

The New Electricity Trading Arrangements

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18. The Way Forward

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Note:

On 16 June 1999, the former regulatory offices, Ofgas and OFFER, were renamed the Office of Gas and Electricity Markets (Ofgem). References in the text to documents and events before this date use the name of the original regulatory office.

The New Electricity Trading Arrangements

Executive Summary

Introduction

This document sets out for consultation further detailed proposals for implementing new electricity trading arrangements in England and Wales.

The proposals build on the trading arrangements suggested by the Director General of Electricity Supply (The Director General) in July 1998.¹ The proposals were to put in place market-based trading arrangements more like those in commodity markets and competitive energy markets elsewhere. They were designed to be more efficient and provide greater choice for market participants while maintaining the operation of a secure and reliable electricity system.

The Director General's proposals were accepted by the Government as the right way forward in October 1998 in its White Paper on Energy Policy.² In November 1998, the Director General published a Framework Document³ which explained how the Programme for the Reform of Electricity Trading Arrangements (RETA) would be taken forward. It confirmed that OFFER and the Department of Trade and Industry (DTI) would lead the process, supported by a Programme Director, and that the Programme would facilitate the full participation of the industry and its customers.

These latest proposals reflect an intensive programme of work, under OFFER and DTI direction and involving all interested parties, which has taken place since November. Subject to time being found in the 1999/2000 Parliamentary session for the necessary primary legislation, it is anticipated that the new trading arrangements will be introduced from the autumn of 2000.

¹ Review of Electricity Trading Arrangements: Proposals, OFFER, July 1998.

² Conclusions on the Review of Energy Sources for Power Generation and Government response to fourth and fifth Reports of the Trade and Industry Committee – October 1998.

³ Review of Electricity Trading Arrangements: Framework Document, OFFER, November 1998.

Reasons for Reform

The Electricity Pool of England and Wales is at the centre of the present trading arrangements. It was set up on privatisation, based on the existing Central Electricity Generating Board (CEGB) arrangements for system operation. The Pool provides a mechanism for setting a single wholesale price and despatching generating plant to meet demand, thereby ensuring the electricity system is kept in physical balance at all times. It is compulsory for licensed generators to sell the vast majority of their electricity output into the Pool and for licensed suppliers to purchase all their supplies out of the Pool to meet the demand of their customers.

The National Grid Company (NGC), on behalf of the Pool, provides an estimate of system demand; requires generators each day to provide offers specifying the price at which they are prepared to sell their electricity; ranks the offers in ascending order to meet its estimated demand; and determines Pool prices at the highest accepted offer price (i.e. system marginal price). A capacity payment is calculated and added to the price. It varies in size depending on the amount of generation capacity declared available relative to forecast demand. As System Operator, NGC despatches plant to balance demand, taking into account any constraints on its transmission system.

The Review of these arrangements carried out in 1998 noted that, in some respects, they have worked satisfactorily. The balancing arrangements have maintained the quality and security of supplies. The trading and pricing arrangements have assisted new generators in entering the market and have allowed competition in supply to be introduced.

However, the Review found that many of the concerns about the arrangements are justified. In particular, bids into the Pool by generators are not reflective of costs and movements in Pool prices have not matched reductions in costs. Since 1990 wholesale electricity prices have been largely unchanged, while the costs of generation in terms of fuel costs and capital and operating costs have reduced by almost 50%. Market power has been a factor in maintaining or increasing Pool prices. But the present trading arrangements have facilitated the exercise of market power at the expense of customers by enabling all generators to receive a uniform price which in practice has been set by just a few of them.

To the extent that prices have been higher than they would have been in a more competitive market, in part due to the trading arrangements, it is possible that this has encouraged excess new entry at the expense of existing plant. Entry has been dominated by gas-fired plant whereas the majority of plant closures have been of coal-fired capacity.

Electricity suppliers do not pay on the basis of negotiated prices, but on a single Pool price, which inhibits supply side price pressure. There is limited involvement from the demand side within the Pool, which leads to higher prices overall and taller price 'spikes' than otherwise would be the case. The complexity and opacity of the Pool's price setting process and the lack of competition in price setting has inhibited the development of derivatives markets and reduced liquidity in the contracts markets. This results in high margins on the financial contracts struck between generators and suppliers, thereby further raising prices to customers above those that would prevail with more competitive arrangements.

Capacity payments are intended to provide both a short-term and a long-term signal of capacity requirements. However, they do not provide a very effective short-term signal to encourage generation and demand to respond to rapidly changing circumstances, since they do not accurately reflect short-term changes in capacity margin. Also, from year to year, capacity payments have not worked as intended: in years when capacity payments have been low, generators have increased system marginal prices. In addition, these complex and administered payments provide a poor long-term signal for the need for capacity.

Increasing interaction between the gas and electricity markets will lead to inefficiencies if generators are not faced with the financial consequences of withdrawing scheduled output from the Pool. More generally generators and suppliers do not face fully the costs and consequences of their actions because neither group make firm commitments to generate or consume electricity.

Present Pool governance arrangements are inflexible and have precluded change or delayed reform. Until relatively recently customers have had no role in governance, and still have no voting powers on the Executive Committee. The Director General cannot take steps directly to secure change in the Pool.

It is important that new trading arrangements continue to provide for electricity supply and demand to be balanced efficiently moment by moment to deliver secure supplies. But there is no simple way to modify the Pool's centrally planned price setting mechanism to achieve more competitive prices. Recent experience in the Pool continues to show that, despite reduced concentration in the generation market, Pool prices are still capable of being manipulated.

Market-based trading arrangements, in which most electricity is sold and purchased in competitive markets, and where only the residual trading required to ensure system balancing remains the responsibility of NGC in its role as operator of the national grid system (System Operator), should provide lower prices whilst maintaining security.

Experience elsewhere in the world where electricity liberalisation is taking place shows a trend towards market based solutions. The trading arrangements in England and Wales are no longer at the 'cutting edge' as they were when first introduced.

Overview of the Trading Arrangements

The basic outline of the trading arrangements remains unchanged from that described in the July 1998 Proposals document.

The proposals are based on bilateral trading between generators, suppliers, traders and customers. They include:

- ◆ Forwards and futures markets, which evolve in response to the requirements of participants, that will allow contracts for electricity to be struck up to several years ahead;
- ◆ Short-term power exchanges, also evolving in response to the requirements of participants, to give participants the opportunity to 'fine tune' their contract positions in a simple and accessible way;
- ◆ A Balancing Mechanism in which NGC, as System Operator, accepts offers of and bids for electricity to enable it to balance the system; and
- ◆ A Settlement Process for charging participants whose contracted positions do not match their metered volumes of electricity, for the settlement of accepted Balancing Mechanism offers and bids, and for recovering the System Operator's costs of balancing the system.

It is envisaged that the present Pooling and Settlement Agreement will be replaced by the Balancing and Settlement Code (BSC) incorporating the rules of the Balancing Mechanism and Settlement Process. NGC, as System Operator, will be obliged to maintain the Code. Licensees will be obliged to conform to it. The Code will include flexible and effective governance arrangements to allow for modifications to the rules.

Forwards, Futures and Short Term Bilateral Markets

The contractual freedom and bilateral pricing associated with these markets should ensure that prices better track costs as generators seek out purchasers for their power, suppliers and customers seek the most competitive terms from generators, and traders enter the markets, thereby increasing liquidity.

The RETA Programme initially considered whether it might be necessary to procure the establishment of a short-term (24-hour) screen-based power exchange to facilitate fine-tuning of contractual positions. However, it was decided that this was unnecessary given the extent of interest in such a venture. This decision has been borne out by subsequent expressions of intent to establish such a market by experienced market operators.

The forward, futures and short term power exchanges are expected to become the main wholesale markets, where the vast majority of electricity will be traded and priced. By the time the Balancing Mechanism opens for a trading period - 4 hours before 'real time' - it is expected that generators' contract positions will generally closely match their anticipated metered generation output and suppliers' contract positions will be close to the anticipated metered demand of their customers.

The Balancing Mechanism

The main focus of the work Programme since November 1998 has been on devising rules for the Balancing Mechanism and the associated Settlement Process. The balancing and settlement rules need to ensure efficient balancing of the system by the System Operator, whilst encouraging generators and suppliers to contract ahead for most of their requirements in forward, futures and short-term markets.

The Balancing Mechanism will provide a basis whereby NGC, as System Operator, can accept offers of electricity (generation increases and demand reductions) and bids for

electricity (generation reductions and demand increases) at very short notice. The System Operator will accept offers to increase generation (or reduce demand) if it forecasts that the system will be short of electricity, or accept bids to reduce generation (or increase demand) if the system is expected to be over supplied. Accepted offers will be paid for at the prices offered (and accepted bids will pay the prices bid).

The System Operator will also contract in advance (sometimes up to a year or more ahead) for some balancing services such as reserve, frequency control and voltage support. Such contracts, together with its actions in the Balancing Mechanism, will enable it to balance physically the system second by second, and thereby maintain quality and security of supply.

To help assess the likely physical balance of the system, the System Operator will ask participants to notify their expected physical position for each half hour trading period (i.e. their anticipated metered generation output and expected metered demand). The final submission of physical notifications will take place as the Balancing Mechanism opens. These notifications will also provide the baseline for bids and offers from generators and the demand-side.

A wide range of participants will be able to make bids and offers to the System Operator through the Balancing Mechanism, including generators, suppliers and customers. They will be required to sign the BSC. However, nobody will be obliged to make bids or offers into the Balancing Mechanism.

The Settlement Process

The position of all BSC signatories will be assessed to determine whether their metered output or consumption of electricity matches their contracted position. If it does not then they will be 'out of balance'. Generators will be paid for uncontracted generation and charged for contracted volumes not covered by generation. Suppliers will be charged for uncontracted supply and be paid for contracted volumes not matched by consumption. Traders will be charged if they have sold under contract more electricity than they have purchased and will be paid if they have bought more electricity than they have sold. Generators' metered generation and suppliers' metered demand will be compared with their notified contractual position as the Balancing Mechanism opens together with any accepted Balancing Mechanism trades. The sum total of contracts

negotiated in forward, futures and short term bilateral markets will be added together to arrive at these contract positions.

The price paid or charged to 'out of balance' market participants varies depending on whether they are over or under contracted. In general, generators who are under-contracted (and suppliers who are over-contracted) and 'spill' electricity on to the system, potentially imposing balancing costs on the System Operator, will receive a lower price for their electricity than if they had been fully contracted. Suppliers who remain under-contracted as the Balancing Mechanism opens (and generators who under-generate), thereby potentially imposing balancing costs, will similarly be charged a higher price than if they had entered into contracts for their full requirements. These different charges are reflective of the additional costs incurred by the System Operator in instructing generators, suppliers or customers to vary their output or consumption at short notice to meet unanticipated imbalances via the acceptance of Balancing Mechanism offers and bids.

All licensed generators and suppliers will be required by their licence to comply with the BSC, which will include the Settlement Process rules. Licence exempt generators – such as the majority of renewables generators and some CHP plant – will not be required to sign the BSC. To the extent that their output is sold to licensees, it will be taken into account by the licensees when notifying their positions.

As well as achieving an overall physical balance on its system, the System Operator will need to accept offers and bids at short notice and at different locations to overcome transmission constraints. These costs will be recovered from all signatories to the BSC. The System Operator will be incentivised to balance the system efficiently, including to overcome transmission constraints.

IT Systems to Support the Balancing Mechanism and Settlement Process

Both the Balancing Mechanism and the Settlement Process will require new IT systems to be built and operated. Expressions of interest for the provision of these services were called for earlier in the year and a short list of 9 interested parties has been compiled. Detailed specification of the Invitations to Tender will now be drawn up. Letting of the work is expected towards the end of the year. NGC will be the contracting party, but

the procurement process will be managed by the RETA Programme under the leadership of Ofgem and the DTI.

Governance of the Balancing and Settlement Code

The rules for the Balancing Mechanism and Settlement Process, which will be incorporated in the BSC, will need to evolve in the light of experience and to ensure that the arrangements remain efficient and customer focused.

An obligation to establish and modify the Code will lie with NGC as System Operator. However, a Balancing and Settlement Code Panel will be formed to supervise proposed modifications to the rules, which will comprise experts competent to reflect the views of a wide range of interested parties, including customers. It is expected that the Director General will appoint the Chairman of the Panel. The Director General will also approve all modifications to the Code. This will enable firm regulatory oversight of the rules that govern this central part of the market.

CHP and Renewables

Most sites with CHP plants will benefit from the new trading arrangements, because they import power and they will therefore benefit from the expected lower wholesale electricity prices. Many large CHP plants that export power can predict their load and so will be able to maintain their position relative to other generators. Plants which have unpredictable loads and impose balancing costs on the System Operator will be more exposed to imbalance charges than other types of plant. However only the largest of these plants will have any direct exposure. A small number of CHP plants may fall into this category; the vast majority will not. Exempt generators will not be required to participate in the Settlement Process directly. However, all flexible generators are free to make offers and bids into the Balancing Mechanism and be rewarded for doing so.

Competition and the New Trading Arrangements

A major feature of the new arrangements is that the 'demand side' will be fully incorporated into the new arrangements. Suppliers and customers can bid load reductions into the Balancing Mechanism in direct competition with generators. In addition suppliers, in seeking to manage their 'out of balance' position, are likely to be more responsive to their customers. It will be important for suppliers to understand

their customers' demand requirements more fully and to work closely with those customers able to offer load management services.

The new trading arrangements will help promote competition by replacing restrictive characteristics of the Pool that have served to facilitate the exercise of market power. More effective competition in generation also depends on changing the market structure through divestments, which are underway; on continuing to open generation to new entrants; and on increased pressure on generators from electricity suppliers resulting from effective competition in electricity supply to domestic and larger customers. However, without effective trading arrangements, restructuring of the generation and supply markets will be less effective in producing real benefits to customers. For suppliers, the new arrangements provide an opportunity to differentiate themselves from their competitors by keen power purchasing. For generators, the arrangements mean that they must seek more actively buyers for their power and sell it at the prices that purchasers are willing to pay.

Transparency and Liquidity

Some concern has been expressed that vertical integration between supply and generation in the electricity market will render the new trading arrangements less effective than they might otherwise be, by reducing liquidity and transparency in the bilateral markets due to internalised trading in the vertically integrated companies. A substantial degree of vertical integration raises competition issues when effective competition has not yet fully emerged in generation and supply. However, vertically integrated companies can only avoid trading if load shapes on both generation and supply are the same, which is typically not the case at present. Moreover, experience in other markets, such as the GB gas market and the North American gas market suggests markets are usually liquid and transparent even if they take only relatively small proportions of the physical market. In addition, a common approach to gas and electricity trading, which will be established through these new trading arrangements, should lead to greater liquidity in both markets. The proposed market arrangements are designed to provide the same opportunities for all market participants. The market rules do not benefit vertically integrated players at the expense of participants who are not vertically integrated. A consequence of this is that some rules (such as the settlement rules) will encourage contracting by all participants including by vertically integrated players. This will, in turn, foster liquidity and transparency.

Transparency will occur, in common with other commodity markets, as price reporting develops as a valuable service to market participants. Transparent prices are also expected to be available from a short-term power exchange and Balancing Mechanism offers, bids, prices and volumes will also be accessible to market participants.

These market developments will provide a greater depth of price information and transparency. Price indicators are expected to develop that will reflect prices over the short-, medium- and long- term. This contrasts with the present Pool arrangements, where price setting is complex and, until recently, market prices have not been available longer ahead than one day. Greater confidence in the pricing arrangements will in turn encourage more participants in to the market thereby increasing liquidity and efficient pricing.

It is expected that over time the new market will develop a rich range of price information. However, it may take some time for this degree of price transparency to develop, although there are already encouraging signs of price reporting appearing in advance of the new market. If required, the Regulator could set in place arrangements to publish prices in the newly emerging markets. Such reports might take the form of simple price indicators drawn from information on real contracts. The Regulator could require, using his statutory powers, market participants to give him the necessary information for such indicators to be published. This would be a temporary arrangement which would be implemented only whilst price reporting developed.

Security of Supply

The new trading arrangements will encourage market participants to balance their own positions ahead of real time, since imbalances will be exposed to potentially unfavourable cash-out prices. These enhanced incentives for self-balancing will contribute to the achievement of efficient levels of supply security in both the short and long term.

In periods when the demand is relatively high in relation to capacity, prices in bilateral markets will be driven up, providing incentives to increase supply and reduce demand. In the short term, higher prices will encourage generating plants to be made available to meet demand, and in the long-term they will encourage the building of new plant. The expected emergence of forward prices for electricity several years ahead will provide

better signals than currently exist of the longer term balance between demand and capacity, and therefore of the capacity required to maintain security of supply.

Security of supply in the short term will be underpinned by the actions of NGC in its role as System Operator. NGC will call for bids and offers in the Balancing Mechanism to change output and demand at short notice so as to maintain system balance. When the system is under stress, prices realised in the Balancing Mechanism will tend to be high, and possibly very high, again providing incentives not only to provide extra output in these periods but also to have plant regularly available to take advantage of such commercial opportunities as and when they arise. Prices in the Balancing Mechanism should more closely reflect the actual supply/demand balance on the system than do Pool prices as the Balancing Mechanism will start operating much closer to real time than does the Pool.

NGC will also contract ahead for a number of Balancing Services, including the provision of reserve. This will provide additional security in the short term in that the SO will not need to rely solely on the Balancing Mechanism to match supply and demand in all circumstances. NGC purchases of Balancing Services will also contribute to security of supply in the medium and long terms by providing a further source of revenues for flexible plant and by providing rewards for flexibility on the demand side that will, over time, stimulate greater responsiveness of demand to price.

Assessment Against Objectives

The proposed trading arrangements detailed in this document promise significant advantages over the present arrangements. They will deliver more efficient and more competitive trading, greater choice of markets and more scope for demand management. Forward price curves will facilitate efficient new entry, by providing both generators and suppliers with clearer signals of when entry is likely to be profitable. New balancing arrangements will ensure short term quality and security of supply, while the settlement process will provide sharper incentives to manage risks.

These advantages suggest that the new arrangements offer the prospect of relatively large and rapidly achieved reductions in wholesale electricity prices and lower prices for both industrial and domestic customers. Beyond the immediate change in price level, there is the prospect of continuing pressure to reduce prices. It is estimated that,

if wholesale prices are reduced to a level equal to the full costs of new generating capacity, the benefits to consumers could be of the order of £1.5bn per annum. At the same time both long term and short term security of supply will be maintained.

The costs of implementing and operating the new trading arrangements are estimated to be between about £136m to £146m per annum, for a five-year period. Thereafter the operating costs are expected to be of the order of £30m per annum. These estimates take no account of any of the costs that will be avoided as a result of the reforms, including as a consequence of terminating Pool contracts.

The Way Forward

Consultation on the present proposals will extend until mid-September and include a public seminar in early September.

Responses to this consultation will be taken into account in finalising the detailed business rules for the operation of the central procured parts of the new arrangements – the Balancing Mechanism and Settlement Process. Subject to time being found for legislation in the 1999/2000 parliamentary session, contractors for designing and operating the supporting IT systems are expected to be appointed towards the end of the year, after legislation is announced.

Implementation will then be on target for Autumn 2000.

1. Introduction

1.1 The Purpose of this Document

This document sets out for consultation further detailed proposals for implementing new electricity trading arrangements in England and Wales. The proposals build on the market-based trading arrangements suggested by the then Director General of Electricity Supply (The Director General) in July 1998 and accepted by the Government in October 1998 in its white paper on Energy Policy.⁴ They reflect an intensive programme of work, under OFFER and DTI direction and involving all interested parties, which has taken place since November.

Responses to this consultation will be taken into account in drawing up detailed business rules for the operation of central parts of the new arrangements – the proposed new Balancing Mechanism and Settlement Process - and in specifying Invitations to Tender (ITTs) for the construction and operation of the IT systems required to support them. Subject to time being found in the 1999/2000 Parliamentary session for the necessary primary legislation, it is anticipated that the new trading arrangements will be introduced from Autumn 2000.

1.2 The Process So Far

These proposals are an important step in the process of reform which began in October 1997 when the then Minister for Science, Energy and Industry invited the Director General to consider how a review of electricity trading arrangements might be undertaken. Terms of reference for the review were agreed in March 1998.⁵ OFFER implemented an extensive and open process of consultation and the valuable input made by interested parties was taken into account in drawing up proposals for reform.

In July 1998, the Director General published a report containing proposals based on bilateral trading between generators, suppliers, traders and customers. They included forwards and futures markets operating up to several years ahead evolving in response to the demand of participants and a short-term bilateral market, operating from at least

⁴ Conclusions on the Review of Energy Sources for Power Generation – Government Response to fourth and fifth Reports of the Trade and Industry and Committee.

⁵ Review of Electricity Trading Arrangements: Report of Consultation on Terms of Reference, OFFER, March 1998.

24 hours before a trading period, to give market participants the opportunity to 'fine tune' their contract positions. There would also be a Balancing Mechanism in which the National Grid Company (NGC), as System Operator, accepts offers and bids for increasing or decreasing generation or demand to enable it to balance the system. A Settlement Process would be required for charging participants who are out of balance between their contracted positions and their metered volumes of electricity and for settling accepted Balancing Mechanism offers and bids, and for calculating the System Operator's costs of balancing the system.

In October 1998 the Minister for Energy announced that the Director General's proposals on the reform of the electricity trading arrangements were the right way forward and that further work on these proposals should be commenced. The Government indicated that it would legislate to support the changes. It suggested that OFFER and the DTI should be responsible for the overall direction and leadership of the implementation process; that a full-time Programme Director should be appointed; and that the Programme should enable the full participation of the industry and its customers.

In November 1998, the Director General published a Framework⁶ Document which explained how the Programme for the Reform of Electricity Trading Arrangements (RETA) would be taken forward. It confirmed OFFER and the DTI would lead the Programme, that they would be supported by a Programme Director, a Development and Implementation Steering Group (DISG) composed of senior staff representing all interested groups within the industry including customers, and Expert Groups. The Programme, set out in the Framework Document, covered the design and development of the Balancing Mechanism and the associated Settlement Process and required further consideration to be given to the establishment of a short-term screen-based bilateral market (i.e. a power exchange).

Following the November Framework Document, DISG and Expert Groups were established (members are listed in Appendix 1). These groups meet on a regular basis and produced and reviewed a number of papers. A bibliography of papers published by the DISG and Expert Groups is presented in Appendix 2. Public seminars have been

⁶ Review of Electricity Trading Arrangements: Framework Document November 1998.

held to discuss progress. Throughout the review process, a panel of Special Advisors (Lord David Currie, Mr Nicholas Durlacher and Sir Peter Walters) has supported OFFER and the DTI.

1.3 Outline of the Document

The first part of the document explains the reasons for reforming the electricity trading arrangements. Chapter 2 provides background on the objectives of the proposed changes. Chapter 3 examines the concerns that continue to be expressed about the present trading arrangements and experience to date. It draws on previous papers published as part of the Review process, but also includes recent experience. Chapter 4 indicates the scope for change, based on updated developments in other markets.

The second part of the document sets out details of the new trading arrangements. Chapter 5 provides an overview of the arrangements, whilst Chapter 6 details the proposals for the operation of the Balancing Mechanism and Chapter 7 explains how the Settlement Process will operate including how imbalance 'cash-out' prices will be calculated. Chapter 8 focuses on the role of NGC as the System Operator and explains the need for new incentives schemes, consistent with the new trading arrangements, to ensure the System Operator balances the system efficiently. Chapter 9 covers the Legal and Regulatory Framework for the New Trading Arrangements and Chapter 10 sets out proposals for governance of the Balancing and Settlement Code, including how the Code will be modified.

Part three explains how the new trading arrangements might impact on participants. Chapter 11 concentrates on CHP and Renewables generators whilst Chapter 12 provides examples of how a variety of participants may interact with the new arrangements – suppliers, customers, traders as well as generators.

Part four analyses the new arrangements from a variety of perspectives. Chapter 13 considers the prospects for greater participation of the 'demand-side'. Chapter 14 considers the trading arrangements in the context of developing competition in generation and supply. Chapter 15 sets out interactions between the New Electricity Trading Arrangements and the similarly structured New Gas Trading Arrangements. Chapter 16 analyses Security of Supply under the New Trading Arrangements and Chapter 17 assesses the new arrangements against objectives. Chapter 18 in Part five

sets out the way forward to enable the new trading arrangements to be introduced from Autumn 2000 and includes some discussion of the preparations already taken by market participants. Supporting appendices are published in an accompanying volume. A separate detailed draft document, the Balancing Mechanism and Imbalance Settlement specification, is also available on request from the Programme Director's Office

1.4 Views Invited

In keeping with the extensive and open process of consultation adopted throughout the review exercise, Ofgem is seeking comments on the detailed arrangements outlined in this report. These should be sent by 10 September 1999 to:

Dr Brian Saunders
RETA Programme Director
10th Floor
Regents Place
338 Euston Road
London NW1 3BP.

Electronic responses may be sent to:
bsaunders@offer.gsi.gov.uk

Respondents are free to mark their replies as confidential although we would prefer that, as far as possible, we were able to place responses to this paper in the Ofgem library. If you wish to discuss any aspect of this report, initial contact should be made to the RETA Communications Manager (Dawn Astbury) at the Programme Director's Office on 0171 874 1620.

A seminar will be held at the NEC, Birmingham, on 2 September to discuss the trading arrangements outlined in this report. A workshop on the following day will provide an opportunity for more detailed debate. Registration details are available from the RETA Communications Manager.

2. Objectives and Principles

2.1 *Objective of the Review*

The objectives of the Review were originally outlined in OFFER's Report of Consultation on Terms of Reference (March 1998) and reiterated in the Government's White Paper on the Review of Energy Sources for Power Generation.

The objectives of the Review were to provide electricity trading arrangements which:

- ◆ meet the needs of customers with respect to price, choice, quality and security of supply;
- ◆ enable demand to be met efficiently and economically;
- ◆ enable costs and risks to be reduced and shared efficiently;
- ◆ provide for transparency in the operation of the pricing mechanism and the market generally;
- ◆ respond flexibly to changing circumstances in the future;
- ◆ promote competition in electricity markets, including by facilitating ease of entry to and exit from such markets;
- ◆ avoid discrimination against particular energy sources; and
- ◆ are compatible with Government policies to achieve diverse, sustainable supplies of energy at competitive prices and with wider Government policy, including on environmental and social issues.

In addition to these objectives, the White Paper identified some issues where further consideration would be needed:

- ◆ continued security of electricity supplies in the long and short-term;
- ◆ prices that are transparent and ensure liquidity; and
- ◆ appropriate consideration of CHP, renewables generators, small embedded generators, NFFO generators and Interconnectors.

2.2 General Principles

In order to meet the objectives set out above general principles have been adopted with regard to the detailed design of the trading arrangements.

The principles include that participants should be able to choose how to conduct their business via freely negotiated contracts between willing buyers and sellers with centrally administered mechanisms kept to the minimum, consistent with the safe and reliable operation of the system. It has also been a key aim to ensure that the demand-side will be able to participate fully in the market. In relation to the demand-side, but also more generally, it has been recognised that transparent and simple arrangements are key to increasing liquidity throughout the market.

The new arrangements will place more reliance on markets for the efficient trading and pricing of electricity, through forwards and futures markets and short-term power exchanges. To this end, the prices emerging from centrally administered systems required to ensure the national grid system remains physically balanced at all times, should not give rise to distortions in the freely traded markets.

Compared with present arrangements, the buyers and sellers of electricity will have a wider range of options available to them with regard to the way they conduct business. The relative costs of the alternative options with regard to trading in the market will influence the choices made by each participant. For example, to the extent that participants choose not to enter into contracts ahead of a trading period they will be exposed to imbalance prices which, on average, are likely to be less favourable.

Views regarding the level and volatility of such prices will influence the decisions of participants as to whether to accept the risks of exposure to imbalance prices or to enter into contracts ahead of time to remove such risks. Different participants might be expected to take different views about the level and acceptability of these risks. From time to time it is to be expected that the costs of maintaining the system in balance close to real time will be high and that on such occasions the imbalance cash-out price will be expected to be high.

This implies a greater role for buyers and sellers of electricity in deciding whether to balance their own electricity supply and demand closer to real time, or accept the

consequences for their profits of choosing not to balance. NGC's role in achieving an overall system balance by matching generation and consumption may therefore be expected to be less under the new arrangements than at present. The role might be expected to reduce still further over time as market participants seek to contract ahead to mitigate the risks of being out of balance in each half hour trading period.

As NGC's overall energy balancing role reduces, its principal balancing role will be in relation to overcoming locational constraints on its transmission system and to actions taken to correct energy imbalances within time-scales less than half an hour. It is not envisaged that participants will be able to respond to market signals directly within these very short timescales. NGC will therefore continue to be responsible for system balancing on a second by second basis.

Increased transparency is a key objective of the new arrangements to provide efficient signals to participants. Its achievement should also enable any abuses of market power that might arise to be identified more easily. New governance arrangements must allow for effective and timely interventions in these circumstances.

Should any market abuse be observed under the new arrangements, a range of remedies in addition to the more effective governance arrangements may be available under the Electricity Act (1989) and/or the Financial Services Act⁷ (if applicable) and/or the new Competition Act (1998). As in other competitive markets, effective policing of the rules is important and is in the interests of all market participants and, most importantly, in the interests of customers.

The increased role of the demand-side in the new arrangements includes the possibility of making offers and bids to the System Operator for short timescale response via the Balancing Mechanism. It could also include indirect participation whereby suppliers with a portfolio of customers make Balancing Market bids that reflect the terms for adjusting demand negotiated by the suppliers with their customers. It is an important element of the new market arrangements that suppliers are able to enter into much

⁷ The Financial Services Act (1986) is to be replaced in 2000 by the Financial Services and Markets Bill that was introduced into Parliament in June. The Financial Services Authority (the 'FSA') is responsible for regulating persons authorised under the existing Act, and will be so responsible under the Bill.

more innovative contracts with their customers for managing and sharing risks. A necessary pre-cursor to this is that suppliers face incentives to obtain a much better understanding of all their customers' demand patterns and potential responsiveness to market-based price signals.

2.3 Further Considerations

In addition to the objectives listed above, OFFER's Report of Consultation on Terms of Reference outlined a number of issues for which the implications of any changes to the trading arrangements would need to be considered. These include:

- ◆ the role of NGC;
- ◆ the development of competition in generation and supply;
- ◆ trading arrangements in Scotland;
- ◆ the development of contracts markets (including for physical delivery, CfDs and futures contracts);
- ◆ interactions between electricity and gas; and
- ◆ legislation on competition and utility regulation in Great Britain and the European community.

Chapter 17 assesses the new trading arrangements against objectives and further considerations.

3. The Present Trading Arrangements - Experience to Date

This chapter analyses experience with the current trading arrangements to date, identifying the key features that have attracted criticism from industry participants and the Regulator. It outlines the background to the review of the current trading arrangements, the recognised achievements of the Pool and the criticisms that have been expressed about it. Each of the major concerns and their consequences is discussed in turn.

3.1 Background

The Pool in England and Wales was one of the first mechanisms of its kind when it was set up at privatisation in 1990. This meant that in its creation, and in the rules associated with it, there was little by way of guidance from other countries to draw on. It was developed in a process that gave considerable weight to the existing arrangements operated pre-vesting by the Central Electricity Generating Board (CEGB), when the electricity system was publicly-owned and centrally planned.

The market design that emerged requires generators, each day on a day-ahead basis, to provide details of the price at which they are prepared to make generation available. NGC, on behalf of the England and Wales Pool, provides an estimate of system demand at the day-ahead, calculates a schedule of generation to meet this estimate and determines Pool prices. Under obligations in the Transmission Licence, NGC dispatches plant on the day, taking into account the day-ahead schedule but modifying it as necessary, for example, to take account of unexpected changes in demand or failures by generating plant and to resolve system constraints.

The ownership of generating plant in England & Wales has changed significantly since the Pool was established. For example, before Vesting, the CEGB accounted for over 90 per cent of the electricity produced in England and Wales, and controlled the output of the remainder. In the first year after Vesting, two companies accounted for about three quarters of the electricity generated and three other companies for almost all the remaining generation. Now, the largest two companies account for 40 per cent, five other companies for the next 40 per cent and over 30 others for the remaining 20 per

cent. As a result, there is an increasing requirement for each company to be able to organise its own affairs as far as possible to reflect its own changing circumstances.

As in other markets, generators, competitive suppliers, traders and customers need to react continuously to changing market conditions. This need is reinforced by the development of a competitive gas market interacting with a competitive electricity market. Centralised day-ahead submission of data to the Pool, centralised price setting at the day-ahead stage and centralised dispatch instruction for all generation plant do not fit well with the need for flexibility, which is a key to increased efficiency in the increasingly competitive generation and supply markets.

3.2 *Achievements and Concerns*

The initial consultation paper⁸ on the Review of Electricity Trading Arrangements noted the achievements of the present trading arrangements. These include:

- ◆ quality and security of supply has been maintained;
- ◆ prices set on a half-hourly basis have underpinned trading between generators and suppliers ;
- ◆ the arrangements have enabled plant to compete in terms of offers to run;
- ◆ access to the Pool has assisted new generators in entering the market; and
- ◆ arrangements have enabled competition in supply to be introduced.

These achievements should not be underestimated. However, the large body of criticism that has built up about the Pool cannot be ignored.

The main criticisms of the current trading arrangements can be summarised as follows:

- ◆ the lack of competition in price setting;
- ◆ the relative lack of customer and demand-side participation;
- ◆ the complexity of bidding and price setting;

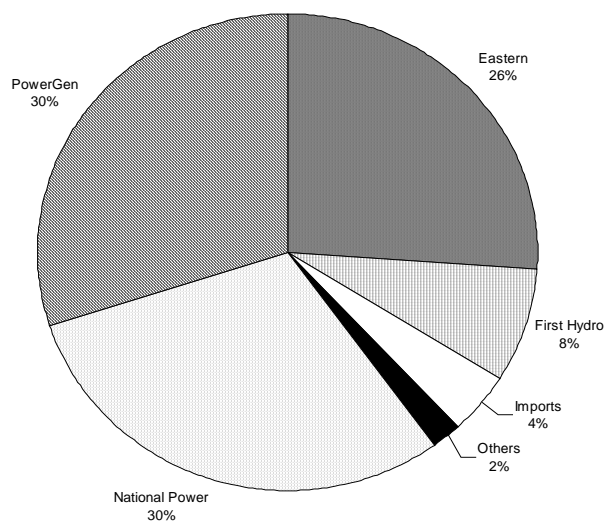
⁸ Review of Electricity Trading Arrangements: A Consultation by OFFER, 5 November 1997.

- ◆ the failure of capacity payments to signal capacity requirements in the short and long-term;
- ◆ the ability to manipulate, and actual manipulation of, prices;
- ◆ inefficient gas and electricity market interactions;
- ◆ the compulsory membership and heavily centralised nature of the Pool; and
- ◆ the slow pace of reform in the Pool.

3.2.1 Lack of Competition in Price Setting

Although the number of generators selling through the electricity Pool has increased substantially from 8 at Vesting to 38 in 1999, competition in price setting remains limited. The vast majority of new entry has been by combined cycle gas turbines (CCGTs). As a result of the long-term offtake contracts most of these plant have signed, they do not compete at the margin and only rarely set prices (3% of the time in 1998/99). Consequently, price setting remained dominated by the three main portfolio generators (see Figure 3.1).

Figure 3.1 – 1998/99 SMP Setting Shares



A consequence of the lack of effective competition in price setting is that the development of liquid electricity derivatives markets has been hampered. The Pool is

perceived as an environment dominated by a few companies who are able, and have proved willing, to manipulate prices. Concerns about the Pool have been reinforced by complexity of the price setting process which has made it difficult for traders to understand how electricity prices are likely to move. Consequently, little confidence has developed in the underlying electricity price (i.e. the Pool price) against which derivatives could evolve. Recently, the volumes traded via Electricity Forwards Agreements (EFAs) have increased,⁹ but this appears, at least in part, to be attributable to the review of the trading arrangements, as buyers and sellers have begun to anticipate market conditions post-RETA.

The issues surrounding competition under the current trading arrangements are discussed further in Chapter 14.

3.2.2 The Relative Lack of Supplier Pressure and Customer and Demand-Side Participation

A competitive market is usually characterised by the interaction of the supply and demand sides. Licenced generators are obliged to sell most of their output through the Pool and all suppliers purchase most of their electricity from the Pool at a common clearing price and are electricity price takers. This prevents suppliers using their bargaining strength to bring downward pressure on prices.

The Pool does not encourage significant direct demand-side participation and in fact, the rules restrict demand-side participation to a handful of large customers. Currently the number of participants in the Pool's direct Demand-Side Bidding Scheme is limited to 30, although the Pool Executive Committee has recently agreed to increase the participation in the Demand-Side Bidding Scheme to 40 and the Chief Executive's Office has been actioned to implement this decision. The weakness of effective demand-side participation has hampered the development of the wholesale electricity market.

To date, even the demand side participation that is allowed in the Pool has been relatively ineffective in terms of providing competition to the generators. This is

⁹ Brokers estimate that approximately 40 TWh were traded in the EFA market in 1997/98 and that this increased to 60 TWh in 1998/99.

illustrated by the fact that, since November 1995, demand-side bidders have set the Pool price in just 20 half-hours.

The lack of significant demand side participation stifles customers' ability to decide on the level of security of supply they require and forces most of them (those not supplied on Pool price related terms) to accept the level implied by the administered Value of Lost Load, currently £27.68/MWh (1999/00). Moreover, the centrally administered treatment of security of supply effectively results in all suppliers facing the same level of security which stifles any incentives for suppliers to develop innovative tariff structures with their customers.

3.2.3 The Complexity of Bidding and Price Setting

Pool price setting is complex. On the face of it, the Pool provides transparency. However, although all offer and price information is made available, the complexity of the bidding and price setting mechanisms make it extremely difficult to understand the relationship between the offers made by generators and outturn prices. And the relationship between prices and supply and demand conditions frequently does not follow expected patterns. In practice, the operation of the Pool is far from transparent. The structure of offers made into the Pool (which can contain up to nine price related parameters), the use of an optimising scheduling tool and the complex methodology used for the calculation of the various Pool price components all reduce the transparency with which the market works.

It is difficult to identify how offers from generating plant influence SMP due to the complexity of the algorithm (SuperGoal) underpinning the SMP calculation. In particular, new market participants (whether generators, suppliers or traders) cannot make simple assumptions when assessing the operation of the market. Although the amount of data now available from the Pool to market participants has increased considerably since Vesting, this has not necessarily led to an increase in the efficiency or transparency with which the generation market operates, as recent experience of price movements indicates.

The structure of an offer into the Pool is designed to reflect the underlying cost curve of thermal plant relevant to bidding a price a day ahead, subject to some limitations imposed for schedule optimisation purposes. This structure was designed to reflect the costs of generation plant under the CEGB. However, generators now inevitably submit offers that reflect their overall commercial objectives. The wide range of data that generators submit to the Pool, which includes availability profiles, dynamic data and inflexibility flags as well as price data, increases the options by which they can achieve their aims.

A recent example of this has been the use of inflexibility markers to influence the profile and level of prices.¹⁰

3.2.4 The Limitations of Capacity Payments

There is also evidence that the capacity payments mechanism has not been operating as was originally intended. These payments are the function of the Loss of Load Probability (LOLP) and Value of Lost Load (VOLL). LOLP was intended to provide both a short and a long-term signal of capacity requirements. However, LOLP is of limited value as a short-term signal to encourage either generation or demand participation in the market to respond to rapidly changing circumstances, as a change in the availability of a plant has to last for eight consecutive days before it affects the LOLP calculation. This was particularly evident during the autumn of 1995. The flow on the interconnector between England and France ranged on a daily basis between 2,000 MW of imports into England and 400 MW of exports to France. Nonetheless, for the purpose of the LOLP calculation, the available supply was always 2,000 MW.

In the short to medium-term, rather than being a mechanism that encourages extra plant availability, capacity payments have tended to provide a further means by which generators can influence Pool prices to their own advantage. The level of payments can be increased, possibly quite sharply, by withholding capacity from the market, and there is evidence indicating that system marginal prices have tended to be high in years when capacity payments have been low, contrary to what might be expected if the arrangements were working as intended.

¹⁰ Pool price – OFFER Decision Document, May 1999.

Capacity payments have also proved a relatively poor signal for the longer-term need for capacity. LOLP's sensitivity causes relatively small changes to plant margin at times of high demand to lead to very large changes in capacity payments. This has led to considerable year on year variation in capacity payments since the Pool was created with little correlation between the overall level of capacity payments and the margin of installed capacity over peak (the plant margin). Further problems with the existing capacity payment mechanism are discussed in Appendix 3.

3.2.5 The Manipulation of Prices

Pool inquiries have been a regular feature of the post-privatisation industry. For example, over the past two years, OFFER has instigated two inquiries¹¹ into Pool prices. The reports investigated both the pattern of prices over the year and their overall level. In general, prices rose despite limited demand growth, plentiful supply and reducing costs, leading to concerns that generators were manipulating prices. The most recent experiences of very high Pool prices in July 1999 supports this view as does the long-term term evidence indicating that, despite a reduction in generating costs of nearly 50%, there has been no downward trend in prices. Recent experience in the Pool continues to show that, despite reduced concentration in the generation market, Pool prices are still capable of being manipulated. Further details of the various OFFER investigations can be found in Appendix 3.

To the extent that prices have been higher than they would have been in a more competitive market, in part due to the trading arrangements, it is possible that this has encouraged excessive new entry at the expense of existing plant. Entry has been dominated by gas-fired plant whereas the majority of plant closures have been of coal-fired capacity.

3.2.6 Inefficient Gas and Electricity Market Interactions

As increasing use is made of gas for electricity generation, differences in the rules of the two markets can, in themselves, create opportunities for gas-fired plant to operate in different ways than would be expected if trading arrangements in the two markets were more aligned. For example, a CCGT plant can be scheduled in the Pool at the day-ahead stage. On the day, it may be able to sell its gas into the gas market (currently via

¹¹ Report on Pool Price Increases in Winter 1997/98 (June 1998); Pool Price – Decision Document (May 1999).

either the Flexibility Mechanism or the Spot Market) at a higher price than it would receive for generating. If it chooses to do this, since offers into the Pool are not firm it is not responsible for the additional costs that it imposes on the electricity system as a result of NGC having to call upon more expensive plant, nor are the PPP values for the day affected. In the case of a company owning a portfolio of generating plant, it may receive additional benefits from such a strategy if one of its own plants is called to make good the deficit from the CCGT choosing not to operate. The Pool arrangements therefore clearly create a distortion in the incentives to trade on gas and electricity markets.

Closer interactions between gas and electricity markets resulting from increased consistency in trading arrangements could, in principle, improve the security and competitiveness of both markets. Inefficiencies will still occur if decisions taken by generators as to whether to generate or sell gas into the gas market are predicated on differences in the rules of the two markets rather than on underlying opportunity costs and market conditions. In this respect, following the implementation of RGTA, the electricity market stands in greater need of reform.

3.2.7 The Compulsory Membership of the Pool

Membership of the Pool is compulsory for most generators and suppliers, the consequence of which is that all output must be sold to or bought from the Pool. As part of their licence conditions, all licensed generators and suppliers have an obligation to join the Pool and trade all their sales and purchases through the Pool. Exempt generators and suppliers may also be required to join the Pool under the terms of their Connection Agreement to the transmission or distribution system.

Innovative contracting strategies that might have developed if participants were able to trade bilaterally outside the Pool have been inhibited by the compulsory trading requirement. Furthermore, mandatory participation has reduced the incentives on the Pool itself to be innovative in the services it offers, since the Pool does not have to compete in order to retain membership.

3.2.8 The Slow Pace of Reform

The current governance arrangements for the Pool are inflexible and have led to delays in the introduction of needed reforms. Modifications to the rules require significant

voting majorities;¹² these are often difficult to achieve since voting rights are reflective of Pool members' market shares and on many issues there is, unsurprisingly, no consensus of views between the generation and supply sides. Furthermore, customers as a general class¹³ do not have any voting rights although they can attend Pool meetings as observers. Even in the event that there is agreement on the need for a change, the process of defining and implementation can be lengthy.

An example of the slow pace at which reforms can proceed is provided by the case of demand-side bidding. In December 1996, the DGES urged the Pool to resolve long-standing issues with regard to demand-side bidding and capacity payments but these issues remain unresolved.

Recognising the criticisms that have been levelled about the governance arrangements, the Pool established a Pool Review Steering Group, at the end of 1997 (which contributed to the Review of Electricity Trading Arrangements), which amongst other things considered governance changes to the Pool. This project was closed in November 1998 awaiting the outcome of the present review of trading arrangements.

The Director General cannot directly secure changes to the operation of the Pool. He can only raise concerns or ask for further work to be done by the Pool, and react to concerns expressed by Pool Members to him.

3.3 Summary

The present Pool has made positive contributions on a number of fronts – it has maintained security of supply, the half-hourly pricing structure has underpinned trading between generators and suppliers, and it has facilitated new entry into the generation market and allowed competition in supply to be introduced.

¹² The Pool Chairman and any Pool Executive Committee (PEC) member can demand that a question or issue be put to a vote of its members. Decisions in the first instance are made based upon a simple majority of the votes cast, each member is entitled to one vote. After the vote the Chairman or members can refer the decision to a poll (as often happens). Resolutions decided by a poll need to have a majority of not less than 65% of the votes cast. After the poll has been conducted, Committee Members still have the opportunity to refer the matter to Pool members for decision.

¹³ Some large customers have voting rights by virtue of being second tier suppliers.

However, the Pool has also failed to deliver on several, very major counts. Instigation and realisation of reform has been slow. Demand-side participation has been limited. The compulsory Pool membership has hindered potential innovation, in both contracting strategies and within the Pool itself. The complexity of both the offers that generators submit and the price setting arrangements in the Pool have done little to facilitate the development of competition between generators, and has reinforced the market power of the major players. In addition, this complexity has limited any meaningful price transparency with which participants can make better-informed decisions. Despite increased entry, the major players retain power over price setting. The ability and willingness of the major generators to influence the underlying Pool price has led to high, unrepresentative Pool prices which have inhibited the development of an electricity derivatives market and limited liquidity of the contracts market. Most important of all, these various effects have contributed to a situation in which consumers have faced higher prices than would have otherwise have been feasible.

There is no simple way to modify the Pool to overcome its weaknesses. Any worthwhile reforms would require the removal of compulsory membership, the introduction of firm offers, the incorporation of the demand-side and the implementation of 'pay-as-bid' pricing. These are very substantial changes and would, for example, necessitate the introduction of a balancing mechanism. They point strongly to the arrangements argued for in this paper.

4. Developments in Other Markets

The purpose of this chapter is to provide an update on recent developments in international energy markets since the RETA background paper¹⁴ was published. It focuses on the major issues surrounding RETA and how they have been addressed in other energy markets.

4.1 *Update*

Since the RETA background paper was written, significant developments in the various international electricity markets have taken place.

It is now possible to examine the early experiences in the Australian, Californian and the Spanish markets. Other long running and mature markets such as those in Scandinavia have also developed over the last year. In June 1998, Finland joined NordPool, and in March 1999 the separate Finnish and Swedish on-the-day trading (adjustment) markets, were replaced by a continuous trading and balancing market, Elbas, that covers both Sweden and Finland. Also, since February 1998, other countries (not covered in the International Background Paper) have developed and implemented competitive trading arrangements. In the United States, for example, state by state introduction of competitive electricity markets has continued apace. The Californian market started at the end of March 1998, while that operated by PJM Interconnection¹⁵ went 'live' in April 1998 and that in New York (replacing the current New York Power Pool) which is to be operated by the new New York SO (NYISO), is due to begin in September of this year. Finally, European countries have developed proposals for implementing the EU Directive.¹⁶ For example, the Amsterdam Power Exchange (APX) opened in the Netherlands on 25 May this year and there are plans to open an exchange in Germany in early 2000.¹⁷

¹⁴ Electricity Trading Arrangements in Other Countries (February 1998).

¹⁵ PJM Interconnection is an Independent System Operator (ISO). The system it operates covers all or part of the states of Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia.

¹⁶ Directive 96/92/EC (the 'IME Directive') sets out common rules for the internal market in electricity with a view to achieving a competitive market.

¹⁷ A consortium including Deutsche Börse and NYMEX plan to open the German Electricity Exchange (GEX) based in Frankfurt.

