The new electricity trading arrangements

Volume 2

The New Electricity Trading Arrangements

Table of Contents

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.

Appendix 1 Group Membership

Development and Implementation Steering Group
Chair: Brian Saunders

Members		
Name	**Sector**	**Company**
Tony Bramley	CHP/NFFO	Tanaris Energy Ltd
Gary Cardone	Financial Bodies	Dynegy UK Ltd
Andrew Clements	Nuclear Generators	British Energy Trading Ltd
Yvonne Constance	Customers	Electricity Consumers Council
Paul Dawson	Second-Tier Suppliers	Enron Europe Ltd
Phil Edgington	PES	NORWEB plc
Nick Holding	Interconnected Parties	Scottish Hydro-Electric plc
Andrew Macdonald	Embedded Generators	Fibrowatt Ltd
John Over	PES	Yorkshire Electricity Group plc
Eldon Pethybridge	Second-Tier Suppliers	Centrica plc
Jeff Scott	NGC	The National Grid Group plc
Simon Skillings	Portfolio Generators	PowerGen plc
Graham Southall	PES	Eastern Power and Energy Trading Ltd
Bob Spears	Customers	Utility Buyers' Forum
Brian Stalker	IPPs	First Hydro Company
Lisa Waters	Customers	Energy Intensive Users Group
Alternates		***Alternate to:***
Martin Alder	The Renewable Energy Company Ltd	Paul Dawson
Liz Anderson	London Electricity plc	John Over
Richard Berry	Magnox Electric plc	Gary Cardone
Jan Devito Mike Boxall	St Clements Services Ltd Manweb plc	Graham Southall
Sam Turney	BP Amoco Gas Marketing Ltd	Andrew Macdonald
Terry Brookshaw	British Gas Trading Ltd	Eldon Pethybridge
Hugh Conway	Rugby Group	Bob Spears
Paul Evans	Humber Power Ltd	Brian Stalker
Robert Sansom	SEEBOARD plc	Phil Edgington
Paul Gardiner	British Sugar plc	Tony Bramley
Nigel Knee	British Energy Trading Ltd	Andrew Clements
David Mannering	National Power plc	Dr Simon Skillings
Mike Calviou	The National Grid Group plc	Jeff Scott
Hugh Mortimer	BOC Gases	Lisa Waters
Brian Paget	ScottishPower plc	Nick Holding
Ken Prior	Electricity Consumer Councils	Yvonne Constance

Expert Groups – Members and Invited Experts
Balancing Mechanism/ Settlements Expert Groups
Chairs: Richard Haigh, Neil Cohen

Name	Company
Peter Bedson	Barking Power
Martin Mate	British Energy Trading Ltd
Mike Pool	British Energy Trading Ltd
Terry Brookshaw	British Gas Trading Ltd
Mark Holloway	Cap Gemini UK plc
Steve Macey	Customers (British Steel plc)
Ian Gibson	Customers (Ceramic Federation)
Megan Goss	Dynegy UK Ltd
Ben Willis	Eastern Power and Energy Trading Ltd
Chris Rowell	Chief Executive's Office
Justin Andrews	Chief Executive's Office
Martin Thomas	Energy Settlements and Information Services Ltd
Nigel Hawkins	First Hydro Company
Simon Lord	First Hydro Company
John Stoney	Customers (ICI)
Mark Fitchett	Customers (ICI)
David Ward	Magnox Electric plc
John Hayling	Midlands Electricity plc
Terry Ballard	Midlands Electricity plc
David Tolley	National Power plc
Geoff Martin	Northern Electric plc
Knut Fossdal	OM Energy Solutions
Sarah Swinson	PowerGen plc
Tony Dicicco	PowerGen plc
Drew McGregor	Scottish Electricity Settlements Ltd
Steve Wilkin	St Clements Services Ltd
Duncan Jack	St Clements Services Ltd
Mike Calviou	The National Grid Group plc
David Coan	The National Grid Group plc
Jackie Moran	The National Grid Group plc
Phil Johnson	The National Grid Group plc
Nigel Major	UK Data Collection Services Ltd
Sarah Breaden	UK Data Collection Services Ltd
Bill Evans	UK Data Collection Services Ltd
Dean Tuel	United Gas Company Ltd

Markets Expert Group – Members and Invited Experts
Chair: Julian Bagwell

Name	Company
David Shipway	Accord Energy Ltd
Hugh Mortimer	Customers (BOC Gases)
Brian Stalker	First Hydro Company
James Hoare	GNI Ltd
Luke Jemmett	International Petroleum Exchange
Richard Ward	International Petroleum Exchange
Richard Berry	Magnox Electric plc
Chris Hall	Magnox Electric plc
Chris Pooley	Magnox Electric plc
Jo Allman	National Power plc
Charlotte Rhodes	National Power plc
Richard Hyde	Scottish Power plc
Adam Gray	SEEBOARD plc
Steve Garrett	Slough Energy Supplies Ltd
Keith Miller	Teesside Power Ltd

Security of Supply Expert Group – Members and Invited Experts
Chair: Julian Bagwell

Name	Company
Mike Pool	British Energy Trading Ltd
Don McGarrigle	Customers (Major Energy User’s Council)
Phil Russell	Eastern Power & Energy Trading Ltd
Roger Thompson	Eastern Power & Energy Trading Ltd
Philip Davies	Enron Europe Ltd
Paul Mott	London Electricity plc
Tim Russell	National Power plc
Joep Wouters	PowerGen plc
Nigel Cornwall	St Clements Services Ltd
Chris Teverson	The National Grid Group plc
Mark Bailey	Yorkshire Electricity Group plc
Barbara Vest	Yorkshire Electricity Group plc

Legal Expert Group
Chair: Gareth Forrester

Name	Company
Nigel Fowkes	British Energy Trading Ltd
Sue Challenger	British Energy Trading Ltd
Steven Eyre	British Energy Trading Ltd
Nick Lumley	British Gas Trading Ltd
David Burditt	Customers (Electricity Consumer Councils)
Yvonne Constance	Customers (Electricity Consumer Councils)
Robert Buckley	Customers (Energy Information Centre)
Denis Cain	Customers (Energy Information Centre)
Phil Russell	Eastern Power and Energy Trading Ltd
Roger Barnard	London Electricity plc
David Linton	Manweb plc
Sally Barrett-Williams	National Power plc
Nigel Bromley	PowerGen plc
Henry Loweth	PowerGen plc
Paul Chesterman	South Western Electricity plc
Nigel Cornwall	St Clements Services Ltd
Jackie Moran	The National Grid Group plc

Specials Expert Group
Chair: Simon Street

NAME	COMPANY
Wyn Jones	Alcan Smelting and Power UK (embedded generation)
Peter Clubb	Associated Electricity Supplies Ltd
Liz Aveyard	Customers (British Steel plc)
Graham Meeks	Energy Technology Support Unit (part of AEA Technology/Environment)
Colin McNaught	Energy Technology Support Unit (part of AEA Technology/Environment)
David Smol	Ilex Energy Services Ltd (on behalf of Renewables)
Stephen Andrews	Ilex Energy Services Ltd (on behalf of the Combined Heat and Power Association)
David Mannering	National Power plc
Andrew Wood	Non-Fossil Purchasing Agency
Louise Elder	The National Grid Group plc
Robert Brown	NORWEB plc
Robert Hackland	Scottish and Southern Energy plc
Mike Harrison	Scottish Power plc
Tony Bramley	Tanaris Energy Ltd (small CHP)

Appendix 2 RETA Programme: Bibliography of Papers

The attached bibliography lists those papers that are currently available from the RETA programme.[1]

If you wish to receive a copy of any paper, please contact Robert Jones on:

Tel: 0121 456 6338

Fax: 0121 456 6473

Email: rjones@offer.gsi.gov.uk

[1] DISG papers are available on OFFER's website: http://www.open.gov.uk/offer/offer.htm.

Development and Implementation Steering Group

Paper Ref	Title
01/01	Terms Of Reference
01/02	Committee Procedures and Processes
01/03	Identification and Prioritisation of Outstanding Issues
01/04	Future Meeting Dates
02/01	Design Assessment Criteria
02/02	Expert Group Appointment
02/03	Imbalances and Imbalance Prices
02/04	Transmission Access and Pricing
02/05	A Voluntary Day-Ahead Auction
02/06	Future Meeting Dates
02/07	Internet E-Mail Contact Points
02/08	Corrigendum to DISG 02/03
03/01	Security of Supply
03/02	CHP and Renewables
03/03	Balancing and Settlement Code High Level Principles
03/04	Issues to be Resolved Concerning The Balancing Regime
03/05	Committee Procedures and Processes (Release and Circulation of DISG Papers)
04/01	Liability of Those Participating In The Programme
04/02	Preliminary Conclusions on the Balancing Markets
04/03	Prospects for Price Transparency
04/03a	Prospects For Price Transparency
04/04	Recommendations from Specials Expert Group Relating to Action from DISG to Consider Boundary of RETA

Paper Ref	Title
04/05	Communication and Dissemination of Expert Group Papers
04/06	Procurement Approach
05/01	Further Development of the Balancing Market and Settlement Mechanism
05/02	High Level Objectives and Business Principles
05/02 revised	High Level Objectives and Business Principles
05/03	Governance of the Balancing and Settlement Arrangements
05/04	The RETA Procurement Process and the Role of NGC
05/05	The Vision of the Enduring Transmission Capacity Regime
05/06	Allocation of Transmission Losses
05/08	Communications Strategy and Plan
05/09	Relying on Market Solutions to Provide Security of Supply; Assessing the Implications
05/10	Terms of RETA Participation
06/001	Expert Group/DISG Provisional Deliverable Timetable and Workplan
06/002	Propositions on the Balancing Mechanism and the Settlement of Imbalances
06/003	Rebidding in the Balancing Market
07/001	Expert Groups Progress Report for the DISG
07/002	Trading Across Interconnectors: Preliminary Proposals
07/003	Seeding a Short-Term Bilateral Market
07/004	The Balancing Mechanism and Cash-Out Arrangements
07/005	Firmness, Ramping Energy and Purchase of Bids and Offers in the Balancing Mechanism
07/006	Imbalance Cash-Out Pricing
08/001	A Clarification of Deliverables for the Policy Phase
08/002	Governance of the Balancing Settlement Code

Paper Ref	Title
08/003	Programme Route Map
08/004	Comments on Paper DISG 07/004
08/005	Towards a Prompt Imbalance Cash-Out Price
08/006	Expert Group Progress Reports
09/001	Expert Group Progress Reports
09/002	The Boundary of RETA
09/003	The Settlement Process: Preliminary Overview
09/004	Definition of a Trade
09/005	Common Clearing Price: The Effect on Market Liquidity
09/006	Re-bidding in the Balancing Mechanism
09/007	RETA Participation by Generators, Suppliers and Third Parties
09/008	Gas and Electricity Interactions
09/009	Shipping Electricity
10/01	Expert Group Progress Reports
10/02	Prices, Participation and Product
10/03	Tender Evaluation Board: Terms of Reference
10/04	Revised Schedule of DISG Meeting Dates
11/01	Expert Group Progress Reports
11/02	Implementation Management Workstream
11/03	The BSC Code Panel and Modification Process
11/04	RETA and NBP Trading
11/05	Dynegy and Accord Proposal - Enhanced Market Model
11/06	Facilitating a Power Exchange
11/07	Information Flows

Paper Ref	Title
12/01	Expert Group Progress Report for the DISG
12/02	Economic Modelling within RETA
12/03	Security of Supply
12/04	Aggregation Rules
12/05	Security of Supply
13/01	Expert Group Progress Report for the DISG
13/02	Views from the Specials Expert Group Relating to the Impact of Cash-Out Proposals
13/03	Bi-Lateral Trading: The Interface with the Balancing Mechanism Cash-Out
13/04	Progress Report on the Design of the Balancing Mechanism and Imbalance Cash-Out
13/05	Contract Notification
14/01	Expert Group Progress Report for the DISG
14/02	Interconnectors
14/03	Response to DISG 08/05: “Towards a Prompt Imbalance Cash-Out Price”
14/04	Operational Information and Transparency
15/01	Expert Group Progress Report for DISG
15/02	Energy Contract Notification and Imbalance Calculation - Worked Examples
15/03	The Balancing and Settlement Code Panel
15/04	The Treatment of Stage 2 Settlement Contractual Arrangements Under RETA
15/05	Views from the Specials Expert Group Relating to the Impact of the Proposed Trading Arrangements
15/06	Consideration of the July Report
15/07	Cash-Out Modelling
15/08	Forecasting Demand RETA

Paper Ref	Title
15/09	Issues for the Renewables Industry
15/10	Issues for the CHP Industry

Programme Management Board

Paper Ref	Title
01/02	Balancing and Settlement Code High-Level Objectives, Business Principles, Business Rules and Detailed Business Rules
01/03	Report From Programme Management
02/03	The Role of the PMB
02/04	The RETA Procurement Process and the Role of NGC (as DISG 05/004)
02/05	Draft Programme Charter - Structure Review
02/06	Programme Plan Review
02/09	Programme Charter - Planning and Programme Assumptions
02/010	Proposed Monthly Reporting Structure/Mechanism
06/02	Programme Workbook (June 1999)

Balancing Mechanism Expert Group

Paper Ref	Title
01/001	Interim Rules Regarding Transmission Access Rights
01/002	The Balancing Market: Definition of the Product
01/003	Participation in the Balancing Market - Discussion Paper
01/004	Scope and timescales of Balancing Market, and requirement for pre-gate closure action by NGC
01/005	Balancing Market Volumes
02/001	Preliminary Conclusions on The Balancing Market
02/002	Post Gate Closure Trading
02/003	Volumes In The Balancing Market

Paper Ref	Title
02/004	Balancing Market Volumes
02/005	Participation of Profiled Customers in the Balancing Market
02/006a	Participation in the Balancing Market - Further Discussion Notes
02/006b	Final Physical Notifications and Imbalance Charges
02/007	The Cash-Out Regime in Gas - Pros and Cons
03/001	Constraint Cost Estimation, Allocation and Incentives
03/002	FPN's, Incs and Decs (with accompanying slides)
03/003	Interaction Between FPNs, the Balancing Market, Options and Reserve Contracts
04/001	An Efficient Incentive Structure for The Balancing Market and Settlement of Imbalances
04/002	The Norwegian Balance Market: How and Why?
04/003	Defining The Product
04/005a and b	Further Development of the Balancing and Steering Mechanism
04/006 (original and revised)	Balancing Market Issues
04/007	Retaining existing Transmission Rights in the Balancing Market
04/008a	Payment for "non-delivered" Incs and Decs
04/008b	Implications of a Large Volume Balancing Market
04/009	Setting The Scheduling Charge
04/010	Frequency Response -Market Processes (formerly paper TUG 98/99-13)
05/001	Recommendations from Specials Expert Group Relating to Action from DISG to Consider Boundary of RETA
05/002	Dynamics and the Balancing Market
05/003	System Operator Decision Tools for the Balancing Mechanism
05/006	The Demand Side and FPN's
06/002	The Basis for the Balancing Market Scheduling Charge
07/001	Demand Participation and FPNs

Paper Ref	Title
07/002	Boundary of RETA – Further discussion on SPEG's conclusions
07/006	DISG Paper - Boundary of RETA - For BMEG Review
07/007	Information Imbalance Charge - Principles and Indicative Calculation, and Effectiveness Compared to an Obligation on Information Accuracy.
07/009	Dynamics and Balancing Market - Revisited
08/001	Model A Introduction
08/002	Balancing Market Options for Modules B1 and B2
08/003	Requirements for Dynamics in a Minute by Minute Balancing Market
08/004	Definition and Settlement of the Volume of Accepted Bids
08/005	Flexibility Market Session
08/006	Energy Constrained Demand Side Participation in the Balancing Mechanism
08/007	Attributes of Model 2
08/008	Despatch Instructions
08/009	The Scope of Bid/Offer Data
08/010	Revising Bids After Gate Closure
10/001	Summary of Slides from 8th and 9th Workshop Sessions
10/002	Energy Imbalance Prices
10/003a	Energy Imbalance Price
10/003b	Incentive Effects of Dual Prices
10/004	Information Imbalance Pricing
10/005	Transparency of the Value of Flexibility
12/004	Definition of the Accepted Bid Volume When the Bidder is not at their Expected MW Level, or Revises their FPN
12/005	Specification of the Demand Dynamic Parameter - MWh or Time Constrained
12/006	Arbitrage Opportunities Endemic in Market Design

The Balancing Mechanism Expert Group and Settlements Expert Group, from May 7, have merged into one group - the Balancing and Settlement Group (BSEG). Please see separate BSEG list for papers.

Balancing and Settlement Expert Group

Paper Ref	***Title***
02/001	*A Specification for the Balancing Mechanism and Imbalance Settlement (Draft 1)*
02/002	*Split of Settlement Functions*
02/003	*Energy Contract Volume Acquisition*
02/004	*Issues Surrounding Reserve and Response in RETA*

Legal Expert Group

Paper Ref	**Title**
01/001	Terms Of Reference
01/002	Legal Expert Group Workplan
01/003	Diagram: Asset Register
02/004	Issues Regarding the IME Directive and Despatch Provisions Under RETA
02/005	RETA Stage 2
02/006	RETA and Competition Law
02/007	Framework Document
03/010	Legal Framework Document
03/011	NGC Transmission Licence
03/012	Generation Licence (National Power)
03/013	Public Electricity Supply Licence (London)
03/014	Second Tier Supply Licence (January 1998)
03/015	MCUSA – As Amended
03/016	Grid Code Revision 27 (Effective from 1/1/99)
03/017	RETA: Competition Law Procedures

Paper Ref	Title
03/018	RETA and the Reform of the Financial Services Regulation
03/019	Governance of the Balancing and Settlement Arrangements (as DISG 05/03)
04/020	Governance Design - Objectives and Choices
04/022	Development of the Balancing and Settlement Code and Panel
04/023a	Comparison of Enduring Governance Proposals from Overseas Electricity Markets
04/023b	Description of Alternative Enduring Governance Arrangements
04/024	Scope of the Balancing and Settling Code
05/025	Governance Questions
06/026	Proposed Functions of the BSC Panel
06/027	Governance Design Objectives
06/028	Governance Arrangements in Australia and New Zealand
06/029	Governance Arrangements/Proposals
06/030	The Balancing and Settlement Code Panel: Design Options
08/032	Links Between the MCUSA and P&SA
08/033	Governance Progress Paper
08/034	Calculations for Voting and Representation
08/035	Network Code Modification Rules - Outline Summary of Procedures
09/036	Comments on Governance Progress Paper (LEG 08/033)
09/037	BSC Modification Procedures
11/038	Pool CEO Functions
12/039	Governance - Financial Control
12/040	Appeal of BSC Panel/Board Decisions
12/041	Disputes Process Under the Balancing and Settlement Code

Paper Ref	Title
12/043	Composition of the B & SC Panel/Board
12/044	Objectives of the B & S Code
12/045	Funding the B & S Code and BSCCO
12/046	Code Objectives
13/048	Progress Paper
13/049	B & S Code - Compliance

Markets Expert Group

Paper Ref	Title
01/01	Terms Of Reference
02/02	The Degree of Price Transparency in Different Market Mechanisms
02/03	Potential Use of Markets By A Supplier
02/04	Trading Products, Timescales and Price Reporting
02/06	Development of Transparency in the Natural Gas Traded Market
03/01	Market Transparency: The Issues
06/01	Seeding a Short-Term Bilateral Market
06/02	Information Availability in CfD Market
06/03	What is a Trade?
06/04	A Simple Pricing Mechanism
07/01	Information Flows
08/01	Information Flows - Redraft
08/02	Seeding A Short -Term Bilateral Market
08/03	A Note on Facilitating a Power Exchange
09/01	Information Flows (Draft for May 13 meeting)
09/02	Facilitating A Power Exchange

Paper Ref	Title
09/03	Response to DISG 08/005 ("Towards a Prompt Imbalance Cash-Out Price")
10/01	Response to DISG 08/005 ("Towards a Prompt Imbalance Cash-Out Price") - Revised
10/02	Scoping Paper on "A Day in the Life" - Appendix to the July Report
11/01	Response to DISG 08/005 ("Towards a Prompt Imbalance Cash-Out Price") - Revised (as previous)
11/02	Further Paper on the Role of the PDO in Facilitating a Power Exchange
11/03	Prices in Special Events
11/04	"A Day in the Life": Chapter 14 of the July Report
11/05	"A Day in the Life": Appendix 7
12/01	Default Prices

Settlements Expert Group

Paper Ref	Title
01/001	Terms Of Reference
02/001	Metering Information
02/002	Settlement Processes
02/003	Imbalance and How it Should be Defined
03/001 (Slides)	Settlement Process (accompanies 02/002)
03/003	Metering Information Availability (revised 02/001)
05/001	Trading After Gate Closure
05/002	Clearing House Operations (presentation slides)
05/003	Pooling and Existing Funds Transfer Mechanisms (presentation slides)
05/004	Force Majeure
06/001	Trading After Gate Closure (revised version)
06/002	Force Majeure (update)

Paper Ref	Title
06/003	A Model for the Separate Settlement of Imbalances and Balancing Market Trades
06/004	Security Cover and Credit Risk Management
07/001	Settlement of Balancing Trades and Imbalances
07/002	Pros and Cons of Settlement Strawmen Models
07/003	Frequency Response
07/004	Proposed Model of Settlement of Balancing Mechanism and Imbalances
08/001	The Imbalance Settlement Process
08/002	Trading After Gate Closure
10/001	Balancing Mechanism Funds Transfer
11/001	Transmission Losses in a Bilateral Market

The Balancing Mechanism Expert Group and Settlements Expert Group, from May 7, have merged into one group - the Balancing and Settlement Group (BSEG). Please see separate BSEG list for papers.

Specials Expert Group

Paper Ref	Title
02/001	Terms Of Reference
02/002	Licence Exempt Generation, CHP, Renewables and Non-CDGU Treatment Under RETA
02/003	Note on Generator and Supplier Requirement to Sign the Settlement Agreement for Scotland
02/004	Boundaries of the New Trading Arrangements
03/001	Issues Needing To Be Considered re: Interconnectors Continuing to Trade Under RETA as Under the Present System
05/001	External Participants and Trading Across Interconnectors
05/002	Discussion Paper on Interconnector Issues

Paper Ref	Title
07/001	Trading Across Interconnectors
07/002	Model of Proposed Settlement Rules

Security of Supply Expert Group

Paper Ref	Title
01/01	Terms of Reference
01/03	Programme of Work
02/01	How NGC Delivers Security of Supply in Operational Timescales, and What Information Flows Aid This Process in the Short and Long Term
02/02	Load Management of Profiled Customers
02/03	International Experience of Security of Supply
02/03a	Capacity Payments - Overseas Experience
02/04	Security of Supply - Regulatory Framework
02/04 (revised)	Security of Supply – Regulatory Framework
02/05	Scope of the Security of Supply Issue
02/06	Programme of Work Update
02/07	Comments on Terms of Reference
03/01	Security of Supply Arrangements at Nuclear Generation Installations
03/07	Demand Participation in the New Trading Arrangements
03/08	Common Mode Interruption of CCGTs
03/09	Risks and Issues
03/010	Identify Questions for the Group
03/011	A Note on the Electricity Supply Regulations
04/01	The Development of an Options Market in Liberalised Electricity Markets: the example of Norway and Sweden
04/02	Power Station Emission Limits to 2010

Paper Ref	Title
04/04	Load Management Opportunities Currently Available in the >100 KW Market
04/05	Information Required For System Security
04/07	Stress Testing for RETA
04/08	Questions for the Security of Supply Expert Group
04/09	An Efficient Incentive Structure for the Balancing Market and Settlement of Imbalances
04/010	The Norwegian Balance Market: How and Why
04/011	Structure
04/012	Impact of Balancing Market Pricing Rules on System Security
05/01	Emergency/Curtailment Provisions Under The Grid Code
05/02	Imbalance Price Discovery
05/03	Comments on Stress Scenarios
06/01	Note on Future Meeting Arrangements
06/02	Radio Tele-Switching
06/03	Emergency/Curtailment Provisions Under The Grid Code (05/001 revised)
07/01	Security of Supply Provisions Under The Present Arrangements
07/01a	Ancillary Services Under the Present Arrangements
07/02	Long Term Security of Supply Issues Under RETA
07/03	Short-term Issues (Scoping Paper)
08/01	The Impact of RETA on Short-Term Security of Supply Issues
08/02	Other Issues (Scoping Paper)
09/01	Security of Supply under RETA - Other Issues
09/02	Features of Standing Reserve
09/03	Volumes and Costs of Ancillary Services
09/04	Notional Reserve Under RETA

09/05	Implications for Security of Supply of Balancing Mechanism - Changing Offers Post Gate Closure
12/01	Provision of Reserve, Response and Reactive
12/02	Ancillary Services (Extract from Summary Paper)
12/03	Security of Supply Expert Group - Summary
14/01	Initial Physical Notifications

Appendix 3 The Present Trading Arrangements - Experience to Date

This Appendix analyses experience with the current trading arrangements to date, covering specifically, the investigations conducted by OFFER/Ofgem in recent years into high prices and/or generator manipulation of prices.

3.1 The Ability to Manipulate, and Actual 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 inquiries[2] 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 and plentiful supply, leading to concerns that generators were manipulating prices.

Most recently, in July 1999, Ofgem launched a formal investigation into extremely high levels of both SMP and capacity payments during the summer period when demand is traditionally low. Depending on the outcome of this investigation, Ofgem may pursue one of a number of different options available to it under the current regulatory regime.

3.1.1 Price Competition Through the Year

Some differential between summer and winter prices is to be expected as a result of seasonality in demand. However, in recent years the differential between SMP in the summer and SMP in the winter appears to have been artificially widened by the behaviour of some generators, with winter SMP levels rising significantly. This has been in contrast to the downward trend in capacity payments. In a competitive market, there might have been expected to be a positive correlation between the level of capacity payments and SMP and the fact that the opposite has been seen strengthens the argument that prices have been manipulated.

