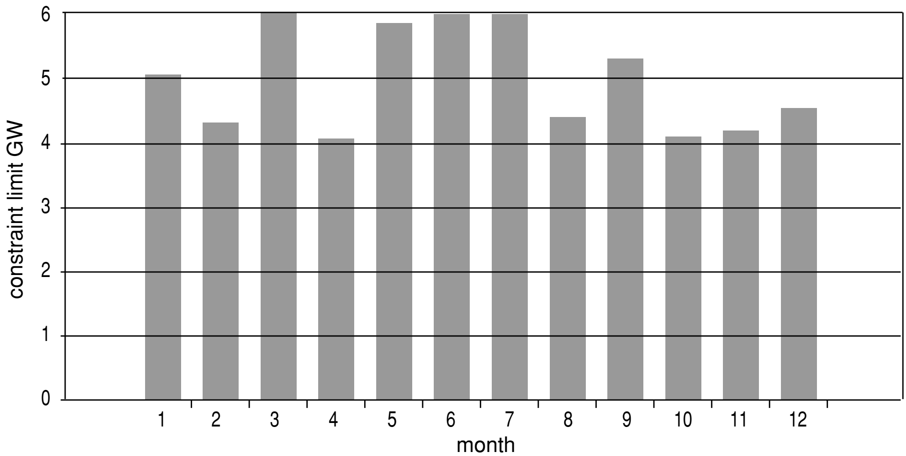

Figure 19.3 Optimal transmission outage pattern. 12 months 1989-90, target 60 out of 72.

Investment Evaluation

Cost 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 incremental 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 £18 M/year for an extra GW of capacity in this example. 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 £18 M in this case. Since the cost function is non-linear it would be necessary 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.

Losses

As well as savings in transmission constraints any new lines 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 criterion with 10 similar lines in service, each line carried $I = 0.5$ GW. Given a line resistance of r then the total losses and the change may be calculated.

In this case the reduction is in the ratio of 10/12 and given a typical resistance of 0.6 on a 100 MVA base and an average energy price of £25/MWh the annual saving would be of the order of £0.3 M which is small in relation to the cost of active constraints.

Commercial Arrangements

In market operation the impact of constraints on operating costs can be signalled through one of three ways:

- full nodal pricing of energy as applies in New Zealand where every node could in theory have a different price
- zonal energy pricing as applies in Norway, California and Australia where parts of the system will from time to time be identified as being in a constrained zone
- uniform energy pricing with the increase in costs due to transmission constraints shared by all energy users after the event as applies in England and Wales

The first two approaches signal the impact of constraints directly to those affected by them and are most likely to encourage investment. The problem is that those generators receiving constrained on payments may lose income if the constraint is removed, and might oppose the development. The transmitter would also lose the opportunity to make money from managing constraints. Only consumers and suppliers would benefit but are not in a position to directly initiate the development.

The England and Wales approach is to assume that transmission decisions were not made by the new generating companies but inherited and as such their cost is most equitably shared by all consumers – but who will sponsor investment? One option is to establish a long-term incentive scheme for the transmitter to encourage cost-effective investment. All interested parties would need to be involved in the decision through a user group and the benefits would need to be shared, recognising the losers from the investment. That proportion due to the transmitter should result in a benefit function consistent with LRMC but any assessment would need to be based on realistic cost data and not artificially inflated prices.

Having decided that an investment in increased capacity across a boundary is worthwhile, we need to translate this into a new physical line or a line 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 can be used but for larger ones the use of genetic programming and simulated annealing may be more appropriate. (Romero, 1996).

Conclusion

This Chapter has established an approach to making realistic assessments of the worth of an increment in transmission investment taking account of outages. It has been shown how a function can be derived of transmission constraint uplift costs 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 constraint cost functions are equal. The technique was used in an example to demonstrate the principle and the optimal value for a particular year was derived. It is proposed that the resulting value of λ provides the best estimate of the worth of an increment in infrastructure transmission capacity. Finally the benefit of reduced losses is discussed and the overall commercial arrangements to establish funding through a joint agreement with all players who stand to gain or lose.

Part 2 of this book has reviewed international practice in charging for transmission services and their shortcomings in encouraging the optimal level of investment. A distinction is drawn between recovery of historic costs through use of system charges and the recovery of additional operating costs due to constraints. Alternative methods of apportioning the operating costs are advocated which take account of the benefit derived by the market players. An approach has been developed to assess the worth of transmission infrastructure and interconnection and to establish the optimal prices and levels of investment. The increased 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 England and Wales market structure will meet all the requirements identified in Chapter 15.

- open transmission access is provided but it is biased with discriminatory location charges
- there is no obvious mechanism to encourage the optimum levels of investment
- there is a mechanism to encourage efficient real time operation but no incentive to optimise the medium-term outage plan

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

Other countries believe that an energy market based on zonal or nodal SMPs would 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. Which beneficiaries would act as sponsors would also be clear and the additional charges resulting from zonal energy prices would be used to reduce overall use of system charges or fund new investment. A potential problem is that this approach could lead to fragmentation of ownership of transmission, storing up administrative problems for the future. The alternative approach being pursued by EdF and ENEL of a single buyer model enables integrated planning and avoids these issues.

It is considered that on balance single ownership and accountability for development is preferred with some arrangement to strike agreements involving all interested parties. 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 et al, 1996). This would address some of the perceived shortcomings by ensuring fair governance, open access and joint planning. In England and Wales 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 reach agreements and find willing owners for transmission.

PART FOUR

The Impact on Utility Operations

Part 4 examines the impact on the utilities and how they need to adjust to survive in the post-deregulated environment. It discusses how to manage commercial operation while keeping the lights on and how to reduce the costs of the process through automation. The utility cost base and the prospective savings through mergers and takeovers are identified. A new approach to planning for uncertainty is developed and it is shown how to provide flexibility and the ability to respond to market needs. Developments in asset management and charging for services are described together with the establishment of a commercial framework to meet the needs of the business. The development of an IT infrastructure is described and the stringent requirements for auditability accuracy and security in the post deregulated environment are outlined.

CHAPTER TWENTY

Impact on System Operation

Many observers believed that the introduction of market operation into electricity supply would endanger the security of the system and cause power failures and there have been some incidents in the US alleged to have been aggravated by unconstrained trading. In England and Wales this has not happened in large measure owing to the work in re-engineering the operational processes to assimilate the new ways of working without losing sight of the prime objective of keeping the lights on.

This chapter discusses the impact of privatisation on the process of system operation to identify the changes that need to be engineered by those utilities embarking on deregulation in order to maintain the security of the system whilst facilitating the market. The behaviour of a power system is governed by the laws of physics and there are certain basic functions that have to be performed irrespective of the structure of the market. There is a requirement to balance supply and demand at all times to maintain system frequency and the generation and absorption of reactive power must also be kept in balance to maintain voltage levels. What changes, however, is the mechanics by which these fundamental requirements are met and the apportionment of responsibilities. There is also the additional requirement to facilitate market operation from bidding through call-off to settlement. In England and Wales it was decided that the day to day running of the market would be superimposed on the role of the system operator because of the synergy with its normal role and that the control centre would always be available to receive data. After-the-event settlement was established as a separate business activity. In the US and elsewhere an Independent System Operator (ISO) is preferred with a separate unit managing Power Exchange (PX). In either case the market process must be designed to ensure that the physical requirements of the system can be met along with facilitating the market. This means providing the Grid Operator with control over the physical inputs to the system in sufficient time before the event to plan and exercise control.

Keeping the Lights On

Operational Planning

The key to avoiding difficulties in real time operation is to maintain an effective operational planning process that enables most of the problems to be anticipated in a time frame that permits ameliorating action. The immediacy of the response of the power system is such as to be unforgiving to error or omission in the event. Prior to privatisation the programme of generation and transmission outages for maintenance was firmed up well in advance of the event. Since privatisation market, players have been reluctant to freeze their options and the process is subject to many more short-term changes. A number of factors have interacted to complicate the process post-privatisation:

- there is no fixed merit order against which to plan future generation operation since prices are now the subject of daily bids
- there is no requirement to coordinate generation and transmission outages and generators may alter plans unilaterally
- new generation has been less than ideally sited and this has exacerbated transmission constraints
- the notice to close generation may be very short and at best six months
- increased power transfers have led to the need for more system reactive and active power compensation equipment which complicates system operation

These developments have generally made it much more difficult to plan operations effectively and a great deal of activity is necessary in the short term to establish viable system running arrangements. It is also more difficult to optimally plan the outages of generation and transmission required for maintenance and this may explain some of the volatility seen in prices.

Demand Prediction

Accurate predictions of demand are the starting point for secure operation. Traditionally techniques have relied heavily on stored data for similar periods going back several years. One impact of privatisation has been the consumer response to very high peak demand prices resulting in lopping the peak and improving the overall load factor. The peak is also a key determinant in scheduling generation and as consumer response develops its effect will need to be modelled in the prediction process. The difficulty is that as the expected peak price is not known in advance it is not possible to estimate the peak and some judgement is required.

There is also a need to model the effects of demand side bidding where the consumers choose to reduce load in response to high prices. It is important that data banks are retained which reflect the inherent consumer demand and this will become increasingly difficult as supply competition increases the use of demand management. A more complex modelling approach will be necessary which is able to simulate the effect of consumer response.

Unit Commitment

The process of organising the commitment of generation has to take place irrespective of the market arrangements. What will be different is who is responsible. In some implementations the generators may self-commit and dispatch, in others they may only self-commit or the total process may be managed by the Grid Operator.

In the England and Wales model the process is managed by NGC who are required to demonstrate that their studies are based on the data as submitted by the generators the day ahead with no room for error in handling data. Prior to privatisation the generation pattern was relatively stable and only changed as fuel price differentials changed. Since privatisation the generators choose their price for commercial reasons and this alters the pattern of generation from day to day. It is therefore necessary following the receipt of bids to analyse the network to establish a viable system and derive any transmission constraints necessary for inclusion in the scheduling study prior to undertaking the main operational study as shown in Figure 20.1.

It is quite usual for scheduling algorithms to distinguish between different types of generation and to treat them differently, e.g. peaking units and pumped storage would be assigned specific roles for shaving peaks and troughs. In a competitive market this is unacceptable and the process has to be designed without discrimination even to the point of not favouring a particular generator because of the order in which it is analysed through the database.

Pre-privatisation, generating units were made available to system operators according to their actual capability. Since privatisation, generators may choose to profile their availability to achieve a particular running regime for overriding commercial reasons. This discontinuity in the availability profile will result in swapping out generation and this may confound the scheduling process necessitating a redesign introducing more complication.

At some point during the day the generation prices used in studies will need to change to take account of the new bids. The timing of the transition may usefully be chosen to coincide with a trough when most of the generation will continue to run. Even so there is likely to be some disruption to

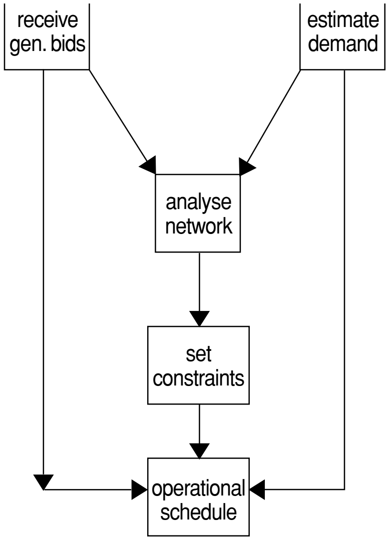

Figure 20.1 Operational Schedule.

the schedule. Since most algorithms can only accommodate one price for each unit some mechanism will be necessary to manage the changeover.

Unit Dispatch

Emphasis on the dispatch phase of operation is increasing as market activity encroaches more and more into the day of real time operation. It is becoming a process in which the Operator has to pick up the trading agreements and translate them into viable system operating arrangements. The closer to real time that this gets the more risk there is to system security.

The CEGB like some other groups of utilities used to operate in the dispatch phase on an interarea transfer basis whereby each area of the system was dispatched to meet its own demand with National Control maintaining economic transfers between areas. This process is not rigorous and does not produce a national optimisation and may therefore favour some generators in preference to others. To avoid this a solution is required which optimises the use of all the generation submitted into the pool including that submitted by external generators trading through interconnectors.

It is equally a requirement of the dispatch phase that the data used is exactly as submitted and updated by the generators through redeclarations. This data together with updated demand estimates is used to update the generation schedule through a new study as shown in Figure 20.2. Because

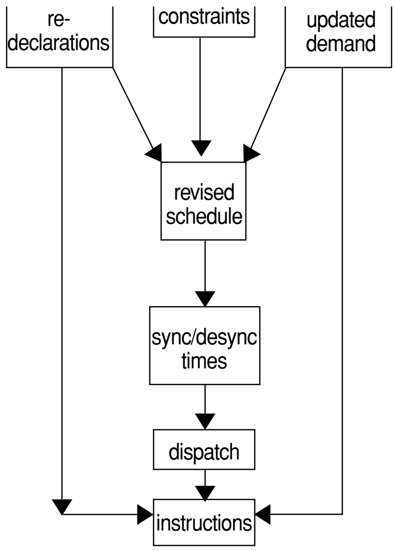

Figure 20.2 Resheduling Process.

of the short time-scales and the need for accuracy, manual data handling is impractical and it has been necessary to set up links for electronic transmission. As the instructions from the grid operator may affect payments if they are not followed, these also need to be recorded and again electronic transmission is the preferred mechanism.

The bids made by generators into the England and Wales pool are not firm and they may be redeclared as unavailable during the dispatch phase. This obviously complicates the maintenance of adequate generation margins on the day and some problems have been experienced in practice following the withdrawal of gas generation. It is necessary to set contingent reserve levels in the scheduling study to accommodate this potential shortfall and to cater for demand estimation error and forced outages. This adds to the cost to end consumers through additional uplift costs.

Facilitating the Market

Bid Data Management

Where centralised commitment and dispatch are maintained a large number of items of information are required to be submitted for each unit entered into the pool. Prices may include up to three sets of incremental prices in England and

Wales as well as start-up and no-load prices. In Australia up to ten incremental prices may be submitted but no start up or no-load prices. Off-loading prices are also included in the offer to enable compensation of generation that has to be disconnected at low demand levels. The available capacity is expressed as a time-varying function for the bid period together with a minimum stable generation. The dynamic characteristics of the units include piece-wise linearised run-up and run-down rates as well as minimum on and off times.

