May 2001

Transmission Access and Losses under NETA

A Consultation Document

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Summary

On 27 March 2001, New Electricity Trading Arrangements (NETA) were implemented in England and Wales (E&W). NETA saw the introduction of new arrangements for the wholesale electricity market similar to those in operation in other commodity markets. NETA was designed to bring greater competition to the wholesale electricity market to ensure that wholesale prices better reflected underlying market conditions, to the benefit of customers.

In December 1999, Ofgem issued a consultation document setting out our initial thoughts on a number of issues including the need for and possible approach to new transmission access and pricing arrangements and enduring arrangements for the treatment of transmission losses for the National Grid Company's high voltage transmission system in England and Wales. In the document, Ofgem argued that new transmission access, pricing and losses arrangements were necessary to complement the NETA reforms and ensure that the full benefits of NETA were realised by customers.

The document also proposed introducing a new Connection and Use of System Code (CUSC). The CUSC will provide a new contractual framework for connection to, and use of, National Grid Company's (NGC) high voltage transmission system in E&W. It will introduce more flexible governance arrangements that will enable arrangements for connection to and use of NGC's transmission system to develop over time. In particular, it will provide the contractual framework for the introduction of new transmission access arrangements. It will also clarify the role of the regulator in settling disputes over access to the transmission system. Following extensive consultation with the industry and other interested parties over the last year, the Secretary of State is expected to exercise powers granted to him under the Utilties Act to implement the CUSC in the next few weeks.

The purpose of this document is to set out for further consultation developments in Ofgem's thinking in these areas. The issues and options considered in this document build on the initial thinking presented in the December Consultation, in the light of responses received to that document and following further consultation at various public workshops and industry meetings held since the December Consultation was published.

The need for reform

The initial NETA arrangements for transmission access and losses share many of the features of the old Pool arrangements and are deficient in a number of respects, including:

- the possibility that traded electricity markets under NETA could be distorted by inappropriate transmission arrangements. Electricity prices might be influenced by transmission effects in ways that could reduce market liquidity and lead effectively to market segmentation. This, in turn, could give rise to increased opportunities for locational market power to be exercised;

- Participants will not receive appropriate economic signals related to short-term transmission losses, transmission constraints and locational decisions for major new connections and disconnections, particularly power stations, because participants can impose costs on NGC from their use of the system which are not reflected in their use of system charges;

- NGC will also not receive efficient signals and incentives with regard to both operating the system and investing in it to meet customers' needs; and

- the initial NETA arrangements for transmission access are not consistent with those in the gas market. Given the increasing convergence between the two markets this could lead to inefficient or perverse arbitrage decisions being taken by participants.

Objectives of reform

Ofgem believes that the four most important objectives for new transmission access and losses arrangements, which will address all of the deficiencies identified in the initial NETA arrangements, are:

- **NETA related effects:** to ensure traded electricity markets are not unduly distorted by transmission related actions and effects and the exercise of locational market power, by separating the pricing of energy from the pricing of transmission capacity, thus ensuring transparency in the actions of all participants;

- **Short and long term efficiency issues:** to establish a framework that more accurately targets the short and long term costs imposed on the transmission system by the locational patterns of generation and demand;

- **NGC investment signals and incentives:** to provide effective signals to and unified incentives on NGC to make transmission capacity available in the short term and to invest appropriately in transmission capacity in the long term; and

- **Gas – electricity interactions:** to provide the framework for efficient and effective interactions between the gas and electricity markets in the short and long term.

Ofgem considers that the best means of achieving these objectives is the establishment of firm tradable access rights and appropriate charging for transmission losses.

Transmission losses

Ofgem continues to believe that the enduring scheme for transmission losses should incorporate more efficient arrangements for the charging of transmission losses including the use of locational marginal loss factors. We have considered two general approaches:

- **Option 1** would be to adjust participants' metered volumes using estimates of average zonal loss factors. A separate financial payment or levy, calculated to reflect the difference between estimated marginal loss factors and the average factors used to adjust metered volumes, would be included in the Balancing Services use of System Charges (BSUoS); and

- **Option 2**, originally proposed by NGC, would be to use estimates of the costs of marginal locational losses to set loss related reserve prices in any auctions for access rights.

Ofgem considers that the first option is preferable because it is a more market based approach and, unlike the second option, would not require administered estimates of the costs of the losses to be made. Moreover, if Option 1 were to be adopted, it might be possible to implement a more cost reflective regime for transmission losses independently of the implementation of transmission access arrangements. However, we accept that the further consideration should be given to both the options that have been put forward.

Transmission access

Ofgem remains of the view that the introduction of a market in firm access rights is likely to be the most effective way of meeting the objectives for reform outlined above. In order for a market in firm access rights to be successful, the rights to be traded must be defined in a way which ensures that:

- they can be valued in the primary and secondary access markets by all participants, given the most up to date information available to them;
- they are capable of reflecting effectively the underlying physical characteristics of the transmission network; and
- they are capable of reflecting the temporal and spatial nature of transmission constraints.

There are a number of different ways in which these objectives can be achieved, but Ofgem considers that the implementation of a system based on firm entry and exit access rights has considerable merits. It will be important that these rights are allocated in a non-discriminatory way, which allows the value that participants place upon them to be revealed in an efficient manner. Ofgem remains of the view that the auctioning transmission access rights is an efficient means of achieving these aims. Thus, one option would be to employ auctions for both entry and exit rights, with secondary trading being used by participants as well as the System Operator (SO) to fine tune their positions and an access imbalance regime designed to incentivise participants to match their physical positions to their access right holdings.

However, we accept that the extent to which the demand side as a whole can help to resolve constraints may be limited as compared to the generation side of the market (although individual large customers may have an important role to play), particularly if it is considered impractical to adapt their current registration and data collection systems[1] to allow for greater regional differentiation of access rights on the demand side. Hence, Ofgem considers that it may be better to concentrate on arrangements for the demand side that facilitates this kind of approach. Thus, whilst our initial view is that generation (entry) access rights should be auctioned, we believe that it might be preferable to allocate firm exit rights to all consumers in return for the payment of a locationally varying access charge, possibly set on the basis of the prices emerging from the primary auction of entry rights.

A firm access rights regime means that participants must purchase sufficient access rights to match the amount of electricity they wish to transmit across the transmission system (i.e. a 'ticket to ride'). A firm regime also means that NGC must repurchase access rights that it has previously allocated, if it fails to deliver them. To ensure participants purchase sufficient rights, some form of imbalance regime which incentivises participants to purchase access rights consistent with the amount of electricity they expect to input into and offtake from the transmission system will be needed.

We believe that the allocation process should make available the maximum possible volume of access rights (given the transmission network in place) through a combination of the primary allocation mechanism and appropriate incentives on NGC to release further capacity in the short term (including close to real time) and invest in further capacity, where efficient and economic, in the long term. Thus, it will be important that NGC faces unified incentives with respect to constraint alleviation through a link between transmission output measures defined as part of the Transmission Price Control and the incentives on day to day management of constraint alleviation under the SO incentive schemes. Equally, the SO incentive scheme will need to deliver consistent signals with regard to NGC's actions in electricity balancing, system balancing and access right trading. Ofgem considers that NGC should be fully exposed to the costs of

[1] Supplier Volume Allocation (SVA) system, known as Stage 2 under the Pool.

constraints where it fails to invest to deliver output measures agreed as part of the Transmission Price Control and should be allowed to earn additional revenues where it exceeds them. In this way, NGC should be incentivised to invest in the transmission network to meet customers' needs where it is efficient to do so. Such an approach would be consistent with the long term investment regime proposed for Transco's National Transmission System (NTS) in gas.

With respect to the form and structure of transmission charges after the introduction of new transmission access and pricing and losses arrangements, Ofgem believes that some adjustment to the basis for calculating Transmission Network use of System Charges (TNUoS) is likely to be required. Specifically, it may be appropriate to reduce or remove the locational differentiation in TNUoS charges and to move to a per MWh charging arrangement for all generation and demand.

Way forward

Following publication of this document, Ofgem will consider the responses received. We plan to issue a further paper, setting out our views on these responses, and our subsequent thinking on the issues raised in this consultation paper and on the general direction of the overall design of the new arrangements.

Following the publication of this further paper, the next step will be a design phase for new transmission arrangements to be led by NGC, in consultation with all interested parties. Ofgem expects substantial progress on the detailed design of the arrangements to have been made by the end of the year.

We envisage that modifications to the CUSC will be the main vehicle through which new transmission access arrangements will be implemented, which Ofgem will need to approve. Thus, following completion of the design phase, detailed modifications to the CUSC to implement the new regime will need to be proposed, drafted and submitted for approval via the CUSC governance arrangements. In addition, changes are likely to be required to NGC's transmission licence and its charging methodologies. Modifications may also need to be raised in respect of the Balancing and Settlement Code (BSC), particularly with regard to the treatment of transmission losses.

Ofgem's vision for harmonising arrangements in Scotland with England and Wales involve the development of a single BSC for Great Britain (GB), a single GB CUSC, a single market for settlement purposes, common principles for transmission access and for setting transmission charges and changes to the role of the three transmission companies in GB. While this consultation paper is set in the context of the E&W institutions and arrangements, it is anticipated that the majority of the principles and concepts discussed within it would be applicable to GB wide access arrangements under a GB electricity market based on NETA.

1. Introduction

The purpose of this document

1.1 The New Electricity Trading Arrangements (NETA) were implemented in England and Wales on 27 March 2001. In December 1999, Ofgem issued a consultation document (the 'December Consultation')[2] setting out our initial thinking on a number of changes to the regulation of transmission and system operation under NETA. These included the role of, and incentives on, the National Grid Company plc (NGC) as both System Operator (SO) and Transmission Asset Owner (TO) under NETA, new transmission access arrangements and enduring arrangements for the treatment of transmission losses.

1.2 The purpose of this document is to set out for further consultation developments in Ofgem's thinking on transmission access arrangements and enduring arrangements for the treatment of transmission losses under NETA. The issues and options considered in this document build on the initial thinking presented in the December Consultation, in the light of responses received to that document and following further consultation at various public workshops and industry meetings.

1.3 Subject to designation by the Secretary of State, Ofgem expects the new Connection and Use of System Code (CUSC) to be implemented shortly. Modification to the CUSC will be the main vehicle through which new transmission access arrangements will be implemented. As a result, following the publication of this document and the designation of the CUSC, an industry wide consultation will begin, led by NGC, to develop detailed proposals for new transmission access arrangements for England & Wales.

1.4 The design of the transmission access arrangements in England & Wales will be of importance for the development of Great Britain (GB) wide electricity and transmission arrangements as part of the British Electricity Trading & Transmission Arrangements (BETTA) project. It is anticipated that the GB

[2] 'NGC System Operator Incentives, Transmission Access and Losses under NETA, A Consultation Document', Ofgem, December 1999.

arrangements will be based on the underlying principles established for new arrangements in England and Wales.

The process to date

The December Consultation

1.5 In the December Consultation, Ofgem argued that, in keeping with the principles underlying NETA, new transmission access arrangements should create a framework for the establishment of traded transmission markets. This would: establish the value of transmission access and help ensure electricity transportation is efficiently priced; avoid complex centrally administered solutions wherever possible; and be open, transparent and non-discriminatory, promoting competition. Ofgem's initial preference was for development of an approach based around the allocation and trading of firm access rights. We suggested that the firm rights could be allocated through open auctions and then be traded in secondary markets.

1.6 Under these arrangements, NGC would buy-back access rights from participants and sell additional rights in order to resolve transmission constraints. NGC would also be able to sell any rights made available but not purchased in the initial auction. 'Use it or lose it' provisions would be required to prevent the hoarding of access rights which could distort the operation of the market in firm access rights; thus, we suggested that access rights that had been purchased but remained unused should be made available to other participants. The access rights would be financially firm. Participants would face over-run charges (and possibly under-run charges) if their metered volumes exceeded their access rights and NGC would have to buy-back, ahead of the trading period, any access rights it sold but was unable to deliver due to constraints and other transportation problems.

1.7 Ofgem's initial view on the treatment of transmission losses was that marginal losses should be charged to all participants on an *ex ante* zonal basis. The metered volumes of both generators and suppliers would be adjusted using marginal locational loss factors, prior to the calculation of energy imbalances. Ofgem considered that this approach would provide the most appropriate signals to market participants of the costs of losses associated with generation and production in different locations. Any surplus revenues generated by such a scheme would be offset against other transmission costs.

1.8 Given the locational signals emerging from the proposed transmission access and losses regimes, Ofgem suggested that it might be necessary to consider changing the structure of Transmission Network Use of System (TNUoS) charges.

Industry workshops and further consultation

1.9 Since December 1999, Ofgem has given further thought to the details of how a transmission access regime based on firm entry and exit rights might work in practice. These issues have also been discussed in seminars at the Charging Principles Forum of the Transmission Users Group (TUG-CPF) in February 2000 and June 2000 and were discussed further at the NETA Seminar in June 2000.

1.10 Ofgem held an industry workshop in August 2000 (the 'August Workshop') that focused on two key issues concerning the proposed transmission access arrangements: the core design issues related to the trade-offs involved in defining firm entry and exit rights and the systems requirements for the proposed transmission access regime. NGC and other participants made valuable contributions to this debate.