Liberalised gas markets around the world can provide general lessons for those seeking to reform electricity markets, as well as insights into more specific issues. For example, increased use of gas for power generation in many countries has meant that those seeking to liberalise gas and electricity markets need carefully to consider the implications of interactions between them, particularly so as to ensure that barriers to efficient trading between gas and electricity are reduced. The particular developments that are taking place in the GB gas market are discussed in Chapter 15. The main developments in and some background on the markets in Scandinavia, Australia and California are summarised in Appendix 4.

4.2 Major Issues for RETA and Developments in Other Markets

The experience of other markets relating to five key issues that are particularly pertinent to the design of the new trading arrangements in England and Wales is discussed below. Appendix 4 discusses two further issues, namely the interaction between energy and ancillary services and the allocation of transmission access rights in other markets, and how they have been treated in various international electricity markets.

4.2.1 Responsibility for Energy Balancing

It is a prerequisite of any efficient electricity market both in terms of achieving an economically desirable market outcome and maintaining real time security of supply that the means for delivering energy balancing are effective and clearly defined. Thus, who is responsible for energy balancing and how it is achieved are clearly critical issues.

In general, international experience suggests that responsibility for energy balancing and the mechanisms used to achieve it are closely related to whether despatch is centrally co-ordinated (often associated with a mandatory energy market) or whether participants are able to self-despatch and the energy markets are voluntary.

In voluntary self despatch markets (such as California and Scandinavia) the SO only begins to take responsibility for energy balancing after market participants have provided a firm ex-ante notification of their generation and demand for each trading period (this point is described as 'Gate Closure'). Participants must submit firm generation and demand schedules or bids/offers to the SO at the day-ahead stage. For

example, in California, participants must submit balanced energy schedules¹⁸ to the SO¹⁹ at the day-ahead stage for each hour of the next day. In Scandinavia, Gate Closure is also day-ahead in Elspot.²⁰ Participants in Norway, Sweden and Finland must, at the day-ahead stage, make an ex-ante notification of any bilateral contracts traded up to that point.²¹ The PJM SO runs three markets in the north-east United States – an hourly nodal pricing energy market, a market for reserve, and a market for transmission services, and it also accepts bilateral contract scheduling by market participants. Participants can submit bids and offers at the day-ahead stage for use in the hourly Energy Market and are required to notify the SO of any contracts and self scheduled generation/demand. In all of these systems, once firm physical positions or bids/offers have been submitted to the SO they cannot be changed, except by further trading in later markets where they exist.

In more centralised markets, such as Australia, New Zealand and Spain,^{22,23} participants submit offers to the system/market operator who then decides how best to schedule them. Gate Closure in these markets can be defined as the time at which participants must submit offers (and bids) to the system/market operator in order for centralised scheduling to begin. In all three markets, there is a day-ahead market. In Australia, participants may revise their submitted quantities but not their price offers (or bids), up to five minutes before real time (when the National Electricity Market Company (NEMMCO) issues final firm dispatch instructions). In New Zealand, participants are able to revise both the prices and volumes that they have submitted to the SO (i.e. are allowed to re-bid) until two hours before real time.

¹⁸ California is unique amongst markets surveyed in this chapter in requiring schedules submitted by participants to be in energy balance. These schedules must also be feasible against forecast network constraints.

¹⁹ Commonly referred to as the Independent System Operator (ISO) in the United States. In California, the SO is formally known as the California ISO.

²⁰ The day-ahead voluntary power exchange covering Norway, Sweden and Finland.

²¹ In Scandinavia, day-ahead contract/physical schedule notification does not preclude further bilateral trading on the day.

²² The centralised markets in New Zealand and Spain are voluntary although, so far, very little forwards bilateral contracting and hence self-scheduling has developed. The Australian NEM is a mandatory market.

²³ The Spanish market consists of a day-ahead Pool, in which the majority of trading takes place, supplemented on the day by an intra day market, both of which are operated by an independent market operator (OMEL). Generators receive payments based on day-ahead and intra-day market prices supplemented by Capacity Guarantee Payments linked to availability, and stranded cost remuneration linked to market prices.

In California, participants may continue trading during the day, and can submit new energy schedules to the SO, which must be both supplemental to their day-ahead schedules and in energy balance. In Sweden and Finland, trading on the exchange based Elbas market²⁴ continues right through the day, enabling participants to take physical positions until up to two hours ahead of each trading period, after which the balancing markets in each country begin.²⁵ In Norway, bilateral trading may continue up until two hours prior to real time, in Finland up to 90 minutes before the trading period, whilst in Sweden it can continue up to the beginning of the trading period. In Spain, the market operator (OMEL) also runs on the day voluntary spot markets in six windows (or blocks). In PJM, day-ahead schedules and bids/offers can be adjusted through the day up to an hour before the trading period.²⁶

In each of the NordPool countries (Norway, Sweden and Finland), the SO achieves final energy balance via a real time energy balancing market. Each SO is able to utilise simple bids and offers that have been submitted by market participants (up to two hours before the trading period in Norway, up to 30 minutes in Sweden, and up to 10 minutes in Finland). All bids and offers must be deliverable in very short timescales.²⁷ In California, the SO uses supplemental²⁸ bids and offers submitted up to 45 minutes prior to the beginning of each trading period (as well as a host of ancillary services) to balance the system.

To summarise, in almost all the markets studied participants are able to revise their positions in some fashion close to real time. In some markets they are able to revise the schedules or bids and offers they submit to the SO at the day-ahead stage whilst in others they can achieve much the same effect by trading in later markets where they exist and/or by submitting further schedules or bids/offers.

²⁴ A more detailed description of the Elbas market is provided in Appendix 4.

²⁵ The Swedish and Finnish SOs monitor available interconnector capacity and the level of scheduled cross-border trades. If an interconnector constraint arises, a message is flashed to Elbas participants to prevent further trades in that direction until further notice.

²⁶ Thereafter, the PJM SO is able to utilise these offers or ancillary services to achieve real time energy balance. The PJM SO can cancel actions taken at the day ahead stage (when it will begin to issue despatch instructions and forecast prices) but must pay any start-up costs and no load costs or cancellation fees specified. Since February 1999, PJM has been conducting a trial to test the feasibility of reducing this to 45 minutes.

²⁷ In Norway and Sweden participants must be able to respond within 15 minutes and 10 minutes respectively in order to provide regulating power services to the SO.

²⁸ Supplemental in the sense that they are in addition to each participant's self-dispatch schedule.

International experience suggests, therefore, that although there may be advantages in terms of efficient and reliable system operation in ensuring that the SO can begin to make assessments of the likely need for balancing actions at an early stage, this does not preclude participants continuing to trade very close to real time.

4.2.2 Payments for Balancing Actions

Payments for balancing actions instructed by SOs in markets that operate close to real time are critical in sending the right price signals and rewards to providers of flexible products and services required by the system to achieve real time energy balance. In mandatory central dispatch markets, the concept of payments for balancing actions is not relevant since there are no distinct markets for real time energy balancing.

In California, payments for real time energy market actions taken by the SO are determined every 10 minutes based on the marginal increment or decrement despatched in that period. Accepted bids and offers are settled at this price. To the extent that interzonal constraints emerge in real time, zonal marginal prices are determined and paid or charged.²⁹

In Sweden and Finland, a dual-pricing method is used to settle balancing market trades. All accepted offers are paid the price of the marginal³⁰ offer accepted and all bids get paid the price of the marginal bid³¹ accepted (except constraint relieving or exceptional actions, which are paid the better of offer/bid price and the relevant marginal price). In Norway, a single price method is used in the balancing market operated by the SO, Statnett. Generally, zonal marginal prices from a simple stack of the bids or offers available to meet the net volumes purchased by the SO for each hour are determined. Balancing market actions are paid (or pay) the more favourable of this price and the

²⁹ In the absence of real time *interzonal* congestion, the hourly ex post price will apply to all energy imbalances system wide. If real time *intrazonal* congestion occurs, the SO can take balancing actions based on adjustment bids but these are not used in setting the hourly ex-post price (since they will be out of merit).

³⁰ That is the price of the highest offer to sell energy accepted by the SO.

³¹ Assuming a bid is an expression of interest to buy power off the SO the bid price is expressing the price at which the participant is willing to pay. In which case, the SO will accept highest priced bids first and the marginal decrement price will be defined as the price of the lowest accepted bid.

offer/bid price submitted. In all three Scandinavian countries, actions to relieve constraints cannot set balancing market prices.

Hence, of the markets surveyed in this paper, various forms of pricing have been adopted to remunerate actions taken by the SO in balancing markets that operate close to real time. In California, marginal prices are determined every 10 minutes, which should prevent single (and perhaps unrepresentative) actions take by the SO during the hour long trading period having an undue affect on payments for balancing actions. In both California and Scandinavia, the final deadline for submitting offers and bids to the SO for use in the balancing markets is close to the beginning of the trading period (ranging between 2 hours in Norway to 10 minutes in Finland).

4.2.3 Cash-out Prices and Imbalance Charges

Cash-out prices are a critical element of any set of electricity trading arrangements since they determine the financial exposure of participants in the event that they are out of balance and they provide signals as to the value of trading in forward markets and taking physical positions prior to real time.

In all markets surveyed in this chapter, cash-out prices are determined from prices prevailing in relevant markets in to which participants submit competing bids and offers (as opposed to administered prices³²). Cash out prices may be drawn from organised ex-ante commodity markets or emerge from close to real time balancing markets.

In California, an hourly ex-post cash-out price is determined as the volume-weighted average of the 10-minute marginal prices and is used to settle imbalances (which can be zonal). Participants are cashed out on the difference between their final scheduled (contract³³) quantities and their metered generation or demand. Scheduling Co-ordinators,³⁴ in the first instance, will be billed for any imbalances. One of the responsibilities of Scheduling Co-ordinators is to manage the settlement of contractual

³² Administered prices might be centrally determined 'penalties' or regulated 'tariffs' imposed on participants out of balance. Such tariffs might be volume related or otherwise but in all cases will not be linked to prices emerging from a relevant market.

³³ Given the requirement on Scheduling Co-ordinators to submit balanced schedules in California, scheduled quantities must be backed by contracts signed with generators and customers. This implies, de jure that there is ex-ante contract notification.

³⁴ Scheduling Co-ordinators are intermediaries between the SO and market participants acting to aggregate and conduct bilateral transactions and schedule transmission services.

imbalances (that is allocate any imbalance charges incurred) to the individual participants with which they have contracted. In the first year of the market in California, the SO observed systematic under-scheduling of demand by Scheduling Co-ordinators, which the SO has argued was perpetuated by the requirement to submit balanced schedules.³⁵

In all three Scandinavian markets, hourly marginal pricing is used to cash-out imbalances based on the difference between notified contract quantities and metered generation. In Norway, the same zonal marginal prices used to settle balancing market actions are used to form the cash-out prices (the zonal Elspot price is used if no balancing actions are taken). In Sweden and Finland, the same system wide marginal prices used to settle imbalances are used to form the cash-out prices. If actions are taken in both directions, then separate marginal cash-out prices are determined for long and short positions. The marginal offer price is paid by those who are short, whilst the marginal bid price is paid to those who are long. If no actions have been taken in a particular direction then the cash-out price for that direction is the Elspot price. In neither Sweden nor Finland are zonal cash-out prices used, since constraints are relatively infrequent. When they do occur, the respective SOs simply buy and sell 'out of merit', but a single national price is maintained.

Gas markets in the U.S. have linked cash-out prices to price indices emerging from liquid commodity markets. For example, Pacific Gas and Electric Company (for intrastate imbalances) and Florida Gas Transmission Ltd (for interstate imbalances) both use cash-out prices linked to a number of locational spot price indices. In both these systems, cash-out prices are designed to make participation in the cash-out process unattractive.³⁶

In countries with mandatory markets, the concept of cash-out prices is different since they relate not to imbalances but to all energy flows. In all such markets, the basic principle of marginal pricing has been adopted (i.e. the highest price offer/lower price bid dispatched) albeit of different varieties (national, zonal or nodal) and with price

³⁵ Scheduling Co-ordinators had been underscheduling their expected demand requirements in order (for the supply side) to benefit from potentially attractive cash-out prices.

³⁶ Cash-out prices in both systems are based on adjusted market prices. For long positions, participants only receive a proportion of the market price (e.g. 75%), whilst for short positions participants would be charged a multiple of the market price (e.g. 125%).

determination based on centrally administered scheduling algorithms with differing levels of complexity.

In conclusion, two main types of cash-out prices can be identified:

- ◆ those that emerge from balancing ‘mechanisms’ operating close to real time which therefore reflect, at least to some extent, the value of flexibility (California, Scandinavia). Marginal pricing is used in the markets surveyed in the chapter. However, in all the markets surveyed that have balancing markets, Gate Closure is close to the trading period (Scandinavia, California) and/or marginal prices are determined over very short timescales (California). Such markets have therefore not been faced with the problem of marginal prices established over an extended period being applied to imbalances; and
- ◆ those based on prices emerging from liquid commodity markets operating close to real time (U.S. gas markets).

There is an additional distinction between those markets that have a single cash-out price (California, PJM, Norway) and those that have dual cash-out prices (Sweden and Finland, U.S. gas markets). In most instances, dual cash-out prices try to incentivise participants to trade ahead in forwards markets. In such markets, cash-out prices are either volatile and/or reflective of the costs imposed on the system by participants changing or taking physical positions near to real time.

4.2.4 Security of Supply

Security of supply depends upon the provision of generating capacity that is both adequate to meet demand in the long-term and available to meet short-term demand fluctuations. Based on international experience, three main mechanisms for ensuring both generation adequacy and availability can be identified.

The first mechanism is to rely on energy spot and future prices to provide both long-term investment signals (to indicate the need for new capacity) and short-term availability signals (to ensure that sufficient generation capacity is available to meet expected or unexpected changes in demand). In principle, such systems allow customers or their suppliers to determine the maximum price they are prepared to pay for electricity and hence the security of supply they are prepared to accept. Key

examples of such energy-only markets around the world include California, Scandinavia and Australia. However, in two of these markets price caps are currently in place - California (\$250/MWh) and Australia (AUS\$5000/MWh). In Australia, there have been problems in ensuring that there is sufficient peaking capacity on the system because of the price cap. This has resulted in the SO having to contract with seldom used plant (i.e. undertake a Reserve Trader Role). In California, between April and December 1998 volume weighted Power Exchange (PX) prices in the day-ahead market were around \$28/MWh. For 16% of hours prices were below \$10/MWh, whilst for only 1.5% of hours were prices between \$100/MWh and \$200/MWh. Hence, the price caps have rarely restricted energy prices (in only 48 hours was the price cap hit during the first year of SO real time energy market). Furthermore, there are 11 proposed projects in California with a total capacity of 6 GW, indicating that present pricing arrangements are not deterring the entry of new capacity.

A second type of system, prevalent in the north east United States, is the use of centrally planned reserve requirements with capacity markets, which effectively allow participants to trade reserve. In such systems, a central agency (an independent SO or Regulator) may specify a requirement for planning reserves. The capacity market allows suppliers to trade and reallocate reserve requirements.³⁷ Key examples of such markets include PJM and the New York Power Pool. In October 1998, PJM established a monthly capacity credits market-based on a price auction. The PJM reliability committee determines forecast capacity requirements. Suppliers then trade capacity credits to meet their expected demand obligations. On 22 October 1998, this auction cleared at 100 MW for January 1999, 135 MW for February 1999 and 220 MW for March 1999 at prices of about \$80/MW/day (about \$30/kW/year). A daily capacity credits market was implemented on 1 January 1999 (for a trial period between January and May, participation in the daily market was also made mandatory³⁸).

A third mechanism is the use of explicit capacity payments. Currently, (apart from England and Wales) only Spain and some South American markets make capacity

³⁷ Although, reserve is traded frequently, time lags may mean that the capacity market and the energy market are not quite in equilibrium.

³⁸ All excess capacity held by any participant above their obligations was required to be bid into the market. Any excess capacity not bid in would automatically be bid at a price of zero. Anyone with capacity deficiencies had to put in buy bids. If no buy bids were submitted, the buy price was automatically set at \$160/MW/day.

payments to generators. In some South American markets, the use of capacity payments has been designed to encourage much needed new entry and has been successful to an extent. However, the difficulty of setting the correct level for capacity payments is illustrated by the fact that some South American markets are experiencing overcapacity (due to capacity payments being too high) whilst other markets have capacity shortages (from capacity payments being too low). It has been argued that the Capacity Guarantee Payments in Spain are not so much capacity payments, but an additional stranded cost payment that has led to capacity which is not necessarily economic being kept open.

International experience has shown that it is crucial that the appropriate price signals emerge from the market so that sufficient capacity is available when needed. The wrong signals can lead, in the extreme, to a failure to meet demand. In addition, it is not just capacity payments, but the overall level of revenues (including payments for ancillary services such as reserve) that encourages the building or retention of plant. Furthermore, separate capacity markets induced by administratively set reserve requirements may not be consistent with the energy market requirements and are unlikely to reflect the differing choices of customers with regard to supply certainty and price risk. For example, capacity payments can lead to under pricing of energy, which can discourage demand-side response to energy price signals (as demonstrated in Argentina). Hence, markets are increasingly relying on efficient energy price signals, rather than administered capacity mechanisms to provide an appropriate level of security.³⁹ Forward markets and hedging instruments provide competitive market alternatives to capacity payments and it is through such markets that customers can decide how much they want to pay for security. These decisions will be reflected in the type and quantity of capacity additions that occur.

4.2.5 Information Provision

Real time information provided by SOs can help inform the decisions of market participants on a day to day and even hour to hour basis, whilst information updates from market participants to the SO can help the SO take the most efficient balancing actions. Indeed, the higher the quality of information throughout the day, the more likely it is that balancing actions by participants and the SO, and market prices, will be reflective of expected and actual supply/demand conditions.

³⁹ Reserve generation capacity beyond efficient security levels can be thought of as a hedge against high prices.

California and PJM, through their Open Access Same Time Information System (OASIS) systems, have an open information availability policy covering both market participants and the wider public. The SOs publish a range of information on their websites including outage plans, network flows, demand forecasts, loss factors, ancillary services requirements, planning studies, day ahead and hour ahead market price information and operating procedures. In Australia, NEMMCO publishes bid/offer data, generation schedules and actual generation, regional reference prices and the sensitivity of prices to changes in demand. In addition, it provides a rolling seven-day projection of supply and demand. In Norway and New Zealand, the importance of reservoir storage levels in systems dominated by hydro plant has been recognised by the publication of constantly updated forecast and actual reservoir levels. Furthermore, in Sweden and Finland, the respective SOs provide participants with real time information on balancing market prices. In Sweden, the SO informs participants of the price of the last accepted offer/bid, whilst in Finland, participants are provided with the current estimate of balancing market and cash-out prices as well as the price of the highest unused offer and unused outstanding bid. Information provided by the Spanish market operator, OMEL, to third parties, is currently very limited.

Price reporters and indices in the European markets have begun to emerge. For example, Platts European Power Daily and the Heren Report's European Electricity Markets publish price information covering a range of markets.⁴⁰ Examples of price indices are the Swiss Electricity Price (SWEP) Index and the VIK price index in Germany.

In summary, in electricity and gas markets around the world, the value of timely information is being recognised, as evidenced by information provided by system and market operators and in the emergence of price reporters and price indices.

4.3 Price Comparisons

In Chapter 14, the relationship between trading arrangements, competition, market prices and industry structure is discussed in more detail.

⁴⁰ Both Platts European Power Daily and Heren Report's European Electricity Markets publish price information covering - NordPool (Nordic bilateral trades), UK Pool; UK Electricity Forward Agreement (EFA) market, APX, German cross-border trades; and Spanish Pool.

Forwards and futures markets can provide an indication of the prices at which market participants are able and willing to buy and sell energy. Recent prices in the UK Electricity Forward Agreement (EFA) market show that annual baseload contracts for delivery in 1999/2000 have traded at around £24.00/MWh. This is higher than equivalent forward prices in other markets. For example, the price of annual contracts traded recently at the German border has been quoted at around DM30/MWh (£10/MWh). Similar prices have been seen in the Nordic bilateral market, where annual contracts have been traded at around NOK125/MWh (£10.1/MWh). In the U.S, recent prices for the California Oregon Border (COB) contract traded on the NYMEX futures market would have allowed the purchase of an annual strip of monthly baseload contracts for a price of around US\$29/MWh (£18/MWh). Finally, in Australia, participants are able to trade a monthly electricity futures contract on the Sydney Futures Exchange (SFE). Recent prices for the Victoria Baseload electricity contract traded on the SFE show that an annual strip of monthly contracts can be bought for an annual average price of around AUS\$28.8/MWh (£12.2/MWh).

Hence, the evidence from market prices in a number of key countries is that wholesale electricity is being traded at prices substantially below those currently prevailing in England and Wales.

4.4 Summary of Developments in Other Markets

Developments in other markets, not only since last year, but also since the inception of the England and Wales Pool, have shown that the design of competitive electricity trading arrangements is constantly evolving. Differences in plant mix, transmission network capabilities, historic arrangements and market structure all influence the choices that are made so that no one solution dominates.

Nevertheless, international experience supports the principal elements of the RETA proposals. In general, there is a trend towards market-based solutions for all elements of electricity trading arrangements. In particular, there are several examples of markets in which participants have responsibility for self balancing and where there is movement towards greater choice and flexibility in trading mechanisms and contractual form. Several markets have introduced arrangements that operate close to real time, and impose firmness on volume and price commitments made by market participants. International experience also indicates that markets are increasingly showing confidence

in market-based solutions to security of supply rather than administered mechanisms. International experience of the key issues highlighted in this chapter has informed the development of the market rules outlined in later chapters.

5. Overview of the Trading Arrangements

This chapter provides an overview of how the trading arrangements will operate. Further details on those elements of the trading arrangements that will be set up under the auspices of the RETA Programme – the Balancing Mechanism and Settlement arrangements and their associated governance arrangements – are provided in the following chapters (6 to 10), their associated appendices and the Balancing Mechanism and Imbalance Settlement Draft Specification.

The basic outline of the trading arrangements remains unchanged from that described in the July 1998 Proposals. They still are based on the concept of half-hourly trading periods and incorporate the following features:

- ◆ forwards and futures markets (to the extent required by participants);
- ◆ short-term power exchanges (also to the extent required by participants);
- ◆ a voluntary Balancing Mechanism (initially operating from four hours ahead to the end of each trading period); and
- ◆ a mandatory settlement process.

Taken together these elements will provide a set of trading arrangements with many of the features of other commodity markets. The markets will be two-sided with ample opportunities for the demand-side to participate. The markets will generally be less complex, with simpler forms of offers and bids than under the present arrangements. Importantly, participants will have a great deal more freedom of choice over how they conduct their business with the emphasis being on contracts between willing buyers and sellers at prices they agree rather than prices arrived at via a centrally administered process.

Each of these elements is described in turn below. The chapter ends with a brief discussion of the governance arrangements for the Balancing Mechanism and settlement process.

5.1 Forwards, Futures and Short-Term Markets

It is envisaged that the bulk of trading activity will take place in the forwards, futures and short-term markets. These may include exchange-based markets as well as over the counter (OTC) markets. Trading via bilateral contracts will enable participants to secure cover for their likely output or demand so that, by the time that the Balancing Mechanism opens for a trading period, participants' contract positions will generally closely match their anticipated physical positions (allowing for possible participation in the Balancing Mechanism). Liquidity in the forwards, futures and short-term markets will be enhanced by the entry of traders and other intermediaries, who, while not having a physical presence, will be prepared to manage risks on behalf of others.

Organised forwards, futures and short-term markets may be established by independent organisations if required by market participants but will not be established by the RETA Programme, i.e. they will be created in response to demand rather than imposed by central prescription. The RETA Programme initially considered whether it might be necessary to procure the establishment of a short-term (24 hour) screen-based power exchange (previously known as the short-term bilateral market) to facilitate fine-tuning of contractual positions. However, it was decided that this was unnecessary given the extent of interest in such a venture. A number of parties have now expressed interest in operating exchanges, including the provision of facilities for short-term trading. For example, OM, an electricity exchange operator in Scandinavia and California, announced on 7 June 1999 that it will be creating a spot market that will operate from the day the Pool ceases to operate. The International Petroleum Exchange (IPE) has also publicly expressed its interest in launching an electricity contract.

Market participants will take a range of views on contracting. Some may wish to secure their output or supplies a year or more in advance of physical delivery. Others will prefer to enter into transactions closer to the time that the electricity will be required. Yet others will want to contract and re-contract, continually adjusting their positions. Most will probably opt for some combination of these possibilities. From time to time, participants may also choose to remain uncovered, at least to some extent, and deliberately expose themselves to imbalance charges. However, it is not anticipated that this would generally be an advantageous position to adopt due to the risks associated with the uncertainty and volatility of imbalance prices.

As at present, it is envisaged that NGC, as SO, will contract for balancing services such as reserve, frequency control and voltage support up to a year or more in advance. Such contracts will ensure that the SO has a portfolio of actions available to it that, together with actions in the Balancing Mechanism, will enable it to balance the system on a second-by-second basis.

As in other commodity markets, it is expected that price reporting will develop because the information provided will be valuable to all market participants. The likelihood is that a wider range of information will be made available than at present, reflecting market needs rather than disclosure requirements. However, regulatory mechanisms could be deployed in the early stages of the development of the market in the unlikely event that adequate price reporting does not develop sufficiently quickly. Such reports might take the form of simple price indicators drawn from information on real contracts. The Regulator could require, using his statutory powers, market participants to give him the necessary information for such indicators to be published. This would be a temporary arrangement which would be implemented only whilst price reporting developed.

5.2 *Balancing Mechanism*

5.2.1 *Role*

The Balancing Mechanism will enable the SO to keep the system in energy balance by adjusting levels of generation and demand in the light of the bids and offers submitted.

In addition to maintaining an energy balance, the SO also has to ensure that the system remains within its operating limits, as prescribed by the Supply Regulations⁴¹ and consistent with its statutory duties and licence conditions, and that the pattern of generation and demand is consistent with any transmission constraints. The SO will use the Balancing Mechanism and other contracts that it might have entered into ahead of time to achieve this.

Unlike conventional markets, in the Balancing Mechanism only the SO will be able to accept bids and offers. It will, in this respect, not be a true market. In designing the rules for the Balancing Mechanism, therefore, the guiding principles have been that its

⁴¹ The Electricity Supply Regulations, 1988 (amended 1998).

operation should interfere as little as possible with the other markets. It is also considered necessary to ensure that the SO has appropriate incentives placed on it to minimise the costs of all its balancing activity, including the procurement of services related to reserve and frequency and voltage control.

The initial duration of the Balancing Mechanism for each trading period will be from four hours before the start of the trading period to the end of the period, i.e. a total duration of four and a half hours. This timing reflects a trade-off between a desire for bilateral contracting to continue until as close to real time as possible and the need for the SO to have sufficient time to carry out its balancing functions. NGC has argued that four hours is compatible with the minimum time required by some thermal stations to start up and produce energy.⁴² Over time, as NGC and market participants gain experience of operating under the new trading arrangements, it is anticipated that the duration of the Balancing Mechanism could shorten. An understanding of the level of balancing actions required and the depth of offers and bids available is likely to quickly evolve after implementation. Dealing with transmission constraints via alternative arrangements for transmission capacity⁴³ could also facilitate moving towards a shorter duration for the Balancing Mechanism.

5.2.2 Participation

A wide range of participants will be able to make bids and offers to the SO through the Balancing Mechanism, including generators, suppliers and customers.⁴⁴ However, participation in the Balancing Mechanism will be voluntary.

5.2.3 Information Requirements

To carry out its various functions, the SO will require adequate information to be available on the intended generation and demands of individual market participants. NGC has said that it will require initial information on the expected positions of participants throughout the following day to be made available at the day-ahead stage (say 11:00) via Initial Physical Notifications (IPNs).

⁴² NGC has indicated that a typical 500 MW coal-fired set currently requires around 90 minutes to synchronise with the grid, providing it is already warm, and another 90 minutes to increase output to a reasonable level.

⁴³ Discussed further in Chapter 8.

⁴⁴ Customers will be able either to participate via their supplier or directly if they are licensed.

NGC will use the IPNs to carry out the necessary system studies to configure the transmission system appropriately. NGC will provide information back to the market such as the implied supply-demand imbalances and potential transmission constraints. The information received may prompt NGC to invoke contracts with participants entered into ahead of time that require a relatively long notice period in order to provide useful services in Balancing Mechanism timescales. Appendix 5 presents NGC's current thinking on information flows under the new arrangements.

Participants' positions are likely to continue developing after they submit their IPNs. NGC will require updates on the IPNs culminating in Final Physical Notifications (FPNs), which will be submitted for a trading period when the Balancing Mechanism for that period opens (i.e. at Gate Closure). On the basis of this information and its own forecasts and knowledge of the system, the SO will be able to estimate whether and when any energy imbalances or transmission constraints are likely to occur and their expected magnitude.

Whilst participation in the Balancing Mechanism will be voluntary, the provision of information to the SO will be mandatory for at least some classes of participants, irrespective of their intention to participate in the Balancing Mechanism. The SO will require this information on participants' intended positions in order to balance the system. Obligations to provide information to NGC already exist in the Grid Code⁴⁵ and these provisions will be modified to specify which categories of participants are required to submit IPNs and FPNs for information purposes.

The output or demand of some small participants is likely to be such that any information provided by them to the SO would have no practical value in maintaining system balance and security. This implies that it will be sensible to impose a *de minimis* level below which participants are not required to provide information to the SO. Further consideration is required as to what *de minimis* levels will be appropriate.

Participants that are not required to submit FPNs under the terms of the Grid Code will, nonetheless, need to submit FPNs if they wish to participate in the Balancing Mechanism or Settlement processes. Such FPNs are required to provide a baseline

⁴⁵ The Grid Code presently includes three categories of generator: centrally dispatched, small and minor. Each has different obligations for the exchange of information with the SO.

against which the delivery of Balancing Mechanism actions can be measured. Consequently, any Grid Code obligations will need to be consistent with the information requirements for participating in the Balancing Mechanism.

5.2.4 Operation

Participation in the Balancing Mechanism will be in the form of offers and bids⁴⁶ for movements away from FPNs. Offer prices reflect the payment that participants wish to receive for increasing output or decreasing demand whilst bid prices reflect the payment that participants are willing to make for reducing their output (thereby avoiding running costs) or increasing their consumption. All Balancing Mechanism trades will be settled at the prices included in the accepted bid or offer i.e. under a pay-as-bid system. Some participants have argued for a marginal pricing regime in the Balancing Mechanism but as the July 1998 Proposals and the Government's White Paper⁴⁷ made clear such an approach has not been adopted. In addition to the reasons put forward in the July 1998 Proposals, two further arguments can be made in favour of 'pay-as-bid'.

First, it seems inappropriate that a participant who is able to deliver energy over very short timescales should only receive the same payment as one who can only assist in balancing the system given a much longer notice period. Second, it is likely that many of the forwards and futures markets, that are expected to emerge, will operate on this basis. Since it would be undesirable for there to be a discontinuity in the pricing approaches between these markets and the Balancing Mechanism that might unduly influence participants trading strategies, it follows that Balancing Mechanism payments should be 'pay-as bid'.

The spectrum of types of Balancing Mechanism trades will range from simple offers/bids relating to half-hourly blocks of energy to offers/bids that allow the SO to dispatch energy on a minute-by-minute basis. For offers/bids to be dispatchable, it will not be sufficient for participants simply to submit information on the change in output or demand they are willing to provide. In addition, they will need to submit data specifying any limitations they wish to impose on the delivery profile of that energy or

⁴⁶ Offers are also referred to as 'increments' and correspond to increases in output from generators and decreases in consumption from those on the demand-side. Bids are also referred to as 'decrements' and correspond to load-reductions by generators and consumption increases by those on the demand-side.

⁴⁷ Conclusions on the Review of Energy Sources for Power Generation, October 1998.

demand (the dynamic characteristics of the assets being used to deliver the offer/bid). For example, the speed at which generating units can change their output may be limited whilst demand-side participants may be able to change their consumption level almost instantaneously but may require advance notification in order to be able to do so. Only one price will be attached to an offer/bid whatever its form in terms of energy deliverability. For practical reasons, it is proposed that, at least initially, new bids and offers may not be submitted after Gate Closure for a particular half-hour.

The acceptance of a bid or offer by the SO will be 'firm'. If the SO subsequently decides that the offer (or bid) is not required, a counterbalancing bid (or offer) will have to be accepted either from the same participant or another participant with more attractive prices. Participants who fail to deliver an accepted offer/bid will face a financial exposure.⁴⁸

In determining which offers/bids to accept from the Balancing Mechanism, the SO will inevitably take account of the dynamic characteristics associated with the offers/bids as well as their price. Because of a need for rapid actions to balance the system, at times the SO may call high-priced offers (or low-priced bids) with few dynamic restrictions when other lower-priced offers or higher-priced bids have been submitted. Participants should be able to judge this value by observing the offers/bids that are accepted out of price order and examining the dynamic characteristics they have submitted.

To allow this transparency, it will be important that adequate information is revealed to market participants in a timely fashion. To ensure that this occurs, information on the dynamic characteristics associated with offers/bids will be made available, possibly via a screen-based system along with data on prices and volumes. One option for consideration would be to condense the potentially large volume of information into a flexibility index or indices.

5.3 Settlement Process

The calculation and settlement of imbalances will be the main function of the settlement process. This will ensure that any energy not covered by contracts is paid or charged an

⁴⁸ The exposure will be to the difference between the relevant cash-out price and the prices of the accepted offers/bids, if this difference results in a charge to the participant.

appropriate price. Settlement will also cover a number of other areas including the settlement of accepted Balancing Mechanism offers and bids, the calculation of costs or payments to NGC, and the recovery of administrative and operational costs.

5.3.1 Cash-out Prices

In principle, imbalance cash-out prices should reflect the full costs of imbalances having to be resolved by the SO over relatively short timescales. These costs will be different from the costs of simply purchasing power on the forwards and futures markets since out of balance participants need also to pay for the costs of making use of balancing services. The range of balancing services available is very wide and covers all those flexibility options which give the SO the ability to balance the system. These include Balancing Mechanism offers/bids, contracts entered into by the SO ahead of time, adjustments to the configuration of the transmission system, and allowing the frequency and voltage on the transmission system to vary within the allowed tolerances. Calculating the full costs of these flexibility options is very difficult, even if these are confined to the costs incurred by the parties involved, ignoring possible effects on others. Hence, the construction of any pricing system requires an element of judgement and pragmatism.

Participants who spill electricity⁴⁹ are not, in any meaningful sense, contributing to balancing the system (except accidentally). Consequently, it seems appropriate that participants who are spilling electricity should receive a lower price for their electricity than if they had been fully contracted. Since they may be imposing flexibility costs on the system, withholding these costs from the price they are paid has merits. Conversely, participants on whose behalf the SO has to procure the flexible delivery of electricity should pay the full costs of that 'top-up'. The issue of flexibility costs is particularly relevant when, as will be the case initially, the duration of the Balancing Mechanism is relatively long. Under these circumstances, the information that the SO receives at Gate Closure may well change by real time necessitating the use of flexibility options. This suggests that a dual cash-out price is required.⁵⁰ The use of a dual cash-out price regime

⁴⁹ Spill is used to describe generators whose output is more than their contracted volume and those on the demand-side whose consumption is less than their contracted volume. Conversely, buyers of imbalance volumes (top-up) will be generators whose output is less than their contracted volume and those on the demand-side whose consumption is greater than their contracted volume.

⁵⁰ Other electricity and gas markets have also adopted dual cash-out prices.

will incentivise participants to balance their own positions by Gate Closure and hence the actions that the SO has to take should be minimised. Thus, the cash-out prices should also assist in fulfilling the RETA objective of minimising the role of centrally administered mechanisms and facilitating bilateral trading of electricity.

There is no unambiguously correct way of setting the cash-out prices and a number of options have been widely discussed with interested parties and seriously considered. The first option proposed taking a commodity price from the traded short-term markets and representing flexibility by, say, a 10% differential from the commodity price as an allowance intended to be broadly reflective of the cost of flexibility options. This has the advantage of simplicity and transparency. However, it results in cash-out prices which are not related to the costs incurred by the SO in balancing the system and hence may lead to pricing signals at times of system stress that have little influence on participants' contracting actions. It is true that arbitrary differentials, set up initially, can be improved upon as more is learned about behaviour, but, on balance, the disadvantages of this approach appear to outweigh its advantages.

The second option would be to determine a commodity price from the offers and bids submitted to the Balancing Mechanism (including those offers and bids not accepted by the SO). As in the first option, the cost of flexibility would be represented by a differential of say, 10%. The commodity price will be the volume-weighted average price of the lowest cost offers or bids required to meet the net volume actually purchased or sold by the SO in the half-hour. The bids/offers would be selected for inclusion in the price calculation in order of price, making an allowance for the volume feasibly deliverable given the dynamic characteristics associated with the bid/offer. This method of calculation results in commodity prices which would more closely reflect the costs incurred by the SO in balancing the system. However, at times when the SO needs to take rapid balancing actions to deal with an unforeseen event, it may need to call upon relatively expensive offers or bids. The proposed calculation method would implicitly assume that the SO had perfect foresight of such events and might therefore dampen the cash-out price signals at times of system stress by calling upon more attractive offers and bids that, in practice, may not have been deliverable in the short timescales required.

The third proposal is to take the volume-weighted averages of the accepted offers and bids in the Balancing Mechanism. Thus, buyers of imbalance energy will pay the volume-weighted average of the accepted offers while sellers of imbalance energy will be paid the volume-weighted average of the accepted bids.⁵¹ This method of calculation results in cash-out prices which reflect the costs incurred by the SO in balancing the system and hence will allow short-term price signals to emerge at times of system stress. Spill gets paid what others are prepared to pay not to generate. Top up has to pay what others require to be paid to generate. It does not solve the problem that, during the period in which transmission constraints continue to be resolved in the Balancing Mechanism, these costs will feed through into cash-out prices. It is intended that this will be a short-term difficulty, to be solved by addressing the transmission constraints problem directly, as discussed in Chapter 8.

There are advantages and disadvantages associated with each of these cash-out options. On balance, the third option is preferred as it is simple, transparent and reflective of the costs incurred by the SO in balancing the system.

There will be no administered cap or floor on Balancing Mechanism offer and bid prices or imbalance cash-out prices, which could reach unrestricted levels at times when there is a shortage of electricity.⁵² Against the threat of exposure to extreme prices, customers (or suppliers on their behalf) will be free to choose the level of security of supply for which they are willing to pay.⁵³ In this world, supply licence obligations relating to security of supply will no longer be appropriate.

The net costs (or revenues) from accepted Balancing Mechanism offers and bids, will be passed through to NGC. It is likely that NGC will be incentivised to minimise the overall costs of balancing the system, including the costs of operating the Balancing Mechanism. Other administrative and system costs, such as the costs of running settlements, will also have to be recovered from participants under arrangements that

⁵¹ In this method, the commodity and flexibility prices are combined but there are effectively two flexibility prices (one for system buys and another for system sells).

⁵² Note that at times when the system was particularly long on electricity, sellers of imbalance electricity could face very low or even negative cash-out prices.

⁵³ In practice, there will be limitations on the extent to which this can be achieved. It may not be possible for the SO to distinguish between customers of different suppliers on the same part of the network when it comes to disconnections.

have still to be determined. The role of the SO and its incentives are discussed further in Chapter 8.

5.3.2 Participation in the Settlement Process

Although participation in all the other elements of the market will be voluntary, for most participants involvement in settlement will not. Mandatory exposure to imbalance charges is necessary to ensure that no participant receives the benefit of electricity for which they have not paid.⁵⁴ Exposure to imbalance charges will be compulsory for all licence holders. Participants such as traders, brokers, unlicensed generators (for example, small-scale renewables plant) will be able to choose whether or not to accept direct exposure to imbalance charges i.e. participate in the settlement process. If they choose not to participate in settlement, they will forgo the right to be paid the cash-out price for any electricity they spill and to notify contract volumes, as well as being unable to participate directly in the Balancing Mechanism.⁵⁵

5.3.3 Calculation of Imbalance Volumes

All electricity covered by bilateral contracts, by definition, has been or will be paid for and so the settlement of imbalances resolves into measuring and charging for differences between participants' metered volumes and their contract positions. The contractual position of participants will take account of all relevant trades in the forwards and futures markets (whether OTC or exchange based)⁵⁶ and any accepted offers or bids in the Balancing Mechanism. Contract positions from the forwards and futures markets (including short-term power exchanges) will be notified on an *ex-ante* basis, that is, before the half-hour settlement period in question. It is envisaged that contracts will need to be reported by Gate Closure.⁵⁷ Only the volumes traded under these contracts, and not prices, are required for the imbalance settlement calculation –

⁵⁴ Generators by producing less output than their contracted sales volume could benefit from unpaid electricity in exactly the same way that those on the demand-side could by consuming more than their contracted purchase volume.

⁵⁵ Even those unlicensed participants who chose not to take part in settlement directly are likely to be exposed to cash-out prices indirectly through their dealings with others. Likewise, unlicensed participants could offer services to the Balancing Mechanism through a third party.

⁵⁶ Purely financial trades e.g. swaps and options, which participants may find helpful in managing their business, do not form part of the physical trading arrangements and therefore will not be part of the settlement process. This does not, of course, preclude the development of such forms of trading.

⁵⁷ In practice, it may be necessary to allow sufficient time after Gate Closure for the preparation and transfer of the contract data.

the contracts themselves will be settled bilaterally by the contract counter-parties rather than by the central settlement system.

Some participants have argued that *ex-ante* contract notification will stifle the development of innovative risk management options and limit participants' choices with regard to contract structure. Others have argued that *ex-post* contract notification discriminates between different categories of participants (for example, in favour of larger generators and against smaller generators). However, the most serious objection to *ex-post* contract notification⁵⁸ relates to the ability it confers on the owners of generation assets, even in a generally competitive market, to drive up the prices that participants with short positions have to pay to reduce their imbalance exposure after real time and before contract notification ('*ex-post* trading'). By withholding contract volumes in the forwards and futures markets, generators can ensure that some participants will have insufficient contract cover to match their expected needs. It is also likely that they will be able to ensure that the SO is a net purchaser of energy in the Balancing Mechanism. Hence, there will be insufficient uncontracted energy to match the needs of participants that are short. In these circumstances, the price at which imbalance volumes are traded *ex-post* will rise to just below the cash-out price for being short rather than being close to the average of the two cash-out prices (as might have been expected). This, in turn, might drive up prices in the forwards and futures markets. *Ex-post* trading might also disadvantage smaller participants who might find it harder to trade out their imbalance positions than larger participants and hence be exposed to a disproportionate share of balancing costs. The trading arrangements need to be robust against a range of possible market structures. *Ex-post* contract notification would not meet this criterion.

A further argument in favour of *ex-ante* contract notification relates to the ease with which notification procedures could be changed in the light of experience. If *ex-post* contract notification were adopted, and the concerns discussed above regarding the possibility of contract volumes being withheld from the futures and forwards markets were found to be a serious problem, it would be extremely difficult to move from an *ex-post* to an *ex-ante* notification system, once the new arrangements had been introduced. This is because the timescales over which an *ex-ante* system would need to operate

⁵⁸ *Ex-post* notification would allow participants to notify their contract volumes after they received information on their metered volumes.

would be much tighter than those for an *ex-post* system so it is unlikely that an *ex-post* system could be modified to make it applicable to *ex-ante* notification. However, it would be relatively straightforward, both from a system and an operational perspective, to move at a later date from *ex-ante* to *ex-post* notification if confidence in the new arrangements and the competitiveness of the market was such that the approach appeared beneficial.

The *ex-ante* contract volumes notified to settlements will need to specify MWh values for each half-hour. Participants will, nonetheless, be free to enter into contracts under which volumes are not fixed in advance – for example, contracts linked to metered quantities (so called ‘full requirements’) or related to weather conditions – in order to achieve the allocation of risks that the counter-parties desire. Although the imbalance settlement systems will not explicitly recognise the *ex-post* volumes traded under such contracts, parties bearing volume risks on behalf of others (under the terms of the contracts they have signed) will be able to mitigate their potential exposure by placing offers and bids in the Balancing Mechanism.⁵⁹ If participants do have access to flexible generation or demand resources at Gate Closure, they will have a commercial incentive to make such resources available to the market via the Balancing Mechanism. In this way, the incentives for participants to change their physical positions after Gate Closure without instructions from the SO should be reduced.

Participants’ metered volumes will be adjusted for transmission losses. To provide the greatest possible flexibility with regard to the allocation of these losses, the settlement systems will be designed to be capable of applying individual loss factors for every entry and exit point to the transmission system. The issue of how losses should be allocated is closely tied to the treatment of transmission access and will be reviewed in that context. In the interim, the default position is that, as now, uniform transmission loss factors will be applied to all participants on the demand side but not to generators.

In the calculation of metered volumes for settlement purposes, it is proposed that it will be possible for the volume from an individual meter to be split between a number of participants. This will allow, for example, a customer to sign supply contracts with

⁵⁹ A participant managing volume risk on behalf of others should be able to use revenues from accepted Balancing Mechanism offers or bids to offset payments due to its contractual counter-parties.

more than one supplier without acting as its own supplier (with all the associated costs and liabilities of being a licensed supplier). Suppliers will be able to notify volumes relating to a share of a meter, to meet part of a customer's needs. The complexity implied by including this functionality means that it may not be deliverable at the opening of the market, although the mechanism by which this would be achieved will need to be specified as part of the systems procurement process. Impacts on Stage 2 settlement will also need to be considered.⁶⁰

It would be inefficient not to allow imbalance volumes to be aggregated up from the individual meter level, at least to some extent. There has been considerable debate as to the appropriate level of aggregation. Many participants have argued that aggregation should allow production and consumption imbalances to be netted off one another rather than be treated separately.

Netting off production and consumption imbalances would disadvantage participants who were only on one side of the market relative to those on both sides and hence would reduce the range of entrant types. This would not be consistent with the objectives of avoiding distortions and encouraging competition (particularly with regard to facilitating entry). Moreover, splitting generation and consumption imbalances will enhance the role of traders in the market. The emergence of traders is an important part of the process of developing a competitive market, particularly since this can be of benefit to small players.

Consequently, imbalances relating to production (export) and consumption (import) meters will be calculated separately.⁶¹ However, all the production meters registered to a participant will be aggregated together on a nationwide basis, regardless of their geographical location. Similarly, all the consumption meters registered to a participant will be aggregated. Participants with both production and consumption meters would need to specify whether each notified contract was to be set off against either the aggregated production or consumption position. Pure traders, with no physical input or

⁶⁰ Stage II is a set of systems designed to allocate electricity between suppliers that enable domestic customers to choose their own suppliers.

⁶¹ The allocation of meters to production and consumption accounts will take place when they are registered for settlement purposes.

offtake positions, will have zero meter readings and will effectively be able to allocate all their contracts against one imbalance account.

5.3.4 IT Systems to Support the Balancing Mechanism and Settlement Process

Both the Balancing Mechanism and the Settlement Process will require new IT systems to be built and operated. Expressions of interest for the provision of these services were called for earlier in the year and a short list of 9 interested parties has been compiled. Detailed specification of the Invitations to Tender will now be drawn up. Letting of the contract(s) is expected in towards the end of the year. NGC will be the contracting party, but the procurement process will be managed by the RETA Programme under the leadership of OFFER and the DTI.

5.4 Governance

There will need to be a set of operational rules, objectives and provisions that specify the rights, obligations and duties of all participants in the Balancing Mechanism and Settlement process. These will be contained within a Balancing and Settlement Code (BSC).

The obligation to establish the BSC will be added to the transmission system operator's licence i.e. NGC's Transmission Licence. It will be given contractual force via the BSC which will be signed at least by all licensed participants and the SO. The obligation to sign the BSC will be imposed on all licence holders via an additional licence obligation, replacing the existing obligation to be a Pool member.

There will be a Panel whose function will be to supervise the implementation, operation and modification of the rules within the BSC. It is expected that the Director General will appoint the Chairman of the Panel. The Panel members will be comprised of experts competent to reflect the views of a wide range of interested parties, including customers. The Director General will also approve all modifications to the Code. A limited liability company (BSCCo), funded by all BSC signatories, will carry out the functions associated with the management and operation of the Balancing Mechanism and settlement processes

The BSC will lay down procedures for modifications to the rules contained within it. To ensure that the widest possible range of views is reflected, all BSC signatories, the SO

and certain customer and other representative bodies will be able to propose modifications and the modification procedure will include a wide consultation process.

5.5 Views Invited

Views are invited on the proposals outlined in this chapter. In particular, views on the following general elements of the trading arrangements are sought:

- ◆ appropriate *de minimis* levels for the provision of information to the SO;
- ◆ the alternative cash-out arrangements described in this chapter; and
- ◆ governance arrangements.