In June 1998, OFFER published a report on Pool price increases during the winter of 1997/98. The report found that SMP was 26% higher in 1997/98 than it was in the corresponding period of the previous year, although capacity payments were 56% lower. Moreover, prices during the summer of 1997/98 were 20% lower than those in 1996/97. Overall, the Pool Purchase

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

Price (PPP) in 1997/98 rose by 4%. As the report concluded, this strongly suggests that winter SMP levels were deliberately increased to compensate for lower capacity payments.

The main price-setting generators (National Power, PowerGen and Eastern) are generally able to influence winter SMP to a greater extent than summer levels due to the higher level of demand in winter. The increase in demand between summer and winter is almost wholly met by additional output from coal-fired stations owned by these companies. Coal contributes only some 16% of total output in summer but around 45% in winter. Thus, there are competitive pressures in summer from plant not owned by these three generators which ease in the winter, allowing them to increase the prices they submit for coal plant and hence SMP levels. Similar effects were also seen in 1998/99 (see Table 3.1).

Table 3.1 – Average Offer Structure of a Typical 500 MW Coal-Fired Generating Set

	No Load (£/hr)	Inc 1 (£/MWh)	Inc 2 (£/MWh)	Inc 3 (£/MWh)	Start Up (£)	Table A offer[3] (£/MWh)
January 1999	6432	20.4	39.0	39.0	4200	45.8
May 1999	2010	13.3	20.9	20.9	4132	23.2

SMP levels were somewhat lower (7%) than in 1997/98, but considerably higher than in previous winters despite sharp falls in the coal prices being paid by the generators, which were some 20% lower in 1998/99 than in 1997/98. Again, high levels of SMP were matched with low capacity payments, see Table 3.2.

[3] One commonly used measure of a generator's average price is the so-called Table A offer, which is given by a Pool-specified formula. Each settlement period is defined either as a Table A or Table B period. When the spare capacity of scheduled generation exceeds 1000 MW a period is defined as Table B. There are a maximum of 20 Table B periods in a day. All other periods are Table A. Start up and no load costs for all periods when a genset is running are only spread over Table A periods.

Table 3.2 - Winter Pool Prices (November to January) – £/MWh

	1996/7	1997/8	1998/9
SMP	24.31	31.62	30.43
Capacity Payments	5.73	2.86	1.69
PPP	30.04	34.48	32.12

Notwithstanding the generally ability of the main price-setting generators to influence prices in the winter, from time to time opportunities arise for generators to increase summer prices, particularly when large quantities of generating plant are being maintained. Such a situation arose during July 1999.

Partly in response to this evidence of the continuing exercise of market power in price-setting, National Power and PowerGen have each been required to divest 4GW of coal-fired power plant. These divestments are due to be completed by the autumn of 1999. Whilst this divestment should tend to increase competition in price-setting, concerns about the ability of all generators to influence the price-setting mechanism remain, as discussed below.

3.1.2 Winter 1998/99 Price Spikes

Over the winter of 1998/99 there was a significant increase in the number of SMPs set above £60/MWh, during periods of relatively low demand. The increasing incidence of such 'price spikes,' which was sufficient to influence the overall level of SMP,[4] led to OFFER conducting another Pool price inquiry. Table 3.3 outlines the number of SMP spikes in Winter 1996/97 as compared to those in 1997/98 and 1998/99.

[4] OFFER estimated that prices in January 1999 were £90m higher than they would have been in a more competitive market.

Table 3.3 - Number of SMP Spikes in Winters 1996/97 to1998/99

	1996/97	1997/98	1998/99
£60-£70/MWh	25	108	298
£70-£80/MWh	14	48	89
£80+/MWh	20	178	194
Total	**59**	**334**	**581**

The increasing number of SMP spikes in periods when the underlying supply and demand fundamentals suggested that prices should be low, significantly increased the risks associated with Pool participation. For suppliers, this was primarily translated into higher contract premiums, which are likely to be passed on to customers. The inability of other market participants to forecast price movements on the basis of changes in supply and demand increased the risks associated with output planning.

OFFER concluded that the increasing incidence of these price spikes was the result of some generators deliberately submitting offers designed to produce spikes. Generators were able to exploit the way in which the scheduling tool operates in order to achieve this. The scheduler searches for a pattern of output that minimises the costs of operating the system over an entire day rather than for individual half-hours. Consequently, the optimiser may find that it is cheaper overall to use additional high-priced output from a plant that is already running rather than start up a new plant. However, these two options are treated differently in the price-setting algorithms. The costs of additional output from a plant that is already running will be allocated to a single half-hour (or a small number of half-hours), thus producing a price spike. On the other hand, the costs associated with starting up and running a new plant are likely to be spread over many half-hours so that no one single period has a particularly high price. This feature of the price-setting algorithm means that price spikes can be produced even when only a few MW of high-priced output are scheduled.

In its February report on activities in the Pool during winter 1998/99, OFFER also argued that generators were manipulating inflexibility markers. Some portfolio generators have been using inflexibility markers to ensure that their plant operate at specific times of the day which further reduces price competition in these periods, and compounds the price-setting influence of the portfolio generators.

All these examples illustrate the complexity of the Pool and how it facilitates the manipulation of prices. Specific instances of manipulation, such as the creation of price spikes, can potentially be addressed by rule changes or modifications to the software, but many more opportunities for manipulation will likely remain to be identified and exploited. The concern remains that the unsatisfactory findings of Pool reviews will, in the absence of more fundamental reforms, continue to be repeated. The most recent experiences of very high Pool prices in July 1999 support this view.

Appendix 4 Developments in Other Markets

This Appendix outlines developments in markets examined in the International Background Paper[5] and also provides a discussion on two additional issues of importance to the England and Wales market. These are: the interaction between energy markets and ancillary services; and the allocation of transmission access rights.

4.1 Update on Key Markets

4.1.1 Scandinavia (NordPool)

In the International Background Paper, the trading arrangements in Norway and Sweden were discussed at length…

> *"A generator only power pool (now called Elspot) was established in Norway in 1971. This was essentially only used for balancing purposes with the majority of power being traded under bilateral contracts. Pool membership was extended to non-generators in 1991 and in January 1996, a joint exchange, NordPool, covering Norway and Sweden began operation. Finland launched an electronic power exchange, El-Ex, in August 1996. Finnish players are also free to trade on NordPool. The El-Ex and NordPool power exchanges are expected to merge in the future".*

The El-Ex power exchange began as an integrated spot and forward market, with physical settlement. Prior to the integration in June 1998 of El-Ex into NordPool, the Finnish SO, Fingrid, acquired ownership of El-Ex. As part of the integration process, Fingrid then sold 50% of its shares in El-Ex to Svenska Kraftnat,[6] the Swedish transmission grid owner and operator.

There is now a separate price index within NordPool for Finland, as there has been for Sweden since 1996, and effectively all day-ahead spot trading is focused in Elspot. However, El-Ex continues to provide services to market participants in Finland and acts as an agent for NordPool in Finland. More importantly, El-Ex/ NordPool has developed and implemented (on

---

[5] Review of Electricity Trading Arrangements: Background Paper 2, Electricity Trading Arrangements in Other Countries, February 1998.

[6] In addition, Fingrid has reduced its spot power transmission rates, and has abolished its interconnector exchange and spot pricing charges. The network operators in Sweden and Norway have reciprocated.

1 March 1999) a new 'short-term adjustment market', Elbas[7] (with OM Group as market operator) to replace the on the day trading markets that existed in Sweden and Finland. Elbas provides market participants in Sweden and Finland with the opportunity to conduct short-term energy trading and balancing between the closure of Elspot and two hours before real time.

In large part, the creation of, and philosophy, behind Elbas is rooted in the greater proportion of thermal generation in Sweden and Finland than in Norway.[8] Thermal plants, in general, require more time than hydro plant to adjust their output. Elbas allows fine-tuning of positions established in day-ahead and forwards markets, thus allowing participants to accommodate the dynamic constraints of thermal plant. Plans are currently being discussed for the implementation of Elbas in Norway. Furthermore, an exchange traded options market is due to open on 10 October 1999.

Approximately 145 TWh was traded in total on the Elspot and Eltermin (the Nordic futures market) markets in 1998, comprising 56 TWh in Elspot and 89 TWh in Eltermin. This represents a growth of nearly 50% from 1997. However, the majority of power is still traded through over-the-counter bilateral agreements. There has also been a substantial growth in the number of players in NordPool. There are now 258 firms registered, compared to 199 in January 1998.

4.1.2 Australia

Electricity restructuring in Australia has followed different paths in each state. The International Background Paper described the trading arrangements that existed in Victoria and the proposed arrangements for the full National Electricity Market (NEM) which was due to commence in May 1998 covering the south eastern states, Australian Capital Territory, New South Wales (NSW), South Australia and Victoria. In fact, the NEM did not commence until 13 December 1998 following software problems and late changes to the market and system operation rules. The National Electricity Market Management Company (NEMMCO) also administers a separate market in Queensland using the NEM systems and procedures, and will do so until an interconnector linking Queensland and New South Wales is completed, at which time Queensland will join the NEM.

---

[7] Elbas enables the continuous trading of single hour blocks (with a minimum lot size of 1 MWh) up to two hours prior to delivery, and is divided into Finnish and Swedish hourly markets. Participants are able to trade in both markets within the limits of cross border capacity between the two countries.
[8] Source: NordPool ASA.

Few changes in the market design have occurred since the International Background Paper was written. The NEM continues to be a mandatory market with gate closure for bid and offer prices occurring at the day-ahead stage. Zonal prices are set *ex-post* at five-minute intervals. NEMMCO separately tenders for ancillary services. Constraints are resolved by the SO through zonal pricing and despatch.

In the first six months of NEM, despatch data available from NEMMCO showed that significant energy flows have taken place between states. Victoria is a net exporter to South Australia with hourly flows of between 200 and 500 MW.[9] Flows between Victoria and the Snowy Mountains area are two-way, whilst the Snowy Mountains area is, in general, a net exporter to NSW. Consistent with this pattern of interstate energy flows, significant differentials exist between spot prices in each of the major states participating in NEM. For example, in the week beginning 30 May 1999, there was a AUS$10/MWh[10] range in spot prices between NSW (AUS$27/MWh) and South Australia (AUS$37/MWh). The lowest and highest prices in the same week ranged from around AUS$7/MWh to over AUS$100/MWh.

4.1.3 USA (California)

Two new institutions were created to operate California's new market structure, the California Power Exchange (PX) and the California Independent System Operator (ISO). The PX and ISO began operation on 31 March 1998. The ISO manages three key markets – competitively procured ancillary services, a Real-time Energy market and a Congestion Management market. The PX operates three energy markets,[11] a daily auction for each hour of the next day, an on-the-day market and a Block Forwards market. The PX currently has over 60 participants. For the first half of 1999, the average daily volume of power traded on the PX has been 513 GWh compared with an average daily demand of 630 GWh. Over the same period, average prices in the PX and the ISO markets have been $25.4/MWh and $25.0/MWh respectively.

---

[9] This represents respectively between 4% to 10% of hourly average Victoria demand and between 15% and 35% of hourly average demand in South Australia.

[10] Prices shown for each state are time-weighted averages for the week.

[11] The original Day-Ahead market established prices and quantity of electricity for delivery during each hour of the following day and provided zonal pricing information if transmission system congestion was expected. In July 1998, an Hour-Ahead market was established but market power and market operation issues forced the PX to abandon this market in favour of what it calls a Day-Of market. The Day-Of market conducts its 24 hourly auctions during three auction periods at 6 a.m., noon and 4 p.m. The Block Forwards Market offers market participants standardised contracts for on-peak energy on a forward month basis for up to six months in advance of delivery.

Market prices in the ISO Real-time Energy and Ancillary Services markets have been volatile over the year with thin market participation exacerbated by a series of heat waves in the summer of 1998. Price spikes in the Ancillary Services market followed the first heat wave in July 1998. To protect customers the ISO immediately capped prices in the Ancillary Services market at $500/MWh. The price cap has since been lowered to $250/MWh. In response to this price volatility, in February 1999, the California ISO announced a comprehensive redesign of the California Ancillary Services markets. Key features of the new design include greater discretion for the ISO in procuring ancillary services,[12] permitting ancillary service trades between Scheduling Co-ordinators,[13] and allowing the ISO to defer purchase of up to 10% of its day-ahead forecast ancillary services requirements to the hour-ahead auction.[14]

Liquidity problems in the ancillary services auctions have also necessitated the introduction of special payments to generators for providing ancillary services. For some ancillary services that are either highly location dependent (such as black start) or where the zonal market design might provide opportunities for the exercise of local market power, generators can be designated 'Reliability Must Run'. These generators receive administered fixed cost payments (as opposed to payments emerging from an ancillary services auction) for being available (to provide ancillary services) when called by the ISO for local reliability purposes. In the future, the ISO also intends actively to promote demand-side responsiveness, which so far has not been significant.

Over 99% of the time, the ISO's Real-time Energy market has functioned to balance supply and demand through price signals, without needing to rely on the price cap in place. This was initially set at $125/MWh but was raised to $250/MWh in May 1998. When the cap ($250/MWh) was hit, significant amounts of additional generating capacity were offered, so that short-term supply shortages did not threaten system reliability.

The ISO conducts both day-ahead and hour-ahead interzonal congestion management, as well as real-time intrazonal congestion management, using 'adjustment' bids and offers submitted by market participants. The interzonal congestion market is not an energy market, but rather a

[12] The ISO will be allowed to substitute higher quality services for lower quality services, when doing so reduces total costs.
[13] Scheduling Co-ordinators are intermediaries between the ISO and market participants acting to aggregate and conduct bilateral transactions and schedule transmission services.
[14] The aim is to increase liquidity in the hour-ahead market and reduce the cost of Ancillary Services purchased at day-ahead stage (by basing purchases on the better information available at the hour-ahead stage).

mechanism for valuing and allocating transmission access. Currently, four zones are identified by the ISO but only two of them are active. Overall, the Congestion Management market has worked well in allocating available transmission capacity, with congestion costs totalling less than one percent of total energy costs. In the future, if new and significant constraints occur, the ISO can define new zones.

4.2 Major Issues for RETA and Developments in Other Markets

4.2.1 Interaction Between Energy Markets and Ancillary Services

In almost all markets, SOs perceive the need to procure balancing services in advance of real time through Ancillary Services markets. In systems where ancillary services are competitively procured SOs will initially buy, in forwards markets, the capability to provide an ancillary service from market participants. A separate price may then be specified which is payable whenever the SO calls on the participant actually to provide the service (a utilisation price).

California was one of the first markets in the world to procure ancillary services through a competitive and transparent bidding (open auction) process. The capability to provide four main ancillary services, Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserves[15] are procured in separate day-ahead and hour-ahead auctions. All generators providing Regulation must have Automatic Generator Control (AGC) fitted, which allows the SO to control the output of generators in real-time. Initially, the ISO used the generation and demand schedules submitted by participants to determine what ancillary services to procure, but it has now moved to procuring on the basis of its own load forecasts.[16] In September 1998, the ISO stopped simply buying Regulation and began to procure Increment Regulation and Decrement Regulation separately. The purpose of this was to sharpen price signals to provide Regulation and hence to improve the volumes available. The ISO is able to despatch the energy component of ancillary service bids/offers as well as supplemental energy

[15] These Ancillary Services can be defined as follows:
Regulation: Generation that is already up and running, and synchronised with the grid so that generation can be increased or decreased instantly through Automatic Generation Control (AGC).
Spinning and Non-Spinning Reserves: Generation that is already up and running (spinning) or generation that is readily available but not running (non-spinning) that can provide specified levels of additional output quickly (e.g. within10 minutes) but not instantaneously.
Replacement Reserves: Generation that is capable of starting up and synchronising with the grid over somewhat longer timescales (e.g. 1 hour).
[16] Because participants were consistently under scheduling energy requirements, the ISO found itself procuring too few Ancillary Services at the day-ahead stage.

bids/offers submitted by Scheduling Co-ordinators along with day-ahead and hour-ahead schedules, in the real-time energy market.

The actions taken by the ISO are then used to determine cash-out prices. Ancillary service utilisation prices (i.e. the energy component of ISO procured ancillary services) can be used to set the marginal real-time energy price and therefore the utilisation prices of ancillary services can be targeted within cash-out prices. However, the capability costs of ancillary services and any utilisation costs that cannot be targeted (because they are not energy related) are currently[17] shared out *pro rata* based on forecast demand at the day-ahead stage. The procurement and charging of ancillary services costs can be zonal. Scheduling Co-ordinators have the right to self provide most[18] ancillary services and can avoid the smeared costs of ISO procured ancillary services by doing so. Ancillary Service costs typically represent between 9% and 15% of monthly energy costs. In the future, measures introduced to aid liquidity in the ancillary services market (such as the removal of the $250/MWh price cap) may, the ISO expects, result in the total costs of procuring ancillary services rising.

In Norway, generators are required to provide a specified level of reactive power and are not remunerated for doing so, but are paid if they provide more reactive power than this amount. In Norway and Sweden, other ancillary services (including those controlled by the SO via AGC) are purchased under long-term contracts. The respective SOs are able to choose whether to accept balancing market bids or call ancillary services.

In Australia, seven key ancillary services have been procured through an open tender process. A review is currently underway that is investigating the possibility of procuring, through short-term open auctions, ancillary services for which there is deemed to be sufficient competition between generators to provide. Payments for ancillary services are based broadly on capability and utilisation. There is an obligation on generators to provide reactive power. AGC and related services are also procured from market participants (the equipment required is paid for by generators themselves and recovered through capability and utilisation fees). In Australia and New Zealand, ancillary services are used to supplement rather than substitute for central

[17] The ISO has proposed to move to charging the costs of Ancillary Services based on metered demand from the summer of 1999.
[18] Participants are able to self provide Regulation, Spinning and non-spinning reserves, replacement reserve, but not voltage support or black start capabilities, which are procured on a long term basis.

Spot market despatch decisions. In Australia, the costs of ancillary services procured and utilised are recovered through a *pro rata* sharing of costs by all loads.

4.2.2 Allocation of Transmission Access Rights

Whilst the allocation of transmission access rights is not currently being reviewed as part of RETA, how transmission access rights are allocated is critical to the long-term success of any set of electricity trading arrangements. Key issues that need to be considered include:

- How are transmission access rights allocated and what rights or obligations do they confer or impose?
- Is energy and capacity separated, i.e. is there a separation of the energy to be transported and the right to transport that energy? How are constraints handled?

The allocation of transmission access rights is most advanced in the U.S, where, for example, Firm Transmission Access Rights (FTRs) are sold in an open auction and through secondary markets in Pensylvania, New Jersey Maryland (PJM). FTRs entitle the holder to receive compensation for transmission congestion charges that arise from locational differences in the hourly market prices (the Locational Marginal Prices - LMPs) resulting from the despatch of generators out of merit in order to relieve congestion. FTRs, therefore, do not represent a right to the physical delivery of power, but ensure that access is financially firm. Participants in California cannot yet reserve physical transmission rights prior to the scheduling process but this is planned. In its October 1997 ruling, approving the operation of the California ISO, the Federal Energy Regulatory Commission (FERC) determined that a market for FTRs was needed in order to conform with FERC's Order No. 888, which is due to be implemented in early 2000.

The current transmission access regime in California is based around a Congestion Management market run by the ISO. Self-despatch schedules are accommodated except when transmission capacity between or within zones is not sufficient to accommodate all the flows requested. Currently, four zones are identified by the ISO but only two of them are active. Each zone corresponds to areas between which constraints are expected to occur frequently but within which constraints are unlikely to be significant.[19] It is between zones, therefore, that the need

[19] This reflects the physical characteristics of the transmission system in California. Each transmission system owner has developed a well integrated transmission system. However, interconnection between systems is often through point to point transmission lines. It is over such lines that constraints are most frequent and around which the zones are defined.

to allocate transmission access rights becomes critical. If interzonal constraints are forecast to occur, the available transmission capacity[20] is allocated to those who value it most as indicated by the adjustment bids and offers submitted to the ISO. In allocating transmission access rights, the ISO may change the absolute level of generation and demand that a participant wanted to flow, but must leave the schedule overall in energy balance.[21] The marginal value of transporting electricity across the constraint is determined (based on the adjustment bids/offers submitted) and forms a congestion usage charge that is paid by all Scheduling Co-ordinators with flows across the constraint. The net amounts collected from interzonal congestion usage charges are paid to transmission owners. In the event that congestion occurs within a zone (intrazonal congestion), the ISO is allowed to change energy schedules by paying generators not to run and paying other more expensive generators elsewhere. Adjustment bid/offers accepted by the ISO are 'paid-as-bid' and the intrazonal congestion price is set at the average cost of alleviating congestion within each zone and charged to all customers within a zone.

In Norway, Sweden and Finland, transmission constraints are relatively infrequent and a dedicated mechanism for allocating transmission access rights has not been seen as essential. Instead, Elspot is used to clear both the energy market and the rights to transport that energy. In the event that constraints do occur, up to seven zonal prices can be determined (up to five within Norway; and one each for Sweden and Finland). A congestion charge for the constrained parts of the network (the difference between the relevant zonal prices) is charged to participants transporting electricity between zones. Generators and suppliers within a zone are paid and pay the zonal price. 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.

In Australia, NEMMCO utilises day-ahead bids and offers to determine constraint feasible despatch schedules and to set zonal prices. Hence, transmission access rights are allocated on the basis of energy despatch instructions and, in this sense, are non-firm.

[20] Transmission capacity remaining after removing capacity reserved under the existing transmission contracts.
[21] Participants are not paid or charged for changes to their final schedules resulting from congestion management.

In the Netherlands, the electricity SO (TennetT) sells access to major interconnectors with neighbouring countries. Priority for international access depends on the duration of the energy contracts held by participants with long-term contracts taking priority over shorter-term trade.

In gas markets around the world, there is now a widespread use of price auctions to sell pipeline capacity (transportation rights). In the United States, for example, many interstate pipeline companies use auctions to sell firm transportation capacity in open auctions conducted by the pipeline operator. Furthermore, secondary trading of capacity by bilateral agreement or open auction is possible in the U.S, which allows the value of capacity to be more fully revealed to market participants.

International experience of mechanisms for allocating transmission access rights suggests that markets that are voluntary and which allow self-despatch have tried to separate the purchase and sale of energy from the right to transport that energy, and in the process have created financially firm transmission access rights (PJM, California from 2000, U.S. gas pipelines). Scandinavia is an exception to this thesis, since the mechanism adopted for allocating transmission access rights is more like that currently used to resolve intrazonal constraints in California. Given that constraints are in any case less frequent in Scandinavia than in other systems, it is unclear that a mechanism for allocating transmission access rights such as that in implemented in PJM would be justified. In mandatory central despatch markets (Australia), the right to transport energy is determined by the scheduled energy of a participant. This is equivalent to the current situation in England and Wales.

Appendix 5 NGC Paper on Operational Information

DEVELOPMENT & IMPLEMENTATION STEERING GROUP

DISG 14 - 6 July 1999

Operational Information and Transparency

(Paper by Jeff Scott and Mark Fairbairn, NGC)

1. INTRODUCTION

1.1 An objective of the proposed new market arrangements is to maximise the level of commercial freedom available to individual participants. A key factor contributing to market efficiency will be access to information for all market participants.

1.2 In addition, prior to and after gate closure NGC requires information from market participants concerning intended physical delivery, to enable it to plan to balance the system in real time while maintaining the integrity of the system and relieving constraints.

1.3 NGC is committed to providing timely access to relevant information to the fullest extent practicable, and will be adopting a variety of policies and practices to ensure that this is achieved.

2. MEDIUM TERM INFORMATION

2.1 As now, NGC will receive information on the planned availability (via the Grid Code, OC2) of the market participants. NGC can continue to provide an indication on the national operating margin and zonal margins based on this information and its own demand forecasts. It is likely that this information will be useful to the market participants as one of the factors taken into account during their trading activities.

Proposal 1	In the medium term NGC continues to receive availability data

Proposal 2	As now NGC publishes national and zonal margins based on this availability data

3. DAY AHEAD INFORMATION

Current Arrangements

3.1 Under the current Pool arrangements bid information is made available to NGC, from which it constructs an intended generation schedule against which plant can be despatched. Offer data is made available to NGC at 10:00 hrs and by 11:00hrs a preliminary GOAL run is carried out which feeds into NGC's power system analysis software to enable engineers to assess system constraints and determine fault level limitations.

3.2 Any plant that has long notice to synchronise and/or run up rates and is required for a constraint or as contingency reserve is 'ordered' as required. Participants are notified of their intended schedules by 16:00 hours and a final "plan" is handed over to the Control Room by 17:00 hrs which includes an analysis of system constraints, changes to network running arrangements and operating margins.

3.3 Any changes that arise between the provision of the initial Offer data and real time may require a re-assessment to take place to determine if the changes have a material effect on how the system can be operated. Any generators previously ordered which are no longer required will be stood down (and paid a proportion of their Start-Up price).

Impact of RETA

3.4 With RETA this offer data is no longer provided to NGC at the day ahead and market participants will need to decide their own generation and consumption schedules based on their contracted positions. These will evolve, based on information made available to them from the markets. Under RETA there will also be a requirement for NGC to provide information to the market to aid day ahead contracting and there will be a requirement for information to be made available to NGC to enable it to assess how the system can be operated.

Information NGC can provide at the start of the day ahead

3.5 To aid the day ahead process it may be beneficial for NGC to publish some preliminary information to market participants:

Proposal 3	In preparation for the day ahead phase NGC publishes at 09:00 hrs (D-1) the following:- • a forecast of system demands, by zone and nationally • an indication of the operating reserve requirement • national and zonal margins from previous days availability data submission • other strategic factors of potential importance to the market

Timing of IPN

3.6 The optimal timing for Initial Physical Notification information to be provided to NGC would be in the morning of the day ahead, say 11:00 hours. This would allow a comprehensive assessment to be carried out by NGC of the likely system constraints and enable proper consultation to be entered into with other parties e.g. REC distribution systems on interface issues. An early indication of the IPN would also enable timely signals to be passed to the market prior to the end of the working day, highlighting likely imbalance volumes and zonal margins.