1.11 Ofgem asked those that attended the August Workshop to provide written responses to some of the issues discussed including the appropriate definition of access rights, the benefits of a new transmission access regime and the possible cost of systems required to implement any new arrangements.

Outline of this document

1.12 The first part of this document sets out the background to and an overview of the proposed new arrangements. Chapter 2 discusses the current and future regulatory and legal framework and provides some background on the treatment of losses and transmission constraints at the start of NETA. Chapter 3 discusses why new transmission access and pricing arrangements are needed and considers what objectives should be considered in evaluating potential reforms. Chapter 4 describes the process to date. Chapter 5 presents an overview of Ofgem's current thinking on the design of new transmission access and losses arrangements. Chapter 6 presents a possible overall approach to transmission access and losses arrangements and Chapter 7 considers the way forward and summarises the key issues on which views are invited.

1.13 The second part of this document contains a number of appendices that consider in detail, the key design features of the proposed new arrangements.

1.14 Appendix 1 considers the spatial and temporal definition of the transmission access rights, whilst Appendix 2 considers how firm access rights could be allocated and the basis for defining a volume of access rights to be made available. Appendix 3 discusses the role and form of secondary markets in access rights, NGC's involvement in secondary trading and the ways in which NGC may be incentivised in relation to such trading. Appendix 4 examines the interactions between new transmission access and pricing arrangements and the electricity market regime under NETA. Appendix 5 considers how access rights can be made firm on all participants, for example through the introduction of access rights imbalance charges. In particular, it discusses how such charges might be determined and applied. In Appendix 6 we discuss the treatment of transmission failures. Appendix 7 looks at the interactions between the proposed transmission access regime and the Transmission Price Control. Appendix 8 discusses the enduring treatment of transmission losses in England and Wales. Finally, in Appendix 9 we focus on the development of systems and processes required to implement new transmission access and losses arrangements.

Related issues

Connection and Use of System Code

1.15 The December Consultation highlighted some problems with the existing contractual arrangements governing connection to, and use of, NGC's transmission system. In particular, it expressed concern that the procedures for modifying the Master Connection and Use of System Agreement (MCUSA) and its Supplemental Agreements[3] were slow and cumbersome. It also discussed the

[3] Parties to the MCUSA are required to sign appropriate Supplemental Agreements. These set out the terms for connection to and use of the transmission system and for payment to NGC of connection charges and use of system charges. A separate Supplemental Agreement is in place between NGC and each user of a site connected to the transmission network. There are presently in excess of 400 agreements in place. The Supplemental Agreements specify the equipment at each connection site and the basis of charging for that equipment.

lack of clarity in relation to the resolution of disputes under the MCUSA. Ofgem proposed that the current MCUSA be replaced with a new CUSC which would incorporate more flexible governance procedures similar to those in place for the Network Codes of gas transporters and for the Balancing and Settlement Code (BSC) under NETA. Dispute resolution procedures under the CUSC would be made clearer, allowing for a more transparent and streamlined regulatory framework.

1.16 In March 2000, Ofgem/Department of Trade and Industry (DTI) published a consultation document (the March CUSC document[4]) which set out our initial views on the content and scope of a CUSC and the changes to licence conditions that would be required to implement it. Ofgem/DTI proposed that the CUSC would be designed to cover most transmission-related issues (connections, transmission access and use of system obligations and charges, and provisions relating to mandatory balancing services.[5]) and perhaps some elements of the incentive scheme on NGC as SO. The CUSC would comprise of provisions currently contained in the MCUSA, generic elements of the current Supplemental Agreements in relation to connection and use of system and the provisions of the Ancillary Services Agreements, so far as they relate to balancing services. It would contain new provisions relating to disputes and governance. Site specific data and charges would form individual bilateral agreements to be agreed between NGC and the relevant party.

1.17 The March CUSC document was followed by another consultation document in June 2000 (the June CUSC document[6]), that set out Ofgem/DTI's initial thinking on the detailed legal drafting of the changes to licence conditions 10, 10A, 10B and 10C of NGC's licence, which contain provisions relating to connection and use of system.

[4] 'NGC's Connection and Use of System Code. An Ofgem/DTI consultation on the scope and content of the Connection and Use of System Code', Ofgem/DTI, March 2000.
[5] It might also potentially cover Transmission losses.
[6] 'Connection and use of System Code. Proposed changes to the National Grid Company's licence. A consultation document', Ofgem, June 2000.

1.18 In August 2000, Ofgem/DTI published a further document (the 'August CUSC document[7]) that summarised the responses to the March and June documents. It set out Ofgem/DTI's final proposals for the content and scope of the CUSC and the necessary changes to NGC's licence and the proposed new licence conditions for generators, Public Electricity Suppliers (PESs) and second tier suppliers. It was proposed that the CUSC licence conditions would also apply to all relevant distributors, when distribution licences are introduced.

NGC consultation

1.19 Following the publication of the August CUSC document, NGC completed a consultation process on the detailed drafting of the CUSC. NGC published a consultation document on the CUSC and an initial draft of the CUSC in September 2000. This consultation invited nominations for working group attendees. Working group sessions involving industry participants took place in October and December 2000, looked in detail at the various sections of the CUSC and an updated draft of the CUSC was placed on NGC's website.

1.20 NGC provided Ofgem/DTI with its proposals on the detailed drafting of the CUSC and an initial version of its charging methodologies and charging statements to close the consultation process, in late December 2000.

Further Ofgem/DTI consultation

1.21 In December 2000, Ofgem/DTI published a further consultation on the CUSC,[8] which outlined the potential need to make a number of changes to the proposed licence conditions. This need had been identified during the course of NGC's consultation on the CUSC.

1.22 In February 2001 Ofgem/DTI published a consultation document[9] (the 'February 2001 CUSC document'), which set out Ofgem/DTI's initial views on the draft CUSC provided by NGC following its consultation process and on the licence conditions necessary for implementing the CUSC. Following receipt and consideration of responses to this document, Ofgem/DTI published a

[7] 'NGC's Connection and Use of System Code: scope, content and licence changes – an Ofgem/DTI final proposals document', Ofgem/DTI, August 2000.
[8] 'NGC's Connection and Use of System Code: further proposed licence changes. An Ofgem/DTI Consultation Document', Ofgem/DTI, December 2000.
[9] NGC Connection and Use of System Code: and associated licence changes. An Ofgem/DTI Document', Ofgem/DTI, February 2001.

conclusions document in May 2001.[10] It is intended that the CUSC and the licence conditions will be designated by the Secretary of State using the NETA power (provided in the Utilities Act 2000) so that the CUSC takes effect as soon as is practicable.

Consultation on NGC's charging methodologies

1.23 Under the licence conditions proposed in relation to the CUSC, NGC is required to produce charging methodologies for use of system and connection, which must meet the relevant objectives specified in the respective licence conditions. These methodologies must be approved by Ofgem. NGC submitted its draft charging methodologies to Ofgem in December 2000. On 9 January 2001, Ofgem issued a letter inviting interested parties, to give views on whether the charging methodology meets the relevant objectives. Ofgem will consider these views in deciding whether to approve the draft methodologies. It is expected that Ofgem will issue a decision document at the time of the CUSC designation.

British Electricity Trading and Transmission Arrangements (BETTA)

1.24 In August 2000, Ofgem published a document outlining interim proposals for the reform of Scottish Trading Arrangements.[11] Ofgem summarised the main factors inhibiting the development of competition in Scotland and proposed that:

- enduring trading arrangements for Scotland should be part of a Great Britain (GB) electricity market;
- enduring transmission access and charging arrangements for Scotland should be part of a GB set of arrangements;
- British transmission and trading arrangements be developed by April 2002; and
- there should be interim arrangements to provide a smooth transition to enduring GB arrangements.

[10] 'NGC's Connection and Use of System Code: scope, content and associated Licence Conditions - An Ofgem/DTI conclusions document', Ofgem/DTI, May 2001.
[11] 'Interim proposals for the reform of Scottish Trading Arrangements: British Electricity Trading and Transmission Arrangements (BETTA)', Ofgem, August 2000.

1.25 Ofgem's vision for harmonising arrangements in Scotland with England and Wales involve the development of a single Balancing and Settlement Code (BSC) for GB, a single GB CUSC, a single market for settlement purposes, common principles for transmission access and for setting transmission charges and changes to the role of the three transmission companies in GB.

1.26 Ofgem has set up a BETTA Steering Group to monitor the overall direction of and progress on the development of harmonised arrangements across GB. Three workstreams have also been formed to consider:

- the commercial and technical issues surrounding the introduction of a GB SO with a GB Balancing Mechanism;
- GB transmission access and charging arrangements; and
- scoping the system changes for GB NETA, including GB settlement and changes to the BSC.

As noted above, the arrangements for transmission access and charging in England and Wales (E&W) are expected to form the basis for GB arrangements. While this consultation paper is set in the context of the E&W institutions and arrangements, it is anticipated that the majority of the principles and concepts discussed within it would be applicable to GB wide access arrangements under a GB electricity market based on NETA. Respondents are invited to read the paper in this context. Ofgem will continue to consult widely on all significant policy matters relating to BETTA.

NGC Transmission Price Control

1.27 In March 2000, Ofgem published a document[12] that set out the form, scope and duration of the next NGC price control, to take effect from 1 April 2001. This provided information on NGC's forecasts of its future operating and capital expenditure requirements.

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[12] 'The transmission price control review of the National Grid Company from 2001, Initial thoughts consultation document, Ofgem', March 2000.

1.28 The document also set out Ofgem's initial analysis of NGC's costs over the period of the next control, including its cost of capital. In June 2000, Ofgem published its initial proposals for the NGC Transmission Price Control.[13]

1.29 In September 2000, Ofgem published final proposals for the NGC Transmission Price Control.[14] The price control proposed for NGC's role as TO was based on the RPI-X formula, with X set at 1.5, and its duration was extended from four to five years. NGC's proposed TO allowed revenues for 2001/02 were set at £758 million, which is equivalent to allowing revenues of £800 million for the transmission business as a whole during the same period. This figure is based on a number of assumptions including a pre-tax real cost of capital of six and a quarter per cent, efficient capital expenditure of £1320 million and efficient controllable operating costs of £1020 million over five years. NGC agreed to Ofgem's proposals and they were implemented from 1 April 2001.

1.30 Although the initial Transmission Price Control proposals included allowances for NGC's internal SO costs, Ofgem decided that it was more appropriate to consider these costs alongside NGC's external SO costs. We believed that the regulatory framework for NGC's SO role should be designed to provide it with strong incentives to reduce total SO costs (both internal and external), as customers ultimately pay for the total costs rather than separate elements. Hence, NGC's SO internal costs were reviewed as part of a separate SO Price Control Review and initial proposals relating to this were also published in September 2000 (the 'September SO Initial Proposals document'[15]). NGC estimated that, following the implementation of NETA, it would need £226m to cover its SO internal costs for the period 1 April 2001 to 31 March 2006. Ofgem proposed that the target for these costs should be reduced to between £216m and £223m. It was proposed that the SO price control should take effect from April 2001, simultaneously with the new TO price control.

[13] 'The transmission price control review of the National Grid company from 2001, Draft proposals', Ofgem, June 2000.
[14] 'The Transmission Price Control review of the National Grid Company from 2001; Transmission Asset Owner, Final Proposals', Ofgem, September 2000.
[15] 'The Transmission Price Control review of the National Grid Company from 2001; System Operation, Initial Proposals', Ofgem, September 2000.

The role of and incentives on NGC as SO under NETA

1.31 Ofgem published a Final Proposals document[16] on SO incentives in December 2000. Ofgem's final proposals presented NGC with the option of four combinations of incentive scheme target, sharing factors and cap/collar in relation to the incentive on SO external costs. These were chosen to provide NGC with a choice of targets and parameters to ensure an effective incentive to manage these costs, which are ultimately borne by customers. NGC accepted the fourth of Ofgem's options which specified a deadband between £471m and £500m, upside and downside sharing factors of 40% and 12% respectively, and a cap and collar of £45m and £15m respectively.

1.32 The Final Proposals also contained Ofgem's views on appropriate revenues and incentives for NGC's internal SO costs. Revenue targets (including both incentivised and non incentivised elements) were proposed for the period 1 April to 31 March 2006. However, recognising the importance of aligning NGC's incentives with regard to controlling internal and external costs, the other incentive scheme parameters were only set until 31 March 2002. The same sharing factors as for the SO external scheme (namely 40% upside and 12% downside) were proposed but no cap or collar (except in relation to BSC Contingency Provisions[17]) was set. NGC also accepted the incentive arrangements proposed for SO internal costs.

[16] 'NGC system operator price control and incentive schemes under NETA, Final proposals', Ofgem, December 2000.

[17] In relation to Manifest Errors in Balancing Mechanism Transactions and Special Provisions for Computing Systems Failures (collectively known as Contingency Provisions), NGC may, in certain circumstances, be required to pay compensation to BSC Parties as a result either of Manifest Errors that it makes (in relation to the accepting of bids or offers in the Balancing Mechanism) or of the failure of its computing systems. An incentivised cost-recovery mechanism for such costs is included within the internal cost Balancing Services Activity revenue restriction, which operates on a monthly basis and provides that NGC is exposed to 40% of any Contingency Provision costs it incurs in any month, subject to an overall cap on its exposure of £250,000. Thus, if the Contingency Provision costs it is exposed to exceed £625,000 (£250,000/0.4) in any month, NGC will be allowed to pass through in full the costs in excess of £625,000. Equally, if as a result of NGC making a Manifest Error, it receives compensation so that overall it receives Contingency Provisions payments in any month, then these revenues will be passed through in full.