6. Balancing Arrangements

The Balancing Mechanism forms one of a portfolio of tools that the SO can use to balance the system on a real-time basis. This chapter provides greater detail on how the mechanism is expected to operate.

6.1 Scope of Balancing Mechanism Actions

The bilateral markets under RETA are likely only to provide for the trading of MWh integrated over half-hour settlement periods. More specialised products will be required to maintain a balanced system which is operating securely.

At Gate Closure, the SO will have information on the intended pattern of generation and demand (both directly from participants and via its own forecasts) across the country for the following four and a half hours. The SO then has the tasks of balancing the system both at the gross (half-hourly) level and on an instantaneous basis, resolving transmission constraints, placing plant in a position to provide balancing services, and ensuring that all transmission equipment will continue to operate within safe limits.

NGC has estimated⁶² that these activities may, on average, require around 2 GW (7% of average demand) of actions to be taken, broken down as shown in Table 6.1. However, the totals should be treated with caution since not all the volumes are additive. For example, additional output from a generator can cover both a transmission constraint and a plant failure. Currently, NGC's balancing actions are covered by Ancillary Service contracts (primarily for response and reserve), scheduled reserve and NGC instructing plant up and down from their day-ahead schedule positions.

⁶² In a paper to the Balancing Market Expert Group, BMEG 02/003 (February 1999).

Table 6.1 - NGC Estimates of Volumes of Actions Required to Secure the System from Four and a Half Hours Out (MW)

	Average requirement	99% confidence level
Demand forecasting errors	+/-400	+/-1800
Plant failures and re-declarations	+ 450	+ 1100/-2400
Failure to follow dispatch instructions	+ 150	+ 200/-400
Transmission constraints	+/-350	+/-2000
Frequency response	+/-1000	+/-1700
Total	+ 2350/-1750	+ 6800/-8300

Under the new arrangements, these actions will be provided primarily by a combination of Balancing Mechanism actions and balancing service contracts signed by NGC. Balancing Mechanism offers and bids will be made directly to NGC in relation to each half-hour settlement period, with information being provided in a transparent manner. At present, ancillary services contracts apply for much longer periods and are contracted either through a tendering process or via direct bilateral negotiations with NGC. It is envisaged that, under the new arrangements, NGC's procurement processes for balancing service contracts will be more open, transparent and contestable than the present ancillary services contracts,⁶³ and may be struck for shorter periods, such as a week or a month.

In balancing demand on an instantaneous basis, NGC will choose between accepting offers or bids in the Balancing Mechanism and calling on its balancing service contracts. Present thinking is that payments for electricity under most balancing service contracts should be made via the Balancing Mechanism. In effect the balancing services contracts would be option contracts for electricity or demand reductions which can be called upon at very short notice. For example, such contracts might specify that offers or bids be made into the Balancing Mechanism at pre-determined prices and the contract

⁶³ Under the present arrangements, the procurement of ancillary services by NGC has developed, with more services being open to competition via tender arrangements and with NGC entering into demand-side (customer) contracts as well as contracts with generators. For further details, see Appendix 6.

would effectively guarantee that such Balancing Mechanism offers or bids would be available. This is similar to the present way that payments for the energy element of ancillary services are made through the Pool. To allow for this incorporation of possibly very flexible balancing service contracts within the Balancing Mechanism, offers and bids may need to be dispatchable on a minute-by-minute basis and it is presently envisaged that the settlement system will need to include appropriate functionality to convert dispatch instructions to integrated half-hourly values.

6.2 Duration

Initially, the Balancing Mechanism for a half-hour settlement period will open four hours before the start of the half-hour, at Gate Closure, and run until the end of the half-hour. As discussed in Chapter 5, it is envisaged that over time it will be possible to move Gate Closure towards real time.

6.3 Participation

Participation in the Balancing Mechanism will generally be voluntary⁶⁴ and signatories to the BSC will be entitled to submit offers and bids in respect of any power flows through meters for which they can be deemed to be responsible. A participant submitting an offer/bid will be responsible for complying with the BSC rules and any relevant Grid Code obligations.

Certain restrictions may be placed on participation in the Balancing Mechanism. Participants will either have to be licensed or licensed exempt or trade via a participant that falls into one of these categories. There is likely to be a minimum size for all offers and bids, possibly of 1 MW. There will also be rules relating the maximum allowed size of offers and bids to the size of the physical assets to which they relate. Interim proposals in this respect are discussed below, in section 6.6, whilst more enduring proposals are outlined in Chapter 8.

Since the SO may need to overcome local transmission constraints by accepting offers and bids at specific points on its transmission system, it is desirable that offers and bids

⁶⁴ At times of system stress, if there are insufficient Offers and Bids available to balance the system, the SO will be able to invoke Deemed Offers (for demand) and Deemed Bids (for generation) from all participants to curtail generation and demand. These are discussed later in the chapter.

relate to measurable changes at as specific a location as possible on the transmission grid. In practice, the degree to which this can be achieved varies between different categories of participants and a generic term, 'BM Unit',⁶⁵ has been introduced to cover the range of possibilities. FPNs and offers and bids will have to be made for specific BM Units, which will relate either to individual meters or groups of meters. BM Unit definitions will be established broadly as follows:

- ◆ for generating stations directly connected to the transmission network i.e. almost all generating plant larger than 50 MW, BM units will correspond to the gensets or CCGT modules used in the present arrangements;
- ◆ for large half-hourly metered customers directly connected to the transmission network the BM Unit will be the meter at the Grid Supply Point (GSP) to which the customer is connected;
- ◆ for embedded⁶⁶ generation plant and half-hourly metered embedded customers whose meters do not fall within the Stage 2 system, the BM Unit will be the meter at the GSP below which the generation is deemed to be connected ;
- ◆ for other embedded demand and generation the BM Unit will be formed by aggregating all the meters within a GSP Group for which the participant is responsible (including those for any licence exempt generators with which the participant has signed a contract); and
- ◆ for interconnectors the BM Unit will be the proportion of the interconnector meters allocated to each Interconnector User.

Trading sites⁶⁷ will not receive special treatment with regard to the submission of Balancing Mechanism offers and bids. That is, the individual BM Units of which the trading site is composed will have to submit separate offers and bids. However, their status will be recognised with regard to the treatment of losses and the settlement of imbalances. Each BM Unit within the trading site will be treated in the same manner with regard to losses. If the trading site as a whole is exporting electricity over a half-

⁶⁵ Where 'BM' stands for Balancing Mechanism.

⁶⁶ Embedded refers to generation or demand connected to a distribution network rather than to the transmission network.

⁶⁷ In simple terms, trading sites are power stations with demand located on the same site as the power station.

hour, then all the BM Units will be treated as export meters and vice versa. Similarly, all the BM Units will be allocated to the same type of energy account for settlement purposes (either generation or consumption). This means that the status of trading sites under the new arrangements will be similar to their status under the present Pool arrangements.

There are some categories of demand that may need special treatment, for example customers on off-peak tariffs that allow their suppliers to determine remotely when their off-peak electricity is delivered by radio-delivered teleswitching codes. Since the same teleswitching code can apply to customers of more than one supplier, the acceptance of an offer or bid from one supplier may alter the positions of other suppliers. Consequently, it may be necessary to be able to link BM Units (and any associated offers/bids) in a manner that has yet to be determined.

Except in the case of interconnectors, meters will not be split for the purpose of defining a BM Unit although it will be possible to split meters for settlement purposes (see Chapter 7). It is necessary to allow interconnector meters to be split (and aggregated) because there might be several BSC signatories behind a single set of interconnector meters. For example, in Scotland there are presently three External Pool Members – Scottish Power, Scottish and Southern and BNFL – trading through a number of meters. In general, participants external to England and Wales will be able to trade across interconnectors in ways similar to those under the Pool but adapted to be consistent with the new trading arrangements.

6.4 Format of Offers and Bids

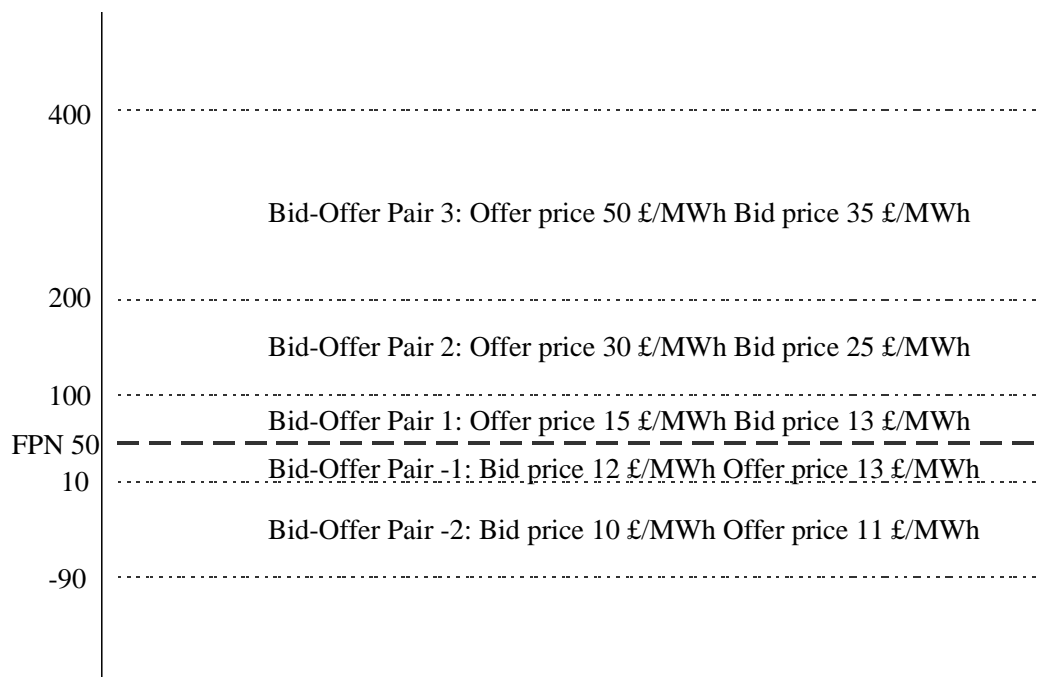
The submission of an offer or a bid indicates a willingness on the part of participants to increase or decrease the volume of active generation or demand flowing through a BM Unit from the pre-defined level of its FPN. Offers may be delivered through increasing generation or by decreasing the demand taken by a particular BM Unit. Conversely, bids may be delivered through decreasing generation or increasing demand.

The information contained within an offer or bid only applies for an individual half-hour period and has to be submitted to the SO by Gate Closure, four hours before the half-hour starts. Offers and bids will be submitted in matched pairs, 'Bid-Offer Pairs'. Thus, for a particular change in the output or consumption of a BM Unit, there will be a price

both for accepting an action and for undoing it. Each Bid-Offer Pair will consist of two prices – an offer price and a bid price (both specified in £/MWh), and information on the range of output or consumption (relative to the BM Unit’s FPN) for which the prices apply. For example, if the SO initially accepts a BM Unit’s offer to increase its output by 50 MW and then decides that only a 30 MW increase is required, the offer price will be applied to the initial acceptance of 50 MW and the bid Price to the 20 MW of action subsequently withdrawn by the SO.

Participants will be able to submit several Bid-Offer Pairs for the same BM Unit covering different ranges of output or consumption and containing different prices. These will effectively form a price ‘ladder’ as shown in Figure 6.1. If, for example, the SO instructs the Unit to operate at an output level between 50 MW and 150 MW above its FPN of 50 MW, the relevant offer price is 30 £/MWh. Note the convention that has been adopted is that Bid-Offer Pairs relating to output or consumption above the FPN level have positive numbers whilst those for output or consumption below the FPN level have negative numbers.

Figure 6.1 - Example of a Set of Bid-Offer Pairs



All participants who have signed the BSC will, in principle, be obliged to submit FPN data for all the BM Units for which they are responsible. However, participants will be

able to make use of the default provisions in the BSC rules to avoid having to submit data every half-hour.⁶⁸ In the event that a participant never submits a FPN value for a BM Unit, a default value of zero will be assumed for settlement purposes. Nonetheless, participants may have additional obligations regarding the provision of information under the terms of the Grid Code. Both FPNs and Bid-Offer Pair capacity data will be specified in terms of MW at spot times.⁶⁹ In principle, this method of specifying volumes will enable participants to submit Bid-Offer Pairs that range from the equivalent of half-hourly blocks of energy (constant spot MW) to complex shapes reflecting commercial and/or technical constraints. However, as an initial restriction to ease the task of the SO whilst it develops its systems, it is proposed that, whilst it will be possible for FPN data to be profiled, Bid-Offer Pair capacities will have to be constant across a half-hour. Since Bid-Offer Pair capacities are measured relative to FPNs, this implies that the size of action that they allow will not vary across the half-hour.

For offers and bids to be dispatchable, it will not be sufficient simply for participants to submit information on the volume of electricity or demand that they can provide and the price that they wish to be paid or pay for it. They will need to submit data specifying any technical limitations on the how the electricity or demand is delivered. For example, generating units may be limited in the speed at which they can change their output whilst demand-side participants may be able to change their consumption level almost instantaneously but require advance notification in order to be able to do so.

Although such dynamic data could be associated with individual Bid-Offer Pairs, for system design reasons, it has been decided that the data should relate to BM Units. It also reduces the scheduling risks to which participants could be exposed if they attempted to reflect the way in which dynamics change with output through a series of independent Bid-Offer Pairs. The dynamic data that participants will be required to submit for each BM Unit are for further consideration. At the most detailed level they might include:

⁶⁸ If a FPN value is not submitted for a half-hour, the value submitted for the previous half-hour will be assumed. Thus, in principle, participants will only ever be required to submit a single FPN value for a BM Unit. In practice, participants wishing to submit Offers/Bids into the Balancing Mechanism are likely to wish to update their FPN values regularly.

⁶⁹ Spot times refer to an instant in time rather than a period e.g. a minute starting or ending.

- ◆ Notice to Deviate from Zero (the shortest time after receiving an acceptance that a participant whose output/consumption is currently zero can respond);
- ◆ Notice to Deliver Offers and Bids (the shortest time after receiving an acceptance that a participant whose output/consumption is not currently zero can respond);
- ◆ A number of Run-Up Rates⁷⁰ (and their associated elbow points) defining the rate at which generation can be increased or consumption decreased;
- ◆ A number of Run-Down Rates (and their associated elbow points) defining the rate at which generation can be decreased or consumption increased;
- ◆ Minimum Zero Time (if a participant's output or consumption is reduced to zero, the shortest time before it can be increased again);
- ◆ Minimum Non-Zero Time (if a participant's output or consumption is increased from zero, the shortest time before it can be reduced to zero again);
- ◆ Stable Export and Import Limits (the minimum sustainable level of generation or consumption);
- ◆ Maximum Delivery Volumes and Periods (the maximum volume of action that the BM Unit can provide in MWh and the period over which the action can be provided); and
- ◆ Maximum Export and Import Limits (the maximum output and consumption levels at which a BM Unit can be instructed to operate as a result of accepted Balancing Mechanism actions).

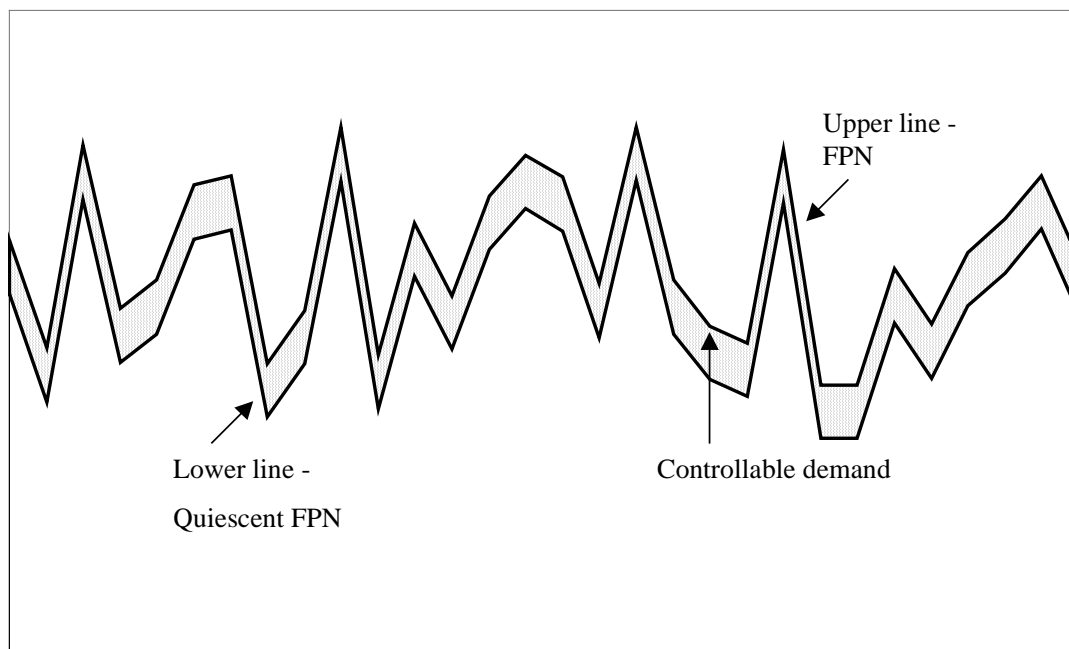
The draft Balancing Mechanism and Imbalance Settlement specification includes this level of complexity with regard to dynamic data. However, it is for consideration whether a simpler approach may be more appropriate. Dynamic data will effectively be standing data but participants will be able to change whenever they wish.

Participants on the demand-side have raised the point that they may only be able to control part of their consumption (for example, one process out of several that are taking place at a site). Moreover, the rate at which their overall demand can change may be much greater than the rate at which their controllable consumption can change. These

⁷⁰ Run up and down rates will apply for different absolute levels of output so the SO will have to calculate which rate applies for a given movement away from a participant's FPN.

factors suggest that it may be insufficient for such participants to submit a single FPN for a BM Unit (particularly if any form of consistency checking between FPN values and dynamic data is introduced). One solution for consideration would be for participants to be able to submit two FPNs per BM Unit – one for total generation or consumption and one for uncontrollable generation or consumption (a 'Quiescent FPN'). The dynamic data would only be applied to the difference between the total FPN and the Quiescent FPN. This concept is illustrated in Figure 6.2, where for a demand-side participant, the shaded area between the lines represents the controllable demand.

Figure 6.2 - Example of a Quiescent FPN



In principle, participants should be permitted to submit Bid-Offer Pairs at any time. However, for practical reasons,⁷¹ it is proposed that for initial implementation, Bid-Offer Pairs must be submitted by Gate Closure.⁷² However, participants will effectively be able to withdraw Bid-Offer Pairs (either partially or wholly) by reducing their Maximum Export and Import Limits. Conversely, by increasing their Maximum Export and Import

⁷¹ First, it will greatly assist the SO's decision-making process if Offers and Bids remain constant for a long enough time to permit the SO to make purchase decisions without Offers and Bids changing. Second, in order to minimise the initial volume of data that needs to be processed by the System Operator from the initial implementation of the New Trading Arrangements.

⁷² It is proposed that offers/bids will lapse at the end of a trading period unless they are flagged as 'evergreen', in which case they will be rolled over unaltered to subsequent trading periods until further notice.

Limits, they can effectively increase the available capacity of Bid-Offer Pairs. Over time, it is hoped that the restriction on re-bidding can be relaxed. In addition, it is anticipated that, as experience with the new trading arrangements grows, Gate Closure will be moved closer to real time.

6.5 *Transmission Access Limits*

The transmission access rights held for a BM Unit will limit the FPN that can be submitted in respect of that unit. Initially, these access rights will mean that the FPN for a BM Unit will have to lie between its Demand Capacity and its Generation Capacity.

The Generation Capacity values defined in the BSC will correspond to the Genset Registered Capacities currently defined in the Pooling and Settlement Agreement and used by NGC in calculating Transmission Network Services Use of System Charges. Demand Capacity values will be negative in sign to provide a consistent treatment across generation and consumption but it is difficult to find a suitable definition for Demand Capacity. One suggestion is that the Demand Capacity of a BM Unit in respect of a particular settlement period will be equal in size to the maximum metered demand over a half-hour recorded for that unit over the previous twelve months up to, and including, the given settlement period. Under this approach, Demand Capacity values for a half-hour would not be available when the FPN values for that half-hour were submitted, so any breaches of this limit would have to be identified and, if material, resolved after the event. An alternative, more pragmatic approach would be to base Demand Capacities on the maximum metered demand during the previous winter (possibly weather corrected) unless the participant provides evidence that their demand has increased for some well-defined reason.

6.6 *Measurement of Accepted Offers and Bids*

Based upon the information provided, the SO will select appropriate Balancing Mechanism actions to meet system requirements. In balancing the system, the SO is unlikely to be thinking in terms of individual half-hour periods in isolation. Given the FPN data and Bid-Offer Pairs submitted for each open Balancing Mechanism period, the SO will aim to take the balancing actions which minimise the costs of keeping the system in balance over the entire period, taking into account its incentive arrangements.

Balancing actions relating to that period are likely to be required up to and during the half-hour as generation and consumption patterns change from expectation.

If all the available offers and/or bids have been exhausted and further actions to balance the system are still required, the SO will be able to make use of Deemed Offers (to curtail demand) and Deemed Bids (to reduce generation, if necessary to zero). If the offers and bids submitted by a BM Unit do not allow its output or consumption to be reduced to zero, it will be assigned a Deemed Bid/Offer, which will have a zero price. The size of the Deemed Offers and Bids will be automatically set to increase the range covered by offers and bids so that the output or consumption of a BM Unit can be reduced to zero. Tight restrictions will be placed on the use of Deemed Offers and Bids and NGC will be required to provide justification for their use.

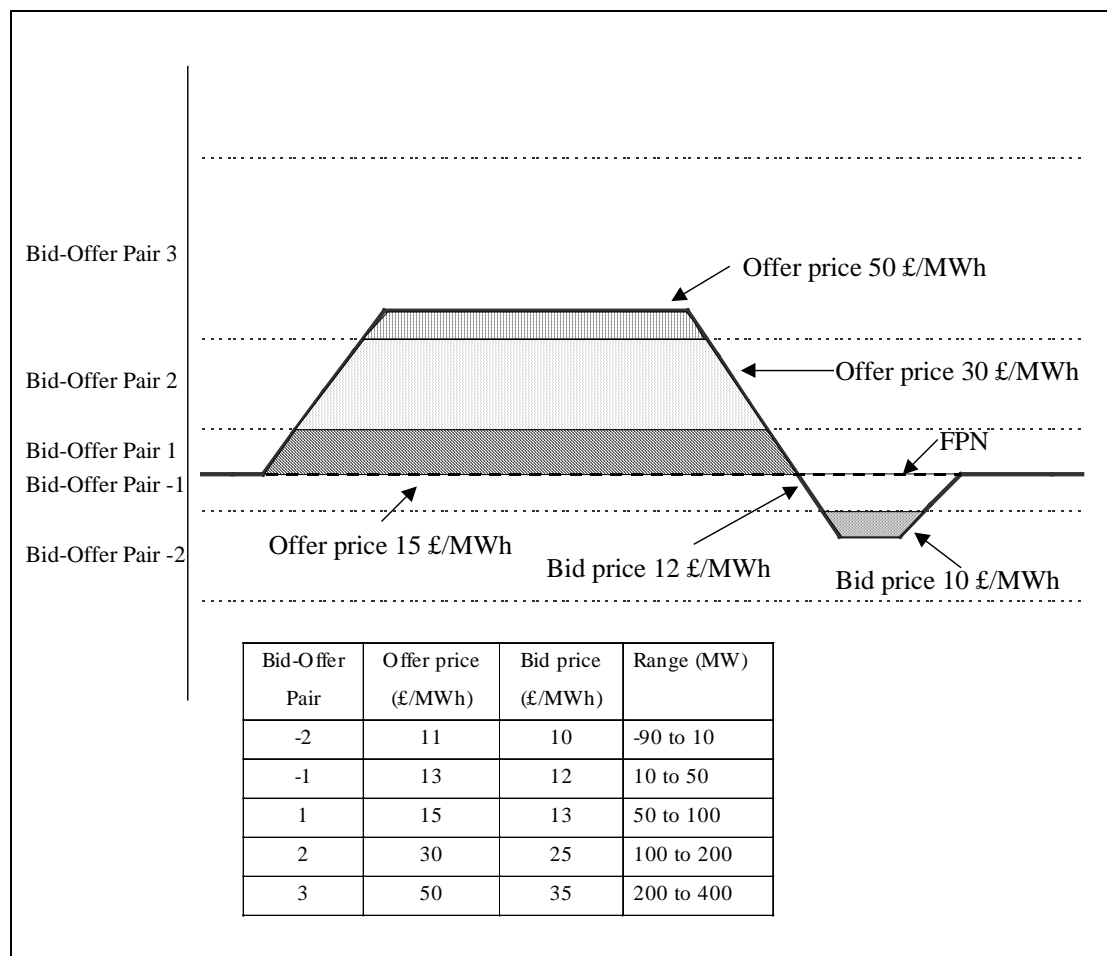
The selection of balancing actions will be given effect by the SO issuing 'Bid-Offer Acceptance' orders. In each Bid-Offer Acceptance, the SO will indicate the profile of output or consumption that it wishes the BM Unit to follow via a series of coupled spot MW and time dispatch instructions. The dispatch instructions will have to be achievable by the BM Unit taking into account its current operating position and its dynamic parameters. Bid-Offer Acceptances will be able to span several half-hours although they cannot extend beyond the end of the last half-hour for which Gate Closure has taken place. This period has been designated the 'BM Window Period' and corresponds to the period for which offer and bid prices are known. By interpolating between the spot values and deducting the FPN volume, the total volume accepted by the SO under the Bid-Offer Acceptance can be calculated. Thus, the dispatch instructions have to be 'closed'. In most instances, this will mean that the final instruction has to be one that returns the BM Unit to its FPN level, as modified by any previous Bid-Offer Acceptances.

If the final instruction is for the spot time at the end of the BM Window Period, this can be at a level different to the BM Unit's FPN. In these circumstances, for settlement purposes the BM Unit will be deemed to return to its FPN level at the end of the Window Period, if necessary, via a deemed step change in output (even though this may be inconsistent with the unit's dynamic data). In this way, the accepted volume of offers and bids is always well defined. Although a BM Unit may not actually be able to return to its FPN level at the end of the Window Period given the instructions it has

received from the SO, the FPN submitted for the following period⁷³ can take this into account. The participant may also be able to trade out any uncontracted position resulting from the SO's actions by trading in any short-term markets that may emerge.

Bid-Offer Acceptances can imply the acceptance of more than one offer and/or bid, as shown in Figure 6.3 for a generating BM Unit. The solid line represents the profile instructed by the SO within a half-hour and the patterned sections within it are the parts of the various offers and bids that have been accepted.

Figure 6.3 - Example of a Single Bid-Offer Acceptance Within a Half-hour

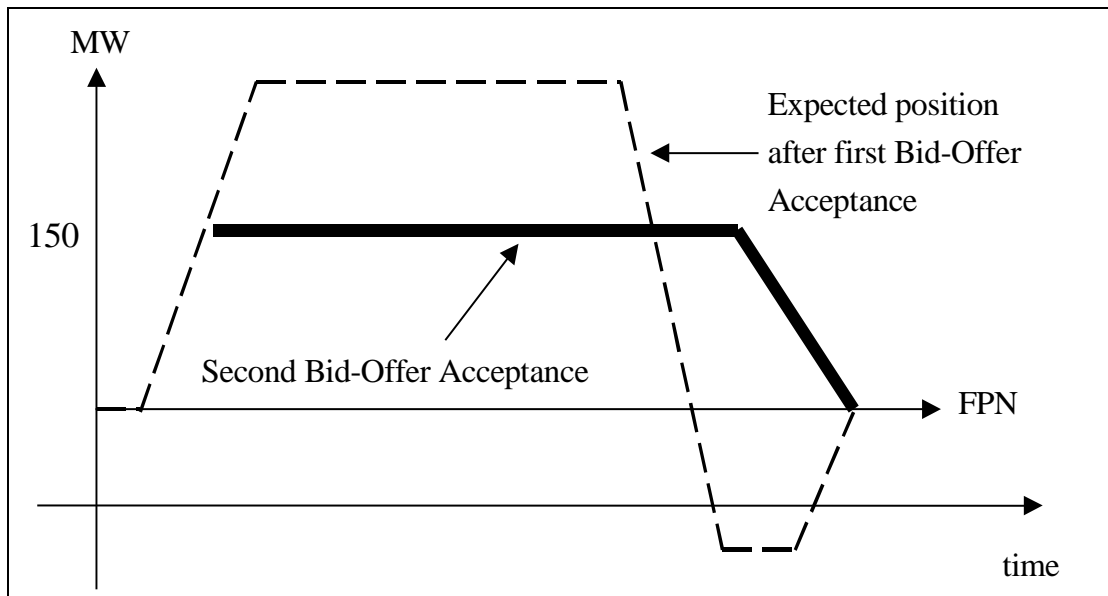


The profile of output or demand specified in a Bid-Offer Acceptance must be physically deliverable based on the information available to the SO at the time. Thus, although at

⁷³ By definition, the FPN for the following period will not yet have been submitted, otherwise the end of the Window Period would not have been reached.

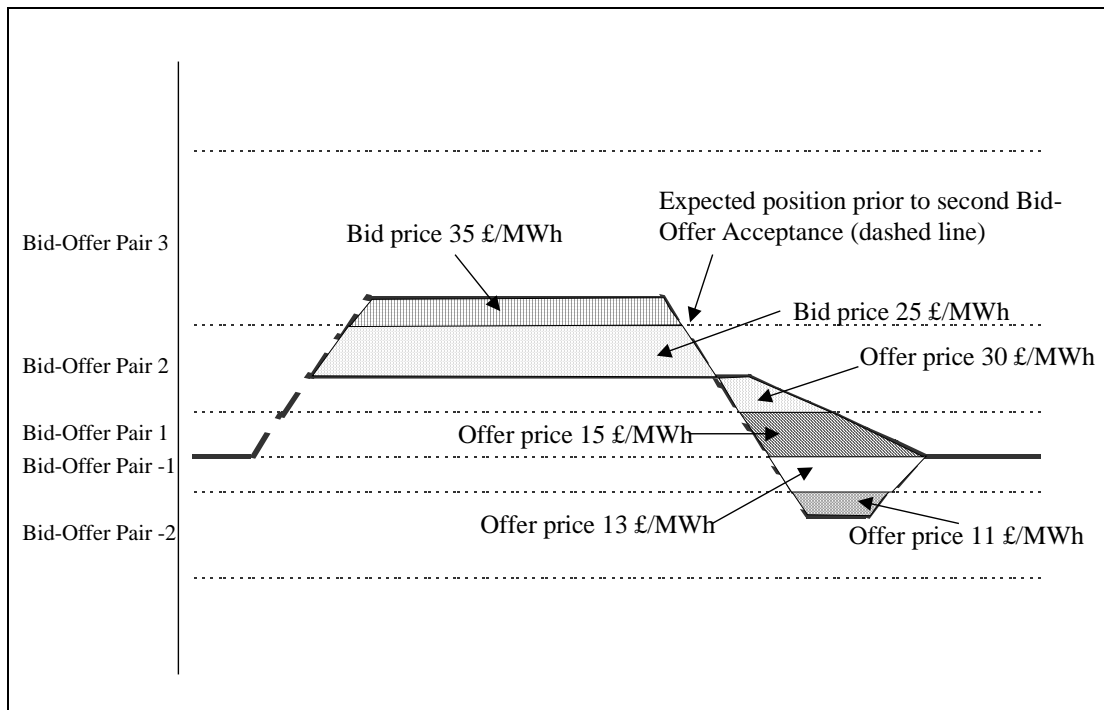
Gate Closure, the FPN of a BM Unit corresponds to its expected position, its expected position will be modified if a Bid-Offer Acceptance for the unit is issued. It is against this modified expected position that subsequent Bid-Offer Acceptances for the same BM Unit will be measured, as can be seen in Figure 6.4 which follows on from Figure 6.3 and also assumes that the SO issues a second Bid-Offer Acceptance for the same unit.

Figure 6.4 - Effect of Second Bid-Offer Purchase



The approach of modifying expected positions also allows Bid-Offer Acceptances to be firm on both the SO and the Balancing Mechanism participant. To cancel an accepted offer (or bid), the SO will need either to purchase a bid (or offer) from another market participant or issue a second Bid-Offer Acceptance to the BM Unit that modifies the original Bid-Offer Acceptance. The SO will therefore be exposed to any spread that exists between the offer price and bid price of the BM Unit, if it takes a balancing action that it subsequently decides to undo. Since Bid-Offer Acceptances are always measured relative to expected positions, it follows that the second Bid-Offer Acceptance shown in Figure 6.4 corresponds to the SO initially accepting bids and then accepting offers. This is shown in Figure 6.5, which illustrates the fact that both the bid price and the offer price (delivery price) of a Bid-Offer Pair can be involved when a further Bid-Offer Acceptance modifies a previous one.

Figure 6.5 - Additional Offer and Bid Volumes Implied by Second Bid-Offer Acceptance



As the above example shows, in determining what offer and bid volumes have been accepted by the SO, both for settlement purposes and to allow the SO to determine what prices are applicable to further actions, a sequential calculation of the impact of all previous Bid-Offer Acceptances is required. The SO can continue adjusting the position of a BM Unit within the range defined by its prevailing Import and Exports Limits as many times as proves necessary.

6.7 Payments for Balancing Mechanism Actions

Balancing Mechanism actions will be remunerated on a 'pay-as-bid' basis for instructed volumes that have been delivered. Payments will be calculated for each BM Unit for each half-hour.

Although Bid-Offer Acceptances can span several half-hours, it will always be possible to determine what volumes of which offers and bids have been accepted in a particular half-hour using the sequential approach outlined above. These volumes are then multiplied by the corresponding offer or bid price for that half-hour in order to determine the payment due to or from the participant responsible for a BM unit. It is

likely that payments for Balancing Mechanism actions will not be corrected for frequency sensitive operation. Although this would be technically possible, present thinking is that this would unnecessarily increase the complexity of the settlement arrangements.

In common with other contracts that participants may notify to settlement, volumes sold or purchased in the Balancing Mechanism are treated as firm for settlement purposes. Thus, contracts are settled assuming delivery, i.e. paid in full as accepted, and participants will be deemed to be out of balance if they fail to deliver the volume contracted. However, given that the price paid or received for any undelivered portion of the balancing action could be more favourable than the energy imbalance price, a special non-delivery rule is applied to the imbalances of Balancing Mechanism participants. As described in Chapter 7, in addition to Energy Imbalance Charges, this non-delivery rule exposes participants to the difference between the price of the accepted undelivered offer/bid and the relevant energy imbalance price (the System Buy Price for non-delivered offers and System Sell Price for non-delivered bids). The rule ensures that, in principle, participants can never gain financially from non-delivery of an accepted Balancing Mechanism offer or bid.

6.8 Transparency

It is important that adequate information is revealed to market participants in a timely fashion to help them to discover the prevailing value of balancing energy and flexibility and information disclosure provisions will be included within the BSC, as discussed in Chapter 9. In addition to price movement at times of shortage or surplus, the market will observe that certain Balancing Mechanism offers are accepted at prices that are higher than those of other available offers (and bids are accepted at lower prices than those of other available bids). What is necessary, therefore, is to ensure that along with prices and volumes, information on the dynamic parameters associated with Balancing Mechanism offers and bids and their locations will be made visible in real time.

The information on offers and bids (including FPNs and the dynamic data for BM Units) will be passed to the SO through NGC's existing communications systems. This data

will then be collated and presented to participants,⁷⁴ probably via information screens. It is intended that offers and bids that have been accepted by the SO will be flagged, possibly including an indication of the volumes accepted. The detailed design of the information delivery system is yet to be undertaken. Its specification will allow for flexibility in the information presented and will be further developed in the procurement process, which will precede delivery of the Balancing Mechanism and Settlement systems.

6.9 *Balancing Service Contracts*

In general, it is envisaged that, at least initially, the procurement of balancing services contracts by the SO will be similar to the existing arrangements for procurement of ancillary services. However, to the fullest extent possible, the procurement of balancing service contracts should take place competitively via transparent processes e.g. auctions.

Currently, NGC ensures that Ancillary Services contract holders are in a position to provide their contracted service by instructing their generation or consumption levels appropriately.⁷⁵ It is likely that under the new trading arrangements some of the offers and bids (including those for BM units with balancing service contracts) that NGC accepts in the Balancing Mechanism will be chosen for the same reasons. Nonetheless, there will inevitably be interactions between the provision of balancing services, Balancing Mechanism costs and cash-out prices.

It is for consideration what, if any, role NGC's Ancillary Services Business will have in the procurement of balancing services contracts. If the Ancillary Services Business is involved, it would be necessary to decide whether the activity would need to be licensed and accounted for separately, as at present.

The remuneration for the energy-related costs of NGC's Ancillary Services Business is currently provided via the Pool whilst its Transmission Business pays all the transport related costs that arise in the Pool. If an equivalent split of payments and costs were to

⁷⁴ One option for consideration would be to condense the potentially large volume of information into a flexibility index or indices.

⁷⁵ For example, NGC may de-load a generator so that it is capable of providing reserve and then re-load it if that reserve is required.

continue in future, then the mechanisms for recovering balancing services payments would need to be covered by the BSC. The costs of such services in conjunction with the net Balancing Mechanism costs might define the scope of the revised incentives that NGC will face (as discussed further in Chapter 8). The details of how these costs are treated and their interaction with settlement and cost recovery through the BSC will be considered as part of the consultation process when setting NGC's incentives under the new trading arrangements.

There has been considerable debate surrounding the issue of response and reserve. NGC presently contracts for both these services to ensure that frequency deviations can be contained and corrected. Frequency deviations occur for a number of reasons that include the loss of a generating unit and unexpected spikes in demand. The difference between response and reserve is largely one of timing with reserve being provided over longer timescales than response. Response and reserve capabilities are both important elements in ensuring that security of supply can be maintained in the very short-term. Although the ongoing need for such services is generally acknowledged, different views have been expressed concerning the appropriate volume of such contracts. On the one hand, it has been argued that, as a transitional measure, additional reserve contracts should be signed. NGC, for example, has argued that this would provide reassurance that there will be adequate volumes available in the Balancing Mechanism to secure the system. On the other hand, it has been argued that centrally procured reserve and response contracts may reduce the incentives on participants to balance their positions and could be construed as a move away from market-based solutions.

Similar debates have taken place with regard to NGC signing option contracts for electricity. These would allow NGC, outside of Balancing Mechanism timescales (for example, at the day-ahead stage), to issue instructions to BM units that had long notice to delivery periods. Such contracts do not currently exist,⁷⁶ but it has been argued that they will be required given that the Balancing Mechanism for a period will open at most four hours before the start of the period. Present thinking is that such contracts should be allowed.

⁷⁶ Although on the generation side, NGC pays for cancelled starts when it issues an instruction to a plant to synchronise and then cancels it with the notice to start period of the plant.

6.10 Views Invited

Views are invited on the detailed specifications that have been developed and outlined in this chapter, particularly on the following specific issues:

- ◆ the dynamic data that should be provided by BM Units;
- ◆ an appropriate minimum size for Balancing Mechanism offers and bids;
- ◆ the need for Quiescent FPNs;
- ◆ an appropriate definition for Demand Capacities;
- ◆ the scope and volume of balancing services contracts (particularly with regard to response, reserve and options contracts for electricity); and
- ◆ the role of the Ancillary Services Business.

7. Cash-Out and Settlement Arrangements

As described in Chapter 6, the SO will be calling upon a portfolio of balancing services and products to keep the system in balance. This chapter provides more detail of the imbalance and settlement arrangements (collectively referred to as Settlement). It also covers the calculation of imbalance prices and the settlement of imbalances between participants metered volumes of electricity and their contract position. The chapter then considers a number of other areas including the payment of Balancing Mechanism offers and bids, information imbalance charges, credit arrangements and participation in imbalance settlement.

7.1 *Imbalance Cash-Out Prices*

Imbalance cash-out prices are designed to target the costs of balancing the system onto the parties on whose behalf the SO has taken balancing actions. Electricity covered by bilateral contracts, by definition, has been or will be paid for and so the settlement of electricity imbalances resolves into measuring and charging for differences between participants' metered volumes and their contract positions. This will ensure that any electricity not covered by contracts is paid or charged an appropriate price.

A two price cash-out regime is proposed for imbalances. Imbalance cash-out prices should reflect the costs to the system of imbalances having to be resolved by the SO over short timescales. These costs are likely to differ from the costs of simply purchasing power on the forwards markets - cash-out prices should also incorporate the additional value associated with the flexible delivery of electricity i.e. the ordering and delivery of electricity after Gate Closure. Provided they include the value of flexibility, cash-out prices should incentivise participants to balance their own positions by Gate Closure and hence the actions that the SO has to take should be minimised.

It is proposed that 'buyers' of imbalance electricity through the settlement system will pay a price calculated as the volume weighted average of the offers accepted in the Balancing Mechanism (i.e. the average price at which electricity is bought for the system). We refer to this imbalance cash-out price as the 'System Buy Price'. 'Sellers' of imbalance electricity will be paid the volume weighted average of accepted Balancing Mechanism bids (i.e. the average price at which the system sells electricity). We refer to this imbalance cash-out price as the 'System Sell Price'.

This method for setting the imbalance price has the advantage that it is conceptually simple and straightforward to implement. It is recognised that imbalance cash-out prices calculated in this way may reflect the costs of Balancing Mechanism actions taken for reasons other than to maintain overall electricity balance. In particular, the imbalance cash-out prices will include the costs incurred by the SO of accepting offers and bids to resolve transmission constraints (unless constraint-related trades could be explicitly excluded from the calculation, for example, by flagging constraint trades).

Some participants have argued for a marginal pricing approach to determine either a single cash-out price or dual cash-out prices. However, the marginal pricing approach has drawbacks that are common to both of these options. Given that Gate Closure is four hours ahead of real time and that (as will be the case in the initial implementation of the new trading arrangements) participants are not allowed to revise offers/bids after Gate Closure, there is a significant risk that marginal prices would be set by unrepresentative actions (for example, a high price offer accepted early in the trading window). More generally, there are concerns, based in part upon past experience of Pool pricing, that a marginal pricing approach could be highly vulnerable to manipulation and could lead to greater volatility in cash-out prices than would be justified by demand and cost fundamentals.

Default cash-out prices will be required in the event that no offers or bids for balancing actions are accepted in a particular direction or the other in a given half-hour. This is likely to be an infrequent occurrence given that the SO will typically be taking actions related to constraints or balancing services contract delivery or intra-half hour balancing even if action to maintain overall electricity balance is not required. The method to be used for setting default cash-out prices will be subject to further discussion. A number of options exist for setting default prices, including using;

- ◆ the relevant price from the previous half-hour;
- ◆ an average of all the relevant cash-out prices over the past 7 days (to reflect the daily and weekly patterns in electricity demand);
- ◆ the price of the offer /bid that would have been taken first, based on the criteria of price, in the relevant direction (i.e. the lowest priced offer or the highest priced bid); or

- ◆ a price indicator from a traded spot market, possibly adjusted by a transaction fee reflecting the costs that a participant would have incurred had it traded out the imbalance for itself.

7.2 *Calculating Imbalance Volumes*

The volume to which the cash-out prices are applied, the 'Imbalance Volume', is the difference between a participant's notified contract volume and metered volume. A participant's notified volume is the sum of all trades (whether over-the counter or exchange-based) notified to Settlement, together with any volumes accepted by the SO in the Balancing Mechanism.

The aggregation of volumes from individual meters for the purpose of settling participants' electricity imbalances will be included within the settlement process – cash-out charges will not be applied at the individual meter level. Imbalances relating to production (export) and consumption (import) meters will be calculated separately. All the contributions from production meters associated with a participant will be aggregated together, regardless of their geographical location. Similarly, all the contributions from consumption meters of a participant will be aggregated. Pure traders, with no physical input or offtake positions,⁷⁷ will have a zero meter reading.

7.2.1 *Splitting Metered Volumes*

So as not to restrict participants' commercial freedom, it will be possible for the volume from an individual meter (strictly speaking, a 'BM unit', as defined in Chapter 6) to be split between a number of participants for the purpose of calculating energy imbalances. The precise details of how these arrangements will work requires further consideration and it is recognised that the present Stage 2 arrangements, that were introduced in 1998 to facilitate supply competition, may impose some constraints on the implementation of this facility. Nonetheless, the intention is to allow, for example, a supplier to notify volumes relating to a share of a meter, in order to meet a customer's requirements for partial supply.

Present thinking is that a single agent will notify settlements of the percentage allocations of metered volume to individual participants in advance of the trading

⁷⁷ Also referred to as a non-physical participant.

period. One participant (to be determined on the basis of the contractual arrangements entered into by the parties) will take responsibility for submitting FPNs and any Balancing Mechanism offers or bids at the 'BM unit'. The percentage allocations for the remaining participants would then be used to pro-rate the difference between the metered volume and any Balancing Mechanism action (which is assumed to be delivered).

7.2.2 Notifying Contracts

The Settlement system will not require both parties to a bilateral energy contract to notify volume data to Settlement.⁷⁸ Instead, the contract counterparties will need to authorise a single agent to submit data on their behalf. This agent could be either of the two contract parties or a third party, such as a specialist matching administrator or data collector. In the case of cleared exchanges for trading electricity contracts, the clearing house may take responsibility for submitting volumes. The verification of the data submitted will be a matter for the contract counterparties (and the contract notification agents) to resolve.

As noted in Chapter 5, it is intended that contract volumes should be notified to settlement by Gate Closure. In practice, to allow sufficient time for the preparation and transfer of contract data, the final deadline for contract data submission might need to be delayed somewhat, for example, to half an hour after Gate Closure. The contract notifications must be in the form of a MWh volume for the half-hour. If the details of a particular contract do not change from day to day, the contract notification agents will be able to make use of an 'evergreen' flag to indicate that the data applies until further notice.

Participants with both production and consumption accounts will need to specify whether each notified contract is to be set off against their production or consumption account. Pure traders will be able to allocate all their contracts against their one electricity account.

⁷⁸ The settlement systems will not be designed to accommodate notifications from both parties to a contract.

7.2.3 Transmission Losses

The new Settlement systems will be designed and built so that individual transmission loss factors can be allocated to BM Units. These will be capable of being set individually in order to recover the cost of losses on a geographically differentiated basis. Loss factors will be provided for both generation and consumption meters. At present, consideration of the most appropriate way to allocate the costs of losses under the new arrangements will be taken forward in the context of a separate consultation on the SO incentives schemes (discussed further in Chapter 8).

7.2.4 Deemed Balancing Mechanism Bids and Offers

As described in Chapter 6, the SO will be able to make use of Deemed Offers (to curtail demand) and Deemed Bids (to reduce, and if necessary desynchronise, generation) in the event that all available offers and bids in the Balancing Mechanism have been exhausted and further actions to balance the system are still required. Actions instructed by the SO via the acceptance of a Deemed Offer or Bid will be treated in the same manner as volumes accepted in the Balancing Mechanism. A participant's net contractual position will therefore be adjusted by the volume of the instructed action. Hence, provided the participant reduces its output or demand in line with the instructed action, its overall imbalance position will be unchanged – the SO's acceptance of a Deemed Offer and Bid will not in itself expose a participant to imbalance charges.

Deemed Offers and Bids will be settled at a price of zero. This will help incentivise participants to submit bids and offers into the Balancing Mechanism. It is proposed that accepted Deemed Offers and Bids will not be included in the calculation of imbalance cash-out prices. The price signals arising from the imbalance cash-out regime will therefore be neutral to the acceptance of Deemed Offers and Bids. It is anticipated that the SO should only need to call upon Deemed Offers or Bids in response to unusual, unforeseen events - all circumstances that might reasonably be predicted by participants should be reflected in the prices of offers and bids submitted to the Balancing Mechanism.

7.2.5 Distribution Failures

When a distribution network fails or encounters insecure conditions, embedded customers or generators may be disconnected. As a result, participants may be driven into imbalance. For example, embedded generators would be charged the System Buy

Price if they generated less than their notified contract volumes, while customers (or their suppliers) would receive the System Sell Price for under-consumption. The SO may also need to take balancing actions as a result of the distribution failure to maintain overall balance on the transmission system. Within the Settlement Process the risk of exposure to imbalance charges arising from distribution failures will fall on participants.