Given the large sums of money involved in the commercial transactions it is crucial that errors are not introduced into the data handling process. This requirement is most effectively met using electronic data transmission which affords the opportunity for automatic audit checking. This is essential to obtain a satisfactory external audit opinion of the data handling process.

Unconstrained Schedule

In the England and Wales system a unit commitment study is used to identify the marginal generator and in turn derive the system marginal price. It is essential that it is based on the data as submitted by the generators, hence the importance attached to the audit trail. The transmission constraints are ignored in this study on the premise that they are not within the control of the generators and therefore they should not be affected by them. The similarity of the process to normal operational scheduling means that the incremental cost of performing this additional study for the pool is small and the two requirements can be usefully integrated and managed by the Operator. Both the data as submitted and the results of the study need to be captured to enable after-the-event settlement and all information needs to be archived for a year or more to enable retrospective studies to resolve disputes.

Ancillary Services

To enable the Grid Operator to maintain system security and satisfactory frequency and voltage control it is necessary for the generators and some consumers to provide what are called ancillary services. These services are the subject of separate contractual arrangements which need to be called off and managed on a minute-to-minute basis. Generators bid in for the provision of reserve services against a complex form of contract that details the levels of immediate response they expect to provide for different frequency deviations and output levels. The response may be categorised as immediate, within 10 s, or within 5 min.

In operational time-scales these services are called against contract prices to meet the system overall need. The process of monitoring and call-off needs to be supported by computer based aids to optimise the process and enable it to be managed in operational time-scales. This requirement interacts with the dispatch process in that the provision of reserve response requires units to operate part loaded and there is a trade-off between the replacement cost of the reduced output and the reserve holding costs. In practice this requirement can be met by including the reserve requirement in the linear program formulation of the dispatch algorithm. Consumers may also participate in the reserve market if they are prepared to reduce demand at short notice.

To manage system voltage requires the control of reactive sources of power which are principally provided by generators or reactive compensation equipment connected to the transmission system. In England and Wales the generators are required to provide a range of dynamic capability as defined in the Grid Code and are paid annually for this capacity. It has been proposed that this should be developed to include both a capacity and an output element payment.

Transmission Services

In the England and Wales model the grid owner and operator are responsible for managing the uplift costs incurred in operation on the day, to meet demand and cater for generation shortfall and transmission constraints. An incentive scheme has been put in place whereby the transmitter benefits financially if these costs are contained below a predefined level. This particularly applies to those aspects that the transmitter can influence like constraints and losses. In operation it is necessary to monitor these costs and take action to minimise them, and real time displays have been developed to support this process and contain the workload. They indicate the actual costs being incurred as a result of active transmission constraints.

The Independent System Operator

There is no reason why the process of operation should not be managed as a separate activity divorced from any ownership of primary plant as has been proposed in the US. Important aspects of the role are seen as being:

- providing fair governance
- having no vested financial interests
- providing open access
- ensuring short-term reliability complies with set standards
- controlling transmission facilities
- managing transmission congestion according to set rules
- promoting efficiency in operation
- accommodating a pricing regime that promotes efficiency of use and investment

- making transmission information available
- managing transfers
- supporting a disputes process

The ISO would undertake all the day-to-day operation including scheduling and dispatch, and management of the network and ancillary services. It has also been proposed that interconnection prices should be adjusted by the ISO in near to real time as a means of alleviating congested transmission routes. The duties would include the normal energy balance, frequency and voltage control and the management of reserve. The organisation of energy trades could be handled by a separate organisation, the 'Power Exchange'(PX), with the results passed to the ISO. Operational planning would have to be undertaken by the market players either unilaterally or in unison through a Regional Transmission Group. In practice the various roles identified for the ISO and PX are tightly coupled and their segregation would require careful definition of the interfaces and roles to ensure trouble-free operation.

Conclusions

Privatisation has had a significant impact on system operations and the process of keeping the lights on, with the addition of the role of facilitating the market. It has not changed the underlying physical process of system management but it has affected how control is achieved. The overall emphasis is now on letting the market prevail in all decision-making and this results in the time available to plan and establish a viable power system being reduced. In practice there is a limit in time beyond which the operator must be able to unilaterally direct operation to meet the physical needs of the system. The challenge to system operators is to take on their new role without jeopardising system security. To meet these needs and contain costs it is necessary to re-engineer the processes in a way that utilises IT and automation to meet the compressed time-scales and maintain accuracy. The market players must agree a firm cut-off time beyond which the Operator will be left to manage the commercial agreements against the hard physical constraints of the system.

CHAPTER TWENTY-ONE

Impact on System Development

The development of the generation, transmission and distribution system was traditionally planned as an entity by vertically integrated utilities. Planning would start from a demand prediction based on the aggregated views of the distribution boards and the transmission division. Generation development proposals would be designed to meet the demand and take account of the need to maintain diversity in fuel sources and zonal balance. The transmission system would be developed to enable the connection of the new generation and to remove any bottlenecks arising from the changes in the demand and generation pattern. The distribution system would be extended to accommodate the new demand and imports from the grid while maintaining security. Capital investment was generally planned well in advance to give a smooth workload for the industry and its suppliers and there were few major surprises. The overall process is shown in Figure 21.1 and the objectives may be summarised as:

- meeting the overall reliability requirements expressed in terms of the probable incidence of loss of supply
- minimising the ongoing capital and operating costs
- maintaining diversity against fuel price changes or shortages
- establishing a stable planning environment for consumers and plant suppliers.

Since privatisation planning by the new companies has been undertaken unilaterally and there is no requirement to undertake integrated resource planning. The planning objectives are now different and driven more by the commercial and marketing policy of the new companies with the overriding

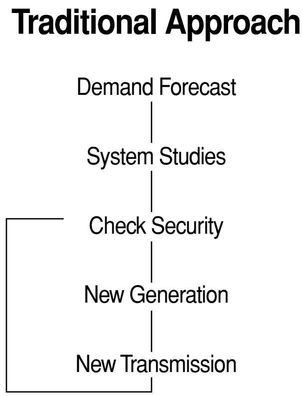

Figure 21.1 Traditional Approach.

requirement to maintain shareholder value and enable customer choice. This has created high levels of uncertainty in future system development which has to be accommodated in a new planning process as described in this chapter.

Generation Planning

Within an integrated environment a new station would have a planned operating regime based on global operational studies using fuel costs and unit heat rates. In the new regime the generator has to assess when it might be running and its profit, and hedge against the risk of it not materialising. In a competitive market this requires a prediction of pool marginal prices to enable the levels of utilisation and income to be predicted against the fixed and operating costs throughout the accounting period.

A larger portfolio generator will have more opportunity to spread risk between diverse plant types to minimise the overall exposure. It will also be less sensitive to fuel price movements if it has a mix of station types or even dual fired generators capable of operating with different fuel mixes. It will also have more negotiating power with its fuel suppliers because of its size. Because of the inherited non-base-load plant the larger generators are able to offer firm supplies and are less sensitive to plant problems that affect performance. The portfolio generator is, however, susceptible to the entry of new more efficient base load generation making its older generation redundant. If the investment is likely to go ahead anyway it may be forced to invest at the expense of reduced operation of its own generation rather than stand still and lose market share. The larger generator has to strike a balance between realising profit and maintaining market share.

The new Independent Power Producers (IPPs) are also less encumbered by the practices and procedures of the older generators and can operate with lower overheads. However, whereas they have sometimes enjoyed a special regulatory status they are now coming into direct competition with the fragmented public sector generators and competing for finance. Without long-term contract options they will be forced to consider alternative financing strategies with a proportion of high yield debt. The volatility of pool prices will not help and will lead to higher charges. Their flexibility in providing integrated energy services including heat, gas and electricity presents an opportunity to increase profitability and these markets can be expected to converge. The IPPs will have little opportunity to influence market outturn and will need a thorough understanding of the forces in play in the market if they are to be successful in their planning.

The risk exposure is managed by hedging contracts and forward agreements with the distribution of risk allocated in line with the ability to control it. The generator will cover plant risks and the supplier will accept responsibility for demand. The fuel costs may be covered by indexing the electricity price to reflect fuel price movements. The balance between short- and long-term contracts will depend on expected market movements and the number of short-term players. The removal of the local franchise for supply will make it increasingly difficult for suppliers to enter into long term contracts and generators will need to operate in the short-term market. Speculation as opposed to hedging will require an assessment of the likely investment and strategy of competitors, and their impact on market prices.

Against this background the development of new stations is focused on maximum efficiency and minimum capital and running costs. It is also attractive to have a short construction period to give improved cash flows and the flexibility to respond to changes in the market. The CCGT stations win on all these counts as well as having low emission levels and this has led to the rapid expansion of this tranche of generation. There is also an increased use of automation to support operation and very low staffing levels with as few as 40 staff for a 1320 MW CCGT station.

Transmission

The uncertainty in generation development feeds through into transmission and a major impact of privatisation in England and Wales has been the need to respond to an unprecedented level of requests for new generation connections, with in excess of 22 GW being planning in the first five years following privatisation. To respond to these requests within a defined time-scale it was necessary to establish multidisciplinary teams to progress each scheme. The timing is critically important to ensure equal treatment for all players in access to the limited system resources. The policy adopted is one where the first request has prior claim and subsequent requests may have to bear the cost of system reinforcement to support their connection. This encourages early application to lay claim to key routes and to avoid ‘prebooking’ there is a requirement that the offer connection must be formally accepted within a 28-day period.

Despite the zonal cost message in the use of system charges, generators have chosen to locate in areas which already have surplus generation. This has exacerbated transmission problems and led to the need for the widespread application of compensation equipment to stretch the capacity of the system to its limits and to create the flexibility to meet the new demands. Potential voltage problems have been ameliorated by the use of reactive compensation equipment and quadrature boosters have been applied to balance line power flows and maximise the transfer across boundaries. This in turn has required the development of new analytical tools to control the devices to realise the optimal system running arrangements. Figure 21.2 shows how quad boosters have been applied in England and Wales to balance flows on the parallel circuits linking the generation in the north of the country to the load centres in the midlands and south.

The uncertainty in the future generation that will be built and closed, together with unpredictable prices and merit orders, makes the assessment of future transmission needs difficult if not impossible. Emphasis in planning now has to be given to identifying the solution that gives maximum flexibility to accommodate change. To realise this some of the compensation equipment has been made relocatable so that as system conditions change it may be moved. Several thousand MVAr of static and dynamic compensation has been installed since privatisation and quad boosters are being widely applied to control power flows.

The Planning Code

To support the new process in England and Wales a planning code was introduced as part of the Grid Code to define the interaction between participants in the planning phase. It provided for the issue of a statement indicating expected conditions for up to seven years ahead and all parties are expected to provide details of their intended developments for inclusion. The intention is to indicate where there may be new generation opportunities. A specific request for connection would be the subject of a bilateral connection and use of system agreement, and the code defines in detail the data required from the system user and the relevant network data to be provided by the transmission owner to support design of the installation.

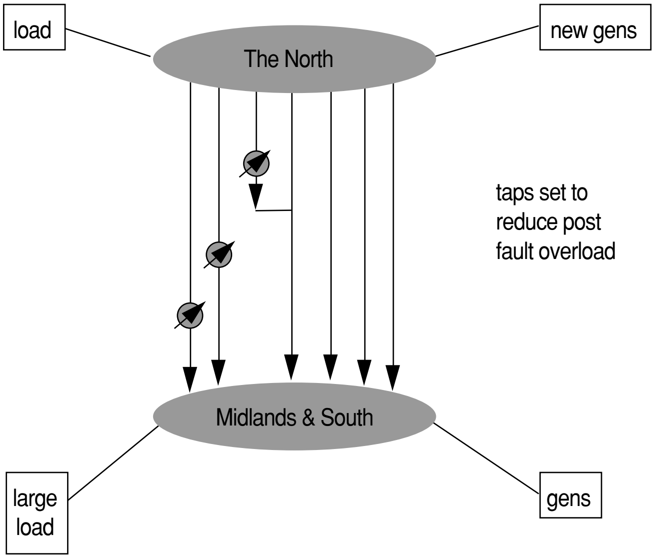

Figure 21.2 Application of quad boosters.

There is now no overall responsibility to establish an optimal system and the new planning process is not designed to encourage optimal investment but places emphasis on creating the flexibility to meet customer requests and making data available to facilitate the design and modelling of the resulting system.

Distribution Planning

The traditional objectives of distribution planning were to provide uniform standards of supply security and quality set by the utilities with no discrimination and little regard to consumer preference. There is now a need to retain consumers and respond more flexibly to meet their requirements. This involves tailoring tariffs with variable time of day charges and distinguishing between different levels of reliability. Load modelling will become more difficult as the supply business becomes fragmented following the removal of the franchise and the introduction of a diverse range of tariffs. There is a need to maintain readily accessible customer information to support demand prediction and planning now that consumers are able to change their supplier freely.

In the past there was little incentive to manage demand and planners responded to meet demand as it occurred against tariffs based on cost. There is now much more interest in the potential to manage demand and in some instances tariffs may be used to contain demand growth in some areas and delay the need for reinforcement. Demand side management by direct control can also be expected to increase and will require the development of further models to support planning.

A gradual build-up of small embedded generation can be expected as local authorities and corporate organisations seek to exploit opportunities to develop combined heat and power schemes or waste incineration generation. The incentives to encourage alternative clean energy sources will also result in the addition of wind and small-scale hydro generation to the distribution network. As the distribution networks are often radial the injection of peripheral generation can result in a complete reversal of power flows. It also introduces potential quality of supply problems resulting from the variation of output causing voltage disturbances or waveform distortion. The distribution networks were never designed on an integrated basis able to support alternative generation output routes and it is debatable how much firm output can be attributed to security in the analysis of system reliability. These developments will also have a significant effect on fault levels and it is essential that their impact is assessed in future planning strategies.

The pressure to reduce costs while maintaining standards can be expected to result in increased use of automation to isolate faulty parts of the network and manage demand. These provisions will need to be built into the development of the network to support remote indication and control of switches and isolators. The realisation of distribution management centres on a par with those used in transmission will require the availability of cheap communication to the many outstations. The potential for remote control and post-fault load management opens up a new dimension in the range of planning options that need to be considered as well as creating new options in operation.

The challenge will be to provide the flexibility to meet the changing needs of consumers and generators.

Conclusions

Privatisation has resulted in the traditional integrated planning process becoming fragmented with no overall objectives or control and each player seeking to maximise their position. This makes prediction of the future conditions for planning very difficult with no certainty in the behaviour of consumers or generators and little data to support analysis. All planners are now faced with the need to re-engineer their approach to create the maximum flexibility in their choice of developments and minimise the risk of stranded assets. This may mean in some circumstances not choosing the cheapest option but that giving the most flexibility. This can only add to the end consumer costs and undermine the security and quality of supply.