Proposal 4	The Initial Physical Notification (IPN) is first provided by participants to NGC at 11:00 hrs D-1.

Information required by NGC at the IPN

3.7 At the day ahead stage constraints will still need to be rigorously assessed using the most up to date information and final strategies determined for managing how the system can be secured. These will include:

- constraint resolution
  - ⇒ assessing what generation or demand management opportunities to secure the system may be available in the balancing mechanism
  - ⇒ post-fault generation output changes agreed, based on unit effectiveness at relieving particular overloads and the time available to respond (dependent on short-term circuit ratings)
  - ⇒ network re-switching (often this needs to be done overnight for the following day to take advantage of lower fault levels)
  - ⇒ intertrip selection (generation and demand)
  - ⇒ quadrature-booster settings
  - ⇒ accelerating or postponing planned circuit outages
- system voltage profile and optimal reactive reserve holding
- fault level assessment
- operating reserve and response requirements
- contingencies (defensive measures against known events/risks)

3.8 To enable NGC to carry out an assessment of the transmission system at the day ahead stage participants, who intend to have a physical position (above a de-minimus level), need to inform NGC of their intended generation and consumption profiles. Under RETA it is proposed that this initial physical notification (IPN) is provided at the day ahead of the trading day and for each settlement period of that trading day.

Proposal 5	IPNs (and FPNs) are provided by all participants, who intend to have a physical position, above the agreed de-minimus level.

Proposal 6	IPNs (and FPNs) are an indication of a participants intended physical position in real time not including any intended balancing mechanism bids.

3.9 NGC would use the IPN (and FPN) information from all demand-side participants as a factor in determining its own forecast of demand. The weighting of these IPN submissions as a factor in the NGC demand forecast process would increase as the accuracy of the demand participants submissions increased.

Proposal 7	Demand not participating in the balancing mechanism should still be required to submit an IPN (and FPN).

3.10 Under RETA there is no longer a 'schedule day' as the balancing mechanism is on a rolling four hour basis; however for day ahead information provision it is important for NGC to still have a view of the entire day at this stage. This is because decisions taken for any part of that day can affect the entire day (e.g. the need to split a substation due to evening peak fault levels may require the substation to be operationally split the previous evening). Operationally the day definition is best defined for the period from 05:00:01 hrs to 05:00:00 hrs as this runs between system minimum demand periods.

Proposal 8	IPNs are provided at the day ahead stage covering the entire following operational day from 05:00:01 - 05:00:00 hours.

Format of IPN

3.11 The IPN is the initial indication of intended output for a genset and intended consumption for a demand. The data should be in whole MW, be continuous across the operational day with linear ramps assumed between data points.

Name	Start Time / Date (HH.MM) (DD/MM/YY)	Output/Demand (MW)
PART-1	XX.XX XX/XX/XX	XXX
PART-1	XX.XX XX/XX/XX	XXX

Proposal 9	IPN format provides a continuous profile in whole MW for each period. For demand the intended MWhr consumption can be presented as a straight line at the appropriate level giving the required total MWhr requirement for each period.

Additional Information

3.12 As part of participants IPN submission it would be helpful for NGC to know, in addition to their intended schedules, the expected volume of increments and decrements that participants are intending to bid into the balancing mechanism. This would enable an intended balancing mechanism capability to be determined and the following assessments to be made:-

- whether there are sufficient incs to meet the forecast demand taking into account constraints, reserve and response requirements
- if the level of flexible plant on the system at minimum demand periods is sufficient
- if post-fault actions are sufficient to resolve transmission constraints

Proposal 10	As part of the IPN the following information is provided at the day ahead:- • intended balancing mechanism capability • relevant dynamics which might restrict that capability

3.13 Dynamic parameters should apply for each genset or demand bidder intending to bid in the balancing mechanism and should be seen as separate 'stand alone' data relevant to each Control Point for each operational day. Dynamic parameters should not be seen as purely commercial parameters attached to each separate bid (e.g. there should not be different dynamic parameters for the same unit for the same MWs between different periods). To enable changing circumstances to be reflected it should be possible to update dynamic parameters, but these would apply across all operational periods for each day.

Proposal 11	Dynamic parameters should apply to each Control Point over each operational day. These parameters can be updated if required.

4. MOVING FROM IPN TO THE BALANCING MECHANISM

Current Arrangements

4.1 Currently generators and demand-side bidders notify NGC of changes to their intended availability or dynamic parameters by submitting redeclarations at the time of the change.

Updating IPN

4.2 The July Proposals, section 5.27 states, *"......The SO would also need to be informed of any changes in the intended output or demand of those submitting initial physical notifications, as and when such changes occurred. The notifications by generators would be specific to a generating unit at a specific grid supply point. Those made by customers might initially relate to a grid supply point group because settlement for demand will take place at this level under the 1998 arrangements for full supply competition."*

Proposal 12	IPNs should be updated as changes occur to participants intended physical position.

Proposal 13	Intended balancing mechanism capability and relevant dynamic parameters should be updated if changes occur.

NGC information to the market

4.3 Following on from the provision of an IPN or an updated IPN, NGC can then indicate to the market issues such as imbalance volumes, operational margins and zonal margins. It would be fairly quick, say within 1 hour from receiving the data, to be able to provide an indication of the difference between the IPN schedules and NGC's forecast demand. This would determine the likely imbalance volume.

Proposal 14	NGC can provide an indication of the imbalance volume within 1 hour of submission of the IPN (i.e. by 12:00 hrs).

4.4 NGC can then issue more detailed information to the market after assessing the locational issues. This could be published within 4 to 5 hours of receiving the IPN ,i.e. by 16:00 hrs (see Appendix 1 for a possible format).

Proposal 15	NGC information to market (i.e. by 16:00 hrs) • Indication of likely level of balancing mechanism trades required for imbalances • Indication of level of balancing mechanism trades required for transport reasons • sufficiency of availability/ national margin • zonal margins can continue to be made available

4.5 While updated information is passed continually to NGC from participants it might be necessary to delay issuing information to enable exposed participants to trade on the power exchange.

Proposal 16	NGC provides information back to the market, based on updated IPNs, at regular but discrete intervals.

Common format of IPN and FPN

4.6 It would be sensible to make the IPN and FPN format identical. This would prevent the need to duplicate data transfer systems and would also enable participants to submit schedules via the IPN, which if not updated could default to becoming their FPN. Hence IPN schedules can be overwritten at any time prior to gate closure; however if they are not overwritten they automatically become the final schedule.

Proposal 17	The format of IPN and FPN information is identical.

Proposal 18	If an IPN schedule is not overwritten it automatically becomes the FPN.

IPN and FPN Provision Rules

4.7 Their must be a strong obligation on participants to submit an accurate IPN and FPN to NGC. Poor information provided to NGC will result in increased reserve costs being incurred and may jeopardise security of supply. The IPN and FPN information requirement and format should be primarily identified in the Grid Code, with appropriate cross-referencing to the Balancing and Settlement Code. The Grid Code should therefore take precedence in defining the requirement and format of the IPN and FPN, as this is primarily operational data for use by NGC

Proposal 19	The IPN and FPN information requirement and format are primarily identified in the Grid Code with appropriate cross-references to the Balancing and Settlement Code. The Grid Code should take precedence in defining the requirement and format of the IPN and FPN.

5. BALANCING MECHANISM

5.1 NGC will select balancing mechanism bids to:-

- meet any imbalance energy
- resolve system constraints
- part load plant for response and reserve

5.2 Information about balancing mechanism bids and offers will be made available in real time from the Balancing Mechanism Information System. For example, screen-based information on the last accepted deal and on present bids and offers could be made available to all participant.

Proposal 20	Screen based information on trades selected by and available to NGC will be made available to all participants via the Balancing Mechanism Information System.

6. POST EVENT INFORMATION

6.1 Post event information could be provided by NGC to market participants to compliment the information available from the settlement administrator. Some information could be provided fairly quickly after the operational day whilst some information with a high-level explanation could be provided as part of a regular, say monthly, report. Examples of possible data that can be provided include:-

- forecast demand, actual demand and demand forecast error
- actual energy imbalance volume purchased
- actual national and zonal margins
- actual reserve and response volumes purchased
- trades purchased for constraints
- information on the flexibility of bids
- information accuracy
- IPN and FPN schedules

The availability of this information should help participants to review and refine their market position.

Proposal 21	Post event information can be provided by NGC to supplement market information

7. COMMUNICATIONS OVERVIEW

7.1 Easy access to information by all market participants on an equal footing will be essential to facilitate the new trading arrangements. The Balancing Mechanism Information System will provide the most effective way for information to be quickly disseminated to market participants.

7.2 The use of the internet to facilitate communication with a wide range of parties, including external bodies not directly trading in the Balancing Mechanism, is shown to be effective on the basis of international experience. Consideration will be given to using the internet where practicable for general information dissemination.

8. SUMMARY

Proposal 1	In the medium term NGC continues to receive availability data
Proposal 2	As now NGC publishes national and zonal margins based on this availability data
Proposal 3	In preparation for the day ahead phase NGC publishes at 09:00 hrs (D-1) the following:- • a forecast of system demands, by zone and nationally • an indication of the operating reserve requirement • national and zonal margins from previous days availability data submission • other strategic factors of potential importance to the market
Proposal 4	The Initial Physical Notification (IPN) is first provided by participants to NGC at 11:00 hrs D-1.
Proposal 5	IPNs (and FPNs) are provided by all participants, who intend to have a physical position, above the agreed de-minimus level.
Proposal 6	IPNs (and FPNs) are an indication of a participants intended physical position in real time not including any intended balancing mechanism bids.
Proposal 7	Demand not participating in the balancing mechanism should still be required to submit an IPN (and FPN).
Proposal 8	IPNs are provided at the day ahead stage covering the entire following operational day from 05:00:01 - 05:00:00 hours.
Proposal 9	IPN format provides a continuous profile in whole MW for each period. For demand the intended MWhr consumption can be presented as a straight line at the appropriate level giving the required total MWhr requirement for each period.

Proposal 10	As part of the IPN the following information is provided at the day ahead:- • intended balancing mechanism capability • relevant dynamics which might restrict that capability
Proposal 11	Dynamic parameters should apply to each Control Point over each operational day. These parameters can be updated if required.
Proposal 12	IPNs should be updated as changes occur to participants intended physical position.
Proposal 13	Intended balancing mechanism capability and relevant dynamic parameters should be updated if changes occur.
Proposal 14	NGC can provide an indication of the imbalance volume within 1 hour of submission of the IPN (i.e. by 12:00 hrs).
Proposal 15	NGC information to market (i.e. by 16:00 hrs) • Indication of likely level of balancing mechanism trades required for imbalances • Indication of level of balancing mechanism trades required for transport reasons • sufficiency of availability/ national margin • zonal margins can continue to be made available
Proposal 16	NGC provides information back to the market, based on updated IPNs, at regular but discrete intervals.
Proposal 17	The format of IPN and FPN information is identical.
Proposal 18	If an IPN schedule is not overwritten it automatically becomes the FPN.
Proposal 19	The IPN and FPN information requirement and format are primarily identified in the Grid Code with appropriate cross-references to the Balancing and Settlement Code. The Grid Code should take precedence in defining the requirement and format of the IPN and FPN.

Proposal 20	Screen based information on trades selected by and available to NGC will be made available to all participants via the Balancing Mechanism Information System.
Proposal 21	Post event information can be provided by NGC to supplement market information

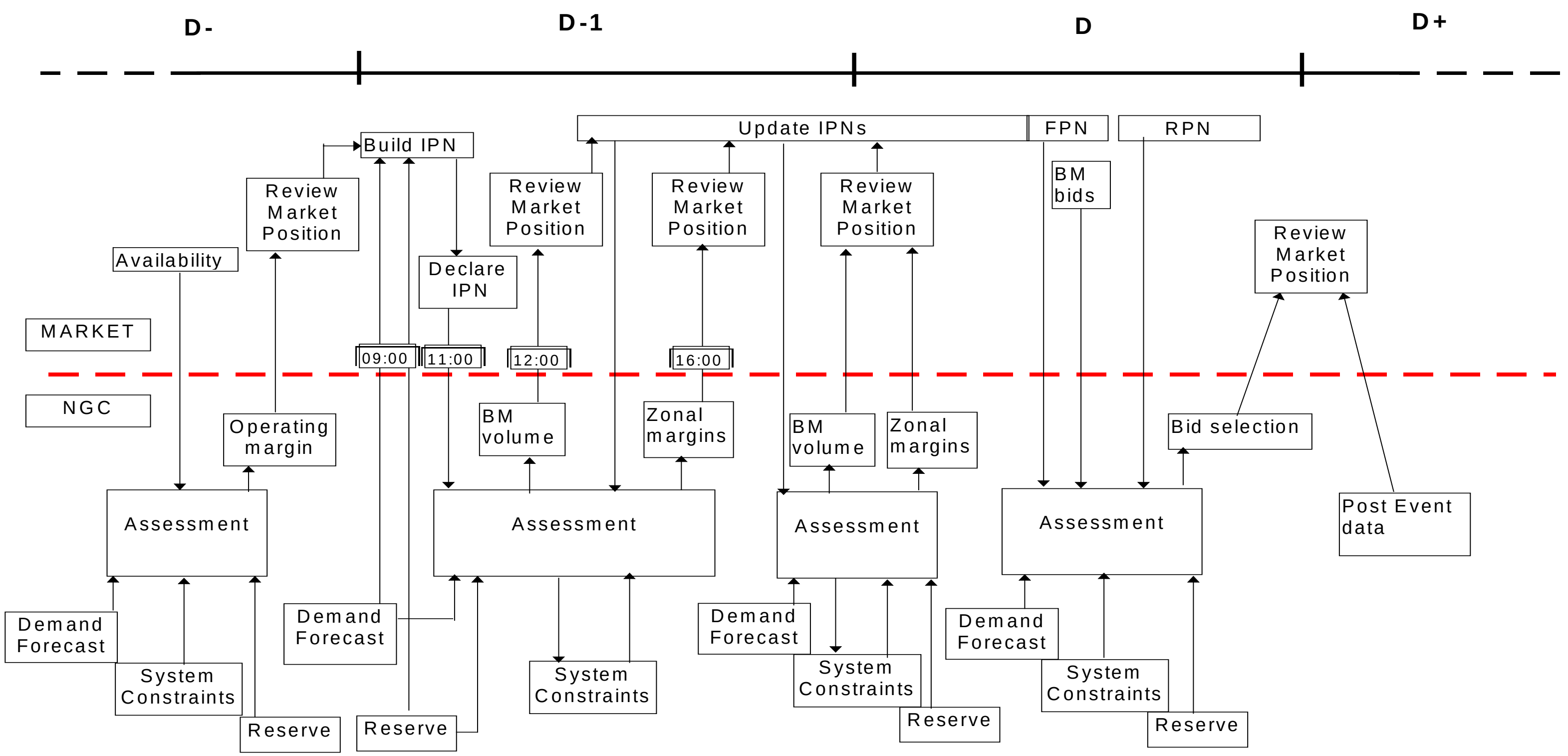
Appendix 1 - Example Of Possible NGC Information To The Market

	Forecast or Requirement (MW) / Time Based on data received at 1100 hrs	....	1630 hrs	1700 hrs	......
	OPERATIONAL MARGIN				
	Demand				
(a)	NGC National Demand Estimate	....	44500	45000	....
(b)	Demand IPNs	....	43900	44800	....
(c)	Gensets[22] IPN Output	....	44000	44600	....
(d)	Demand Imbalance (a)-(b)	....	**600**	**200**	....
(e)	MW change required to meet forecast demand (a)-(c)	....	**500**	**400**	....
	Synchronised/Spinning Reserve[23]				
(f)	Spinning Reserve Target	....	1400	1400	....
(g)	Gensets IPN Spinning Reserve[24]	....	500	500	....
(h)	Additional Spinning Reserve required (f)-(g)	....	**900**	**900**	....
	Unsynchronised Reserve				
(i)	Unsynchronised Reserve Target	.....	1700	1700	....
(j)	Unsynchronised participants meeting criteria[25]	....	1500	1500	....
(k)	Excess/Shortfall (i)-(j)	....	**200**	**200**	....
	Export Constraints				
(l)	Gensets declaring an IPN which NGC intends to accept decremental bids for constraints	....	**200**	**200**	....
	Total Requirement				
(m)	MW change required (e) + (h) + (k) + (l)	....	**1800**	**1700**	....

[22] Including certain classes of demand participants netted off forecast.
[23] Part loaded plant required to provide response and regulating reserve services (demand providers having been netted off the target requirement).
[24] Plant declaring a maximum output in the balancing mechanism timescale greater than the IPN with the appropriate dynamic parameters.
[25] Criteria set to ensure reserve is available to return the frequency to within operational limits which must be sustainable and repeatable.

	Downward Regulation[26]				
(n)	Downward regulation requirement	.....	2000	2000	....
(o)	Downward regulation available	....	7000	7000	....
(p)	Margin (o)-(n)	....	**5000**	**5000**	....

[26] Downward regulation ensures that NGC can respond to a high frequency incident.



This paper has been produced in accordance with the Terms of RETA Participation as set out in paper DISG 05/010 dated 1 March 1999 and which is available from the Programme Director's (Birmingham) Office

Appendix 6 Ancillary Services Under the Present Arrangements

This Appendix describes the present arrangements for procuring and delivering ancillary services. It draws on work done by the Security of Supply Expert Group.

6.1 Introduction

Ancillary services are services that are essential to the management of the power system and ensure that electricity supplies are of acceptable quality. The main services are frequency response, reserve, black start and reactive power.

NGC is required through its Transmission Licence to procure sufficient services to secure the system and despatch energy (LC6 & LC7). Certain services are required from generators under the terms of the Grid Code[27] and the Master Connection Use of System Agreement (MCUSA). The Grid Code (CC8) sets out certain requirements for generators to provide ancillary services. These are divided into two categories, System and Commercial Ancillary Services.

System Ancillary Services are divided into Part 1 services, which are mandatory and which all generators are obliged to be capable of providing; and Part 2 services, which are services that are not required from every generator, and which are provided when agreed on a site by site basis as necessary. Commercial Ancillary Services are those other services procured by NGC to secure the transmission system not covered under System Ancillary Services.

Many of these commercial services are procured under the terms of bilateral contracts struck between NGC and individual ancillary service providers. Services may be remunerated on the basis of the underlying costs of service provision or based on the value of the service, established through competitive tender or bilateral negotiations between ancillary service providers and NGC.

The compulsory nature of certain ancillary services has, historically led to 'cost-based' remuneration for such services. The notion of cost-based remuneration has, however, become increasingly anachronistic as the electricity market in England and Wales has developed.

[27] For example the Grid Code requires all gensets of 50MW or more to be capable of providing reactive power and frequency response.

Progress towards promoting competition and markets in the provision of an ancillary services and the introduction of associated value-based remuneration has been made. Standing reserve has, since 1993, been procured through competitive tender. In 1998, a competitive tendering process for the remuneration of reactive power was introduced and similar proposals are being taken forward for the procurement of frequency response under the auspices of the Transmission Users Group (TUG). Furthermore, demand-side competition in the provision of ancillary services has been encouraged and has grown.

The Transmission Licence requires NGC to purchase ancillary services on an economic basis. Whilst this economic purchase obligation is discharged through the Ancillary Service Business, the interaction between the costs of purchase of ancillary services and certain uplift costs (e.g. constraints and scheduled reserve) is also recognised. The Transmission Services arrangements place financial incentives on NGC to manage the costs of both ancillary services and the relevant elements of Uplift.

NGC has Ancillary Services Agreements (ASAs) with:-

- all large centrally despatched generators who are obliged to contract with NGC through the MCUSA;
- externally interconnected parties; and
- smaller generators and load managers who provide commercial services.

As at June 1999, NGC had ancillary service contracts with 50 different companies in total.

The types of ancillary services (frequency response, reserve, black start, constraints and reactive power) are discussed in section 6.2. An estimate of the volumes and approximate cost of these services are given in section 6.3. A complete list of System Ancillary Services, and a list of Commercial Ancillary Services, together with a high level service description of each of the six types of ancillary service contracted to date, is given in Annex 1. Annex 2 describes standing reserve in more detail.

6.2 Breakdown of Ancillary Services

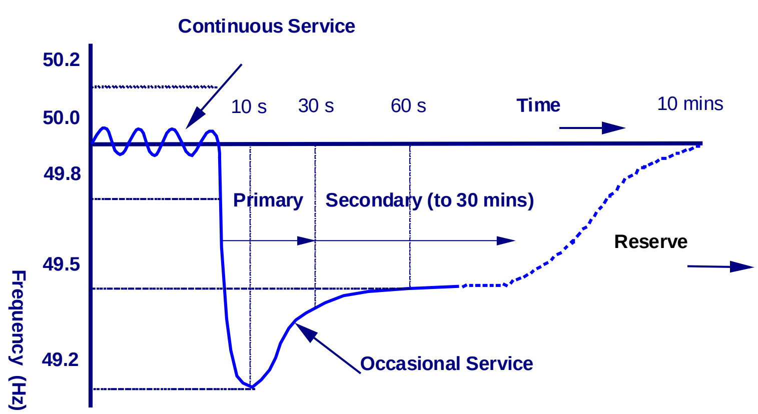
6.2.1 Frequency Response

System frequency varies with the balance between generation and the total system demand at any one instant. In order to maintain a secure and stable transmission system there is a statutory obligation on NGC to maintain the frequency of the system within the range 49.5Hz to 50.5Hz. This is achieved by automatically balancing demand and generation such that the system frequency remains within the required limits.

In order to ensure that frequency can be managed satisfactorily in all circumstances, all large generators must be capable of contributing to frequency control. Such obligatory services are currently provided on a cost-reflective basis. Generators, in many cases, provide extra commercial services. Frequency can be managed both by changing demand as well as generation and NGC has arrangements with some large electricity consumers who are prepared to interrupt their demand for short periods.

NGC utilise a range of services that operate over different time scales in order to manage system frequency effectively. Figure 6.1 shows the broad categories of services that are used:

Figure 6.1 - Frequency Response



Source: NGC.

Response

The continuous service shown above is a response service provided by automatic devices (governors) that can be used at any time to contain frequency deviations and to return frequency to normal. Synchronised generators and demand provide the service and the volume of contracted response is sufficient to cover the loss of the largest infeed and to maintain system frequency within statutory limits. The service provided by synchronised generators is automatically delivered by units specifically selected to operate in frequency sensitive mode and is generally provided by pump-storage and part-loaded steam plant.

Containment

If a frequency deviation cannot be met by frequency responsive generation and demand, the next step is to contain the frequency deviation by utilising plant that has the capability for an almost instantaneous increase in output (or demand which provides the service via the operation of low frequency relays). The change in output must be sustainable for up to 30 seconds following a fall in frequency or until the normal level (50Hz) is regained following an increase in system frequency. These services are formally referred to as 'primary response' and 'high frequency response' and are described in more detail in the Grid Code.

Recovery

To allow the containment plant to be restored to their standby level, recovery services produce additional output (or reductions in demand) within 30 seconds which must be sustainable for a further 30 minutes. This is formally referred to as 'secondary response'. Beyond these timescales the system relies on reserve rather than response.

As outlined above, the system is operated via a portfolio of services, some of which are required continuously to provide dynamic services and others only required on an occasional basis.

NGC's selection of which services to utilise on the day is a trade-off between constrained on and off payments and the costs of response services. The incentives on NGC to minimise uplift costs are designed to ensure the most economic selection is made.

6.2.2 Reserve

Frequently the electricity system requires extra power (reserve) to deal with situations when demand is greater than forecast or where plant breakdowns occur. Reserve is also used to take over from frequency response services. These requirements are met by part loaded synchronous plant, and by non-synchronous sources, such as standby generators and demand reduction from large industrial consumers. In addition NGC schedules contingency reserve at much longer timescales, 4 to 16 hours ahead, to cover potential demand forecast error and plant losses, taking into consideration locational concerns.

Broadly speaking, different types of reserve operate over different timescales, and as progressively slower reserves are called, they allow faster[28] reserves to be restored to their pre-incident state so as to be in a position to deal with the next incident.

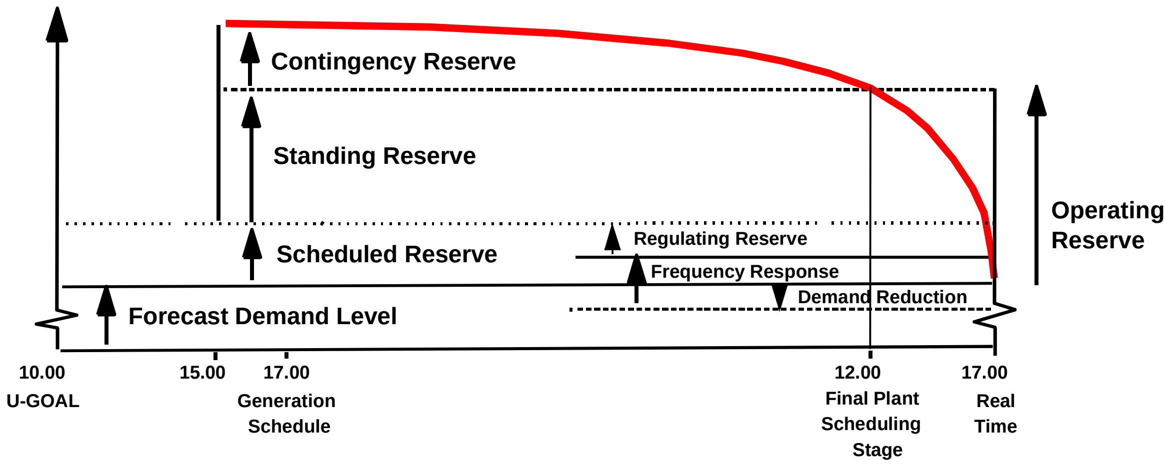
In total, the System Operator plans on the basis of having sufficient reserve to meet the perturbations caused by whatever single incident would have the maximum impact. Usually the planning is on the basis of the single largest loss on the system, although occasionally demand events, such as a surge at the end of a major sporting event, are also taken into account.