7.2.6 Transmission Failures

As described in Chapter 8, in the future, transmission rights could be sold by NGC on a firm basis and secondary markets in transmission capacity could emerge. Under such arrangements NGC would effectively buy back capacity from holders of firm rights in the event of a transmission failure. In the absence of such arrangements, provision will need to be made to deal with possible transmission failures. One possibility would be to treat transmission failures in an equivalent manner to transmission constraints. This would require a deemed volume (and possibly a price) to be associated with the parties affected by the failure and its impact.

7.3 Non-delivery Rule

In common with other contracts notified to Settlement, volumes sold or purchased in the Balancing Mechanism are treated as firm for Settlement purposes. Thus, contracts are settled assuming delivery, and participants will be deemed to be out of balance if they fail to deliver the volume contracted. However, as it is possible that the price for the balancing action would be more favourable than the imbalance price, there could be situations in which non-delivery would result in a net gain for the Balancing Mechanism participant. Therefore, in addition to imbalance charges, participants will, where appropriate, be additionally exposed to the difference between the offer/bid price and the relevant cashout price.

Non-delivery arises when there is an imbalance in the opposite direction to the net volume of a participant's accepted balancing Offers and Bids in a half-hour Settlement period. Under the non-delivery rule, an additional imbalance charge will apply (over and above the usual imbalance charge) if the offer price exceeds the System Buy Price (for non-delivered offers) and if the System Sell Price is greater than the bid price (for non-delivered bids). Thus, for non-delivered offer volumes, BM participants will be exposed to the positive difference (if any) between their offer price and System Buy price and for non-delivered bids participants will be exposed to the positive difference

(if any) between their bid price and System Sell price. This will reduce the opportunity for participants to benefit financially from non-delivery of Balancing Mechanism offers or bids. Examples of the way in which the non-delivery rule will work in practice are given in Appendix 7.

7.4 Information Imbalances

Imbalance price will be levied on differences between participants' contract volumes and their metered volumes of electricity. However, it has been suggested that there should also be a charge on differences between participants' FPNs, modified by accepted bids or offers, and their metered volumes – i.e. an information imbalance charge.

The Grid Code already contains obligations on certain classes of participant to provide detailed information to the SO each day. An information imbalance charge would represent a penalty for providing inaccurate information or for changing physical positions after Gate Closure other than in response to instructions from the SO.

An information imbalance charge would apply at the BM Unit level, that is, at a less aggregated level than electricity imbalance charges. The information imbalance volume would be defined as the difference between the metered volume and expected output (FPN adjusted for accepted bids and offers) for the half-hour.⁷⁹ The information imbalance charge would then be given by the product of this volume and the information imbalance price, irrespective of whether the metered volume is higher or lower than the expected level.⁸⁰

The idea of charging information imbalances has been widely discussed. For the present, it is proposed not to impose such a charge (the value of the information imbalance price should be set to zero). We understand that NGC is of the opinion that obligations upon participants to provide accurate information are likely to prove sufficient to enable NGC to balance the system efficiently. If this proves not to be the case, then an information imbalance charge could be introduced at a later date. To

⁷⁹ No adjustments for transmission losses would be made to either the metered volume or expected output.

⁸⁰ One proposal for the information imbalance price is for it to be referenced to the costs of balancing services such as reserve, on the grounds that inaccurate information from participants increases uncertainty for the SO and leads to a greater requirement for such services.

accommodate this possibility, the procured Settlement systems will be capable of calculating an information imbalance charge for each participant.

7.5 Cost Recovery

Generally, a net surplus or deficit will be associated with the revenues and payments from imbalance charges, as a consequence of two cash-out prices (it is unlikely the two cash-out prices will be identical) and different volumes (long and short imbalances) to which the two cash-out prices will be applied. How the revenues (or costs) associated with imbalance cash-out charges will be treated will be subject to further discussion. They could, for example, be passed through to the SO to modify the costs that it incurs (or revenues that it earns) from accepting Balancing Mechanism actions. Alternatively, the revenues (or costs) could be returned to (or recovered from) all participants via some form of shared charge.

Other administrative and system costs, such as the costs of running Settlements, will also have to be recovered from participants. Present thinking is that a predetermined proportion of central administration costs be allocated to MWh metered volumes. The remainder will be allocated to MWh contract volumes.

7.6 Settlement

The scope of Settlement covers the input, processing and output of all data pertaining to the Balancing Mechanism and the Settlement of imbalances. This data ranges from the offer and bid date submitted by market participants to the flow of funds from debtors to creditors. Both the Balancing Mechanism and the Settlement process will require new IT systems to be built and operated. The Settlement process will also need to have provisions with regard to credit cover and a defined process in the event of financial default by any party. Settlement will impose standards for infrastructure such as metering and information systems.

7.6.1 Data

Settlement will be based on the data items that describe balancing actions and imbalances. These data items fall into the following four broad categories:

- ◆ Standing data;
- ◆ Balancing Mechanism data;

- ◆ Meter data; and
- ◆ Notified contract volume data.

7.6.2 Processes

A number of processes will be performed on the above data, in order to execute the overall process of Settlement. These processes have been grouped together by function. A different body or 'Agency' could in principal, carry out each function. In practice however, it is likely that at least some of the Agency functions will be performed by the same body. Many of these Agency functions exist under the present trading arrangements.

Funds Administration Agent (FAA)

The Funds Administration Agent will effect the payments resulting from Settlement, maintain financial and tax documentation and manage credit and default arrangements. Under the present arrangements, this role comprises the settlement of participants' imbalances, essentially collecting funds from suppliers for their total demand and making payments to generators for their total output. In the new arrangements, only net imbalances will be settled (i.e. imbalances against notified contract volumes).

Settlement Administration Agent (SAA)

The Settlement Administration Agent will calculate payments for all Balancing Mechanism actions and all imbalances, and provide data on liabilities and credits to the Funds Administration Agent. The details of the calculations under the BSC will clearly be very different from those in the Pool.

Energy Contract Volume Aggregation Agent (ECVAA)

The Energy Contract Volume Aggregation Agent, a new role under RETA, will provide the Settlement Administration Agent with net Energy Contract positions for all Parties, for each Settlement Period. The Energy Contract Volume Aggregation Agent will also be responsible for enforcing credit limits on Energy Contract volumes, using data provided by the Funds Administration Agent.

Energy Contract Volume Notification Agents (ECVNAs)

Energy Contract Volume Notification Agents will provide energy contract Volume data to the Energy Contract Volume Aggregation Agent, on behalf of participants. These

Agents will be Agents of Parties, rather than of the BSCCo. This is a new function arising under RETA.

Credited Energy Percentage Notification Agents (CEPNAs)

When a BM unit is split between several participants and is not registered in a Supplier Meter Registration System, a CEPNA will submit deemed metered amounts for each BM unit to the Settlement Administration Agent. This is a new function arising under RETA.

Interconnector Administrators (IAs)

For each interconnector, an Interconnector Administrator will be responsible for submitting deemed metered data for the BM units associated with different Interconnector Users and the Interconnector Error Block Administrator to the Settlement Administration Agent.

The Interconnector Administrator will be a BSC signatory responsible for the submission of timely and adequate data for Settlement. The accuracy of this data will however be a matter for Interconnector Users and the Interconnector Error Block Administrator, lies outside the scope of the BSC.

Interconnector Error Block Administrators (IEBAs)

The difference between the sum of deemed metered amounts submitted by the Interconnector Administrator and the actual metered amount will be allocated to an Error Block, for which the Interconnector Error Block Administrator will be financially responsible in BSC Settlement as a Party. The Interconnector Error Block Administrator will be a BSC signatory taking financial responsibility for energy into and out of the integrated England and Wales transmission and distribution networks. Allocation and/or recovery of funds to/from Interconnector Users and others are outside the scope of the BSC.

7.6.3 Credit Arrangements

In order to provide some security to creditors within the Balancing Mechanism and Imbalance Settlement, credit cover will be required from all parties. Further consideration needs to be given to the appropriate form of credit cover (which will be subject to the approval of the BSC). Possible candidates could be one (or a combination) of the following:

- ◆ a letter of credit;
- ◆ a parent company guarantee (where the parent company would provide the relevant level of cover);
- ◆ an appropriate credit rating (various ratings would be deemed to reflect certain levels of cover); and
- ◆ a cash deposit.

7.6.4 Financial Default

Parties who fail to cover their BSC debt will trigger a default process. The details of this default process require further consideration, including consideration of what particular arrangements need to be put in place if the defaulting party is a supplier.

In any event if a signatory to the BSC defaults, any uncovered liabilities (the shortfall) will be borne by the all the remaining signatories. It is proposed that these liabilities could be charged on the same basis as the BSC administration costs, namely in relation to participants' metered and contractual volumes.

7.6.5 Infrastructure

Metering

Licensees (who will be obliged to sign the BSC), licence exempt Parties and unlicensed parties who choose to sign the BSC will all have obligations to install or have installed meters of appropriate standard at all Meter Points for which they are responsible. The exceptions to this are a number of unmetered supplies, where a Meter Administrator will be employed by the Party to establish a deemed reading, calculated according to a BSC set of rules. These standards will be captured by metering Codes of Practice, which will be described in the BSC. These are expected to be the same or consistent with the existing Metering Codes of Practice.

Information Systems

Agents will be required to install systems according to a set of criteria established in the BSC. These criteria will impose quality requirements, both in terms of management and control and in terms of the design of the systems themselves. A particular example would be the use of Accreditation of Agents and Certification of Information Systems, where the Agent and System were to be employed by a Party to the BSC in order to

fulfil BSC obligations. Another example of a quality requirement would be a regular audit in respect of the consistency between Information Systems and the BSC rules.

7.7 Participation in Imbalance Settlement

For many participants in the electricity industry, participation in the imbalance settlement process will be mandatory. Supply and Generation licensees will be obliged, by licence condition, to comply with the BSC.

Licence exempt entities wishing to participate directly under the BSC, will be obliged to install meters, in the same manner as a licensee. Signing the BSC would allow the licence-exempt party to participate directly in the Balancing Mechanism, to take the cash-out price for spill volumes and to notify contract volumes for settling imbalances. If, however, a licence exempt entity did not wish to sign the BSC, then the licence exempt entity would participate indirectly under the auspices of a BSC signatory, which would be covered by the above obligations.

Unlicensed entities (for example traders who never take responsibility for physical flows of electricity) may also wish to sign the BSC in order to notify contract volumes for the purpose of settling imbalances.

The SO acts as an Agent (for the purposes of the BSC) in providing Balance Mechanism data to Settlement. It is for further consideration whether a PES, in its capacity as the operator of a Distribution Network, will be obliged to be a signatory to the BSC. There are two reasons why this might be required. First, to ensure that metering of an appropriate standard is installed at the boundaries between distribution systems. Second, to use Distribution Network operators to register and procure meter operation for GSP meters. However, with regard to the latter requirement it would also be possible to place the obligation on NGC (as most meters are in NGC substations) or on the BSCCo (as the meters are only required for settlement purposes).

7.8 Views Invited

Views are invited on the proposals set out in this chapter. In particular, views are invited on the following aspects of the proposed settlement process:

- ◆ the way in which the potential problem of default should be dealt with under the new arrangements. In particular, Ofgem would welcome views on whether, and if so, how, any uncovered shortfalls resulting from the default by a BSC signatory should be recovered from remaining signatories;
- ◆ how the net costs/revenues from imbalance cash-out charges should be treated;
- ◆ the practicality of the final deadline for the submission of contract data being at Gate Closure;
- ◆ how distribution and transmission network failures should be treated;
- ◆ the most appropriate approach to credit and security cover; and
- ◆ the need for Distribution Network operators to sign the BSC.

8. The Role and Incentives of the System Operator

NGC currently both operates and owns the transmission system i.e. it acts as System Operator (SO)⁸¹ and transmission asset owner (TO). The SO function covers all the short-term operational activities required to keep the system balanced and operating within safe limits. The TO function relates to the maintenance and longer-term development and investment in the transmission system.

There are strong interactions between the SO and TO functions. For example, investment in and the maintenance of the transmission network (a TO function) can have significant impacts both on the way in which the overall balance of electricity on the system may be maintained and on the existence of transmission constraints. This chapter provides a preliminary discussion of the role and incentives on NGC under the new trading arrangements. The issues will be addressed in greater detail in subsequent consultation papers, outside the scope of RETA but closely related.

8.1 The Role of NGC Under RETA

The SO and TO functions will continue to be undertaken by NGC under the new trading arrangements, although there will be changes in the way that they will be assigned and carried out. As now, NGC will have available a broad portfolio of options with which to fulfil its SO role. Its principal tools will be Balancing Mechanism offers and bids and the contracts that it enters into ahead of time for balancing services. In accepting offers and bids in the Balancing Mechanism, NGC will not be acting as counter-party to the trades but it will be exposed to the net costs of (or revenues from) the actions that it instructs.⁸² NGC will also face costs as a result of a range of balancing services contracts it chooses to enter into, for example with regard to the provision of reserve, frequency response, reactive power and black start.

⁸¹ The role of SO can conceptually be split into two parts – Balancing Operator (BO) and Transmission Services Operator (TSO). The BO function covers balancing the supply and demand of electricity on a second by second basis. The TSO function encompasses all the other short-term operational activities including the management of transmission constraints and losses and the purchase and use of ancillary services. Whilst Gate Closure remains four hours ahead of a trading period, participants will not be able to respond to market signals with regard to the need for balancing measures. Consequently, the BO and TSO functions will not be separated initially.

⁸² Payments to and from participants for Balancing Mechanism actions will take place under the settlement rules of the BSC and NGC will then receive an invoice for the net costs or revenues associated with those actions.

As discussed in Chapter 7, two different approaches are possible with regard to the treatment of the revenues (or costs) associated with imbalance charges. First, these revenues (or costs) could be passed through to NGC to modify the costs that it incurs (or revenues that it earns) from accepting Balancing Mechanism actions. Second, the revenues (or costs) could be returned to (or recovered from) all parties to the BSC via some form of shared charge.

The New Electricity Trading Arrangements will result in a greater role for suppliers (and hence customers) and generators in deciding whether to balance their own electricity supply and demand closer to real time, or to accept the market consequences of choosing not to balance. NGC's role in achieving an overall supply/demand balance may therefore be expected to be less significant under the new arrangements than at present. Its role might be expected to reduce further over time as market participants seek to develop new arrangements to mitigate the risks of being out of balance.

NGC's role in the overall balancing of electricity production with consumption half-hour by half-hour is expected to decline over time. However, it will retain its SO role in relation to overcoming locational constraints on the transmission system and to taking actions to correct sudden deviations of supply and/or demand within time-scales of less than half an hour. NGC's SO role is therefore expected to continue to be a substantive one.

There have been some concerns expressed about NGC trading under the new arrangements, and in particular about NGC's monopoly in respect of certain types of information. To address these concerns, Ofgem will be carefully considering the scope of information available to suppliers and generators and the scope of information available only to NGC.

To the extent, however, that any market abuse is observed under the new arrangements, a range of remedies may, depending on circumstances, be available under one or more of the Electricity Act, the Financial Services Act and the new Competition Act. As in other competitive markets, effective policing of the rules is important and is in the interests of all market participants and, most importantly, in the interests of customers.

8.2 *Areas of Incentives*

The SO and TO roles both require NGC to incur costs which are subsequently passed on to market participants. NGC is a monopoly provider of services and hence it is important that it is properly incentivised to minimise the costs that participants have to pay, subject to maintaining a secure and reliable system. The formulation of incentive structures for the SO and the TO, as well as the determination of the boundary between the responsibilities of the two, is therefore important for the future development of electricity markets.

In considering the SO and TO roles it is possible to identify a number of areas which might need to be covered by incentives. These include:

- ◆ transmission constraints;
- ◆ balancing services costs;⁸³
- ◆ demand forecasting errors; and
- ◆ transmission losses.

The question of incentives links to questions of appropriate charging methods for the services covered by the incentives. In addition, given the functions likely to be covered by incentives, there are also links to issues concerning access to and charging for transmission capacity.

Choices have to be made regarding whether or not cost categories should be unbundled and separately incentivised. For example, by investing in extra capacity, the TO can significantly reduce constraint costs and transmission losses. Any incentive structure must recognise this effect and seek to set rewards in a way that promotes efficiency, considering both system operation needs and longer-term investment together. For example, it would be inappropriate to create an incentive scheme which gave a fixed revenue to the SO, thereby encouraging reductions in the SO's costs, whilst allowing the TO to recover the full costs of extra investment in the network. If, as is currently the case, the SO and TO functions are performed by a single company, the effect of these arrangements would be to encourage excessive investment. The TO would recover

⁸³ As described in Chapter 6, balancing services will include current ancillary services and reactive power.

incremental capacity costs through use-of-system charges but then derive a second benefit in terms of reduced costs and higher profits in its SO activities.

8.3 NGC's Current Incentive Schemes

At the present time, NGC is subject to four incentives schemes relating to:

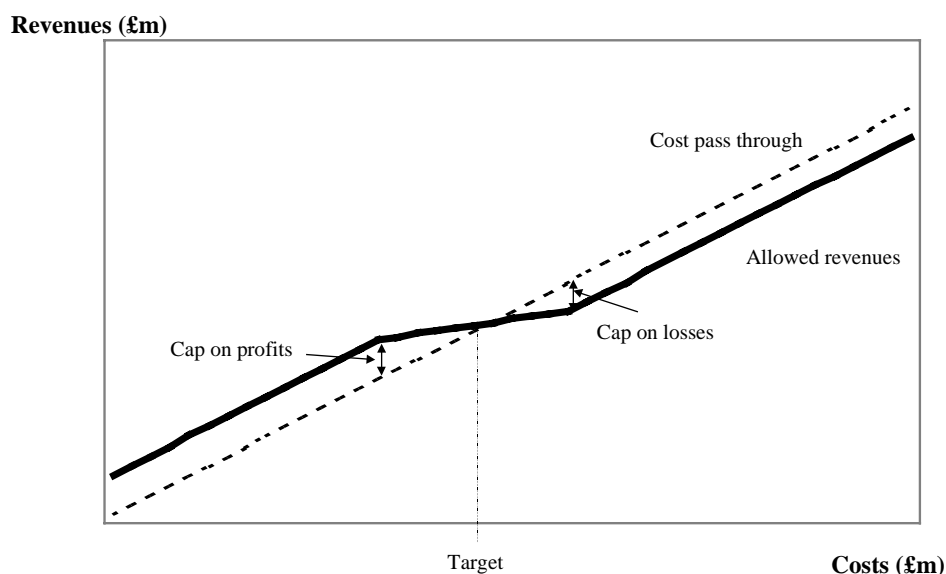
- ◆ **Transmission Services Uplift:** This covers the costs of re-scheduling plant, which may be required for a number of reasons including transmission constraints, and the need to hold reserve and frequency response. It also includes some of the costs associated with the procurement of ancillary services. Target costs for transmission services uplift for 1999/00 are £215 million.
- ◆ **Reactive Power Uplift:** Reactive power is a particular type of service that NGC requires in order to maintain system voltage within the limits prescribed in the Grid Code. The incentivised costs are associated with NGC's bilateral contracts for reactive power. Target costs for 1999/00 are £50 million.
- ◆ **Energy Uplift:** These costs arise from demand forecasting errors and generator re-declarations of availability (including plant breakdowns). Target costs for 1999/00 are £25 million.
- ◆ **Transmission Losses:** Currently losses are charged through the Pool and NGC is incentivised to limit the costs of these losses. Losses are targeted at 5.1 TWh (approximately £130 million) for 1999/00.

The Transmission Services Uplift and Reactive Power Uplift Incentive Schemes are included in NGC's licence conditions but the incentives on Energy Uplift and Transmission Losses are implemented via an agreement with Pool members. The total targeted costs for 1999/00 for the four incentive schemes amount to £420 million. For comparison, NGC's allowed revenues under its present price control are approximately £870 million in 1999/00. The costs covered by the incentive schemes, which collectively are known as 'Uplift costs', are recovered largely from suppliers⁸⁴ either from NGC or as a surcharge on the Pool price or as a direct charge largely to suppliers. NGC uses a variety of techniques to manage these costs. For example, by reconfiguring the National Grid and planning maintenance programs efficiently, NGC can ensure that generating sets are less likely to be constrained-on or off. The incentive schemes in

⁸⁴ Generators pay Uplift when importing power.

place are all of the sliding scale type. Figure 8.1 illustrates how such incentive schemes works by comparing the revenues that NGC would be allowed to keep with the costs it incurs.

Figure 8.1 - Illustration of Sliding Scale Incentive Scheme



All of the incentive schemes have appeared to work reasonably well over the past few years in that Uplift costs have fallen. However, the current trading arrangements have limited the extent to which NGC can actually reduce the costs of Uplift:

- ◆ offers into the Pool may not be reflective of costs and hence constraint costs can be overstated; and
- ◆ the non-firm nature of the day-ahead market means that generators and suppliers are not faced with the full costs and risks of their actions, which are instead passed onto customers through higher Energy Uplift payments.

8.4 Proposed Incentives

As discussed in section 8.2, it is desirable to have incentives that cover both the SO and TO functions. Although the NGC incentive schemes will be the subject of separate consultation exercises, in considering the design of the new trading arrangements it is important to take account of present thinking on these issues.

To date, the development of the schemes designed to incentivise NGC to manage the costs of Uplift have focused on a progressive unbundling of the cost categories, with each cost category having its own incentive scheme. This has resulted in the four incentive schemes described above. This process of progressive unbundling has been successful in so far as it attempted to target the costs over which NGC has some control and which it can therefore reduce. The unbundling has also enabled separate markets to emerge for the provision of the various incentivised services. This, in turn, has enabled a growing number of market participants to offer services to NGC, including from the demand-side. The way that NGC now procures reactive power and reserve under contracts struck following competitive tender processes are good examples of the greater transparency and lower costs that have been achieved.

However, unbundling of cost categories with separate incentives placed on each does have drawbacks, since there are strong interactions between the unbundled Uplift costs. For example, actions taken by NGC to procure Reactive Power, for which it is incentivised under the Reactive Power Uplift scheme, can affect the costs of Energy Uplift, which are separately incentivised. This means that, inevitably, NGC will take actions designed to maximise its returns under the various incentive schemes rather than to improve efficiency overall.

Given the experience of the current incentive schemes, one of the principal issues for consideration with regard to NGC incentives under the new trading arrangements is the extent to which cost categories should be unbundled. Consequently, two different approaches have been considered whose principal differences relate to the degree of unbundling they incorporate.

8.4.1 Approach 1 – No Incentive on Energy Balancing Costs

Under the first approach, the costs associated with energy balancing (by which is meant the matching generation and demand at the half-hourly level) would be separated from the costs of alleviating transmission constraints and other SO costs. No incentives would then be placed on NGC regarding the costs of energy balancing, but all other costs would be subject to an incentive arrangement. This approach assumes that NGC's potential for influencing the costs associated with transmission constraints (for example) might be expected to be much greater than its potential for influencing energy balancing costs. This would particularly be the case if NGC's only tool for resolving energy

imbalances was the Balancing Mechanism, since Offer and Bid prices would be largely outside NGC's control.

Such an approach suffers from two significant drawbacks. First, it is not straightforward to separate NGC's energy balancing costs from its total SO costs. NGC has informed us that it will be impossible to attribute individual trades to either constraint alleviation or energy balancing. This means that an artificial mechanism would be required to separate constraint and balancing costs. Under the new trading arrangements, this could be achieved via the use of an *ex-post* unconstrained schedule, a method presently used to separate Energy and Transport Uplift. However, an *ex-post* unconstrained schedule type approach can distort and blunt price signals, since an *ex-post* unconstrained schedule assumes perfect foresight.

A second problem with this approach to incentives is that it would reduce the interest that NGC had in the balancing costs incurred and hence in the prices charged to market participants that were out of balance in a particular half hour. Experience both from the early days of the electricity market and from the GB gas market has shown that, where a monopoly SO is allowed a direct pass through of the costs it incurs, little effort is made to reduce these costs. Without incentives on balancing costs NGC could, for example, accept extremely high price offers in the Balancing Mechanism for energy balancing rather than exercise some of the options embedded within balancing services contracts (since balancing services costs would be subject to an incentive scheme while actions in the Balancing Mechanism would not be incentivised in the same way).

8.4.2 Approach 2 – Incentive on Overall Costs

Under the second approach to incentives, NGC would be incentivised to minimise the overall costs it incurs in fulfilling its SO role, including balancing costs. This would have a number of distinct advantages. First, it would not be necessary to separate balancing costs from other costs (something that it is now widely recognised can only be done by making a number of simplifying assumptions that can significantly affect outcomes). Second, NGC would have a direct interest in the level of balancing costs and its interests in this regard would be aligned with those of customers i.e. to reduce overall costs. And third, with such incentives in place, the SO would be encouraged to make use of the most efficient mix of the different instruments available to it in

operating the system, including contracts for balancing services and Balancing Mechanism offers and bids.

Under this approach to incentives, a sliding scale incentive schemes would be set around an overall cost target for NGC. A number of approaches to setting the overall target could be adopted. However, consideration would be likely to be given to NGC's present costs associated with Ancillary Services contracts entered into substantially ahead of time. Also the quantities of electricity called on by NGC at short notice under present arrangements may serve as a starting point for assessing the net volumes that might need to be bought or sold in the Balancing Mechanism to maintain system balance and security. Views on the prices associated with these balancing volumes would then be required as part of the assessment of an overall revenue target. It might, for example, be appropriate to incentivise NGC relative to the prices emerging from a power exchange.

In general, placing incentives on overall SO costs (i.e. approach 2) appears a framework that is more consistent with the new trading arrangements.

It is important to recognise that the workings of the incentive schemes discussed above will depend on how the arrangements interact with the Transmission Network price control. For example, in the case of the Reactive Power incentive scheme, NGC can provide Reactive Power using its own static compensation equipment. In setting the scheme, it will therefore be necessary to take account of NGC's assets relating to Reactive Power provision. Currently these capital costs are taken into account in NGC's Transmission Network price control. Any arrangements to include NGC's own equipment in a Reactive Power scheme, or in an overall cost incentive scheme, would therefore require such costs to be reallocated for price control purposes.

8.5 Transmission Losses

Transmission losses increase with the distance between generation and consumption.⁸⁵ Thus, it may be cheaper to schedule a relatively expensive power station located close

⁸⁵ This assumes that energy flows from the point of generation to the point of consumption. Depending on location, incremental generation and consumption can also serve to reduce net flows, and transmission losses can also decrease with the distance between the relevant increments. There are also components of losses that are not related to distance.

to a demand centre instead of a more remote station with a lower price. At present, the costs of losses being recovered by the application of a uniform scaling factor to demand. However, the systems procured for balancing and settlements purposes will be required to have the capability to:

- ◆ scale generation as well as demand for losses, and
- ◆ incorporate locational scaling factors.

The procurement of such systems will allow for the implementation of a system of charging for losses that more accurately reflects the extra costs imposed by changes in generation output or demand at particular locations.

A further issue for consideration is how losses should be purchased initially. At present, participants effectively purchase losses directly but it would be possible for the SO to purchase them and then pass on the costs to participants. If NGC were to be incentivised on the basis of its overall SO costs (approach 2 above), then there would appear to be merits in the SO purchasing losses. NGC's overall incentives would be such that it would wish for these purchases to be made efficiently and would wish to use the full portfolio of options available to it (including contracts struck ahead of time and balancing mechanism actions) to minimise costs. One possibility is that NGC could recover the costs associated with the purchase of losses via use of system charges and could charge these costs out on a locational basis if there were efficiency gains (and hence potential benefits under its incentive scheme) from so doing.

8.6 Transmission Capacity

Transmission constraints arise whenever network capacity is not sufficient to meet all transmission requirements so that more expensive generation has to be scheduled (or demand decreased) in more favourable locations in place of cheaper generation behind the constraint. NGC does not wait for transmission constraints to arise before taking action, but instead calculates what transmission constraints would occur in the event of a double circuit failure and then acts to prevent them arising in this eventuality.

Transmission losses and constraints represent the short run costs of electricity transmission. If these costs were reflected accurately in the charges, the market should send correct economic signals to the TO and transmission system users over both the

short and long term. This, in addition to influencing the location of new generation or of large consumers and highlighting the need for grid reinforcements, should lead to efficient decisions being made regarding the day-to-day operation of the network.

At present there are no locational price signals apart from the annual Transmission Network Use of System charges, which vary on a zonal basis in a manner intended to reflect the long run costs of constructing and maintaining transmission capacity. Without short-term locational signals, the alleviation of transmission constraints has to be centrally administered by the SO.

The current RETA process has largely focussed on improvements to the electricity trading regime, although attention has also been devoted to the treatment of transmission constraint costs under the proposed arrangements. Detailed considerations of access rights and use-of-system charges are beyond the immediate scope of the programme. It is, however, important that changes implemented in the shorter term be consistent with prospective longer term developments that recognise the linkages between the SO and TO functions.

A review of all aspects of the transmission pricing regime is due to commence shortly as part of the preparations for setting revised incentive schemes consistent with the new trading arrangements and for the next NGC transmission price control, which will take effect from April 2001. The interval between the introduction of the new trading arrangements and the commencement of the next NGC price control is a relatively short one. It will be appropriate, in the near future, to commence detailed work on longer-term options for transmission access and pricing (this will be the subject of a future consultation that Ofgem proposes for the autumn of 1999). Present thinking on these issues is outlined below.

A market-based solution, based on tradable access rights, would be consistent with the general thrust of the proposed reforms in electricity trading. For example, a solution that encouraged the value of transmission access to be discovered via the trading of rights by interested parties would be preferable to an approach under which transmission access prices are determined by a centrally administered calculation. Having established a general framework for transmission capacity trading, parties would be free to establish amongst themselves the prices at which they were willing to trade.

This approach might be expected to lead to a market for the trading of transmission capacity operating in parallel with, but distinct from, the wholesale electricity markets in which electricity is traded as a commodity.

In the GB gas industry, the reform process has maintained a distinction between the title to gas and the right to transport gas over the network.⁸⁶ It is for consideration whether a suitably modified version of the transportation capacity market model envisaged for the gas industry⁸⁷ could have applications in electricity transmission access and pricing.

It will be important to ensure consistency between transmission pricing in gas and electricity, in the light of the new gas trading arrangements. This will remove any perverse incentives for generators to locate new gas plant on the basis of market-related gas transmission charges with little regard for the costs imposed on the electricity transmission network as a result (since these will only be weakly reflected in the Transmission Network Use of System charges they pay).

Any new transmission capacity regime that allocates firm access rights will require that the allocation of rights does not exceed the physical capability of the transmission system.⁸⁸ One possibility would be for NGC to sell firm capacity rights in a primary auction. Such a process should be designed so that the maximum possible capacity is made available to the market. This maximum initial amount could be profiled against the capacity that is likely to be available at different times both over the course of a day and a year.

A secondary market might also develop so that individual participants could refine their capacity purchases to better match their requirements. To the extent that, in aggregate, the firm transmission capacity services sold by NGC were not available on the day (i.e. transmission was congested), NGC would have to buy back transmission rights through the secondary market so as to alleviate the constraint. If NGC had extra capacity, it would, likewise, be able to sell this on the market. In this instance, NGC would be a

⁸⁶ The New Gas Trading Arrangements, May 1999.

⁸⁷ For example, in electricity, unlike gas, it might not be appropriate to sell capacity rights at individual entry points i.e. power station gates, but on a more zonal basis. It may also be necessary to introduce simultaneous auctions for entry and exit rights given the complementarity between the two.

⁸⁸ Although it is possible to envisage forward sales of unbuilt capacity.

buyer and seller in the market, which on average could lead to costs near to zero. This might then represent a possible 'target cost'. NGC could be exposed to a proportion of the costs above the target level, and could benefit when the costs were reduced below the target level, with a cap and collar on the potential losses and benefits.

Any changes to how transmission capacity is booked and paid for will have implications for how NGC receives revenues for its existing assets under its price control. There may need to be a reallocation of monies if revenues from alternative methods of pricing capacity (such as auctions) exceed or fall short of that allowed under the price control. Potential changes to the role of the SO and a more formal separation from the transmission asset owner role could also impact on the way new capital expenditure is authorised within the price control. It is proposed that prior to the implementation of new price controls on NGC, NGC will continue to recover costs through the present combination of Transmission Services Use of System charges (revenues from incentive schemes), Transmission Network Use of System charges (price control revenues) and connection charges.

8.7 Duration of Incentive Schemes and Interim Arrangements

The current incentive schemes have durations ranging from a year to two years. NGC, in past discussions on this issue, has argued that this approach to regulation delivers inappropriate incentives to undertake activities whose pay back time is greater than one year. For this reason, it has long advocated that it might be more appropriate for these incentive schemes to have a longer duration as this would encourage NGC to undertake more activities in uplift management that would have long term beneficial effects.

The reason for setting a control, up to now, that lasted only one to two years was that there was uncertainty over the development of the revised trading arrangements. This uncertainty remains, we therefore propose that the initial incentive schemes implemented in place of the present schemes should again only last for a year.

Discussion and analysis will be needed to determine the appropriate figures for the first year. The scheme will need to be continually monitored and reviewed. If costs deviate significantly from those expected, it may be necessary to review the scheme during the course of the year. The new trading arrangements are not due to be implemented until the autumn of 2000 whereas new incentive schemes will have to be put in place for

April 2000. During this interim period, the new NGC incentive arrangements should largely represent a roll-over of the present scheme. However, it will be appropriate to consider changes in a number of areas, including the extent to which it will continue to be appropriate for the costs associated with a broad range of unforeseen events simply to be 'passed through' to suppliers, thereby removing them from the incentives arrangements.

From the autumn of 2000, it will be possible to incentivise NGC on the basis of the overall costs associated with undertaking its SO role. It is expected that the target figures used in future incentive arrangements for NGC will be adjusted as the role of NGC adjusts and as more experience is gained with the new trading arrangements.

8.8 Longer Term Incentives

In respect of longer-term investment incentives, SO costs arising from transmission constraints and from losses can provide an important signal as to the appropriate level and direction of capacity expansion. Such signals can potentially be turned into incentives by linking TO revenues to a relevant, separately and clearly identified measure of system operation costs. In developing interim SO incentives under the new trading arrangements it will, therefore, be necessary to take account of potential future developments in the incentives regime for the TO.

Given the efficient implementation of a new transmission capacity regime, NGC could be held wholly responsible for meeting the requirements of holders of firm transmission rights. This would mean that it would benefit from any upside and similarly incur any downside in the secondary market.

Under these arrangements, it would be possible to establish significant financial incentives for efficient long-term investment. In particular, any failure to make transmission capacity available would lead to financial penalties as NGC would be required to buy-back transmission capacity rights. Thus, NGC's revenues would depend directly on its performance in providing firm transmission capacity.

Moreover, the magnitude of the effect on revenues would vary according to the supply/demand balance for the relevant capacity. If demand was high in relation to available transmission capacity, then transmission capacity prices would tend to be high

and the required buy-backs would also tend to be expensive. There would then be incentives on NGC to expand capacity in order to reduce these financial penalties. If, on the other hand, demand at particular locations fell short of available capacity, prices would tend to be low and buy-backs would be relatively inexpensive. In such circumstances, there would be no incentive to invest so as to increase capacity.

8.9 Summary

The SO and TO functions will continue to be undertaken by NGC under the new trading arrangements, although there will be changes in the way that they will be assigned and carried out. The formulation of incentive structures for the SO and the TO, as well as the determination of the boundary between the responsibilities of the two, is therefore important. The question of incentives also links to wider issues for example concerning access to and charging for transmission capacity and transmission losses. Ofgem will be issuing consultation documents on both NGC's incentive schemes and its price control, which will deal in more detail with the issues raised in this chapter.

9. Legal and Regulatory Framework

9.1 Introduction

This Chapter describes the legal framework within which RETA will be implemented. It contains an explanation of the legal scope of the RETA Programme, an outline of the changes required to licences and other regulatory instruments, a description of the proposed BSC, an outline of the changes required to key industry documents and an explanation of the proposed legislative route for RETA implementation. It then briefly describes the implications for the new trading arrangements of the European Directive on the internal market in electricity, European and domestic competition law and financial services regulation. A summary of the existing legal framework for electricity trading arrangements is set out in Appendix 8.

9.2 Legal Scope of RETA

The RETA programme will establish the Balancing Mechanism and Settlement arrangements described in Chapters 5, 6 and 7 (as explained in those Chapters, the establishment of forwards and futures markets, and a power exchange, is not within the scope of the RETA programme).

The related legal framework is concerned with the revisions and additions to key legal instruments and documents necessary to establish these arrangements. More specifically, these are:

- ◆ the new Balancing and Settlement Code (BSC) itself;
- ◆ new licence conditions for NGC, generators and suppliers to support the BSC;
- ◆ other changes to licence conditions appropriate to reflect the new arrangements;
- ◆ the changes to the Pooling and Settlement Agreement (P&SA) needed to allow it to co-exist with the BSC for a 'run-off' period, and then to expire; and
- ◆ changes to other industry documents appropriate to reflect the new arrangements.

The RETA programme has identified at a high level the kinds of changes that will be required to these documents. The precise definition of the legal framework to underpin the new arrangements will be developed further in the implementation phase.

9.3 Description of Licence Changes

9.3.1 Licences

It is proposed to implement the new trading arrangements by way of modification to existing generation, transmission, public electricity supplier (PES) and second tier supplier licences (see section on 'Implementation' below).

The content of the licence changes will depend on the outcome of this consultation and further development of the detailed business rules. However, it is anticipated that changes will be along the following lines.

It may be necessary to make specific provision for the run-off arrangements under the P&SA. In addition, consequential changes will be required to definitions and licence conditions that refer to the P&SA. The obligation placed on NGC to schedule and despatch available generating plant in accordance with a merit order system and the obligation in relation to operation and maintenance of a settlement system will also need to be removed.

It is proposed that the new arrangements for balancing and settlement will be contained in the new Balancing and Settlement Code (BSC). The licence requirements in respect of the P&SA will be replaced by duties in respect of the BSC.

In the case of the transmission licence, NGC will be obliged to have in force at all times a BSC as approved by the Director General. The scope of the BSC will be defined in the relevant licence condition. NGC will be under a duty to be a party to the framework agreement (see below) and to comply with the BSC. NGC will be required to amend the BSC with the consent of or at the direction of the Director General where a modification proposal is considered better to facilitate achievement of a number of objectives set out in the licence condition. The proposed objectives are described in Chapter 10. The rules for making, evaluating and consulting on modification proposals will be outlined in NGC's licence condition and set out in detail in the BSC itself. Those rules will themselves be subject to modification in the same way as other rules in the BSC. Further details of these arrangements are set out in Chapter 10.

In the case of generation and PES and second tier supplier licences, there will be a requirement to be a party to the framework agreement and comply with the BSC.

Current provisions in NGC's licence relating to the maintenance of records and dissemination of information about, among other things, transactions under the P&SA will be replaced by suitable alternative requirements in respect of the BSC.

There may be a need for certain rules about the behaviour of parties under the BSC. If so, these should more properly be included in relevant licences (or rules/guidelines developed pursuant to a licence condition) rather than in the BSC itself. These matters are currently under consideration. However, examples might include:

- ◆ rules about NGC's use of the Balancing Mechanism (e.g. non-discrimination⁸⁹ etc);
- ◆ rules about the use and disclosure of market-sensitive information; and
- ◆ rules about the completeness and accuracy of physical notifications.

The obligation on generators to submit certain plant to central despatch will be removed from the generation licence, although there may be a residual duty (in addition to requirements following a direction issued under the Electricity Act 1989 or the Energy Act 1976) to run plant in emergency situations. This duty could be included in licences and/or the Grid Code and/or the BSC. Consequential changes will be required to other licence conditions in the generation licence to reflect the removal of the obligation to submit plant to central despatch.

It is proposed that the generation security standard in suppliers' licences will be removed. The rules of the BSC will be structured to provide incentives on participants to contract in advance of the trading period. The objectives by which modifications to the BSC will be evaluated are likely to include explicit reference to this goal. NGC will be placed under a duty to take balancing actions required to balance generation and demand and will be prohibited from interrupting customers where Balancing Mechanism offers and bids sufficient and suitable to meet that requirement remain available at the time in question (i.e. regardless of price). The wording of these duties and the interface with use of balancing service contracts and NGC's incentive scheme requires further consideration.

⁸⁹ It is proposed that this requirement will be procured via changes to NGC's incentive scheme but it may be necessary, in addition, to set out certain broad rules in this area.

The Government has announced its intention to create a separate licensable activity of electricity distribution. The analysis in this section focuses primarily on the supply (rather than the distribution) activities of authorised electricity suppliers. However, there may need to be provisions in the distribution licence relating to the new trading arrangements (for instance, in relation to registration of meters at the Grid Supply Point).

The next section in this Chapter outlines some of the key changes which will be required to other industry documents in order to implement the reform of the wholesale electricity trading arrangements. It is anticipated that licences may include one or more 'implementation' conditions (for example, requiring licensees to use their best endeavours to procure such changes as are necessary to these industry documents in order to give full effect to the new trading arrangements).

Other consequential changes will be required to all licences to reflect the modifications described above. For example, the relationship with ancillary services, and balancing services more generally, requires further consideration and definition. The outcome of this process may necessitate changes to the definition of 'Ancillary Services' in the generation and transmission licences and/or to the conditions in each of those licences relating to ancillary services, in order to distinguish these services, where necessary, from NGC's activities under the BSC.

9.3.2 Exemptions

A number of consequential changes will be required to the Electricity (Class Exemptions from the Requirement for a Licence) Order 1997 (for instance, in relation to references to the 'Pooling and Settlement Agreement').

However, the current view is that no substantive changes will be made to this Order. This will need to be kept under review pending the outcome of consultation on the 'participation' issue discussed below.

9.4 Description of BSC

9.4.1 Status and scope of BSC

A new condition contained in its transmission licence will require NGC to establish and modify the BSC. There will be a licence obligation on licensed generators and suppliers (and NGC) to comply with the BSC.

The BSC will set out:

- ◆ the rules of the Balancing Mechanism;
- ◆ the rules for Settlement, including contract notification, meter registration, metered data collection and aggregation, imbalance calculation, and payment requirements (this will include what was known under the P&SA as Stage 2 settlement); and
- ◆ the rules for governance of the BSC (see Chapter 10).

9.4.2 Framework Agreement

In addition to its regulatory force (by licence condition), the BSC will also take effect as a contract, so that settlement obligations are established as debts between participants. The BSC will be given contractual effect by a short multilateral Framework Agreement. The parties to the Framework Agreement will include BSC participants (see below), NGC and the BSCCo (see Chapter 10). For convenience, parties who have signed the Framework Agreement are referred to as 'parties to the BSC'.

The mechanism for admission of new participants to the BSC will be by becoming a party to the Framework Agreement. Either the BSCCo or NGC will be authorised (on behalf of all parties to the Agreement) to sign accession agreements admitting new parties who have complied with the admission requirements which will be contained in the BSC.

9.4.3 Participants

The term 'participants' is used to refer to parties under the BSC who participate in the trading arrangements for which it provides. (Thus NGC and BSCCo, although parties to the BSC, are not participants.)

A participant under the BSC may be involved in the following activities:

- ◆ contract notification – the participant may notify volumes of electricity, under bilateral contracts which it has entered into, to be taken into account in calculating its imbalance;

- ◆ meter registration and metered electricity allocation – the participant may be the registrant of a meter and be allocated a metered quantity to be taken into account in calculating its imbalance; and
- ◆ Balancing Mechanism – the participant may make bids in the Balancing Mechanism (which if accepted will be taken into account, in calculating its imbalance, as adjustments to its contract position).

Participation in the BSC will be mandatory for certain categories of party, and optional for others.

9.4.4 Mandatory Participation

Each licensed generator and supplier will be obliged, by a condition in its licence, to be a BSC participant (in other words to sign the BSC Framework Agreement). The effect will be that it will be necessary for licensed generators and suppliers to comply with the relevant requirements of the BSC.

Such participants, as the registrants of certain meters, will have the electricity quantities at such meters allocated to them for the purposes of imbalance calculation and settlement. A licensed supplier will be the registrant of the meter at the premises that it supplies. A licensed generator will be the registrant of the meters of the generating plant at which it generates electricity, excluding generating plant in relation to which the generator would benefit from a licence-exemption if it were not otherwise licensed.

9.4.5 Optional Participation

Generators

Generators and suppliers who are licence-exempt will not be obliged to be BSC participants. They will have the option of becoming participants, provided they comply with the admission requirements under the BSC. An exempt generator who opts to become a BSC participant, and a licensed generator in respect of 'exempt' generating plant, will have the option under the BSC to be the registrant of the meters at its generating plant. Where an exempt generator does not opt to be a BSC participant (or to be the registrant of the relevant meters), a supplier (in the same GSP Group) may become the registrant of those meters under netting-off arrangements. Chapter 11 also describes possible proposals under which an 'aggregator' may be permitted to trade in

the BSC on behalf of a number of small generators. The implications of these proposals require further consideration.

Customers

As at present, a customer will have the option of acting as its own supplier. In such a case, the customer would need to be a signatory to the BSC and under the present licensing regime be a licensed supplier, unless it benefits from any of the exemptions mentioned above. The customer would then be able to purchase electricity by way of bilateral contract notified for settlement purposes under the BSC, and to submit bids into the Balancing Mechanism. The customer would be exposed to imbalance settlement in the same way as any other participant.

'Non-physical Participants'

A person who is neither licensed nor exempt will also have the option of becoming a BSC participant, provided it complies with the admission requirements under the BSC. Such a person (a 'non-physical participant') would be able to notify contract volumes for settlement under the BSC. A non-physical participant would not be able to be registrant of any meter (because the circumstances in which it could be a registrant would require it to hold a licence or exemption), and would not be able to submit bids in the Balancing Mechanism. By definition, in calculating such a participant's imbalance, its metered allocation will be zero.

Being a non-physical participant will enable such a person to write contracts with other BSC participants that can be notified for settlement under the BSC. There is no need however for a 'requirement' for any such person to become a BSC participant. If a trader is not a participant, the contracts which it writes will not be capable of recognition under the BSC. There may be a need to distinguish this type of non-physical participant from the 'aggregator' function described above.

Interconnectors

Broadly speaking, interconnector users, Interconnector Administrators and Interconnector Error Block Administrators would be signatories to the BSC Framework Agreement and, therefore, be bound by the BSC.

9.4.6 GSP Registration

As described in Chapter 7, a further technical question relating to BSC participation concerns the registration of meters at Grid Supply Points. For settlement purposes it is assumed to be necessary to have a registrant of these meters, although there might be no financial consequences in settlement of this registration (subject to consideration of the treatment of certain 'default' embedded generation). Currently, the Host PES acts as registrant. After the separation of distribution and supply, there appears to be no particular logic in selecting any given supplier as registrant. On the other hand including all licensed distributors (in England and Wales) as BSC parties for this purpose alone appears unnecessarily complex. Further consideration is required of this issue. Other options might be, for example, NGC or the BSCCo.

9.4.7 BSC Modification

The proposals for governance (including modification) of the BSC are set out in Chapter 10. From a legal standpoint, NGC (as 'promulgator' of the BSC under the proposed new licence condition) will be responsible for making modifications of the BSC. NGC may only modify the BSC with the consent or at the direction of the Director General. As explained in Chapter 10, the new transmission licence condition will contain 'relevant objectives' which will be the criteria against which proposals to modify the BSC will be judged by the Director General.

The BSC Framework Agreement will bind the parties to it to the BSC as from time to time modified. Thus, no further step (beyond the modification by NGC) will be needed to give contractual force to BSC modifications.

9.4.8 Co-ordination

It will be important to ensure that there are appropriate change co-ordination provisions between the BSC and other key industry documents in order to be able to give full effect to the modification process under the BSC in a timely and efficient manner. This may be achieved in a number of ways. The BSC is likely to contain rules to address this issue.

It will also be necessary to ensure that there is as little duplication or conflict of arrangements across key industry documents. For example, it will be necessary to

provide consistency in entry, performance assurance and exit processes across agreements.

9.5 Description of Other Key Changes

This section provides a very brief overview of changes required to the main industry documents.

As described above, it is currently envisaged that licences will include an obligation to take all reasonable steps within the licensee's power to effect changes required to industry documents in order to implement the new trading arrangements.

9.5.1 Grid Code

The principal change required to the Grid Code will be the removal of large parts of the Scheduling and Despatch Codes to reflect the abandonment of the existing scheduling, despatch and merit order arrangements.