1.33 Following a consultation on the proposed licence drafting in February 2001, NGC has agreed to the necessary modifications to its licence to implement the new TO and SO internal cost price controls from 1 April 2001 and the SO external cost incentive scheme from the start of NETA. NGC as SO will, under the form of the proposed arrangements for transmission access and pricing described in this document, face a number of changes in its role from that at the start of NETA. Therefore, the implementation of such arrangements will require changes to both the form and parameters of the incentive schemes on NGC as SO.

Further reform of the gas balancing regime

1.34 In February 2001, Ofgem published a document[18] that set out for consultation Ofgem's proposed further changes to the gas balancing arrangements in Great Britain. The consultation document assessed the operation of the current gas balancing regime and identified inefficiencies which, given further interactions with the electricity market and greater trading across the gas interconnectors, are likely to increase in the future in the absence of reform.

1.35 Ofgem has proposed a number of reforms to the gas balancing regime in the light of this assessment, including: shorter balancing periods for shippers; the sale of linepack (via price auctions) to help shippers operate with the shorter balancing regime; revised cash-out of imbalances; and increased information provision to market participants and others. Ofgem also outlined proposed reforms to Transco's SO incentives and role, consistent with the new SO arrangements for NGC under NETA. The reforms proposed include: allowing Transco greater contractual freedom to enable it to act efficiently in its role as residual gas balancer and a new licence condition to re-enforce Transco's obligation to operate an efficient and economic system.

Long term signals and incentives for investment in transmission capacity on Transco's National Transmission System (NTS)

1.36 It is important that, over time, the incentives on transmission asset owners and SO in the gas and electricity markets are consistent, to ensure efficient

[18] 'The New Gas Trading Arrangements, Further reform of the gas balancing regime, A Consultation Document', Ofgem, February 2001.

interactions between the two markets. In May 2000, Ofgem published its initial review and proposals for improving signals and incentives for investment in Transco's NTS. The document proposed extending the use of capacity auctions to cover longer term capacity rights based on output measures agreed as part of the next Price Control Review, subject to improved output related incentives on Transco, based on these output measures. Ofgem discussed these issues at a seminar on Transco's Price Control Review held on 9 August 2000.

1.37 Subsequently, in December 2000, Ofgem issued a document[19] that summarised respondents' views on the initial proposals put forward in May 2000, drew conclusions on the framework for improving long term investment and outlined a number of issues for consultation.

1.38 In March 2001, Ofgem detailed proposals[20] for improving the long term signals and incentives for investment in Transco's National Transmission System (NTS). The reforms will be introduced to coincide with the introduction of Transco's new price control in April 2002. The document sets out the overall framework designed to improve Transco's incentives to ensure that it invests in the NTS to meet customers' needs where it is efficient to do so. The framework seeks to achieve this by fully exposing Transco to the costs associated with constraints at entry and exit that arise due to its failure to invest to deliver output measures agreed as part of the NTS price control, and by allowing it to earn additional revenue where it exceeds the agreed output measures.

1.39 Ofgem also proposes the use of longer-term auctions of entry capacity rights. Under the incentive framework, Transco's investment will respond to the price signals emerging from these auctions and from secondary trading of capacity. The document also outlines the interrelation between the transmission operator and SO price controls. The framework proposed will fully align Transco's incentives relating to capital expenditure with those relating to operating expenditure under the price control. Under the existing price control, any reduction in operating expenditure below the target level set as part of the price control is retained by Transco for the duration of the control. Similarly, Transco

[19] 'Long term signals and incentives for investment in transmission capacity on Transco's National Transmission System: Conclusions on the framework', Ofgem, December 2000.
[20] 'Long Signals and Incentives for Investment on Transco's National Transmission System - The New Regime', Ofgem, March 2001.

is fully exposed to any increase in operating expenditure above the target level set. Under the new framework proposals, incentives on capital and operating expenditure for a given level of NTS capacity outputs will be fully aligned.

1.40 Ofgem also published a document that puts forward consistent proposals for reform of the exit capacity arrangements within the new long-term signals and incentives framework (see below).

The Transco price control review

1.41 Ultimately, any proposals to implement new arrangements for the allocation of longer term capacity rights will be taken forward as part of Ofgem's work on setting the next Transco price control, which is scheduled to commence from April 2002. Further information on the Transco price control process can be obtained from the Ofgem consultation documents published in May 2000 and November 2000.[21] Following the papers in May and November 2000, Ofgem published an initial thoughts consultation paper in February 2001[22] on the form and structure of Transco's price control including the output framework. Ofgem is planning to publish an initial proposals consultation document on the price control in June 2001 with a final decision to be made in September 2001.

Exit and interruption regime in the gas market

1.42 In March 2001, Ofgem published a review[23] of Transco's NTS exit capacity, interruption and Liquefied Natural Gas (LNG) arrangements. The review identified a number of weaknesses in the current arrangements and set out Ofgem's proposals for reform. Ofgem argued that it is important that the arrangements for entry capacity, exit capacity and gas balancing are consistent to reduce the scope for perverse incentives on Transco and/or other market participants.

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[21] 'Review of Transco's price control from 2002: Initial Consultation Document', Ofgem, May 2000. 'Review of Transco's Price Control from 2002: Update Paper', Ofgem, November 2000.
[22] 'Review of Transco's price control from 2002: Initial thoughts consultation document', Ofgem, February 2001.
[23] 'The New Gas Trading Arrangements: Review of Transco's exit capacity, interruption, and liquefied natural gas. A consultation document', Ofgem, March 2001.

1.43 In reforming the existing arrangements Ofgem argued that it would be desirable to establish market-based arrangements that establish the relative price of firm and interruptible exit capacity.

1.44 Under Ofgem's proposals:

- all load at exit would be deemed firm and customers would pay the relevant NTS transportation exit charge. Customers would be free to enter into longer term exit arrangements of, for example five years, that guaranteed them exit capacity in return for an obligation to pay the relevant exit capacity charge;

- Transco would hold auctions (over varying durations of for example five/three/one year and monthly and daily) to determine the price and duration of interruptible services that customers would be willing to offer and would enter into interruptible contracts with customers who offered the best terms;

- Transco LNG and/or shippers and customers holding firm entry capacity rights would be able to participate in these auctions; and

- Transco would then be able to call on these interruptible contracts to manage network constraints and/or energy imbalances where it was efficient to do so.

1.45 These arrangements would be put in place within the long-term investment framework. This would mean that Transco would be entitled to retain any additional revenue associated with selling firm exit capacity rights over and above those agreed as part of the price control. Transco would, however, be fully exposed to the costs associated with any interruptible contracts agreed with customers, shippers and/or Transco LNG. As it will be fully exposed to all of the costs, in the longer term, Transco will, in deciding how to meet customer requirements in the most efficient manner, be able to trade off the costs associated with using LNG and interruptible contracts with the costs of additional investment in the pipeline system. In the shorter term, it is proposed that it will be able to trade off the costs of calling interruption with the costs of gas purchases and/or entry buy- backs.

The way forward on transmission access and losses under NETA

1.46 A more detailed consideration of the way forward and next steps in designing and implementing new transmission access arrangements is presented in Chapter 7 and Appendix 9. Ofgem will be considering responses to this document and we expect the views expressed in responses to this document to feed into an on-going consultation process. After the publication of this document, NGC will lead the design phase of the new arrangements in consultation with the industry. Ofgem will closely monitor how this develops and make contributions to the debate as required.

Views invited

1.47 Ofgem is seeking comments on the initial proposals outlined in this document. It would be helpful if responses could be received by 4th July 2001, addressed to:

Dr Eileen Marshall CBE

Managing Director

Competition and Trading Arrangements

Office of Gas and Electricity Markets

9 Millbank

London SW1P 3GE

1.48 Electronic responses may be sent to: lorraine.ladbrook@ofgem.gov.uk

1.49 Respondents are free to mark their replies as confidential although we would prefer, as far as possible, to be able to place responses to this paper in the Ofgem library. Unless clearly marked 'confidential', responses will be published by placing them in the Ofgem library.

1.50 If you wish to discuss any aspect of this document, Colin Garland (020 7901 7303) would be pleased to assist.

2. Background

Introduction

2.1 This chapter summarises the current legislative, licensing, and regulatory regimes relevant to transmission issues and describes planned developments through which it is intended that transmission related reform will be implemented. It also describes the present arrangements under which transmission access rights are conferred and the costs of transmission constraints and losses are recovered from participants.

2.2 Details on the development and implementation of CUSC, given its central importance to the development and implementation of new transmission access and pricing arrangements, can be found in Chapter 1. Further details on the developments in the licensing and regulatory regime can be found in the June 2000 NETA document[24] and the February 2001 CUSC document. The June 2000 NETA document outlined Ofgem/DTI's conclusions on the licence conditions required to introduce NETA whilst the February 2001 CUSC document outlined Ofgem/DTI's latest views on the proposed licence conditions required to introduce the CUSC.

The regulatory and legal framework

The legislative framework

The Electricity Act 1989

2.3 The Electricity Act (as amended by the Utilities Act) provides the framework for the functions of the Gas and Electricity Markets Authority ("the Authority"), of the Gas and Electricity Consumer Council ("the council"), and for the licensing to enable the supply, distribution, generation and transmission of electricity.

The Utilities Act 2000

2.4 The Utilities Act 2000 (the Utilities Act), which received royal assent on 28 July 2000, inserted a section in the Electricity Act 1989, which allows the Secretary

[24] 'The New Electricity Trading Arrangements: Proposed Licence Conditions. Ofgem/DTI Conclusions Paper', Ofgem/DTI, June 2000.

of State to modify existing licences granted under the Electricity Act 1989, where he considers it to be necessary or expedient for the purposes of implementing or facilitating the operation of NETA. This power is exercisable within two years from the date of enactment. The Secretary of State exercised this power in August 2000 to impose a number of NETA licence conditions, amongst other things requiring licencees to sign the BSC. Some of these licence conditions came into effect in August 2001 and the remaining conditions took effect by a direction from the Secretary of State on Go live. The Secretary of State is expected to exercise this power again in order to introduce the licence conditions required for the implementation of the CUSC, as a necessary part of NETA.

2.5 The Utilities Act introduced other reforms to the gas and electricity markets and the regulation of these markets, some of which took effect recently whilst others are expected to take effect in the next few months. These reforms include:

- the transfer of the functions of the Director General of Electricity Supply and the Director General of Gas Supply to the Authority[25] which took place on 20 December 2000;

- the introduction of a new principal objective (primary duty) on the Authority "to protect the interests of consumers in relation to electricity conveyed by distribution systems, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity";

- the introduction of standard licence conditions for each type of electricity licence granted under the Electricity Act and provisions for making modifications to standard licence conditions;

- the separation of the licensing of electricity supply and distribution;

[25] The Authority determines strategy and decides on major policy issues. It is made up of non-executive and executive members. The final appointment to the Authority was made by the Secretary of State in February 2000.

- provision for contracts for the supply of electricity to be deemed between suppliers and small customers in certain circumstances;

- arrangements to ensure continuity of supply to small customers in the event of a supplier failing or losing its licence; and

- the creation of an additional power to enable the Authority to impose financial penalties on companies found to be in breach of their relevant licence under the Electricity Act 1989.

Licensing and regulatory duties

The duties of the Authority

2.6 The general duties of the Authority are set out in sections 1, 3A-C and 47 to 50 of the Electricity Act 1989. The Authority must exercise its functions in the manner it considers is best calculated to protect the interests of consumers in relation to electricity conveyed by distribution systems wherever appropriate, by promoting effective competition between persons engaged in commercial activities connected with the generation, transmission, distribution or supply of electricity. The Authority will have regard to the need to secure that all reasonable demands for electricity are satisfied and that licence holders are able to finance their licensed activities.

2.7 Subject to these primary duties, the Authority also has a duty to exercise its functions in the manner it considers is best calculated:

- to promote efficiency and economy on the part of persons authorised by licences or exemptions to transmit, distribute or supply electricity and the efficient use of the electricity conveyed by distribution systems;

- to protect the public from dangers arising from the generation, transmission, distribution or supply of electricity; and

- to secure a diverse and viable long-term energy supply, having regard to the effect on the environment of activities connected with the generation, transmission, distribution and supply of electricity.

The transmission licence

2.8 Under section 9(2) of the Electricity Act 1989, NGC is obliged to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the supply and generation of electricity.

2.9 NGC is the sole possessor of a transmission licence in England and Wales. It owns and operates the national grid, which transports electricity at high voltage from the generators to the Public Electricity Suppliers' (PES') local distribution networks and to customers connected directly to the transmission system. It has a further duty not to discriminate in use of or carrying out works for connection to the transmission system and interconnectors with Scotland and France.

2.10 NGC's transmission licence imposes a number of other obligations on it including duties to:

- operate the Licensee's Transmission System in an efficient, economic and co-ordinated manner (Licence Condition 7B(1));
- publish a statement in a form approved by the Authority, setting out the basis upon which charges for connection and use of system will be made[26] (Licence Condition 10(1))[27];
- offer terms for connection and use of system (licence Condition 10B)[28];
- to operate the system within prescribed frequency and voltage limits defined in the licence (licence Condition 12) and the Grid Code; and
- implement and comply with a Grid Code, which sets out the detailed technical aspects of connection to and the operation and use of the licensee's transmission system.