CHAPTER TWENTY-TWO

The Commercial Infrastructure

Vertically integrated utilities are often owned and controlled by the state and are set target levels of return on capital employed and external financing limits governing the extent to which capital investment is self-funded. They are also used from time to time to exercise a degree of fiscal control over economic growth which sometimes led to cycling of investment. The industry is able to finance large-scale research and development programmes including nuclear and hydro schemes. It provides a uniform standard of service to even the remotest customer. The tariff structure can be used to foster economic development in deprived areas or to help embryonic industries. Internally the industry is sometimes technologically driven rather than commercially and this leads in some circumstances to the pursuit of technical excellence beyond what would be considered commercially viable. The size of the industry means that it can help to sponsor the development of new products but it sometimes encourages levels of refinement which make them uncompetitive. Against this the industry is focused on improving its overall efficiency in energy conversion as one of the visible indicators of its performance and this encourages the efficient use of fuel and the pursuit of improvements in generation performance as the major determinant in end consumer prices.

Fuel policy is a major factor affecting overall prices and is often heavily influenced by successive governments interested in protecting indigenous industries and maintaining fuel supply diversity. In the UK there was a requirement to burn a high proportion of coal (some 70 M tons) to maintain the coal-mining industry. These requirements constrained the development of the optimal fuel policy to minimise the cost of electricity. It was suggested that the introduction of private capital into the financing of the industry would have provided a useful balance to government intervention and in some countries a proportion of private generation was positively encouraged to create a better balance of state and private ownership.

Since privatisation the industries have been obliged to become more commercially focused and to strive to maintain shareholder value and dividends with a reduced emphasis on the technical quality of the service. This Chapter discusses the impact of this cultural change on the industry and its commercial infrastructure.

Generation

The income for generators is based on the returns for the supply of energy augmented by payments for the provision of ancillary services to support system operation and availability payments. The energy payments are based on the pool profile of system marginal price unless separate arrangements have been made for contracts for differences with suppliers which fix the price. Where generators are exposed to the marginal price then they will seek control through the price bids of the marginal generators. The larger portfolio generators are most likely to own the plant at the margin and will dominate parts of the merit order curve. The England and Wales Regulator has sought to undermine this control by forcing the larger generators to divest themselves of tranches of generation to create a wider ownership of marginal generation. The removal of the local franchise to supply is also expected to undermine the ability of suppliers to guarantee to take energy to back up a contract for differences. These developments will lead to the introduction of added risk which will need to be covered by a proportionate increase in returns or hedging contracts. Whereas the Regulator was expecting household bills to be reduced by some 12% as a result of opening up the franchise, in response to united pressure from the industry this has now been reduced to 7% and in practice is likely to be less. The collective industry has no interest in reducing its common income stream and overcapacity would seem a prerequisite to creating internal conflict over the share of the cake. This, however, introduces more risk, which has to be covered.

These initiatives may discourage local investment and prompt the expansion of generation developments overseas in areas where regulation is less oppressive and investment needs to be encouraged. As deregulation expands and creates wider opportunities, the aspiring global generators will identify the areas providing the best potential returns at reasonable risk and the most competitive markets may suffer from a decline in investment in new more efficient generation.

On the cost side the principal factor has been fuel. In England and Wales the coal contract following privatisation lasted for three years with prices of 180p/GJ covered by pass through take contracts with the RECs. This was replaced by a five-year contract with a take or pay of 40 M tons in the first year reducing to 30m tons thereafter with prices of 150p/GJ reducing to 133p by 1998. Further reduction is likely in any new agreement with prices of 120p/GJ being discussed. The generators are also more likely to avoid commitment and to buy as needed from wherever to retain flexibility. The portfolio generators are also likely to exploit arbitrage or withdraw generation as they now have no commitment to make capacity available. This may leave those governments interested in maintaining fuel security and supporting indigenous industries with a problem and may explain why some utilities like EdF and ENEL support the single buyer model.

Transmission

The transmission business is usually funded by the income it receives for use of its system and a mechanism to equitably apportion this charge had to be developed. In England and Wales the division of charges between generators and suppliers was set, somewhat arbitrarily, in the ratio of 25:75. In that the generator will pass most of the cost onto the supplier the ratio is in part academic but there is also a differentiating element between generators and suppliers according to their location. To encourage generators to locate in zones of the system where demand exceeds existing generation the charges are lower or even negative in contrast to zones with an existing surplus, and range from some +7.5 £/kW to –6.5 £/kW. The generators pay a use of system charge according to their registered capacity. The zonal charge applying to suppliers has the inverse relationship to that for generation and is aimed at discouraging demand in deficient zones and varies from +3 £/kW to +20 £/kW. These charges are based on the so-called triad demand, being the three half-hours of maximum demand separated by ten days or more. These charges are passed through to customers in the form of tariffs which vary with zone and it could be argued that some users suffer because of a decision over which they have no influence.

The actual charges need to relate to the current cost base which in turn is affected by the level of injected debt at flotation. Consideration was given to long and short run marginal costing and various formulations were evaluated. The approach finally adopted was investment cost related pricing, where the charge is based on the proportional change in flow on all lines resulting from the injection of generation or load into the system at the connection point. The cost of investment for each line is then shared in proportion to the flow injected by each user. In 1996–1997 the expansion cost was some 20–25 £MW/km. The regulatory process is aimed at driving down these charges to the minimal cost level consistent with maintaining the quality of the service.

Investment cost related pricing provides the level of return necessary to cover the existing investment cost but does not necessarily lead to the optimal level of future investment or test the existing level of investment against its worth. There is no direct mechanism for arbitrage between generation and transmission in this approach as the transmitter unilaterally sets zonal charges without testing alternative generation location costs. This might best be realised by the adoption of a pool operating with zonal energy charges, where the benefit of new transmission is more evident and calculated by the market. Faced with successive cutbacks in allowable charges by the Regulator the transmitter has cut back in controllable staff costs by some 30% and will, like the generators, seek to establish overseas equity investment and income streams not subject to stringent regulation.

Distribution

Distribution like transmission is usually regarded as a monopoly requiring regulation. The income is principally derived from the use of system charges levied on all users of the network. There are also pass through charges for exit from the transmission system and for any consumers directly fed from transmission voltages. They also charge for connection on a pass through basis although the Regulator in England and Wales has expressed the view that this service should be open to competition.

The distribution costs are very dependent on the geography of the area and the demand density, which are not factored into the regulatory formula, and this has led to some concern about the regulatory formula applied. Currently it includes a scaling factor related to the number of units distributed plus an equal element proportional to the number of consumers.

Supplier Income

Suppliers buy energy wholesale from generators through the pool and receive income from sales to consumers with relatively small profit margins of 1–2%. The suppliers may be a ring-fenced part of a generator or distributor with separate accounts and no cross-subsidy or a separate entity. Second tier suppliers are those trading into a public supplier's area as the local franchise is removed and making use of its distribution network. They are a new development for the industry and their introduction has not gone smoothly, with debate still raging about charges for metering systems. Because the margins are small the contribution to profit represents a very small part of the total to a distributor or generator. However the capital employed is low and there are economies of scale which are likely to encourage new entrants dealing in total energy supply particularly where they already have a customer interface through retail outlets.

Licenced/Unlicenced

The emphasis of regulation is on the monopoly parts of the industries not subject to open competition and this has led the companies to break up their internal organisations into asset owners and operators, and 'suppliers' who give support through the provision of services. The intention was to open up the provision of these services to external competition, when, it was argued, it would become an unlicenced activity not subject to regulation. Apart from the demoralising effect on staff of creating what was seen as a second-class company, the new profit centres did not necessarily pursue policies which were in the best interests of the parent group. These reorganisations were, however, successful in quickly establishing a more commercial outlook in the 'supplier' organisations, which was not always appreciated by internal customers.

Culture

The common binding culture of the industry was always to maintain supplies to consumers at all costs and in emergencies it would exhibit very high levels of cooperation, cutting across organisational and commercial boundaries to secure the system. There is only one physical power system and it is highly interactive and responsive and normal commercial market mechanisms cannot establish the sort of response necessary to manage emergencies which require direct control action. There is evidence in the US that the commercial contractually agreed flows have deviated from the physical flows leading to problems in operation.

The blackouts on the west coast of the USA can in part be attributed to a failure to exercise joint planning and operating strategies across commercial boundaries. In the new environment the common view is that blackouts are bad for the industry at large but it is less clear how this can be distilled into joint action which may be contrary to the commercial interests of the individual companies.

Take-overs and Mergers

On the supply side there are obvious benefits in the integration of customers services for the supply of gas, water and electricity which all involve the maintenance of an interface with the end consumer. Savings can be made in meter data collection, processing, registration and billing.

The interest of a generator in taking over a regional electricity company is likely to be based on the desire to secure markets for the output of its stations and if progressed could lead to the formation of a few geographical vertically integrated utilities trading at the boundaries. Any economies of scale in generation are more marginal and the Regulator needs a sufficient number of small players to realise effective market competition and avoid price control. There is, however, interest in becoming global energy providers encompassing gas, oil and electricity provision and major companies like Shell are buying power generation interests and larger electric utilities are buying into gas companies. Some facility suppliers have also bought into generation. It is anticipated that the privatisation of electricity generation will open up the opportunity for multinationals to secure a major holding in a key commodity sector with strong strategic influence. This is particularly likely where the value of the industries has been written down by governments anxious to realise a successful flotation. The large increase in share values since privatisation in England and Wales of some 400% is evidence of the low asset valuation – which invites takeovers.

Conclusion

Privatisation has generated a lot of activity in support of the commercial process which does not directly contribute to the physical process of generating and supplying electricity to consumers. It introduces uncertainty and risk into the future income streams and it is yet to be proven whether this results in constructive competition and real cost savings. The regulatory process adds a further level of uncertainty and it is difficult to see how end consumers will benefit. The industries appear likely to react by developing into global players less subject to the influence of a local regulator or even government.

CHAPTER TWENTY-THREE

The IT/Communications Infrastructure

One of the areas that has seen a significant change as a result of privatisation has been the IT/communications infrastructure of the new companies. Whereas the vertically integrated utilities operated with an overall single corporate system of IT and communications the new companies wished to quickly establish their own confidential systems to support their developing commercial operations. IT has developed as the key enabler of process re-engineering and also as a means of introducing automation and cutting costs. The timely development of these supporting systems is playing a key role in enabling privatisation to take place and this Chapter highlights some of the necessary developments.

Background

Prior to deregulation the communication requirements of power stations and substations were principally to service the needs of Substation Control and Data Acquisition (SCADA). The main function was to provide general indications to the grid control centre on plant status and metered flows. The facilities for remote control were limited, with most instructions for switching and dispatch being transmitted verbally via a tailored control telephony system able to ‘knock down’ administrative calls. The data on generator status and available capacity was obtained verbally from discussion with station operators and manually entered into algorithms for scheduling and dispatch.

Since deregulation the generation companies have split from transmission and this has radically altered the requirements for communication between power stations, substations and grid control centres. The driving forces have been:

- the need for accurate metering data to support retrospective settlement
- the requirements to monitor performance against contracts for ancillary services and instructions
- the need to be able to demonstrate to auditors that the correct data has been used in scheduling and setting prices
- the desire to automate the process to reduce manpower and costs

Prior to deregulation the telecommunications network was based on the SCADA infrastructure with the grid control centres acting as the major network nodes. The new requirements to support commercial operation have changed the basic structure and have led to the development of separate systems serving the needs of each company.

New Requirements

Offer Data

Generators and those consumers offering demand side management are required to submit offer data as bids into the pool. For large generators this may consist of several megabytes of data four or five times a day making error-free manual handling impractical and necessitating the use of electronic file transfer.

Redeclarations

Between the times of bulk data transmission any changes to plant status or capability have to be notified to the Grid Operator who may as a result have to redispatch the generation. As these changes affect payments, the new values and the time of change have to be recorded for settlement.

Dispatch Instructions

Loading instructions to power stations now have to define in detail the time at which the instruction should start and is to be completed in accordance with declared ramp rates. Other instructions related to frequency regulation and MVAr output also have to defined and recorded in detail as they may also affect payments.

Metering and Monitoring

There is a need to monitor performance against instructions and contracts as failure to complete may result in payments being withheld. Ancillary service contracts are complex and define different levels of generation output response depending on the frequency change and the standing load. The response is too rapid for manual monitoring and automatic systems have been developed to check performance against contract provisions and record data for settlement.

Remote Control

Within an integrated utility the control of substations was often undertaken from the nearest permanently manned point which may have been another substation or power station. Since the power stations are now under separate ownership this service is subject to a charge and the service may be withdrawn at short notice owing to demanning or station closure. This has promoted the wider application of remote substation control direct from the grid control centres. There is also developing interest in remote power station control as automation and management facilities are developed.

Design Considerations

The integrity of the systems required to support commercial operation may exceed that required for technical reasons as the financial consequences of failure are large. For example, the failure to lodge bid data or the loss of generator indications may run into several million pounds and result in disputes.

The new market players require strict confidentiality in managing their commercially sensitive bid data and this complicates the communication mechanism and necessitates 'fire-walling' between the companies to control external access.

The process of generation dispatch is important to maintaining the integrity of the power system and where electronic communication is used it has to be demonstrated that it is fully available and its status continually monitored by 'handshaking' communication.

To meet these requirements it has been necessary to establish triangulated routes to secure against the loss of a link. Test transmissions are also used to check the integrity prior to the main transmission of bid data. Confidentiality requirements have been met by extracting data from generator systems without them having a log on ID for the collecting system and by the strict classification of routers.