Consideration needs to be given to whether some of the rules covering the new trading arrangements are best placed in the Grid Code (instead of or in addition to the BSC). For instance, rules relating to the submission of initial and final physical notifications may sit more properly in the Grid Code. Also, some of the rules for calling off balancing offers and bids may be placed in the Grid Code.

It is currently assumed that there will be no substantive changes to the Planning Code⁹⁰ or Connection Conditions. However, certain aspects of the Operating Codes will need to be examined further in the light of the new arrangements and in the light of decisions about the scope of the BSC. Examples include co-ordination of outages, operating margin, testing and monitoring of plant, demand control and system warnings. In particular, it is anticipated that the interaction between the Balancing Mechanism and ancillary services may need to be defined in the Grid Code more explicitly. There may also need to be a requirement for better or additional provision of information to NGC in certain circumstances and provision for NGC to be able to issue despatch instructions in emergency situations.

⁹⁰ See Appendix 8 for an overview of the codes and conditions specified in the Grid Code.

Finally, a number of consequential changes will be required to definitions and other provisions of the Grid Code to remove references to the P&SA and, where appropriate, insert references to the BSC.

9.5.2 Master Connection and Use of System Agreements (MCUSA) and Supplemental Agreements

The requirement to be a Pool member will need to be replaced by a requirement to be a party to the BSC. The disclosure to NGC of settlement data required for the purposes of calculating transmission charges and otherwise operating the system will need to remain, but will have to reflect the BSC arrangements in place of the existing P&SA arrangements. Appropriate linkages between maximum FPN quantities and the relevant charging provisions of the supplemental agreements will be required. Also, references to registered capacity declared pursuant to the P&SA will need amendment. Other changes may be required to the supplemental agreements, depending on the chosen cost recovery mechanisms.

As with the Grid Code, a large number of consequential changes will be required to reflect the replacement of the Pool with the BSC arrangements and changes to the Grid Code.

9.5.3 Master Registration Agreement (MRA)

The interface between the P&SA and the MRA is currently encapsulated in what are known as the 'Pool Requirements'. These provisions will need to be replaced by the relevant requirements of the BSC, in order to ensure that the rules for Settlement under the BSC (as with the P&SA) can be given effect. In addition, the provisions for change co-ordination (where a change affects the BSC requirements under the MRA) will require amendment. As described above, it is likely that the BSC will contain rules or procedures intended to ensure that the BSC modification process is not frustrated or unduly delayed as a result of the need to effect consequential changes to other related documents. Consideration also needs to be given to who should replace the Pool Agent as representative of the BSC participants' interests under the BSC.

As with the other documents, there will be consequential changes required to reflect the replacement of the P&SA with the BSC.

9.6 Description of Consequential Changes to Other Documents

Consequential changes will be required to a number of other industry documents to take account of the demise of the Pool and introduction of the BSC, including (by way of illustration) the Fuel Security Code, the Distribution Codes, the Electricity (Non-Fossil Fuel Sources) (England and Wales) Orders, the Data Transfer Services Agreement, the Settlement Agreement for Scotland, the British Grid Systems Agreement, the NGC/EdF Interconnector Agreement, the Master Ancillary Services Agreement, NFFO purchase contracts and others.

9.7 Implementation

It is intended that the RETA legal framework will be implemented by the introduction of changed licence conditions pursuant to new legislation. The Government has stated its intention of introducing a utilities reform bill when Parliamentary time permits. This bill is likely to address utilities reform in several areas, as foreshadowed in the DTI White Paper: A Fair Deal for Consumers (July 1998). It is intended to include separation of distribution and supply licensing and the alignment of electricity and gas regimes under the new single regulator. It is also intended to provide for a regime of standard licence conditions for electricity (as currently exist for gas).

The intention is that the new legislation will provide a power for the Secretary of State to modify transmission, generation and supply licences so as to incorporate the new and changed licence conditions required for RETA implementation as described above. (It is expected that that power might be exercisable before the introduction of standard licence conditions.) These licence modifications might be made effective as from the 'go-live' date of RETA (i.e. the date when the BSC comes into full force). Alternatively, the modifications might be made on an earlier date on the basis that certain requirements in the new licences (specifically the requirements bringing the new BSC into force) would take effect at a later date.

Modification of licence conditions will provide for the basis on which the BSC is to come into force. As noted above, a number of changes to other industry documents will be required. In some cases (for example, the Grid Code), existing licence powers may confer on the Director General the necessary powers to ensure these changes are made. In other cases it may be open to licensees to secure that the changes are made – in which case making the required changes could be a further new licence condition (or

perhaps an initial obligation under the BSC). There may be other cases where changes can only be made with the co-operation of a party who is not a licensee.

9.8 IME Directive

9.8.1 Summary of Relevant Provisions

Directive 96/92/EC of 19 December 1996⁹¹ concerning common rules for the internal market in electricity (the 'IME Directive') establishes certain measures with a view to achieving a competitive market in electricity. The measures are primarily concerned with the opening of transmission and distribution systems to enable generators, suppliers and an increasing number of customers, both within and outside the territory in question, to enter into direct supply contracts with each other on the basis of voluntary commercial agreements. To this end, the IME Directive lays down rules about the structure and organisation of the electricity sector in each Member State. These rules are set within a framework of objectivity, transparency and non-discrimination, being the key principles underpinning the more detailed rules.

9.8.2 Compliance

The Department of Trade and Industry ('DTI') confirmed its view in a consultation paper issued in July 1998⁹² that the present arrangements in England and Wales meet the requirements of Articles 7 and 9 of the IME Directive. Similarly, it confirmed its view that the present arrangements for despatch and merit order are fully consistent with the rules of Article 8, and noted that any new arrangements would need equally to comply with the relevant provisions of the Directive.

The DTI and Ofgem believe that the new arrangements are fully consistent with the IME Directive.

9.9 Competition Law Impact on BSC

9.9.1 Summary of Relevant Law

Article 81(1) (formerly Article 85(1)) of the EC Treaty prohibits agreements between undertakings, decisions by associations of undertakings and concerted practices which

⁹¹ The deadline for implementation of the IME Directive in the majority of Members States was 19 February 1999.

⁹² DTI Consultation Paper 'Implementation of Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity', July 1998.

may affect trade between Member States and which have as their object or effect the prevention, restriction or distortion of competition within the common market. This prohibition applies where there is an appreciable effect (whether actual or potential) on competition.

Article 81(3) enables these provisions to be declared inapplicable in the case of agreements, decisions or concerted practices which contribute to improving the production or distribution of goods or to promoting technical or economic progress, while allowing consumers a fair share of the resulting benefit, provided there are no restrictions which are not indispensable to the attainment of these objectives or which afford the possibility of eliminating competition in respect of a substantial part of the products in question. In other words, individual exemptions may be granted where there are some 'public interest benefits' shared with consumers, the restrictions are necessary for achieving those benefits and the benefits outweigh the anti-competitive effect of the restrictions.

In principle, UK competition law may also apply to the new arrangements. The new Competition Act 1998 contains a prohibition similar to Article 81(1) of the EC Treaty in relation to matters which may affect trade within the UK (or any part of it) – the so-called Chapter I Prohibition. This prohibition does not apply, however, to an agreement to the extent to which it is made in order to comply with a 'legal requirement'. If, however, this exclusion does not apply, the arrangements will nonetheless be exempt from the Chapter I Prohibition where they have an exemption (a 'parallel exemption') under Article 81(3) of the EC Treaty. The Director General has concurrent jurisdiction with the Director General of Fair Trading in exercising the functions and powers of the DGFT under the new Competition Act

In addition, the way in which the rules of the BSC are drafted should not allow or cause any dominant player (including NGC) to abuse a position of single or joint dominance in breach of Article 82 of the EC Treaty and/or the Chapter II Prohibition under the Competition Act 1998.

9.9.2 Procedures

Notifications of the arrangements to the European Commission for negative clearance (i.e. for a declaration that there are no grounds for proceeding under Article 81(1)) or for

an individual exemption under Article 81(3) can be made by any one or more parties to the arrangements (or their authorised representatives), although the notifying parties must inform the other parties of the fact of notification and give them at least a non-confidential copy of it.

If there is a UK Competition Act element as well, both regimes may apply in principle. However, the Director General of Fair Trading has indicated in guidelines issued under the new Competition Act 1998 that he considers the European Commission is the more appropriate authority to whom notification should be made if the agreement is caught by Article 81 of the EC Treaty (i.e. if it has cross-border effects).

In practice, the Commission issues very few formal decisions on an application for negative clearance and/or exemption. Instead, it tends to deal with the application by way of informal comfort letter. While this is not legally binding, it has persuasive effect and parties are generally willing to accept this alternative. Indeed, the P&SA (and the Network Code in gas) were both dealt with by way of comfort letter.

Although there is no parallel exemption under the Competition Act 1998 where a comfort letter is issued by the European Commission instead of an exemption, the Director General of Fair Trading has indicated in guidelines issued under the new Act that, as a general policy, he will not depart from the Commission's assessment as set out in the comfort letter, except in certain limited circumstances.

9.10 FSA

The Financial Services Act 1986 (the 'Act') prohibits the carrying on of prescribed activities in relation to prescribed investments without authorisation or exemption. The Act is to be replaced in 2000 by the Financial Services and Markets Bill (the 'Bill') that was introduced into Parliament in June. The Financial Services Authority (the 'FSA') is responsible for regulating persons authorised under the Act, and will be so responsible under the Bill. It is appropriate to consider whether participants in any of the new trading arrangements would engage in activities that are likely to require authorisation or exemption under the Bill.

To determine whether authorisation or exemption will be required, one has to consider whether the activity and the investment fall within the perimeter of the Bill. If no

investment is involved, it is not necessary to consider the activity. Under the Bill, 'investments' will be defined in an order. A draft Regulated Activities Order (the 'Order') was published by HM Treasury in February 1999. Both the Act and the Order include investments relevant to the new electricity arrangements, namely futures, contracts for differences and options as investments.

The views expressed below as to whether investments will be involved are preliminary and will have to be revised once the trading arrangements are finalised and the Bill and the Order become law. Potential participants should satisfy themselves as to whether they need authorisation.

9.10.1 Imbalance Settlement

Imbalance settlement applies to all contracts that go forward to 'delivery'.⁹³

The straightforward approach is that bilateral contracts (intended to be notified under the BSC) for electricity, whether entered into a power exchange or bilaterally off-exchange, are contracts for the future sale or delivery of electricity. On this basis, they may be analysed as 'futures' for the purposes of the Order or as 'forwards' (depending on whether the parties have entered into those contracts for an investment or commercial purpose).

This raises the possibility that on or off-exchange bilateral contracts may be viewed as contracts for differences (i.e. the difference between the contract price and the imbalance cash-out price). However, Ofgem and FSA believe that the better view is the straightforward one, namely that imbalance settlement is merely a mechanism required to determine whether physical contracts for the supply or generation of electricity have been delivered.

9.10.2 Power Exchange and Futures and Forwards

It will be for the market operator(s) of any power exchange to be set up and its participants to determine whether authorisation under the Bill will be required. However, if the operator is a recognised investment exchange, any contract for the future generation or supply of electricity made on that exchange is likely to be a 'future',

⁹³ Contracts that are performed by the seller physically delivering power rather than being settled for cash.

and therefore an investment within the definition in the Order. Dealing in such futures is likely to be a regulated activity for which authorisation will be required, unless an exclusion to the activity applies (e.g. dealing in futures with or through an authorised or exempted person).

Participants dealing in electricity forward of the balancing market, off-exchange, will need to consider whether or not the contracts involved are futures (i.e. for forward delivery made for an investment purpose) or contracts for differences (no delivery).

9.10.3 Balancing Mechanism

It is also necessary to consider whether activity in the Balancing Mechanism may require authorisation. It will only do so if investments are involved.

Balancing offers and bids will be accepted up to four and a half hours forward of actual generation or supply. The Order, when it is finalised, is likely to exclude from the definition of *futures*, contracts for delivery to be made in less than 7 days (unless made on a recognised investment exchange or if there existed an understanding between the parties that delivery would, despite the contract terms, not be made within the 7 days). Balancing offers and bids will not be made on a recognised investment exchange and it is likely that the intention of the bidder will be actually to generate or supply more or less electricity. The Code will contain incentives to encourage participants to match accepted bids/offers with physical generation/supply. If these assumptions are correct, balancing contracts are not likely to be futures within the meaning of the Order.

9.11 Views Invited

Views are invited on the legal and regulatory issues outlined in this chapter, including:

- ◆ **the position of aggregators under the new arrangements; and**
- ◆ **the extent to which rules are placed in the Grid Code rather than the BSC.**

10. Governance

This chapter provides an outline description of the arrangements for the governance of the Balancing and Settlement Code (BSC). A more detailed description is set out in Appendix 8 to this document.

10.1 The Need for New Governance Arrangements

The new balancing and settlement arrangements described in this document will be underpinned by new rules, systems, processes, agreements and institutions, all of which must be implemented and managed effectively. The effect of new legislation will be that the Pool will cease to exist and hence the existing wholesale market governance arrangements will fall away.

There has been much criticism of the form of governance of the existing trading arrangements over a number of years. In particular, there has been criticism that Pool governance arrangements have given undue preference to larger incumbents, especially the larger generators and Regional Electricity Companies (RECs), and that, in consequence, rule changes have been difficult to deliver. There have been some changes to these arrangements recently, but the general concern has persisted.

The limited provision for the role of regulation in Pool governance has also been criticised, primarily on the grounds that the Director General has had relatively little power to bring about desirable changes. While there is explicit provision in the PSA for the Director General to request the Pool to consider changes, this has proved impracticable, as it would have fettered the ability of the Director General to hear appeals under the PSA. Since the operation of the Pool is not a licensed activity, the Director General has had no locus to monitor, enforce and modify licence obligations relating to the Pool itself. For the same reason, the Director General has been unable to make any licence modification reference of the Pool to the Competition Commission in order to examine particular issues and seek the power to make particular changes. The only alternative - licence references of all the individual licensee members of the Pool or a Fair Trading Act reference of the whole industry - would have been a lengthy, wide-ranging and burdensome processes.

The proposals set out here are, therefore, intended to deliver simpler and more flexible governance arrangements than exist at present, and arrangements which address the perceived deficiencies in current market governance.

10.2 Scope of the BSC Governance Arrangements

Governance of the BSC will cover the following:

- ◆ the way in which changes to the BSC rules are proposed, developed and decided;
- ◆ letting and administering contracts with service providers for implementation of the BSC rules;
- ◆ decision-making required under the BSC rules, such as approval of subsidiary documentation, or admission or expulsion of participants;
- ◆ monitoring and enforcing compliance (by market participants) with the BSC rules;
- ◆ facilitating resolution of disputes between participants under the BSC rules; and
- ◆ undertaking other key management activities required for the implementation of the BSC rules and processes.

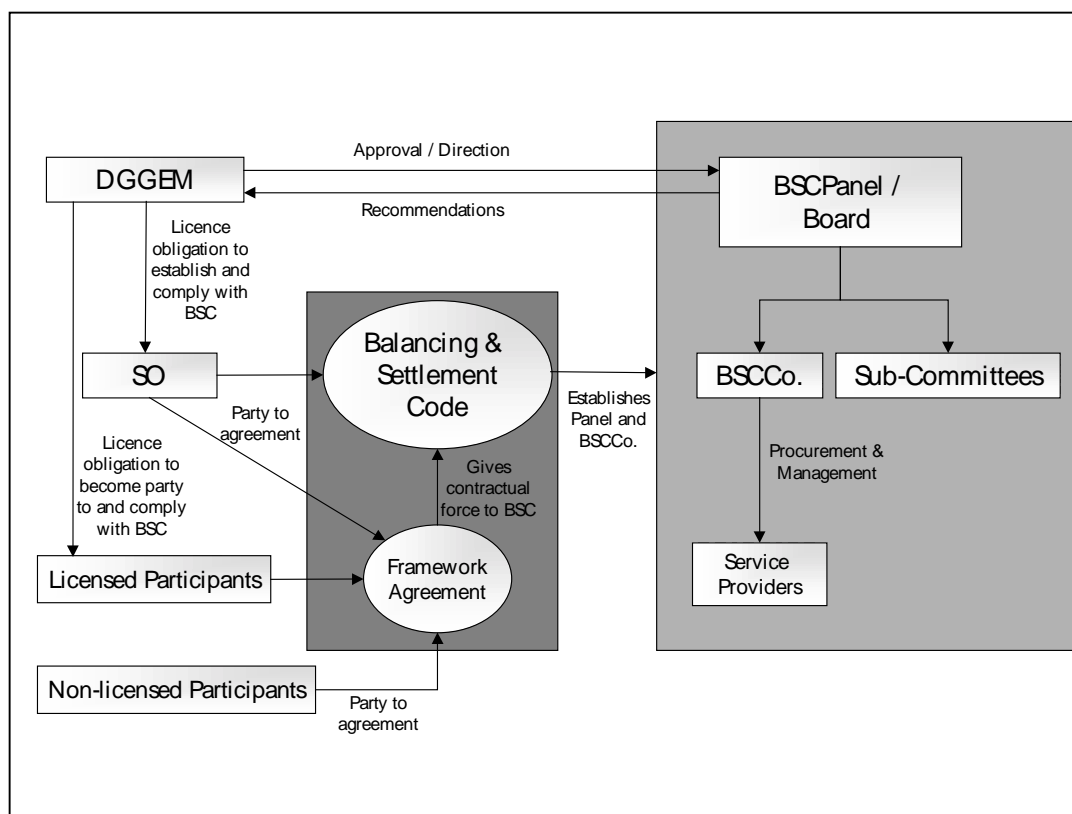
10.3 Outline of the New Governance Arrangements

The arrangements for the governance of the new balancing and settlement arrangements can be summarised as follows:

- ◆ a Balancing and Settlement Code (BSC) containing the rules, structures and processes for the balancing mechanism and imbalance settlement will be established through an obligation in the SO's (NGC's) licence (although the initial version of the BSC will be prepared within the RETA Programme);
- ◆ the SO's licence obligation will specify defined high-level objectives for the BSC, against which any proposed developments will be considered;
- ◆ the BSC will be given contractual force by a separate multilateral framework agreement signed by all relevant market participants and the SO;

- ◆ the BSC will provide for the existence of a limited liability company ('BSCCo'), funded by all BSC participants, to carry out functions associated with the management and operation of the new arrangements;
- ◆ the BSC will also provide for the establishment of a BSC Panel to supervise the management of the BSC rules and to operate the modification process; and
- ◆ all proposed modifications to the BSC will be subject to the approval/direction of the Director General.

Figure 10.1 – Outline Governance Structure



10.4 Design Principles

In addition to placing the new trading arrangements on a more sound regulatory footing than at present, as discussed above, the new governance arrangements are also intended to meet a number of further objectives:

- ◆ *Objectivity* – the decision-making processes within the BSC should be objective and not unduly biased by the interests of any particular party or group. Key to achieving this is that decisions should be made by reference to predefined objectives, and that decision makers should have full access to all relevant information;
- ◆ *Transparency* – decisions should be taken transparently. This means that information must be available to all affected parties and that discussion and analysis should be visible;
- ◆ *Inclusivity* – there should be no exclusion of relevant information or viewpoints. Consequently, contributions should be allowed from all interested parties on key decisions;
- ◆ *Effectiveness* – decision-making processes should balance the need for timely decision making and thorough consideration of issues; and
- ◆ *Efficiency* – the scope of governance arrangements extends beyond the design and overseeing of market rules. It also includes the procurement, management and enforcement of contracts with service providers, the monitoring and enforcement of rules, financial control and dispute resolution. These need to be undertaken impartially and efficiently, with scope and responsibilities laid out clearly.

10.5 The Regulatory Framework

The new Balancing Mechanism and settlement arrangements are designed to facilitate and complement bilateral contracting and the secure and reliable operation of the system. It is important that the Director General should have a substantial role in achieving change to the new trading arrangements - with greater ability to achieve change than he currently has in relation to the Pool. It follows, therefore, that some entity should be under a regulatory duty to establish (and hence, to change, if approved or directed by the Director General) the relevant arrangements.

Within the existing basis of regulation, this means giving a licensee this duty, pursuant to a condition in its licence (and precludes a governance structure established solely by industry agreement). It is therefore proposed to use the NGC's transmission licence as the vehicle to establish the BSC. This is very similar to the basis on which, in the gas industry, a public gas transporter is required to establish and modify a Network Code.

10.6 The BSCCo

The BSC will provide for the existence of a limited liability company ('BSCCo'). The primary purpose of BSCCo will be to provide a vehicle to facilitate the effective delivery, implementation, operation and development of the trading arrangements, while minimising the potential for any conflicts of interest that might exist should the SO carry out these functions directly. BSCCo's functions will therefore include:

- ◆ to act as the contracting party in respect of service providers to the BSC arrangements (e.g. procurement and contract management of settlement administration, funds administration etc.);
- ◆ to employ any individuals involved in management of the BSC; and
- ◆ to provide secretariat and resources to the BSC governance arrangements (decision making, modification and management activities).

It is proposed that the BSC will provide for the shares of BSCCo to be owned by the SO, although its running costs will be funded by all BSC participants. The charge-out arrangements for these central BSC administration costs are discussed in Chapter 7. There will be efficiency drivers in the BSC to ensure that the costs incurred within BSCCo are limited (e.g. objectives relating to efficiency, rules ensuring expedient process, performance measures, financial reporting, external efficiency audit etc.).

There will be a board of directors of BSCCo. BSCCo's constitutional documents (Memorandum and Articles of Association) will provide appropriately limited objectives for BSCCo so as to minimise any scope for its directors to owe duties to NGC as shareholder which would conflict with decisions appropriate to implement the BSC.

10.7 The BSC Panel

The BSC will provide for the existence of a Panel to supervise the management, modification and implementation of the BSC rules. This Panel will be the key body tasked with ensuring that the BSC is effectively and efficiently managed, and that appropriate revisions to the trading arrangements are secured in a robust and timely manner. It is therefore important that the Panel is appropriately constituted and that its functions and processes are clearly defined.

10.7.1 Functions of the Panel

The functions of the Panel can be described as falling into three broad categories:

- ◆ Management;
- ◆ Modification; and
- ◆ Compliance.

The management function of the Panel will be to establish, supervise and administer the operation of BSC functions, systems and processes.

The modification function of the Panel will be to supervise the development of the BSC, including operating a modification process, and submitting recommendations to the Director General for approval.

The compliance function of the Panel will include some level of policing, technical audit, performance assurance and enforcement of the BSC rules.

10.7.2 Nature of the Panel

Decision-making under the existing Pool governance arrangements has been inherently factional in nature, with diametrically opposed interests often leading to impasse and delaying beneficial change. A different approach is now desirable, with emphasis more on objective decision-making with reference to predefined objectives than on negotiation amongst competing commercial interests.

It is therefore proposed that Panel members should not formally represent any predefined constituency (as was the case under the Pool Executive Committee arrangements, for example) but will be there primarily to provide relevant expertise and experience in carrying out the duties assigned to them in accordance with the principles set out in the BSC. The aim is to establish rules and structures to ensure as far as possible that Panel members act impartially in accordance with the objectives of the BSC and not merely in accordance with the interests, wishes or directions of a particular company or group. This should avoid factionalism as far as possible and encourage a constructive, efficient and objective approach to decision-making, although it is recognised that if Panel members are drawn from within the industry (see options below) there is a risk that they will always be partisan to some extent.

10.7.3 Composition and Appointment of the Panel

As explained above, the guiding principle is that the composition of the Panel should avoid factionalism (in order to encourage a constructive approach to decision making), while capturing relevant knowledge and expertise (in order to ensure that decisions are taken on an informed basis). The process for appointment of Panel members must therefore reflect these considerations. On balance, it is also preferable to choose a smaller, rather than a larger, Panel on the assumption that a smaller Panel is more likely to deliver effective and efficient decision-making. At the same time the Panel needs to be large enough to capture sufficient expertise and breadth of knowledge.

Two proposals for the composition and appointment of the Panel have been considered and are described below. Under both options the Panel Chairman would be appointed by the Director General in order to inhibit factionalism.

Option 1: Panel members are elected from and accountable to market participants:

- ◆ The Panel Chairman would be appointed by the Director General after advertisement of the post. The Chairman would also be Chairman of the BSCCo and would be required to ensure the effective and efficient implementation of the BSC rules through the functions that the BSCCo would provide directly or contract for. He/she would therefore need to be proficient in the management of such an organisation.
- ◆ Nominations for other Panel members would be sought from all BSC participants. Nominees could be (but need not necessarily be) employees of participant companies.
- ◆ Panel members would not be explicitly representative of any class of participants, and would be obliged to act independently in carrying out their functions as Panel members.
- ◆ BSC participants would elect Panel members from the list of nominees. There would be a number of predefined categories of seat on the Panel (defined with reference to classes of expertise rather than constituency). The categories would be designed to

- ◆ ensure that the Panel contained the full range of relevant knowledge and expertise in respect of industry understanding, system operation, consumer viewpoints and more general expertise (e.g. IT, finance, economics etc.).
- ◆ There would be consumer seats on the Panel. They could be nominated and appointed by the National Electricity Consumers Council (NECC) (formerly the Electricity Consumer Councils).
- ◆ The SO would identify an individual to attend the Panel who would have expertise in system operation.
- ◆ The Chairman, Panel members and BSCCo management would all be remunerated under the BSC.
- ◆ All, some, or none of the Panel members might also be directors of the BSCCo. This is for further consideration. The Chairman would appoint senior management of the BSCCo to assist in the everyday running of the organisation (who might also be directors of the BSCCo).

If Option 1 above were adopted, further consideration would need to be given to the definition of the precise categories of expertise in respect of which seats on the Panel would be reserved and its members expected to deliver. An appropriate set of election rules would then need to be developed.

Option 2: Panel Members are appointed by the Chairman and are independent of market participants:

- ◆ The Panel Chairman would be appointed by the Director General after advertisement of the post. The Chairman would also be Chairman of the BSCCo and would be required to ensure the effective and efficient implementation of the BSC rules through the functions that the BSCCo would provide directly or contract for. He/she would therefore need to be proficient in the management of such an organisation.

- ◆ The Chairman's first responsibility would be to appoint members to the Panel and to appoint senior management of the BSCCo. The Chairman would have discretion to appoint whatever posts he felt were necessary to support him in managing the BSCCo. (e.g. directors and general manager).
- ◆ The Chairman would seek applications for Panel membership (via advertisement). All successful applicants would need to demonstrate that they possessed relevant expertise and that they were independent of any vested interests (e.g. that they were not currently employed by any industry participant). It would be open to the Chairman to consider individuals identified and recommended by interested parties, so long as they fulfilled the criteria of being independent.
- ◆ The Chairman would select between 5 and 10 applicants to become Panel members. In so doing, he would be seeking to ensure that the complete Panel, through the knowledge and experience of its various members, captured the full spectrum of relevant expertise. The range of expertise required could be specified in the BSC (and might include, for example, industry understanding, system operation, consumer viewpoints and more general expertise (e.g. IT, finance, economics etc.)).
- ◆ The Chairman, Panel members and BSCCo directors would be remunerated under the BSC.

10.8 Modifying the BSC

There will be a process by which BSC rules and provisions can be updated and revised to reflect changing market conditions. This is described in detail in Appendix 9 to this report. The BSC Panel will play a significant role in that process, overseeing the modification procedures. It is currently envisaged that the Panel will be charged with making a recommendation to the Director General as to whether or not a modification proposal should be implemented, in light of analysis undertaken, views expressed and consideration against the defined objectives of the BSC (see section on objectives below). There is thought to be benefit in the modification process crystallising at the Panel level in this way. However, some parties have argued that the Panel should not take a position on the merits of proposals, and should simply administer the process.

The Director General will have to approve or direct all proposed modifications to the BSC. In considering whether to do so, the Director General will need to have regard to

his statutory duties and the objectives of the BSC. The Director General will not have the power to propose modifications himself.

There will be procedures enabling modifications to be proposed, evaluated, consulted on and developed, and then submitted to Director General for approval. These modification procedures will ordinarily be managed by the BSC Panel. However, if the Panel fails to progress a modification proposal in accordance with the procedures (for example by failing to adhere to prescribed timescales or such that a lack of progress was inconsistent with the Director General's statutory duties), then the Director General will have power (via the licence modification route) to direct the SO to take over the procedure for that proposal.

All BSC Participants, the SO and certain customer and other (e.g. exempt generator) representative bodies will be entitled to submit modification proposals (these bodies might be designated by Director General or, in the case of customer bodies, by the National Electricity Consumer Council). Under this proposal, the route for a consumer wishing to propose a modification would be to channel this through one of the eligible consumer organisations. Equally, a non-signatory industry party (e.g. exempt generator) would seek to channel any proposal through one of the designated representative bodies (which might include, for example, the Association of Electricity Producers or Combined Heat Power Association).

There will be procedures in the BSC for circulating and consulting on all modification proposals with a very wide group of interested parties. The panel will be charged with preparing a report to Director General, containing certain prescribed elements. The Panel may also provide its own recommendation on whether to make the modification (on which the Panel will have taken a vote) at this time (see earlier discussion of this point). Importantly, all interested parties' submissions on a proposal will also be forwarded to the Director General. In this way, the process will be transparent and inclusive, ensuring that the views of even the smallest parties are taken into account in reaching decisions on whether rule changes should proceed.

The BSCCo management team will be responsible for administering the modification process on a day to day basis, including receiving proposals and initiating and managing the general consultation on them. In this way the process should be as

expedient as possible, allowing potential changes to be assessed and progressed without any undue delay.

10.9 Objectives

As noted earlier, the SO's licence will contain a condition which will specify 'relevant objectives' as criteria by which the Panel should recommend and the Director General decide whether to approve (or direct) a modification to the BSC. The Director General will also be bound by his general duties under the Act in exercising his function of approving or disapproving modification proposals. The objectives will seek to ensure that the BSC and all modifications to it:

- ◆ facilitate the efficient and economic operation of the system;
- ◆ facilitate competition in the sale and purchase of electricity;
- ◆ ensure efficiency in the implementation and administration of the balancing and settlement arrangements.

The BSC will also contain objectives which apply to the Panel and, possibly, to BSCCo, in relation to the discharge of their functions (primarily the decisions they take). These functions can generally be characterised as giving effect to the BSC. These objectives will seek to ensure that the Panel and BSCCo conduct their business efficiently, economically, transparently and without undue discrimination.

10.10 Managing the BSC

The management functions of the Panel will include: managing settlement disputes; establishing committees to deal with the conduct of Code business; establishing and operating procedures and criteria for admission and exit of BSC participants; adopting subsidiary procedures, codes of practice, etc for BSC implementation; overseeing the negotiation and operation of contracts with service providers; collecting information as specified under the Code, to publish reports and to disseminate information relating to the performance and administration of trading under the Code; exercising financial control of BSC activities, including budget approval; implementing approved or directed modifications; establishing a central design authority; undertaking change management and providing services to participants and the Regulator.

A number of the day-to-day management activities will be delegated to and performed by the management team of the BSCCo and by appropriate sub-committees (for example, it is likely that there will be a dedicated 'Disputes Panel'). However, certain key decisions to be made under the terms of the BSC will be retained by the Panel (for example, decisions affecting budgets).

The BSC will contain all the rules and processes relating to 'Stage 2 Settlements' that currently reside under the current PSA. Placing governance of the Stage 2 arrangements under the BSC will have implications for the scope of activities of the BSCCo. A number of functions currently fulfilled by the Pool Chief Executives Office will require to be provided or procured (e.g. performance assurance, contract management, audit). The Programme will consult with related parties on how the transition of the management of these activities from the Pool to the BSCCo can best be achieved. It will also be necessary to consider how industry wide change and design should be dealt with and to ensure there is no overlap or duplication.

10.12 Summary and Views Invited

Views are invited on the governance arrangements described in this chapter. In particular views are invited on:

- ◆ **the constitution and role of the BSC panel;**
- ◆ **the relative merits of the two options for the composition and appointment of the BSC Panel; and**
- ◆ **whether the BSC Panel should take a position on the merits of proposals or whether it should simply administer the modification process.**

11. Combined Heat and Power Plant and Renewables

This chapter discusses the implications of the new trading arrangements for Combined Heat and Power (CHP) and renewables schemes.

11.1 Definitions

A Combined Heat and Power (CHP) plant is a facility involving the simultaneous production of usable heat and power in a single process. Typically CHP schemes include heat recovery equipment which enables the steam or hot water produced as a by product of generating electricity to be used for a variety of purposes such as industrial processes, community and space heating.

CHP provides a secure and highly efficient source of electricity and heat on site. Due to the utilisation of heat from electricity generation and the avoidance of transmission and distribution losses, CHP typically achieves a 35% reduction in primary fuel usage compared with traditional generating facilities and heat only boilers. This, in addition to the possible avoidance of some transmission and distribution charges, can create significant economic advantages for some facilities given the right blend of electrical and heat loads.

Renewable energy can be defined in many ways. The UK Renewable Energy Advisory Group (REAG) defined renewable energy as ...

“the term used to cover those energy flows that occur naturally and repeatedly in the environment and can be harnessed for human benefit. The ultimate sources of most of this energy are the sun, gravity and the earth's rotation.”

The Electricity Act 1989 makes a distinction between fossil and non-fossil fuel generation - fossil fuel is defined as coal, coal products, lignite, natural gas, crude liquid petroleum or petroleum products, and non-fossil fuel is everything else. Typically, renewable fuel sources cover active solar heating, photovoltaics, wind power, wave power, large and small-scale hydro, biofuels and geothermal aquifers all of which are non-fossil fuels. The major sources currently in use in the United Kingdom are hydro, biofuels and wind.

The development of renewable sources of energy makes an important contribution to reducing the overall level of emissions in the United Kingdom by displacing the use of fossil fuel. The enhanced efficiency of CHP schemes also reduces the level of emissions, in relation to total energy production, when compared to a mix of boiler plant and conventional generating electricity stations. The current mix of CHP installations achieves a reduction of 30% in CO₂ emissions when compared to generation from coal stations and 10% when compared against generation from CCGTs.⁹⁴

11.2 Government Policy Regarding CHP and Renewables

In the Review of Energy Sources for Power Generation consultation document,⁹⁵ the Government stated that a key part of its overall energy policy framework was encouraging the development of CHP and renewables plant given the environmental benefits of both renewables and CHP and the efficiency advantages of CHP.

For CHP the Government has set a target of 5,000 MWe⁹⁶ capacity by the year 2000 and is currently in the process of finalising a target for 2010. It is working towards a target of renewable energy providing 10% of UK electricity supplies as soon as possible. It also hopes to achieve this by 2010. The Government is presently consulting on ways to encourage the development of renewables capacity which would be included in the forth coming Utility Bill.

Given the Government's objectives of securing diverse, sustainable supplies of energy at competitive prices and of avoiding discrimination against particular energy sources, it is important that consideration is given to the impact of the new trading arrangements on CHP and renewables schemes.

The Government's primary objective is to ensure that all forms of generation, including CHP and renewables are treated equitably. Consequently, in parallel with the RETA

⁹⁴ Digest of United Kingdom Energy Statistics, 1998, DTI.

⁹⁵ Review of Energy Sources for Power Generation, Consultation Document, 25 June 1998.

⁹⁶ MWe refers to electrical capacity while MWth (referred to later) refers to thermal or heat capacity.

process, the Government is examining issues particular to embedded generators to ensure that the costs they face are fair and that they face no discrimination.

The Government announced its intention to introduce a Climate Change Levy and, within that, is considering the treatment of electricity from CHP and renewables generation.

11.3 Background

11.3.1 Breakdown of CHP

A recent study completed by ETSU⁹⁷ for Ofgem, provided a range of information on CHP schemes in England and Wales in 1997, and importantly highlighted the diversity of CHP schemes. For England and Wales, ETSU record 1132 CHP schemes, with approximately 3,300 MWe and 13,000 MWth capacity.

Table 11.1 - Breakdown of CHP schemes in England and Wales, 1997

	Number of Sites	Generating Capacity (MWe)	Heat Capacity (MWth)
Exporting	232	1,795	5,436
Non exporting	900	1,534	7,661
Total	1,132	3,329	13,097

Source: ETSU.

The Table 11.1 provides a breakdown of these sites based on whether or not they exported electricity in 1997. Of the approximately 15.2 TWh of electricity generated by these schemes in 1997 around 7 TWh was exported to a combination of the Pool, suppliers and other customers (see Table 11.2).

⁹⁷ Energy Technology Support Unit.

Table 11.2 – Electricity exports from CHP schemes above 250 kWe in England and Wales

	Number of sites	Total Exports (GWh)
Pooled, Centrally dispatched	3	4,530
Pooled, Non-centrally dispatched	3	431
Non-pooled	95	2,003
	101	6,964

Source: ETSU.

Of schemes over 250kWe,⁹⁸ an estimated 65% of total electrical exports were from three large centrally despatched plants; the remaining exports were from three Pooled non-centrally despatched plants (6% of total CHP exports) and 95 non-Pooled plants (29% of total CHP exports).

For most industrial CHP sites the production (or manufacturing) process, is considered the principal determinant of available CHP electrical exports or required imports. For all sectors of the economy in which CHP plant operate, production scheduling of the sites' processes, including electricity generation, is most likely to take place at least 24 hours or longer in advance. In common with most generating facilities, generating plant outage or failure is likely to represent a major cause of unpredictable and volatile output. Such failure is determined largely by the age, condition and characteristics of the CHP plant rather than by the sector. With regard to the predictability of CHP plant, the Review of Energy Sources for Power Generation consultation document suggested...

“Neither is the Government convinced that an expansion of CHP would be detrimental to the electricity system. Although the operation of industrial CHP plant can be inflexible because it tends to be driven by the requirements of the host site, most of the electricity is also typically used in the host site, and the net effect may be as likely to improve predictability of the supply/demand balance, as it would to make it more uncertain.”

⁹⁸ Exporting schemes less than 250 kWe account for less than 1% of exporting total capacity.

11.3.2 Breakdown of Renewables

At the end of 1997, only wind, hydro and biomass renewables technologies were operating commercially in any significant volume in the United Kingdom. Table 11.3, gives details of these schemes.

Table 11.3 - Breakdown of Renewables Schemes in the United Kingdom

		Capacity	1997
		(MWe)	Output (GWh)
Wind	Onshore	135.4	665
Hydro	Small scale	55.8	159
	Large scale	1,438.0	3,969
Biofuels	Landfill gas	168.4	880
	Sewage sludge	92.7	400
	Municipal solid waste combustion	115.0	934
	Other	45.6	335
<i>Total (excluding large scale hydro)</i>		612.9	3,372
Total		2,050.9	7,341

Source: Digest of UK Energy Statistics 1998.

Notes:

Data is for all UK.

Excludes pump storage stations.

Biofuels other includes farm waste digestion, waste tyre combustion and poultry litter combustion.

The degree to which renewables generators can predict their load accurately is likely to vary vastly across different technologies and schemes, with the primary determinants including controllability of fuel inputs and forced outages.

Hydro – the fuel for a hydro station arrives in the form of hydrological inflows. The degree to which the generation of such schemes is predictable will depend on the predictability of the inflows and the availability of a reservoir to capture and store the water for controllable releases at a future time. Hydro plant is generally highly reliable and suffers from few forced outages.

Biomass – biomass schemes are akin to thermal generation facilities in that they should have control over the input of fuel and therefore should be in a strong position to forecast load. Where biomass generation is attached to a CHP process the electricity load is likely to be dependent on the down-stream process to which it contributes. However, as with other combustion technologies the reliability is likely to be less than that of hydro (or wind), due to a higher frequency of outages, particularly at older sites.

Wind – wind plant is likely to have the most volatile load of all renewables technologies as their output depends entirely the wind's speed and direction. The predictability of their output is governed by the accuracy of local wind forecasts and hence wind plant are likely to be amongst the most unpredictable renewables technologies. As with hydro, wind technology is generally highly reliable.

Non Fossil Fuel Obligation (NFFO)

The Electricity Act 1989 allows the Secretary of State to make Orders requiring PESs in England and Wales to secure specified amounts of electricity from renewable energy sources. PESs through their agent, the Non-Fossil Purchasing Agent (NFPA) contract collectively in order to meet the obligations set out in the Orders. The difference between prices paid to the NFFO generators and the Pool Selling Price is charged to customers via the Fossil Fuel Levy, thus leaving the PES revenue-neutral with respect to these contracts. To date there have been five renewables Orders in England and Wales, three in Scotland and two in Northern Ireland. Table 11.4 gives details of the England and Wales Orders. Not all of the projects awarded contracts under previous Orders have gone ahead. Reasons for this include failure to obtain planning and other consents, difficulty in obtaining the appropriate fuel and problems in the application of a new technology.

Table 11.4 - England and Wales Renewables Orders, Contracted Projects and Bid Prices

	Date ordered	Contracted Projects		Bid prices (p/kWh)		
		<i>Number</i>	<i>MW</i>	<i>Min</i>	<i>Max</i>	<i>Average</i>
NFFO 1	1990	75	152.1	4.69	13.02	8.46
NFFO 2	1991	122	472.2	4.16	13.45	8.08
NFFO 3	1994	141	626.9	3.71	9.88	4.92
NFFO 4	1997	195	842.7	2.83	6.17	3.68
NFFO 5	1998	261	1177.1	2.34	4.60	2.71
Total		794	3271.0			

Source: Fifth Renewables Order for England and Wales, September 1998. OFFER.

Note:

Bid price data is expressed in April 1998 prices.

The bid prices of proposals have reduced markedly over the five NFFO Orders (see Table 11.4). This is in part due to improved efficiency and cost reductions in renewables technology and in part due to extensions in the length of NFFO contracts which has lengthened the period over which new schemes can expect to recoup their capital outlays.

Table 11.5 – United Kingdom Renewables Orders, Contracted Projects by Type

	Wind	Small Scale Hydro	Biofuels	Total
Installed Capacity (MW)	135.4	55.8	421.7	612.9
Capacity covered by all NFFO / SRO contracts (MW)	132.3	32.0	342.3	506.6
% covered by all NFFO / SRO contracts	98%	57%	81%	83%

Source: Digest of UK Energy Statistics 1998.

Table 11.5 gives details of the installed capacity covered by Renewables Orders (excluding large-scale hydro) as at December 1997. However, NFFO 1 and NFFO 2 contracts ended in December 1998, which accounted for 321.6 MWe or 52% of total

capacity. Many of these projects have joined the Renewable Generators' Consortium, which negotiates terms, on behalf of its members, for the sale of power to suppliers.

11.4 CHP and Renewables Under the New Trading Arrangements

Lowering of Wholesale Prices

One of the objectives of RETA is to improve efficiency by encouraging responses to price signals to thereby improved production and consumption decisions. This increase in efficiency, together with more effective competition in generation and supply is expected to lead to lower wholesale prices, thereby better safeguarding consumers' interests. Lower prices will inevitably adversely affect the economic viability of higher cost existing generators and proposed new projects across the whole industry including CHP and renewables schemes

For CHP schemes, lower overall prices are likely to have different consequences for schemes operating as a net importer of power and those with net exports. Existing sites that are net Importers (80% of existing sites), as with all consumers, benefit directly from lower prices and greater demand-side innovation. For such sites, RETA is likely to bring substantial benefits. Conversely, existing exporting sites, like other generators, may receive a lower price for exported power following the implementation of RETA, depending on the nature of any electricity sales contracts that they might have entered into.

A study by ETSU (Assessment of CHP Potential⁹⁹) suggests that the price of imported power was a significant factor in determining the future economic potential for CHP across a number of economic sectors. The price received for exported power was shown to be less important, although in certain sectors it remained significant.

Electricity prices are only one factor of determining the economic viability of a proposed CHP scheme. Consequently, shifts in electricity prices considered in isolation may be of less significance than other aspects of the energy market, particularly differentials between electricity and primary fuel costs.

Renewables generation covered by existing and any possible future contracts under NFFO (or replacement schemes resulting from the Government's current consultation)

⁹⁹ Assessment of CHP Potential RYCA 1850113, ETSU, July 1997.

will not be affected by lower wholesale prices, given the fixed price specified in the contracts. Lower wholesale prices may reduce the revenues of existing non-NFFO renewables schemes of which the vast majority are schemes whose NFFO contracts have now expired (53% of capacity at December 1997). Such schemes will already have recovered most of the costs of building their assets and such schemes will only need to be competitive on the basis of their avoidable costs. The efficiencies and costs¹⁰⁰ of renewables technologies continue to improve. Some technologies are reaching the point where they could be competitive with conventional generation.

In addition to a general lowering of wholesale prices, there are two principal concerns that operators of CHP and renewables schemes have identified that may increase the risks facing such plant under the new trading arrangements:

- ◆ the risks and subsequent costs associated with buying or selling power through the imbalance cash-out mechanism (i.e. exposure to imbalance charges); and
- ◆ the removal of Pool Purchase Price (and Pool Selling Price) as established 'marker' prices on which small operators base contracts. The reference price used to calculate the net payment due to PESs as a result of NFFO contracts will also disappear and a replacement will be needed (i.e. removal of price markers).

Each of these is considered in turn.

Exposure to Imbalance Charges

Most CHP and renewables will be able to choose whether or not to sign the BSC, and therefore whether or not to accept direct potential exposure to imbalance charges. Only licensed generators will be required to sign the BSC and the majority of CHP and renewables schemes are licence exempt (under the current conditions of exemption). Only 480 MWe¹⁰¹ of CHP capacity in the UK was licensed at the end of 1997, less than 15% of the total installed capacity. If a CHP or renewables scheme chooses not to sign the BSC, it can contract with a supplier within the same GSP group, forgo the right to be paid the cash-out price for any electricity it spills, or allow a BSC signatory to take

¹⁰⁰ Evidence of these can be seen in declining bid prices in sequential NFFO orders. More recently, bid prices for large wind projects in the Third Scottish Renewables Order (December 1998) were as low as 1.89 p/kWh, well below current England and Wales pool prices.

¹⁰¹ Of this, 236 MWe was accounted for by one plant.

responsibility for its imbalances. If a CHP or renewables scheme is required to sign the BSC, or chooses to do so, it will have the ability to pass responsibility for its meter to another signatory (such as an aggregator) thus passing on or sharing any imbalance liability. By assigning all its metered volumes to a third party, a BSC signatory need take no further action to avoid exposure to imbalance charges – it will not, for example, need to notify Settlement of any contract volumes. This transfer of liability could be incorporated into contracts made by CHP operators for back-up supplies and export sales, or may be negotiated independently of these arrangements.

All CHP and renewable generators will therefore have the ability to trade in a manner which would avoid direct exposure to imbalance charges. However, third parties offering contractual terms to CHP and renewables schemes will clearly take account of the potential exposure to imbalance cash-out prices that they would be taking on. The risks associated with exposure to imbalance prices may be greater for a single site operator than for operators with a portfolio of plant. In particular, it could be more difficult for a single site operator to absorb imbalance charges since such charges might be significant in proportion to the size of operation. Smaller single site generators are also less likely to have backup technology available to continue generating during periods of plant breakdown. Conversely, a portfolio operator of CHP and renewables might more easily absorb the exposure caused by a plant failure, since it may be able to meet any contractual commitments through generation from other plant within its portfolio. Because of the benefits arising from operating a portfolio of plant, aggregators, who take responsibility for a number of single site operations, are likely to have an important role to play in mitigating the risks of single site operators. Competition amongst aggregators should ensure that the terms offered to CHP and renewables schemes involve the sharing of aggregators portfolio benefits with single site operators.

CHP and renewables schemes with unpredictable output will be most at risk from exposure to imbalance prices. Schemes able to forecast their load with a degree of certainty before contract notification (including most CHP and many of the renewables schemes) will have mechanisms available to them (or to third parties acting on their behalf) via the bilateral markets to close out their position in advance, thereby minimising any risks and costs associated with exposure to the imbalance cash-out process. In the long-term, reducing the period for which the Balancing Mechanism

operates will reduce generation uncertainty at Gate Closure and increase the time available to close out positions closer to real time, further reducing risks and costs. As discussed above, for most CHP schemes the electricity load requirements are primarily driven by the processes they support, which are generally decided at the day-ahead stage. Thus, the most likely source of unpredictability within Balancing Mechanism timescales is likely to be plant failure,¹⁰² which is a risk, faced by all market participants, and not just CHP schemes.

Operators of CHP and renewables schemes will have a number of options available for selling and/or buying electricity. They can choose to manage their trading function internally or pass the function to a third party. The option that each scheme adopts is likely to be determined by its potential exposure to imbalance charges and the credit requirements for trading actively. As an example, consider a scheme whose annual value of electricity production is around £2m.¹⁰³ If value could be increased by 10%–20% by adopting an active trading strategy rather than taking a passive approach (i.e. not seeking actively to manage and reduce risks) the sums of money involved (£0.2m–£0.4m) are likely to be sufficiently high to command the attention of management. For such a scheme, it could be valuable to establish an internal trading unit to manage imbalances provided, of course, that the costs of doing so were less than the expected benefits. For a scheme a tenth this size, it probably would not be worthwhile managing the trading function internally. However, the scheme could derive significant benefits from using the services of a third party, possibly an aggregator managing many such schemes. Below the positions of different categories of CHP and renewables schemes is considered in more detail.