2.11 With the advent of NETA, NGC has also been made responsible for having in place and maintaining a Balancing and Settlement Code (see below).

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[26] Section 14.7 of the MCUSA places an obligation on NGC to charge in accordance with this statement.
[27] The numbering of these licence conditions will change with the introduction of CUSC.
[28] The numbering of these licence conditions will change with the introduction of CUSC.

2.12 The Authority can settle any dispute where there has been a failure to enter into terms for connection and use of system, or at the request of NGC or any other party, where a dispute arises following a proposal by NGC to vary the existing terms for connection and use of system.

2.13 Condition 4F of NGC's licence sets restrictions on the revenues that NGC is allowed to earn. NGC carries out two main functions – System Operator (SO) and Transmission Asset Owner (TO). This split is reflected in Condition 4F through a distinction between the Transmission Network Services (TNS) activity, which is related to NGC's TO functions, and the Balancing Services Activity (BSA) related to NGC's SO functions. The TNS activities of NGC are defined in its licence as including all undertakings in the planning, development, construction and maintenance of the transmission system excluding the BSA and excluded services.

2.14 The BSA is defined in the transmission licence to mean the activity undertaken by the licensee "as part of the Transmission Business including the operation of the licensee's transmission system, the procuring and using of Balancing Services for the purpose of balancing the licensee's transmission system". NGC can be thought of as undertaking two distinct roles as SO. First, it balances electricity supply and demand at a gross half hourly level (electricity balancing). Second, it ensures the quality and security of supplies (system balancing) by ensuring the provision of Ancillary Services and resolving transmission constraints.

2.15 **In previous documents, electricity balancing was referred to as "energy balancing".** However, Ofgem believes that the term "electricity balancing" is preferable, given the likely need for balancing between energy markets i.e. the electricity and gas markets, and hence the potential confusion over the use of the term energy balancing. The use of the terms electricity and system balancing will also mean that the electricity market terms mirror those used in the gas market (gas and system balancing).

2.16 Part 1 of licence condition 4F provides for a price control to be set by the Authority on all revenue obtained from NGC's TNS. The present price control on the TNS started on 1 April 2001 and expires on 31 March 2006. Part 2 of licence condition 4F currently provides for two profit sharing incentive schemes covering the internal and external costs of the BSA.

2.17 NGC also has responsibility for maintaining security and quality of electricity supplies. Under Licence Condition 12, NGC is required to plan and develop its transmission system in accordance with various Central Electricity Generating Board (CEGB) Planning Memoranda[29] and the Grid Code and operate and maintain the licensee's transmission system in accordance with the CEGB's Operation Memorandum No. 3 and the Grid Code.[30] These security standards set out the criteria and methodologies[31] relating to the planning and operation of Generation Connections, Demand Connections and the Main Interconnected Transmission System (MITS).

2.18 For Generation Connections, the security standards specify the maximum loss of infeed power acceptable in the event of certain contingencies, including busbar failures, single and double circuit transmission failures and generation circuit failures. For Demand Connections, the standards specify acceptable levels of: loss of supply capacity; overloading of transmission equipment; deviation from voltage limits; and system stability in the event of a set of contingencies based on transmission circuit and busbar failures. Broadly speaking, the security standards for the MITS, specify that the system must be able to maintain Planned Transfer Capabilities[32] in the event of a failure of a double circuit overhead line, a section of busbar or the simultaneous failure of up to two transmission circuits. The security standard allows for derogation from the deterministic standard on economic grounds or at the request of system users in the case of Generation and Demand Connections. Derogation from the deterministic standard for the MITS can be made on the basis of a cost benefit analysis in consultation with the Authority. Until now, NGC has broadly assumed that if the costs of meeting the

[29] PLM-SP1 (Planning Standard of Security for Connection of Generating Stations to the System), PLM-SP2 (Planning Standard of Security for the Supergrid Transmission Network and associated standards of technical criteria) or Engineering Recommendation P2/5 (October 1978 revision) of the Electricity Council Chief Engineers' Conference.

[30] Or such other standard of operation as the licensee may, following consultation (where appropriate) with any authorised electricity operator liable to be materially affected thereby and with the approval of the Director, adopt from time to time.

[31] These criteria and methodologies are summarised in "NGC Transmission System Security and Quality of Supply Standard" available from NGC.

[32] These Planned Transfer Capabilities are determined by scaling the capacity of all directly connected and large embedded power stations to the level of the Average Cold Spell (ACS) peak demand and assessing the desired level of flows that would occur on the system. The ACS peak demand in any year has a 50% chance of being exceeded due to weather variation alone.

planning standard exceed the Value of Lost Load there is an economic case for a derogation.

Other related documents

The Master Connection and Use of System Agreement (MCUSA)

2.19 The MCUSA is a multi-party agreement between NGC, the Public Electric Suppliers, second-tier suppliers, licensed generators and some non-licensed generators and a small number of customers who are directly connected to the transmission system. There are presently over 100 parties to the MCUSA.

2.20 The MCUSA, and its Supplemental Agreements, set out terms and conditions for connection to, and use of, the transmission system. These include payment methods, metering, modifications to the transmission system, variations to the MCUSA, compliance with the Grid Code and dispute resolution. The Authority is not a party to the MCUSA or the Supplemental Agreements. The Authority has limited powers for resolving disputes relating to the MCUSA and can only make such determinations in relation to specific types of disputes. In respect of variations to the MCUSA, the Authority has power to determine disputes in relation to proposed variations to the MCUSA, if proposed by NGC. The MCUSA makes provision for an arbitrator to settle any disputes which relate to the interpretation of provisions contained within the MCUSA.

Supplemental Agreements

2.21 Parties to the MCUSA are also required to sign appropriate Supplemental Agreements. A separate Supplemental Agreement is in place between NGC and each party connected to or using the Transmission network. There are presently more than 400 such agreements in place. The Supplemental Agreements specify the equipment at each connection site and the basis for charging for that equipment.

2.22 Appendix E of the Supplemental Agreements sets out some of the charging rules for both connection to and use of the transmission system. It includes the provisions whereby NGC revises its charges annually. To do this, NGC is required to notify customers by 31 October in the preceding financial year of the intended basis of calculation to be used in the following financial year. NGC is required to confirm this basis of calculation by 30 November in the preceding financial year.

2.23 Through a schedule to the MCUSA, the Transmission Users Group (TUG) was set up to discuss changes to NGC's transmission business, which impact on the MCUSA and its Supplemental Agreements.

Connection and Use of System Code (CUSC)

2.24 In the near future MCUSA and its Supplemental Agreements, together with the Ancillary Services Agreements (to the extent relating to Mandatory Ancillary Services) will be replaced by the CUSC. This will have a governance structure similar to that of the BSC.

2.25 The CUSC will constitute a new contractual framework governing connection to and use of NGC's system and will contain in a codified form the provisions of the MCUSA and its Supplemental Agreements and the mandatory Ancillary Services Agreements, except where changes are required to implement the new governance arrangements and to clarify the dispute resolution procedures.

The Balancing and Settlement Code (BSC)

2.26 The BSC has now been implemented and its scope is defined in general terms in the transmission, generation and supply licences. As discussed above, the BSC is maintained by NGC. The Code covers arrangements for the:

- Balancing Mechanism: making, accepting and settling offers and bids to increase or decrease electricity delivered to, or taken off, the total system (NGC's transmission system and the distribution systems) to assist NGC in balancing the system; and

- Settlement process: determining and settling imbalances, Balancing Mechanism acceptances and certain other costs associated with operating and balancing the transmission system.

2.27 A panel has been charged with overseeing the management, modification and implementation of the BSC rules. The panel has representatives from the industry, consumers and NGC as well as independent members. The Panel Chairman has been appointed by the Authority and is also the Chairman of the

Balancing and Settlement Code Company (Elexon).[33] The primary purpose of Elexon is to provide or procure a range of operational and administrative services, both directly and through contracts with service providers, to implement the provisions of the BSC and modifications to it.

2.28 The details of the modification procedures are contained in Section F of the BSC. The modification procedures are designed to ensure that the process is as efficient as possible whilst ensuring that as many parties as possible can propose modifications and have the opportunity to comment on modification proposals. The Authority is the only body that can take a decision to modify the BSC. Any decision of the Authority to modify the BSC after its procedures have been carried out takes the form of a direction to NGC to make a modification. Under Condition 7A of its transmission licence, NGC must modify the BSC upon receipt of a direction to do so from the Authority.

2.29 The Authority also has the ability, in certain circumstances, to direct NGC, in relation to a particular modification proposal or approved modification, to step-in to:

- take responsibility for the modification procedures in accordance with the Authority's direction; and
- assume the powers, function and duties of the Panel and Elexon in relation to the modification procedures as set out in the direction.

2.30 The Authority is entitled to direct NGC to step-in if the Authority considers that the Panel and/or Elexon is failing (or is likely to fail) to comply with any material provision of the BSC Modification Procedures and/or the implementation of approved modifications, and the Authority has given notice to the Panel and/or Elexon to comply with the BSC Modification Procedures within a specified time period and they have failed to do so. This power for the Authority is a back-stop measure designed to ensure that the Panel and Elexon comply with the modification procedures and process modifications in accordance with the provisions of the BSC (and in an efficient, economic and expeditious manner).

[33] The BSCCo was named Elexon Limited on 7 June 2000.

2.31 In addition, the Authority, for the first 12 months following the Go Live date, can require the BSC Panel to consider urgent modifications to the BSC, if the Authority considers that "there is a substantial disruption to the implementation and/or operation" of NETA or that "urgent action is necessary to prevent such disruption".

The Pooling and Settlement Agreement (P&SA)

2.32 Generators, suppliers and transmission companies were required by their licences to be party to the P&SA. This agreement contained the rules and arrangements for the market in wholesale electricity (the England and Wales Electricity Pool). With the introduction of NETA, there will be a run-off period for the P&SA, the rules regarding which are set out in the BSC.

Determining the need for new transmission investment

2.33 Condition 12 of the Transmission Licence recognises NGC's interlinked roles (TO and SO) and sets out the security standards to which the system has to be developed and operated.

2.34 The two main drivers for NGC's capital investment are changes in the pattern and level of generation and demand (load) and the reliability of its network. Capital investment is carried out in accordance with the security standards defined in the Transmission Licence (see paragraph 2.14). NGC has argued that the drivers for load related and non load related capital expenditure are distinct, but it addresses the two activities together to ensure efficiency in the development and replacement investment decisions.

2.35 NGC argues that it invests to provide new customer connections, network reinforcement and asset replacement. This expenditure ensures that over the medium to long term appropriate levels of transmission capacity and network reliability are maintained, environmental obligations are met, and the health and safety of both staff and the general public are ensured.

2.36 NGC considers that it undertakes a carefully managed asset replacement programme, that takes account of the need for the phased replacement of ageing assets. In this way, NGC seeks to maintain a high availability for the system while supporting new construction, asset replacement and maintenance.

2.37 Overall, NGC, as both TO and SO, is responsible for ensuring that, subject to generation being available, all reasonable demands for electricity are met. NGC has some incentive, under the Transmission Price Control and the SO incentive schemes, to make transmission capacity available and ensure that sufficient transmission capacity is built (in conjunction with Licence Condition 12). There are strong interactions between the roles of TO and SO, which impact on the charges faced by market participants and the efficiency of the electricity system as a whole. For example, the capacity of the transmission system is determined by the TO function as a result of its licence conditions and its Transmission Price Control. Clearly, the size and configuration of the system will significantly influence the actions the SO has to take in order to manage transmission constraints and keep the system within safe operating limits.

The New Electricity Trading Arrangements

2.38 The New Electricity Trading Arrangements (NETA) were implemented in England and Wales on 27 March 2001. One of the basic principles of NETA is that those wishing to buy and sell electricity should be able to enter into freely negotiated contracts. It is expected that under the new trading arrangements, the bulk of electricity will be traded either on power exchanges or through “over the counter” bilateral contracts. Those buying and selling electricity are likely to include not only physical players - generators and suppliers; but also non-physical traders. Thus, one of the key innovations of NETA is the introduction of traded markets in electricity, encompassing forward, future, spot and real time electricity markets. Key features of the new arrangements include:

- forwards and futures markets (including short-term power exchanges), that allow contracts for electricity to be struck over timescales ranging from several years ahead to on-the-day markets;
- a Balancing Mechanism in which NGC, as System Operator, accepts offers of and bids for electricity to enable it to balance the system; and
- a settlement process to settle differences (imbalances) between the notified contractual positions and physical positions of market participants.

Initial arrangements for transmission access under NETA

2.39 Charges relating to the use of the transmission system are split between Transmission Network Use of System (TNUoS) and Balancing Services Use of System (BSUoS) charges broadly relating to NGC's TO and SO roles respectively. Both these charges are paid by both generators and suppliers. NGC's allowed revenues for TNUoS together with pre-Vesting connection charges are determined under the terms of its licence by the Transmission Price Control. This is set and reviewed by Ofgem on a regular basis and the current Price Control began on 1 April 2001. The BSUoS charge is subject to an incentive scheme on NGC that allows for a sharing of profits or losses for performance that exceeds or falls short of target values.