Structure

The basic structure of the SCADA communication system used prior to privatisation in England and Wales was as shown in Figure 23.1. The SCADA

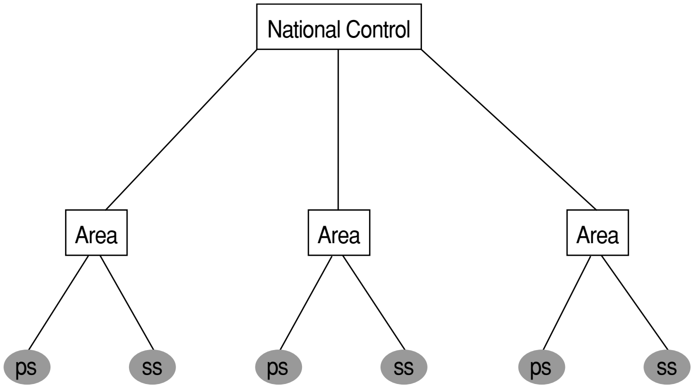

Figure 23.1 Communication infrastructure, pre-privatisation.

and control and administrative telephony were based on the grid control structure which was organised geographically into areas, with links into local substations and power stations. Indications and metering data was transmitted in real time from substations and power stations to the control centres to support system monitoring and management. A proprietary protocol was used for the SCADA, tailored to meet the needs of special data types. The volume of data was such that relatively low baud rates (120) could be used. This system did not provide a suitable base to meet the new commercial needs and it was necessary to establish a new more open computer environment able to support intercompany communication based on widely available technology and protocols.

Following privatisation there was a desire by the generators to establish their own control infrastructure to support commercial operation and this led to the introduction of Energy Management Centres (EMCs) as shown in Figure 23.2. They acted to collate and submit generator bid data and since the new data was handled largely electronically this reduced the workload on the original area grid control centres. This coupled with the progressive introduction of remote substation control created the opportunity to close the area centres and focus operation on the National Centre. Effectively the old area centres have been displaced by the emergent EMCs.

The other major change was the development of the systems necessary to support settlement. This requires copies of bid and instruction data to effect retrospective settlement and it also provides back to the market players data on the prices and the results of processing data for payments.

The high volumes of data traffic required the establishment of wide-band kilostream channels between the National Control Centre and the EMCs, and settlement systems and all routes are triangulated for security with the

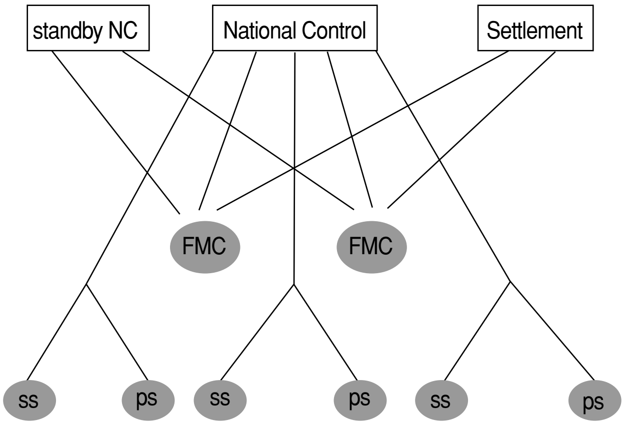

Figure 23.2 Communication infrastructure, post-privatisation.

standby National Centre. The EMCs have also established links to their power stations to support data collection and commercial management.

Station Links

The communication to power stations has also changed to support the new requirements and as well as the traditional SCADA information there is additionally the need to support the electronic submission of redeclarations from the station to the control centre and dispatch instructions in the reverse direction. Provision is also made to monitor the performance against ancillary service contracts. The single-station companies may also exploit the same communication link to support the submission of offer data.

The original SCADA link can be equipped with multiplexors and new modems able to meet all the requirements of single generators. They can be based on more open general purpose protocols with a convertor to enable the original SCADA data to use the new link.

Conclusions

The new requirements resulting from privatisation have transformed the basic infrastructure of the communications and IT systems supporting power system operation. No single body is now responsible for the overall design and development of the network with each party seeking to exploit its own investment. Rather than being planned as a single entity, the network for

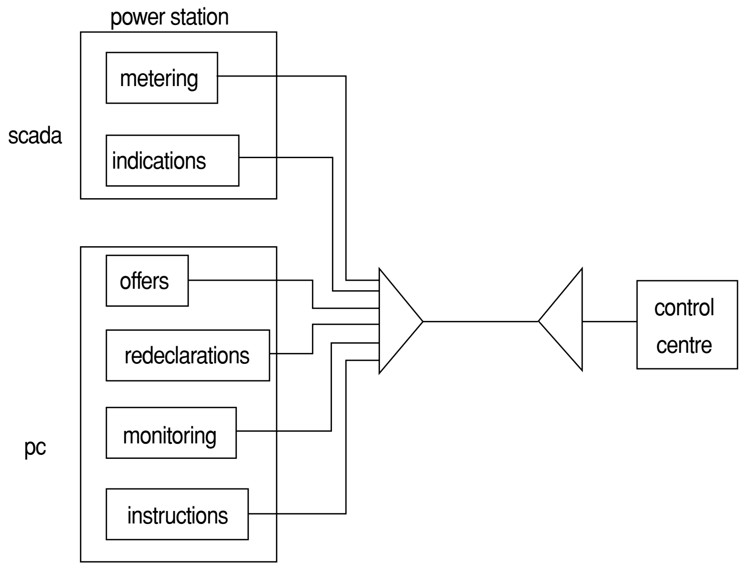

Figure 23.3 Typical power station installation.

commercial data now evolves through a series of bilateral agreements between each new company and the grid or settlement operator. The requirements for integrity have become critical because of the significant commercial implications of error or failure in transmission and most of the commercial data is likely to be transmitted electronically. To support commercial data processing there is advantage in establishing a new stand alone computing environment specifically designed to meet the requirements for communication and data security, with controlled interfaces to the existing infrastructure.

PART FIVE

The Changing Market for Facility Providers

Part 5 describes how the changes in the basic structure and operation of the industry will radically affect the opportunities for suppliers of equipment and facilities. It discusses the new businesses and their drivers and how requirements can be expected to change. The likely changes in the primary plant market are discussed and the impact on IT, metering and communication needs is outlined.

CHAPTER TWENTY-FOUR

New Businesses and Drivers

Privatisation radically changes the relationship between utilities and their suppliers, and affects both the trading interfaces and the market for products and services. The large vertically integrated utilities were a dominant force in the market and had the power to influence the development and design of products to meet their perceived needs sometimes irrespective of international market trends. The new fragmented industries do not operate collectively and have less influence in the market place, they are more inclined to accept standard products if the price is right and are less inclined to take the lead in development. The state-controlled industries tended to act collectively and adopt a common approach through coordinating organisations like the UK Electricity Council. The new industries are more likely to be interested in gaining competitive advantage and maintaining commercial confidentiality. This Chapter discusses the new interfaces and business drivers of the emerging businesses and how suppliers will be affected.

New Interfaces and Drivers

The vertically integrated industries consist typically of one organisation managing all generation and transmission feeding into a number of state-owned distribution companies as shown in Figure 24.1. These large integrated utilities have now been replaced with a much larger number of smaller players resulting from the break up of the state generation into several separate companies and the addition of an increasing number of new independent generators. The monopoly franchise of the distribution companies has been progressively removed, to be replaced by a larger number of suppliers. These changes have resulted in a pool membership in England and Wales of some 60, with 24 suppliers, 24 generators, and 11 generator/suppliers all trading through the commercial pool which now overlays the physical transmission and distribution system as shown in Figure 24.2. Even where state ownership did not exist the reforms involve unbundling of transmission, generation and distribution, coupled with fragmentation of generation ownership to foster competition. All the new players will require a separate interface to their service and equipment suppliers.

The new industries have different drivers and are no longer preoccupied with technical excellence but rather with satisfying the objectives of shareholders and customers. The new businesses are more likely to be looking to be able to

- respond to the changing needs of the market ahead of the competition
- contain and cut the costs of ongoing operations
- meet the new licence and statutory requirements
- pursue economy in operation rather than security at any cost
- exploit new technology and track developments

The old customer contacts can be expected to disappear and be replaced by a fragmented and often less informed buyer looking for a total solution service.

The new utilities are seeking overseas outlets to build their non-regulated business and are often interested in taking an equity stake in the local industry. They tend to take a more global view of requirements rather than focusing on local issues. This can sometimes bring them into direct competition with their traditional suppliers where both are tendering to provide services to develop power systems.

New Needs

The downsizing in staff of some 30–50% following privatisation means that the new industries carry less in-house design capability and are more reliant on the

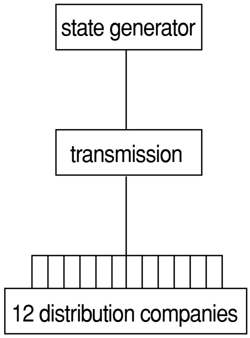

Figure 24.1 Vertically integrated utility.

supplier to provide a total service. This comes at a time when the requirements have significantly changed and are less clearly defined, and part of the service will now involve the development of the new user specification for the new facilities. Whereas the integrated utilities placed great emphasis on system security the new players are more likely to place price high on their list in the evaluation of tenders. Because each buyer now only represents a small part of the market there is a much greater propensity to accept standard products rather than tailor systems to meet some perceived special needs. This means that the providers will need to invest more in product development and cannot rely on utility direction and sponsorship. The ability to respond rapidly to meet the changing market needs is now considered paramount and invitations to tender are usually accompanied by uncomfortably short delivery times.

There is much more willingness to out-source services rather than carry in-house specialists particularly if the facility is not considered business critical. The vertically integrated utilities tended to maintain segregated facilities reflecting their internal divisions. The new requirement is for data to be available across the company to support commercial decision making. Whereas operational data was the sole province of the operations department it is now of interest to the commercial and finance departments. This leads to the need to rationalise and integrate data from what were previously separate systems and make it available corporately.

These developments offer a challenge and an opportunity to those suppliers able to bridge the gap to the new businesses by establishing a new approach.

Supplier Response

The successful suppliers in the new environment will be those that recognise the new interfaces and requirements and are able to provide a responsive service.

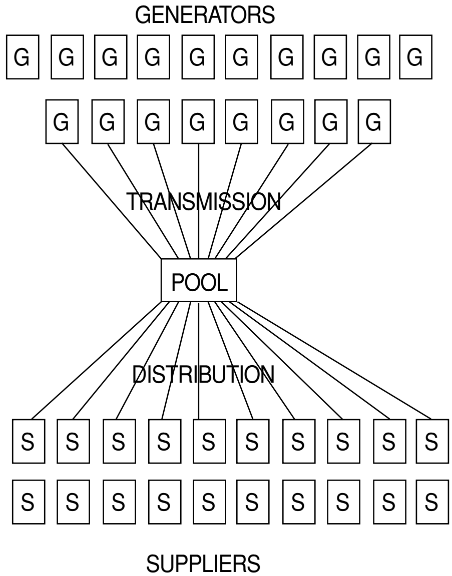

Figure 24.2 Post-privatisation network.

The FT of 23 June 1997 reported that the senior executives of one large supplier had concluded that they needed a more decentralised and flexible organisation to cope with fast changing markets, and in particular with privatisation and deregulation in power creating more potential customers, and were reacting by creating some forty senior 'Country Managers' to provide the response.

Some suppliers have tended to focus on products relying on the utilities to develop overall system designs. In the new environment there is a need to offer a total solutions capability probably using a range of products from different suppliers with integration of diverse systems. Some suppliers need to build this development capability into their organisations and can no longer rely on support from the utility R & D organisations which have largely been dispersed.

The successful suppliers will need to develop a detailed knowledge of their clients' business processes to be able to work alongside the new customers who are now sometimes very small and lack the full range of expertise carried by the large integrated utilities.

Future

The large number of take-overs and mergers will result in the utility industry becoming more global and probably more specialised in a particular part of the industry with non-core activities divested. It is likely that these new international utilities will develop a preferred process model for their activities and will focus on a specific product set to support it. Eventually this trend in mergers will lead to the local power of the national vertically integrated utilities being replaced by the global purchasing power of specialised sector companies who will set the standards.

The integration and rationalisation of customer services for gas, water, telecommunications and electricity will also affect the supplier market and it is likely that the requirements for metering, data collection and billing will be merged into a single system which will also support more active consumer participation and response to price.

The need to develop facilities to support trading and risk appraisal in the new commercial environment will attract the entry of new suppliers with traditional financial service skills. More emphasis will be placed on asset valuation and management to contain costs through the exploitation of automation.

CHAPTER TWENTY-FIVE

Primary Plant For Generation Transmission and Distribution

Deregulation can have a dramatic effect on the requirements for primary equipment in generation transmission and distribution, arising from the introduction of new players in the competitive market for generation and in the provision of open transmission access. With vertically integrated utilities development plans were largely the result of responding to increases in consumer demand and the need to replace life-expired equipment. It was usual to maintain a steady construction workload consistent with the size of the in-house workforce and a stable capital investment level. In the new markets there is no overall control of the introduction of new generation and its location or in the coordination of the timing of station closures. The result is that the demand for new facilities does not follow the gradual trend of consumer demand growth but is less predictable, compounding the difficulties for suppliers in planning production. The vertically integrated utilities would generally plan the development of new stations with their preferred suppliers and mix the placement of orders to maintain a balance one year on another in order to maintain at least two suppliers in competition. In the new world there are a multiplicity of new customers with little interest in joint planning with competitors or suppliers and the demand can be expected to be spasmodic and cyclical. Suppliers need to be in a position to anticipate trends and focus their organisations to track and exploit the changing markets.

Actual Developments

Demand

Figure 25.1 shows the actual demand change since privatisation and that predicted through the plan years. It can be seen that the demand has only increased by some 2 GW in the first six years with a projected increase of a further 4 GW plus over the next six. There is some evidence of demand management depressing peaks while energy levels are being maintained.

Generation

Although the demand has only marginally increased during the period some 22 GW of new generation was planned for the England and Wales system during the first five years following privatisation and that currently planned rises to some 27 GW. It can be seen from Figure 25.2 that most of it was based on CCGT technology and was built by new entrants who were often supported by attractive take contracts with RECs anxious to balance the market power of the large generators. To offset this increase in capacity the larger generators brought forward plans to close older generation which would otherwise be underutilised. During the same period it can be seen that some 12 GW of existing generation has been closed or is planned to be, with a further 4 GW of generation moth-balled having been declared ‘long notice cold’. This still, however, leaves a significant increase of generation over demand and results in the predicted high plant margins of some 40%. The incidence of addition of new CCGT generation is shown in Figure 25.3 and can be seen to show a steady expansion. The graph also shows that the proportion added by the ‘large’ generators is small in relation to their size.

The generation has not always been ideally sited to suit the system needs because it has often been linked into a northern industrial complex to exploit waste heat production, or sited close to the gas network.