NFFO Renewables Generators

As Table 11.5 shows at the end of 1997, 83% of renewables capacity (excluding large-scale hydro) in the United Kingdom was covered by Renewables Orders¹⁰⁴ under which the generator is guaranteed a fixed price for the output of the plant irrespective of season or time-of-day. However, due to the expiry of NFFO 1 and NFFO 2 contracts only around 30% of this capacity is now covered by such contracts. Existing NFFO

¹⁰² Plant failure could include generator failure, loss of heat load or the loss of the process demand.

¹⁰³ Approximately, equivalently to a 20 MW plant running at 60% load factor and a wholesale electricity price of £20/MWh.

¹⁰⁴ This includes Renewables Orders in England and Wales, Scotland and Northern Ireland.

contracts will be continue under the new trading arrangements. In England and Wales, such schemes will have no need to perform a trading function as the PES with whom the scheme has a contract will effectively absorb and manage the risks associated with the variability of the scheme's output.

CHP Electricity Importers

CHP sites that are net importers can effectively be considered conventional electricity consumers and as such, do not raise particular problems under the new trading arrangements. Like all consumers, importing CHP schemes will have a wide range of contracting options available to them. Moreover, they can expect to benefit from the lower prices and demand-side innovation that is expected to develop under the new trading arrangements. For smaller sites, there should be a wide range of suppliers prepared to offer them electricity. Larger sites may prefer to contract more actively in the bilateral markets to secure energy, as it becomes clear what their demand is likely to be as real time approaches. To do this they would have to sign the BSC and consequently be exposed to imbalance charges.

It is likely that the prices paid by an importing CHP scheme whose level of electricity imports is highly unpredictable will be higher than for a scheme whose level of power imports is stable and predictable. This is due to the fact that they are likely to be imposing additional costs on their supplier associated with managing the risk of their unpredictable or volatile output. However in this respect, the position of the importing CHP scheme is no different to that of a customer whose load is highly unpredictable.

CHP Electricity Exporters and Non-NFFO Renewables

Although sites operating net exporting CHP schemes or non-NFFO renewables schemes may be worse off as a consequence of lower prices, they will have a wider range of options available to them, which may mitigate this effect. Larger schemes or schemes operated as part of a portfolio are likely to choose to manage the business of selling surplus power actively through a combination of trades in the bilateral markets, as well as some trades in the Balancing Mechanism. Currently an estimated 65% of all electricity exports from CHP are sold through the Pool by three large centrally dispatched plants while an additional 21% of electricity exports are exported by non-

centrally dispatched schemes that are owned as part of a portfolio.¹⁰⁵ Such plant can be regarded as traditional generators and thus might be expected to adopt this active strategy. However, participation in the Balancing Mechanism is likely to require a degree of flexibility, which may preclude the participation of many CHP and renewables schemes, or involve participation only at high offer prices (or low bid prices).

Managing short-term trading internally will require a good understanding of the risks to which the business might be exposed and a willingness to manage such risks actively if the maximum benefits from direct market participation are to be extracted. For some of the very largest schemes, such trading activity may well be considered a core business activity and something that could be incorporated within the plant's existing energy management activities.

For small portfolio or single site projects of a few MW or less, it may be that this approach would not be viable, as the costs of implementing such a strategy may exceed the possible benefits. For such schemes there appear to be two options:

- ◆ first, simply 'spill' electricity into the market, accepting the imbalance cash-out price for the surplus electricity. Presently, spill by many small-embedded generators attracts no payment unless they have a contract with their local supplier. Instead, any spill simply reduces the deemed take by all suppliers within the Grid Supply Point group in which the generator lies. To avoid this continuing under the new trading arrangements, the scheme would have to sign the BSC with its attendant costs and obligations. As experience with the new arrangements grows, schemes adopting such a strategy may use information they gain on the general pattern of cash-out prices at various times and to make modest adjustments to their plant output in order to attempt to benefit from higher than average prices.
- ◆ A second, and perhaps, preferable option might be to sell surplus output under contract to a third party. This would probably be either a supplier within the same GSP group or a BSC signatory that was able to extract benefits associated with trading, either on account of its market position, or its superior trading skills (or both). An exporting scheme with volatile and unpredictable output might expect to

¹⁰⁵ Portfolio operation includes schemes operated by a PES or second-tier supplier.

get a lower price on average than a scheme with predictable output. However, selling directly to a supplier would reduce that supplier's deemed take at the GSP group level and the uncertainty of the scheme load may be negligible compared with the supplier's overall demand uncertainty. Such a supplier might choose to contract with several licence exempt generators below a grid supply point group in the knowledge that it is the net imbalance of all the generators that is relevant for imbalance purposes, not their individual performance. Suppliers might also choose to contract with generators which have a flexible output. Such contracts would offer suppliers the opportunity of managing their imbalance during the period after Gate Closure by requiring physical changes in the output of the embedded generating sets under contract. A third party (possibly an aggregator) might offer its services to a wide range of schemes, effectively benefiting from the portfolio effect described above. The benefits for the scheme of contracting with such an aggregator, compared to spilling at the cash-out price, would be the reduced risk associated with potentially volatile cash-out prices and the avoidance of administration and other costs associated with direct BSC participation.

Removal of Price Markers

With respect to renewables schemes, the removal of presently used price markers appears to raise three issues, whilst only two of these apply to CHP.

- ◆ The first issue relates to the effect that the removal of the Pool price will have in calculating the Fossil Fuel Levy payments made to PESs that have entered into NFFO contracts with renewables generators. This technical problem must be addressed to ensure that the NFFO generators continue to receive their contracted payments and that PESs are compensated to the extent that such payments are above market prices. There appear to be a number of possible ways of ensuring that the commercial details of the NFFO contracts can be carried forward. In the short-term, some administered price index designed solely for the NFFO schemes could be used. Over time, however, it would be preferable if the PES compensation payments were based on a reference price emerging from an electricity commodity market, such as a power exchange.

- ◆ The second issue concerns the potential removal of a price established at the day-ahead stage that non-NFFO renewables generation and CHP can use to price any exports of power. Under the new arrangements, exports will either be priced at the imbalance cash-out price or at prices established in the bilateral markets. The former will not be available *ex-ante*¹⁰⁶ but bilateral market prices should be available *ex-ante*. It is therefore likely that there will still be price markers that schemes can use to inform their production decisions, not just at the day-ahead stage but also on-the-day and over longer timescales. There is no reason to believe that these prices will be the same as Pool prices are presently, but a key objective of the new trading arrangements is to ensure that market prices better reflect market conditions, including supply and demand conditions, than do present Pool prices.
- ◆ The third issue is a more general point concerning price transparency. The current arrangements are seen by some to offer a 'visible reference price' to which all market participants have equal access. Some have expressed a concern that under the new trading arrangements, smaller generators would be at a disadvantage in negotiating contracts since they might not have access to up-to-date information about movements and trends in the market. It has also been suggested that a lack of price transparency might also have a detrimental impact on new entry. However, the emergence of price reporters and the development of power exchanges should ensure that market prices are available to schemes seeking to value power. Information on the Balancing Mechanism and imbalance cash-out prices will be widely available to all participants. It is presently envisaged that, where practicable, information will be disseminated via the Internet in addition to dedicated communication channels. The issue of price transparency under the new trading arrangements is discussed further in Chapter 14.

11.5 Summary

Electricity prices that better reflect supply/demand conditions on the day will benefit industry, consumers and the economy as a whole. It is in this context that the impact on CHP and renewables generators of the new trading arrangements must be considered.

¹⁰⁶ Although, as experience grows, the predictability of such prices will increase.

The Government has made it clear that encouraging the development of CHP and renewables schemes is part of its overall energy policy and it is therefore necessary to consider the impact of the new trading arrangements on such plant in the future. The fall in wholesale prices that is expected, in part due to the new trading arrangements, will have differing implications for CHP and renewables schemes. Sites operating CHP schemes that continue to import significant volumes of power will benefit directly from lower prices and greater demand-side innovation. Some renewables schemes are covered by NFFO contracts, which ensure that the operators of such schemes will not be adversely affected by the new trading arrangements given the fixed price they receive for their output. Exporting CHP sites and non-NFFO renewables schemes, as with all generation, are likely to be adversely affected by lower prices but they will have a wider range of options available to them, which may mitigate this effect.

Only those CHP and renewables schemes that are sufficiently large to require a licence will be obliged to sign the BSC. The vast majority of CHP and renewables schemes fall below the licensing threshold. Such schemes can choose to participate directly in the central settlement system or trade through a third party. All schemes will be able to make use of the risk management services offered by aggregators and other traders.

The new trading arrangements will ensure that all forms of generation are treated equitably and this will have different effects on different market participants, including individual CHP and renewables schemes. Plants with a predictable output should be able to offer the benefits of embedded generation to other market participants without adding significantly to imbalance risk. Flexible plants will have even wider opportunities. Plants with an unpredictable output that are outside of NFFO will be able to enter into arrangements which will help to manage the risks associated with this form of generation.

12. A 'Day in the Life'

The new arrangements are designed to transform the wholesale trading of electricity in England & Wales. They will introduce new options for both trading and the management of positions. This Chapter describes ways in which market participants might use the proposed trading arrangements. Appendix 10 looks in detail at the issues facing various types of market participant.

12.1 *The System Operator*

In relation to the day to day operation of the system, the SO will be responsible for:

- ◆ collecting and subsequently making available information about intended physical flows into and out of the network;
- ◆ performing demand forecasting and system modelling studies to ascertain whether balancing actions are required to ensure safe and secure operation of the system, and making available the results of such studies;
- ◆ despatching such balancing actions either through the acceptance of offers and bids or through calling appropriate ancillary services contracts; and
- ◆ submitting data to settlement.

NGC's present thinking on information flows to and from the SO is summarised in a recent paper to the DISG (reproduced in Appendix 5).

Participants¹⁰⁷ that are responsible for energy flows into and/or out of the system will make the following information available to the SO:

- ◆ by 11:00, an initial schedule for the next day (the Initial Physical Notification, IPN). If unchanged, the IPN will become the FPN;

¹⁰⁷ Except those below the agreed *de minimis* levels.

- ◆ at any time between 11:00 day ahead and Gate Closure, revisions to that schedule and any Balancing Mechanism offers and bids that the participant wishes to submit;¹⁰⁸
- ◆ at any time between Gate Closure and the end of the Trading Period, any information relevant to system operation (such as notification of inability to conform to FPN or to deliver a Balancing Mechanism offer or bid).

The SO will broadcast relevant information to the market, to inform trading in the short-term bilateral markets and to facilitate participation in the Balancing Mechanism.

Further consideration needs to be given to the range of information to be provided by the SO and the timescale over which it would be applied. For example, the information provided could include:

- ◆ at 09:00, preliminary information for the day-ahead such as national and zonal demand forecasts;
- ◆ following submission of IPNs, indications of the likely level of energy and transport balancing actions required, updated at regular intervals to reflect revised IPN data;
- ◆ real-time information on the Balancing Mechanism such as the offers and bids made available and balancing actions accepted;
- ◆ ex-post reports of balancing activity.

The SO will notify participants of any balancing action that has been accepted, and issue revised schedules and/or profiled despatch instructions, as well as any instructions related to reactive power or other ancillary services.

Finally, the SO will send to the central settlement system:

¹⁰⁸ The data held by the SO at 'Gate Closure' will be the participant's FPN and any Balancing Mechanism offers and bids submitted.

- ◆ a list of balancing actions that have been dispatched (to allow them to be settled);
- ◆ a list of the accepted Balancing Mechanism bids and offers (to allow imbalance prices to be calculated).

12.2 Markets and Services

Participants are likely to trade energy over a wide range of different time-scales. In this chapter, the following terminology is used:

<i>Longer-Term</i>	more than a year ahead
<i>Medium-Term</i>	from a year ahead up to approximately one day ahead
<i>Short-Term</i>	essentially from day ahead up to Gate Closure ¹⁰⁹
<i>Real Time</i>	from Gate Closure to the end of the trading period

12.2.1 Longer-Term Markets

Longer-term markets are likely to display the following features:

- ◆ bilateral over-the-counter ('OTC') trading;
- ◆ annual 'strips' of baseload or recognised daily shape load curves; also more complex tailored contracts, and 'one off' long term specific contracts to underpin project financing for independent power producers (IPPs);
- ◆ the potential role for organised exchanges to trade standardised products;
- ◆ no trading for individual half hours; and
- ◆ large volumes of electricity traded.

Long-term contracts can expose parties to price risks due to the potential for divergence between the contract price and prices on other shorter term markets. Parties may also

¹⁰⁹ Any power exchanges which operate over this timescale are likely simply to represent the short term part of a rather broader forwards market. In addition, it may be that the short term market may be better defined in terms of products rather than time, and that in consequence the market may cover, say, seven days rather than one. Such decisions are for the market to decide; the use of a day rather than several days to distinguish this market is not important in this context.

be exposed to volume risks in that changes to their anticipated output or demand will require fine-tuning in the short-term markets to avoid exposure to imbalance charges. On the other hand, long-term contracts are likely to be useful for certain parties, such as independent power producers seeking debt finance, and both generators and suppliers seeking price certainty, for at least part of their anticipated generation and demand, and some electricity traders.

It is envisaged that market participants will continue to develop innovative means of allocating risks between contract counterparties. Recent years have witnessed, for example, the evolution of longer-term contracts indexed to prices in the short-term power and fuel markets and of tolling-type contracts for managing the market risks faced by power stations. The new trading arrangements will facilitate a wide variety of contract forms. Many participants may wish to sign contracts that can be taken to physical delivery. New forms of financial instruments are also likely to emerge – these would be settled for cash against an agreed short term reference price (just as contracts for differences are settled against Pool prices in the present arrangements). It is anticipated that organised exchanges will be set up to facilitate trading of the more common products (one year baseload strips for example).

12.2.2 Medium-Term Markets

Medium-term markets are likely to display the following features:

- ◆ both OTC trading and screen-based exchanges;
- ◆ quarterly, monthly or weekly strips, baseload and recognised load curves;
- ◆ relative standardisation of products;
- ◆ limited trading for individual half hours; and
- ◆ significant volumes.

Many participants will require substantial adjustments to their contractual positions within a year. This could include suppliers winning or losing customers, and generators subject to a prolonged plant outage. Some participants may prefer to enter into transactions closer to the time of physical delivery rather than secure their anticipated

output or demand a year or more in advance. Liquid trading in medium-term products is likely to attract financial traders, further improving liquidity and transparency.

12.2.3 Short-Term Markets

Short-term markets (day-ahead or within day) are likely to display the following features:

- ◆ OTC, screen-based exchanges and possible day-ahead auctions;
- ◆ trading in standard products (half-hour or simple combinations of half-hours); and
- ◆ limited volumes; many participants, most offering relatively small volumes.

Short-term trading is expected to develop under the RETA proposals, whilst it is now impeded by the Pool arrangements. The size of many of the individual transactions is likely to remain small, since participants may choose only to fine-tune their positions in these markets. However, the short-term markets may be very active if participants continually seek to avoid exposure to imbalance cash-out prices by adjusting their contract positions in the light of recent information on the weather, plant condition, etc.

12.2.4 Balancing Mechanism

The Balancing Mechanism is also a way of buying and selling electricity, with the following features:

- ◆ it is primarily for maintaining system security, very short time-scales;
- ◆ it will cater for bids and offers called by the System Operator and settled centrally;
- ◆ complex products reflecting the ability of generating units and consumers to respond within short timescales;
- ◆ limited volume of basic commodity (MWh) exchanged, intra half-hour trading in the form of profiled instructions; and
- ◆ the ability to respond to BM lead times will be an important influence on the ability to submit and offers bids into it.

Assuming that the potential exposure to cash-out prices encourages participants to seek contract cover for the majority of their requirements before Gate Closure, average

volumes traded in the Balancing Mechanism could be relatively modest. Indeed, if participants were fully covered at Gate Closure, the Balancing Mechanism's role would be limited to the resolution of transmission constraints, the provision of operating reserve and load following within the half-hour and the resolution of the inevitable imbalances that will arise because most participants will not be able to match their actual physical positions precisely to their FPNs.

Only participants that have flexible generation or load, or those at particular locations which can help in the alleviation of persistent transmission constraints, are likely to view participation in the Balancing Mechanism as a core element of their overall trading strategy. For others, such as baseload plant seeking contract cover for the majority of their output, the difficulty of predicting whether their offers or bids will be accepted will preclude them placing undue reliance on the Balancing Mechanism as a trading vehicle. For such participants, the Balancing Mechanism will essentially be the method by which they are compensated for any deviation from their FPNs requested by the SO. Even relatively inflexible baseload plant, for example, will have a price at which they would be prepared to turn down or shut off.

In addition to these forms of trading, the SO, being incentivised to reduce balancing costs, will seek to match any mutually beneficial offers and bids, even if these were not required to balance the system.¹¹⁰

12.2.5 Imbalance Settlement

The imbalance settlement mechanism will ensure that physical positions and contractual positions are reconciled, and that no participant is, for instance, taking electricity without paying for it. It will also provide incentives to participants to contract bilaterally, as noted above. Its main features are:

- ◆ post-event;
- ◆ the cashout of all imbalances is effected centrally as set out in the BSC;

¹¹⁰ For example, if a market participant made an offer into the Balancing Mechanism at £10/MWh for a particular half-hour and another participant made a bid at £12/MWh for the same half-hour, and for the same volume, the SO could accept both the bid and offer even if no balancing action was required. This would lead to a reduction of costs of £2/MWh.

- ◆ basic commodity (half-hourly MWh);
- ◆ limited volumes; and
- ◆ mandatory for most system participants.

The imbalance Settlement mechanism will be an unattractive trading option of last resort, for electricity generated or taken without a contract counterparty.¹¹¹ Participants are likely to minimise their exposure to imbalance cash-out by entering into appropriate forms of contracts ahead of time. These could include a variety of sophisticated risk management instruments, such as options, or contracts linked to temperature or customer numbers. Participants holding contracts whose volume cannot be represented by a simple MWh value ex-ante (and as 'full requirements' contracts in which the contract volumes is set equal to the quantity measured at a particular meter) will need to settle some of their imbalances outside the central Settlement system via arrangements specified within individual contracts.

The parameters that will determine both the volumes of power in imbalance settlement and the number of participants that will be exposed to such settlement include: the willingness of parties deliberately to enter into imbalance exposure; the incentives on parties to deviate from their contract positions in particular circumstances (for example the expectation of a high system sell price might encourage participants to take long positions); the ability to exercise control in real time; and the ability to forecast precisely in advance a physical position. The difficulties in relation to the last point is likely to mean that in most trading periods most participants are likely to be out of balance, but probably only by small amounts.

12.3 Using the New Arrangements

Given the risks and opportunities of short-term trading and the balancing and imbalance settlement arrangements, it appears likely that most participants will wish to use the long- and medium-term markets to seek to cover most of their anticipated requirements.

¹¹¹ Counterparty in this context including the SO in relation to accepted offers and bids in the Balancing Mechanism.

Where possible, participants are likely to take advantage of opportunities to aggregate in order to mitigate their exposure to electricity imbalance prices.

Many participants will act both as buyers and sellers in particular circumstances. For instance, a supplier with long and medium term contract cover who finds himself in a situation of having bought too much electricity will be able to sell the excess on a short-term basis.

The remainder of this chapter examines in broad terms the issues faced by different market participants and the trading options available to them. As stated earlier, Appendix 10 provides a more detailed assessment for various categories of market participants. Incumbents and potential new entrants will undoubtedly wish to become more familiar with the new arrangements prior to implementation, so as to be confident of their ability to trade effectively and to begin positioning themselves to benefit from any new opportunities open to them. Simulation exercises can be a valuable tool in this familiarisation process – Appendix 11 describes work underway in this area. The underlying model used in the simulation exercises will be released to market participants so that they can use it as part of their own trialling and preparation for the new markets.

12.3.1 The Generation Side

Many generators will generally be sellers of electricity in bilateral markets. However, they face a number of risks that may require them to buy back electricity in some circumstances. These risks include:

- ◆ plant failure;
- ◆ fuel cost increases and/or interruption;
- ◆ coping with the effects of planned outages; and
- ◆ changes in availability due to temperature.

In addition, generators may choose to buy back power from the market if the price is advantageous, in comparison, for example, to their own production costs. In such cases, a generator's profitability would be improved if it met its contractual obligations with power sourced from the market rather than produced by its own power station.

It might be possible for generators to cover some of their risks in advance, for instance through provisions in power purchase agreements, or option contracts exercised in case of plant failure. However, there is a cost to such cover, and some generators may choose to react in shorter time-scales, for example, by trading on a Power Exchange or actively participating in the Balancing Mechanism. Depending on their expectation of the imbalance prices, other generators may at times prefer the option of accepting cash-out exposure.

A baseload generator might be expected to trade in the long- and medium-term markets in order to match its contractual commitments to its production and maintenance plans, and from time to time to use shorter-term markets to cover for unexpected outages.

A portfolio generator with flexible plant may choose to play an active role over the range of markets, including the short-term markets and Balancing Mechanism. It may also decide to hold back some of its potential output in order to cover unexpected changes in availability elsewhere in its portfolio or to place offers in the Balancing Mechanism. With the exception of Balancing Mechanism trades, the portfolio generator's contracts are unlikely to be linked to the output of any particular power station, allowing commercial flexibility to optimise the production schedule on a day to day basis.

A generator that does not have control over its fuel supply, such as a wind turbine or a gas-fired plant with an interruptible supply, may use short-term markets to adjust its position within a few hours of delivery. Such a generator may wish to cover its residual imbalance risks with option contracts or by entering into a whole-output contract with a larger participant or aggregator able to trade more actively and benefit from the offsetting of uncorrelated risks within its portfolio.

A single site, fully contracted Independent Power Producer (IPP), may continue operating very much as now, with the majority of risks essentially managed by the purchasers of energy. Smaller generating sites (e.g. renewable and other embedded generators) may find it to their advantage to contract for the whole of their output with one or more counterparties, and therefore to remain outside the scope of the BSC altogether. As noted above, only licensed generators will be obliged to sign the BSC, exempt sites can choose whether or not to participate directly in the central Settlement

process. The price received by such generators is likely to reflect the certainty and controllability of their output.

A supplier holding an offtake contract with a flexible exempt generator will be able to manage its imbalance position after Gate Closure by calling upon the generator to adjust output, thereby changing the supplier's net metered take at GSP Group level.

Alternatively, the generator's flexibility could be offered to the Balancing Mechanism, possibly with some form of profit-sharing arrangement between the generator and its contractual counterparty. Embedded generators could also benefit from the services of aggregators, since the risks to a group of participants should be less than the sum of the risks to each individually. The trading options available to CHP and renewables generators were discussed in some detail in Chapter 11.

12.3.2 The Demand Side

Suppliers face volume risk, to the extent that their contracts do not give them control of the operations of their customers. In order to manage their potential exposure to imbalance cash-out, it is expected that suppliers will seek to better understand their customers' requirements, and offer increasingly innovative load management services. As described in the following chapter, nearly 50% of demand is now half-hourly metered. The greatest increase in active demand-side participation is initially likely to come from this sector, with suppliers seeking to focus interruptible and other similar offerings to this group. Aggregators are likely to play a significant role in harnessing the potential contribution of the demand-side, initially by developing the potential among the smaller half-hourly metered customers.

Suppliers with substantial volume risk may choose to contract for their minimum requirements in the long- and medium-term, and perhaps to adjust their position in the short-term in view of updated weather and demand forecasts. Differences between forecast and actual metered amounts (or deemed quantities in the case of non half-hourly metered demands) would have to be covered by options or cashed out in imbalance settlement. Smaller suppliers may decide to enter into requirements contract with larger traders better able to manage their risks.

Suppliers with greater control over their customers consumption, such as industrial customers (perhaps supplying themselves), or users of teleswitching facilities, may trade

more in the short-term market to take advantage of their customers' ability to respond to price signals. Some may also participate in the Balancing Mechanism.

12.3.3 Other Participants

Traders¹¹² are expected to play an increasing role in actively managing risks on behalf of other market participants. The entry of traders will improve market liquidity and provide established participants with a wider choice of contract counterparties and risk management options. Pure traders will not physically generate or consume power, that is, they will not be responsible for metered flows in the settlement process. However, such traders will be exposed to electricity imbalance prices for any mismatch in their contractual sales and purchases. As a result, they are likely to seek to close out the majority of their positions before Gate Closure. Traders may be particularly active in the medium- and short-term markets. Some may also seek to operate as market makers in organised exchanges.

Exporting interconnector users and trading sites will most likely behave as generators, but some may need to be more active in the short-term markets to cover the greater uncertainty of their net output (due for instance to changes to interconnector capacity or to on-site demand).

Trading sites with flexible demand and/or generation will be able to take advantage of this by submitting offers and bids in the Balancing Mechanism or profiting from any opportunities that may arise in the short-term markets.

In addition, as referred to in the previous sections, aggregators are likely to emerge. Aggregators are participants who seek to build portfolios of generation and or demand, taking advantage of the lower risks that arise from aggregation. Aggregators are likely to offer their services to several classes of participants, including:

- ◆ smaller generators who are unwilling to manage their risk exposure themselves and/or are unwilling to invest in the resources, such as trading and risk management capabilities, necessary to participate fully in the new arrangements; and

¹¹² In this context, trading is taken to mean buying and selling power other than for own requirements.

- ◆ customer groups who display demand characteristics that in aggregate allow better risk management, for example because load is more predictable, or because different groups might offset each other's demand variations.

Unlike pure financial traders, aggregators may offer to take responsibility for metered quantities on behalf of, say, half-hourly metered customers or embedded generators. As with other participants, they will be cashed out on the difference between their notified contract position and aggregated meter quantities, with production and consumption separately treated.

12.4 Summary

Most categories of participant will be affected in some way by the change in trading arrangements. An aim of RETA is to sharpen incentives and increase efficiency by transferring risks, which in the Pool, are smeared across all participants, to the participants responsible for them. A range of trading options is therefore expected to develop to manage risks efficiently through bilateral contracts.

13. Demand-Side Potential

Increasing the role of the demand-side in the new trading arrangements is seen as a major development and has always been a key RETA objective. This chapter discusses the potential for greater demand-side involvement.

13.1 Potential Benefits

Greater demand-side involvement would stimulate competition by increasing rivalry between suppliers, who would be induced to offer innovative contracts to their customers. Suppliers' rivalry would also lead to more competitive buying of electricity, which in turn would put more competitive pressure on generators. Incentives to manage risks would be sharpened, encouraging development of liquid contract markets. Creating more demand responsiveness would also enable the SO to balance the system at lower cost.

Thus, the essential benefit of incorporating the demand-side would release the normal market opposition between the buyers' and sellers' interests. Innovation on the demand-side would reveal the latent responsiveness of demand, which, under the present trading arrangements, is treated in a highly aggregated manner assuming very little responsiveness.

The 1998 July Proposals recognised that further consideration would have to be given to the implications for detailed arrangements. The next key question was the potential scale of the extension of demand-side influence and how, in practice, the market would develop, and at what speed. Reference was made to the limitations of the 1998 supply competition arrangements through the need to aggregate demand at the GSP group level. This concerns profiling and domestic demand in particular. The question of how to harness domestic consumption to play its role directly in the demand-side has prompted considerable interest since July 1998.

13.2 Developing the Demand-Side

Customers with a half-hourly meter present a ready avenue to the development of demand-side opportunities. Individually, most do not consume enough electricity to make it worthwhile to deal directly with the SO via balancing service contracts or

Balancing Mechanism bids and offers. However, when their loads are grouped by a supplier their participation becomes feasible. For this reason, this section focuses on the already half-hourly metered customer first, rather than on smaller customers who presently do not have half-hourly meters.

There are other reasons for this focus. First, the developments of the existing system involving half-hourly meters to conform to the RETA proposals are thought to be minor. Second, suppliers contracting with customers with a half-hourly meter have the opportunity to apply greater control to purchases of electricity, because the consumption of their customers can be readily observed. Much of such suppliers' business success will depend directly on their purchasing skills and will sharpen the demand-side influence on generation. Third, as active suppliers of half-hourly metered customers can be expected to emerge early, they will have the opportunity to build businesses, which can be readily extended to smaller consumers, currently without half-hourly meters, as metering costs fall.

Given the above, the two major issues are: the scope of the half-hourly metered sector; and the contribution that this demand can be expected to make to meet the fundamental objective of system balance (in addition to that already contributed by the existing demand-side participation).

Table 13.1 describes the estimated annual consumption through half-hourly meters, by consumption band in 1998/99.

Table 13.1 – Consumption Via Half-hourly Meters in 1998/99

Consumption band (GWh)	Number of half-hourly meters	1998/99 Consumption (GWh)	% total consumption in the half-hourly meter set	Cumulative total %
0-1	48,490	19,852	14	14
1-9	18,120	49,602	34	48
9-20	1,603	20,804	15	63
20-39	471	13,106	9	72
40-99	296	20,946	14	86
100-149	44	5,438	4	90
150 plus	46	15,084	10	100
<i>Total</i>	<i>69,070</i>	<i>144,832</i>	<i>100</i>	

Source: ESIS.

Total electricity demand on the NGC system for 1998/99, excluding self-generation and some embedded generation, was 296,000 GWh.¹¹³ Domestic consumption in England and Wales is estimated at 96,000 GWh¹¹⁴ for 1998/99. In terms of total consumption, half-hour meters account roughly for 49%, domestic consumption about 32%. Most of demand-side potential is in the half-hourly metered sector.

The highest and lowest consumption bands in this half-hourly metered demand may not be readily convertible into extra demand-side participation. Many of the customer sites in the highest consumption bands are already participating in the demand-side in different ways: by responding to Triad Warnings;¹¹⁵ as part of the formal Pool demand-side bidding scheme; in NGC ancillary service contracts (including reserve and frequency response) and under load management contracts with suppliers. With regard to the first, NGC estimates that a maximum of 2,400 MW of demand-side response has been delivered at one time. With regard to the second and third, NGC actively seeks offers from the demand-side to provide ancillary services through standing reserve, and

¹¹³ NGC Seven Year Statement 1999.

¹¹⁴ Based on information in Digest of UK Energy Statistics, DTI, 1998.

¹¹⁵ Triad Avoidance involves a reduction or avoidance of Transmission Network Use of System charge by decreasing demand at system peaks in response to Triad Warnings issued by Suppliers.

through the still evolving market in frequency response. The larger, reserve, accounts for about 680 MW from the demand-side (including self-generation). Frequency response accounts for about 320 MW. In 1998/99, NGC spent a total of £11.5 million on these two aspects of the demand-side contribution to system balancing.

In practice, because of little incentive to participate in the existing schemes, predominantly only very large customers are currently involved. Furthermore, NGC considers that loads under 3 MW are not commercially viable for centrally instructed load management. A limited number of firms participate in another manifestation of exploiting demand responsiveness, namely, the Pool's demand-side bidding scheme. These comprise 30 sites,¹¹⁶ which can deliver up to 2,000 MW for load reductions. The precise identity of the customer sites in demand-side activity is not in the public domain, but they are likely to be amongst sites consuming over 100 GWh, which account for about 7% of total consumption.

At the other end of the scale of half-hourly metered customers, the benefits available are likely to be limited which may diminish interest. Reasons for this may include: the relative size of existing electricity bills; the costs of transition; and in effect paying for aggregators' gross margins. For example, at the average of the 1-9 GWh range, consumption per site is 2.4 GWh, corresponding to an annual bill of about £102,000 at an average price of 4.25p/kWh. This could be large enough bill to command the attention of management, however, only about 60% or £61,000 relates to the energy component, which will be the focus of competition.

Estimates of responsiveness, of consumption to price changes, are already built in a minor way into NGC forecasts of demand. These are typically low, e.g., an elasticity of demand of -0.1.¹¹⁷ However, it might be expected that supply competition could improve demand responsiveness through efforts to develop markets and target customers. A supplier in the new market environment might attract customers by, for example, offering a manufacturer a revenue increase for a load reduction¹¹⁸ at specified

¹¹⁶ Although the Pool Executive Committee have recently agreed to increase the participation in the Demand Side Bidding Scheme to 40 and the Chief Executive's Office have been actioned to implement this decision.

¹¹⁷ This corresponds to a 1% drop in demand for a 10% rise in price.

¹¹⁸ Load reduction is the more familiar direction of useful demand response, however, the argument holds for offers in the reverse direction.

times. Towards the top of the 1-9 GWh range, (rather than the average taken in the example above) smaller percentage changes are likely to be sufficient to create interest.¹¹⁹

The potential contribution of the lower size customers is likely to be less than that of larger customers. Most importantly, the lowest size band merges with the non-half-hourly meter customers. For the immediate future, the potential in the half-hourly metered market probably lies mostly in the 9 to 99 GWh bands, a total consumption of 55,000 GWh, or about half the size of the total domestic market or 16% of the total market. Some of the > 100 GWh sites are not already contributors on the demand-side. In particular, the 4% of half-hourly metered consumption in the 100-149 band may yield more.

13.3 Arrangements for Realising the Potential

Compared with the scale of present demand-side participation, the potential in half-hour metering is substantial. The transaction costs increase as the lead-time necessary to provide flexibility shortens. Consequently, offers/bids for minute-by-minute changes in load are less likely to be readily available on the demand-side. Nevertheless, present market participants see potential in specific industrial and service processes (such as cold storage).

More generally, the critical business of the new participants will be to discover what parts of the half-hourly metered market can become interested in providing demand response. Work has begun to identify suitable processes; for example, intensive use of electric heating in industrial processes (e.g. arc furnaces), refrigeration (e.g. cold storage and ice stores), bulk pumping of liquids (e.g. sewerage) and space heating (e.g. for hotel swimming pools).

There are difficulties in conducting systematic searches of potentially responsive customers, as the basic data (the half-hourly meters set) must be classified to standard industrial classifications (SIC), and hence the scope for the application of suitable processes must be assessed. This involves connections between data on who operates

¹¹⁹ In particular cases, customers will be interested in possibilities of change in both directions, applied at different times of year.

meters, through ownership data, to industrial and service categories and hence to electricity consumption figures and the processes typically used in the category concerned. These connections are not yet readily made by non-governmental sources. However, if there was truly value in such information, it could be expected that such a service would emerge. To facilitate this it may be beneficial to initiate a programme of classification of customer and process types centrally to ease the path of prospective innovators.

13.4 Domestic Markets

Expansion into the domestic markets depends on overcoming built-in obstacles. The Stage 2 settlement system uses standard profiles to estimate the consumption pattern of non half-hourly metered customers. These profiles allow for Economy Seven tariffs, where (principally) storage heaters are timed to take electricity overnight. Some sites can be more finely controlled using teleswitching, under which the storage heaters are switched remotely at variable times.

However, the control equipment will already be set up to avoid consumption at times of daily system peak, which is when the price signals will continue to be strongest. It is therefore unlikely that there is much potential for further load management from the small consumers without the introduction of profiles that are more sophisticated, technological advances in control systems and the extension of switchable demand to other applications.

13.5 Demand-Side Participation in the Balancing Mechanism

Within the Balancing Mechanism, a number of issues will affect the practicalities of greater demand-side involvement. Namely:

- ◆ the information requirements (e.g. FPN provision); and
- ◆ the practical ability of the demand-side to participate directly in the Balancing Mechanism (for example, the need for customers to hold a supply licence to enable direct participation in the Balancing Mechanism; the complexity of bids required; minimum quantity constraints and the ability to aggregate).

As an ideal, information provision from all participants would be required at the finest resolution. However, due to the transaction cost of collecting this information and the usefulness to the SO this is impractical. Consequently:

- ◆ for the majority of the demand-side, information will be required at the GSP group level;
- ◆ there may be a *de minimis* level, below which information provision will not be required; and
- ◆ for some individual participants, information may be required at a finer resolution. For example, information from customers directly connected to the transmission network will be required at the GSP level.

The Balancing Mechanism arrangements described in Chapter 6 have been designed to facilitate active participation from the demand-side. In addition, consideration is being given to allowing participants to distinguish their controllable and non-controllable loads in their FPN submissions. The dynamic parameters that participants will be allowed to specify along with their offers and bids require further consideration but it is intended that these will accommodate the characteristics of flexible responses from both the generation and demand-side.

With regard to the suppliers described above, a crucial issue is the ability to aggregate a number of smaller sites into a single service offered to the SO. As discussed in Chapter 6, such aggregation is possible if: the sites are suitably registered; and for direct participation in the Balancing Mechanism, the aggregators are licenced.

13.6 Summary

Greater demand-side involvement was a key innovation and objective within the RETA proposals. During the early stages of the new trading arrangements, the greatest increase in demand-side participation is likely to be seen from customers with half-hourly meters. The reasons for this include the relative ease with which such customers could be incorporated into new systems compared to the non half-hourly metered portion of the market. Many of the sites already participate in some form of demand-side participation through: load management contracts; triad avoidance; the Pool's demand-side bidding scheme; and NGC ancillary service schemes. However, there is still a large potential for greater demand-side participation. Suppliers (aggregators)

could play a large role in realising this potential. Expansion into the domestic markets depends on the introduction of more sophisticated profiles, technological advances in the control systems, the extension of switchable demand to other applications, and the extension of competitively priced half-hourly metering.

14. The Strength of Competition and the Trading Arrangements

Competitive pressures in wholesale and retail electricity markets will both affect and be affected by the new trading arrangements. Varying degrees of competition can be expected to have effects on the liquidity of markets and on the efficiency with which electricity is traded, whilst changes in the rules that govern the trading of electricity can be expected to lead to changes in selling and buying strategies of companies operating in the relevant markets. The chapter considers competition today in Part I and analyses the interaction between competition and the new trading arrangements in Part II.

Part I – Competition Today

14.1 The Promotion of Competition

The Director General has a statutory duty to promote competition in generation and electricity supply. The introduction of the new arrangements represents a further major step towards open liberalised electricity markets. In particular, restrictions on business conduct arising from compulsory membership of the Pool, which have had distorting effects on competition but which are judged to be no longer necessary for achieving secure and efficient balancing of the system, will be lifted. The new trading arrangements will, therefore, change the context in which competition policies are pursued, in ways that facilitate the further development of competition. The achievement of effective competition requires that market power be substantially curbed. For at least the immediate future, it is to be expected that some degree of market power (the ability of one or a group of firms significantly to influence market prices) will remain in both wholesale and retail electricity markets.

There is no simple relationship between market structure and market power. Certain forms of market structure may be incompatible with effective competition, but there can be (possibly quite wide) ranges of market structures and types of business conduct that are compatible with the existence of effective competition. It is important, therefore, that electricity trading arrangements be flexible enough to function effectively across a range of different industry structures and types of business conduct.

There have been major changes in the structure of both wholesale and retail electricity markets since privatisation. What is less clear is the effect that these changes have had on the competitive pressures bearing down on companies operating in the relevant markets, since the links between easily documented measures of industrial structure (such as market shares) and the strength of competitive pressures can be tenuous, and in any case quite complex. For example, among the influences that need to be considered in assessing the strength of competition are:

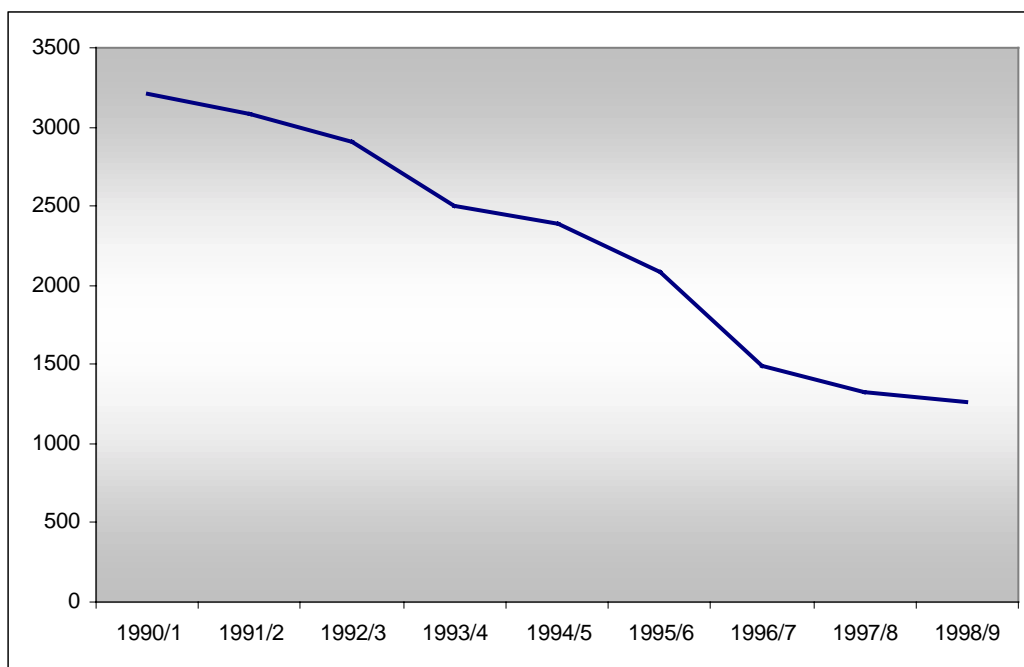
- ◆ the conduct of incumbent companies and the intensity of their rivalry;
- ◆ potential competition; and
- ◆ demand side factors in the market, whether wholesale or retail, including (a) the availability of substitutes for the relevant product/service and (b) buyer concentration.

14.2 Electricity Generation

14.2.1 Rivalry

Since privatisation, there has been a substantial increase in the number of companies supplying wholesale electricity and an accompanying substantial fall in industrial concentration, however measured. Figure 14.1, based on ownership interests, shows movements of the Hirschman/Herfindahl index (HHI) of concentration in the supply of energy (defined as the sum of the squares of company market shares) over recent years.

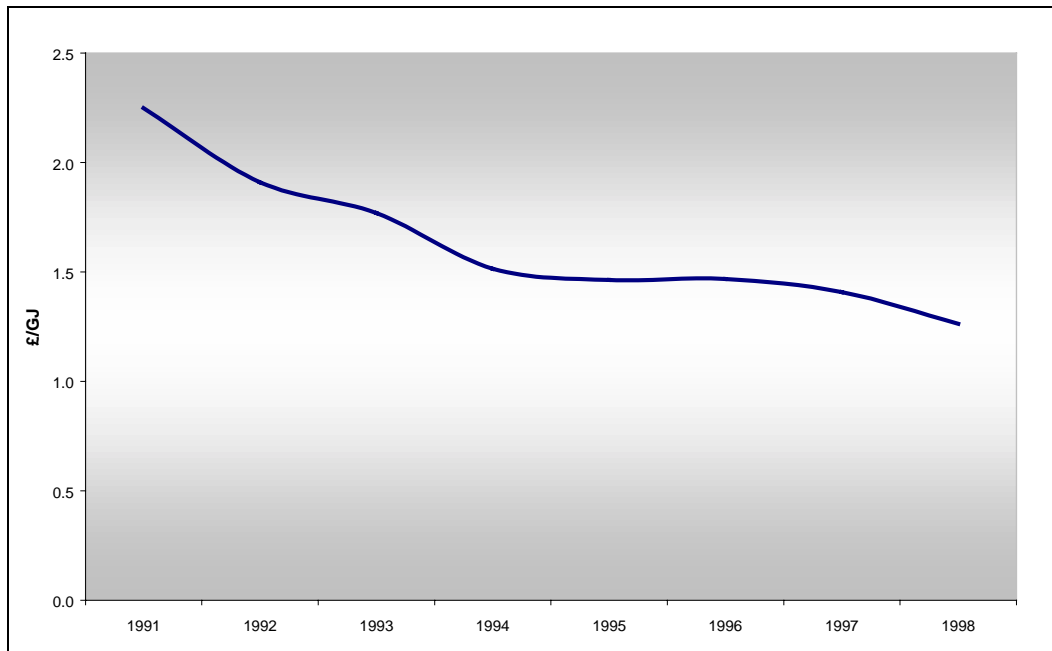
Figure 14.1 - Generation Market Output - HHI Index



The sharp reduction in concentration is the result of a combination of factors, including plant divestment by incumbent generators, new entry based on the construction of additional gas fired capacity, increased output from the nuclear stations and the subsequent division of Nuclear Electric into two companies. Prima facie, it might be expected that such a major change in the structure of supply would have had a major impact on margins and prices in generation. There is, however, no direct, simple link between aggregate measures of market concentration and the strength of competition, as is borne out by the history of Pool prices in the 1990s.

Notwithstanding the downward trend in market concentration and substantial reductions in fuel prices, particularly coal (see Figure 14.2), Pool selling prices have failed to fall. Even in a fully monopolised market it is to be expected that falling input prices, which reduce costs, will lead to lower output prices. Yet, in electricity, increases in the margin between wholesale selling prices and avoidable costs (comprising fuel and variable operating costs) has more than offset the effect of the decline in input prices.

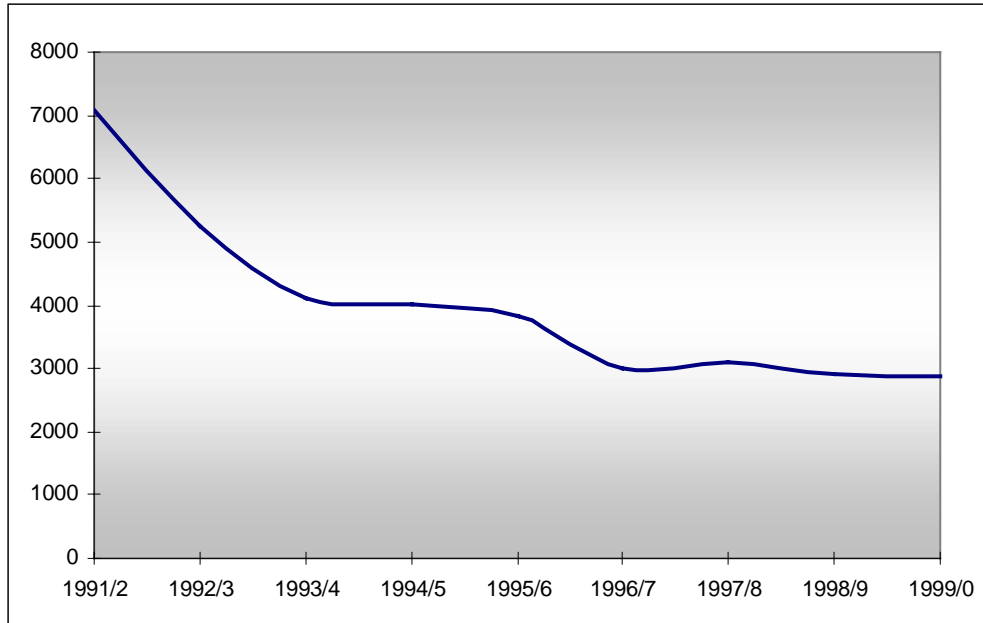
Figure 14.2 - Average Price of Coal Purchased by Major Generators



This outcome suggests that there has been no great intensification of competition in pricing among rival, incumbent generators. Hence, pricing strategies have been heavily influenced by factors other than aggregate market concentration or falling input costs.

Of particular importance here is the fact that many of the generators operating in the market do not actively participate in setting market prices. If attention is restricted to companies that have actually set the system marginal price, the resulting concentration levels are significantly higher than those shown in Figure 14.1, as Figure 14.3 shows. Although aggregate market concentration is at a level that can be described as 'moderate', and may soon fall into the 'low' category (i.e. a HHI of below 1,000), concentration for price-setting plant now is still between 2500-3000 (high concentration is generally to be above 1800).

Figure 14.3 - SMP Setting HHI Index



Another, major concern in relation to the issues addressed by RETA is the way in which short-term spot markets for electricity operate. This typically involves repeated bidding (in the case of the Pool, once every day), which tends to facilitate implicit co-ordination of pricing behaviour that can lead to non-competitive outcomes. This tendency can be strengthened by factors such as:

- ◆ a single, highly visible reference price (the Pool Selling Price) which can be used for signalling and co-ordination purposes, and
- ◆ relatively static market conditions, which imply that companies do not have to keep re-learning and re-adjusting strategies to find the most profitable outcomes.