2.40 TNUoS is currently an annual charge differentiated by a participant's location (on a zonal basis) and is designed to reflect NGC's estimate of the long term costs of constructing and maintaining a transmission system for the bulk transportation of electricity at different locations on the network. Currently the network is divided into 15 generation and 12 demand zones for TNUoS charging purposes. Connection charges are based on the costs of providing the physical assets that provide connection to the transmission system for a participant. The division between TNUoS and connections charges depends on the definition of connection assets. At present, a "shallow" definition has been adopted; that is connection charges do not include the costs of any network reinforcements required as a result of the connection. However, for generators, "shallow costs" include the costs of generation only-spurs (as defined in the NGC's Condition 10 statement).

2.41 A locational transport problem (or constraint) occurs if the desired pattern of flows would breach either the voltage stability limits or the thermal limits on part of the system[34] in the event of one of a defined list of contingencies (including, for example, double circuit failure). Managing such a transport constraint requires a rebalancing of the power flows in the locality of the constraint.

[34] Voltage deviations can cause damage to end user electrical equipment. Thermal limits are designed to ensure the safe operation of the transmission line and a breach of the limits can cause lines to fail. Rapid frequency changes, resulting in the possible breach of thermal limits, without countervailing actions to correct such swings in frequency can damage generator turbines.

2.42 Before new transmission access arrangements are introduced, NGC will primarily manage constraints by accepting bids and offers in the Balancing Mechanism. The costs of constraint actions, along with the other costs that NGC incurs in balancing the system (Balancing Mechanism costs and balancing services contract costs), are recovered from all participants via the BSUoS on the basis of their metered volumes, i.e. on both generators and suppliers.

2.43 Since the interim arrangements for constraint management mean that bids and offers in the Balancing Mechanism are accepted for reasons other than electricity balancing,[35] a "tagging" mechanism is used to exclude most constraint and other system balancing costs from energy imbalance prices. This is described in more detail below.

2.44 On a separate but related issue, through the development of NETA, Ofgem sought to establish the principle that energy imbalance prices should, as far as possible, reflect the costs of all electricity balancing costs whether incurred in the Balancing Mechanism or through electricity balancing contracts purchased ahead of Gate Closure and that all the costs of electricity balancing should be targeted on participants who are out of electricity balance whilst the costs of system balancing should be recovered from all participants. Against this background, a Balancing Services Adjustment Data (BSAD) methodology and the BSC were established with the facility to target the costs of electricity balancing contracts signed by NGC prior to Gate Closure to electricity imbalance prices.

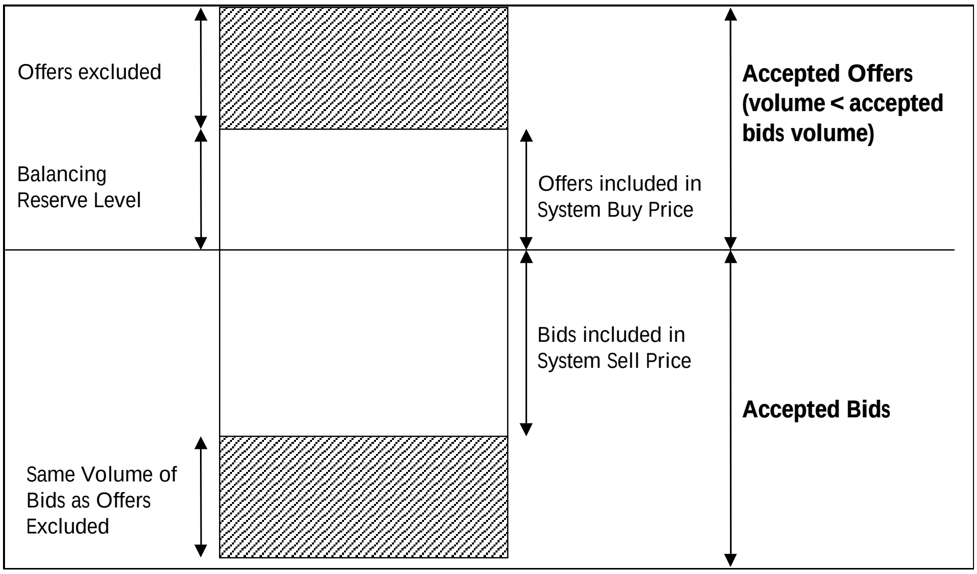
Tagging mechanism

2.45 Under the tagging mechanism, after removing any arbitrage accepted offers or bids,[36] matched volumes of the most expensive accepted offers and cheapest accepted bids are removed from the calculation of energy imbalance prices until a 'Balancing Reserve Level' (discussed further below) is reached for either untagged offer or bid volumes. The Balancing Reserve Level (BRL) is applied to

[35] NGC can be thought of as undertaking two distinct roles as SO. First, it balances electricity supply and demand at a gross half hourly level (electricity balancing). Second, it ensures the quality and security of supplies (system balancing) by ensuring the provision of Ancillary Services and resolving transmission constraints.
[36] Sets of offers and bids where the offers to sell are priced lower than the bids to buy, allowing the System Operator to "arbitrage".

offer volumes if these are in aggregate smaller than the accepted bid volumes and vice versa. The remaining accepted bids and offers are then used in the determination of imbalance prices. Figure 2.1 illustrates how tagging works for the case where the volume of accepted offers exceeds that of accepted bids. If the aggregate quantity of accepted offers, or of accepted bids is less than the BRL, no tagging takes place.

Figure 2.1 - Illustration of tagging



2.46 The BRL allows for the tagging process to be tuned (and potentially turned off). For example, if it is set to a high value then it is likely that then no bids or offers would be tagged and so they would all feed through to the energy imbalance prices. Alternatively, if it is set to a low value, more accepted bids and offers will be excluded from the price calculation process.

2.47 The intention is that the BRL should be set so as to exclude balancing actions taken in relation to the alleviation of transmission constraints and in order to place BM Units in a position to provide frequency response and reactive power, but to include balancing actions for electricity balancing reasons (including the provision of reserve). A number of respondents to the April 2000 Consultation[37], the July 2000 Policy Statement[38] and the July 2000 BSC seminar[39] argued that the BRL should be set *ex ante*. Ofgem saw no reason why this should not be the case, and agreed that the BRL should be set *ex ante*.

2.48 For the start of NETA the value of the BRL has been set to 180 MWh by the BSC Panel, following consultation with BSC Parties and approval by the Authority. It is envisaged that the BRL will be reviewed regularly and adjusted as necessary via the BSC Modification Process. Indeed, the BSC Panel has set up a process for monitoring the effects of the BRL on energy imbalance prices.

2.49 The tagging procedure is only intended to represent an interim approach to removing constraint and other system balancing costs from the energy imbalance prices. Ofgem has recognised that the tagging procedure is relatively crude and is unlikely to exclude fully all the locational aspects from the imbalance price calculation, and that a more robust enduring solution is desirable.

The initial losses regime under NETA

2.50 The key features of the initial transmission losses regime under NETA are:

- ♦ adjustments for transmission losses are based on national, actual (i.e. average) losses and are uniformly recovered on the basis of metered volumes;
- ♦ both generation and demand are exposed to the costs of transmission losses; and

[37] 'NGC system operations under NETA; transitional arrangements, A Consultantion Document', Ofgem, April 2000.
[38] The New Electricity Trading Arrangements and Related Transmission Issues. An Ofgem Policy Statement', Ofgem, July 2000.
[39] Seminar held by the NETA Programme Development Office to discuss the level of Balancing Reserve under NETA.

- ♦ participants are responsible for purchasing losses in the sense that their energy imbalance volumes are adjusted for transmission losses.[40]

2.51 The metered volumes of all BSC parties are adjusted in each settlement period to reflect the actual losses incurred in each settlement period. Forty five percent of the total volume of losses is allocated to generators while fifty five percent is allocated to the demand-side.[41] The rationale for this 45:55 split (rather than a 50:50 split), is that broadly speaking, the Defined Meter Point for generation (under the Metering Codes of Practice) is the high voltage side of the generator transformer, whereas that for demand is the low voltage side of the supergrid transformer. Therefore, the loss volumes calculated do not take into account the supergrid transformer losses already incurred by generators, but do include the supergrid transformer losses on the demand side.

2.52 The adjustment of metered volumes in the imbalance settlement process means that participants are ultimately responsible for purchasing losses under the initial NETA arrangements. Participants can choose to provide for losses themselves by adjusting their contractual position. Alternatively, participants can choose to buy their losses at the appropriate energy imbalance price. Some uncertainty is faced by participants since the adjustment of metered volumes in the settlement process is on the basis of actual ex-post losses. Consequently, it may be difficult to predict accurately, and thereby contract for, the level of losses that will actually be applied.

[40] Distribution Companies are incentivised under the Distribution Price Control to minimise the volume of losses on their networks. Customers pay for distribution losses through distribution use of system charges.
[41] Under the BSC, 45% of losses would be allocated to BM Units in exporting Trading units and 55% of losses to BM Units in importing Trading units.

3. The need for reform

Introduction

3.1 In the December Consultation, Ofgem proposed a set of broad objectives for transmission related reforms to complement the introduction of NETA. In general, most respondents were supportive of the objectives and principles of reform presented. On the other hand, participants, both in their responses to the December Consultation and subsequently, have suggested that the costs of implementing new transmission access and pricing arrangements might not be justified given the low level of constraint costs in the last few years of the Electricity Pool. This was because they considered the main benefit of new transmission access arrangements to be an enhanced ability to resolve transmission constraints efficiently.

3.2 Ofgem believes, however, that the issues involved are much broader than simply the resolution of the current level of transmission constraints, and this chapter therefore deals specifically with the case for enduring reform to the transmission access and pricing arrangements and the treatment of transmission losses. It explains Ofgem's view that the initial arrangements for transmission access and pricing under NETA are inappropriate, as a longer-term solution, in the context of the new wholesale electricity trading arrangements. It also discusses the wider benefits of new transmission access and pricing and losses arrangements in terms of helping to secure the full benefits of NETA, in procuring both short and long term efficiency gains, in giving NGC better signals and incentives to invest appropriately in additional capacity and in providing consistency with developments in related markets, most notably gas.

Weaknesses of the initial NETA arrangements for transmission access pricing and losses

3.3 The initial NETA arrangements for transmission access, pricing and losses share many of the same features as the arrangements that existed under the Electricity Pool and are deficient in a number of respects.

NETA-related effects

3.4 The impact of transmission arrangements on the functioning of traded electricity markets is extremely difficult to quantify, but general considerations indicate that it could be very substantial. NETA has already exerted significant downward pressure on prices and is expected to lead to major economic benefits by, among other things, reducing the distortions caused by inappropriate trading arrangements, including in particular those aspects of the Electricity Pool arrangements that had the effect of increasing the incentives to exploit market power. Deficient transmission arrangements have the potential to undermine significantly these benefits.

3.5 In the absence of a comprehensive reform of transmission, there exists the potential for conduct that would distort traded electricity prices and given the likely scale of electricity trading post-NETA, this could increase the payoffs from the exercise of local market power. A particular concern is that there is no cap on total generation access rights under NETA other than the total installed capacity on the system.[42] Resulting distortions in wholesale electricity markets could, in turn, limit the development of liquidity in those markets and increase prices, with damaging consequences for competition and for consumers.

3.6 A further concern is that rights made available to participants to use the transmission system (access rights) are not well-defined, particularly on the demand-side. Linkages between the requirement to pay use of system charges, the ability to impose costs on NGC from using the system and the entitlement to compensation for the curtailment of notional access rights cannot be consistently applied to all participants.

[42] Under the Pool, the unconstrained schedule provided a cap. Centrally despatched generators effectively secured their access rights at the day-ahead stage by bidding sufficiently low to be part of the unconstrained schedule. Generators were entitled to receive compensation if, in the event, NGC was unable to dispatch their scheduled level of output because of a transmission constraint on the system.
Under NETA, generators must submit physical notifications that are “consistent with the Dynamic Parameters and Export and Import Limits and must not reflect any BM Unit proposing to operate outside the limits of its Generation Capacity or Registered Capacity, whichever is lower (in the case of a BM Unit comprising a Generating Unit or CCGT Module), or Demand Capacity (in the case of other BM Units)” (Balancing Code: BC1.4.2).

Short and long term inefficiencies

3.7 In relation to more direct costs imposed by inefficiencies in interim arrangements, there are three general areas of concern:

- short-term transmission losses;
- transmission constraints; and
- location decisions for major new connections and disconnections, particularly power stations.

3.8 Initially under NETA, transmission constraints will be resolved by the SO accepting bids and offers in the Balancing Mechanism (BM) and by buying balancing services contracts outside the BM. Whilst the BM is likely to be effective in resolving constraints, it will be a mechanism that allocates transmission capacity inefficiently in the sense that the BM is intended to reflect the value that participants place on energy rather than transmission access. Thus, resolving transmission constraints via the BM will, to some extent, distort energy imbalance prices since the simple procedure adopted for tagging and removing the costs of system balancing from cash-out prices (described in Chapter 2) cannot be expected necessarily to remove all transportation costs. Furthermore, the short timescales over which the BM will operate could result in constraint resolution in the BM being more prone to the abuse of locational market power.