At certain times of the day, generating units may be only partially loaded. Reserve provided by part-loaded generation is paid for via the pooling arrangements. At other times, particularly across demand peaks when generation will tend to be fully loaded, there will be little synchronous (regulating) reserve available and so the requirement for Standing Reserve will be much higher. NGC contracts for Standing Reserve via the tender process, as discussed in Annex 2.

Figure 6.2 illustrates NGC's reducing reserve requirements as real-time approaches and broadly how that requirement is covered by the various types of reserve available.

[28] Slower and faster in the sense of speed of response to an instruction from the System Operator.

Figure 6.2 - MW Reserve Requirement/Time Diagram



Source: NGC.

Regulating Reserve

Regulating reserve is that volume of part loaded plant scheduled to very short timescale effects (e.g. TV pick-ups), demand forecast error, plant breakdowns or shortfalls, and is required to deliver in timescales of 5 to 10 minutes.

The volume of plant held as regulating reserve is based on the probability of changes in demand and available generation as real-time approaches. The volumes of regulating reserve held by NGC vary by time of day, type of day and time of year.

Regulating reserve is held on constrained on and off plant and hence, its costs appear in Transport Operational Outturn, against which NGC is incentivised.

Standing Reserve

Standing reserve is required to cater for unexpected generation losses and demand forecast error and must be available in timescales of less than 20 minutes.

NGC has contracted for this ancillary service since 1993 following an initial request from OFFER.[29] This followed the recognition that gas turbine plant plays an important role in providing short-term system security that is not fully valued through the LOLP/VOLL

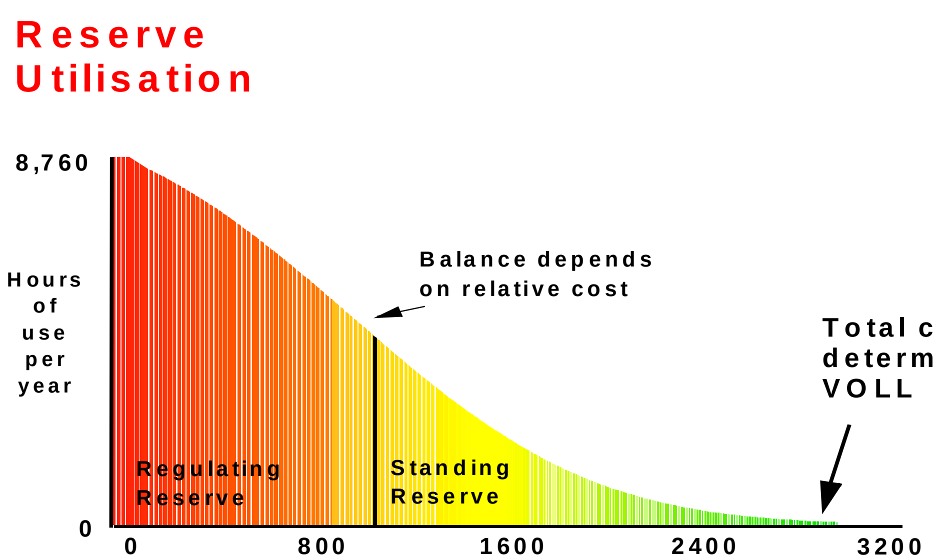
[29] This followed from the “Report on Gas Turbine Plant”, June 1992, OFFER.

mechanism. A market-based mechanism was subsequently proposed which led to a competitive standing reserve tender being undertaken by NGC on an annual basis.

The contract arrangements for standing reserve, which are medium-term in nature, provide availability and utilisation payments. The total costs of the service are around £15m per annum, of which approximately 75% is spent on availability and 25% on utilisation.[30] The costs of the service appear as part of Transport Uplift. A more detailed description of standing reserve is provided in Annex 2.

The diagram below illustrates the typical utilisation of Regulating and Standing Reserve services.

Figure 6.3 - Reserve Utilisation



Source: NGC.

Contingency Reserve

Contingency reserve is provided by plant scheduled at much longer timescales, 5 to 24 hours ahead, to cover potential demand forecast error and plant losses. In scheduling it, NGC ensures that not all reserve is placed within a constrained zone. The plant scheduled for this purpose is commonly plant with long notice to synchronise periods. NGC generally has the option of cancelling the start-up of such plant if it becomes clear they are not required.

[30] These parties also receive Unscheduled Availability payments.

The costs of contingency reserve are captured through cancelled start and hot standby payments if the cancellation occurs within the plant's notice to synchronise period. If a plant is ordered and subsequently cancelled outside its notice to synchronise time then the service is provided free. Actual costs of cancelled starts and hot standby are approximately £7m per annum and appear as an ancillary service charge in Transport Uplift.

6.2.3 Black Start

In the event of a partial or complete failure of the transmission system a 'Black Start' may become necessary. A generating station has Black Start capability when it is able to start-up from shutdown at least one of its generating units without an external electrical power supply. The service was last used during the 1987 hurricane which hit southern England, when plant at Grain and Kingsnorth successfully carried out black starts and re-established power supplies in the region.

NGC currently contracts with Black Start providers on a long-term basis, some under bundled contracts and the remainder under specific service contracts. The costs of Black Start appear in Transport Uplift as an ancillary service cost of around £10m per annum.

6.2.4 Constraints

NGC operates the transmission system to agreed security standards that ensure credible losses of transmission circuits do not cause widespread disruption of supplies. Where a transmission constraint occurs, generation (or demand) will be rescheduled to reduce power flows in that part of the system.

Occasionally, when particular transmission circuit or generator outages occur or when constraints are intrinsically longer term, NGC may be prepared to contract either with generators or with large industrial electricity consumers (typically more than 50MW) to manage network security and costs. Depending on the type of constraint, generation or demand can be contracted 'pre-fault' or 'post-fault'.

6.2.5 Reactive Power

NGC manages the voltage of the supergrid system to meet Transmission Licence requirements for secure and stable power transmission and to ensure quality of supply to customers. Voltages are largely determined by the flows of reactive power on the system and require co-ordination by the System Operator. NGC utilises the reactive power capability of generators and some of its own transmission assets to control these flows in real-time.

Over the last few years, the industry has been developing new arrangements for the procurement of reactive services. Since 1st April 1998, a Reactive Power Market has been established which provides for the payment arrangements for services provided by generators. This provided so-called default rights of payment for large generators as well as the opportunity for these providers and others (i.e. large non-centrally despatched generators or significant customer loads) to tender for alternative market contracts.

Default contracts provide a two-part payment mechanism, based on generator reactive capability and reactive metered output. Capability payments vary geographically across the transmission system, reflecting the relative surplus or deficit of reactive power in each of the 18 electrical zones. These zones and potential payments are described in NGC's Seven Year Statement. Utilisation payments are uniform across all generators. It is currently expected that from April 2000 payments will be paid on a utilisation basis only, i.e. capability payments will cease. Development of this market began well before the RETA programme and is likely to proceed independently of it.

6.3 Volumes and Costs of Ancillary Services

6.3.1 Introduction

A full list of all ancillary services is presented in Annex 1. Table 6.1 reports volumes and costs of all these ancillary services.

6.3.2 Principles of Reporting

Most of these ancillary services impact on volumes and costs within the Operational Outturn ('OO') component of uplift, in addition to those within ancillary services ('AS') alone. For example, when a centrally despatched steam genset holds 1MW of response, it typically is deloaded by 2MW from its unconstrained generation, and thus contributes a volume of 2MW to OO as well as the 1MW of ancillary service; and costs occur in both AS and OO.

The attached table records, where appropriate, volumes as both those of the underlying ancillary service, and any consequent volumes of pooled-on and pooled-off energy within Operational Outturn. The table also records costs within both AS and OO; in all but one case identified, the OO costs fall into Transport Operational Outturn ('T-OO'), rather than into

Energy Uplift ('EU').

Data is presented as a three-year average 1996 to 1998. Volumes are mainly rounded to the nearest TWh, and costs are rounded to the nearest £5m; a cost reported as 'small' is less than £1m pa - normally substantially less.

Table 6.1: Volumes and Costs of Ancillary Services

Volumes are expressed, where appropriate, as both the volume of ancillary service and the consequent volume of pooled-on and pooled-off energy in Operational Outturn ('OO').

Costs are reported as both the ancillary (contract) costs, and the costs in Operational Outturn. Both volumes and costs are averages over 1996 to 1998, and are rounded to the nearest £5m. Small means < £1m.

Service	Volume	Cost £m AS	Cost £m OO	Notes
Reactive	38 TVArh_gen (|lead + lag|)	50	Small	These are the volumes and costs of the Grid Code service through the Reactive Market. Other commercial reactive services are small. The costs and volumes of voltage constraints are included within constraints below.
Response	6.5 TWh of primary response 7.5 TWh of secondary response 5 TWh of high response 5 TWh_gen of pooled-off (OO)	35	40	This is delivered from the portfolio of steam + CCGT, water, and demand-side providers. NB 1TWh of response represents service held (e.g. 110MW of response held all-year), and does not relate to energy delivered.
Scheduled Reserve	10 TWh held	10	50 T-OO + 20 EU	Scheduled reserve covers all categories of reserve held on synchronised plant, excluding frequency response.

Service	Volume	Cost £m AS	Cost £m OO	Notes
				NGC believes that some of the OO costs fall into Energy Uplift.
Standing Reserve	8 TWh of availability contracts; 80 GWh of energy utilisation	5	10	The AS cost is option fees minus exercise rebates. The balance between AS and OO costs is dominated by exercise rebates.
Black Start	15-20 sites	10	Small	
Constraints	3 TWh of both pooled-on and pooled-off in OO	Small	35	In any year, there are very few ancillary constraint contracts.
Emergency Assistance	2 Interconnectors	Small	Small	

GLOSSARY: AS - Ancillary Services; OO - Operational Outturn; T-OO - Transport Operational Outturn; EU - Energy Uplift.

Notes relating to Table 6.1:

1. Part 1 System Ancillary Services are provided by all generators unless they are derogated.
2. Part 2 System Ancillary Services are provided by generators at specific sites only.
3. Precise service definitions are given in the Ancillary Services Agreement - care should be exercised with the shortened definitions / service descriptions given.
4. No distinction is made between directly connected and embedded stations in the requirement to provide system ancillary services.
5. The list of commercial ancillary services is not complete - any new service that has value in managing the transmission system will tend to be a commercial service

Annex 1 - Ancillary Services

This Annex provides a full list of the Ancillary Services currently available to NGC.

Table 1 - List of Ancillary Services

Service	**System Services**	**Commercial Services**	**Description**
Reactive	Part 1 – Reactive Power (see Grid Code CC6.3.2) Default Contracts – The 'default' mechanism to pay for generator reactive capability and utilisation, the payments increasingly weighted each year towards utilisation (i.e. from April 2000 all payments 'on the meter'). Market Contracts – The tender based mechanism for generators to offer unit specific cost / price functions for synchronised capability, available capability and utilisation.	In addition Synchronous Compensation - provided from synchronous rotating plant used specifically for generating or absorbing reactive power. Enhanced services such as extended power factor ability may be offered with market contracts.	A service used to control voltage
Response	Part 1 – Frequency Control (see Grid Code CC6.3.7) Primary – additional output following a fall in	In addition Multi-mode Response - any extra mode or type of generator	An automatic service used to control frequency

Service	System Services	Commercial Services	Description
	system frequency produced within 10s and sustained for a further 20s Secondary - additional output following a fall in system frequency produced within 30s and sustained for a further 30m High Frequency - reduced output following an increase in system frequency produced within 10s and sustained for the duration of the incident	response e.g. different governor droops, overfiring, different operating ranges etc. Spin Gen / Spin Pump - conditions when a pumped storage unit is rotating at synchronous speed, with the turbine dewatered, and programmed to generate / pump if the system frequency falls / increases to a designated level. Pumping Programme - the ability by NGC to modify a pumped storage pumping programme through the application and removal of demand to enable the management of system frequency. Part Load Response - provided by deloaded plant to provide response at agreed prices across specified operating windows at set governor droops. Demand Reduction - demand tripped within 1s and maintained up to 30m.	

Service	System Services	Commercial Services	Description
Reserve	Part 2 – Fast Start Capability (see Grid Code CC6.3.14) The ability of a unit to be synchronised and achieve full load within 5m of an instruction.	In addition Five minute reserve - additional generator output which is available within 5m and sustainable for 4h. Rapid Load / Deload - enhanced generator ramping rates to increase / reduce MW within 5m. Hot Standby - a specified condition of generator readiness to synchronise. Standing Reserve - procured via a tender mechanism over ‘windowed’ periods of the year. This is the output from generating plant and or reduction in demand made available within 20m and sustained for 2-4h. Service types are:- - Committed - service provider commits to make service available, NGC commits to pay - Flexible - service provider chooses to make service available, NGC chooses to use / pay for service.	An instructed service used to match demand / generation

Service	System Services	Commercial Services	Description
		Fast Reserve - additional MW delivered in 1/2m used to assist in the regulation of frequency. Cancelled Start - an instruction for a generator to synchronise is cancelled when heat costs have been incurred.	
Black Start	Part 2 – Black Start Capability (see Grid Code CC6.3.5) The ability of a main unit to be synchronised, within 2h of an instruction from NGC, without an external electrical power supply.	In addition Bundled Services - when 'joint contracted' with standing reserve. Services that can be made available in different timescales.	The service provided by generation plant able to start without an external power supply
Constraints	n/a	Pre and post fault services - may be required for up to 12 hours - Generation - both pre and post-fault, generation available at contracted price - Intertrip - for generators and or demand - Demand - significantly reduced demand pre-fault, load on	A service required for security and or cost considerations when restrictions

Service	System Services	Commercial Services	Description
		relay for post-fault service	occur on the Transmission System
Emergency Assistance	n/a	Emergency power on request (if available)	Required through the Transmission Licence for (mutual) support of any other transmission system linked to NGC's by an interconnector.

Annex 2 - An Overview of Standing Reserve

Standing Reserve plays an important role in how NGC operates the transmission system and delivers security of supply. Following an initial request from OFFER, NGC has contracted for this as an ancillary service since 1993.[31] This followed from the recognition that gas turbine plant plays an important role in providing short-term system security, which was not fully recompensed through the LOLP / VOLL mechanism. A market-based mechanism was consequently proposed which led to a competitive standing reserve tender being undertaken by NGC on an annual basis.

1. Need for Service

Standing Reserve is required to cater for unexpected losses, reduction in generation or demand being higher than forecast. It is contracted on a 'windowed basis' to complement synchronised reserve provided by centrally despatched plant. This means that standing reserve is generally procured coincident with peaks in the daily demand curve but is not required (or has very little value) when there is inherent reserve on the system from part-loaded Pooled generation. NGC contracts for a maximum of around 4500 hours of service each year.

2. Service Volumes

NGC publishes required service windows through its annual tender. Generic demand profiles are recognised through five different 'service seasons' for both working and non-working days. Around 2000MW of standing reserve capability is contracted with typically 1800MW being available on any one day. This level of volume is reflective of the last few years' tenders and is made up of about 1000MW of centrally despatched OCGTs, with the remainder split pretty evenly between water (mainly pumped storage) and demand.[32] It should be noted that more than 40% of OCGT volume is bought under 'bundled' contracts, which is where reserve and Black Start services are bought jointly under fixed term arrangements.

[31] See "Report on Gas Turbine Plant", June 1992, OFFER.

[32] This includes load reduction, initiation of small standby diesels and other small non-centrally despatched generation.

3. Evaluation

NGC buys services based on the expected costs of each tender and selects the most economic. An assessment is undertaken in the autumn preceding the year in question which first identifies the likely range of costs of synchronised reserve.[33] The expected utilisation of service from each tender is then assessed through historical patterns of delivery for each of the 10 seasonal periods (i.e. working days and non-working days for 5 seasons). A composite cost based on likely option (or availability) and call-off payments is then derived, with NGC buying services up to the level of VOLL

4. Service Characteristics

The service is required to help 'takeover' from frequency response services before additional generation is fully available. The service characteristics include:

- instructed service;
- available within 20 minutes from instruction;
- sustainable i.e. for a minimum of 2 hours (ideally up to 4 hours);
- repeatable (at the very least within 20 hours);
- capable of being provided a number of times in week (3 or more);
- economic (in practice this generally means that must be more than 3MW);
- despatchable (mechanisms to receive / confirm instructions, availability etc);
- auditable (needs to be monitored);
- usage limits can be specified in the tenderer;
- volumes of service are specified by the tenderer, and
- prices are specified by the tenderer.

5. Headline Costs

The contract arrangements for standing reserve provide for payments for service availability and utilisation (i.e. when the service is called off). The total costs of the service lie in Transport Uplift, appearing in both 'ancillary services' and in 'Transport Operational Outturn'. In total around £15m is spent each year on the service (with roughly 75% spent on availability and

[33]Each tender has started in September and closed in November for services required for some or all of the following financial year.

25% on utilisation). These costs are approximately shared between OCGTs (48%), water (40%) and demand (12%).

6. Cost Range

Generally, the availability fees for water and OCGTs are relatively high (say £1.50/MW/hr) and those for demand relatively low (typically £0.50/MW/hr or lower). However utilisation costs are the reverse, with demand the most expensive (generally > £100/MW/hr) with water and OCGTs lying predominantly in the range £55 to £100/MW/hr. The average cost of the service is around £9/kW/pa.

7. Usage

The usage of the service is, by definition, not known in advance. Over the last few years typically 400 to 500 call-offs of service have been required annually. These are met by water (40%), OCGTs (40%) and demand (20%); the latter being in general more expensive and thus called off less often.

8. Duration

Duration of call off varies according to utilisation costs and technical parameters, but on average lasts for some 60 minutes.[34] Typical duration of water call-offs average around 0.6hours, with OCGTs and demand each averaging around 1.4hours.

40% of incidents last for less than 30 minutes
30% of incidents last between 30-60 minutes
10% of incidents last between 1 - 2 hours
20% of incidents last more than 2 hours

9. Energy

The total volume of energy called-off under standing reserve contracts is between 60 and 90GWh each year. This is approximately split between OCGTs (33%), water (65%) and demand (2%).

---

[34]See NGC Report on the Tender for the 1998/9 Standing Reserve Service (August 1998) - available on the internet (www.ngc.co.uk\operations\ancillary services\standing reserve).

10. Contract Flexibility

Contracts are structured recognising that from time to time services may not be available. When service providers choose or are not able to be available, they are exposed to penalty type provisions within the contract. Generators occasionally breakdown or may be in the Unconstrained Schedule when energy prices are particularly high. Demand-side providers, can take advantage of flexibility provided for within the standing reserve contracts to 'Triad Avoid' and or to participate in the Pools Demand-Side Bidding scheme. The arrangements for standing reserve are effectively 10 mini-tenders, with potential providers having the option to tender in or not for any or each of these periods under both 'committed' and 'flexible' contract forms. Committed contracts are effectively where the service provider promises to make the service available for all the periods that are required within a service season and NGC in turn commits to buy all the service availability offered. Flexible contracts are where the service provider looks for some flexibility in offering the service, with NGC in turn not firmly committing to buy the service availability offered.

11. Market Observations

NGC has procured standing reserve since April 1993. Overall annual volumes of service have generally been in the range 1900-2300MW. The overall level of OCGT plant has generally decreased matched by increased levels of demand-side options. NGC has held seminars, workshops, advertised and contacted all large electricity users each year in order to increase the market and develop competition. There is some evidence now suggesting that the standing reserve market has generally matured, with relatively few new entrants and market exits each year.

12. Participants

Around 24 companies currently provide standing reserve services. This includes portfolio generators who own auxiliary plant; pumped storage and small hydro together with a number of demand-side participants (some of who choose to contract with NGC via an agent). Demand-side participants generally have energy intensive operations, including many with significant heating, cooling, pumping or gasification loads.

Appendix 7 Worked Imbalance Examples

7.1 Imbalance Volumes

Imbalance volumes are calculated as the difference, at the aggregated level, between a participant's metered volume and its notified contracted volume.

Example 1

	Generator	Supplier
Contracted volume (CV)	250	-250
Metered volume (MV)	250	-250
Imbalance volume (MV-CV)	0	0

In this simple example, a generator signs a contract with a supplier for 250 MWh. The metered volumes of both participants match their contracted volumes and so neither has any exposure to energy imbalance charges. This example illustrates the sign convention that has been adopted. The contract volume allocated to a participant who purchases energy under contract has a negative sign whilst the contract volume allocated to a participant who sells energy under contract has a positive sign. A similar sign convention has been adopted with regard to metered volumes. Export (production) volumes have a positive sign whilst import (consumption) volumes have a negative sign.

Example 2

	Generator	Suppliers	
	G	S1	S2
Contracted volume (G-S1)	250	-250	
Contracted volume (G-S2)	250		-250
Total contracted volume	500	-250	-250
Metered volume	500	-255	-245
Imbalance volume	0	-5	5

All the contracts assigned by a generator to its generation account will be aggregated for the purposes of calculating imbalance volumes. Thus, in this example, the contract volume that is compared with its metered volume is 500 MWh. As far as the suppliers are concerned, the first supplier (S1) is short by 5 MWh i.e. its customers consume more than it has contracted for and hence will pay the System Buy Price for this amount. This is the price at which the system has "bought" electricity i.e. the volume-weighted average of the accepted offers. Conversely, the second supplier (S2) is long by 5 MWh i.e. its customers consume less than it has contracted for, and will be paid the System Sell Price for this amount.

Example 3

	Generators		Suppliers	
	G1	G2	S1	S2
Contracted volume (G1-S1)	250		-250	
Contracted volume (G1-S2)	250			-250
Contracted volume (G2-S2)		100		-100
Contracted volume (G2-G1)	-50	50		
Total contracted volume	450	150	-250	-350
Metered volume	451	148	-250	-349
Imbalance volume	1	-2	0	1

This example incorporates two generators contracting with each other. Both generators allocate this contract to their generation accounts. The second generator (G2) produces 2 MWh less electricity than it has contracted to produce i.e. it is short, and hence will have to pay the System Buy Price for that amount. In addition, the first generator (G1) and the second supplier (S2) are long by 1 MWh each.

Example 4

	Generator (G)	Trader (T)	Supplier (S)
Contracted volume (G-T)	250	-250	
Contracted volume (T-S)		250	-250
Total contracted volume	250	0	-250
Metered volume	250	0	-250
Imbalance volume	0	0	0

As well as generators and suppliers, traders may be exposed to cash-out prices. In this example, a trader buys a contract from a generator and then sells on the same amount to a supplier so that its total contracted volume is zero. Since traders will be assigned a zero meter reading, this means that the trader has a balanced position.

Example 5

	Generators		Trader	Suppliers	
	G1	G2	T	S1	S2
Contracted volume (G1-T)	250		-250		
Contracted volume (G2-S1)		250		-250	
Contracted volume (T-G2)		-50	50		
Contracted volume (T-S2)			190		-190
Contracted volume (G1-S2)	250				-250
Accepted BM bid	-2				
Total contracted volume	498	200	-10	-250	-440
Metered volume	498	200	0	-248	-450
Imbalance volume	0	0	10	2	-10

Any accepted Balancing Mechanism offers and bids modify a participant's total contracted volume, as shown in the above example. In this instance, the bid was accepted because the first supplier (S1) consumed less than expected. Note that Balancing Mechanism volumes are adjusted for transmission losses in these calculations (as are metered volumes). This example also illustrates that traders can be exposed to cash-out prices (in this case the System Sell Price) if their trades do not exactly cancel out. In this example, the trader bought 250 MWh but only managed to sell 240 MWh, resulting in a long position of 10 MWh.

7.2 Energy Imbalance Prices

Accepted offers			Accepted bids		
Volume	Price	Cost	Volume	Price	Revenue
40	15	600	30	8	240
90	20	1800	10	-5	-50
30	40	1200			
160		3600	40		190

In the example shown above, the System Buy Price is £22.50 MWh (£3600/160 MWh) and the System Sell Price is £4.75 MWh (£190/40 MWh). Note that in the case of the accepted bids, one participant had to be paid (rather than paying) to reduce its generation (or increase its consumption). This is unlikely to be a frequent occurrence but may occur from time to time.

7.3 Non-Delivery Rule

Example 1

FPN:	100 MWh input
1st accepted BM offer:	50 MWh at £15 MWh
2nd accepted BM offer:	30 MWh at £25 MWh
Expected volume:	180 MWh
Metered volume:	145 MWh
Non-delivered volume	35 MWh
System Sell Price	£10 MWh
System Buy Price:	£18 MWh

Since the non-delivery rule applies to the more expensive offer first (30 MWh at £25 MWh), the participant would be deemed to be shortfalling against both the accepted offers. The participant would be exposed to the normal cash-out price of either the System Buy Price (£18/MWh) or the System Sell Price (£10/MWh) depending on its overall imbalance position at an aggregated level. In addition, the participant would be exposed to paying a non-delivery charge. Since the participant non-delivers against its accepted offers, the System Buy Price is the relevant cash-out price for the non-delivery calculation. The participant is, therefore exposed to a non-delivery charge of £7 MWh (£25 MWh – £18 MWh) for the first 30 MWh of the shortfall. There would be no non-delivery charge for the remaining 5 MWh of the shortfall since the cheaper accepted offer (£15 MWh) was less than the System Buy Price.

Example 2

FPN:	100 MWh input
Accepted BM offer:	80 MWh at £20 MWh
Accepted BM bid:	30 MWh at £8 MWh
Expected volume:	150 MWh
Metered volume:	160 MWh
Non-delivered volume	-10 MWh
System Sell Price	£10 MWh
System Buy price:	£15 MWh

Since the participant delivers more than expected, it would be deemed to be shortfalling against the accepted bid. In addition to any energy imbalance exposure at the aggregate level, the participant will pay a non-delivery charge of £2 MWh (the difference between the bid price and the System Sell Price) for the shortfall of 10 MWh.