With their standardised rules for price determination and the information flows that they make available, the current Pooling arrangements appear to facilitate implicit co-ordination of prices. There is a counter-argument to the effect that the Pool rules for price determination (i.e. for translating bids into market prices) are so complex and non-transparent that they serve to hinder learning, signalling and co-ordination in pricing. However, the evidence suggests that this latter effect has not to date been dominant, and that, overall, price competition has been muted.

A factor that has clearly provided incentives for strategic bidding is the use of marginal bids by generators to set Pool prices, which then apply to all output. For example, this allows a generator to bid relatively highly at the margin for higher cost supplies whilst protecting its volume position by bidding lower prices for lower cost supplies. If a generator's marginal bid is undercut by a rival, the resulting volume loss is relatively small. The generator, knowing that rivals will also be adopting this same bidding strategy, will anticipate that, if it cuts prices, its volume gain will also be relatively small. Price cutting is therefore made less profitable, and higher prices are encouraged.

Market power problems associated with repeated, standardised price determination can, in principle, be greatly alleviated by the ability of firms to contract on a longer-term basis, since this can very substantially reduce the number of repetitions of the price determination process that occur in similar market conditions. Longer-term contract markets are, however, affected by short-term arrangements, which provide an alternative way of bringing supplies to market. A company may, for example, restrict supplies available under longer-term contracts in order to be able to benefit from high spot prices. Moreover, to the extent that contract cover provides generators with revenue protection against short-run variations in Pool Prices, the costs of using the Pool price as a signalling device - for example, to make an indirect statement to its competitors about what level of market price a generator believes is appropriate, including for new Electricity Forward Agreements (EFA) and CfDs - are reduced. Weak competition in spot markets can therefore undermine competition in longer-term markets and the evidence to date suggest that CfDs and EFAs have had only a limited, pro-competitive effect on bulk electricity prices (CfD prices, for example, have been significantly above Pool prices).

14.4.2 Entry

One of the major effects of the reforms accompanying electricity privatisation was to reduce substantially the barriers to entry into the electricity generation market. Entry was also encouraged by the widespread emergence of CCGT technology with its related low costs and superior environmental performance when compared with new coal-fired stations. As in respect of changes in market concentration, the impact of these developments on the strength of competition has depended on a number of factors.

Freedom of entry suggests that the 'entry price' for new CCGT plant – the levelised price at which such plant can earn a normal rate of return on capital employed – should have been a significant influence on wholesale prices since privatisation. Since this entry price has tended to fall over recent years, as a consequence of lower gas prices and of reductions in other costs (including capital costs), it might have been expected to exert a downward pressure on contract and Pool prices. Such price effects have, however, not been seen.

In their profitability assessments, new entrants will tend to take account of price competition in the market after entry has occurred. Among other things, this is affected by Pool pricing strategies. Any particular new plant will add relatively little to total industry output, and the most profitable strategy for a new entrant might be to pursue a pricing policy similar to those of (pre-entry) incumbents, thereby participating in the benefits of prices that are relatively high in relation to the entrant's own costs. After entry has occurred, incumbents might find no reason substantially to change their own behaviour. In such circumstances, incumbents will tend to suffer from some loss of output, but the effects on their profits may not be substantial. A situation of excess capacity may develop, but the effect on prices may be limited.

The operation of the Pool has facilitated this outcome. Individual new entrants have found it simple to adopt a bidding strategy which guarantees operation and does not directly influence the price setting process. New entrants can do this by flagging their plant 'must run' at the day ahead stage, which ensures operation at a specific level, but, due to the Pool Rules, precludes it from setting the marginal price. Adopting this strategy reinforces the price setting position of the price setting generators.

Loss of volume over time will reduce incumbents' profits, which may encourage them to take steps to slow down the rate of new entry. However, this is unlikely to involve aggressive pricing in the short term, since it is post-entry, rather than pre-entry, prices that will largely drive entrants' decisions. Even if lower prices in the short term did have entry deterring effects, it is relevant that incumbents' profit loss from entry is mitigated, and their profit loss from aggressive pricing in the short term is increased, by the lags between the entry decision and the first supply of power to the market an entrant makes, which typically amount to three years or more.

In practice, the most obvious effect of lower entry barriers has been seen in the investment programmes of incumbents. Given the higher operating costs of coal-fired plant and the increased operating limitations and costs imposed by pollution controls, incumbent generators recognised that CCGTs would eventually displace much of their existing capacity. As a result incumbents sought to develop their own CCGT capacity in order to ensure that their reduced portfolios more closely matched entrants' costs, thereby securing longer term positions in the market. Incumbents have not, however, been in a position to pre-empt all, or even a large fraction of, the construction of new capacity, and have therefore pursued what may be called partial withdrawal strategies, allowing market shares to fall over time whilst benefiting from strong profitability in the short- to medium-term.

Entry of independent CCGT owners, the acceleration of incumbents' CCGT construction programmes, relatively weak short-term price competition, and the incentives for RECs to develop new sources of generating capacity in the face of high concentration in generation in the early post-privatisation years, have together led to the 'dash for gas'.

Notwithstanding the Government's stricter consents policy, significant amounts of new capacity are due to come on stream in the near future including from new entrants. However, because the current price-setting process restricts the competitive effects of new entry, the impact on wholesale prices may be limited.

14.3 The Demand-Side

To date, competitive pressures on generators from the demand side of the market have been relatively weak. There is limited scope for switching easily, at low cost, to substitute sources of energy, particularly in the short-term, and, as a result, inter-fuel competition is fairly weak. More efficient use of energy can be stimulated by higher prices, but the process often requires significant investment and the lags involved may be relatively long. Consequently, the overall demand for electricity is not very responsive to price, which enables incumbents to benefit from higher prices without suffering a substantial loss of output.

The wholesale electricity market is characterised by the presence of large, commercial buyers on the demand side, and this should, in principle, be a major factor in intensifying competitive pressures on generators. However, limitations on supply

competition have served to attenuate such demand-side pressures. The development of competition in the domestic retail market (discussed below) should start to improve matters on this score.

More relevant to the RETA proposals, even where supply competition has been more vigorous, as in the industrial and commercial sectors, the impact of demand side pressures on wholesale prices from suppliers has, to date, been limited. The restricted participation of the demand side in the electricity Pool has been a matter of concern since privatisation, and reforms to date have had only a limited impact. Generators bidding into the Pool have, therefore, been confronted with a short-term, market demand curve where demand is highly unresponsive with respect to price, notwithstanding the fact that, lying behind the trading arrangements, is a set of large buyers who, in other circumstances, could be expected to be keen to negotiate keener prices. That is, the current trading arrangements do not allow large buyers to 'connect' with their suppliers in ways that are typical in other markets.

Buyers and sellers can, nevertheless, negotiate directly over longer-term contracts. The difficulty here is that, in negotiations, a generator always has the option of selling electricity via the Pool, where demand side influences are weaker. This strengthens the bargaining position of generators, making them less willing to discount prices, at least so long as there is a prospect, over the relevant period, of higher Pool prices. In this way, the lack of demand-side pressures in the Pool serves to weaken demand-side pressures in the negotiation of longer-term supply contracts.

It is, therefore, one of the central aims of the RETA proposals to establish a trading framework conducive to the strengthening of demand side influences on wholesale price determination.

14.4 Electricity Supply

Parts of the market for supply of electricity to end users have been liberalised since the Energy Act 1983, but significant competitive activity only developed with the advent of privatisation and its accompanying regulatory reforms. The formal process of liberalisation of electricity supply was completed earlier this year, as the last restrictions on entry into domestic supply were lifted.

The importance of retail competition for the wholesale electricity market is that it might be expected to intensify competitive pressures emanating from the demand side of the wholesale market. Where suppliers have captive retail customers, there will be little incentive to seek the keenest prices. At best, regulation can seek to improve incentives through price controls, but this is unlikely to be a good substitute for competition.

Competition in retail supply implies that the prices at which a supplier purchases electricity are potentially important source of competitive advantage (or disadvantage). If a supplier's input costs can be reduced relative to those of its rivals, its profits will tend to increase. Depending upon the particular market conditions, the profit benefit will be taken as a particular combination of increased margins and/or of higher volumes, where volume increase is associated with lower relative prices and/or greater marketing effort made profitable by the higher margin on incremental sales.

Notwithstanding the potentially very significant impact that supply competition can have on competitive conditions in the wholesale electricity market, the effects to date have been relatively muted. One of the reasons for this is the fact that, until the past year, there has been no competition in domestic supply, which accounts for a substantial fraction of supplier's total sales.

Thus, even though there is considerable evidence of increased competitive pressures in industrial and commercial markets in the 1990s, with significant new entry and substantial switching of suppliers by end users, this does not appear radically to have changed competitive conditions at the wholesale level. It may also be relevant here that the new entrants who captured significant market share from incumbent PESs were incumbent generators (with interests in higher, rather than lower) wholesale prices, rather than by 'independent' suppliers with unambiguous interests in seeking lower wholesale prices. This issue will be discussed further in the section on vertical integration in Part II.

If all trade was done solely through the Pool, then all buyers would face the same price. The possibility of striking financial contracts, such as contracts for differences, provides incentives to compete on purchase prices that are lacking when there is a single, common spot price, since a supplier may be able to secure its inputs, on a longer-term basis, on better terms than its rivals. However, the influence that major generators have

over the Pool price weakens the incentives of those generators to offer lower contract prices, since the Pool price will always be available as an alternative. That is, lack of competitive pressures on Pool prices might feed back into weaker competition in respect of contract prices.

For the future, the impact of the demand side of the wholesale market will depend to a significant extent on the further development of competition in supply, as well as on the reformed trading arrangements. Supply to half-hourly metered customers offers the best immediate prospects for such development (see chapter 13), but there is also potential for competitive pressures in the domestic market to strengthen. In the early months following liberalisation, domestic customers have had access to a wide range of different price offers (see Table 1), and there has been consumer switching to an alternative suppliers at a weekly rate that has increased steadily through to July 1999. By the end of June 1999, the cumulative number of registrations to switch supplier had increased to above 2.3 million, or nearly 9% of the total customer base, with the number increasing at a rate of over 100,000 per week. Much of this switching is associated with dual fuel offers, whereby a single company offers to supply both the electricity and gas requirements of a particular customer. The introduction of dual fuel offers has also led to relatively large-scale entry that, for the first time, is not based upon the prior existence of a significant supplier position in electricity generation.

Table 14.1 - Comparison of PES and Competitors Bills for England, Wales and Scotland at 31 March 1999

	Payment type		Average
Host REC	Direct Debit		£ 256
	Quarterly Credit		£ 265
	Prepayment Meter		£ 279
Second tier supplier	Direct Debit	Average	£ 247
		Maximum saving	£ 25
		Number competing	14
	Quarterly Credit	Average	£ 256
		Maximum saving	£ 25
		Number competing	13
	Prepayment Meter	Average	£ 296
		Maximum saving	£ 17
		Number competing	4

Source: A Review of the Development of Competition in the Designated Electricity Market, OFFER, June 1998.

On the other hand, both the sizes of the discounts on offer and the extent of customer switching have been less than in the comparable periods following the earlier opening up to competition of domestic gas markets. Since, to build significant volumes, a new entrant to a market may have to offer a substantial discount on the incumbent's price in order to induce consumers to switch suppliers, it is not yet clear how quickly, and to what extent, the market power of incumbent suppliers will be eroded. As already explained, the difficulty of obtaining competitive advantage through lower purchase costs for bulk electricity under current arrangements (an issue that did not arise in gas), when coupled with the size of retail margins, with the marketing and administrative costs of acquiring new customers, and with the relatively small average size of the accounts, may facilitate the persistence of retail market power, even given the prospects

for gaining competitive advantage by 'bundling' electricity supply with other products and services, most notably the supply of gas.

Part II – Competition and the New Trading Arrangements

14.5 Vertical Integration, Liquidity and Transparency

Much of the concern expressed about market power as it may unfold in the future focuses on issues surrounding vertical integration. Vertical integration refers to situations in which businesses or business units operating at different stages of the value chain are in common ownership. Such integration can encompass a variety of different business relationships, which may have correspondingly different implications for commercial behaviour. For example, policies and decisions on certain matters, including purchasing and pricing, may be centralised at the corporate level or delegated to individual units that deal with one another at arm's length. If decisions about the terms of transactions among different parts of the same corporate group are centralised, there are a variety of ways in which such terms may be determined: transfer prices, say, may be set to reflect marginal supply costs, or to provide behavioural incentives within the different businesses, or to reflect market prices for equivalent transactions in relevant markets.

The economic effects of vertical integration may also, to a greater or lesser degree, be approximated by alternative contractual arrangements between businesses that are not in common ownership. For example, long-term contracts (e.g. requirements contracts) may sometimes have similar implications for competition as vertical integration of ownership, although, once again, such contracts can take a variety of forms with differing economic effects. Vertical integration can, therefore, be viewed as a sub-set of a much larger set of possible economic relationships among business activities at different stages of the value chain, and there may be no very obvious discontinuities in commercial conduct and economic effects at the boundaries of the sub-set.

14.5.1 Policy Towards Vertical Integration

In general, there is little concern about the possible effects of vertical integration when all the relevant activities are subject to effective competition. In such circumstances, it is desirable that enterprises be free to discover the most efficient forms of contractual relationships among themselves – just as it is desirable for them to discover other ways

of improving their commercial performance – not least because competition will ensure that consumers will benefit as a result.

The difficulties occur when there is substantial market power in one or more of the relevant business activities, since in this case vertical integration may be used for ‘leverage’ purposes. That is, incumbent companies may be able to use their market power in one activity to reduce competition in another, related activity, to the potential detriment of consumers. A principal objective of regulatory policy in the electricity industry has, therefore, been to secure appropriate degrees of vertical separation between monopolistic activities, such as transmission and distribution, and competitive or potentially competitive activities, such as generation and supply, so as to prevent ownership and control of the monopoly areas being used to thwart competition in generation and supply.

The two activities of generation, and supply are not now ‘pure’ monopolies, but neither are they both subject to effective competition. In supply, incumbent PESs continue for the moment to account for very large shares of their local markets, notwithstanding the existence of alternative offers at lower prices. There are, however, also concerns about lack of competitive pressures in the wholesale electricity market, and, as described earlier, these concerns are an important motivation for the reform of trading arrangements. It is therefore possible to conceive of potential leverage effects, associated with vertical integration, in both directions: from generation to supply, and from supply to generation.

14.5.2 Vertical Integration, Liquidity, Transparency and Trading Arrangements

To the extent that there are issues concerning the potentially anti-competitive effects of vertical relationships between generators and suppliers, these can be expected to appear irrespective of the particular form of the trading arrangements. It is not the case, for example, that the liquidity and transparency of wholesale markets will eliminate problems associated with market power.

Even with a highly liquid and price transparent wholesale market, if generators with interests in supply have, individually or collectively, substantial market power, they might, for example, be able to raise rivals' costs and even foreclose retail markets to new suppliers (without generation capacity) by withholding output from the wholesale

market. This would have the effect of raising wholesale prices. A new entrant, purchasing electricity at the market price, would therefore face a higher input cost than a vertically integrated company, in which the incurred cost of extra electricity input to the supply arm would be equal to the lower, marginal generating cost. Particularly if the integrated company holds an incumbent position in retail supply, or if a generator has agreements with a supplier that have similar economic effects to common ownership, the new entrant may find it very difficult to compete.

If wholesale markets became highly illiquid and non-transparent, there could be concerns that any foreclosure effects associated with market power might be exacerbated. This is largely a quantitative issue, raising the question of the degree of liquidity and transparency required to prevent significant exacerbation of possible, anti-competitive pressures.

In respect of liquidity, one of the important questions is the extent to which suppliers who lack generation capacity of their own can obtain, from the market, the additional bulk purchases of electricity they require to expand their businesses. Similarly, it can be asked whether new entrants in generation will have access to sufficient uncontracted demand, to support their business plans in the event that they can offer incremental output at competitive prices.

In both cases, the outcome will depend on the depth of the markets, in relation to the likely volumes of supply or of demand, required to ensure that efficient new entrants will be able to find the required counterparties. In current conditions, there are generally very substantial divergences between the supply and demand positions of vertically integrated companies in the wholesale market. That is, even vertically integrated firms will have to obtain a substantial fraction of their demand requirements from, or will have to dispose of a substantial fraction of their supply to, other companies operating in the industry. Moreover, with competition in both generation and supply, it can be expected that there will be significant fluidity in the net positions of vertically integrated companies in the wholesale market. Thus, a close matching of supply and demand positions through longer-term contractual arrangements or through full integration may, in the event, be extremely difficult to attain. For example, an initially matched position may be disturbed if the supply arm of an integrated company were to suffer significant loss of market share in, say, supply to large commercial and industrial

end-users, where customers are highly unlikely to be 'captive'. Regulatory constraints on vertical integration of ownership and certain forms of contractual arrangements, including those arising from the application of general competition law, will further serve to ensure that wholesale markets are liquid.

14.5.3 Transparency and Market Information

'Transparency' refers both to the amount of information available in the market at large and to individual player's access to it. Greater transparency can help regulators detect unacceptable market behaviour¹²⁰ and, in some circumstances, it can facilitate competition by, for example, inhibiting price discrimination by dominant firms. In other circumstances, however, it may hinder competition, including by making it easier for companies with market power to signal to one another, to monitor each other's behaviour, and hence to align their pricing strategies.

Some concern has been expressed that the RETA proposals may reduce the transparency of price outcomes in spot markets compared with the arrangements currently in place. Although the current arrangements are characterised neither by transparency in price determination (the process by which prices are set) nor by transparency in contract prices outcomes, they might be seen as offering a visible reference price to which all market participants have equal access.

As explained above, however, a single, highly visible reference price can, in fact, facilitate effective collusion, leading to excessive prices to consumers and, to the extent that entry is encouraged by high prices, promote inefficient new entry. Moreover, whilst Pool prices do provide a visible reference price, often referred to as a 'spot price' against which contracts may be struck, other, very important prices are simply not known under the current trading arrangements except to a relatively few. In contrast to most 'Over the Counter' (OTC) markets, such as the gas markets, there are currently no generally recognised price reporters for CfDs. Thus, there is relatively little information on contract volumes and prices.

¹²⁰ Information available to the Director General may not be the same as information available to the market, and the pros and cons of transparency to the regulator will not generally be the same as of transparency to market participants.

Under RETA there will no longer be one published price at which everyone can be guaranteed to be able to buy and sell over the subsequent 24 hours: this is an artificial and restrictive feature of present arrangements. Nor will the proposed arrangements reveal the price and other terms at which every contract is struck. However, meaningful and visible reference prices will emerge under the new trading arrangements, not only for spot trades but also for a range of other products, including forwards and derivatives, a number of which will be of greater value in guiding entry decisions than the current Pool prices.

Prices emerging from the Balancing Mechanism and for example a power exchange, are likely to be published by the respective market operators. A rapid establishment of generally accepted price indices, which would reflect the value of power on a within day, a day to day, week to week, quarter to quarter, or year to year basis is to be expected. This would certainly be consistent with experience in the other competitive electricity markets such as in the United States and the GB gas market. In these markets detailed price information is available over the Internet. Meanwhile, there have been encouraging signs of progress towards greater price reporting in the England and Wales electricity market over the past year, stimulated in part by the RETA programme. EFAs are now reported in several journals.¹²¹ Moreover, in February 1999, National Power launched a day-ahead EFA contract in order to gain experience of trading prompt products and to help establish a new short-term reference price to replace PPP. This day-ahead contract has attracted a healthy level of interest, with peak and off-peak structures being traded in addition to the more common baseload form. There is evidence from the United States and the GB gas market, where forward curves provide price information from the day ahead to over a year ahead, that information becomes established where most liquidity lies.

The new arrangements also provide for transparency in the operation of the pricing mechanism and the market generally. Prices in the Balancing Mechanism (and in Power Exchange) will be based on simple offers and bids, which will increase transparency considerably compared to the complex bidding and price-setting procedures in the Pool. It has been argued that the complexity and opacity of the present pricing mechanism has inhibited the development of financial markets and

¹²¹ For example, Platts European Power Daily and The Heren Report's European Electricity Markets.

reduced liquidity in the contracts market. Institutions and traders have said that this complexity has been one of the factors deterring them from participating in the electricity contracts market.

It is therefore anticipated that there will be more price transparency under the new trading arrangements. The revised trading arrangements will encourage greater entry of traders into the market, thereby improving liquidity and providing established participants with a wider choice of contract counter-parties and risk management options. The development of forwards and futures markets with associated price discovery offers better opportunities for traders to cover the risks of holding exposed positions. Such markets should also lead to more efficient risk sharing.

14.6 Implications of Market Power for the New Trading Arrangements

There are a number of determinants of market power in wholesale electricity markets, and such power can be exercised in a number of different ways. Whilst public policy will continue to promote competition where feasible and to target significant abuses of market power, some degree of market power can be expected to persist in electricity markets.

Trading arrangements in the industry therefore need to be relatively robust across a range of different market structures and it is desirable that, in their detail, they be sufficiently flexible as to accommodate appropriate modifications as and when justified by changing market conditions. The RETA proposals have been developed with these points in mind.

Concerns with existing Pooling arrangements are associated not so much with the fact that they permit the exercise of market power – which is likely to be true for all manner of arrangements – but rather that they tend to facilitate non-competitive outcomes. Among the problems are: the vulnerability of the price setting process to manipulation; the repeated nature of the standardised bidding process; and the small role afforded to the demand side in price determination.

In principle, such problems might be addressed by a programme of Pool reform (e.g. eliminating capacity payments, promoting greater demand-side participation) and of supporting measures. In practice, the Pool has proved difficult and cumbersome to

reform, and the supporting policies that may be required in this scenario run the risk of introducing a prescriptive approach to market structure that may itself be anti-competitive. Most fundamentally, the restrictions on commercial conduct imposed by the Pooling arrangements imply distortions of competition that can not be justified as being the minimum necessary to achieve secure and efficient balancing of the electricity supply system.

In contrast, the RETA proposals seek to remove unnecessary restrictions of competition and to secure a set of relationships between buyers and sellers that are more akin to those to be found in other markets (and which have proved themselves capable of functioning effectively across a range of different market structures). Thus:

- ◆ the simpler process of price formation should lend itself to easier monitoring, aimed at detecting abuse of market power;
- ◆ the elimination of prescriptive rules should open up greater opportunities for discovery and innovation in selling and buying electricity;
- ◆ the contract-based nature of the proposals will put buyers in direct contact with sellers, thus promoting greater demand-side participation in price determination; and
- ◆ the new arrangements, including the governance arrangements surrounding the balancing and settlement code, should facilitate faster, more effective adjustments of the trading framework as and when market conditions change.

14.7 The Impact of the Trading Arrangements on Competition

The RETA programme is only one aspect, albeit a very important aspect, of a wider energy and competition policy framework, and the benefits that it will provide should be judged in terms of its contribution to the effectiveness of that framework, taken as a whole.

The RETA proposals have been developed neither in the expectation that they will, in and of themselves, be sufficient substantially to curb market power nor as a means of tackling specific abuses of market power. They will, on the other hand, directly remove a number of restrictions and barriers that currently impede the development of effective

competition. More specifically, compared with the status quo, the new arrangements should:

- ◆ be less vulnerable to abuse by participants with market power;
- ◆ be more open to innovation;
- ◆ be more conducive to the effective monitoring of anti-competitive practices;
- ◆ strengthen the influence of the demand side on wholesale price formation; and
- ◆ be more flexible and adaptable to changing economic conditions.

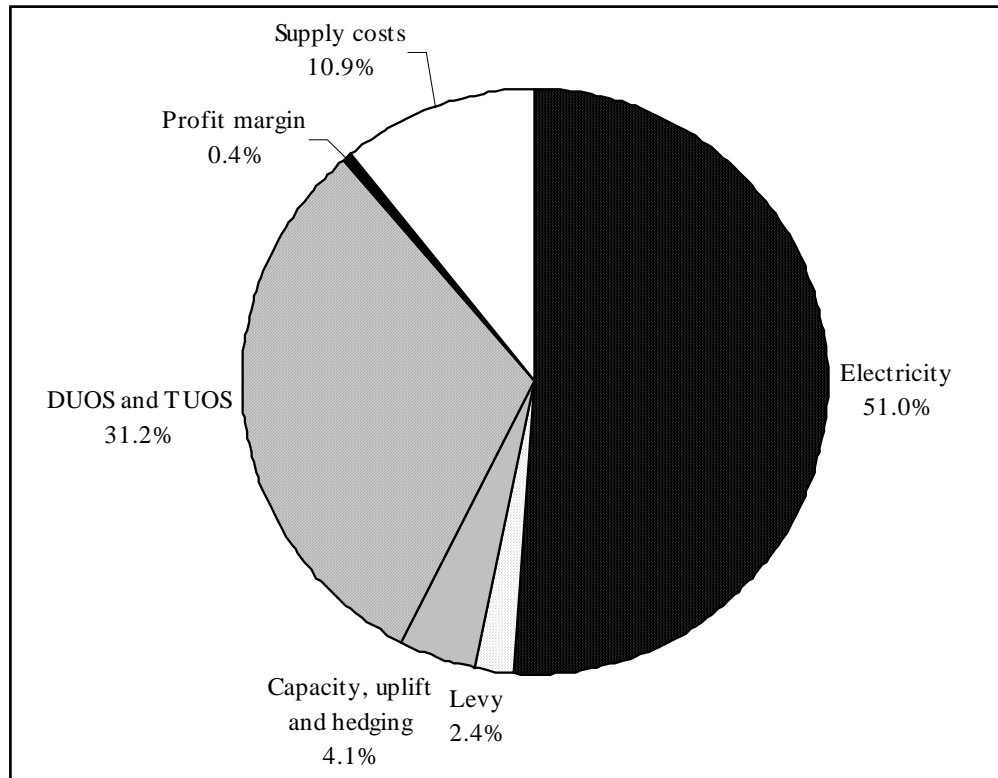
In short, RETA is expected to help accelerate the development of a more competitive and dynamic industry, to the ultimate benefit of consumers of electricity.

14.8 Future of Prices

A major issue that has been considered in the development of RETA is the likely effect of the new trading arrangements on the future level of prices that consumers of electricity will pay. In large part, this is a question about the impact of RETA on the exercise of market power.

Final consumers are affected by electricity prices in two ways - directly through their electricity bills and indirectly through electricity inputs to the other goods and services they buy. Notwithstanding anticipated developments in wholesale electricity markets, there remain particular concerns for the domestic sector since, although there is now substantial switching among suppliers, concentration in supply to the domestic market can be expected to remain very high for a considerable period.

Figure 14.5 - Electricity Costs – Direct Debit for Eastern PES Area (1998/99)



Note: Calculation for the average electricity consumed on the tariff.

The domestic consumer electricity bill, like those for other customers, contains large elements subject to price control (see Figure 14.5, which as an example, indicates the make-up of domestic customers direct tariff bill for the Eastern PES area). Supply costs, the allowed profit margin, distribution use of system charges (DUOS) and transmission use of system charges (TUOS) are all subject to price controls which will ensure falling charges. These account for about 42.5% of the bill. The remaining 57.5% comprises various elements of electricity generated. RETA will affect this latter part of domestic bills.

About half of a generation company's outlay consists of coal and gas inputs. By 2002 taking into account the CCGT plants already started, or with full permission, gas will be the preponderant fuel used. As late as 1994, long-term gas contracts for CCGT operation were struck at around 18p/therm. Judged by contracts struck more recently, the relevant price has fallen considerably, partly because of the rapid development of gas trading. Old take-or-pay contracts have been, or will be, renegotiated downwards.

Average prices for coal inputs are also expected to continue to fall, as international markets continue to exert an influence on the domestic market.

Given that wholesale electricity prices have not reflected the past, substantial falls in fuel input prices, and given that there continues to be downward pressure on those input prices, the evidence suggests that there is scope for substantial reductions in wholesale electricity prices if intensified competitive pressures start to bring prices more into line with efficiently incurred costs. Although a given percentage reduction in wholesale prices translates into a lower percentage reduction in retail prices (if fully passed through) the size of the contribution of wholesale electricity costs to final retail costs is such that the scope for reductions in domestic prices is also considerable.

While it is not possible to be precise about the likely impact of RETA and accompanying measures on final electricity prices, the evidence indicates that the figure of a 10% reduction put forward in the Government's October 1998 White Paper is a realistic one. Among the accompanying measures that are relevant here are those designed to ensure that reductions in suppliers' costs resulting from lower wholesale electricity prices are, in the event, passed on to final consumers. In seeking to ensure that this happens, the Director General will be able to rely on his ability to influence retail prices directly via supply price controls and indirectly through his new powers under the Competition Act 1998.

14.9 Summary

Market concentration in electricity generation has fallen substantially since privatisation, although to a much lesser extent if attention is focused only on price-setting plant. The restrictions inherent in the Pool arrangements have facilitated the exercise of market power such that, notwithstanding falling concentration, new entry and, more significantly, a substantial reduction in generating costs, wholesale prices have not fallen.

The new trading arrangements will remove the Pool restrictions; facilitate innovation in trading, including through the development of a much greater role for the demand side in price determination; and undermine a number of the features of the current arrangements that facilitate the exercise of market power. They will not, and are not intended to, eliminate market power, and the Director General will rely upon his

existing powers and on his new powers under the Competition Act 1998 to continue to promote more effective competition at both the wholesale and retail levels.

It is not expected that vertical integration will impede the development of transparent and liquid markets for electricity, not least because competition in electricity supply and associated variations, over time, in the requirements of suppliers will encourage trading at the wholesale level. By facilitating the development of new forms of trading, the publication of prices for the new products, and greater transparency in price determination, the new trading arrangements should improve market information, help open up the wholesale market, and aid the Director General in promoting effective competition.

15. Interactions with Gas

Energy markets in the UK are developing rapidly and the interactions between them are increasing. Whilst RETA is considering changes in the electricity industry, the gas industry is also implementing a significant change programme.¹²² The first phase of the revised arrangements will be introduced on 1 October 1999. This chapter outlines the new gas trading arrangements and compares them to the new electricity trading arrangements. It concludes with a brief discussion of some of the interactions between the two markets, which will need to be managed by both sets of trading arrangements.

15.1 RGTA

In May 1998, Ofgas consulted on the development of an On-the-day Commodity Market (OCM) for the gas balancing regime. Subsequently, it was recognised that at the same time as introducing wide-ranging changes to the gas balancing regime, it would be necessary to improve the transmission capacity regime.¹²³ Since October 1998, there has been extensive debate on these issues within the gas industry, through workshops, meetings and the submission of papers as part of the BC99 (Balancing and Capacity 1999) forum, which was later renamed RGTA.

During the first half of 1999, the industry developed a set of business rules, which were used as a basis for the legal drafting of the RGTA related modifications 313¹²⁴ and 314¹²⁵ to the Network Code. These modifications respectively implement changes to the gas balancing regime (including the OCM market rules) and the entry capacity regime. Consultation on the modifications began in June 1999. Ofgem will make its final decision on the modifications at the beginning of August.

¹²² The New Gas Trading Arrangements, Ofgem, May 1999.

¹²³ This was mainly due to the constraints at the St. Fergus terminal in the summer of 1998.

¹²⁴ Modification 313: Development of the energy balancing regime to facilitate implementation of the on-the-day commodity market.

¹²⁵ Modification 314: Development of entry capacity entitlements based on a Seasonal Normal Demand (SND) profile.

Ofgem expects that the reforms to be implemented in October 1999 will represent a significant step towards the RGTA objectives. Additional phases are expected to be introduced through further modifications.

15.2.1 RGTA Proposed Capacity Reforms

Currently there is no limit to the amount of entry capacity that shippers can book through Transco and total bookings can exceed the physical capacity at a terminal. Hence, a shipper does not have firm rights to its booked capacity. In the event that the capacity available on a day is less than the total capacity booked, shippers have their capacity entitlements scaled back.¹²⁶ Previously such constraints were dealt with through the Flexibility Mechanism.¹²⁷

During the summer and autumn of 1998 constraint problems at the St. Fergus terminal resulted in direct costs through the Flexibility Mechanism amounting to approximately £22m. There was also a knock on impact on the spot and forward markets. The constraint was compounded by delays in the completion of maintenance operations, and Transco was exposed to a liability of £8.9m to reflect the reduced availability of St. Fergus capacity compared to that advertised in its 10 Year Statement.¹²⁸ Ofgem is currently investigating claims that shippers exacerbated apparent constraints by nominating more than they intended to flow in order to benefit from the resulting system sells that Transco was forced to take.

The constraint problems at St. Fergus and the lack of certainty caused by non-firm rights served to stimulate a wide-ranging review of the entry capacity regime in parallel with the gas balancing review.

A better definition of entry capacity rights and the provision of a firm service are key objectives of RGTA. Therefore, the new capacity arrangements will limit the purchase of entry capacity by shippers to that which is deemed to be available. Appropriate commercial incentives are also to be placed on Transco, as SO, to ensure it maximises

¹²⁶ Modification 271, which allowed for scaling back at all terminals instead of managing constraints through the flexibility mechanism, was introduced in October 1998.

¹²⁷ The screen-based system on which shippers are able to place bids to buy gas from Transco or offers to sell gas to Transco in order that Transco can maintain an overall system balance between inputs and offtakes.

¹²⁸ St Fergus and Bacton investigation: a progress report, Ofgas, March 1999.

the availability of capacity on the day. If, on a given day, Transco is unable to provide the level of capacity that it has sold as firm rights, it must buy back the capacity right from those shippers who are willing to sell, and Transco will bear a portion of these buy-back costs.

With the sale of entry capacity limited to what is physically available consideration needs to be given to the most efficient method of selling that capacity. It is anticipated that price auctions will be introduced in the sale of entry capacity from autumn 1999. Ofgem has consistently stated its belief that price auctions, or selling mechanisms with equivalent economic effect, are the most efficient way of allocating a scarce resource. Furthermore, price auctions would allow shippers to value capacity at different entry points and at different times of the year. Where the price auction resulted in relatively high prices, this would provide useful information to Transco on the need for expansion of entry capacity. Transco is currently consulting on alternative price auction mechanisms for allocating capacity from 1 October 1999.

In summary, Ofgem expects the following changes to the entry capacity regime to be introduced:

- ◆ firm capacity rights for shippers by limiting capacity sales to availability;
- ◆ incentives on Transco to make the maximum possible amount of capacity available;
- ◆ capacity to be allocated via price auctions; and
- ◆ arrangements to facilitate secondary market trading in capacity (including via a day-ahead auction where shippers post bids and offers for capacity rights).

In the longer term, Ofgem expects that the proposals pertaining to entry capacity will be extended to exit capacity. In addition to this, a programme of work on long-term investment signals has been initiated and Ofgem will consult more formally on this set of issues in the near future.

15.2.2 RGTA Gas Balancing Reforms

A key feature of the new gas balancing regime will be the introduction of the independently operated, screen-based OCM. In addition to being used by Transco to balance the system, the OCM will also support shipper-to-shipper trading.¹²⁹

The OCM will provide a tool which shippers can use to fine-tune their own gas balance position (i.e. the extent to which their gas inputs to Transco's system are matched by their offtakes) and thereby enabling them to manage their own imbalances better. Accordingly, Ofgem feels that it is appropriate that the incentives on shippers to balance their portfolios should be strengthened. This will be achieved through the reduction and then removal (from 1 April 2000) of balancing tolerances.¹³⁰ Instead of being allocated tolerances, shippers will be able to purchase what flexibility they require through storage products, including linepack¹³¹ services, which Transco is currently developing for 1 April 2000.

The cash-out regime for energy imbalances has also been the subject of considerable debate within RGTA. Ofgem proposed that the price at which out-of-balance shippers are cashed-out should reflect both the underlying market prices and the cost to Transco of managing system imbalances. Over the longer term this will be achieved via a two-part cash-out price with a commodity element and a flexibility charge.¹³² The commodity element will be based on trades in the OCM. The flexibility charge will be derived from a daily linepack or storage price, once reliable indicators of the short-term economic value of these services develop.

Ultimately the flexibility charge will be targeted on those shippers who impose costs on the system (i.e. those shippers who have had an additional flexibility requirement greater than their purchased linepack tolerances within day). The current level of information resolution means that this is not possible at the moment, as within-day

¹²⁹ A shipper is a licensed company that arranges the transportation of gas across Transco's National Transmission System (NTS) and is a party to the Network Code.

¹³⁰ Balancing tolerances determine the price at which a shipper is cashed-out by Transco. Within its tolerance band a shipper pays System Average Price (SAP), and outside it pays System Marginal Price (SMP). Balancing tolerances are expressed as a proportion of a shipper's supply portfolio.

¹³¹ Linepack is the physical storage capacity available in the pipelines of a gas transmission network that is frequently used to manage the system over short timescales.

¹³² For example, the flexibility charge may reflect the cost of gas storage.

information as to a shipper's physical position is not available. Actual physical flows are not known until end of day. Ofgem believes that better real time information will significantly improve cost targeting and is looking at both commercial incentives and regulatory methods that could improve the provision of such information. In the interim, it may be the case that those shippers who can prove that they were not responsible for Transco incurring flexibility costs will be exempt from charges that they currently bear in common with others (known as 'smeared costs').

The final aspect of RGTA is the introduction of commercial incentives on Transco in its Balancing Operator role.¹³³ Ofgem believes that by implementing an incentive scheme it will encourage changes in Transco's behaviour that will lead to more efficient balancing decisions on their part. This will mean a reduction in overall gas balancing costs. Specifically Transco will be incentivised to take balancing actions at prices close to the Market Average Price.

In summary, the following changes will be made to the gas balancing regime:

- ◆ the introduction of a screen-based, on-the-day commodity market (OCM), run by an independent market operator;
- ◆ a reduction in and eventual removal of balancing tolerances;
- ◆ a more cost reflective cash-out based on the commodity price of gas on the day, and the cost to Transco of managing system imbalances; and
- ◆ commercial incentives on Transco to make more efficient balancing decisions and reduce balancing costs.

15.3 A Comparison of RGTA Proposals with RETA

As both the electricity and gas industries are undertaking fundamental reforms, Ofgem has sought to ensure consistency of approach across the two new regimes. The fundamental principles underlying both sets of arrangements are the same although some detailed implementation rules differ. This is in part due to the different starting points in the two industries and in part due to the different physical characteristics. For example, the ability to use linepack and other on-the-day storage options mitigates the need for second by second balancing in gas. Here some of the approaches that have

¹³³ The balancing operator is the entity responsible for national supply/demand matching.

been adopted in each market are examined, highlighting where they are similar and outlining where and why different paths have been chosen.

15.3.1 Role of System Operator and Balancing Operator

Under the RGTA proposals, transportation capacity¹³⁴ and gas will be two entirely separate tradable commodities. This will, therefore, facilitate a clearer separation of the roles of BO (the entity responsible for overall national supply/demand matching) and the SO (responsible for management of the transportation system). The SO will solve constraints largely through the purchase of capacity rights in the capacity market, and the BO will balance the system using purchases of gas through the gas market. In practice, Transco will initially undertake both of these functions. In electricity, capacity and energy are not yet separate tradable commodities. Therefore under RETA there is currently no distinction between the BO and SO roles, and the Balancing Mechanism will be used for system balancing (including the resolution of transmission constraints) as well as overall national supply/demand balancing.

15.3.2 Obligations to Balance

The new electricity trading arrangements will see the introduction of a cash-out regime in the electricity market that broadly resembles the approach in gas. This means that participants will have a commercial incentive to take responsibility for balancing their own position. Since the introduction of the Network Code, shippers in gas have faced a cash-out regime to incentivise them to balance their inputs and offtakes at end of day. However, under RGTA it was recognised that the current system involving a balancing tolerance band did not provide a strong enough incentive, on all days, for shippers to balance. Therefore, a gradual removal of balancing tolerances was proposed to provide a greater incentive to balance. On the basis of experience in gas, and taking account of need for closer real-time matching of demand and supply flows, there will be no tolerance bands in electricity.

15.3.3 Cash-out

Both RETA and RGTA have adopted the principle that cash-out prices should reflect the underlying commodity price on a day and the costs of the flexibility needed within the system for balancing purposes over short timescales. In both gas and electricity, a two-

¹³⁴ Capacity is referred to in a general sense here. At a finer level, the exact nature of the scarcity of capacity may differ between electricity and gas.

part cash-out regime has been adopted to incentivise participants to balance their positions and thus minimise the actions needed to be taken by the SO.

15.3.4 Incentives on Transco and NGC

Although, in the past, NGC have been incentivised to manage the costs of transmission constraints and the costs of energy imbalances, commercial incentives on Transco are to be implemented for the first time under RGTA. Though the structure of incentives that NGC will face, as a result of the new electricity trading arrangements, has not yet been decided in detail, NGC will continue to be commercially incentivised.

15.3.5 The Role of 'Shippers'

Some participants in the electricity market have suggested that responsibility should be placed on a single category of licensee to provide both input (generation) and output (demand) nominations. This 'nominator' role would be the equivalent to that of a shipper in gas. However, the role of gas 'shipper' was introduced largely as a means of bringing companies with legacy transportation agreements under the same balancing arrangements as the Network Code, without having to renegotiate those contracts.

There is no reason to suppose in electricity that a nominator, responsible for making nominations both for delivery to the system and off-take from the system, should have more or less incentive to balance these nominations than a generator (producer) or supplier making either or both of those nominations. Imposing obligations on just one type of market participant to make nominations appears unduly restrictive and is inconsistent with the RETA goal of allowing the maximum possible flexibility in arranging contracts.

15.4 Detailed Process Interactions

Below the interactions between the gas and electricity markets are examined in detail from the perspective of a generator with a gas-fired power station who holds a gas contract with a shipper, and the options and the potential arbitrage opportunities open to this generator under various scenarios. However, these observations are equally valid for an electricity consumer who has interactions in both markets (for example, an industrial site consuming both gas and electricity).

15.4.1 Price Responsive Plant

When discussing arbitrage opportunities, the most obvious example to consider is probably that of a flexible generator burning gas under contract. In this case the generator has the option to generate or sell the gas from its contract back into the gas spot market at short notice due to the flexibility of these types of plant.¹³⁵ From 1 October the OCM will provide a screen-based mechanism with transparent within day prices for gas. Hence, the generator will be able to watch the price relativities in the two markets, and will decide whether to generate or not depending on the prices within each market.

If there is an attractive price in the gas market before 'Gate Closure' in electricity the generator may decide to sell its gas into the OCM and not generate, submitting a zero FPN. If the generator had a contract position in electricity, it would then face a cash-out exposure; but if it had no contracts there would be no further liabilities. Initially, unless the generator also happened to be a gas shipper, the generator's trades in the OCM would be transacted by a broker (since for 1 October there will be a requirement to hold a shipper's licence in order to be able to trade in this market). However, it is envisaged that other participants will, in the future, be able to apply for licences to trade on the OCM, and it is expected that generators would apply for them. For example, the Association of Electricity Producers (AEP) has stated that some of its members are interested in participating directly in the OCM.

If, in the electricity Balancing Mechanism, the generator submits a non-zero FPN to reflect its contract position and the gas price rises after 'Gate Closure', it has two options. It may decide to generate according to its submitted FPN in order to avoid facing the electricity cash-out price. Alternatively, it may choose not to generate and sell its gas into the OCM. Given the contract position it would face cash-out exposure at an unknown price. The generator will have some idea of what the cash-out price is likely to be from observing the price of bids and offers already accepted in the Balancing Mechanism. However, later acceptances could significantly shift the cash-out price. If, on the other hand, the generator had no contract position then it would again

¹³⁵ It is assumed here that the generator's gas supply contract gives it the right to sell on the gas, though this may not always be the case.

have no cash-out exposure, assuming that the information imbalance charge remained zero.

It is expected that active arbitrage between the electricity and gas markets will be observed, leading to a transfer of energy and a degree of price convergence. In particular the different resolution of pricing (48 half hours in electricity versus currently one day in gas) creates arbitrage opportunities for those plant with the capability to generate for short periods throughout the day. High prices in the electricity market and low prices in the gas market will encourage generators to purchase spot gas and use it to generate electricity, putting upward pressure on the gas price and downward pressure on the electricity price. Conversely high prices in the gas market and low electricity prices will lead to generators selling the gas from their contracts back into the gas market, putting downward pressure on the gas price and upward pressure on the electricity price.

15.4.2 Interruptions

Many CCGT plants have interruptible gas contracts with a shipper who supplies their gas at a discount. Such contracts could result in the gas supply being interrupted either before or after Gate Closure in the electricity market.

Generators whose gas supplies have been interrupted or who have chosen to sell on their gas may be able to continue generating using a back-up fuel. However, under the present arrangements, there is generally no opportunity for them to adjust their bids to reflect the cost of the substitute fuel. Under the new electricity trading arrangements it will be possible to amend offers up to four hours before the trading period, allowing generators greater flexibility to submit offers with prices related to the costs of their substitute fuel.

Additionally, the present trading arrangements allow plant availability to be re-declared on the day without financial penalty, other than the loss of SMP and capacity payments. Opportunities for gas fired plant to sell gas into the gas spot market instead of generating provide opportunities for arbitrage that do not reflect the fundamentals in either market. This reflects the general problem that prices set a day in advance based on forecasts may not reflect events on the day. At times of high demand, however, overall market prices, and not capacity payments on their own, have provided sufficient incentives for

most gas-fired plant to utilise standby fuel supplies to cover gas interruptions and/or arbitrage opportunities. In addition, the Pool has adopted measures to remedy weak incentives, via the NGC System Warning of Inadequate System Margin.¹³⁶ This enables the Pool to make payments to generators when they use distillate fuels as a back up. Under the new trading arrangements, the relevant electricity prices will be set much closer to real time, thereby helping to promote more efficient decisions.

There are two general types of interruptions in gas. The first is Commercial or Supplier Interruption. This is purely a commercial decision made by a shipper to interrupt its customer. The amount of notice a shipper must give its customer is determined by the individual contract between the shipper and the customer.

The second type of interruption is Transportation Interruption. This is broken into two types, both of which are ultimately controlled by Transco. Interruptions under Shipper nominated interruptible (SNI) contracts occur when Transco decides that a certain volume of the NTS is to be interrupted, but allows shippers to nominate which particular sites will be interrupted. Interruptions under Transco nominated interruptible (TNI) contracts occur when Transco directly decides which sites are to be interrupted. Such interruptions apply to customers who are at particularly sensitive points on the NTS. For interruptions under both SNI and TNI contracts, Transco gives the shipper 5 hours notice, and the shipper must inform its customer(s) within an hour. Therefore the customer will always have at least 4 hours notice.

If the generator has offtake contracts, and its gas supply is interrupted it could face exposure for non-delivery if it does not generate. A variety of options for avoiding this exposure are available to the generator,¹³⁷ depending on the type of interruption and its timing, as shown in Table 15.1.

¹³⁶ Inadequate System Margin (OC7.4.8.5, OC6.5, and SDC1.4.5.2.1) System Warnings can be issued at the day ahead or a few hours before a peak demand and advises all users that there is a shortage of generating availability to meet requirements, which includes an element for contingency reserve. The warning is assessed and if necessary re-issued or withdrawn, normally following each control SGOAL study.

¹³⁷ Again assuming that the information imbalance charge is zero.

Table 15.1 - Options for Avoiding Exposure to Electricity Cash-out Prices

Type of interruption	Timing	
	Before 'Gate Closure'	After 'Gate Closure'
Commercial	<ol style="list-style-type: none"> 1. Trade electricity to cover exposed position and do not generate 2. Purchase gas to cover shortfall and continue generating 3. Flow the gas, probably face penalties from shipper and continue generating 	<ol style="list-style-type: none"> 1. Purchase gas to cover shortfall and continue generating 2. Flow the gas, probably face penalties from shipper and continue generating
SNI contracts	<ol style="list-style-type: none"> 1. Trade electricity to cover exposed position and do not generate 2. Flow the gas, probably face pass through of Transco penalties from shipper and continue generating 	<ol style="list-style-type: none"> 1. Flow the gas, probably face pass through of Transco penalties from shipper and continue generating.
TNI contracts	<ol style="list-style-type: none"> 1. Trade electricity to cover exposed position and do not generate 2. Flow the gas, pay Transco penalties and continue generating 	<ol style="list-style-type: none"> 1. Flow the gas, pay Transco penalties and continue generating

Note: Interruptions under TNI and SNI contracts can only occur in the first half-hour after 'Gate Closure' since customers should always have four hours notice of these types of interruption. The options discussed above may be limited by the dynamics of the plant.