There has also been a significant increase in the development of small embedded generation with some 4 GW being connected to the lower voltage networks. The high efficiency realised through small local combined heat and power schemes is an attractive option. Waste incineration systems appeared to kill two birds with one stone and several have been built exploiting the option to export surplus energy to the grid. Smaller embedded generators are exempt from paying transmission use of system charges and this improves their profitability. They can however disturb the operation of radial distribution networks and create the need for reinforcement. The government provided an incentive to develop alternative energy sources using the fossil fuel levy income. This has also encouraged the development of wind farms and small scale hydro generation.

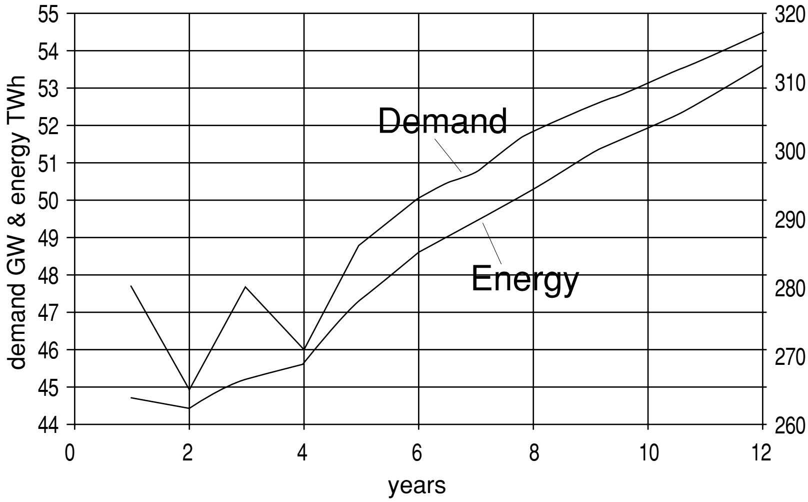

Figure 25.1 Demand and energy, actual and forecast, February 1991 to March 2002.

The rate of entry in other markets has been less pronounced. In Norway and Sweden there was little need for new capacity. In Australia the generation was split up into individual stations with restrictions on cross-ownership. In New Zealand new generation is being planned. In Argentina, to avoid a concentration of generation ownership, companies are restricted to no more than a10% share of the market. The key features that will influence the rate of development are:

- relaxation of government restrictions on fuel utilisation. In England and Wales the reduction in the requirement to burn coal was a significant factor
- the existing plant margin and need for new capacity
- the initial fragmentation of generation ownership as it affects competition
- government policy on the proportion of ownership and market share

Transmission

The bulk of the development undertaken in England and Wales has been in connecting the new generation to the system. For the most part this has been accommodated by extensions to existing substations but a few entirely new substations have also been created. Most of the generating stations are of a size to be connected to the supergrid at either 275 kV or 400 kV, with in

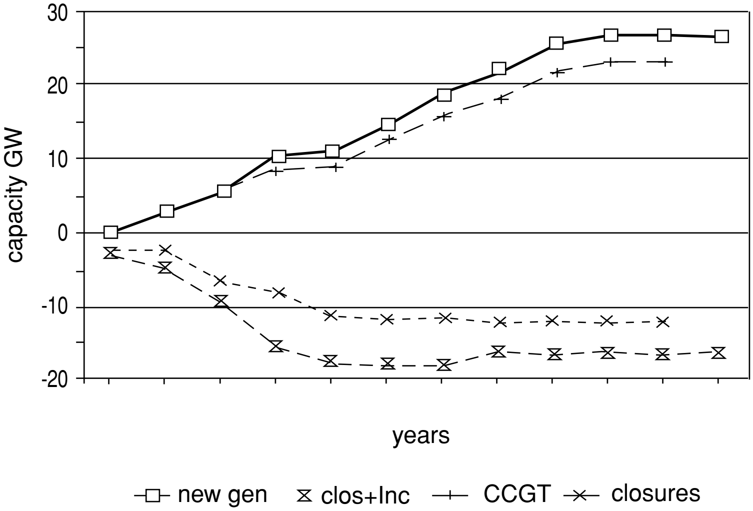

Figure 25.2 New generation and closures, February 1991 to March 2002.

excess of 40 new stations having been contracted for connection since vesting with a registered capacity of some 27 GW.

Transmission infrastructure investment has largely resulted from the need to support the less than ideal siting of new generation. It has usually taken the form of compensation equipment strategically located so as to realise the maximum transfer capability of the existing transmission. Some 34 reactive compensation systems are now installed at supergrid voltages with a reactive absorption capability of some 6000 MVAr and a reactive generation capability of some 3000 MVAr. A similar amount is connected at 132 kV and to the tertiary windings of supergrid transformers with an absorption capability of some 5000 MVAr and reactive generation capability of 4000 MVAr. Some 6000 MVA of quadrature boosters are also located at five installations to balance tie lie flows and it was announced by NGC (in the Grid newspaper of August 1997) that a further investment of £21 M is planned for the installation of two 2750 MVA boosters to regulate North to Midlands power flows. This is largely to accommodate the 8 GW of new generation already connected in the area since 1991 and a further 5 GW contracted.

Distribution

Distribution developments are usually more directly associated with demand developments and as such have not seen the same scale of new works as the generation and transmission sectors. Some work has been necessary to

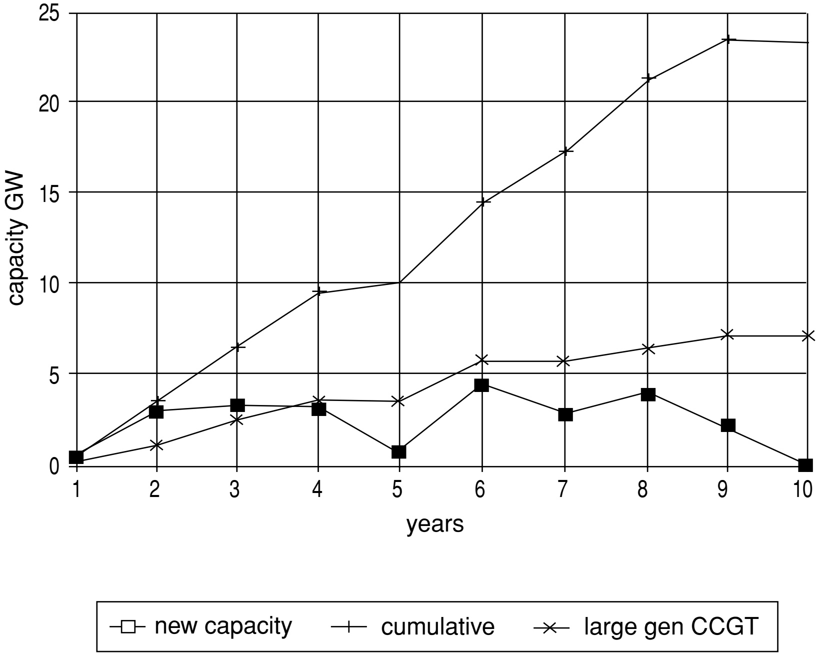

Figure 25.3 CCGT investment, 1991–2000.

accommodate the impact of generation where this has been connected to the lower voltage network. A significant capital expenditure is ongoing to refurbish and replace life-expired equipment and this will continue with deregulation having an impact on the type of systems being developed with more automation being applied.

Projected Market Needs

Generation

The two factors that directly effect the market for new generation are:

- the change in demand
- the replacement of old inefficient generation

In the new deregulated environment the market behaviour exerts a disturbing effect on the basic requirement. If the potential returns appear high then new players will see opportunity in the market and the prospective plant margin will grow beyond the ideal, artificially inflating the demand for new generation. If subsequently full competition comes into force depressing prices then expansion plans will be cut back reducing the demand for new generation. The process is likely to be unstable and cyclical since whereas competition and a collapse of prices could occur overnight the time-scales for new generation planning and construction are several years at best. Given the prospective excessive plant margins in England and Wales and the prospect of more active competition following the complete removal of the local franchise to supply in 1998 all the indications are that this will lead to a cutback in new large generation orders. Given the scale of closures that have already occurred or are planned this cutback is not likely to be offset by the need to replace older generation in the short term. Generation based on CCGT technology is likely to continue in popularity with its many advantages but the development of cleaner coal fired generation may be encouraged by governments taking a broader view of the economy and energy policy.

An indication of medium-term requirements for new generation and associated transmission connection capacity can be gauged from the data in Figure 25.4. This shows the current installed cumulative capacity from its original commissioning date and, assuming a 40-year life, the subsequent reduction in capacity as generation is closed. The graph also shows the predicted demand and demand plus a 20% margin. It can be seen that the margin stays high initially but around 2005 it rapidly decreases reflecting the closure of the large tranche of generation commissioned around 1970. In contrast US margins are currently expected to decline from some 18% to 13% by 2005. The implications are that demand for new generation in England and Wales will cycle down and remain flat for the next few years prior to picking up again around 2002 with plans to replace older units. In general the demand for new generation will be much more cyclical than pre-privatisation but must ultimately track the underlying trend in consumer demand.

Transmission

The requirements for new transmission are influenced by :

- the addition of new generation requiring connection and possibly reinforcement
- increases in demand requiring increased transformer outlet capacity
- increased interconnection requirements
- the need to replace or refurbish old equipment

Based on the England and Wales experience deregulation will affect transmission needs both in enabling generation connection and also in providing compensation to accommodate adverse siting and this will occur over and above the

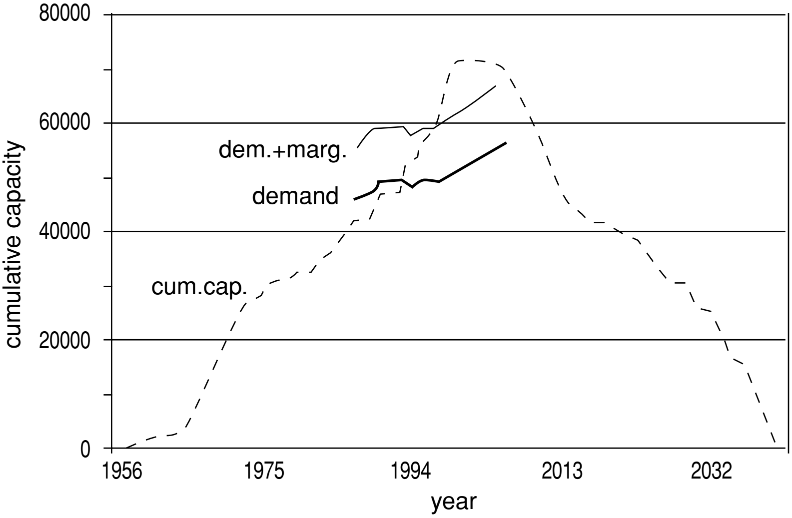

Figure 25.4 Profile of generation capacity, 1956–2040.

underlying demand increase. The demand for new connection will track the cycles of demand for new generation and can be expected to reduce following the initial upsurge.

The requirements for new transformer outlets would normally be expected to track increases in demand and should be less volatile than the need for generation connection. This may, however, be depressed by the new utilities cutting costs and seeking to exploit existing capacity through demand management schemes, selective tariffs and automation.

The prospects for the development of interconnection capacity can be expected to increase as access to new remote customers is opened to other than the local utility. Where energy price differentials are large between zones of the system and across borders then new transmission will be shown to be cost-effective.

A potentially large influence on the market for transmission could arise from the need to refurbish or replace time-expired equipment. The development of supergrid systems occurred over a relatively short period – in the UK in the late 1960s early 1970s. Depending on the realisable life a potentially large programme of work could occur at the turn of the century to replace these systems. To avoid a step-change in expenditure it is more likely that the new commercially orientated utilities will advance expenditure to provide a smoother investment profile.

The continued expansion of small local generation schemes could have a significant effect on the need for transmission development. The advent of small-scale cheap mass-produced integrated energy systems could have a dramatic influence on the future market.

The increasing use of gas generation brings into focus the option of gas pipeline energy transportation as an alternative to electricity transmission. With the increasing difficulty of obtaining way-leave some rationalisation of energy routes may be overdue.

Distribution

The development of the distribution system will be principally influenced by

- the need to support new demand
- the replacement of time-expired equipment
- the need to accommodate the connection of embedded generation
- infrastructure and automation developments

The impact of deregulation will be mainly related to the expansion of small lower voltage generation and the development of automation to contain operating costs and improve the levels of service.

An indication of the requirements for equipment for new demand and replacement can be obtained from the profile of energy demand. Figure 25.5 shows the UK energy demand growth since 1920 and it is reasonable to assume that this will parallel the need for new distribution equipment to support it. If we assume that the equipment installed to meet the original demand needs to be replaced at 40 years then this may be superimposed on the new energy curve to illustrate the replacement need. It can be seen that a significant growth in the need for replacement builds up from 1990 when, taking that as the base year, the replacement need will be some 70% of the total. Some confirmation of the above estimates can be obtained from an estimation of the net and gross CCA values. The information in the Figure would suggest a value of 37% for the net/gross CCA at 1990 which is close to the value at privatisation which was on average 35%. Capital expenditure will need to exceed the depreciation provision to match the expected requirement and manage the profile.

The prospect for smaller embedded generation is less likely to be affected by the macroeconomic position as it is often linked to some local development with an integral market, like combined heat and power or waste disposal. There are also likely to be ongoing incentives for the development of alternative energy sources and this sector can be expected to expand. With the increased awareness of commercial opportunities brought about by deregulation there are likely to be many more joint developments with consumers, involving energy management and conservation particularly when this is encouraged by government legislation.

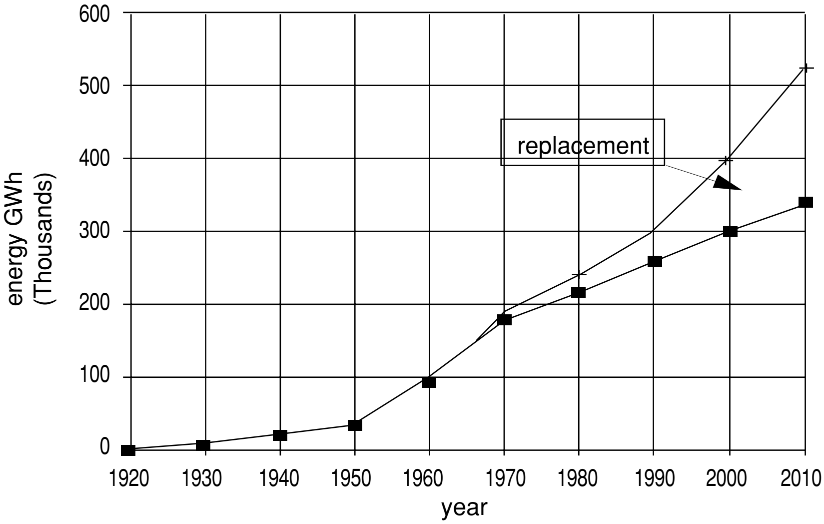

Figure 25.5 Profile of equipment installation, 1920–2000.