Appendix 8 The Existing Legal and Regulatory Framework

8.1 Statutory/Regulatory Background

The Electricity Act 1989 establishes the main regulatory framework within which the electricity industry in England and Wales is to operate. The Act assigns certain functions, powers and duties to the Secretary of State for Trade and Industry (the 'Secretary of State') and the Director General of Electricity Supply (the 'Director General') for regulation of the industry. The functions of the Secretary of State and the Director General respectively are to be exercised in the manner which they consider is best calculated to achieve certain defined objectives, including the promotion of competition in the generation and supply of electricity.

The Government has announced that it intends to replace these primary objectives (or duties) with a new single primary duty to exercise functions in the manner the Director General (or Secretary of State, as the case may be) considers is best calculated to protect the interests of consumers wherever possible and appropriate, through promoting effective competition. It is proposed that the interests of consumers should be interpreted to include prices and conditions of supply, continuity and availability of supply, quality of supply, and where relevant, the range of services offered. In defining the interests of consumers, due weight should be given to their longer and medium-term interests as well as to their immediate or short-term interests. The duty should also make explicit the need to ensure that the regulated companies are able to finance the carrying out of their functions.[35]

In addition to sector-specific legislation (notably the Electricity Act and secondary legislation made under that Act), the industry is subject to general competition law, although there are a number of exceptions and special rules relating to the electricity sector which need to be borne in mind. As regards matters which may affect trade between Member States, the law is principally found in Articles 81 and 82 (formerly 85 and 86) of the EC Treaty. Article 81 prohibits agreements, decisions and practices which have as their object or effect the prevention, restriction or distortion of competition (and are not exempted). Article 82 prohibits

[35] DTI White Paper: 'A fair deal for consumers: modernising the framework for utility regulation. The response to consultation', July 1998.

conduct that amounts to an abuse of a dominant position. These provisions are directly effective in each Member State.

Within the UK, the key requirements are found in the existing scale and complex monopoly provisions of the Fair Trading Act 1973 and in the so-called Chapter I and Chapter II Prohibitions of the new Competition Act 1998.

The 1998 Act is due to come into force on 1 March 2000. It creates two new prohibitions in respect of matters that may affect trade within the UK. The first is against agreements, decisions or concerted practices that have as their object or effect the prevention, restriction or distortion of competition within the UK (the 'Chapter I Prohibition'). The second is against conduct that amounts to an abuse of a dominant position in a market (the 'Chapter II Prohibition'). These prohibitions are modelled on Articles 81 and 82 of the EC Treaty and must be interpreted in such a way as to avoid inconsistency with decisions under those Articles.

The Director General has concurrent jurisdiction with the Director General of Fair Trading ('DGFT') in exercising the functions and powers of the DGFT under the new Competition Act in relation to commercial activities connected with the generation, transmission and supply of electricity. The Director General's Electricity Act duties do not apply to his exercise of concurrent functions under the Competition Act.

8.2 Licences

The Electricity Act 1989 creates three statutory offences, corresponding (broadly) to the generation, transmission and supply of electricity without a licence or exemption. Supply licences fall into two categories: those granted to the fourteen public electricity suppliers (PES) in Great Britain (twelve in England and Wales) in respect of their 'authorised areas' and those granted to all other suppliers, known as second tier suppliers. The activity of electricity distribution is currently regulated via supply licences (notably the PES licences). However, the Government has announced[36] that it proposes to create a separate, additional statutory offence of distributing electricity without a licence or exemption, and distributing electricity will therefore become a separate authorised activity.

[36] DTI White Paper: 'A fair deal for consumers: modernising the framework for utility regulation. The response to consultation', July 1998.

Under the present regime, licences are issued by the Secretary of State, or by the Director General in accordance with a general authority given to him by the Secretary of State. The general authority requires the Director General to include certain conditions in the licences. In addition, the Secretary of State has power to grant exemptions to certain persons or classes of persons. The Government has consulted on possible changes to these arrangements in order to align the regimes for gas and electricity regulation.[37]

For the purposes of wholesale electricity trading in England and Wales, the key licence requirements are currently as follows:

- NGC (as the Transmission Company in England and Wales) is required to schedule and despatch centrally despatched available generation in accordance with a merit order system;
- NGC is required to undertake operational planning for the matching of generation output (including a reserve to provide a security margin) with forecast demand;
- NGC is required to implement, maintain and operate a settlement system in respect of sales and purchases of electricity under the Pooling and Settlement Agreement ('PSA') and to be a party to the PSA;
- NGC is required to maintain certain records relating to, among other things, transactions under the PSA and the use of ancillary services;
- Licensed generators and suppliers are obliged to become Pool Members under, and comply with, the PSA;
- Licensed generators are required to submit to central despatch by NGC all available generation sets forming part of generating stations capable of providing 100MW or more to the total system; and
- Licensed suppliers are required to make arrangements sufficient to meet the 'generation security standard' (being a standard in relation to the maintenance of electricity supply to qualifying customers).

[37] DTI White Paper: 'A fair deal for consumers: modernising the framework for utility regulation. Public consultation paper on the future of gas and electricity regulation', October 1998.

Other relevant statutory or licence duties include:

- NGC is under a statutory duty to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in the supply and generation of electricity;
- NGC is required by licence to have in force, implement and comply with a Grid Code covering all material technical aspects relating to connection to and operation and use of its transmission system; and
- Generators and suppliers are required by licence to comply with the Grid Code.

8.3 Industry Documents

The main industry documents, which constitute the existing legal framework, are the Pooling and Settlement Agreement(PSA), the Grid Code, the Master Connection and Use of System Agreement ('MCUSA') and its Supplemental Agreements, and the Master Registration Agreement ('MRA'). Each of these is briefly described below.

PSA

The PSA is the document that establishes the existing wholesale trading arrangements (the Pool). The parties to the PSA include:

- generators and suppliers as Pool Members;
- NGC as Grid Operator and Ancillary Services Provider;
- the Settlement System Administrator and Pool Funds Administrator;
- External Pool Members (parties who trade in the Pool across interconnectors);
- Externally Interconnected Parties (parties who operate systems connected to NGC's transmission system by interconnectors); and
- Meter Operator Parties.

Chapter 3 describes various key features of the existing trading arrangements in more detail and analyses how those features have operated in practice since the PSA's inception.

Associated with the PSA are a number of agreements, including a Funds Transfer Agreement and contracts appointing various Pool agents and contractors (such as the Profile Administrator, Initial Settlement and Reconciliation Agent and Pool Auditor).

Grid Code

The Grid Code is a code established by NGC under condition 8 of its transmission licence (see above). NGC and licensed generators and suppliers are obliged by conditions in their licences to comply with the Grid Code. In addition, the Grid Code is made contractually binding by the MCUSA (see below).

The Grid Code contains technical rules relating to the transmission system, to be complied with by NGC and users of its system:

- The planning code sets out criteria and procedures applied by NGC in planning and developing the transmission system, and information requirements for users;
- The connection conditions are minimum technical, design and operating criteria for NGC and users connected to (or seeking connection to) the transmission system (as well as certain embedded generation);
- The operating codes contain a range of operational rules covering operation of the transmission system, and plant and systems connected to it, to protect security and quality of supply and safe operation of the transmission system. The operating codes include OC1 (demand forecasting), OC4 (operating margin), OC5 (testing and monitoring) and OC6 (demand control); and
- The scheduling and despatch codes govern the scheduling and despatch of generation on a merit order basis, and the basis on which NGC directs frequency control.

NGC's transmission licence requires it to review the Grid Code (in consultation with licensed and exempt generators and suppliers) periodically or on request by the Director General, report to the Director General on each review, and if directed by DGES to revise the Grid Code. The Grid Code may not be revised without the Director General's approval.

MCUSA

The Master Connection and Use of System Agreement (MCUSA) is a multilateral agreement dealing with the contractual basis for connection to and use of the transmission system. The parties to MCUSA are NGC and users (i.e. persons having connections to or use of the transmission system). Users include generators (including certain embedded generators), public electricity suppliers (both as distribution system operators and as suppliers), second tier suppliers and consumers directly connected to the transmission system.

The MCUSA contains general contractual obligations for NGC and users, including the obligation to comply with the Grid Code, and provides the framework within which separate bilateral supplemental agreements are signed. These supplemental agreements contain site-specific and/or user-specific details and obligations, including the obligation for users to pay connection and use of system charges. Charging rules in the supplemental agreement set out rules for payment of charges, reconciliation in payments (where relevant data is changed) and security for payment. The actual charges payable are determined from a charging statement issued by NGC each year pursuant to condition 10 of its transmission licence.

Amendments are made to the MCUSA and Supplemental Agreements as required by: changes in the transmission licence, an order or direction under the Act or any licence (under the Act) or as a result of the Director General settling the terms of an agreement for connection or use of system (under condition 10C of the transmission licence).

MRA

The Master Registration Agreement (MRA) is a multilateral agreement between Host PESs (including those in Scotland) and suppliers, established pursuant to a condition in PES licences. All suppliers are required by licence condition to be party to and comply with the MRA. Other parties to the MRA include the MRA Service Company Ltd, a Pool Agent (representing interests of Pool Members) and Scottish Electricity Settlements Limited (SESL). The latter two are parties because of the interdependence of settlement arrangements with the MRA.

The MRA contains the rules under which particular suppliers are registered as responsible for particular meters (at consumer premises) for settlement purposes. The MRA includes provisions relating to:

- the provision by PESs of meter point administration services, as required by their public electricity supply licences;
- procedures for meter point transfers (enabling consumers to change supplier);
- a Data Transfer Catalogue (definitions, flows and forms of data transfers needed under the MRA); and
- arrangements for governance of the MRA.

Associated with the MRA is the Data Transfer Services Agreement under which data transfer services are provided (by a company formed by the PESs and known as Electralink) to facilitate electronic data transfers for a variety of purposes including the provision of settlement data.

The MRA provides for the establishment of the MRA executive committee (MEC), whose members are representatives of different classes of party to MRA. Decisions made by the MEC require unanimous consent. The MEC's decisions may be appealed (on various grounds) to the 'MRA Forum' (a forum of representatives of all MRA parties). Decisions of the MRA Forum (including on appeals from the MEC) can be appealed on similar grounds to the Director General.

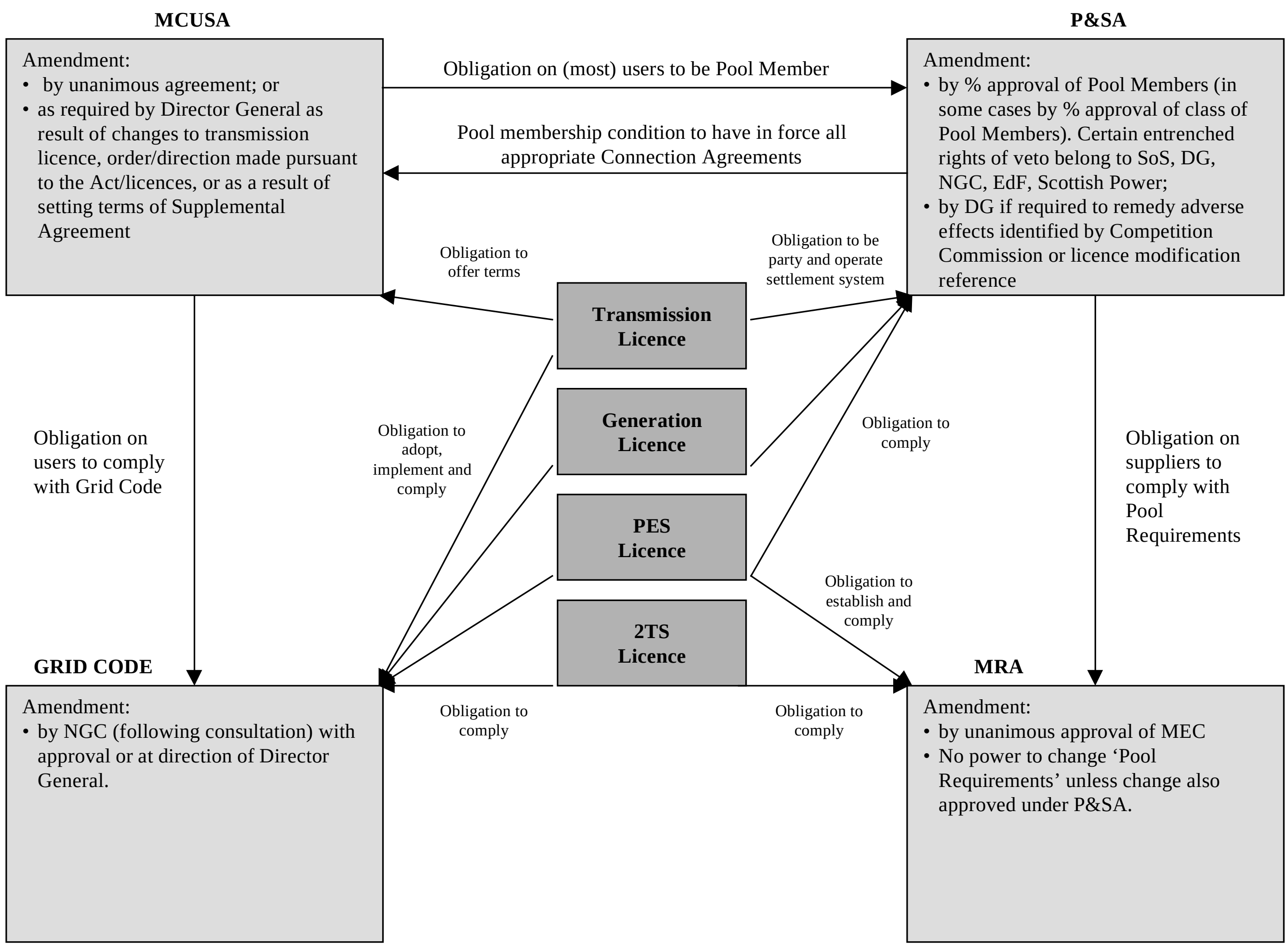
Any party to the MRA may propose a change to it. Change proposals are considered and decided by MEC after consulting with MRA parties. The MEC's decisions on change proposals are subject to appeal as above. Special arrangements apply to change proposals that affect 'priority provisions' of the MRA – provisions that have particular interdependencies with settlement arrangements under the PSA or in Scotland. In essence, such changes cannot be made without the approval of the Pool Agent (or SESL).

8.4 Other Industry Documents

In addition to the above documents there are a number of other industry documents including:

- Distribution codes: each PES has a distribution code which sets out technical rules (analogous to the Grid Code) for connection to and use of its distribution system;
- Distribution connection and use of system agreements, between PESs and parties using or connected to their systems;
- The Fuel Security Code, which provides for modification of trading arrangements within the Pool in cases where the Secretary of State exercises his powers under the Electricity Act to direct the operators of power stations to stock and to use particular fuels, or the transmission system operator to operate its system in a particular manner;
- Documents relating to the use and operation of the interconnectors with France and Scotland and the Isle of Man;
- Documents relating to the procurement and use of Ancillary Services; and
- Documents entered into in connection with the Electricity (Non-Fossil Fuel Sources) (England and Wales) Orders.

Figure 8.1 - An Overview of the Regulatory and Contractual Links in the Current Trading Arrangements



Appendix 9 Governance

Chapter 10 provided an outline description of the arrangements for the governance of the Balancing and Settlement Code (BSC) – the new industry document that will underpin the reformed trading arrangements. This Appendix expands on a number of elements of those arrangements, including the following:

- the functions of the BSC Panel and BSCCo;
- the BSC modification process;
- the ‘Disputes Panel’;
- appeal of decisions under the BSC; and
- financial control of BSC activities;

9.1 Overview

As described in Chapter 10, the arrangements for the governance of the new balancing and settlement arrangements will be 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;
- all proposed modifications to the BSC will be subject to the approval/direction of the Director General.

9.2 Functions of the BSC Panel and BSCCo

The BSC Panel will be the central body charged with ensuring the effective implementation of the rules contained within the BSC. The options for the composition and appointment of the Panel are outlined in Chapter 10. It will perform a number of functions directly, although the day to day management of BSC business will often be exercised through the BSCCo and sub-committees of the Panel. The main functions to be delivered by the Panel (either directly or indirectly via the BSCCo and sub-committees) will be as follows:

- to establish, supervise and administer operation of Balancing and Settlement Code functions and processes (including those let by BSCCo), including:
  - ⇒ managing disputes, for instance by establishing a disputes panel;
  - ⇒ 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 administration of contracts with service providers, and where appropriate letting such contracts;
  - ⇒ 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.

- To supervise the development of the BSC, including the modification process, and to submit recommendations to the Director General for approval or direction, including:
  - ⇒ receiving and circulating modification proposals and stakeholder representations on them;
  - ⇒ establishing working groups to review and develop proposals;
  - ⇒ commissioning any advisory work;
  - ⇒ commissioning and reviewing legal drafting; and
  - ⇒ preparing a modification report to the Director General.

- To ensure compliance of participants with the provisions of the BSC, including some level of monitoring, policing, technical audit, performance assurance and enforcement of the BSC rules.

- To perform any other functions conferred on it from time to time by the Code.

9.3 The BSC Modification Process

This section of the report details the procedures for modification of the BSC.

Overview

NGC will be the 'custodian' of the BSC under a new condition in the transmission licence. All proposed modifications of the BSC will be submitted to the Director General for approval or direction. The condition will specify certain objectives which will be the criteria by which the Director General approves (or directs) or disapproves proposed modifications.

The governance proposals envisage procedures enabling modifications to be proposed, evaluated, consulted on and developed, and then submitted to the Director General for approval. These modification procedures would ordinarily be managed by the BSC Panel. However, if the Panel failed to progress a modification proposal in accordance with the procedures, the Director General would have power to direct NGC (as SO) to take over the procedure for that proposal. This would certainly be the case under Panel *Option 1* described in Chapter 10. Under Panel *Option 2*, the Panel would be accountable to the Director General who would therefore have more direct locus to ensure that the Panel was executing its duties properly.

The NGC licence condition will specify the basic requirements for the modification procedures. In particular, proposed modifications should be submitted to the Director General as soon after receipt as is consistent with adequate consultation, evaluation and development of the proposal. The modification procedures will themselves be contained in the BSC (and will therefore also be eligible for modification, subject to the requirements in the licence).

The modification procedures will specify required time periods for most steps. These must achieve a balance between ensuring the rapid progress of a modification proposal through the procedures and allowing the Panel adequate oversight of the proposal's progress. Timing is discussed further below.

For convenience, certain defined terms are used in this section. A Panel Member is a member of the BSC Panel.

The Secretary is the secretary to the BSC Panel. Customer Bodies are the customer representative bodies able to propose modifications (see below). A Participant is any person who is party to the BSC (i.e. has signed the BSC framework agreement) as buyer or seller; this includes non-physical participants. A Modification Consultee is a party or organisation entitled to be sent copies of and make representations on a modification proposal (see below). The relevant objectives are the objectives that act as the criteria for the Director General's approval of proposed modifications. A modification report is the report given to the Director General at the end of the modification procedures, by which a proposed modification is submitted for the Director General's approval or disapproval.

The Role of BSCCo

The Panel will be supported by employees of the BSCCo. The staff of the BSCCo will be responsible for the administration of the modification process, and for arranging technical support to the process. The Panel will access the BSCCo secretariat and resources via the senior management of the BSCCo and the Panel secretary, who will attend Panel meetings. The day to day involvement of the BSCCo staff will ensure that the modification process is continual and expedient and not constrained by how often the Panel meets.

Aside from pure administration, BSCCo staff will provide substantial support to the Panel (and work groups - see below), such as preparing draft papers and reports. Any external advice or consultancy would be obtained by BSCCo acting at the Panel's direction. BSCCo will also manage the interface with BSC contractors/service providers (such as a settlement system operator) in the modification process.

Making Modification Proposals

Modification proposals may be made by:

- any BSC Participant;
- NGC (as System Operator); and
- certain customer and other (e.g. exempt generator) representative bodies. These might be designated by the Director General or, in the case of customer bodies, by the National Electricity Consumer Council (NECC – the statutory consumer body).

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) could seek to channel any proposal through one of the designated representative bodies (which might include, for example, AEP, CHPA).

Various alternatives have been considered. One is that anyone could propose a modification. This would risk an excessive number of vexatious or frivolous proposals which would be time-consuming and costly to process. Another is that only Panel Members could propose modifications; anyone wishing to propose a modification would need to find a Panel Member willing to sponsor the proposal. However, this would create confusion and possible conflict as to the role of Panel Members, who should not be seen as promoters of particular proposals.

A modification proposal would be made in a prescribed format, specifying the proposal in reasonable but not excessive detail; the parts of the BSC affected; and the purpose of the proposal and the proposer's opinion as to why it meets the relevant objectives. It would not contain legal drafting for the modification. The modification proposal would be addressed to the Secretary.

The proposal would nominate an individual (on behalf of the proposing organisation) to present the proposed modification to the Panel, and possibly represent the proposer during development if requested by the work group.

Promptly, on receipt of every modification proposal the Secretary will copy it to each Participant, each Consumer Body, and to other parties identified as having a proximate interest in the outcome. Examples might include externally interconnected parties, distribution licensees, and organisations representative of exempt parties. These Modification Consultees will be invited to submit written representations on the proposal. This is the first of two opportunities to comment on modification proposals - the second being on the draft modification report (discussed later).

The modification proposal will also be copied to Panel Members and the Director General. It will also be posted on a website. Possibly, all documentation provided to Modification Consultees could be posted on the website.

It would cause confusion to have a modification proposal made while the modification procedures are under way in relation to an earlier proposal on the same subject. (The Panel could decide whether two modification proposals are on the same subject, perhaps by applying the test whether, if both were made, they would be inconsistent with each other). Further modification proposals on the same subject would not be permitted until the modification process for the first was completed - i.e. until the Director General's decision is given on a final report. However the would-be proposer can express their views by making representations (see below). An alternative modification on the same subject may, therefore, be considered by the work group considering the issue, as one of a range of options.

Initial Procedures

Upon receipt of a modification proposal, there will be initial procedures whereby the Panel will decide the BSC process by which it should be progressed. Options will include undertaking a development process involving a work group, proceeding directly to a modification report, or submitting a proposal to further review.

It is not intended that there should be explicit separate provision for making urgent modifications. Instead, all modification proposals should be progressed as expediently as possible. The default timescales that will be prescribed will provide for a relatively swift process. Where a longer period is required to give full consideration to a particularly complex issue, it will be for the Panel to make the case to the Director General that the process should deviate from the normal timetable.

The Panel will consider the modification proposal at its next regular meeting. The proposer's nominated representative will be required to present the proposal.

Ordinarily the modification proposal would be referred to an ad-hoc or possibly a standing work group (see below). The Panel would establish the composition of the (ad-hoc) work group; and would agree and instruct the Secretary to prepare terms of reference for the work group. (The Secretary would probably have prepared draft terms of reference to go with the modification proposal to the initial Panel meeting). The terms of reference would include a timetable.

By exception (and perhaps by increased majority) the Panel could instead decide that the proposal should skip the development phase, and go direct to a modification report. This could be on the grounds either that the proposal does not merit further consideration, or that the proposed modification self-evidently should be made and does not require further evaluation or development.

In the GB gas industry, proposed modification to the Network Code can also be submitted to review. The review process is intended to deal with the case where a broader assessment is required (for example, as to whether a problem exists) before it can be decided whether any modification proposal would be necessary or appropriate.   The review process is otherwise similar to the development process - a work group under Panel terms of reference carries out the review and reports to the Panel.   The review report recommends whether any modification is appropriate. A similar process is proposed here. It will be necessary to develop safeguards against abuse of this process (i.e. any attempts to cause undue delay to the progress of a modification).

Development Process

There will be guidelines as to the size and composition of ad-hoc work groups. Participants might nominate experts in various fields to standing lists maintained by the Secretary.   Work group members would be drawn from these lists.   The Panel would appoint the work group chairman.

It is preferable for work groups to be non-voting. In the absence of consensus on any issue the chairman would decide how the group would report, with dissentient views being fully reflected.

The task of work groups is to evaluate and develop proposals (considering the representations made by Modification Consultees) to the point where they can be reported to Director General for approval. Work groups will submit regular progress reports to the Panel and may seek guidance from the Panel on any issue. The Panel can intervene to redirect the work of a work group or to require it to follow particular procedures, and can consent to a variation of a work group's timetable.

BSCCo staff will provide administrative and technical support to the work groups, preparing working papers and draft reports. With the Panel's approval (or possibly within a budget set in the work group's terms of reference) the work groups may require the BSCCo to procure external technical advice.

Work groups (through the BSCCo) will be able to require the participation of contractors (such as settlement system operators) in the development work, and will obtain time and cost estimates from contractors for systems and process changes necessary to implement the proposed modification.

In many cases it will be necessary to co-ordinate with change processes for other documents. For example, changes to the BSC may impact on the terms of the MRA, MCUSA or Grid Code. A work group’s terms of reference might include guidance from the Panel on the procedures to be adopted, or possibly an early task of the work group would be to report to the Panel on the interaction with other documents. Work groups may need joint sessions with equivalent groups under the governance arrangements for the other documents. Another possibility would be for the Panel to establish standing liaison groups with representatives from those other governance arrangements. Issues requiring change co-ordination would then be dealt with through those liaison groups.

Work groups may, with the Panel's approval, develop variations of the proposed modifications if in their view this would better meet the relevant objectives. Their reports would then cover both the original proposal and the suggested variation.

Work groups will submit reports to the Panel, covering broadly the same matters as are contained in modification reports. They will include the work group's view on whether the relevant objectives would be met by the modification. The report of a work group will, in effect, serve as the basis for the modification report.

The Modification Report

The Panel will consider a work group’s report at the next meeting after the report is received. The Panel may remit the report back to the work group if it is unclear, incomplete or the proposed modification has not been sufficiently developed to enable the modification report to be prepared.