Transmission losses

3.9 Locational signals reflecting the costs of transmission losses can significantly increase short run economic efficiency. For example, NGC estimates that in 2006/7 at the time of system peak demand, an increase in generation (or decrease in demand) of 100 MW in West Lancashire would increase total system losses by 3 MW.[43] Conversely increasing generation (or decreasing demand) in the South Coast area by 100 MW would reduce total system losses by 5 MW.

3.10 At present the market does not take into account these locational effects: a single national loss factor is applied to all generation and demand. This is an

[43] Source: NGC Seven Year Statement 2000.

inefficient use of resources and, all other things being equal, in the example above it would be more efficient to provide generation from southern England than from West Lancashire. The efficient charging of transmission losses would mean that participants would compete with each other on the basis of the total cost of electricity. This would mean that a generating plant in West Lancashire would have to produce electricity more cheaply than a plant in Southern England in order to deliver electricity at the same price once transmission losses were taken into account.

3.11 Independent academic research has indicated that the economic cost of using a system of uniform (national) pricing versus a more locational pricing regime in England and Wales is approximately 0.6% of the cost of generation.[44] This is equivalent to nearly £40m per annum.

Transmission constraints

3.12 There are a number of reasons why the reported out-turn of transmission constraint costs do not provide an effective signal of the costs of electricity transportation, either in the short term or as the electricity market develops in the long term. We discuss these in turn below.

3.13 Inefficient use of resources: Historic constraint costs only reveal the cost of constraining on and off plant in order to resolve transmission constraints. They do not reflect the economic costs arising from inefficient generation and demand decisions given a constrained network, either in the short term (operating decisions) or in the long term (location and disconnection decisions). Hence, inefficient consumption and generation decisions can be made.

3.14 Hidden constraint costs: A further concern under the current arrangements is that the constraint costs related to exports from Scotland into England and Wales are not fully recognised. NGC, in day to day operation, restricts exports from Scotland through agreements with the two Scottish companies, on the basis of capacity restrictions in North Yorkshire. Currently, the Scottish Interconnector is

[44] This is based on comparing the net welfare of the market between using uniform system prices and optimal spot prices based on the consumer surplus and generators' operating costs. Inclusion of the costs of inefficent long term investment would increase these costs further. "Electricity Transmission Pricing: How much does it cost to get it wrong?" Richard Green, 1998 POWER working paper PWP-058.

constrained as a result of insufficient capacity in North Yorkshire.[45] Thus, some of the costs of North Yorkshire transmission constraints are currently hidden by limitations on the nominal capacity of the Scottish Interconnector which can limit flows of power from Scotland. With the proposed move to GB trading arrangements, it will be important that these costs are targeted to those that cause them.

3.15 Changing pattern of generation and demand: Over the longer term changing patterns of generation and demand in England and Wales and changes in the pattern of imports and exports across Europe could also influence the costs of resolving transmission constraints. Inefficient investment decisions are likely to occur unless appropriate signals of the short and long term costs to the transmission system of new capacity in different locations is readily available.

Location

3.16 The costs of inefficient location decisions are very significant, and they are influenced by how the other issues (losses and constraints) are addressed. For example, incorrect location decisions by generating plant can raise generation costs by 12%, and such effects can persist for periods of approximately 20 years (related to plant operational lifetimes).[46]

[45] ScottishPower plc and Scottish and Southern Energy plc have agreed with NGC an increase in the Anglo-Scottish Nominal Interconnection Capability from 1600 MW to 2200 MW. However, this additional capacity will only become available when NGC completes a new Cleveland to North Yorkshire line. Final planning permission for this new line was granted in July 2000 and it has been estimated that construction will take two to three years.

[46] Based on analysis by David Newberry ('Privatisation, Restructuring and Regulation of Network Utilities', The Walras-Pareto Lectures, 1995, MIT Press, 2000, page 269) using NGC data on the effectiveness of generation at different locations in meeting demand.

3.17 The current TNUoS charging regime provides some long term locational signals based on NGC's estimates of the costs of reinforcing the network (the Investment Cost Related Pricing (ICRP) methodology). However, this regime has a number of shortcomings. They include:

- the ICRP methodology is an approximation to the long run cost of incremental generation and demand; and

- the locational signals sent by the methodology are related to the long run costs of incremental generation and demand at zones on the system (i.e. charges derived from the costs of network reinforcement). This does not necessarily send the correct economic signals since participants should also be exposed to short run signals related to the direct costs of the transmission system, namely those related to transmission losses and transmission constraints.

3.18 As a result of these shortcomings, the locational decisions of generation and demand could be distorted. Participants will tend to make siting decisions based on a range of factors which differentiate the costs of siting at one location versus another. If the locational signals relating specifically to the transmission network are not effective and consistent, the consideration of trade-offs will not result in an efficient outcome overall. For example, generation could be inappropriately incentivised to site near fuel sources rather than near sources of load.

NGC investment signals and incentives

3.19 The maximum capacity of the transmission system is determined by NGC as TO, whilst its day to day availability depends both on TO decisions and on NGC's actions as SO. The size and configuration of the system will significantly influence the actions the SO has to take in order to manage transmission constraints and keep the system within safe operating limits. Thus, there are strong interactions between the roles of TO and SO, which impact on the charges faced by market participants and the efficiency of the electricity system as a whole. However, there is currently no unified incentive on NGC to manage all aspects of constraint alleviation since the TO function is regulated via the (RPI-X) Transmission Price Control whilst the SO function is regulated via a sliding scale or profit sharing control.

3.20 Ultimately, the weaknesses of the initial NETA arrangements, with regard to unified NGC signals and incentives, could manifest themselves in three types of effect:

- there will be a failure to maximise the capacity available to participants as NGC will not be appropriately penalised for providing insufficient capacity nor will it receive any benefits from providing additional capacity. This will affect the efficiency with which supply and demand can be matched and will impact on the liquidity of traded wholesale electricity markets;
- administered and regulated investment drivers will tend to result in inefficient levels of transmission investment that could be inconsistent with the requirements of users of the transmission system; and
- NGC could face conflicting signals as to the impact of incremental investment across its TO and SO activities.

Gas – electricity interactions

3.21 Given the growing significance of gas-fired electricity generation within the plant mix, it is important that new entrants and existing players receive consistent pricing and locational investment signals across the gas and electricity markets. A new transportation access entry regime has already been implemented in the gas market and it is important that arrangements in electricity are broadly consistent with the new arrangements in gas, for the following reasons:

- a divergence in arrangements could lead to inefficient or perverse decisions being taken by participants, particularly in respect of long term location decisions. This could lead to inappropriate network investment decisions and/or potentially higher costs of network operation; and/or
- short term trading within and between the two markets could be distorted if the gas market was responding to short-term transmission capacity signals whilst the electricity market was responding to much longer-term signals.

3.22 Given the extent of gas-fired generation in the electricity market, it is important that the exit arrangements in the gas market and the entry arrangements in the electricity market do not lead to distortions in the interactions between the two markets. The initial NETA arrangements for transmission access and pricing are not consistent with the proposed exit capacity regime in gas. Over the long term, the inconsistency between the two regimes, if allowed to continue, will lead to distorted decisions by NGC and new entrants on the location of new investments and in the short term to interactions between the gas and electricity markets which do not reflect consistent incentives and price signals.

Objectives of reform

3.23 To overcome the deficiencies outlined in the previous section, Ofgem believes that the four most important objectives for new transmission access and losses arrangements are:

- **NETA related effects:** to ensure traded electricity markets are not unduly distorted by transmission related actions and effects and the exercise of locational market power, by separating the pricing of energy from the pricing of transmission capacity thus ensuring transparency in the actions of all participants, better to identify any market abuse, accepting that locational market power may remain an issue in the transmission market.

- **Short and long term efficiency issues:** to establish a framework that more accurately targets the short and long term costs imposed on the transmission system by the locational patterns of generation and demand;

- **NGC investment signals and incentives:** to provide effective signals to and unified incentives on NGC to make transmission capacity available in the short term and to invest appropriately in transmission capacity in the long term; and

- **Gas – electricity interactions:** to provide the framework for efficient and effective interactions between the gas and electricity markets in the short and long term.

3.24 Ofgem considers that the best means of achieving these objectives is the establishment of firm tradable access rights and appropriate charging for transmission losses. As discussed below, such an approach will address all of the weaknesses in the initial NETA arrangements with regard to transmission issues.

The benefits of reform

NETA – related issues

3.25 NETA has been established on the basis of treating electricity as a single system-wide tradable commodity. In order to encourage liquid trading in forward electricity markets, trading is without regard to location. However, due to the costs of losses and transmission constraints, the value of electricity can differ according to its location. Market based arrangements for transmission access and losses will capture this locational diversity, transmission related costs will not unduly influence traded electricity prices and liquidity in forward electricity markets will increase. The result of this will be to make the pricing of forward electricity contracts more transparent and straightforward, thus reducing volatility, increasing liquidity in forward electricity markets and hence increasing the efficiency gains expected from NETA.

3.26 By separating the energy and transmission markets, new arrangements based on tradable transmission capacity access rights will also simultaneously reduce the opportunities for, and the scope of damage from, exploitation of locational market power – for example, by facilitating leverage of locational positions into the wider electricity market – and increasing the effectiveness of regulatory oversight of such adverse conduct. Ofgem accepts that no set of electricity trading and transmission access arrangements can remove locational market power and hence, that if such market power is abused then we will need to take action either under the Competition Act 1998 or via the enforcement of appropriate licence conditions. However, we consider that a significant benefit of the proposed reforms to the transmission access arrangements would be to reduce the benefits of abuse and make it more transparent that locational market power is being abused.

Short and long term efficiency issues

3.27 Ofgem believes that market based transmission access rights and new losses arrangements will ensure that the locational variation in the costs of electricity that arises because of transmission constraints and losses are reflected in prices faced by participants.

3.28 Exposing participants more fully to the economic costs of their own actions will encourage *ex ante* trading in NETA markets that reflects, more accurately, the configuration of the transmission network. In turn, this will facilitate competition in generation and supply. Furthermore, it will reduce the need for the SO to adjust participants' intended running profiles in the BM with constraint relieving trades.

3.29 In the longer run, the access prices emerging from the new arrangements will more accurately reflect the scarcity of transmission access at each location on the system and influence long term investment and retirement decisions for generating plant, and for significant demand sites, accordingly.

NGC investment signals and incentives

3.30 Market based transmission access arrangements will allow NGC's TO and SO incentives to be unified, by relating the capacity it is required to make transmission availability on a daily basis to the level of transmission capacity availability that NGC has agreed to provide as part of the Transmission Price Control. As a result, investment in new transmission capacity and decisions made with regard to making the maximum amount of existing transmission capacity available, will reflect both the long term costs of constructing and maintaining the transmission network and the short term costs of using the transmission network. For example, to the extent that the costs of resolving transmission constraints through a market in transmission access rise in the short term, this will be felt by NGC through the SO incentive schemes, since it will be required to buy-back firm capacity rights from holders. NGC will then face an incentive to invest in the transmission system to relieve constraints (which it would pay for under the Transmission Price Control) if the costs of investing in the network are lower than the expected future cost of relieving transmission constraints through capacity buy-backs.

Gas - electricity interactions

3.31 The introduction of market based arrangements for trading firm access rights will result in electricity trading arrangements that are consistent with the gas trading arrangements.

3.32 The benefits of consistent market based transmission arrangements in gas and electricity will be threefold:

- enhanced security and quality of supplies as short and long term interactions between the two markets are improved;
- more efficient location decisions will reduce the short run costs of operating the gas and electricity transmission system and the long run costs of building and maintaining the networks; and
- as the transparency and consistency in gas and electricity markets increase, trading opportunities between the two markets will increase and participants will face increased incentives to innovate, particularly in respect of contracting and risk management strategies.

Summary and conclusions

3.33 In this chapter, we have explained that the reasons for addressing issues associated with transmission access and losses go considerably beyond concern with the historic level of constraint costs and losses. Specifically, in relation to the problems with the initial arrangements, we believe that:

- **NETA related effects:** a reformed regime for transmission access is required to ensure that the full benefits of NETA are realised, and that those benefits are not jeopardised by distortions arising from current transmission charging arrangements. Effective arrangements for transmission access and losses should facilitate the development of undistorted competition in electricity generation and supply.
- **Short and long term efficiency issues:** market based access arrangements will encourage more efficient short-term use of the transmission network, by more accurately reflecting the economic costs imposed by the actions

of any given transmission network user, as revealed by the market rather than by administrative determinations, and more efficient location decisions by generators and large loads.

- **NGC investment signals and incentives:** by providing greater scope for the emergence of market-based signals as to the value of transmission capacity, and for the emergence of SO incentive structures based on those signals, reformed arrangements for access and losses will contribute to more efficient operation of the system day to day and better investment decisions by NGC, particularly where those decisions involve trade-offs among: incremental transmission capacity, location of new generation and load, and incremental investment in both the production and transportation of gas.

Gas – Electricity market interactions

3.34 Introducing consistent transmission arrangements on both the gas and electricity networks can increase efficiency and security of supply in both the short term and long term. As result, market based arrangements for transmission access and pricing and losses will protect the interests of customers, promote effective competition in electricity markets, promote efficiency and aid the development of a diverse and secure supply of electricity for all customers.