With the emphasis on the need to contain costs it is expected that the application of automation to distribution will expand. Energy management systems have been extensively applied at transmission voltages but generally the costs have been too high to justify widespread application at distribution voltages. The advent of cheaper communications and intelligent relays and meters now makes this a realistic option and the sector is expected to continue to expand.

Conclusions

Deregulation has a radical effect on the requirements for new facilities. Generation developments are more likely to be influenced by commercial opportunism than tracking demand growth and can be expected to be more cyclical. Following an initial high growth period in the first four to seven years plans for new stations in England and Wales appear likely to decline until demand catches up and older generation needs replacing leading to more viable prospective plant margins. Transmission investment will be very much influenced by the provision of facilities to connect the new generation. Depending on the level of success in encouraging the optimal siting of the new generation infrastructure, reinforcement may be necessary. In England and Wales reactive compensation equipment has been widely applied along with quadrature boosters to enable maximum transfers over the existing network between the new generation and load centres. An increase in embedded generation connected to the distribution network has led to the need for some distribution reinforcement. A significant programme of distribution replacement is imminent based on a 40-year life expectancy and it is expected that the new utilities, under pressure to contain operating costs and maintain service levels, will take the opportunity to equip the system for automation.

CHAPTER TWENTY-SIX

IT Metering and Telecommunications

Privatisation has had a significant impact on the IT and telecommunications infrastructure of the utilities, with a doubling of the resources applied and investment levels of the order of several £100 M across the industry. Whereas the vertically integrated utilities maintained a single national IT and telecommunica-tions system the new unbundled businesses each wish to establish their own private facility. The statutory bodies co-operated to agree standards and facilitate intercommunication whereas the emphasis now is on maintaining data security and confidentiality. The expansions in the requirements can be attributed to the following:

- establishing and processing metering at the new commercial boundaries
- enabling intercommunication of commercial data between the new businesses
- supporting commercial data processing and analysis
- automating data handling to reduce costs and to improve the audit trail
- capturing data for settlement and billing
- managing and registering the assets of the new businesses

Whereas the requirements for the old industry were well established and known, the specifications for the new systems are not defined and have evolved with experience. In that the systems may offer commercial advantage over competitors there is much less willingness to establish agreement on common approaches with suppliers. The result is that reaching agreement on developments in a pool environment can be extremely difficult and protracted. For those interested in supplying systems to support privatised operation it is a major challenge to distill the generic needs into a base line product and to develop a set of modules that can be integrated. This chapter gives an indication of the scope and scale of the IT systems likely to be needed in support of deregulation.

Metering Systems

The tariff metering for the operation of a vertically integrated utility is principally that located at the interface to the consumer. Where distribution is separate from generation and transmission then additionally there will be metering at the bulk supply points as was the case with the CEGB. In the new environment there is a need for metering at the new ownership boundaries, i.e.

- the boundary between generation and transmission
- the boundary between transmission and distribution

For each of these systems there is a need to collect and process the data as the means of settling the actual energy exchange between the systems for each half-hour of the day. To manage the large volumes of data with minimum error these requirements have been met by the provision of automatic data collection and processing systems. Meeting the specified accuracy requirements may in turn require the provision of new current or voltage transformers of the appropriate class.
The line marked with squares in Figure 26.1 shows a typical expenditure profile for transmission metering equipment. The actual will depend on system size and the number of generation units and grid supply points.

An added level of complication results from the need to apportion use of system charges. For transmission this is related to the registered capacity of generation and the maximum energy transfers during the designated three half-hours of maximum system demand. Centrally dispatched generation is charged net of average metered station load and according to the zonal generation tariff. Non-centrally dispatched generation is not charged and its output is credited to the host REC, reducing its liability to charges or those of the assigned second tier supplier.

In the case of distribution charges there is a need to reconcile the use of the system by the second tier suppliers, i.e. where the customer is supplied by other than the local distribution company. In this case the local REC transmission charge is reduced and the charge is levied on the second tier supplier for its use of both the transmission and distribution system. With the complete removal of the local franchise potentially large volumes of data will need to be managed to register customer details and supplier. In the absence of half-hour recording it is also necessary to record an agreed profile for each type of consumer to enable

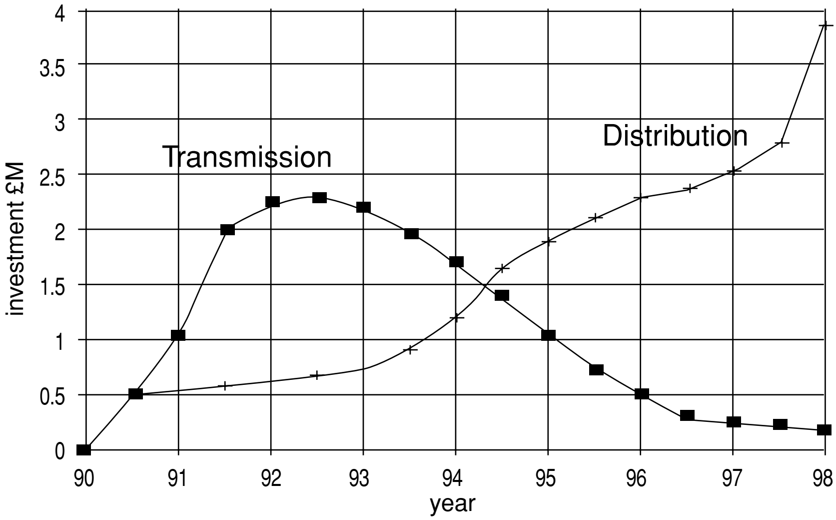

Figure 26.1 Profile of expenditure on metering; equipment after privatisation.

reconciliation with the pool half-hourly system of charging. In practice more consumers may chose to adopt half-hourly metering if the price is low enough and automatic collection can be arranged. A typical profile of expenditure on metering at the distribution level is shown as the dashed curve in Figure 26.1 and its shape reflects the timing of the changes in the franchise and the rate of take-up by customers.

A special metering requirement results from the need to monitor generator dynamic performance against the contract. This applies to its response to dispatch instructions where accurate operational metering is now required to confirm that the output is within agreed error bounds. It also applies to the dynamic response defined in ancillary service contracts where the speed of response necessitates special monitoring systems. The original SCADA systems did not provide sufficient accuracy to meet the requirements for monitoring performance against commercial contracts.

From a supplier perspective these developments expand the market for tariff metering and data collection and processing systems. At higher voltages this may also result in a need for new current and voltage transformers and metering summation systems to aggregate and process data. At lower voltages interest will be focused on enabling more complex tariffs with variable period charges and automatic reading and data collection. The scale of the market for processing the data can be judged from the costs estimated for the systems to support the removal of the REC franchise, which range from £100 M to £300 M in England and Wales.

Commercial Data Handling Systems

This is largely made up of managing the bid data into the pool and the output from the process of settlement in addition to the metering data described above. All players will have a need to manage their data and information flows.

For the generators the bid data has to be constructed on the basis of data from power stations and historic information, and transmitted to the centre responsible for receipt of bid data. The larger generators in England and Wales have chosen to set up Energy Management Centres to handle this activity. This requires data links to power stations to collect information, links to the Grid Operator to support bid submission and links to the settlement system. There would usually be a need to simulate operation using scheduling algorithms to support bid assessment and facilities to check the settlement data and process the results. Data links are also desirable between the power stations and the grid control centres to support the transmission of dispatch instructions and parameter redeclarations electronically. For the smaller generator it may be cheaper to combine these functions into a single system based on the existing SCADA links. The number of energy management centres to be created will depend on the number of generators but with the England and Wales 50 GW system it eventually led to the creation of some five EMCs together with backup centres. There was also a market for some twelve smaller station based systems to support the operation of the independents. To realise security most of the data communication was established on dedicated kilostream links with alternative routing. In total the cost of establishing these systems was probably in excess of £20 M with a profile as shown in Figure 26.2 and ongoing revenue costs of a some £5 M.

The suppliers have a requirement to process metering data and to appraise contract options and assess risk. They will also require links to the settlement process to receive reports and to check and process the results to review their commercial strategy. Major consumers also have an interest in benefiting from their size and negotiating the best terms for their supplies. This will include appraisal of tariff options and the development of demand monitoring and management systems.

Settlement Systems

The settlement system is the core of the pool commercial operation, it is required to capture all the relevant data to enable the bills and payments to be calculated and reconciled for all the players in the pool. The process has to be accurate, auditable and repeatable. In the England and Wales implementation the bid data is received via the grid operator who also undertakes

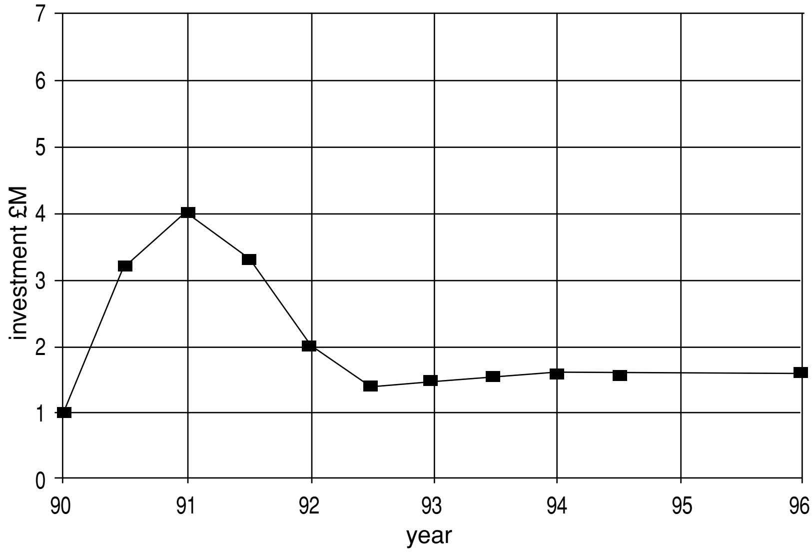

Figure 26.2 Commercial data handling and bidding; system expenditure.

the scheduling study that identifies the marginal generation. The information is extracted from the operational systems by the settlement system once a day together with generation dispatch information. The data has to be processed strictly in accordance with pool rules to establish the payments and charges due to each player and these are passed to a separate payments system. The total facility may cost tens of millions to set up with a similar cost for annual operation.

Asset Management Systems

The management of assets within the state-owned utilities was less than rigorous in contrast to what is considered to be necessary to support privatised operation and there is a general requirement to establish new detailed asset registers. Coupled to this is the desire to improve the asset management process with systems to manage outages and maintenance and to support field work. Sometimes new management structures have been introduced to focus attention on the asset base and to monitor and manage the life-cycle costs. The systems are important to support the commercial operation of the company and its charging and may also provide a useful source of registered technical data for use in analysis of the power system.

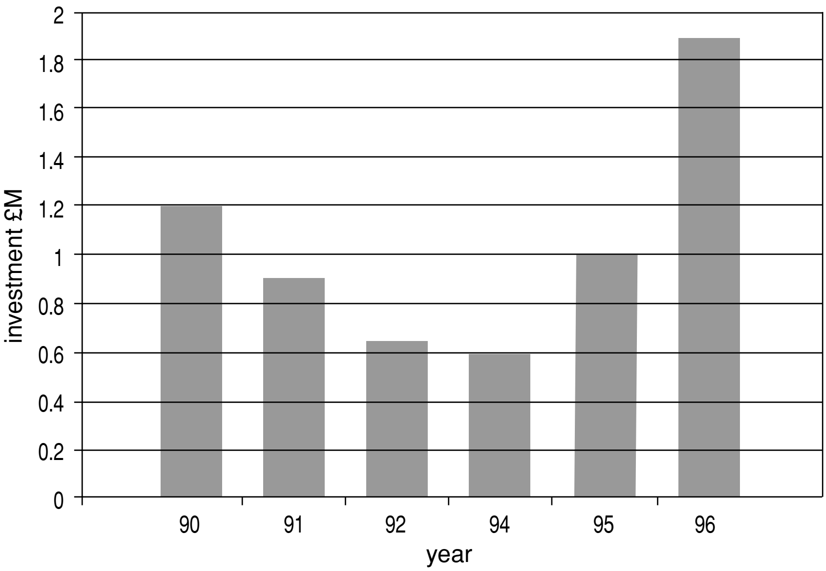

Figure 26.3 Operational expenditure on IT for commercial systems.

Operational Systems

In addition to the work undertaken on behalf of settlement there is a need for operations departments to manage commercial call-off generation and ancillary services or contractual terms, and to control transmission uplift costs. This requires the development of new facilities to monitor these services and to provide advice on their optimal allocation. An indication of expenditure purely on commercial systems is shown in Figure 26.3 where it can be seen that following the provision of basic systems to enable externally imposed privatisation time-scales to be met, a second wave of development can be expected to refine the systems.

The generation scheduling and dispatch process also has to be restructured to establish an auditable unbiased system and to accommodate electronic data transmissions. The importance of the results necessitates the development of data consistency checking and the provision of automatic audit checks. Network analysis and planning have to be developed to enable the impact of changing generation patterns to be assessed in much shorter time-scales and optimal power flows have been exploited to identify the best running arrangements. To provide the accuracy necessary to support commercial operation new metering systems were required based on tariff metering sources costing 4–5£ M.

Conclusions

It is difficult to generalise on the market for new facilities because they will depend on the chosen pool structure, its method of operation and the size of the utility. The estimates given are based on observations of developments in England and Wales and are indicative only of the scale of the work to be undertaken and its profile, with a prediction of future expenditure. They should, however, enable utilities undergoing reforms to consider and plan to meet their future resource needs.

PART SIX

The Market and the Future

Part 6 concludes this book and by discusses the regulatory framework and its limitations in improving efficiency and encouraging the optimum levels of investment. It addresses the question why six years on from privatisation the Financial Times is still carrying headlines ‘Warning over stifled electricity competition’ (10 June 1997). The principal findings of the book are reviewed and potential market improvements are described. This part concludes with a discussion of how markets may develop and the likely future for the industry.