If the generator has been commercially interrupted, there is no physical reason why the generator cannot receive gas and it therefore has available a number of options for continuing to generate. The purchase of alternative sources of gas (either OTC or on the OCM) can take place after the event, up until the end of the gas day. Continuing to flow gas in the event of a transportation interruption of either kind will result in penalties being levied either on the generator's shipper (SNI) or directly on the generator (TNI). This will be the case even when additional sources of gas have been purchased and hence it is not a realistic option. Additional purchases of gas therefore are only likely to be a realistic option in the case of a commercial interruption. In these circumstances, it is for the generator to determine whether the cost of purchasing gas outweighs the exposure it faces from contractual penalties with its shipper or via the electricity cash-out price.

If a generator has posted Offers/Bids on the Balancing Mechanism and is notified of an interruption after 'Gate Closure', it can simply withdraw the Offers/Bids by changing its Maximum Output Volume, assuming that no Offer or Bid has already been accepted. If an Offer/Bid has been accepted then the generator can either accept exposure to the cash-out price or pursue the post gate-closure options shown in Table 15.1.

Those generators with access to supplies of back-up fuel (such as gas oil or coal) will have an additional option for managing their contractual exposure in the event of a gas interruption. A generator in this position will need to trade-off the costs of running on its alternative fuel against the OCM gas price and its expectations of the cash-out prices in each market. Moreover, if the interruption occurs before 'Gate Closure', the generator will be able to reflect the costs of running on back-up fuels in any Balancing Mechanism offers or bids it chooses to submit.

15.5 Summary

The gas and electricity industries are both undertaking fundamental reforms of their trading arrangements, and many of the features emerging in both markets are the same, such as the emphasis on participants taking responsibility for balancing their own positions. Where the industries have taken a different path, it is mainly due to their different starting points or to relevant differences in systems operation and overall supply/demand balancing. While the precise details may differ, the fundamental principles underlying both sets of arrangements are the same.

Efficient interactions between the gas and electricity industry will be greatly facilitated as a result of the introduction of the proposals under RGTA and RETA. These reforms provide greater commercial flexibility for all market participants and allow them to manage their exposure with a range of new options for managing risks. The increased interactions between the two sets of markets can be expected to lead to a more efficient determination of within day commodity prices for the energy industry.

16. Security of Supply

This chapter discusses security of supply in the context of the new trading arrangements

16.1 Definitions

Issues concerning security of supply generally relate to one or more of three, distinct aspects of market balancing:

- ◆ long-term security – ensuring that there is adequate generation capacity to meet the overall level of demand, which is frequently assessed by reference to the capacity margin (i.e. the margin between maximum generation capacity and expected peak demand);
- ◆ short-term security – ensuring that capacity will be available to meet demand when and where required 'on the day'; and
- ◆ supply quality - ensuring that electricity supplies meet the technical standards that are in force.

The relevant capacity includes transmission, as well as generation capacity, although the focus of this chapter is on the latter.

Additional security of supply can be provided at extra cost, for example by increasing capacity. An efficient level of provision will be realised when the incremental costs correspond to amounts that electricity customers would be willing to pay for security (i.e. for changed probabilities of supply failures). Well-functioning markets should provide signals to both generators and demand-side participants to maintain an efficient level of overall security which should allow customers (or suppliers acting on their behalf) to choose the level of security that, taking account of the costs involved, best meets their requirements. For example, efficient arrangements should lead those customers who value security least to shed load at times of system stress in order that others, who value security more, can continue to be supplied. As discussed in Chapter 4, the approach of relying on market signals to determine the appropriate levels of security of supply is increasingly being adopted in international electricity markets.

16.2 *The Present Arrangements*

Under the present trading arrangements, there are a number of provisions that are intended to achieve what is deemed to be an adequate level of supply security over the long and short-term. These include:

- ◆ the capacity payment mechanism;
- ◆ the information flows between NGC and market participants;
- ◆ NGC's co-ordination of ancillary services delivery; and
- ◆ the supply licence generation security standard condition;

Experience with the current arrangements indicates not only that signals to consumers are very deficient but also that:

- ◆ capacity payments appear to have had only a limited effect on generators' decisions to build new generation plant and have not been very effective as a short-term signal to encourage the availability of existing plant;
- ◆ capacity payments have also led to opportunities for arbitrage between gas and electricity markets which have not reflected the fundamentals in either market, and hence have potentially been detrimental to security of supply.

Experience also shows that accurate and timely information flows between NGC and market participants over all timescales (including real time) make an important contribution to security of supply and that ancillary services, which are important for security and quality of supply, are also of great importance in providing the flexibility required for NGC's minute-to-minute operation and short-term planning of the power system.

The generation security standard condition in suppliers' licenses is fulfilled by suppliers joining the Pool and hence agreeing to purchase electricity at prices up to an administered ceiling, the Value of Lost Load (VOLL).¹³⁸ In practice, it has no direct impact on suppliers' behaviour with regard to security of supply.

¹³⁸ This parameter is intended to reflect the value of any curtailed demand. It was set at £2,000/MWh in 1990. It increases each April by the annual rate of inflation (RPI) measured to the preceding December, and its value for 1999/00 is £2,768/MWh.

The capacity payment mechanism was intended to provide an incentive to generators to declare plant available for despatch by the SO. This payment is a function of two factors: the Loss of Load Probability (LOLP) and VOLL. LOLP¹³⁹ was intended to reflect the probability that there will be insufficient plant available to meet demand. All generation capacity that is declared available receives payments under the capacity payment mechanism.¹⁴⁰

Table 1 provides evidence that the plant margin was at a historically high level at Vesting and even considerably above the planning margin used by the Central Electricity Generating Board.¹⁴¹ Thus, it is unsurprising that, despite considerable new entry, the plant margin has declined somewhat; that is, plant withdrawal has exceeded new capacity. Since 1996/97 the plant margin has stabilised (NGC estimates that the plant margin for 1999/00 will be 23.8%). Table 1 also shows evidence on the historical level of capacity payments. On a year by year basis there has been some evidence of an inverse relationship between capacity payments¹⁴² and plant margins. However in the nine years since Vesting, there have also been some marked anomalies, for example in 1991/92 and 1996/97.

¹³⁹ The Loss of Load Probability is calculated for each half-hour using NGC's demand forecast and Generator Availability Declaration data, together with their associated uncertainty.

¹⁴⁰ Those that are scheduled to produce energy are paid $LOLP \times (VOLL - SMP)$ whilst those generators that are not called to generate are paid unscheduled availability payments equal to $LOLP \times (VOLL - \max\{\text{bid}, SMP\})$.

¹⁴¹ The CEGB's planning margin varied throughout the 1960's, 70's and 80's but never exceeded 28%.

¹⁴² To be precise, the relationship is expected between LOLP and margins, but as VOLL changes only slowly, the product of LOLP and VOLL (i.e. capacity payments) can be used as a reasonable proxy.

Table 16.1 - Capacity Payments and Peak Demand

	Capacity Payments		New Capacity (GW)			Peak Demand	ACS Plant Margin ¹⁴³
	£/MWh	£/kW	CCGT	Other	Total	GW	%
1990/91	0.05	0.4	0	0	0	47.2	32.1
1991/92	1.30	11.1	0.2	0	0.2	47.7	28.8
1992/93	0.17	1.5	1.8	0	1.8	44.9	26.3
1993/94	0.28	2.4	2.6	0	2.6	47.7	27.6
1994/95	3.22	28.2	3.1	1.6	4.7	45.9	21.5
1995/96	4.47	39.3	0.7	0	0.7	48.8	18.4
1996/97	3.23	28.3	3.5	0.1	3.6	49.7	24.8
1997/98	0.85	7.5	1.4	0	1.4	49.7	23.0
1998/99	1.00	8.7	2.2	0	2.2	49.1	22.3

Source, NGC Seven Year Statement 1999.

Over the long-term, the decisions to build or close plant are based on expectations of total revenues (and of costs) that a plant may earn over the relevant future periods, including any revenues available from capacity payments. Capacity payments have varied between years and there has been considerable uncertainty regarding their level from one year to the next. High or low levels of payment in a particular year are therefore not necessarily a good signal of likely total capacity revenues over the relevant plant lifetimes. While significant new entry has occurred, neither the level nor the pattern of entry appears to have had much to do with the level of capacity payments.

In the initial period following the introduction of the new trading arrangements, it is anticipated that the opening capacity margin (currently around 24%) will be more than sufficient to provide market participants with adequate time to adjust to the new incentive structures relevant to investment and closure decisions, without risk to efficient, long-term security of supply.

16.3 International Experience

As discussed in chapter 4, liberalised electricity systems around the world are increasingly relying on market approaches to secure efficient security of supply. In these approaches, generators are expected to recover their fixed costs through the revenues they receive from energy supplied, from bilateral contracts that involve a fixed

¹⁴³ ACS (average cold spell) Plant Margin: Total registered capacity potentially available at peak demand divided by the weather corrected winter peak demand (ACS).

fee element (e.g. contracts that give the buyer the option to call energy at a given strike price in return for a fixed payment), or from the provision of Ancillary Services to the system operator. Security and reliability is achieved by voluntary trading that ensures that supply and demand are in balance, without regulatory interventions that impose either designated plant margins or mandatory capacity payments.

16.3.1 The Midwest of the United States

The Midwest is not a unified electricity market: there is no overall system operator and no centralised trading organisation, which potentially exacerbates any security of supply problems that may exist. In June 1998, this area experienced a shortage of capacity that led to extremely high prices.¹⁴⁴ It is understood that two marketers went bankrupt, as they were short on contract commitments. It should be noted, however, that the system did not fail physically: no customers were involuntarily curtailed, although there were widespread pleas that led to some voluntary load reduction.

The very high prices seem to have had a number of consequences, two of which are particularly relevant. First, a number of plans to build peaking plant have since been announced, although it can also be noted that some participants have subsequently stated that they have chosen not to invest in, or buy output, from such plant, indicating that they believe that the probability of similar events occurring again is not sufficient to warrant the extra expenditures involved. Second, the value of peaking contracts has substantially increased as suppliers' perceptions of risk and the importance of risk management practices have changed.

A subsequent investigation by FERC,¹⁴⁵ the federal regulator, found that the major causes of system stress were above average plant outages, extraordinarily high temperatures leading to unexpected demand, and transmission outages leading to constraints. It concluded that the price spikes did not threaten the reliability of supply and that regulation in the form of price caps, which had been proposed by some stakeholders as a remedy for the problems experienced, was unnecessary as it would distort the market signals and potentially cause shortages. In other words, FERC believed that extreme price spikes were part of the effective functioning of the market in that they

¹⁴⁴ Up to a reported maximum of US \$7,500/MWh (approximately £4,600/MWh).

¹⁴⁵ Staff Report to the Federal Energy Regulatory Commission on the Causes of the Pricing Abnormalities in the Midwest during June 1998. Federal Energy Regulatory Commission.

gave signals of the value of capacity in stressed conditions and rewards to those who had provided such capacity.

FERC also commented on a number of potential failings of the market. Two of the more important in terms of system design were:

- ◆ the lack of price information close to real time which, if available, could have facilitated more appropriate adjustments in the positions of market participants; and
- ◆ the lack of demand responses: demand side participants were given no price signals to encourage them to adjust their demand (although subsequently there has been a reported increase in demand responsive contracts, which again indicates an appropriate market response to the events).

It would be inappropriate to draw strong conclusions for the England and Wales system from the Midwest case, not least because of the absence of an overall system operator in the Midwest. It has been argued that the behaviour of some Midwest market participants was influenced by the expectation of some regulatory relief for losses, and some reports on the events have taken a more critical view of the state of the Midwest markets and on the prospects for a recurrence of the situation.¹⁴⁶ Nevertheless, the regulatory agencies see the longer-term solution as increased transmission co-ordination, greater price transparency and market liquidity through the development of a Power Exchange, and the development of new risk management tools. All of these are consistent with the arrangements proposed for England and Wales.

However, an important implication of the Midwest case for RETA is that, consistent with the FERC reasoning, it is important that market participants understand that, during times of system stress, the market will be allowed to function without the threat of regulation that would have the effect of dampening price signals. More generally, interventions to influence market prices during such periods risk creating either incentives for deficient investment in capacity (if price spikes are suppressed) or for excessive capacity (if the rewards provided are too high), as has happened in some other electricity systems. In practice, it has proved extremely difficult for regulators and

¹⁴⁶ For example, the report of the Ohio Public Utilities Commission into the same events.

politicians to set prices or to find other forms of intervention that ensure that security of supply will be provided at an efficient level.

16.4 Short-term issues

In the short-term (i.e. on-the-day), security of supply is driven mainly by the availability of plant (both generation capacity and capacity on the demand-side) already in existence. Under the new trading arrangements, market participants will be encouraged to balance their positions through the incentives provided by the cash-out regime. Strong on-the-day signals, to which participants can respond, will emerge from the Balancing Mechanism and the short-term market(s) that will develop. Under-contracted suppliers and exposed generators will seek to trade out their exposure in advance of Gate Closure in order to avoid unfavourable cash-out prices on imbalances, and short-term prices will rise in response to avoid such imbalances. This will, in turn, influence the prices of offers and bids submitted to the Balancing Mechanism, and hence increase imbalance prices, reinforcing the signals to participants. This implies that, at periods of system stress, prices may rise to very high values (as was the case in the Midwest in 1998). Such trades are expected to represent only a small proportion of the total electricity traded.

The price signals that emerge when the supply-demand gap is tight will encourage generators who have spare capacity to make it available either in the short-term forwards markets or to the SO via the Balancing Mechanism. Similarly, the signals will, over time, encourage an appropriate level of demand-side response (as discussed in Chapter 13), which is limited in the present Pool system. For smaller customers, opportunities to participate in short-term balancing may come through innovative use of radio teleswitching and developments in respect of deemed profiles. Thus, price information from both the short-term forwards markets and the Balancing Mechanism will provide valuable information to customers or their suppliers that should assist them in formulating their strategies. Whilst the nature of the interest from the demand side remains to be seen, some demand has quite short lead times and might well be interested in obtaining value for that flexibility.

16.4.1 The Balancing Mechanism

In relation to short-term security of supply, the principal opportunities for adjustments is during the operation of the Balancing Mechanism. Apart from balancing services contracts, the primary tools that NGC will have to manage the system are the offers and bids submitted to the Balancing Mechanism by those participants willing and able to make adjustments to their notified positions. NGC will select such offers and bids as are necessary to ensure demand is met and security is maintained. As discussed in Chapter 6, in the very unlikely event that there are insufficient offers and bids available in the appropriate locations, in securing the system NGC will be able to make use of Deemed Offers and Bids from all licenced and licence-exempt signatories of the BSC. These Deemed Offers and Bids, which will be zero priced, will not be included in the calculation of imbalance prices.

Unlike the current Pool, the Balancing Mechanism will operate close to real time and information on the acceptance of offers and bids will be visible to all participants. Hence, participants will have better information than they have presently when making offers and bids at the day-ahead stage and will be able to adjust their position to better reflect the state of the market. The information available is likely to include price information from the short-term forwards markets, information concerning their own position and market based forecasts from external sources. For example, NGC is proposing to publish regular demand and plant margin forecasts.

As discussed in Chapter 15, the new trading arrangements will also lead to more efficient interactions with the gas market, as the arrangements in the two markets will be more effectively synchronised. Generators who choose to arbitrage between the markets will be exposed to electricity imbalance prices if they sell on their gas and do not generate. The SO will receive information from them that updates their planned positions, and they will be able to re-submit offers reflecting their expected generation on the day. Generators will also be able to purchase power on the day to cover their contractual exposure to imbalance prices if they sell on gas or are interrupted. As a result, on the day prices in both gas and electricity markets should better reflect the supply-demand positions in the two markets, and arbitrage will be driven by more accurate economic signals (rather than, as now, by arbitrary differences in trading arrangements for gas and electricity).

16.5 Medium-term

During a cold spell or unexpected plant failures, security of supply will be determined mainly by the decisions of existing generators, suppliers and customers on a week to week basis. Participants will have already made their decisions as to whether they wish to enter or exit the market (e.g. build or close plant) and so, as in the short-term case, it is the availability of plant that is the central issue.

Since the price of offers/bids in the forwards/futures market and in the Balancing Mechanism will tend naturally to rise as the prospective capacity margin in any half-hour reduces, a cold spell or a prolonged plant failure will result in high short-term prices that persist for the relevant period. The possibility of exposure to disadvantageous imbalance prices over such a period should encourage short-term contracting activity by customers/retailers in the event of unexpectedly high demand and by generators whose plant is more likely to fail.

To the extent that option contracts become widely traded, their price will provide a good signal of the value of capacity to suppliers and customers at times of peak demand or low availability. Option contracts can provide a source of stable revenue by which availability of peaking plant can be encouraged. The holders of options are likely to exercise them in response to periods of high demand or low plant availability, thus increasing the capacity of plant committed to generation in such periods. Although, since options will have to be exercised by Gate Closure (unless they are in the form of a financial hedge), such contracts are unlikely to play a significant role in ensuring appropriate adjustments very close to real time. Another source of revenue for plant that can be made available for short-term balancing purposes will be from contracts for the provision of balancing services to the SO.

16.6 Long-term

Over the long-term (on a year to year basis) new plant build and plant closures are the main influence on generation security of supply. The encouragement of properly functioning, two-sided markets, with greater demand side participation and the availability of forward price curves, should provide robust signals of the capacity required to ensure an efficient level of security of supply.

Compared with current arrangements, the development of forward curves for electricity prices will provide more accurate signals as to potential future revenues for generation plant, and will therefore encourage more efficient entry and exit decisions. Such forward curves have developed in other electricity markets where bilateral contracting plays a substantial role, notably NordPool,¹⁴⁷ and the UK gas market.¹⁴⁸ Forward price curves provide a direct way in which short and medium-term economic signals can inform long-term decisions. Furthermore, the greater number of shorter-term contracting options should increase the confidence of project developers when making decisions to build plant.

16.7 The Role of the System Operator

The overall responsibilities of NGC, as SO, for managing the system, which are of central importance in ensuring adequate short-term security of supply, will remain, but the manner in which they are discharged will change. One of the main changes will be that the SO will have to reschedule plant and demand-side bidders at shorter notice than at present. The SO currently begins scheduling plant at the day-ahead stage, but it currently has to determine a complete schedule for all the available plant and demand side bidders. Under the new trading arrangements, the SO will only have to adjust schedules that participants have themselves determined, so that the magnitude of the task facing NGC will be correspondingly smaller. The incentives on participants to self-balance, which will result from the dual cash-out price regime, should serve to limit the scope of the short-term actions that the SO has to take, and thereby make such actions more manageable within short timescales.

The SO will be able to call, as now, on balancing services contracts for frequency response, reserve, reactive power, constraints and black start. In the early stages of the new trading arrangements, NGC contracts for reserve will be important in providing confidence that short-term security of supply will be maintained. There is a trade-off between reliance on contracts and reliance on the Balancing Mechanism for achieving short-term balancing of the system. On the one hand, it can be argued that contracts for reserve might tend to dampen the price signals emerging from the Balancing Mechanism, and thus weaken the incentives on participants to manage risks themselves.

¹⁴⁷In the NordPool futures market, Eltermin, contracts are traded for up to three years ahead.

On the other hand, NGC will be able to provide greater short-term security of supply through forward contracting for balancing services and related balancing products.

One of the factors that will determine the resolution of this trade-off will be the incentive arrangements faced by NGC and, as explained in Chapter 8, it is desirable that the SO's incentives encourage use of the most efficient mix of alternative balancing instruments. It is for further consideration whether a general incentive scheme will be sufficient to encourage the SO to secure system balancing in the most efficient manner, or whether some additional limitations should be placed on the extent to which the SO can contract for some or all of the relevant balancing products, particularly in the longer term.

The SO will continue to need some externally imposed parameters to guide its operation of the system with regard to technical standards. The standards presently given in the Electricity Supply Regulations will continue to be used in this regard. These specify that, except in exceptional circumstances, electricity supply characteristics must be maintained within the following limits:

- ◆ frequency: within 1% of 50 Hz; and
- ◆ voltage: between +10% and –6% of 240 V.

The information flows between NGC and market participants will make an important contribution to delivering an efficient level of security of supply. As now, NGC will be able to obtain the information it requires from participants to maintain the operational security of the system under the terms of the Grid Code and/or the BSC. Similarly, NGC will continue to have obligations with regard to information provision to the market.

Over the long-term, NGC's Seven Year Statement will continue to provide information on long-term demand forecasts and the new plant build and closure decisions that have been notified to NGC. In the short-term, IPN data from market participants will be used by NGC to conduct system studies to identify potential system problems. NGC will

¹⁴⁸In the IPE exchange based market contracts are traded for delivery up to twelve months ahead. However, over-the-counter trades have been completed for delivery up to two or three years ahead.

feed back information to the market such as demand and imbalance forecasts on a national and zonal level. Closer to real time, FPN data from participants will allow NGC to determine the appropriate actions it needs to take to balance the system. Price and volume information from the Balancing Mechanism will also be available. Appendix 5 reproduces a DISG paper in full presented by NGC outlining its current views on the form and timing of information exchange between itself and the market. The exact form and timing of information exchanges between the SO and market participants is for further consideration.

16.8 Emergency Arrangements

Emergency arrangements will remain much as now. As now, as a last resort, the SO will instruct rota disconnections to maintain overall system integrity. These affect the whole of a particular geographic area and customers are disconnected without regard to the contract position of their supplier.

Although the position of all suppliers with regard to disconnections will be the same, this may well not be the case with regard to their exposure to imbalance prices. Rota disconnections will be one form of Deemed Offers. As explained in Chapter 7, the acceptance of a Deemed Offer, which would only occur after the SO had exhausted all the relevant offers in the Balancing Mechanism, does not affect the imbalance position of a participant. Thus, a fully-contracted supplier would remain in balance whilst an under-contracted supplier would be exposed to the System Buy price. Given the stress that the system would be under in periods when rota disconnections are invoked, the relevant System Buy price could be expected to be extremely high, and hence the under-contracted supplier would be penalised for making inadequate provisions for its customers. Consequently, some of the concerns that have been raised with regard to the potential for 'free-riding' by suppliers would not seem to be justified. Customers will be free to move from one supplier to another for their electricity requirements. The financial consequences of under contracting could not be passed on by that supplier to its customers in the form of higher prices.

16.9 Generation Security Standards

All supply licences currently contain a provision relating to the maintenance of generation security standards. Under the new trading arrangements, with their reliance upon markets to deliver an appropriate level of security of supply, it will no longer be

appropriate to impose the present condition, which defines the required level of security of supply, upon suppliers. Consequently, this condition will be removed from suppliers' licences. Instead, it is anticipated that suppliers will be obliged to continue purchasing electricity whatever the price unless they have made appropriate arrangements with their customers for the curtailment of their supply.

16.10 Summary

Under the new trading arrangements greater reliance will be placed on efficient pricing signals emerging from the market, NGC will also continue to play a major role in securing system balancing over very short time scales and will be incentivised to do so in an efficient way. It is expected that long-term security of supply will be enhanced by the emergence of forward prices for electricity that extend several years ahead. The emergence of fully functioning, two-sided markets, with an increasing role being played by the demand side, will provide both better signals of requirements for more or less capacity and incentives for market participants to respond in the appropriate ways.

17. Assessment Against Objectives

This Chapter assesses how far the new trading arrangements offer advantages over the present arrangements with respect to the objectives and further considerations of the Review. It also comments on potential costs and benefits.

17.1 Assessment Process

The objectives against which the trading arrangements were to be assessed were set out last year in OFFER's March 1998 working paper and appear again in Chapter 2.

Judgements have to be made as to how well the arrangements perform in terms of meeting each of the specified objectives of the Review, taking into account further considerations. These have been used as the framework for this Chapter.

17.2 Objectives Against Which to Assess the New Arrangements

The objectives of the Review are to consider whether, and if so what, changes in the electricity trading arrangements will best:

- ◆ meet the needs of customers with respect to price, choice, quality and security of supply;
- ◆ enable demand to be met efficiently and economically;
- ◆ enable costs and risks to be reduced and shared efficiently;
- ◆ provide for transparency in the operation of the pricing mechanism and the market generally;
- ◆ respond flexibly to changing circumstances in future;
- ◆ promote competition in electricity markets, including by facilitating ease of entry to and exit from such markets;
- ◆ avoid discrimination against particular energy sources; and
- ◆ be compatible with Government policies to achieve diverse, sustainable supplies of energy at competitive prices and with wider Government policy, including on environmental and social issues.

In addition to these objectives, the White Paper identified some issues where further consideration would be needed:

- ◆ continued security of electricity supplies in the long and short-term;
- ◆ prices that are transparent and ensure liquidity; and
- ◆ appropriate consideration of CHP, renewables generators, small embedded generators, NFFO generators and interconnectors.

Further, it was decided that the Review would also consider the implications of any changes to the trading arrangements for:

- ◆ the role of NGC;
- ◆ the development of competition in generation and supply;
- ◆ trading arrangements in Scotland;
- ◆ the development of contracts markets (including for physical delivery, CfDs and futures contracts);
- ◆ interactions between electricity and gas; and
- ◆ legislation on competition and utility regulation in Great Britain and the European community.

17.3 Assessment

This section presents the results of the assessment of the new trading arrangements against the formal objectives of the Review. The analysis includes comments on how the new arrangements compare to the present Pool arrangements.

17.3.1 Meeting Needs of Customers

The proposed arrangements remove the present provision in the Pool for nearly all generators to receive the same SMP price and will modify other elements in the revenue the generators now receive via the Pool. Instead, all generators will need to find buyers (whether suppliers, traders or customers) and to do that they will need to offer prices at least as good as are available elsewhere in the market. Purchasers will have richer options. All market participants will need to exercise greater judgement about when to contract, on what terms and in what quantities. This will be a process more akin to that

in other competitive markets. It can be expected to yield greater efficiencies and lower prices on average than would be the case if the present Pool were retained.

The incorporation of the demand side implies greater choice for final customers, derived from suppliers' ability to make use of a greater range of markets, such as forwards and futures markets, the Power Exchange, options markets, and the Balancing Mechanism. There will be greater incentive for generators and suppliers to participate actively in such markets. The new arrangements should facilitate freer entry into supply than the present arrangements, which will lead to greater choice, better service and lower prices for customers, since there will be more freedom to provide energy and risk cover in ways which suit the needs of individual participants. Individual customers and a wide range of customer groups have supported the proposed arrangements, and argued that they would better serve their interests.

Quality and security of supply will be maintained. Market incentives to make adequate capacity available will be sharper. The SO will continue to act to alleviate transmission constraints and to balance generation and demand in real time. In doing this the SO will be able to call on new market offers, while retaining emergency powers. Balancing services contracts will be part of its portfolio of actions, which will include contracts for reserve capacity.

Forward prices will indicate the need for new capacity to be built. The new arrangements will not include capacity payments. There is little evidence that explicit capacity payments have been important in retaining plant on the system or in providing additional security over and above other elements of the existing arrangements. Most competitive electricity markets overseas do not use capacity payments to achieve security of supply, nor do other commodity markets. Generators will submit offers which aim to recover their costs and this will lead to prices that will be at whatever level is necessary to induce generators to provide the necessary capacity.

17.3.2 Meeting Demand Efficiently

The proposed markets offer a variety of ways in which greater demand side participation will be possible. For example:

- ◆ suppliers and traders will be able to mobilise the large potential among half-hourly metered customers and domestic customers;
- ◆ the emergence of price reporting will allow the demand side to understand better the prices that energy is attracting at different points in time forward, which will be reflected in more flexible and informed contracting instruments;
- ◆ new power exchanges, operating closer to real time than the Pool, are likely to provide signals of market conditions to which demand side participants may choose to respond; and
- ◆ the Balancing Mechanism provides an opportunity for that part of the demand side that is prepared to respond close to real time to seek a market value for that response.

These new opportunities, and the prospectively lower costs of supply, should enable demand to be met more efficiently and economically.

17.3.3 Reducing Costs and Risks

The third objective is that costs and risks be reduced and shared efficiently. The arrangements propose firm bids and offers in a number of markets, together with the cashout of imbalances. This will enable the costs of matching supply and demand to be allocated more precisely to those market participants who cause the costs, through the workings of the Balancing Mechanism and the imbalance settlement system. The use of simple bids and offers further serves to assign risks associated with despatch to the parties best placed to manage them. Some of the markets will work much further in advance of the trading period than does the Pool; this ought to promote forward price discovery, as already happens in the gas market. Other markets, especially the Power Exchange, will operate closer to real time than the Pool, and will provide opportunities that do not exist now both to fine tune positions and to deal with unanticipated events. This variety of instruments will also reduce risk and allow it to be managed better.

The incorporation of the demand side will also reduce risks of exposure to imbalance settlement for both customers and suppliers. Those customers who are prepared to vary, typically to reduce their consumption, and those suppliers who offer contract terms to take advantage of this, can provide important load management options to the System Operator whilst at the same time reducing their cost exposure.

17.3.4 Providing Transparency

Prices in all markets will be based on simple offers and bids; this will increase transparency considerably compared to the complex bidding and price-setting procedures in the Pool. Offers and bids posted on the Balancing Mechanism will be visible to all participants. It is expected that, additionally, information regarding the depth of the market and the most recent prices accepted for offers and bids will also be available. Price reporting, because valuable to participants, may be expected to develop for the forward and futures markets, and the new power exchanges that are expected to emerge. In addition, at least some of these markets are likely to report the last accepted trade and outstanding bids and offers. All these elements are likely to provide a greater degree of transparency as compared to the present arrangements. Price reporting in the forwards market may however take time to develop. If the lack of price information proves to be adversely affecting the operation of the market then some price information may be provided through regulatory means.

17.3.5 Responding Flexibly to Changing Circumstances

The new arrangements enhance the ability of the market to respond flexibly to changing circumstances in future. They are themselves a more flexible set of arrangements than those in place at present. They invite market operators to establish a variety of markets and products. Actual or threatened competition in the form of alternative markets or products will ensure that this happens. The revised governance arrangements for the Balancing Mechanism and imbalance settlement will ensure that a greater variety of interest groups will be involved and that proposals for changes to the market rules are dealt with effectively, and in a speedier manner than at present.

17.3.6 Promoting Competition

Since the Review began, concerns have been expressed that it does not address issues of market power. The Review has always been alert to this issue, whilst recognising that changes in trading arrangements will not attack many aspects of the underlying ability to exercise market power. The government has also accepted this approach, and has taken a number of important steps, including agreements on the divestment of further plant by two of the major generators.¹⁴⁹ The Director General will continue to monitor closely the development of Pool prices and subsequent market prices. The Director General

¹⁴⁹ Plant was previously divested under an earlier agreement in 1995.

will alert the Secretary of State to any further concerns he may have. The Director General will also have recourse to the strengthened powers under the Competition Act 1998, and the retained 1973 Fair Trading Act provisions.

However, the new trading arrangements will make the exercise of monopoly power more difficult in important ways. The normal opposition of buyer and seller interests in markets will be substantially advanced in electricity. Entrants will have the benefit of more secure forward price information on which to base their plans. New hedging opportunities will encourage independent decision-making in both supply and generation.

17.3.7 Avoiding Discrimination Against Energy Sources

To the extent that prices have been higher than they would have been in a more competitive market, in part due to the present trading arrangements, it is possible that this has encouraged excess new entry at the expense of existing plant. Entry has been dominated by gas-fired plant whereas the majority of plant closures have been of coal-fired capacity.

The new trading arrangements, which form an important part of wider electricity reforms, will have to ensure that market prices more closely reflect costs. Consequently, entry into the market will be made on the basis of entrants seeking profitable opportunities to undercut the prevailing market prices. This will ensure that existing capacity is not disadvantaged by excessive entry of new capacity.

17.3.8 Compatibility with Government Policies

Trading arrangements should be compatible with Government policies to achieve diverse, sustainable supplies of energy at competitive prices and with wider Government policy, including on environmental and social issues.

The proposed arrangements move towards pricing electricity closer to real time through the use of on the day markets rather than a day-ahead auction. Such a development enhances the value of plant that can respond flexibly to changing circumstances. Part-loaded thermal units (fired by coal, gas or fuel oil), open cycle gas turbines (fired either by gas oil or gas) and pumped storage units are all capable of adjusting their output rapidly. Acknowledging the value to the system of these different types of plant should

help to secure their continued availability and hence help to achieve diverse supplies of energy.

A consequence of arrangements that provide a clearer recognition of the benefits of flexible plant is a relatively lower reward to less flexible plant, particularly plant whose output is less predictable. This does not necessarily mean, however, less diversity or an adverse environmental impact. Any plausible change in price or risk as a consequence of these arrangements is unlikely significantly to affect the output of the nuclear stations already in existence, or to affect future decisions to close or build nuclear stations. In addition, participants external to England and Wales will be able to trade across interconnectors in ways similar to those under the Pool.

With regard to CHP and renewables, many existing schemes will either benefit directly from the lower prices resulting from the new arrangements or, because of their stability and predictability of output, will easily be able to accommodate, within their present commercial operations, changes associated with the new trading arrangements. Other schemes which may be less well positioned due to the unpredictability of their output will be able to contract with other parties who will be better placed to manage such unpredictability on behalf of many such participants.

17.4 Further Considerations

In addition to the objectives listed above, the Review also has to consider the implications of any changes to the trading arrangements for:

- ◆ the role of NGC;
- ◆ the development of competition in generation and supply;
- ◆ trading arrangements in Scotland;
- ◆ the development of contracts markets (including for physical delivery, CfDs and futures contracts);
- ◆ interactions between electricity and gas; and
- ◆ legislation on competition and utility regulation in Great Britain and the European community.

17.4.1 The Role of NGC

Under the present trading arrangements, NGC carries out a variety of functions including System Operator (SO), and transmission asset owner (TO). It also undertakes some of the activities of the Market Operator on behalf of the Pool including that of Settlements System Administrator (SSA). The proposed trading arrangements will secure that the discharge of these functions will continue.

The SO/TO has a statutory duty to develop and maintain an efficient, co-ordinated and economical transmission system. In the longer term, SO activities would be little changed – the new incentives to be placed on the SO will ensure that it will procure efficiently a wide range of balancing services, including the acceptance of offers and bids in the Balancing Mechanism. The SO will acquire information from the major generators regarding plant availability and planned maintenance schedules to allow it to plan for shorter term events.

The SO will be responsible for:

- ◆ collecting information about intended physical flows into and out of the network;
- ◆ performing demand forecasting and system modelling to ascertain whether balancing actions are required to ensure safe and secure operation of the system;
- ◆ despatching such balancing actions by accepting bids/offers in the Balancing Mechanism;
- ◆ submitting data to the Settlement Administrator.

The SO will, as now, observe the changing state of the system and use its own forecasts to anticipate likely demand. These will be augmented by IPNs and subsequently FPNs. Further, the SO is likely to monitor prices in the forwards markets and the Power Exchange, insofar as these provide insights into the likely balance of supply and demand.

On the basis of its assessments, the SO will broadcast relevant information to the market in relation to national and/or zonal forecast imbalances and margins. If it has such contracts available to it, the SO might also call option contracts for generation or demand reduction significantly in advance of Gate Closure.

Another principal difference with the present arrangements is the use of firm bids and offers and the disincentives to use the imbalance settlement mechanism as a vehicle for primary trading. Participants will match their requirements in the market and then self despatch in accordance with those market trades. This should facilitate the SO's task of matching supply and demand in real time, because generators and suppliers will have stronger incentives to meet their generation and demand commitments.

The SO will continually notify participants of any balancing action that has been accepted through the Balancing Mechanism, and issue revised schedules and/or profiled despatch instructions, as well as any instructions related to reactive power or other ancillary services.

Finally, the SO will send to BSC Central Settlement a list of balancing actions that have been despatched (to settle them) and a list of the Balancing Mechanism bids and offers (to calculate imbalance prices).

17.4.2 Competition in Generation and Supply

The analysis in this Review suggests that the proposed arrangements will inhibit the exercise of market power, and will be more conducive to reducing it than the present Pool. The new arrangements also seek to encourage, and rely more upon, the development of financial markets. The efficiency of these depends, *inter alia*, on the inability of any participant substantially to influence market outcomes.

The proposed arrangements will promote more competition by providing better price discovery in the contracts markets than is currently available.

Increased transparency of the pricing mechanism can be expected to assist competition in generation and supply. Potential new generators and suppliers would have more confidence under these arrangements of understanding how the market operates and of being able to trade effectively. Any abuses of market power would be more readily identified and dealt with since, because of the simpler offer and bid formats, it would be easier for the Director General and other market participants to identify any attempt on the part of such companies to exploit their position.

17.4.3 Trading Arrangements in Scotland

The proposed trading arrangements will not alter the ability of the Scottish generators to participate in the England and Wales market. Externally connected parties will be able to continue operating in England and Wales.

As regards the situation in Scotland, respondents variously argued that the present arrangements in Scotland are highly unsatisfactory; that either Scotland wide or GB wide trading arrangements need to be implemented rapidly; that there should be early work on the prospects of extending the new trading arrangements to Scotland; that a discussion document on changing interconnector arrangements would be helpful; and that new Scottish trading arrangements must be in place no later than 2005.

At present, Scottish Power and Scottish and Southern are obliged to provide supplies to second tier suppliers on the basis of an administered pricing system (the Scottish Wholesale Price) which is related to the Pool price in England and Wales. If an administered system were to continue in Scotland after the proposed trading arrangements had been implemented in England and Wales, an alternative reference price would have to be identified. If an alternative reference price were also required in some of the contracts between the Scottish generators, this would in the first instance be a matter for the generators themselves.

The agreement implementing the present administered price system lasts until March 2000. Thereafter, new arrangements will need to be made in any case. A review of Scottish trading arrangements, including interrelated interconnector issues is underway.

17.4.4 The Development of Contract Markets

The proposed trading arrangements will facilitate the development of financial markets and financial risk management products. The complexity and opacity of the present pricing mechanism have inhibited their development, as has the extent of market power in generation. The development of forwards and futures markets with associated price discovery offers better opportunities for traders to cover the risks of holding exposed positions. Such markets should also lead to more efficient risk sharing.

17.4.5 Interactions between Electricity and Gas

At present there is a potential lack of co-ordination between the gas and electricity markets resulting from differences between the trading arrangements in the two markets. The proposed trading arrangements help to reduce this by replacing day-ahead bidding by a series of markets and mechanisms that are more in line with gas trading arrangements. At the same time they facilitate efficient arbitrage between the markets which can help secure lower prices overall.

Generators whose gas supplies have been interrupted or who have chosen to sell on their gas will be able to continue generating using a back-up fuel where suitable facilities exist. Under the present trading arrangements, there is generally no opportunity for them to adjust their bids to reflect short-term variations on the cost of the substitute fuel. The proposed arrangements envisage markets in which offers can be amended up to four hours before the trading period, allowing generators greater flexibility to submit offers with prices related to the costs of their substitute fuel. In addition, if the system is under stress, the SO has the option to invite re-bids, allowing the costs of substitute fuel to be reflected at less than four hours notice in some circumstances.

More generally, the new arrangements bring the ability to react to prices closer to real time, allocate the cost of the failure to meet commitments more accurately and should thus improve the arbitrage between the gas and electricity markets.

17.4.6 Legislation on Competition and Utility Regulation

The Government has indicated that it will bring forward legislation in order to implement the new trading arrangements. It has said that it is committed to early implementation and will bring forward legislation as soon as Parliamentary time permits.

The proposed arrangements incorporate a variety of markets, with bilateral contracts being the primary means of establishing trades. Financial sector regulation, including oversight by the FSA, will be applicable to activities in these new electricity markets, although this will not apply to the Balancing Mechanism. This should facilitate competitive trading and identifying and dealing with suspected market abuse. For example, market operators have to comply with specified conditions, and financial

services/regulators will have powers to impose penalties on companies that transgress trading rules.

The present proposals are fully consistent with the intentions of the Competition Act 1998, which will markedly strengthen the Director General's ability to seek out and discourage anti-competitive behaviour.

17.5 Costs

The July 1998 proposals indicated that the new trading arrangements might cost between £100m and £110m per annum over a 5-year period. Since that estimate was made, further information has been sought to refine it, involving further discussions with the existing, and likely future, participants. Appendix 12 sets out the detailed estimates.

As in July 1998, the estimates consider two sources of costs: set-up costs, including initial procurement, and ongoing operation costs. They also distinguish costs which will be incurred centrally from those borne by market participants. Strictly, the relevant costs to be attributed to the change in trading arrangements are those incurred over and above those that would have occurred in any case under current arrangements. In the case of the set-up costs, calculations of costs that will be avoided by the new arrangements would have been particularly difficult, especially since the number of market participants will likely be substantially increased as a result of RETA. For ongoing operation costs, on the other hand, such estimation would have been more feasible, although still difficult and uncertain.

It should be noted, therefore, that the estimates set out in Appendix 12 and summarised below are of gross costs, which should appropriately be adjusted downwards to arrive at estimates that are net of the costs that will be avoided as a result of RETA. Put another way, the figures can be expected to be over-estimates of the net costs attributable to RETA.

Bringing the estimates of set up costs and operating costs together, the total gross costs are estimated as follows:

Table 17.1 - Set Up Costs: Yearly over 5 Years

	£million
Central	10 – 20
Participants	96

Table 17.2 - Operating Costs: Yearly

	£million
Central	No change
Participants	30

In total, these suggest a range for total costs, before deduction of costs that will be avoided as a consequence of RETA, of £136m to £146m per annum. Of these costs, it would be reasonable to take the operating cost figure as an estimate of the occurrence of costs beyond 5 years.

In the last year, particular concern has been expressed about participants' set-up costs. Appendix 12 reports the results of new work in this area. The figures quoted above for these costs are the upper end of a likely range. Discussants in general were inclined to think that the actual figure would be somewhat lower. Work to refine the estimate further is being carried forward. Appendix 12 also provides further information on how these costs, both central costs and participants' costs, are likely to be recovered.

17.6 Benefits

As in other cases of market liberalisation, quantification of the overall benefits of RETA is a problematic exercise. It cannot be known with any certainty how market participants will react to the new opportunities that will be presented to them. Indeed a large part of the rationale for liberalisation is that it creates circumstances in which participants will have greater incentives to discover and act upon opportunities for efficiency improvements that, pre-discovery, are not known to exist. Nevertheless, the success of market liberalisation to date, in many sectors of the economy and manifested particularly in the innovation that has occurred, gives comfort that the process is generally beneficial, and both UK and EU policies are firmly set upon this course.

Within this general policy framework, the current Pooling arrangements amount to a set of restrictions on trade. The restrictions were initially established with the aim of extending the role played by markets in the electricity industry whilst simultaneously ensuring the secure balancing of the system. Recent international experience confirms, however, that they are no longer the least restrictive way of achieving the desired end. In short, the Pool creates distortions of competition that can be avoided by the much less restrictive set of trading arrangements now proposed, which will replace compulsion with choice. Indeed, in keeping with general principles of competition law and developing regulatory practice, it can be argued that any case for retention of the Pool would now need to satisfy a strong “burden of proof”.

The Government’s White Paper on Energy Policy also made it clear that RETA was a part of a wider set of measures directed, among other things, at lowering the cost of generation in the electricity bills facing consumers. RETA was seen to have an essential part to play in bringing about the anticipated fall of 10% in final consumer prices.

Chapter 14 reviewed the underlying reasons why a fall in prices of this magnitude is a realistic prospect. The costs of key inputs into electricity generation – gas and coal costs, investment costs, and operating costs – have fallen substantially since privatisation, whilst Pool prices have not. An illustration of the potential for lowering prices by creating more competitive conditions is provided by the current estimate of the margin of 25% that would be available for a new CCGT power station, operating at a 60% load factor, on the assumption that its revenues came only from sales to the Pool at 1998/9 prices. That is, it is estimated that the relevant prices are around 25% higher than required to remunerate the full costs of such a plant, including a normal return on capital, and the estimated margin would be higher still if, as appears realistic, the owner were assumed to have opportunities to enhance revenues by selling output in different ways or by offering additional products and services.

The total costs of electricity traded through the Pool at present are of the order of £7.5 billion. If it were to be assumed that these costs were similarly 25% higher than costs established on the basis of competitive entry to the market, wholesale prices would fall by around £1.5 billion if they fell to the estimate of the gas entry cost. This is far in excess of the estimate of the gross costs of RETA set out above. Further, if the resulting

price reductions were passed on to consumers, the impact would be a reduction in electricity bills of around 14% for a domestic customer.

Whereas the estimated costs of RETA represent real resource costs, price reductions to consumers do not represent real resource benefits: for the most part they would amount to a reduction in financial transfers from consumers to companies. However, apart from giving rise to resource misallocations as a result of prices being poor signals of relevant costs (an effect that is likely to be modest in magnitude), excess profits associated with high prices also give rise to various real resource costs that are incurred as companies seek to secure a share of the excess returns that are available.

Where entry is relatively free, as it has been in electricity, perhaps the most important of these effects are distortion of investment decisions (e.g. excess entry) and the associated withholding of available capacity from the market. In the limit, with free entry, the extra costs created by such effects can fully “dissipate” the excess returns that are initially available. However, even if only a fraction of the £1.5bn potential benefit to consumers is dissipated in this way – and concerns about distortions of investment decisions (the ‘dash for gas’) and the withholding of available capacity from the market have been major issues in electricity -- by implication the value of the potential real resource savings that can be made would likely still far exceed the net costs of implementing RETA.

17.6 Summary

The proposed new trading arrangements offer a significant number of advantages over present ones, in terms of the objectives and further considerations of the Review:

- ◆ the needs of customers will be met by lower prices from more efficient and competitive trading, based on greater choice of markets, while maintaining quality and security of supply, enhanced by an options market;
- ◆ greater demand management and responsiveness will come from enhancing the influence of the demand side, with greater efficiency in meeting demand as a result of trading closer to real time;
- ◆ more competition will result from bilateral trading and from the new flexibility of the demand side. Better forward price curves will facilitate new entry;

- ◆ costs and risks will be reduced and assigned more efficiently by firm bids sharpening incentives to manage risks and better forward price discovery to facilitate risk management;
- ◆ there will be more development of markets offering financial as well as physical products;
- ◆ transparency will come from simple instead of complex bidding in the Balancing Mechanism, and increased price reporting from more transparent markets;
- ◆ greater flexibility will result from competing markets and more responsive governance of the balancing market involving wider interest groups and more effective resolution of issues;
- ◆ the incentives for excessive new entry will be reduced thereby avoiding potential discrimination against any fuel sources;
- ◆ arrangements will be compatible with government policy;
- ◆ NGC as SO will continue to secure the system;
- ◆ Scottish generators will continue to be able to trade in England and Wales through the interconnector, with a prospect of better arrangements in Scotland in due course;
- ◆ gas and electricity markets will be more closely aligned through effective means of arbitrage; and
- ◆ the expected benefits will far outweigh the costs.

18. The Way Forward

It is intended that the new trading arrangements will be introduced in Autumn 2000, and a considerable amount of detailed work remains to be completed in the intervening period. It will, however, not be necessary to wait until then for the impact of the reforms on market behaviour to start to come through. Commercial conduct is already being influenced by the prospect of the new arrangements, and the impact can be expected to intensify as the implementation date approaches.

Among the recent developments in the industry that have been influenced by RETA are:

- ◆ expressions of intentions to establish a power exchange, which indicate that one or more market operators will emerge relatively quickly;
- ◆ expansion in the volumes being traded in the EFA market; and
- ◆ the emergence of new forms of contracts for trading electricity, such as the new day-ahead EFA contracts.

When contracting forward for electricity during and beyond Autumn 2000, market participants must necessarily take account of the anticipated shape of the market in the relevant periods, and evidence from brokers active in the market suggests that market prices are already being influenced by the reforms. As details are firmed up, uncertainties are reduced, and the implementation date draws nearer, the scope of such impacts on prices can be expected to increase. Consumers should not, therefore, have a long wait before some of the benefits start to feed through to them.

Considerable work is currently being undertaken by the various, interested parties to prepare for the new trading arrangements, and this will continue and deepen. One of the requirements is for detailed trialling and testing of trading arrangements. The Programme is already engaged in a business simulation exercise, and the underlying model will be released to potential market participants so that, if they so wish, they can use it as part of their own trialling and preparation for the new markets.

The DTI and Ofgem will continue to consult frequently and widely, both on the new trading arrangements themselves and on closely connected issues, such as the appropriate incentive structure for the System Operator.

Consultation on the present proposals will extend until mid-September and include a public seminar in early September. Responses to this consultation will be taken into account in finalising the detailed business rules for the operation of the central procured parts of the new arrangements – the Balancing Mechanism and Settlement Process. Subject to time being found for legislation in the 1999/2000 parliamentary session, contractors for designing and operating the supporting IT systems are expected to be appointed towards the end of the year, after legislation is announced.

Implementation will then be on target for Autumn 2000.