4. The process to date

4.1 This chapter describes the process that has occurred to date with respect to the development of new transmission access and pricing arrangements and arrangements for transmission losses in England and Wales.

4.2 In the December Consultation, Ofgem argued that new transmission access and pricing arrangements are required in England and Wales to complement NETA and reflect properly the value of transmission access and losses and therefore the locational value of electricity. Ofgem argued that, where it was feasible without imposing excessive costs, centrally administered mechanisms should be avoided, as should undue complexity to facilitate trading. Ofgem also argued that changes to transmission losses arrangements should be designed to provide appropriate signals of the value of generation and demand at different locations on the network.

4.3 Ofgem held an industry workshop in August 2000 (the ‘August Workshop’) that focused on some of the key issues concerning the proposed transmission access arrangements. Ofgem asked those that attended the August Workshop to provide written responses to some of the issues discussed including the appropriate definition of access rights, the benefits of a new transmission access regime and the possible cost of systems required to implement any new arrangements.

December Consultation

Transmission losses

4.4 Ofgem proposed that losses should be charged by scaling the metered volumes of both generators and suppliers prior to settlement on the basis of predetermined (ex-ante) locational marginal loss factors. These loss factors would be based on historic data. We believed that this arrangement would provide efficient economic signals to participants as well as providing them with considerable commercial freedom to manage their exposure to transmission losses. The December Consultation went on to present a detailed proposal for a loss charging arrangement under NETA based on a scheme originally devised for use under the Electricity Pool trading arrangements.

4.5 The December Consultation also suggested that the surplus revenues that would accrue from the use of marginal rather than average loss factors should be offset against other transmission charges. Furthermore, Ofgem argued that with the introduction of locational loss charges it might be appropriate to consider changes to the way that TNUoS charges are calculated so as not to overexpose participants to locational signals.

Transmission access and pricing

General approach

4.6 At a very broad level, and given the interlocking nature of the concerns over the current transmission access and pricing arrangements, we outlined three general approaches that could be taken to creating a more coherent and consistent set of transmission access and pricing arrangements:

1. Provide all participants with <u>unlimited</u> access rights (subject to legal/regulatory safeguards with regard to providing misleading information designed to exploit market power). NGC would then resolve constraints via the BM and constraint contracts, and would charge these costs to all participants. This would effectively amount to a development of the arrangements that were in place at the start of NETA;

2. Provide all participants with specified maximum firm access rights but allow NGC to scale-back these rights to resolve constraints in return for paying compensation at an administered price; or

3. Allow participants to choose the level of access rights they wish to purchase via a market-based mechanism and allow NGC to resolve at least a significant fraction of constraints via trading activities. Under this approach, NGC would be given a financial incentive to make all transmission capacity available to participants on non-discriminatory terms.

4.7 The first two approaches limit the extent to which participants are able to influence the charges (approach 1) or the payments (approach 2) they face since both options rely upon administered mechanisms and prices. Moreover, neither option allows participants' views on the value of access rights in different locations to be taken into account in determining investment in the transmission network.

Form of regime

4.8 The December Consultation concentrated upon possible ways of implementing transmission access and pricing arrangements based upon approach 3:

- locational marginal pricing (LMP) to provide bundled electricity and transmission prices on a locational basis;
- a transmission-related balancing mechanism (a congestion market) separate from the main (energy) balancing mechanism, which would provide a locational electricity price in addition to a national energy price; or
- markets for transmission access based around the allocation and trading of firm access rights operating in parallel with, but distinct from, the trading of electricity in forwards markets.

4.9 Of the options presented in the December Consultation, Ofgem argued that the trading of firm access rights best fitted with the objectives and principles set out for this review and the wider framework provided by the new electricity trading arrangements.

4.10 Thus, Ofgem suggested that a volume of locationally defined firm access rights should be allocated to market participants by the SO in a non-discriminatory and transparent manner probably via the use of auctions. Secondary trading of access rights would allow market participants to fine-tune their holdings and adjust to changing circumstances, and would allow NGC, as SO, to adjust the overall volume and locational dispersion of access rights to take account of actual transmission capabilities. To provide for sufficient liquidity in such secondary markets, Ofgem suggested that the access rights should be defined on a zonal rather than nodal basis. Participants would face financial incentives to ensure that the volume of rights held matched their pattern of generation and demand. NGC would also be incentivised to maximise the level of transmission capacity made available and to resolve transmission constraints in the most cost effective manner.

4.11 The December Consultation also considered the appropriate structure for charges to recover the costs of the transmission network. Ofgem's initial view was that the value of electricity at different locations on the transmission network would be signalled by the proposed new transmission access (and losses) arrangements. Given this, Ofgem suggested that it might not remain appropriate to levy TNUoS charges on a locational basis.

4.12 The December Consultation also set out the framework for incentivisation of NGC's SO role under NETA and suggested that it might be appropriate for revenues or costs arising from NGC's role in transmission access markets to form part of the overall SO incentive arrangements.

NGC's views

Transmission losses

4.13 NGC was supportive of the objective of establishing an efficient regime for the treatment and charging of transmission losses. Although it agreed that locational marginal loss factors could provide appropriate economic signals to market participants, it felt that there were important implementation issues to do with the correct calculation of these factors, the efficient collection of any revenue surplus that might arise and the interaction with other locational charges.

Transmission access and pricing

4.14 NGC, in its response to the December Consultation, agreed that a market based arrangement around firm access rights has the potential to send appropriate short-run economic signals to market participants and enable some transmission constraints to be resolved before gate closure. However, NGC expected its effectiveness to be limited if the access rights were zonal rather than nodal.

4.15 NGC also believed that it would be inappropriate to link revenues from an access market to the income required by NGC to develop and maintain the transmission system i.e. its allowed revenue under the Transmission Price Control. NGC argued that the access market will reveal the short-run costs of constraints and losses but that its capital expenditure should continue to be based on meeting the system security standards and its revenue requirement set by price reviews. Thus, NGC stated that there would still be a requirement for TNUoS charges under the proposed regime.

4.16 NGC also noted that a well designed and competitive access market would deliver short-run locational marginal prices, which should incentivise efficient investment decisions by participants. NGC believed additional locational signals through TNUoS charges would distort the signals to participants and hence that, if an access market is introduced, TNUoS charges should become non-locational.

4.17 Finally, NGC noted that many of its customers had expressed the view that the current low materiality of constraints might not justify the development and operation of an access market.

Other respondents' views

Transmission losses

4.18 Thirty respondents to the December Consultation commented on issues related to the treatment of transmission losses under NETA. Of these, the majority supported the need for reform to the treatment of losses. However, a few noted that more detail would be required before they felt able to comment on the proposals.

4.19 A majority of respondents had reservations over the introduction of marginal losses related arrangements, especially if this was to occur at the same time as the introduction of NETA. However, most respondents were in favour of both sides of the market (i.e. generation and demand) being charged for losses. On the whole, respondents agreed that the SO should not retain any surplus resulting from a marginal loss charging regime.

Transmission access and pricing

4.20 Seventeen respondents to the December Consultation commented on issues related to the need for new transmission access and pricing arrangements. Most respondents believed an examination of the issues covered in the December Consultation was long overdue.

4.21 However, many respondents felt that more time and detail was required to analyse the issues discussed, given their breadth and complexity. Respondents also felt that the arguments for reform needed to be more clearly explained and analysed before they could reach a decision. On balance, eight respondents were in favour of the breadth of reforms being considered, whilst nine were against it.

4.22 Six respondents to the December consultation raised concerns over how NGC would be funded under new transmission access and pricing arrangements. Most comments were of a general nature suggesting that TNUoS charges should be reduced to reflect the costs that participants would face in purchasing access rights. However, one large integrated energy company believed that the price for access rights should encompass both the costs of long-term transmission system development and short-run congestion costs. This respondent believed that both long and short-run signals would be required to give the correct economic valuation of system access and that cost recovery through a combination of access right charges and use of system charges would not be appropriate.

4.23 Four respondents commented on whether NGC should retain any revenues generated by the trading of access rights to offset against other transmission charges. Of these, two respondents were against NGC retaining these revenues whilst a group representing consumers was in favour. Two respondents, a generator and a large integrated energy company, commented that it would be necessary to ensure that NGC is appropriately incentivised to make transmission capacity available.

4.24 Regarding the timing and the way forward, a large number of respondents requested that more time should be given for consideration of the issues raised and that the development phase of any new arrangements should be postponed until after the introduction of NETA.

4.25 Respondents' views on specific areas of the December Consultation are covered in more depth in Appendices 1 to 8 of this document.

Responses to the August Workshop

4.26 All nineteen respondents to the August Workshop signalled broad support for an enduring solution to transmission access arrangements which incentivises the efficient use of the transmission network. However, views on the precise way forward were diverse. A few respondents suggested a development of the current transmission pricing regime might be more desirable than the fundamental overhaul envisaged by the Ofgem proposals. Eleven respondents felt a more detailed examination of the need for reform was required given the relatively low materiality of constraint costs currently.

4.27 A number of smaller participants expressed concern that the proposed complete overhaul of transmission access and pricing arrangements might be too burdensome given their limited resources particularly if it required them actively to trade access rights as well as energy. One supplier emphasised that the electricity and gas sectors are very different and no decisions based on the treatment of gas entry rights should be taken until there has been time to evaluate the gas approach, once the final arrangements are in place.

4.28 The concept of using transmission flowgate rights was presented by one of the attendees to the workshop as a means of dealing with transmission constraints. The holder of a flowgate right has the right to flow power through a particular circuit or circuits (the flowgate) for a specified time period. Flows of power through a flowgate above or below the level of rights held by a participant result in an imbalance charge liability (or potentially receipt). Several participants commented that the concept of access rights based on flowgates should be investigated. This approach is considered further in Appendix 1.

4.29 Regarding the timing and the way forward, a large majority of the respondents believed that considerable demands on resources currently facing industry participants in the lead up to the introduction of NETA and CUSC, meant that there would be benefits in delaying further progress on transmission access until NETA beds down. They advocated waiting until an assessment could be made of how NETA has affected constraint costs and the scope for synergies with NETA systems.

4.30 The majority of respondents expressed interest in participating in further developments on transmission access and there was widespread support for the use of expert groups to take forward the key issues. Three respondents suggested using TUG-CPF as an industry forum, and pointed out that TUG-CPF has been considering many of the core issues over the last year.

Ofgem's views

Transmission losses

4.31 Ofgem continues to believe that any enduring arrangement for transmission losses should be designed to expose participants to the costs of locational marginal losses. We accept that this could be achieved in different ways but are not convinced by the arguments in favour of long-term transitional arrangements. In addition, we believe that there is strong merit in allowing participants themselves to manage their exposure to transmission losses.

Transmission access and pricing

4.32 Ofgem has carefully considered the views put forward by respondents. For the reasons described in Chapter 3, Ofgem remains convinced that without new transmission access and pricing arrangements, we will continue to see inefficiencies in both the short term operation and long term development of the electricity and gas markets.

4.33 On the direction of reform, Ofgem continues to believe that a new regime based around a market in firm access rights will offer the most transparent, non-discriminatory and effective means of valuing and pricing transmission access in the short and long term.

4.34 In addition, Ofgem agrees that experience during the early days of NETA, particularly the effectiveness or otherwise of the current tagging arrangements, should inform the final design of new transmission access and pricing arrangements. Nevertheless, we believe that now that NETA has been implemented the initial design phase should commence as soon as is practicable.

5. Overview of issues relating to new transmission access arrangements

5.1 This chapter provides an overview of Ofgem's current thinking on transmission access and losses in the light of the consultation process to date. Whilst the issues of access and pricing and losses are inter-related, some issues relating directly to losses are relatively straightforward to summarise. These, therefore, are briefly considered first, with a much fuller discussion set out in Appendix 8.

5.2 The rest of the chapter then focuses on transmission access and pricing issues. We summarise, first, the key building blocks of new arrangements that, depending on decisions made, may need to be developed, and the key issues for consideration in relation to each. A more detailed consideration of the issues and options summarised in this chapter is provided in the appendices. We then, based on the detailed discussion in the appendices, present Ofgem's initial view on the overall design of new transmission access and pricing arrangements. Finally, we briefly consider the interaction of the access regime with the Transmission Price Control and the structure of transmission charges faced by participants.

The enduring treatment of transmission losses

5.3 Ofgem accepted the concerns raised by NGC and other respondents to the proposals in the December Consultation with regard to attempting to implement a full locational marginal loss factor scheme in time for the start of NETA. Thus, currently, adjustments for transmission losses are based on actual (i.e. average) losses across the system (i.e. with no locational element) and are, in effect, uniformly recovered on the basis of metered volumes. Participants' metered volumes are adjusted for losses before imbalance volumes are calculated with 45% of the loss volume allocated to generators and 55% to the demand-side. Nonetheless, Ofgem continues to believe that the enduring scheme for transmission losses should incorporate more efficient arrangements for the charging of transmission losses including the use of locational marginal loss factors.

5.4 We are currently considering two general approaches:

- **Option 1** would be to adjust participants' metered volumes using estimates of average zonal loss factors. A separate financial payment or levy, calculated to reflect the difference between estimated marginal loss factors and the average factors used to adjust metered volumes, would be included in BSUoS charges; and

- **Option 2** originally proposed by NGC, would be to use estimates of the costs of marginal locational losses to set loss related reserve prices in any auctions for access rights.