CHAPTER TWENTY-SEVEN

The Role and Effect of Regulation

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 England and Wales, for transmission, the regulatory formula for the maximum average charge in £/kW, M in year t is given by:

$$M_t = \left[1 + \frac{\mathrm{RPI}_t - X_g}{100}\right] \times P_{t-1} \cdot G_t - K \tag{27.1}$$

where P_t–1 is the price/kW in year t–1 which is in turn a function of that for previous years, i.e.

$$P_{t-1} = P_{t-2}\left(1 + \frac{\mathrm{RPI}_{t-1} - X_g}{100}\right) \tag{27.2}$$

and G_t = 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

$$M_t = \left[1 + \frac{\mathrm{RPI}_{t\,-}\,X_d}{100}\right] \times P_{d_{t-1}} \cdot A_t - K_d \tag{27.3}$$

and for suppliers the initial restriction on charges was

$$Ms_t = \left[1 + \frac{\mathrm{RPI}_t - X_s}{100}\right] \times P_{s_{t-1}} + Y_t - Ks_t \tag{27.4}$$

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

$$Y_t = E_t + F_t + T_t + U_t + S_t \tag{27.5}$$

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 unlicensed services. (UK Department 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 (Monopolies and Mergers Commission). The Director has described his role as that of a referee and will adjudicate in disputes between licensees or licensees and consumers (Littlechild, 1991). 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.

International Practice

Regulation of monopolies has been practised for many years in the US and is known to suffer from a number of problems. It exists at three levels:

- FERC. The Federal Energy Regulatory Commision covers wholesale prices, monopolies and terms and conditions, transmission and hydro facilities,
- SEC. The Securities and Exchange Commission which regulates the business structure of utilities
- State Regulators who set rates and approve new plant

The structure can encourage 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 suppliers given the wealth of information that they can make available to support their case.

Norway has a Regulator to control the activities of the monopolies and promote competition in the market. In Australia a Regulator General covers several sectors and is also charged with promoting competition and protecting customers. In New Zealand there is no regulator but the industry is covered by general legislation on competition.

Where the price control is set to allow a defined return on assets employed, overinvestment can be encouraged. The formula proposed for the England and Wales was designed to overcome this deficiency by focusing on charges but has the problem that if it continues to be tightened at successive reviews it might destroy incentive. It might also reduce investment if less favourable borrowing terms were to result from a reduction in perceived shareholder value and lead to the need for higher returns on capital investment.

Experience

In England and Wales 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 1990 to 52% in 1998, but it is generally accepted that the two major players are still able to control prices (OFFER Report, July 1994) and few observers believe that real competition exists. 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 70% of customers with demand greater than 1 MW taking supplies from other than their local REC. In the case of the emerging 100 kW market, some 50% are contracted with other suppliers, although not without problems in introduction. The date for 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 £300 M). Speculation suggests that the margins of the suppliers are already tight and competition might result in savings of 5% at best.

The entry of new generation into other markets has been much less, owing to a number of reasons related to fuel policy and existing capacity levels, as outlined in Chapter 25. In Australia, the introduction of supply competition has followed the England and Wales approach of gradual liberalisation. Norway and New Zealand have enabled supply competition and in California plans have been established to introduce retail choice. In many cases the need for special metering to benefit from market prices has constrained take-up and the alternative of predefined demand profiles is being accepted. The continuing fall in the price of processors can be expected to feed through to meters and change this situation.

Impact on Generation and Transmission

In England and Wales the government of the day believed that generation was not a natural monopoly: price control was not necessary 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 other markets the initial structure has sought to break up generation into smaller modules with restrictions on market share and they may be more successful in promoting competition.

In England and Wales the 1996 proposals of the regulator saw the need to impose a one-off reduction in 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 longer-term investment appraisal very difficult.

The regulator also ruled on 6 August 1996 that Scottish Power and HydroElectric could use the full interconnector capacity to export to England and Wales. Prior to this decision the amount of capacity available could be restricted by any 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. If enforced this would obviously not have been a sensible exploitation of investment in interconnection and eventually the principle of superposition was accepted.

The Nuclear Position

The UK 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 in order to be able to bear the costs. On 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 RECs 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 to fund 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 England and Wales industry is disadvantaged (Newbery, 1993). As the levy currently recovers some £1.3 bn/year against the requirement for an accumulated sum of some £9 bn for decommissioning, 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 £95 M/year. Stranded assets are generally a problem where utilities have long-term arrangements or contracts which are not sustainable in a competitive market.

Gas Electricity Arbitrage

The availability of cheap gas is resulting in the development of an increasing proportion of electricity generation being met by combined cycle gas generation (CCGTs). The full implications of this have yet to materialise but some problems have already been experienced in electricity operation when the result of invoking gas interruption contracts has led to shortfalls in electricity generating capacity. Failures of gas supply lines might also cause widespread disruption to electricity generation. Electricity failures may in turn affect gas supply systems. Whereas the gas market operates on a firm basis generators can withdraw capacity from the electricity market on the day without penalty.

For the most part the two sectors operate independently and this may not be in the best interests of market players or consumers. Some companies have recognised the opportunity presented by being able to trade in gas and electricity and to exercise arbitrage in real time and are operating in both markets. There should be more benefit in enabling interaction in appraising investment opportunities and joint operational planning. The integrated development of the infrastructure of gas pipelines and electricity transmission would seem desirable but not readily enabled in the current environment.

A fundamental regulatory issue is whether gas and electricity transmission should be regarded as two separate monopolies independently regulated or as a single open access energy transportation system. A strong case can be made to establish mechanisms to facilitate joint development and avoid duplication and common system bottlenecks. Benefits should also derive from joint planning of outages and procedures to manage faults. If alternatively they are seen as being in competition then they are no longer monopolies and regulation should be relaxed. More open access to data is necessary to support the full investigation of these issues.

Impact on Investment

In England and Wales the threat of referral to the Monopolies and Mergers Commission (MMC) is seen by some 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 advantage 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 industry's 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 charges tends to discourage investment and development and focuses attention on presenting the best face to the regulatory review on the justifiable cost base and building non-licenced activities. As these industries may not benefit financially from an improvement in the service they provide it can sometimes be difficult to justify expenditure even though it would benefit the overall industry. It is very difficult through the cycle of regulatory reviews to establish stable plans for the long-term development of the network when compounded by the uncertainty in future generation and its location.

It is difficult to see how the process of regulation, as currently framed, can 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. The introduction of more self-regulation against targets and competition through service level agreements is likely to serve the industry better.

CHAPTER TWENTY-EIGHT

Conclusions

The Market

The arrangements and performance of electricity markets were reviewed in Part 1. It was shown that the England and Wales market has shortcomings in realising stable low prices through competition and in encouraging the optimal generation margin and mix. Alternative market structures were described and compared in terms of their likely effect on competition, efficiency, and integrated planning. It was suggested that the climate most likely to encourage competition is one where there are a large number of generators with no dominant control over the marginal units. The introduction of full competition in generation and supply encourages efficiency but at the expense of a high cost in setting up and running the market and increased volatility and uncertainty. The alternative 'single buyer' or mixed private and public generation models can derive much of the benefit of competition through competitive tendering for generation whilst retaining the ability to plan the development of the overall system optimally.

An approach to modelling the market and assessing the performance was discussed and illustrated by reference to the England and Wales system. It was outlined how income and expenditure could be assessed using cost based models and the performance was demonstrated by comparison with results recorded from actual operation. This showed that prices in England and Wales have risen above what would be expected considering the falling trend in fuel prices.

The theory of system marginal pricing and its relationship to plant mix was developed and illustrated using a graphical and an LP formulation of the optimal plant mix problem. These showed the relationship between load shape, plant mix and SMP and how the plant margin and system cost profile affect the volatility of marginal prices. A dichotomy was shown to exist 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.

The theory supporting the loss of load element of pool pricing was developed from first principles 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 generator pooling. Finally it was shown how the optimal plant margin could be derived, i.e. 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 was suggested that the payments need to be focused directly on encouraging and financing additional capacity or abandoned.

The theory supporting the derivation of the ideal energy and capacity prices was discussed in order to equate incremental cost with the consumer added benefit. A comparison was made against the use of a simple bulk supply tariff (BST) and actual charges. It was concluded that energy prices were some 12% above a marginal cost based assessment.

Part 1 concluded with a review of the market mechanisms and suggested alternatives. It was 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 the requirement is unlikely to be met by a day ahead market. It was proposed that a more effective futures market could be established using a medium-term prediction of operation rather than a day ahead market. It could 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 could also facilitate consumer participation and should be contractually firm leading to more stable prices. It was argued that a market developed taking account of the principles of optimisation algorithms and providing simulation in time-scales more consistent with investment appraisal offers the best prospect of realising long-term efficiency in the industry.

Generation Investment Appraisal

In Part 2 the implications of deregulation for the approach to generator investment appraisal were reviewed. It was shown that the classical technique based on an LP formulation, with the objective function set to minimise costs, is no longer applicable. A new iterative LP formulation was developed to maximise generator profits and it was used to confirm that this produced different results because all energy is paid for at the marginal price. The implication is that portfolio generators will make more profit by the retention of older higher cost units that will set high SMPs from time to time and result in more profit from all energy sold than would be realised from the replacement of all the marginal units. The results confirmed this by showing in practice the retention of a higher proportion of small coal stations than would be optimum.

It was postulated that in a true market the high dependence of profits on the SMP makes it essential to predict it using a time series model simulating both the effect of start-up costs and the effect of generator dynamic constraints when tracking demand. The theory and approach were developed, based on an operational simulation model coupled with a post processing algorithm to derive utilisation, costs and profit. Simulations were used to demonstrate the optimal bidding strategy based on marginal cost and to predict the profitability of CCGTs 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 price was being controlled. If post-1998 a true market comes into effect then it will become essential to predict the market price to assess future profitability.

The relationship between the overall generator per unit profit and additional capacity was derived and used to show how total profit varies with capacity in a competitive market. It was shown that it reaches a maximum when the product of price and capacity is highest and further additions would be offset by price reductions. 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, the Stackelburg equilibrium and the Cournot theory. The results further highlight 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 a new LP formulation to establish the total system capacity position, the use of a dynamic operational model to establish accurate SMPs and profit estimates, and using the profit function and interaction model to estimate market share and the optimum capacity addition.

Finally 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 function. It was shown how these could be used as the basis of a model to simulate company interaction taking account of their existing capacity and market share. The results of studies were shown to exhibit similar trends to the actual capacity additions that occurred in England and Wales during the early years. It was concluded that the deregulation process is unlikely to result in optimal expansion planning and that investment cycling may occur.

Transmission Investment Appraisal

Part 3 reviewed 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 were reviewed and the common themes and apparent shortcomings were identified. It is generally accepted 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 entity. There is less consensus on the methods used to establish and apportion charges and none of the approaches appears to provide a basis for the sponsorship or appraisal of transmission investment.

A proposal for the apportionment of costs in relation to benefit was developed and it was suggested that different principles need to be applied to deal 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 the infrastructure each requiring a different approach to the evaluation of benefit and investment.

Simulations were developed to illustrate the interaction of generators, the transmitter and suppliers/consumers through the market and their respective benefits deriving from system interconnection. It was shown how a generator may benefit through influencing the prices in those zones for which it has supply contracts by effectively ‘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 which gives the maximum return to the transmitter. Finally the impact of consumers’ response to prices was included to demonstrate their importance in containing escalation.

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 market to generators raising prices for ‘constrained on’ units makes it essential to establish hedging contracts or adopt a system of zonal energy prices. It was proposed that a long-term transmission services incentive scheme would be necessary to encourage the optimal levels of investment in transmission. The establishment of a system based on zonal marginal energy pricing would more clearly illustrate the impact of constraints on particular players and the benefit to them of the investment needed to remove them but fragmentation of ownership should be avoided and developments should be coordinated with benefit equally shared.

The simulation of operation was further developed to model transmission group constraints and 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 λ's equated to the same value. It was proposed that the resulting value of λ provides the best estimate of the worth of an increment of transmission in reducing out of merit operating costs. This part concludes with an assessment of the benefit arising from reduced losses and a discussion of the commercial conditions necessary to sponsor and promote the optimal levels of investment.

The Impact on Utility Operations

Part 4 discussed the impact of privatisation on the business processes of the utilities and how the role of market facilitator has been overlaid on the already complex task of system operation. It has introduced new levels of uncertainty in generation prices and availability which restricts the ability of operators to forward plan the network and maintenance of security. The role of facilitating the market has brought stringent requirements for all operations to be undertaken in strict accordance with the data as submitted and for the process to be fully auditable. To meet these requirements while containing the cost of operation has necessitated re-engineering of the processes and the development of automated data handling. In many of the developing markets it is proposed that system operations should be established as an independent entity without vested interests.

Planning the development of the network is now primarily driven by the generators by requests for new connections and the system developers have had to adapt their processes to ensure a timely response. Accommodating generation in less than ideal locations has necessitated stretching the capability of the network with the widespread application of active and reactive compensation equipment. In the absence of overall control and with the high levels of uncertainty in future generation expansion and location, the retention of flexibility has become a driving force in the new environment.

Although the industry has been fragmented commercially it still appears to put on a united front to protect its common source of income from consumers. One effect of regulatory pressure has been to cause the industry to look for wider markets overseas and to promote unlicenced business development through internal suppliers.

IT has been the key enabler in meeting the new requirements to support commercial operation and data capture for settlement. It has also been extensively applied to enable downsizing by automating processes to cut costs. The generators have established energy management centres which have reduced the workload at regional grid control centres enabling their closure and further cost savings.

The Changing Market for Facility Providers

Part 5 discussed the impact of privatisation on the relationship between the utilities and their traditional suppliers and the new opportunities for the provision of goods and services. There is a shift away from requiring technical excellence to realising minimum cost with more reliance being placed on the supplier to offer a total solution service. The increased pace of change coupled with widespread downsizing has driven the utilities to out-source more of their operations with an increase in the use of consultants.

Following the inception of a market the initial rate of expansion of generation can be expected to increase over and above the inherent demand growth as new players enter the market. The larger generators will in part offset this by advancing programmes of closures but there may well follow a downturn in new orders until demand growth and natural closures redress the high margins. In the absence of control over generation siting, a poor zonal generation/demand balance may need to be accommodated. This may necessitate the widespread application of compensation equipment to stretch the capacity of the transmission system to support the new connections. There is also likely to be an increase in the use of interconnection and techniques to manage the transfers effectively using FACTS devices. A significant increase in distribution expenditure can also be expected as an increasing proportion of the installed equipment approaches the end of its life-cycle, and it is expected that replacement will focus on realising more automated operation.