Otherwise, the Panel will vote on whether or not it recommends to Director General that the modification should be made (the 'preliminary recommendation'). Where a variation has been developed by the work group, the Panel will vote on both the original and the variation (and the modification report will cover both).

The Panel will instruct the Secretary to prepare a draft final report (based on the work group report and reflecting the Panel's recommendation) which will then be circulated to all Modification Consultees, who may submit preliminary representations. Consideration needs to be given to ways in which parties can be encouraged to make representations at the earliest opportunity, rather than delaying until the final report stage, in order to make the process more efficient.

The modification report will be required to include certain prescribed elements such as:

- A full description of the proposed modification and any variation developed by the work group;
- The recommendation of the Panel (if the agreed process requires a recommendation), and any dissentient view of Panel Members (including details of who voted for and who voted against the proposal);
- An explanation of why the modification does or does not (according to whether or not it is recommended) better facilitate the relevant objectives, and any dissentient view of Panel Members;
- A summary of all representations made by Modification Consultees during the course of the modification process;
- An analysis of the systems and process changes required (to BSC systems) to implement the modification, the estimated costs to BSCCo (based on contractor quotes) and an outline implementation programme and proposed effective date;
- An assessment of the implications (systems development, cost, processes, timetable) for NGC as SO (and possibly as Ancillary Services provider);
- An assessment of the implications (systems development, cost, processes, timetable) for BSC Participants and other interested parties such as exempt parties;
- An analysis of the interaction with other industry documents: related changes, timing, co-ordination, etc.

At a further meeting, the Panel will consider the representations made and will vote to confirm or reverse its preliminary recommendation in the light of the representations received. The Panel will then instruct the Secretary to finalise the modification report, to reflect the representations and any further views the Panel may have on these, and to reflect the final recommendation of the Panel.

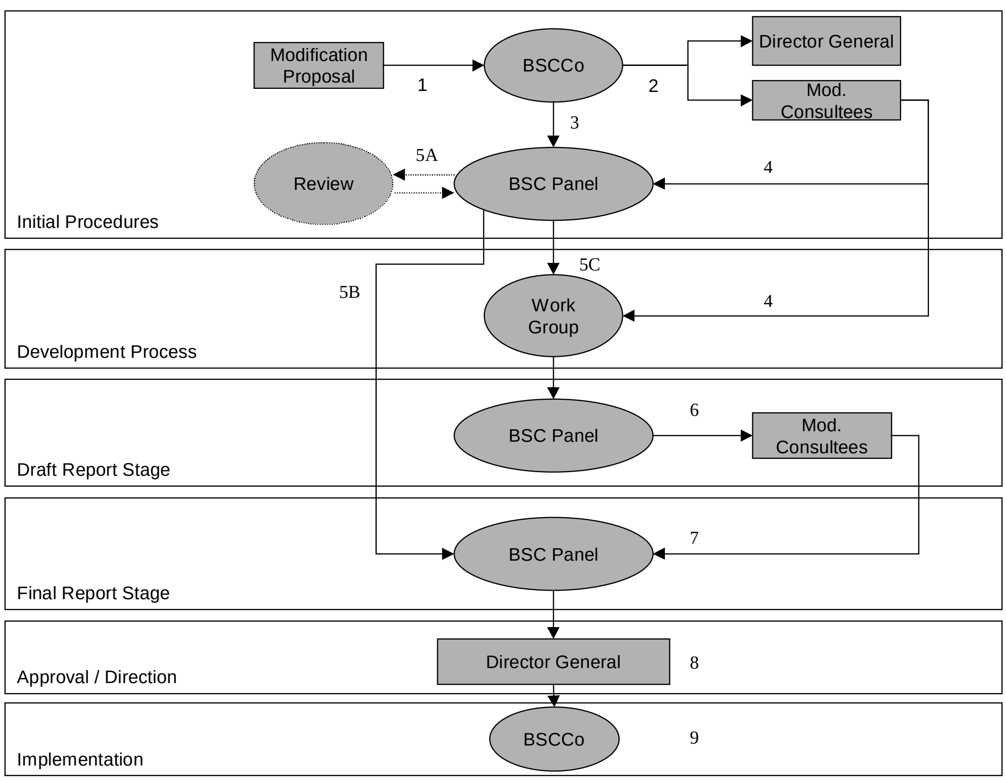
The final modification report, with copies of all representations received on the report, is then sent to the Director General. Copies should be made available to all Modification Consultees (and will probably be posted on a website).

The BSC will then be modified in accordance with the Director General's decision.

Summary of Process

A summary of the modification process described above is provided by the following diagram and accompanying key:

Figure 9.1



Key:

1. Modification proposal submitted to BSCCo secretariat.
2. Proposal circulated to all Modification Consultees and Director General.
3. Modification proposal submitted to next BSC Panel meeting. Panel consider process by which modification is to be progressed (see 5A, B and C below).
4. All written submissions forwarded to BSC Panel and (once established) the relevant Work Group.

5A. Where the proposed modification requires broader assessment prior to development, it can be submitted to review.

5B. Where the proposal does not require further consideration, or the proposed modification self-evidently should be made and does not require further evaluation or development, the Panel may decide to skip the development phase and proceed directly to the Final Report Stage.

5C. The proposed modification will be referred to a standing or ad-hoc Work Group for development.

6. The Work Group submits a draft Modification Report to the BSC Panel. If the agreed process requires a recommendation, the Panel will vote on whether or not to recommend to the Director General that the modification should be made.
7. The draft Final Report will be circulated to all Modification Consultees and representations will be invited. At a further meeting, the Panel will confirm or reverse its recommendation and instruct the secretariat to finalise the report.
8. The final Modification Report, together with a copy of all representations received is sent to the Director General for approval or direction of the proposed modification.
9. The approved or directed modification is implemented.

9.4 Settlement Disputes

This section considers the arrangements for handling settlement disputes that might arise under the terms of the Balancing & Settlement Code (BSC). As a principle, it is envisaged that the disputes arrangements under the BSC will replicate as far as possible those that currently exist under the PSA, which are perceived to have worked well.

What is a Settlement Dispute?

A settlement dispute is an objection to the results of settlement raised by a Party, who believes that the settlement calculation has been undertaken using the wrong data or that the calculation itself has not been undertaken in accordance with the rules.

Who Can Initiate Disputes?

Any signatory to the BSC who has a financial interest in the resolution of an error (i.e. the disadvantaged party) will be entitled to initiate a dispute in respect of that error.

Errors giving rise to disputes will, in most instances, be discoverable through the reports that will be produced by the settlement system and circulated to BSC participants. In addition, the Settlement Administration Agent may be obliged to raise a dispute on behalf of participants if errors in calculations or data are detected or suspected.

The Disputes Panel

The BSC Panel will establish a standing sub-committee - the ‘Disputes Panel’ - to play a key role in the resolution of settlement disputes.

Role and Nature

The main role of the Disputes Panel will be to form a judgement on the validity of each referred dispute (disputes which have not been resolved by agreement among the affected parties), on the basis of all available evidence and with strict reference to the terms of the BSC.

Due to the commercial nature of disputes, it will be important to ensure that the Disputes Panel performs its duties in as objective and impartial a manner as achievable. The members of the Disputes Panel should not be permitted to represent the interests of their own companies at its meetings and will be obliged to act in a completely independent fashion.

Composition

It is proposed that the Disputes Panel should comprise a pool of 8 expert members, from whom an appointed Disputes Panel Chairman will select 5 to make up the panel for a particular hearing. Any members with a potential conflict of interest in relation to the outcome of a dispute would not be eligible for selection for the relevant hearing.

Decision Making

All decisions of the Disputes Panel will need to be made strictly in accordance with the rules of the BSC. In most circumstances the decision of the Panel should be restricted to determining whether or not the BSC trading rules have been followed, without any subjective interpretation (e.g. of the intention) of those rules being required. Where some level of interpretation is required, precedents could be recorded to ensure that subsequent disputes are resolved in a consistent fashion. As an additional safeguard, the Disputes Panel could issue an interpretative guideline in each such case, which might require endorsement by the Director General before becoming applicable. Where redrafting of a BSC provision would remove any ambiguity, this may be achieved through the normal BSC modification process, instigated in this instance by a recommendation of the Disputes Panel to the BSC Panel.

On the basis of the evidence presented, the Disputes Panel will be required to make one of the following types of ruling:

1) Uphold the dispute on behalf of the disputing party (and authorise the appropriate funds transfer);

2) Reject the dispute – e.g. on the grounds that the BSC rules have not been breached; or

3) Defer the dispute – to enable additional evidence or information to be provided. Where there continues to be insufficient evidence to point one way or the other, the Disputes Panel will be entitled to dismiss the matter.

Appeal of Disputes Panel Decisions

It is proposed that any party to a dispute who disagrees with the judgement of the Disputes Panel should be entitled to refer that decision to an external process for resolution by expert determination or arbitration. It is for further consideration on what grounds, and to what person/body the decision of the Disputes Panel may subsequently be appealed (the current PSA disputes process provides for escalation of a dispute to the Electricity Arbitration Association). It is likely that the costs of any such action would fall upon the parties involved, rather than being treated as central BSC costs.

9.5 Appeals

It may be appropriate to provide the opportunity for participants to appeal decisions made under the terms of the BSC under certain circumstances. However, it is not possible to draw any firm conclusions at this stage without a more detailed knowledge of the type and nature of decisions which the BSC Panel and BSCCo Board will be taking and the level of discretion that these bodies will have in carrying out their functions. This will become clearer as the detailed business rules of the BSC are developed. In addition, appeal mechanisms may be more or less appropriate depending on the chosen composition, appointment and accountability of the Panel (see discussion of options in Chapter 10).

In principle, it is proposed that certain types or categories of decisions should be amenable to appeal. These are likely to be decisions of some consequence. Day-to-day administrative or operational decisions should not be capable of being impugned as a rule.

Grounds of Appeal

It will be necessary to define grounds of appeal. Broadly speaking, these fall into two categories:

- jurisdiction; and
- substance.

Appeal may be allowed on one or other, or both, grounds.

An appeal on jurisdiction grounds would challenge whether the Panel/Board had power to take the decision (i.e. did the decision fall within its prescribed functions) or whether the decision was inconsistent with the BSC rules.

If appeal is to be possible on the substance of decisions, it will be necessary to stipulate the basis for such an appeal. There are a number of possible scenarios, some wider and some narrower, under which appeal may be permitted:

- a person does not like, or disagrees with, the decision;
- the decision is inconsistent with the objects of the BSC;
- the decision unfairly prejudices an individual or class of individuals;
- the decision would cause an individual or class of individuals to be in breach of the BSC, its licence or statutory duties;
- the decision is irrational or manifestly absurd or, simply, unreasonable.

If it is concluded that some or all decisions may be challenged on this basis, consideration should be given to the limitations that might be appropriate to avoid trivial and costly appeals (e.g. materiality or other thresholds).

There may be an argument that it is not appropriate to allow appeal of all Panel/Board decisions on any or all of the above grounds. For instance, it is perhaps not desirable to allow appeal of every management decision on the basis that it is inconsistent with high-level objectives (which, by definition, require the Panel to balance potentially conflicting interests).

It will be necessary to analyse each class of decision, once they have been identified, to test whether the general preferred approach on appeals 'fits' the type of decision in question.

Identity of Appeal Body

If appeals are to be allowed, it will be necessary to identify a suitable appeal body, which need not be the same for every type of appeal. The options include:

- the Director General;
- a specially constituted appeals tribunal established under the BSC;
- an independent expert appointed on an ad hoc basis;
- the courts (indirectly via signatory disputes).

It may be appropriate to refer questions about consistency with BSC objects to the Director General. The need for a speedy and credible determination will be key factors in deciding who is best placed to determine the matter.

If, on the other hand, appeal is permitted simply on the basis that a party does not like the decision, it may be undesirable for the regulator to intervene (particularly if an unpopular decision leads to a modification proposal, on which the regulator would then have to adjudicate).

Another option might be to establish an appeals tribunal under the BSC. This might consist of, say, three independent experts, appointed in advance for a fixed term. Provided certain pre-requisites were met (defining the competence of the tribunal), the tribunal could be empowered to substitute its decision for the decision of the Panel/Board (BSCCo) in certain circumstances.

An alternative would be to provide for the appointment of an independent expert on an ad hoc basis, as and when disputes arise. This may be less attractive as it would not allow a level of knowledge and expertise to be built up, with the inevitable result that determinations would be slower, more costly and less consistent.

9.6 Financial Control

The costs to which BSC participants will be exposed by virtue of being signatories to the Code will fall largely into two categories:

- *Management costs* – central administrative costs of implementing/managing the BSC (this will include costs associated with carrying out all the functions of the Panel and BSCCo – the modification, operations and compliance functions) e.g. Secretariat staff, Panel/Board expenses, office/office equipment, IT, external support (legal, finance etc.); and
- *Operation costs* – third party service provider costs (this will include the fees and charges payable to third parties for services procured by BSCCo in relation to the balancing mechanism/imbalance settlement) e.g. systems, auditors, accreditation services.

Efficiency Drivers

The BSC will contain rules, objectives and efficiency drivers aimed at ensuring that management costs are kept to a minimum, consistent with the proper performance of Panel/BSCCo functions.

The BSC may include, for example, requirements for some or all of the following:

- Panel and BSCCo to carry out their functions subject to a general efficiency objective (i.e. costs to be kept to a minimum consistent with proper implementation of the BSC rules);
- BSC rules and objectives to ensure decisions are taken and implemented as promptly as reasonably possible, taking account of all relevant circumstances;
- all key posts in the Secretariat to be advertised;
- employment contracts of senior BSCCo staff to contain performance measures linked to efficiency targets (with appropriate bonuses/penalties tied to those measures);
- the detailed annual budget to be approved by the Panel/ BSCCo Board;
- production and publication of a business plan on an annual basis detailing likely expenditure over the next three years;
- annual report on income/expenditure to be published within [3] months of the end of each year - this would contain a description of actual performance measured against monthly output targets;
- an external ‘efficiency’ audit to be carried out every [2] years, the results of which would be made public;

- relevant objectives against which BSC modification proposals are to be tested to include an objective linked to cost-efficiency.

Appendix 10 Working with the New Arrangements

10.1 Introduction

This Appendix assesses what the new trading arrangements might mean for the System Operator and various categories of market participants, in terms of their obligations and opportunities.

On the demand-side, the Appendix considers the activities that might be undertaken by:

- a PES;
- a second tier supplier;
- a large customer;
- a medium-sized customer; and
- a domestic customer.

On the generation side, it considers the activities that might be undertaken by:

- a portfolio generator;
- a fully contracted independent power producer;
- a merchant plant;
- a highly flexible plant;
- a nuclear generator;
- an external generator trading through an interconnector;
- an exempt generator;
- a Combined Heat and Power plant;
- a renewables scheme; and
- a trading site.

Finally, two other types of participants are considered; traders and aggregators.

In many respects market participants will be able to continue trading as at present. Most players already participate in contracts markets, albeit for financial rather than physical trades. Under the new arrangements, they will be exposed to imbalance prices rather than Pool prices for differences between their contracted and metered volumes. This should encourage suppliers to manage their demand more actively.

10.2 Using the New Trading Arrangements

For any half hour trading period, it is assumed that a variety of forward and futures markets (trading bilaterally negotiated customised contracts, standardised OTC products and standardised screen-based products) will develop in which most participants will buy or sell to meet the bulk of their requirements. It appears likely that close to real-time, a short-term market, probably a formalised power exchange, will open to allow fine-tuning of positions. Generation and demand sites that can adjust their physical positions within relatively short timescales will be able to submit offers and bids to the Balancing Mechanism. After the trading period has closed, any uncontracted output or take will be settled at the appropriate energy imbalance price.

These arrangements pose different risks and opportunities in different timescales. Given the risks inherent in short-term trading and the balancing and imbalance settlement arrangements, it appears likely that many participants will use the long- and medium-term markets to seek to cover most of their anticipated requirements. In doing so, participants will seek to balance the risks of contracting a long time in advance against those of contracting closer to real time. There are several different trade-offs to be made, including:

- the risk that prices may change as real time gets closer;
- greater knowledge of both system events, and the vagaries of the participant's own position, closer to real-time; and
- the ability to change longer-term positions, by trading again, by taking action such as entering into new and/or different customer contracts back to back against the longer-term position, and by purchasing financial instruments to hedge the longer-term risk.

Different participants will take different attitudes to such risks and opportunities. These will depend in large part on their ability to hedge the risk, through devices such as financial instruments, contracting strategies and access to physical plant or customers. Furthermore, 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 itself in a situation of having bought too much energy will try to sell the excess on a short-term basis. A generator who is normally a seller in the long and medium term markets may need to buy in the short-term markets if it needs to cover technical shortfalls on its plant, or if short-term prices fall below the variable costs of its marginal unit.

Not all contracts will necessarily go to physical delivery since some contracts may be sold on to other market participants. Others, such as financial instruments, will 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). The volume of activity, and how much is related to physical delivery, will depend upon a number of factors such as attitudes to risk, the products offered by traders and the volatility of prices.

10.3 The System Operator

The SO has a statutory obligation to develop and maintain an efficient, co-ordinated and economical transmission system. At the year-ahead stage, the activities of the SO could be little changed from under the present arrangements as there will still be a need to plan the maintenance of the transmission system and to procure balancing services. Over these longer timescales, the SO's plans will take account of the information it receives from the major generators regarding plant availability and planned maintenance schedules.

In the short-term, which here is taken to mean broadly from the day-ahead stage, 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; and
- submitting data to the Settlement Administrator.

Participants[38] that are responsible for energy flows into and/or out of the system will make the following information available to the SO:

- at 11:00, an initial schedule for the next day (IPN);
- 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 such that the data held by the SO at Gate Closure will be the participant's FPN[39] and any Balancing Mechanism offers and bids submitted; and
- at any time between Gate Closure and the end of the Settlement 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).

As at present, the SO would carry out a day-ahead assessment of the security of the system. In the new environment it would use data on system outages and planned station maintenance, its own demand forecast, the data contained in IPNs, its view of likely prices, a study of market price movements and its assessments as to how participants are likely to position themselves given those movements. Potential difficulties in terms of energy balances, transmission constraints[40] and reserve and response requirements could then be identified. The aggregation of IPNs would take the place of the Unconstrained Schedule that NGC, as SO, presently uses when undertaking its day-ahead assessment.

The SO will broadcast specified information[41] to the market, to inform trading in the short-term markets and to facilitate participation in the Balancing Mechanism. Preliminary information for the next day, such as national and zonal demand forecasts could be issued at 09:00. Having assessed the data contained in IPNs, the SO will provide indications of the likely level of energy and transport balancing actions required. These would be updated at regular intervals to reflect revised IPN data. If it has such contracts available to it, the SO might invoke balancing services contracts at the day-ahead stage to initiate the warming-up of plant or the reduction of demand.

[38] Except those below the agreed *de minimis* levels.
[39] If unchanged, the IPN will default to the FPN.
[40] Although much of the data on which the assessment is based is non-locational, IPNs will contain locational information. In addition, it is likely that a principal part of the assessment will be the experience of how the SO coped with similar conditions in the past.
[41] The precise details of what is published and when remain to be determined – Appendix 5 reproduces a recent NGC paper summarising its present thinking on information flows. It will be important that such information is made available promptly and at the same time to all interested parties.

Overnight, the SO would review the likely situation during the morning pickup, update its forecast in the light of any revisions to IPNs and any Balancing Mechanism offers and bids that it has already received and plan the types of action that it might have to take in the Balancing Mechanism for that period. At the same time, the SO would be balancing the system in real time on the basis of studies that it had previously undertaken.

At Gate Closure for each trading period, the SO will reassess the system on the basis of FPNs, its demand forecasts and its knowledge of current system conditions, and assess what, if any, offers and bids it needs to accept to keep the system in balance. Again, it may also use whatever balancing services contracts are appropriate for this purpose, and this might include committing or standing down plant that it had warmed-up and demand reductions that it had prepared, under contracts. From Gate Closure to the end of the relevant trading period, the SO will continue to maintain system balance using these instruments.

As well as balancing the system on a second-by-second basis, the SO would ensure that it could be securely operated during the various periods of the day when the system has to meet particular peaks in demand. These include, for example, the morning pickup (approximately 06:30 to 09:00) and the late afternoon peak (17:00-19:00). The rolling nature of the Balancing Mechanism means that at any time the SO will be engaged in activities relating both to real-time balancing for the present trading period and to the following trading periods for which Gate Closure has already occurred. Simultaneously, the SO will be carrying out studies of future periods of potentially high demand.

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 balancing services. It is envisaged that all interested participants will have access to real-time information on the Balancing Mechanism such as the offers and bids submitted and balancing actions accepted. Where possible, information will be made available over the internet in addition to dedicated communications channels. The SO may also issue regular reports on its balancing activities after the event.

Finally, the SO will send to 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).

The remainder of this Appendix discusses the specific approaches that the various classes of participants listed earlier might choose to take given the risk mitigation strategies most obviously available to them.

10.4 Demand Side Participants

Common Activities

The ways in which participants act in the market will vary widely. The likely approaches to be taken by specified participants are described below.

Common areas of activity relate primarily to notification and settlement. Demand-side participants, their counterparties or agents, will notify contract volumes struck in the forwards and futures markets to settlement. These contract notifications could be on a standing basis if the contract volumes did not change. Subject to *de minimis* levels on information requirements, demand-side participants will also provide information on their intended consumption to the SO.

At some specified time after the day, a participant will receive details from settlements of the energy imbalance prices and any other charges that it has incurred for the day. The participant would also be informed of any payments due or receivable as a result of its activities in the Balancing Mechanism by settlements.

Details of payments resulting from contracts in the organised forwards and other markets will be received by the operators of those markets. The demand-side participant would be responsible for settling bilateral contracts that it had in place in the forwards, futures and short-term markets.

Common Issues

Under RETA, the demand-side will be able to offer and bid into the Balancing Mechanism, as well as contracting forward for most of its requirements. All participants will also be exposed to imbalance settlement for that volume of demand that differs from contracted amounts, plus accepted offers and bids in the Balancing Mechanism.

In general, participants on the demand-side are unlikely to manage this exposure physically to the same degree of accuracy as generators. Suppliers generally may not have real-time metering telling them of their customers' offtakes, and customers participating directly may not be monitoring their position and exposure to each half-hour. Such participants will therefore be concerned to manage their exposure to imbalance settlement in a variety of ways, using the various instruments likely to be on offer in the new markets. Within-day information is likely to be more highly valued under the new trading arrangements than it is today. As participants gain experience of trading under the new regime, they may take steps to improve their access to consumption data on-the-day in order to manage their imbalance exposure more closely. Demand-side participants have already expressed interest in obtaining within-day access to GSP meter data.[42]

Public Electricity Supplier

Although Public Electricity Suppliers (PESs) and second tier suppliers will both have a range of customers, PESs are likely to retain the larger domestic base, at least for some time ahead. This may be one of the few distinctions between PES supply businesses and second tier suppliers after the planned separation of distribution and supply licensing, price controls being another[43].

It is probable that, by the time the day approaches, a PES will have signed contracts to cover most of its forecast demand. These contracts may take a variety of forms - baseload, shaped, and peaking - in order to meet the PES's expected load profile. Generators and traders might, for example, offer contracts matched to particular customer profiles. Some PESs might contract for most of their demand at least a year in advance, with further contracts signed nearer the day to correct for changes in their customer portfolio. Others might sign long- to medium-term contracts for a smaller proportion of their demand and rely more heavily on shorter-term trades. In order to determine its required contract volume, a PES would need to forecast its customers' demand. Nevertheless, some PESs may take steps to improve the accuracy of their demand forecasts, including making greater use of within-day data. Given the uncertainty inherent in its demand forecasting, a PES might wish to contract with a generator, supplier or trader that was willing to accept some volume risk.

[42] This issue was recently discussed in DISG paper 15/08.
[43] It is envisaged that the concept of PES and second tier supply licences will no longer apply after the distribution and supply split.

Participation in the short-term markets is a matter of choice for the PES. As well as considering the need for short-term fine-tuning, there are resource costs to consider. If the PES was satisfied that its contract cover provided a good match with its likely demand, it could consider that such trading was unnecessary and too resource intensive. On the other hand, active participation in the short-term OTC and exchange-based markets might be an integral part of the PES's strategy. By entering into on-the-day trades it would benefit from the certainty of locking in a price for that demand, compared with the uncertainty of exposure for energy imbalances at unknown prices in the imbalance settlement process.

As with the short-term markets, the PES could choose whether or not to participate in the Balancing Mechanism. If the PES did wish to, it would, like any Balancing Mechanism participant, have to notify the SO of its intended consumption pattern for the trading periods for which it wished to submit offers and bids.[44] This information may need to be notified irrespective of whether the PES chooses to participate in the Balancing Mechanism. A PES that was active in the short-term markets might also be more active in the Balancing Mechanism, adjusting its bids and offers as its position changed. It would do so both to hedge against the risks in the imbalance settlement process and as the basis for new types of contracts with metered customers.

It is likely that, at least in the early stages of the new trading arrangements, it will be easier for PESs to submit offers to reduce consumption, rather than bids to increase it. There is, at present, little experience of suppliers encouraging customers to adjust their demand profile and take more demand against the prospect of lower prices, other than teleswitching for heating loads. Over time, however, technological advances may facilitate greater price responsiveness in the demand of domestic customers. Decremental offers could be backed by interruptible contracts, of a familiar type, with some of the PES's larger customers who were prepared to reduce their demand when requested in return for a lower electricity price or some form of profit-sharing arrangement[45]. Indeed, the opportunities for risk mitigation that such contracting offers to the PES, and to other suppliers, suggests that the search for such customers will intensify and that a variety of new contractual arrangements aimed at various categories of customers with particular load patterns and/or abilities to accept interruption will become more prevalent.

---

[44] Depending on the information requirements specified in the Grid Code and/or BSC

[45] Interruptible contracts can be for part as well as all of the load of the customer.

PESs, in common with other suppliers, may include power from licence-exempt and embedded generators amongst their portfolio of power purchases. If the PES undertakes to buy the full output of such generators, the price paid is likely to reflect the predictability and controllability of the generator's output. Indeed, by holding offtake contracts with flexible licence-exempt generators, a PES will be able to manage its imbalance position after Gate Closure by calling upon the generator to adjust its output, thereby changing the PES's net metered take at GSP Group level

Whether or not it chose to participate in the Balancing Mechanism, the PES would have to pay imbalance prices on any demand not covered by contract. This is similar in principle to the exposure to Pool prices that a PES has for any demand not covered by contracts for differences.

Second Tier Supplier

For the most part, the remarks concerning a PES apply equally to second tier suppliers. Compared to a PES, a second tier supplier may have a relatively high proportion of half-hourly metered customers whose demand has the potential to be responsive to price. If its market share is changing relatively quickly, it is possible that a second tier supplier would sign fewer long-term contracts than a PES and instead predominantly use short-term OTC and exchange-based contracts in order to secure cover for its customers' demand. By operating in this manner it would be able to make use of recent data from its half-hourly metered customers and an up to date view of its portfolio of profiled[46] customers in determining its contract requirements.

As with PESs, second tier suppliers might be expected to seek customers who would accept a degree of interruption that in turn would allow the supplier to better manage its imbalance exposure. As that exposure is to net imbalances, other forms of contract, for example containing caps or collars, may emerge as well as the heightened interest in interruptibility. The risks of imbalance settlement exposure might also encourage some suppliers to invest in innovative metering arrangements if these could be used to help manage these exposure risks.

Large Customer

Customers may choose to buy from an authorised supplier, on a first or second tier supply contract, just as now. They may instead choose to sign the BSC as a consumption participant and take out a second-tier supply licence, enabling them to purchase from a generator, as well

[46] Under the '1998' arrangements for supply competition, customers that do not have meters that measure their electricity consumption on a half-hourly basis are allocated a deemed profile of consumption over each day.

as suppliers, and/or accept exposure to the imbalance price for some of their requirements. The choice here will depend to a large extent on the contract offers that they see in the market. By signing the BSC, customers will also be able to present offers and bids direct to the SO in the Balancing Mechanism. Large customers who do not sign the BSC will nonetheless be able to participate indirectly in the Balancing Mechanism through third parties such as suppliers. Taking positions in electricity trading markets may not be a large customer's primary focus, however, and a customer's activity in the electricity market will depend on the nature of its core productive activity. Some large customers will have little flexibility in when they use electricity. If their load is predictable they may be content to sign long-term contracts and not participate in either the short-term markets or the Balancing Mechanism. It is envisaged that customers will be able to sign contracts with more than one supplier, taking advantage of the proposed ability to split metered volumes.

Other large customers with potential flexibility may be attracted to participate more actively in the on-the-day markets and the Balancing Mechanism to realise the value of their flexibility. They may still contract for most of their demand on, say, one year contracts. They may then contract the flexible portion of their demand in the on-the-day markets, or alternatively contract all in advance and be prepared to sell back demand reductions. Such an approach might enable them to obtain an attractive price for the bulk of their purchases made under contract, whilst benefiting from any short-term opportunities that might present themselves. Such opportunities represent options for large customers that are not available under the present arrangements.

Medium-sized Customer

Medium-sized customers with a half-hourly meter, perhaps with an annual maximum demand between 100 kW and 1 MW, are more likely to sign a contract with a supplier than choose to be responsible for their own supply. The activities of such customers need be no more complex than under the present trading arrangements, with minimal involvement required other than the negotiation of contracts with suppliers.

If customers have some flexibility in scheduling their load over the day, they may be willing to participate indirectly in the short-term markets and the Balancing Mechanism, probably via the terms of the contract with their supplier. In return for providing suppliers with this flexibility, such customers would expect to achieve a lower average purchase price. There might be scope to negotiate a share of the profits made in the short-term market.

It is expected that in general medium-sized customers would not be directly exposed to settlement.

Domestic Customer

As far as their supply arrangements are concerned, domestic customers need experience no immediate changes when the new trading arrangements are implemented. They will continue to be able to contract with a supplier for all their demand and to be metered and billed as at present. Moreover, they may also benefit from more imaginative tariffs or contract options offered by some suppliers, both existing PESs and second tier suppliers and new entrants in supply. Over time, the incentives created under RETA should encourage a variety of technologies, such as teleswitching and new metering arrangements, to be applied to enable domestic customers to access the benefits of the new arrangements more directly, and to enable suppliers to manage their risk exposure in consequence.

Even less than medium-sized customers, domestic customers are unlikely to be exposed directly to settlement. Insofar as the arrangements described in the previous paragraph affect the prices that they pay for electricity, domestic customers will see the effects in the invoices they receive from their suppliers.

10.5 Generation Side Participants

Common Activities

Generators, their counterparties or agents authorised on their behalf, will notify contract volumes from the forwards and futures markets to settlement. Some contract notifications could be made be on a standing basis from one day to the next via the use of “evergreen” flags. Volumes traded on an organised cleared exchange are likely to be notified to settlement by the exchange’s clearing house. The SO will notify accepted offers and bids in the Balancing Mechanism.

At some specified time after the day, a generator will receive details of the energy imbalance charges and any other charges that it has incurred for the day. The generator will also be informed of any payments due or receivable as a result of its activities in the Balancing Mechanism. The generator will be responsible for settling bilateral contracts that it had in place in the forwards, futures and short-term markets.

Common Issues

Most of the activities that generators will have to undertake under the new arrangements have similarities to activities that they carry out now. For example, they presently have to submit availability data on a half-hourly basis at the day-ahead stage and notify the SO of any changes in their availability. This is similar to making initial physical notifications at the day-ahead stage and subsequently modifying them as necessary. Generators presently submit offer prices for their plant's output at the day-ahead stage. This necessitates assessing the costs and profitability and likelihood of different levels of output in a way that is analogous to that required for active participation in the short-term markets and the Balancing Mechanism. The ability to post offers and bids in short-term markets and the Balancing Mechanism up to 4 hours before the start of a given half-hour will provide generators with an opportunity to adjust their prices and outputs much closer to real time than under the present arrangements.

Portfolio Generator

This section considers the operations of a generator with a portfolio of power stations across the country, including mid-merit and peaking stations as well as baseload plant.

In order to reduce its exposure to energy imbalance prices, a portfolio generator might enter into a series of bilateral contracts to secure cover for the majority of its expected output, as it can do presently by signing contracts for differences. These contracts would encompass a variety of different load shapes and durations, perhaps ranging from complex multi-year contracts with indexation terms and flexible volumes to simple fixed price and volume deals agreed at the day-ahead stage. It is expected that such a generator would continually be refining its contract portfolio in the light of updated information on the physical position of its plant and to take advantage of any profitable trading opportunities that arise. Contracts are unlikely to be linked to the output of any particular power station, giving the generator commercial flexibility to optimise its production schedule on the day.

In these processes the portfolio generator is likely to rely on the advantages that aggregation of the output of its stations brings with regard to mitigation of some of the risks that it faces[47].

[47] Statistically, the sum of the risks of say outages or output variations from each station is more than the risks from the portfolio as a whole, unless external factors influence each station in the same way. In addition, having a portfolio allows other actions, such as increasing output to offset an outage.

Its very size will also allow it to enter into a range of customer contracts, again permitting risk mitigation through aggregation.

As at present, the generator would be required to inform the SO of its intended maintenance schedules at the start of each year.[48] Close to real time, the generator would submit initial physical notifications for the following day by 11:00 each day. These would specify the expected output for each of its units for each trading period of the day. As at present, the generator would be required by the SO to provide updates to these notifications if its circumstances changed.

A portfolio generator would be likely to continue playing an active trading role on the day. At times, the generator may wish to make short-term purchases of power in order to back its contractual position, either due to forecasting errors or unexpected availability shortfalls within its plant portfolio, or because power can be purchased from the market at prices below the generator's own marginal generation costs. At other times, the generator may have surplus power to offer to the market. By actively participating in the organised and OTC short-term markets and locking in a price for its trades, the generator could reduce its potential exposure to energy imbalance prices whenever changes occur to its expected operational schedule.

Given the geographical and operational diversity of its plant mix, a portfolio generator is likely to be an active participant in the Balancing Mechanism for at least some of its available capacity. The generator could submit a range of offers and bids for the plant in its portfolio so that it would have the potential to benefit from any SO actions to address transmission constraints and energy imbalances. The generator might wish to submit standing offers for its fast response peaking plant such as open cycle gas turbines – although these generating units might typically have zero notified output at Gate Closure, they are capable of responding within Balancing Mechanism timescales.

In certain circumstances, a portfolio generator might voluntarily hold back some power stations from full output so that it could offer additional output to the Balancing Mechanism. In so doing, the generator would need to weigh up its expected income from the Balancing Mechanism, uncertain but potentially high at times, against the opportunity cost of foregoing a secure revenue stream by contracting forward. The issues that such a generator will need to

[48] In fact, there are a number of different notifications starting at longer than a year and ending in much shorter timescales. These will continue.

consider in relation to such a strategy are the expected prices under the alternatives open to it, its attitude to revenue certainty and the risks of exposure to imbalance settlement. The latter will to a large extent be a function of the physical characteristics of the plant mix, and the ease with which output can be varied in response to accepted offers and bids.

Independent Power Producer

The expected output of an independent power producer (IPP) that is not a merchant plant (see below) may be fully covered by long-term power purchase contracts. The first generation of independent gas-fired CCGT plant developed in England and Wales typically secured contract cover for up to 15 years with power prices linked to the price of gas under their fuel purchase agreements. A number of issues in relation to these contracts, and the implications of removing the Pool prices to which they all relate, were discussed in the July 1998 Proposals report. Such contracts will need to be adapted appropriately to reflect the new trading arrangements.

To the extent that its output continued to be covered largely by existing long-term contracts, an IPP might play only a limited role in the forwards and other markets, though the suppliers who purchase this contract cover may wish to sign further contracts. Under some existing IPP contracts, the level of contract cover is understood to be dependent upon the actual physical availability of the power station. This means that the IPP generator is not exposed under its contract during periods of scheduled maintenance, for example. With this type of contract, the supplier is responsible for securing alternative contract cover whenever the IPP is unavailable or accepting exposure to the prevailing Pool price. Under the new trading arrangements, the supplier would have similar options. It could choose either to trade in the short or medium term markets, or to accept exposure to imbalance prices. Other IPPs with fixed levels of contract cover may wish to secure short-term supplies of power in the forwards and futures markets in order to hedge any contractual exposure during maintenance periods.

For those IPPs that do not have existing contract cover for most of their output, it is likely that contracting forward will prove an attractive option. Some may choose to take a shorter-term strategy, although as a single plant player this has potentially greater risks than for a portfolio player. Because of this, some may choose to do deals on a co-operative basis with other participants in a similar position, or turn to an aggregator. There could also be scope for IPPs to develop mutual support arrangements such as are seen in other industries where small producers may face single site risks, for example, oil refineries.

The IPP would be required to submit an initial physical notification to the SO for its plant at the day-ahead stage. Since fully contracted IPPs typically operate at baseload at present, it may well be possible for an IPP to roll over the notifications from one day to the next, only changing the nomination at the start and end of any outages. The IPP could also arrange for the power purchaser or a third party to nominate on its behalf.

A fully contracted IPP generator need not participate in the short-term markets. Depending on the terms of its contracts, however, the IPP may wish to buy power on-the-day to cover any exposure that would result from the plant becoming unavailable at short notice.

Similarly, the IPP might not wish to play an active role in the Balancing Mechanism, preferring instead to maintain a stable baseload operating regime. However, the evidence suggests that IPPs, as well as other generators, can and do vary the output from their plant to some extent. The degree of each IPP's participation will be influenced by the terms of its power purchase contracts, since these are likely to determine how the profits from Balancing Mechanism opportunities would be shared with the contract counter-parties. It should be in the IPP's interest to submit standing bids that reflect its operating cost structure. These bids would be priced to ensure that the IPP would pay less than its avoided fuel cost. In addition from time to time the IPP may have surplus output available that is not covered by contracts; this could be offered into the Balancing Mechanism. In addition, the IPP should always be able to submit a small offer relating to the additional output that a plant can generally produce even if it is nominally operating at full output. Such an offer, equivalent to a maxgen bid under the present trading arrangements, would probably be highly priced.

If an IPP's participation in the short-term markets and the Balancing Mechanism were to be relatively limited, it might not wish to set up a fully functional commercial trading function. Intermediaries such as brokers and traders may offer a lower cost option for access to the short-term markets than direct trading.

Depending on its contract terms, an IPP may find that it is able to continue operating more or less as at present, with little or no exposure to imbalance prices. Under the new arrangements, IPPs will be able to self-despatch to meet their contractual commitments.

Merchant Plant

The activities of a merchant plant operator, that is, a generator without long term contract cover, will be more akin to those of a portfolio generator than a fully contracted IPP, in the sense that it may adopt different strategies for different tranches of the plant's output[49]. The latest merchant plant projects have typically been designed for maximum commercial and technical flexibility, and hence should be well placed to take advantage of opportunities in the short-term markets and possibly the Balancing Mechanism.

The commercial strategy of a merchant plant without long-term power offtake contracts is likely to entail securing cover for much of its expected output in advance of the delivery date. For example, it may build up a portfolio of contracts with various durations and shapes. These power contracts could be complemented by a portfolio of relatively short-term fuel supply contracts, enabling the merchant plant to lock in generation margins in advance. The portfolio would be refined to take account of changes in the plant's expected output and as profitable trading opportunities arose in the fuel and power markets.

A merchant plant may well choose to participate actively in the short-term markets and the Balancing Mechanism, particularly if it is capable of changing its output level at short notice. As for fully-contracted IPPs, some of the single site risks to which merchant plant may be exposed could be mitigated via mutual support agreements with other plant, possibly arranged by intermediaries such as aggregators or traders.

Highly Flexible Plant

The commercial focus of a highly flexible plant, such as an open cycle gas turbine or pumped storage unit, would be to capture the economic value of the flexibility it contributes to the electricity system. Such plant can thus be expected to play an active role in the short-term markets and perhaps even more so in the Balancing Mechanism. Given the uncertainty in the price and volume of transactions in these markets and mechanisms, flexible plant may also wish to secure some long term guaranteed revenue streams. Flexible plant may be in a position to offer peaking and option-type contracts to hedge balancing risk to other market participants in return for a fixed contract fee.

---

[49] The activities of an IPP and a merchant plant can be quite similar. The distinction here is that the merchant plant will deliberately seek to contract short-term rather than longer term.

As is the case under present arrangements, flexible plant will also be major players in the markets for the provision of balancing services, competing in whatever contract tenders or auctions are organised by the SO. The remuneration arrangements under balancing services contracts typically involve capability fees as well as utilisation payments, thereby providing a secure revenue stream for the contract holder. It is likely that at least some balancing services contracts will have similar terms and hence appear attractive to flexible plant. However, balancing services contracts are likely to restrict a flexible plant's ability to participate in the Balancing Mechanism, and the plant owner will need to weigh up this opportunity cost when negotiating or tendering for balancing services contracts with the SO.

Settlement will be on the same basis as that discussed above for generators generally, with additional arrangements applying to whatever balancing services contracts the plant also holds.

Nuclear Plant

Nuclear power stations tend to be more restricted than other plant in terms of their ability to vary their output levels over the course of the day. They are thus likely to be predominantly active in the forwards and futures markets with a particular focus on securing baseload contract cover to match their expected operating regime. Having secured appropriate cover in these markets, nuclear plant will have no exposure to short-term prices provided their contracts can be backed by actual output. Such plant will be able to self-despatch to meet their contractual commitments under the new arrangements. Nuclear and other relatively inflexible baseload generators will be able to signal their desire to maintain a steady level of output by submitting very low or negative bid prices (along with the appropriate dynamic parameters such as notice times and ramp rates) to the Balancing Mechanism. A negatively priced bid, if accepted by the SO, will result in the generator being paid to reduce output (normally, of course, a generator would pay to reduce load – in effect, it is buying energy from the system to replace its own production). This payment would help to offset any potential exposure to imbalance prices that the generator could face in subsequent trading periods (that is, beyond the Balancing Mechanism Window period of 4 to 4½ hours) were it unable either to return to the level of output originally intended or to meet its contractual commitments with power sourced from the short-term markets.

Under the present arrangements, nuclear plant does not get paid for so called over generation, the small spill amounts of power that it produces from time to time. Under the new arrangements, such spill will be paid for at the System Sell Price.

During maintenance periods, nuclear plant may wish to secure short-term supplies of power in order to hedge any contractual exposure to imbalance charges. There will be a range of timescales over which such cover could be secured.

Nuclear plant may have some limited flexibility that may be usefully offered into shorter-term markets. Indeed, it would be expected that nuclear and other inflexible generators would seek ways of increasing the flexibility of their plant provided that the costs justified such actions.

The size of the average nuclear unit is typically large. Assuming that there is, at least to begin with, relatively little flexibility in the rest of the portfolio, then nuclear operators are going to face short-term risks in relation to plant failure and managing any flexibility in the load of their direct customers. They may be expected to adopt a range of techniques for dealing with this, such as finding interruptible customers, striking options contracts and investing in more flexible plant.

External Generators

Externally interconnected parties in Scotland and France may effectively continue to operate as they do under the present trading arrangements. External generators already submit simple offers to the Pool, consisting of one incremental price without no-load or start-up components. Unlike other generators under the present arrangements, they also have the ability to vary their price offers over the day by way of submitting multiple tranches with different availability profiles.

An external generator's contracting strategy may focus primarily on shorter-term contracts such that it will be in a position to react to changing circumstances in its own market. However, depending upon the breadth of generation resources it is able to call upon, the external party may wish to sign a certain level of longer-term export contracts.

If the external party can utilise flexible generation plant in its own electricity system, it could be an active participant in the short-term markets and Balancing Mechanism.

Exempt Generators

An exempt generator is a generator that does not require a generation licence, and hence, under the present arrangements, has no obligation to join the Pool or be centrally despatched. Exemption is granted to the operators of power stations which, in general terms, export less than 50 MW and their capacity is less than 100 MW. The principles that apply to exempt generators apply equally to the output of those stations of licensed generators which, if viewed in isolation, would not cause the generator to need a licence. Such plant include, but are not restricted to, combined heat and power plant and renewables schemes. The specific implications for both these types of plant are discussed separately below but there are a number of general issues that apply more widely to non-centrally despatched plant. Exempt generators are typically "embedded"; that is they are connected to a PES's distribution network rather than the transmission network.

Under the present arrangements, suppliers purchasing non-pooled generation pay an agreed price directly to the generator. Contracts with exempt generators are often for the output of the plant rather than for a fixed volume. Moreover, a supplier, by contracting with non-centrally despatched embedded generators in the same transmission zone (GSP Group), can reduce its exposure to Transmission Network Use of System Charges since its deemed demand will be reduced by the output of the generator measured at the relevant times (this is known as the "Triad benefit"). Triad benefit is conferred by licensed generators as well as exempt ones as long as they are not centrally despatched.

On the basis of present transmission charging, it is envisaged that embedded generators with appropriate contracts will continue to be able to provide Triad benefits. While significant changes to the transmission charging regime are likely over time, these developments will take place outside of the core RETA Programme. The position of embedded generators under a revised transmission charging regime would need to be examined as and when potential changes are being considered.

Unlicensed generators already despatch themselves under the present arrangements, and will continue to self-despatch in the future. Unlike licensed participants, exempt generators will be able to choose whether or not to sign the BSC. Becoming a BSC signatory will entitle the embedded generator to participate directly in the Balancing Mechanism and to take the System Sell Price for any output in excess of contract volume (i.e. "spill"). If the exempt generator chooses not to sign the BSC, it may wish to contract for its full output with one or more third parties such as suppliers. For settlement purposes, the supplier's deemed take in each trading period will be reduced by the output of the embedded generator in the period. In determining what contracts to sign, the supplier will have to take account of the likely output of its allocated embedded generation. The supplier will have to weigh up the potential benefits of purchasing embedded generation against the potential costs of higher imbalance charges if the output of the embedded generator is uncertain.

Thus, exempt generators whose output is stable and predictable either over the year, or some shorter period of time, should have little difficulty in securing attractive contracts. The addition of a stable and predictable level of production to the portfolio of a market participant would be likely to be attractive, as it should reduce the overall risk of the portfolio. Those exempt generators whose output is unpredictable, could still enter into a contract with a counterparty willing to manage the risk associated with possible exposure to imbalance prices. However, the terms of such a contract would be less attractive than for an exempt generator with more stable and predictable levels of output. It is possible that aggregators might be interested in contracting with a number of such participants, if they felt that they could create a portfolio with appropriate risk characteristics. Alternatively, if the generator has signed the BSC, it might sign a fixed volume contract and accept an exposure to imbalance charges.

Exempt generators with fixed volume contracts will need to make arrangements for the sale of output in excess of their contract volume. At present, most exempt generators sign contracts covering this eventuality but if they do not, suppliers at the relevant GSP Group, will absorb the spill power free of charge, that is, the generator does not get paid for it. As stated above, by becoming signatories to the BSC, exempt generators would be paid the System Sell Price for such spill. Exempt generators may also need to purchase top-up or stand-by supplies[50].

Combined Heat and Power (CHP) Plant

CHP Electricity Importers

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 are expected to develop under the new trading arrangements.

[50] Top-up supplies cover the situation where the output of the exempt generator is less than its contract volume whereas standby supplies apply when it is not generating at all.

For smaller schemes, there should be a wide range of suppliers prepared to offer them electricity. Larger schemes may prefer to contract more actively in the bilateral markets to secure energy, when it becomes clear what their demand is likely to be as real-time approaches. If they wish these trades to be taken into account in imbalance settlement they would have to sign the BSC.

CHP Electricity Exporters

CHP plant may be active market participants on-the-day if they have short-term control with regard to their steam load requirements. A CHP plant will have a number of options for selling additional power in the short-term markets if this spill is not already covered by contracts. Organised short-term markets (e.g. a power exchange) could be used to find a buyer for any additional output until four hours before the delivery period. The CHP plant could trade directly in an exchange but many CHP operators might make use of a brokering service, or collaborate with a market participant with greater trading capabilities. These would be likely to represent lower cost options for small-scale or infrequent traders, and would enable the plant operators to focus scarce resources on their core business activities, rather than in trading in the electricity market.

As an alternative to contracting in the forward, futures and short-term markets, the CHP plant could submit an offer for additional output to the Balancing Mechanism; again, it may be possible for this to be arranged through an intermediary. In general, a CHP plant may be more willing to increase output rather than decrease it due to its requirement to deliver a steam load, and possibly also to supply power directly for local consumption.

Another 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 an aggregator that was able to extract benefits associated with trading, either on account of its market position, or its superior trading skills (or both). Suppliers might derive added benefits from contracting with CHP 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 contracted embedded generating sets. An aggregator might choose to contract with several generators in the knowledge that it is the net imbalance of all the generators that is relevant for imbalance purposes, not their individual performance.

Many CHP projects will have exports that are predictable due to the fact that production planning is likely to be done over timescales of more than a day. It is likely that their attractiveness would be recognised through higher prices compared to those for less predictable loads, and to the extent that they could offer benefits.

For those CHP projects whose level of export is less predictable (including those schemes which might change from being modest exporters to large importers of power at very short notice, possibly as a result of some unforeseen change in production processes or plant failures), the situation will be different. There might be advantages in such schemes banding together, providing that the rules allow this, to reduce their risks since their aggregated output might be less uncertain. For example, 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.

Renewables Schemes

NFFO Generators

Renewables projects developed in England and Wales have typically signed offtake contracts with PESs under the Non Fossil Fuel Obligation (NFFO) arrangements. The new trading arrangements will need to take account of the position of NFFO schemes themselves and the position of the PESs with whom those contracts are signed. An alternative reference price will be required to reflect the new circumstances. 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 a spot market.

Under the new trading arrangements, a scheme under the NFFO umbrella will not have the market discipline of securing a buyer for its output as the NFFO contracts guarantee a fixed price for the output of the plant irrespective of season or time-of-day. In addition, 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.

Non-NFFO Renewables

Renewables schemes whose NFFO contracts have now expired (NFFO 1 and 2 contracts expired in December 1998), should already have recovered the costs of building their assets and such schemes will only need to be competitive on the basis of their avoidable costs.

Schemes able to forecast their load with a degree of certainty before contract notification will have mechanisms available to them (or third parties 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. Renewables schemes with a degree of flexibility will be in a strong position to participate directly in the Balancing Mechanism. Many renewables schemes are both predictable and flexible and are thus likely to be in a strong position under the new arrangements. Wind generators are perhaps the most at risk because of their unpredictable output.

In the long-term, reducing the period for which the Balancing Mechanism is open will reduce generation uncertainty at Gate Closure and increase the time allowed for closing out positions, thus diminishing the scope of the problem.

For smaller schemes, the ability to aggregate output with third parties may offer significant benefits. The uncertainty of an individual scheme's output may be offset by opposite imbalances when added to the demand uncertainty of a supplier or the uncertainty of a number of generation sites aggregated together for settlement purposes. A form of aggregation for renewables schemes has already occurred under the current arrangements as many ex-NFFO sites have joined the Renewable Generators' Consortium, which negotiates terms, on behalf of its members, for the sale of power to suppliers.

Trading Sites

Under the present trading arrangements, the treatment of Trading Sites is defined in the PSA. In simple terms, they involve power stations located on the same site as demand. Currently, Trading Site status offers a number of advantages to on-site demand. Consumption on Trading Sites is only liable to Energy Uplift and Transmission Services Use of System charges for any net imports taken by the site in each half-hour. Transmission Losses and Transmission Network Use of System charges are also levied on the basis of net consumption by the Trading Site.

Going forward under the new arrangements, Trading Sites are likely to retain their present advantages. Where a Trading Site consists of a number of individual BM units, all these units will be designated as either production or consumption according to the net aggregated position of the Trading Site. At least initially, Transmission Losses will continue to be applied to net imports at Trading Sites. While NGC's Use of System Charges are outside the direct scope of RETA, the position of Trading Sites will need to be examined as and when changes to the charging regime are being considered.