There is an increase in the requirements for tariff metering to measure the energy transfer at the new ownership boundaries and to support the wider use of time of day tariffs for the larger consumers. The additional needs for facilities for data management systems for settlement and asset management increases the IT expenditure and dependence and creates a market for systems to support market trading.

CHAPTER TWENTY-NINE

The Future

Are Markets Delivering Benefit?

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

- ensuring that true competition is established with prices reflecting marginal costs and equating to consumer value
- ensuring that customer influence exists in the market through choice of energy use and the level of security of supply
- encouraging 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 markets have failed to deliver significant customer benefit through reduced prices. In England and Wales 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 future support problems. More generators have entered the market but the developing dependence on gas supplies with interruptible contract terms may put the system at risk at times of stress. We shall continue to have headlines such as 'Warning over stifled electricity competition' (FT, 10 June 1997) unless the large generators are forced to sell off more generation equipment.

Consumer choice in suppliers is being developed and taken up but little has been done to enable consumers to participate actively in the market in order to influence prices and the generators still have long-term contracts which control prices. The recent climb-down by the Regulator over the price reductions following the 1998 franchise removal shows the industry exercising more control than it probably had under government ownership.

It needs to be established in the new market structures where the responsibility rests for meeting demand. In England and Wales there have been several near misses when generation shortfalls have put the ability to maintain supplies in jeopardy. This has been aggravated by the dependence on gas generation with interruptible contracts and the fact that the generation bids into the market are not required to be firm and are subject to withdrawal without notice. There is a general need to review the implications of gas/electricity arbitrage given the increasing dependence on gas generation. In the absence of a market mechanism to influence plant mix the UK government has put a hold on licensing new gas generation and has initiated a study of potential impact on system security. There has also been pressure on the transmitter by the Regulator to adopt n–1 as opposed to n–2 circuit outage security standards in planning and operation of the system which, if adopted, would introduce further risk to supplies. Whereas the security of generation is signalled by the LOLP mechanism there is no equivalent mechanism by which consumers can signal their needs for transmission and distribution security. It is difficult to see how optimum planning and investment can be realised through the current market mechanisms, and suboptimal development will eventually 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 and it is hoped that this will undermine the ability to fix prices with long-term contracts and open up competition. Faced with concerns from a variety of sources the UK government commissioned in 1998 a review of trading arrangements including trading outside the pool and the development of more consumer influence in the market.

The Economic Theory

There are two schools of economic theory, one sees private ownership and the pressure deriving from that as essential to promote efficiency and all that is necessary. These ‘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 lose their jobs in the event of a take-over.

There is a counter-view that private capital markets encourage short-termism at the expense of long-term strategic investment. The threat of a take-over is not necessary to promote efficiency as evidenced by the performance of Japan and Germany where take-overs are rare. The electricity sector is essentially a complex long-term capital intensive industry and its costs are more likely to be minimised by long-term integrated planning rather than short-term opportunism. An element of public ownership or influence gives the opportunity to maintain those stable prices which are essential to enable the appraisal and funding of large scale infrastructure development.

The efficiency of the electricity industry is dominated by fuel costs and interest and depreciation charges. Typically fuel costs amount to 60% and depreciation and interest to some 20% with other services and staff costs making up the rest. These costs are in turn the result of previous investment decisions and the diversity established in alternative fuel sources. In practice this is 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 by introducing competitive tendering for new generation. The 'dash for gas' could have been managed to avoid the early closures of existing generation and the associated loss of diversity. In the longer term the over-dependence on the gas grid may jeopardise system security. It is against this background of fundamental differences of principle that the industry is moving forward along a number of different paths across the world.

Alternative Structures

Several structures have been proposed and are being applied for managing electricity supply, including:

- the gross pool trading all energy
- bilateral trading with a net pool to manage the residual energy
- the generation single buyer who acts on behalf of all consumers to purchase energy in a competitive generation market.
- zonal pools with nodal pricing of energy and trading across boundaries
- mixed generation with a hybrid of public ownership supplemented by private generation.
- the vertically integrated monopoly of which there are many examples

It is arguable that most of the benefit to be derived from electricity 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 generation that would be difficult to finance privately and in enabling integrated planning. The disadvantage is the absence 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 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 (NUGs) nor are they considered to contribute to firm capacity and plant margins.

The full private ownership implemented in England and Wales introduces competition in supply as well as generation by progressive removal of the REC franchise. It has been suggested, however, that in practice a cartel exists and that the generators will act in their group interest with little saving to end customers. A disadvantage of the England and Wales model is that it does not promote integrated planning and this may have an adverse impact on prices in the long term.

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 book has, amongst other proposals, advanced an alternative to address this shortcoming of the private market by establishing a forward futures market to support investment planning. This could be enabled as an information service or with a principal establishing contracts as the single buyer, but is only likely to happen if the City believes that true competition exists. 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 balancing market to take account of outages and demand estimation errors. The proposal represents a compromise which seeks to enable competition within a control framework which fosters optimal development.

It appears generally accepted that the England and Wales experiment has shown up shortcomings in operation and other arrangements are likely to be developed and applied elsewhere.

Alternative Working Arrangements

It was 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 England and Wales 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 separate from that of the system to ensure open access and fair treatment. Separate system operation companies are now being established in the US to manage scheduling, dispatch and system monitoring and their operation will be viewed with interest. It represents a considerable challenge to implement these proposals while providing sufficient controls for the ISO to maintain system security, but the ISO is likely to emerge as the preferred model. In the England and Wales model the problem is decomposed 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 to how the operational problem can be managed to enable this. Some market proposals enable price and bid manipulation to within an hour of real time operation this leaves little time for the operator to ensure the security of the system and may prove to be beyond what is sensibly practical.

The Way Forward

It is likely that other countries, having observed the operation of the England and Wales market will adopt alternative arrangements which may prove more effective. Their 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 the basic development of its infrastructure before launching into the uncertainty of competitive markets.

Developments are currently being driven at the political and commercial level and there is a danger of discounting and losing the benefits of optimal planning and operation developed to support integrated utilities. Of serious concern is the uncertainty facing investors in the deregulated markets if full competition is realised. This implies risk with the attendant higher returns necessary to cover it which must eventually feed through into prices.

This book has provided a basic framework on which to model and analyse performance and many of the principles will apply equally to other structures and will enable a more considered and structured approach to deregulation. The new challenge is to contain the uncertainty by enabling integrated future planning while facilitating full competition in generation.

Further Developments

Deregulation will continue to sweep through the world as it creates new opportunities for many of the leading players in the industry. In the aftermath a review may show little benefit to the end consumer with the market controlled by a few large players set on maintaining and increasing the income of the industry. Mergers and acquisitions will grow as the deregulated utilities seek to expand their overseas activities and become global players. Their suppliers will follow a similar trend, reducing to a few focused on standard products applied across the world but hopefully sufficient in number to maintain competition. Local governments will have less control and influence on the new super utilities and a key part of their infrastructure may be in the hands of multinationals. The public right to secure supplies at reasonable price has come to be taken for granted and the state prevented any exploitation. It is less clear who will champion the small consumer in the new environment.

Conclusion

This book provides a basic framework of understanding and modelling to enable the evaluation of alternative commercial structures and market mechanisms. This 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 with 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. They also enable 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 but single ownership should be maintained.

In conclusion 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 in a highly complex and capital intensive industry like electricity supply.

SELECT BIBLIOGRAPHY

Aperjis, D., White, D.C., Schweppe, F.C., Mettler, M. and Merrill, H.M., 1982. Energy strategy planning for electric utilities. 11 SMARTE methodology case study, *IEEE Trans Pwr App. Systems,* **PAS-101(2)**, 347–355.

Bellman, R.E. and Dreyfus, S.E., 1994. *Applied Dynamic Programming*. Princeton University Press, Princeton (NJ).

Billington, R. and Ghajar R., 1994. Evaluation of the marginal outage costs of generating systems for the purposes of spot pricing. *IEEE Trans Pwr App. Systems,* **PAS-9(1)**, 68–75.

Bunn D.W. and Vlahos K., 1992. A model referenced procedure to support adversarial decision processes. *Energy Economics*, **14**, 242–247.

Bunn D.W., Larson E., 1992. Sensitivity of reserve margins to factors influencing investment behaviour in the electricity market of England and Wales. *Energy Policy*, **20**, 420–429.

Calviou M., 1993. Charging for use of a transmission system by marginal cost methods. *PSCC 93 Avignon*, **(1)**, 385–391.

Caramanis, M., 1983. Analysis of non-dispatchable options in the generation expansion plan. *IEEE Trans. Pwr App. Systems*, **PAS-102(7)**, 2098–103.

Chiang, A.C, 1984. *Fundamentals Methods of Mathematical Economics*. McGraw Hill.

Cohen, A. and Sherkat, V., 1987. Optimisation based methods for operational scedules. *IEEE Proc.*, **75**, 1574–91.

Embrey, K., Stillinger, W. and Manhire, B., 1987. *Nondispatchable technologies: a computer evaluation of their impact on a power system. IEEE, New York*, NY, USA.

Farmer, E.D., Cory, B.J. and Perera B.L., 1995. Optimal pricing of transmission and distribution services in electricity supply. *Proc. IEE*, **142**(1), 1–8.

Gorenstin, B.G., 1993. Power system expansion planning under uncertainty. *PSCC 93 Avignon*, **I,** 585–591.

Gronheit, 1995. Application and limitations of annual models for electricity capacity development, Symposium. *IFORS*, **35**.

Happ, H.H., 1994. Cost of wheeling methodologies. *IEEE Transactions*, **PAS 9**(1), 147–146.

Hartl, P., 1989. Unit commitment by genetic programming. *Operational Research Proceedings*.

Head, W.J., Nguyen, H.V., Kahle, R.L., Bachman, P.A., Jensen A.A. and Watry, S.J, 1990. The procedure used to assess the long range generation and transmission resources in the Mid-Continent Area Power Pool. IEEE *Trans. Pwr App. Systems* **5**(4), 1137–1145.

Hissey, T. W., 1994. International experience in transmission open access. *IEEE Pwr Eng. Rev.*

Hunt, S. and Shuttleworth, G., 1996. *Competition and Choice in Electricity*. J. Wiley & Sons Ltd, Chichester.

Huber, H.E., Redmond, J.A. and McDonald, J.R., 1993. Multi-attribute tradeoff analysis applied to long-term generation planning. *IEE 2nd Int. Conf. in Power Systems Control*, London.

Jacobs, J.M., 1995. Approximating expected marginal production cost with capacity commitment requirements. *IEEE Trans*actions, **10**(3), 1511–1517.

Keeping, E.S., 1962. *Introduction to Statistical Inference*. International Student Editions, D. Van Nostrand Co Ltd, Canada and New York..

Littlechild, S., 1991. Speech to society of investment analysts, Regulation of the British Electricity Industry, OFFER Library, Birmingham.

Merrill, H.M. and Schweppe, F.C., 1971. Bad data suppression in power system static state estimation. *IEEE Trans Pwr App. and Systems*, **PAS-90**(6), 2718–2725.

Merrill, H.M., Schweppe, F.C. and White, D.C., 1982. Energy strategy planning for electric utilities 1. SMARTE methodology, *IEEE Trans Pwr App. and Systems*, **PAS-101**(2), 340–346.

Muller, H., 1993. Genetic programming and simulated annealing for optimisation of unit commitment., PhD Thesis, University of Vienna.

Newberry, D., 1993. Fossil fuel levy fails efficiency test, *Financial Times*.

OFFER, Report on trading outside the pool, July 94, OFFER Library, Birmingham.

Oliveira, P., 1992. Lagrangian relaxation and its application to the unit commitment and economic dispatch problem. *Jrnl Maths Applied in Business and Industry,* **IMA-4,** 261–272.

Plowman, D., 1994. *Reforming Victoria's Electricity Commission*, Published by Office of State Owned Enterprises.

Post, D.L., 1995. Application of auctions as a pricing mechanism for the interchange of electric power, *IEEE Transactions*.

Schweppe, F.C., Caramanis, M.C., Tabors, R.D. and Bohn, R.E., 1988. *Spot Pricing of Electricity*. Kluwer Academic Publishers, Boston/Dordrecht/London.

Sherali, H.D. and Staschus, K., 1990. A two-phase decomposition approach for electric utility capacity expansion planning including nondispatchable technologies. *Operations Research*, **OR-38**(5), 773–791.

Shirmohammadi, 1989. Evaluation of transmission network capacity use for wheeling, *IEEE Trans.*

Siddiqi, S.N. and Baughman, M.L., 1994. Optimal pricing of non-utility generation. *IEEE Transactions*, **PAS-9**(1), 397–403.

Tabors, R.D. and Monroe, B.L., 1991. Planning for future uncertainties in electric power generation: an analysis of transitional strategies for reduction of carbon and sulphur emissions. *IEEE Trans Pwr App. Systems*, **PAS-6**(4), 1500–1507.

Tabors, R.D. and Flagg, D.P., 1986. Natural gas fired combined cycle generators: dominant solutions in capacity planning. *IEEE Trans Pwr App. Systems*, **PWRS-1**(2), 122–127.

Tabors R. D., 1989. Coal to natural gas seasonal fuel switching an option for acid rain control. *IEEE Trans Pwr App. Systems*, **PAS-4**(2), 457–462.

Tanabe, R., 1993. An algorithm for the optimal generation mix accounting for fuzziness of both decision making and planning parameters. **PSCC-1**, *Avignon*, 593–599.

Transmission Licence, 1990. Issued in accordance with Electricity Act 1989, The National Grid Co L/DE/008/TRN, Published by OFFER, Birmingham.

Turvey, R. and Anderson, D., 1977. *Electricity Economics*. World Bank Research Publication, John Hopkins University Press, Baltimore and London.

Varian, Hair, 1990. *Intermediate Microeconomics: A Modern Approach*. Norton, International Student Edition, W.W. Norton & Company, New York and London.

Vojdani, R., 1996. Transmission access issues. *IEEE Transactions*, p. 41.

Wang and Shahidepour, 1995, Power system marginal cost curve and its application. *IEEE Pwr Transactions*.

GLOSSARY

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

CCGTs combined cycle gas turbine using gas turbines with a back-end steam turbine.

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

Constrained off generation that cannot be run in MO without violating a transmission constraint.

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 electrical 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 number 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 Table ‘B’ price.

***n*–1 and *n*–2** the number of circuits less the number of outages against which the system is secure.

OCGTs 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 equal to 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 ancillary 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.

INDEX

Index Terms	**Links**			

Index Terms	Links	

D

E

Index Terms	Links			

I

L

Index Terms	Links			