As for potential trading strategies under the new arrangements, the position of Trading Sites will be similar in many ways to that of CHP plant. Their contracting options will largely be dependent on whether the sites are net importers or exporters.

Other Participants

Traders

It is anticipated that the revised trading arrangements would 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. They could be expected to build up a set of contracts with market participants which will give them opportunities to construct a portfolio of purchase and sale contracts covering a range of durations, load shapes and pricing terms.

Pure traders will not physically generate or consume power, that is, they will not be responsible for metered flows in the settlement process. However, they will be exposed to energy imbalance prices for any mismatch in their contractual purchase and sales commitments. As a result, traders are likely to seek to close out the majority of their positions before the delivery periods to avoid imbalance charges at unknown prices. Traders may be most active in the short- to medium-term forwards and futures markets. They may also choose to participate as market makers in organised exchanges.

Their knowledge of trading risks, arbitrage opportunities and mitigation strategies means that traders are likely to display a keen interest in developing products that allow other market participants to manage their risk.

Aggregators

Aggregators are participants who seek to build portfolios of generation and/or demand, taking advantage of the lower risks that arise from aggregation. As described in previous sections, many other types of participants may seek to do this. Here we discuss the activities of participants who see this as their primary business.

Providing that the rules allow it, 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 a trading room, necessary to participate fully in the new arrangements; and
- 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, and subject to being able to satisfy the requirements and obligations set out in the BSC and elsewhere[51], 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. Aggregators will provide participants such as embedded generators and half-hourly metered customers with an opportunity to capture the portfolio benefits enjoyed by larger generators and suppliers, thereby reducing potential exposure to energy imbalance prices. Aggregators may also be able to submit offers and bids into the Balancing Mechanism on behalf of their clients, although this issue requires further consideration.

[51] As noted in Chapter 9, the position of aggregators within the legal and regulatory framework requires further consideration.

Conclusions

The new trading arrangements will affect the various categories of market participants in different ways, in terms of the obligations and opportunities open to them. In some respects, market participants will be able to continue as at present. However, the new trading arrangements will provide a range of options for managing risks and assigning them to those participants who are best placed to manage them. They will provide greater commercial flexibility for all market participants and this will create opportunities for those players that are able to respond in an innovative and imaginative way.

Appendix 11 Simulation Modelling

This Appendix describes the economic modelling work that is being undertaken as part of the RETA Programme and discusses how the model will continue to be used in the future.

11.1 The Scope of RETA

To place the modelling efforts in context, it is necessary to describe the proposals to which it relates. That has been done exhaustively elsewhere in this report, and here we simply provide an overview.

The RETA proposals envision a series of bilateral markets traded ahead of real-time. For any half-hour trading period, it is assumed that a variety of forward and futures markets, trading both customised ‘over-the-counter’ (OTC) and standardised screen-based products, will develop in which most participants will buy or sell to meet most of their requirements. Close to real-time, a short-term bilateral market, possibly a formalised power exchange, will open to allow fine-tuning of positions. Four hours ahead of the trading period, Final Physical Notifications (FPNs) will be made, and bids and offers submitted to the Balancing Mechanism. From then on, the System Operator will call off those offers and bids that it needs to operate the system, in terms of both energy balancing and relieving constraints; it may have ancillary services contracts available to it as well which could also be used for these purposes. After the trading period has closed, any uncontracted[52] output or take will be settled at the appropriate energy imbalance price, and information imbalance charges may be imposed on those whose metered position is different from their FPN.[53]

11.2 Modelling Objectives

The Programme has two broad objectives for its economic modelling activities:

- To gain insights into aspects of the new trading arrangements; and
- To provide a platform which potential participants can use to gain experience of the trading environment that they are likely to face under RETA.

[52] Uncontracted here means after taking into account accepted bids and offers in the Balancing Mechanism.
[53] The present proposal is that the information imbalance charge will initially be set to zero.

A variety of different insights can be gained by the use of appropriate models. The Programme has chosen to focus on a few key areas of particular interest, and these are described further in a later section of this Appendix.

The model can also be used to allow potential participants to gauge the implications that RETA will make on their wholesale market operations, as well as allowing them to obtain their own insights into the proposals.

The achievement of these objectives is in part dependent upon the type of modelling that is undertaken. No model can represent completely the real world, and each has its own limitations. It was decided that the Programme should focus on modelling efforts that allowed both of these objectives to be achieved, even if that gave some loss of functionality.

11.3 The Modelling Options

To capture all the markets expected to operate under the new trading arrangements and explore all their interactions within one model would be a considerable task and would result in a model of great complexity, both in its construction and its operation. Nor is it likely that the result would be an accurate representation of the real operation of the new arrangements. Not only will there be interactions between different parts of the new arrangements, but there will be effects on, and therefore changes resulting from, plant operation and construction decisions. This leads to significant risks, including that:

- the development and operation of the model would be prohibitively time- consuming;
- the results of any run of the model would be hard to interpret, as so many factors would need to be taken into account; and
- the model would be too complex for meaningful insights to be obtained from its use by potential participants.

The Programme has therefore decided to focus its modelling efforts on specific parts of the RETA proposals.

The aim of the Programme is to specify and provide the Balancing Mechanism (BM) and the imbalance settlement mechanism, on the assumption that the market as a whole will provide the other elements, in particular the forwards and futures markets and a power exchange(s). Due to interest in the incentives to trade in the various markets that together represent the RETA proposals, the modelling effort cannot focus solely on the Balancing Mechanism and Settlement. At the same time, as noted above, it cannot capture all the markets in their entirety. It has therefore been decided to model a single, short-term power exchange in conjunction with a simple Balancing Mechanism and Settlement process, on the basis that this should provide a reasonable proxy for the operations of the market as a whole.

There is a range of modelling approaches that might be helpful. At this stage of the development effort, the interest is in how prices develop and how structures, particularly those defined in the Balancing Mechanism, influence participants' behaviour. The type of modelling that the Programme has commissioned is termed 'experimental economic modelling', and fits the need to assess behaviour by market participants.

Experimental economic modelling is commonly applied to test hypotheses concerning the behaviour of market participants and the resulting impact on market prices. This type of modelling requires the development of computer software that simulates the market, and provides an environment in which a number of players can trade with each other. To fit the approach to the Programme, it is also necessary to model the Balancing Mechanism and Settlement as well. Subjects are then invited to participate in experiments in which they use the computer software to simulate the actions of market participants.

In this approach, the model looks at a day, and activity in the various trading periods in that day.[54] As a proxy for the forwards and futures markets that operate in advance of any power exchange(s), participants are given an opening position assumed to arise from previous trading. Testing is underway to understand the impact on behaviour that may arise from differences in assumed opening positions.

It is accepted that other models and approaches could also provide insights into the operation of the markets under the RETA proposals. Meetings with various parties active in this area have therefore been held, as described at the end of this Appendix.

11.4 The Model Development Process

The Programme obtained a number of proposals from various groups that have skills in this area. It has software for the model and market clearing software.

[54] For ease of exposition, 24 hourly trading periods are used rather than the 48 half-hourly periods that will actually apply in RETA. No significant distortions are introduced by this simplification.

The providers have carried out the following tasks:

- the preparation of a detailed design brief;
- the development of software to allow the model to provide:
  - ⇒ the submission of FPNs and Balancing Mechanism bids and offers
  - ⇒ the operation of the Balancing Mechanism;
  - ⇒ the operation of the Settlement processes;
  - ⇒ a 'payoff calculator', a decision support tool to allow participants to determine their best trading strategy; and
  - ⇒ a summary screen.
- the integration of the market clearing software with the above and the preparation of an overall model;
- the testing of the model; and
- the supervision of the runs to date.

11.5 An Outline of the Model

The model being developed by the Programme allows a number of participants to play various roles, and to trade with each other on the basis of information held by each in terms of cost structures, customer demand characteristics and the like. The results of that trading are then analysed and are passed back to participants to allow them to amend their behaviour in future runs in the light of experience.

The model simulates trading in a power exchange. A team of people trade in real time, each playing the role of a system participant such as a portfolio generator, an IPP or a supplier. Each participant uses information provided to him or her on prior trades, production or consumption costs, capacity limits and potential prices to develop trading bids and offers. These are offered to the power exchange, which matches beneficial trades. Whilst the exchange remains open participants can change unaccepted bids and offers and submit new ones as well. When the exchange closes for a particular trading period, unmatched positions or spare capacity can to be offered into the Balancing Mechanism; any open positions that are not closed out by the acceptance of offers or bids become subject to imbalance settlement, and any unused capacity not called in the Balancing Mechanism is assumed not to run.[55] The overall results of trading are then analysed and are passed back to participants to allow them to amend their behaviour in future runs in the light of experience.

The model works by using a network of PCs that are the input screens for each participant, linked via the internet to a mainframe which processes bids and offers and clears the market.

11.6 Running the Model

A run of the model works as follows:

- Forwards contracts arising from trades in the forward and futures markets (including contracts between the upstream and downstream arms of vertically integrated participants), generating sets, and a customer base are represented by an ‘opening position’ provided to each participant before a model run begins.

- They then make trades in a power exchange. The model provides a decision support tool called a payoff calculator, which assesses the best trading approach given input on market conditions and likely prices.

- Once the market closes for a particular trading period players submit FPNs for generation to the system operator and, if they so choose, balancing mechanism bids. The model then optimises and balances the system at a single turn, accepting offers and bids necessary to do this and allowing for any random perturbations in demand or generation failures introduced by the model operator.

- System and player volume imbalances are calculated. Imbalance prices and payments are calculated. Participants who are out of balance are charged or paid at energy imbalance prices, and may incur information imbalance charges as appropriate.

- Results are collated and players informed how they have performed.

[55] The model assumes that FPNs, plus or minus accepted offers and bids, becomes the actual physical position. There is a case, therefore, where spare capacity can become exposed to imbalance settlement, where a participant chooses to nominate in its FPN for uncontracted amounts. As long as FPNs are the same as contracted amounts, however, then the exposure described above is correct.

Participants are presented with the overall results of their trading efforts, in terms of customer sales, forward trades (both given), power exchange trades, offers and bids accepted in the Balancing Mechanism and any imbalance receipts or charges, from which is deducted the costs of operating the plant to give a net profit or loss figure.

The same scenario for each group of players is run several times, to see both if behaviour changes as a result of experience of Balancing Mechanism and cash-out exposures, and whether it converges in the sense of broadly similar results starting to emerge. A set of such runs is called a game. Post-game analysis looks at behaviour in a game, or in a series of games.

In its use of the model, the Programme has established a set of games that need to be conducted. Each run of each game requires up to fourteen players representing a variety of industry participants. A gamemaster supervises each run, introduces selected random events such as demand perturbation or a generating station failing, and contributes to the post run analysis. The runs are made in a room devoted to the purpose, fitted with 15 PCs with appropriate hardware and software.

11.7 Simplifications

The model makes several simplifications. These include the following:

- contract terms assumed to have been agreed in the forward market contain price and quantity only. Other terms, such as caps, collars and load-following are excluded;
- plant technical constraints, such as ramping, are not modelled in terms of the feasibility of power exchange or Balancing Mechanism actions;
- explicit modelling of transmission constraints is excluded from the Balancing Mechanism;
- offers and bids to the Balancing Mechanism are made once only; and
- some of the technical issues being debated as part of the Balancing Mechanism design are not included. For example there is no consideration of ramping payments or “within half hour” issues.

11.8 Outputs

The model provides the following types of output:

- traded volumes in the power exchange;
- traded prices in the power exchange;
- Balancing Mechanism trades and volumes;
- imbalance settlement prices and volumes;
- costs of generation; and
- short run profitability for each player.

11.9 The Programme's Use of the Model

The Programme has specified a series of runs to test particular design features. The questions to be tested using the model include the following:

- What are the incentives created by one versus two cashout prices?
- What are the likely impacts if a number of players are vertically integrated?
- Are the arrangements are able to cope with shocks, such as a set unexpectedly failing?
- What sorts of participants obtain what quantity of rents?
- What are the implications of post Gate Closure trading?

The model has been checked and runs commenced shortly before the completion of this Appendix. Preliminary results are expected in the latter part of August and will be made available at the seminar/workshop to be held in September. Thus far, the model has been run using students as role players, but the industry has now been invited to put forward nominations for personnel to participate in model runs in August 1999 and September 1999.

11.10 The Use of the Model by the Industry

As well as the opportunity to participate in the runs being conducted by the Programme, the industry will be able to obtain access to the model on appropriate commercial terms for testing and training purposes. In this form of use, a dedicated game room is not required. Instead, users can load the relevant software onto their own computers, and then use a standard internet connection to gain access to a particular game. The software providers will provide a gamemaster, who will tell participants when a game is starting and stopping and the results of the trades that they have made.

11.11 Interface with Other Modelling Efforts

The Programme believes that a variety of different models should and will be developed to assess the RETA proposals; the modelling work being undertaken by the Programme is only one of a number of models that are of relevance.

A number of academics with interests in this field have begun to publish papers based on the results from running other models that they have developed or amended. Meetings have been held with a number of these academics, both to allow any differences in modelling approach to be understood and to assess results.

Appendix 12 Costs

This Appendix provides further details on the cost estimates summarised in Chapter 17.

The July 1998 proposals made a broad estimate of the likely costs of setting up the new arrangements. It considered the initial procurement and set-up costs and the subsequent operating costs. It distinguished costs that would be incurred centrally from those that would be borne by market participants. It said that initial set-up costs incurred centrally would lie between £50 and £100 million or £10 to £20 million a year for a 5 year amortisation period. For participants, the total set-up costs were put at up to £60 million a year for a 5 year amortisation period. It was far from certain whether operating costs of these systems, either at the centre or for participants, would change compared to now. For the latter, it was postulated that there might be an extra £30 million a year of expense. Thus, the total yearly costs for 5 years might be of the order of £100 to £110 million. The costs attributed to RETA should be strictly the additional costs of implementing new trading arrangements, over and above those that would have been incurred in any case under the current trading arrangements. In estimating the set-up costs to be incurred, the calculation of avoided costs is particularly hazardous, not least because the number of participants might be substantially increased under the new trading arrangements. To ensure that total cost estimates are not biased in favour of RETA we present set-up costs without offsets. As will be seen, further consideration since the July 1998 proposals has not altered the order of magnitudes of the cost estimates.

As in the July 1998 paper, the costs presented here are divided into costs that will be borne at the centre, and those to be incurred by participants themselves. Within both of these categories, costs are further sub-divided into set-up costs and operating costs.

12.1 Central Costs: Set-Up

These costs include costs which have been and will continue to be directly incurred by the Programme in establishing the new trading arrangements (with the exception of Programme procurement costs, which are addressed separately below). These Programme costs relate to the costs of staff, consultants, contractors, legal advice and drafting, accommodation, IT, etc.

Support has been provided to the Programme by a number of consultants and contractors in the key areas of economic and industry consultancy, legal advice and programme management. Secondees and other staff have also been made available by Pool Members from the Chief Executive's Office and some of these costs have been covered by the Programme budget.

The procurement costs incurred by the Programme include the costs of the procurement team, Tender Evaluation Board, ITT production, procurement legal support, management of suppliers, and the costs of the systems and services being provided by suppliers. There will also be costs incurred in establishing the BSCCo.

Central costs of putting new arrangements in place will include a number of components, notably:

- the costs of developing detailed market rules and writing system specifications;
- the costs of system hardware, such as computing and telecommunications facilities, and the costs of software to interface with the new market;
- the costs of training and developing staff to operate under the new arrangements;
- the costs of testing systems before they go 'live'; and
- procurement costs.

The July 1998 proposals estimated these costs at £50m to £100m. For the purposes of illustration, it adopted the convention, followed here, that the recovery period for these would be 5 years, in equal yearly amounts. This gave an annual cost estimate of £10m to £20m.

The initial steps involved in the procurement process have already begun. These will allow firmer estimates of these costs to be develop in the next few months. Estimates of other centrally incurred costs will also become clearer. It would be imprudent to give further cost estimates while a competitive tendering process is proceeding. But we have no reason to suppose that the July 1998 figures will be increased in any significant way.

12.2 Central Costs: Operating

Operating costs are defined as the costs of operating the Balancing Mechanism and Imbalance Settlement processes and systems.

The July 1998 Proposals stated that the Pool's annual operating budget is about £30m. It is not clear that the central operating costs of the new arrangements once in place would be significantly higher than the operating costs of the present arrangements. Many of the major elements will be broadly the same. Some functions of the present arrangements will disappear and new ones will replace them. No net change in central operating costs is anticipated.

12.3 Participants' Costs: Set-up

Participant Numbers

Participants who may face set-up costs will include NGC in respect of certain of its activities, the existing Pool Members and new players. The total costs will depend on the numbers who will participate in the new markets. For estimating purposes it is assumed that around 100 participants, signatories to the BSC, will be active in forwards and futures trading markets, including power exchanges. Of these, roughly 50 will be in addition to the present Pool membership. As to the Balancing Mechanism, it is assumed all the existing generators and demand side bidders will be active along with 20 new participants.

It has been argued that players will be distributed as follows: 100 will require trading systems to interface with power exchanges and other futures markets ("Trading systems"); interface to the Balancing mechanism will involve 70 players in total, of whom 50 will require modifications to their existing systems and 20 will need newly built systems. Interfacing to Settlement will involve all 100 players. There will also be a general need for all 100 players to realign their own financial systems to participate, but in varying degrees. Legal costs will also be incurred, as will other renegotiation costs. The following paragraphs set out the estimated costs involved for the different elements. The categories of cost and the level of cost have been tested with prospective participants who have provided much helpful advice.

Trading Systems

An interface to trading systems (e.g. a Power Exchange) is likely to require standard items based on standard non-specialised hardware and operating systems. Such items are unlikely to be at very high cost, estimated at £1m per participant. All participants would be expected to trade through contracts and thus all 100 participants will require new systems. Thus, the total costs might amount to £100m at maximum.

Interface to Balancing Mechanism

Hardware and software will be needed to connect to NGC's existing system for the control of the network. Most participants wishing to be active in the Balancing Mechanism will already have such a connection. Modifications may be necessary for these to deal with different bid/offer formats and frequency, which would not be expected to be very costly. The 20 new participants might incur costs up to £1m. NGC have not suggested that the existing "backbone" will be unable to support the anticipated new bids and offers.

This interface will give rise to a maximum cost of £20m for new participants.

The Balancing Mechanism information system is likely to be low cost to provide and to connect to. The 50 existing players would incur modest costs of, say, £100 K each resulting in a total cost of £5 m.

Thus, the costs for participants for this category might in total be £25m.

New Interfaces to Settlement

The data and cash flow (albeit for smaller amounts) from Settlements will be similar to today's which are based on half-hourly volumes and charges. Assuming this continues to be dealt with on a daily basis, i.e. 24 hours worth of settlement data batched up and sent out once a day, then the changes will be modest.

All 100 participants would require such interfaces, some of which will be new at the outset, such as for new entrants (e.g. Traders). New players may face a cost of hardware and software to handle settlement reports, which might cost £0.1m per participant. For 50 new players this cost might total £5m.

The existing players might face modifications totalling £2-3m. In total, settlement interfaces may cost around £5m plus £2-3m, i.e. £7m to £8m in all.

Internal Finance System Re-alignment

Existing players' internal finance systems are oriented towards gross income coming through the Pool and modest adjustments through contracts. The RETA arrangements will reverse that. In some cases this may simply require scaling up and down the existing systems, in others it may require complete replacement. The costs will include staff and consultancy expenses as well as the cost of physical systems. Complete replacement is likely to be very costly, say £10m per participant. Others may take a simpler approach to trading, thus requiring less sophisticated systems. There will also be a need for the development of risk management systems for those participants for whom this is a new requirement (those with existing and significant trading interests will, it is assumed, already have this capability). In other cases, it will probably be possible to combine the developments. Still others will be taking the opportunity to integrate the RETA changes with a wider upgrading of business systems so that the additional expenditure attributable to RETA will be difficult to identify.

20 participants might be expected to be heavily affected in one or other of the above ways at a total cost of the order of £10m per participant. More modest changes might be required by 80 participants at a cost of £0.1m each.

The financial realignment costs may therefore be around £208m in total.

Legal Costs of PSA, BSC Changes

These are the costs that participants will face in reviewing the new and old legal documentation in order to agree to sign. They will consist primarily of legal fees.

This will impact on all 100 participants at a cost each of £0.1m, a total of £10m.

12.4 Other Renegotiation Costs

The following set-up costs of renegotiation of various kinds will also be incurred: termination of contracts, Power Purchase Agreements (PPA), project finance renegotiation and credit provisions.

The Electricity Pool of England and Wales may face some costs of termination when the PSA ceases to apply. These have been put as high as £40m, and would fall in a proportional manner on all Pool Members under the PSA rules.

PPAs generally refer to Pool prices and use this as the basis for settlement. Furthermore, some PPAs apparently include Pool rules algebra to deal with the allocation of different elements of the revenue (e.g. capacity versus energy). They are often back-to-back with fuel and financing contracts. The latter contracts could be costly to re-negotiate (ignoring any loss to either side in the outcome of the renegotiation). The costs will be in management time and legal fees. 15 affected participants might incur costs as high as £1m each, leading to a total of £15m.

Project finance renegotiation will involve similar costs to the renegotiation of PPAs, but will in addition involve various banking consortia. Many of these consortia include 10 or more banks around the World. The estimated cost is doubled to account for the multiplicity of banks to give a total of £30m.

Credit cover will be required for participants. This is required by the PSA at present but the new arrangements may call for different terms. The generation side will be potential debtors and so will have to put in place credit cover. This is not necessary under the current Pool arrangements. Appropriate cover may require letters of credit or cash deposits for companies with a low credit rating.

The cost of this is very difficult to evaluate. A total of £15m could be assumed as a conservative estimate.

In total, renegotiation costs of all kinds will occur as follows:

Termination	£40m
PPA	£15m
Project finance	£30m
Credit provision	£15m
Total	£100m

Modifications to NGC and Pool Systems

The two main areas likely to be affected are NGC system operation systems and the Stage 2 systems of the Pool. The impact on each of these is not yet known in detail. Plausible costs can be estimated from the costs of other recent changes. NGC has recently replaced its scheduling software in partnership with Pool Members. The total cost of this was about £14m. Other software has been developed for monitoring generator performance against instruction and aggregating instructions to half hourly implied volumes. The costs for this were of the order of £1m. Thus, allowing for one such major change and a number of smaller changes, a figure of £20m would be an appropriate estimate for the costs of changes to NGC's system operation software.

The Stage 2 software is new and is still being developed. The impact on this of RETA is expected to be modest. Nevertheless, any changes may be difficult to incorporate at this stage and expensive. It would be prudent to allow up to £10m for the costs of making any changes to the Stage 2 software.

Based on these experiences, costs in these two areas might amount to a maximum of £30m in total.

12.5 Summary

Bringing participants' potential set-up costs together, this section has identified the following:

Trading systems	£100m
Balancing interfaces	£25m
Settlement interfaces	£8m
Financial realignment	£208m
Legal	£10m
Other renegotiated costs	£100m
NGC and Pool systems	£30m
Total	£481m

The total of £481m for participants' set-up costs is a figure intended to indicate the upper end of a likely range. Discussants were, in general, inclined to believe the figures would be somewhat lower.

Converting this into an annual cost, participants might be expected to incur at most £96m of costs per annum.

12.6 Participants' Costs: Operating

As with central operating costs, it is not clear that the operating costs to market participants would be significantly different from those under the present arrangements. There would be different markets, processes and software, with some different skills required and perhaps some different staff. But the basic tasks of estimating costs and market trends, scheduling plant, trading and hedging, settling accounts and so on, all have to be carried out and paid for under the present system. Nevertheless, there would be greater emphasis on trading in the new arrangements.

The July 1998 Proposals suggested that for illustrative purposes, it could be assumed that the annual operating costs might increase by up to £1m per major participant. It assumes there would be 30 such major participants, giving a total of around £30m per year. As seen earlier, more work on likely participants has identified a larger number who will, to varying degrees, incur costs. Only a limited number will be faced with the comprehensive participation assumed in the earlier estimate. Further work is underway in this area, drawing on the views of market participants themselves. Meanwhile, we see no reason to adjust our estimate of £30m a year as a "ball park" figure.

Bringing both the estimates of set-up costs and operating costs together, we reach an estimate of total costs as follows:

Set-up costs, yearly, over 5 years	
Central	£10-20m
Participants	£96m
Operating costs, yearly	
Central	No change
Participants	£30m

In total, they suggest a range of £136m to £146m; somewhat higher than the July 1998 papers' range of £100m to £110m. As seen earlier, no adjustment has been made for the avoided costs of developments of the Pool arrangements. A substantial development programme was being contemplated.

Work to refine the estimates further is being carried forward.

12.7 Recovery of Costs

This section discusses the proposed cost recovery mechanisms for the central costs. With respect to participants' set-up and operating costs, it will be for market participants to determine the level of investment that reflects the trading activities they plan to undertake. Participants will then need to factor the recovery of their set-up and operating costs within their trading activities.

Central Costs: Set-up

It is currently proposed that the costs incurred by the Programme in establishing the new trading arrangements (excluding procurement costs) will be recovered from market participants' licence fees.

In line with agreements reached during the Policy Development Phase, NGC will, in the first instance, be the contracting party for systems and services procurement and hence will bear these procurement costs. This agreement was reached on the basis that it would be inappropriate for the Regulator or the DTI to undertake the procurement role. Further, the solution of NGC acting in this role is consistent with the approach being adopted on governance. It is envisaged that these costs will subsequently be recharged by NGC to market participants possibly via an element of imbalance cashout prices.

Central Costs: Operating

The mechanism for the recovery of these costs will initially be set as BSCCo is established, and thereafter will fall within the remit of BSC Panel governance. It is currently envisaged that these costs will be recovered from all BSC signatories on the basis of metered and contract volumes notified as part of the imbalance settlement process.