5.5 Option 1 is a more market based approach than Option 2. However, it can be argued that it may overestimate the impact of losses if the loss factors are set in advance. This is because transmission losses cannot be separated from transmission constraints since the presence of constraints on the network will affect the pattern of flows and hence of losses. In constrained locations, it can be argued that it is not possible to define a marginal loss. However, variants on this general approach (such as setting the loss factors at Gate Closure) which enable losses to be treated via an integrated approach are possible. NGC's preferred option (Option 2) takes account of the constraint interaction problem, but would not allow participants to manage the price they pay for transmission losses since they could not self provide losses and would require a centralised view to be taken on the costs of marginal losses over the period for which the access rights are sold (possibly up to five years).

5.6 Ofgem continues to believe that any enduring arrangement for transmission losses should be designed to expose participants to the costs of locational marginal losses. However, we accept that this could be achieved in different ways and further consideration should be given to the main options that have been put forward.

Building blocks of a tradable firm access rights regime

5.7 This section sets out the key building blocks involved in a tradable firm access rights regime that would apply to all CUSC signatories, and briefly outlines the main options for consideration within each area. Appendices 1 to 8 to this document explore these options in more detail. Ofgem believes that the key building blocks which require consideration are:

- the definition of the access rights to be allocated and traded (Appendix 1);
- the determination of the volume of access rights, and their primary allocation (Appendix 2);
- the secondary trading of access rights, including the role of the SO (Appendix 3);
- the interaction between the access regime and the electricity market arrangements under NETA (Appendix 4); and
- the access imbalance and settlement regime (Appendix 5).

Definition of the access rights to be allocated and traded

5.8 In order for a market in firm access rights to be successful, the rights to be traded must be defined in a way which ensures that:

- they can be valued in the primary and secondary access markets by all participants, given the most up to date information available to them;
- they are capable of reflecting effectively the underlying physical characteristics of the transmission network; and
- they are capable of reflecting the temporal and spatial nature of transmission constraints.

5.9 The definition of access rights is likely to be critical in determining the extent to which the access regime meets the wider objectives related to NETA, captures locational transmission issues and provides appropriate locational incentives to all participants including NGC in relation to long term investment and new entrants with respect to siting decisions. The key issues in relation to the definition of rights are:

- **the specification of access**: This principally relates to whether rights are defined as a right of entry to or exit from the network at a particular location, or whether they are defined as the right to flow power over particular constrained boundaries or "flowgates";

- **participation in the access regime:** This relates to whether all generation and all demand participate actively in the access regime (i.e. are involved in the trading and settlement of access rights), or whether participation is more limited (for example, limited to generation);

- **locational resolution:** The extent to which access rights are defined by individual nodes on the transmission network, and are therefore in theory capable of addressing all transmission constraints, or whether they relate to zones (groups of nodes), leaving some constraints to be relieved by the SO in the BM.[47] If a zonal approach is adopted, there is the further question of the definition of zonal boundaries, and the implications of the choice of boundaries for the metering information available on the demand side of the market;

- **symmetry of locational resolution:** Whether the locational definition of entry and exit rights should be symmetrical between generation and demand, or whether there is merit, particularly with nodal or small zonal definitions of entry rights, in adopting a more aggregated exit right definition to reflect the fact that the demand side tends to have less flexibility to influence transmission constraints; and

- **temporal definition**: this relates to whether rights are defined by half-hour, or by a greater level of temporal aggregation.

[47] With a zonal definition of rights, although constraints between zones could be resolved by the SO buying back and realising zonal rights, constraints within a zone could not be resolved in this way.

Determination of the volume of access rights and the means of their primary allocation

5.10 Following the definition of access rights, the next key building block relates to the determination of the volume of such access rights to be made available, and the way in which that volume will be allocated by the SO (the primary allocation). The key issues in this regard relate to:

- **volume of rights to be allocated**: There are a spectrum of options in determining the volume of rights to be allocated via the primary allocation mechanism, ranging from the theoretical maximum capability of the transmission system, through estimates of actual capability (with some allowance for likely constraints), to an estimate of the maximum certain capability. The interpretation of "capability" is clearly dependent upon whether absolute volumes of entry/exit rights or just transfer capabilities are being centrally determined. Since the level of transmission availability over the medium term should be an important consideration in the Transmission Price Control, the volume of rights allocated will clearly need to be consistent with the assumptions and output measures therein;

- **bundling of rights in primary allocation**: The extent to which the underlying rights are bundled into more aggregated products in the primary allocation process needs consideration. This will clearly influence the extent to which the primary allocation mechanism reflects the variation in transmission system capabilities (both in terms of volume and price discovery), and will also influence the need for participants to fine-tune their positions and hence the liquidity of secondary markets. Given the desirability of a link between the Transmission Price Control and the access regime, the length of the control period is also a relevant consideration;

- **principles of allocation:** Theoretically, there is a range of possible approaches, from administered or grandfathering approaches to price rationing (auctions) – the advantages and disadvantages of each possibility need to be separately considered. Options range from auctioning both entry and exit rights, through auctioning entry rights but allocating exit rights (which would be consistent with the approach proposed for the GB gas market) to allocating both entry and exit rights.

- **extent of SO involvement in volume determination:** In an entry/exit rights access market, it is possible to determine centrally either the absolute volume of entry and exit rights by location (and therefore implicitly the transfer capability between locations), or just the transfer capabilities, and allow load and generation to create "matched pairs" of entry and exit rights; and

- **nature of the primary allocation mechanism**: If auctions are chosen as part of the primary allocation mechanism, a number of further choices may need to be made. For example, if access rights are defined on a zonal basis, should there be separate auctions for each zone or should the auctions for the various zones be linked (perhaps using the simultaneous clearing approach advocated by NGC[48]). Other issues that would require consideration include: should there be more than one round in the auction, should it be a "sealed bid" auction or open and simultaneous, should the auction pricing be pay as bid or uniform. A final consideration is whether reserve prices should be used to set minimum prices for access rights in different locations so as to reflect the avoidable costs of operating and/or reinforcing the transmission network.

Secondary trading of access rights, including the role of the SO

5.11 Following the primary allocation, access rights should be tradable on secondary markets. Such secondary trading is necessary in order that the SO can fine-tune the volume of rights available to the actual capabilities of the transmission system. Secondary trading may also allow participants to fine tune their holdings of rights from the primary allocation (particularly if the rights have been bundled) in order to allow them to update their holdings in the light of updated

[48] Under this approach, the SO would announce maximum transfer capabilities between locations prior to the auction. Participants would submit bids for entry (and possibly exit) access rights at the various locations and these would then be allocated taking account of the valuations revealed through the bids until the maximum transfer limit in respect of each boundary was reached or until participants' requirements were satisfied.

information and requirements. The key issues for consideration in relation to such secondary trading activities are:

- **need for SO facilitation of the secondary trading process**: If access rights are nodally rather than zonally defined, there is likely to be a need for SO facilitation of secondary trading since, at least on the generation side of the market, there will typically only be one participant interested in rights at each node, and participants will not be in a position to know the relative worth of rights at different nodes. SO facilitation would enable trading between different nodes to take place and hence create the potential for liquid secondary trading. In a zonal market, there is no such absolute requirement for SO facilitation, although there may be an argument for at least the establishment of a designated market in which the SO trades to provide transparency with regard to the actions that it takes;

- **extent to which SO should release products other than firm access rights:** The extent to which the SO should trade in products other than firm access rights – for example, access options, constrained-on options or interruptible access rights – is also for consideration; and

- **SO incentives:** Following the primary allocation process, access rights should be firm on both participants (see access imbalance and settlement below) and on the SO. If the transmission system is not capable of delivering the rights already allocated, the SO should repurchase rights in secondary markets. Similarly, if the transmission system can accommodate more rights than have been allocated, the SO should release further rights through secondary markets. It is clearly desirable that the SO's secondary trading activities are subject to an incentive mechanism in order to align its interests with those of consumers (i.e. to manage the costs of buy-back and to make all transmission capacity available). The format of this incentive mechanism is for consideration – ideally, the SO should face consistent incentives across its access, electricity balancing and system balancing activities.

Interaction between the access regime and the electricity market arrangements under NETA

5.12 The trading and pricing of wholesale electricity under NETA is undertaken at a national level i.e. without consideration of locational transmission issues, which is equivalent to saying that it takes place at a single "notional", National Balancing Point (NBP). This will be true both in relation to *ex ante* markets and imbalance settlement. The three key issues in relation to the interaction between the access regime and the NETA electricity balancing arrangements are:

- **treatment of access rights for Balancing Mechanism bids and offers**: Under NETA, participants are incentivised to cover their expected output and consumption of electricity with *ex ante* electricity sales and purchases plus any of their bids and offers that are accepted in the BM. It is anticipated that the transmission access regime would also incentivise participants to acquire access rights to reflect their *ex ante* electricity sales and purchases. Given the timescales involved, it is for consideration whether participants should have to acquire access rights to back their BM offers, or whether NGC should have to purchase the appropriate access rights, or whether the necessary access rights at administered prices should be allocated to participants whose bids and offers are accepted; and

- **Interactions with forward electricity prices**: With a zonal/nodal access rights regime, forward prices will reflect the combined costs of electricity and transmission access at the NBP. Transmission constraints will define the differential between access prices in different locations but not their absolute level. Thus, it is for consideration whether the location of the NBP needs to be specified in order to facilitate the pricing of bids by participants for access rights.

The access imbalance and settlement regime

5.13 A firm access rights regime means that participants must purchase sufficient access rights to match the amount of electricity they wish to transmit across the transmission system (i.e. a 'ticket to ride'). A firm regime also means that NGC must repurchase access rights that it has previously allocated, if it fails to deliver them.[49] To ensure participants purchase sufficient access rights, an imbalance regime which incentivises participants to purchase access rights consistent with the amount of electricity they expect to input into and offtake from the transmission system is needed. Given the potential cost and implementation effort associated with a full half hourly, locational access imbalance settlement regime, it is for consideration whether there are other approaches (for example using rules or licence conditions) that could be adopted to enforce the 'ticket to ride' principle. If, however, a half-hourly access imbalance settlement regime is considered necessary to provide appropriate commercial incentives on participants, the following issues will need to be considered:

- **nature of the access imbalance regime**: The electricity imbalance regime is two-sided in that both over-runs and under-runs attract an imbalance price. It is for consideration whether such an approach would be appropriate for access imbalances;

- **determination of access imbalance volumes:** The key issues in relation to the determination of access imbalance volumes relate to whether entry and exit imbalances could be netted. Further, more detailed, questions relating to how entry and exit imbalance volumes could be calculated (for example, how a finer geographical resolution than Grid Supply Point (GSP) Groups could, if desired, be achieved) are discussed in Appendix 5; and

- **determination of access imbalance price:** There are a number of issues which would need to be considered in relation to the access imbalance price – for example, whether the imbalance price should be zonal, nodal or national, whether the cost of actions taken by NGC in secondary markets, actions taken in the BM and the prices associated with the primary allocation process should be included in the derivation of the imbalance price in some way and whether under-run charges (if they are needed) should be different from over-run charges.

5.14 An important consideration in deciding on any mechanism for calculating transmission access rights imbalances will be its systems implications. Different

[49] This may require the development of systems that enable NGC to buy and sell access rights.

options may require more or less complex systems, both in terms of set-up and ongoing costs for the central settlement system and participants. The extent to which more complex systems allow a better targeting of transmission related costs needs to be traded-off against the higher costs involved.

Design of a firm tradable transmission access right regime

5.15 Based on the detailed discussion of the building blocks of a new transmission access and pricing arrangements contained in the appendices, this section presents an overview of Ofgem's initial views on the various building blocks of such a regime whilst Chapter 6 contains a summary of a possible overall approach that is consistent with our thinking.

The definition of the access rights to be allocated and traded

5.16 Ofgem's initial view on the definition of access rights is outlined below:

- **participation in an access right regime:** Ofgem's initial view is that there is strong merit in a transmission access regime that enables the demand side to play an active role. However, this does not necessarily mean that the two sides of the market need be treated identically in all respects. As well as retaining consistency with the treatment of electricity trading under NETA, there are clear advantages to encouraging demand-side participation in a new transmission access and pricing regime. Not only would it enable the demand-side to contribute to the resolution of transmission constraints, but it would also enable account to be taken of demand side participants' actual requirements and capabilities rather than central forecasts (for example with regard to interruptions);

- **specifying the access product:** Our initial view is that the definition of access rights should be based on an entry and exit, rather than a flowgate approach. There are a number of drawbacks to defining access rights in relation to flowgates on an intermeshed transmission system such as that which exists in England and Wales (see Appendix 1 for details). These drawbacks include the need for a stable network topology (so that participants can determine the flowgates through which their power will flow and hence for which they require rights), the potentially large number of access right products required (to capture adequately all the enduring constraints on the systems via flowgates) and the complexity in valuation of rights (their value is derived from modelling of the change in overall despatch costs as a result of an increment in the capacity of the particular flowgate and this depends on the capability of all transmission lines and the likely behaviour of all market participants on the system). Taken together these drawbacks suggest that an entry/exit market may be preferable;

- **locational resolution:** Ofgem's initial view is that a definition of access rights based on a relatively small number of zones would be desirable since it would facilitate liquid secondary trading. However, it seems likely that it will not be possible to create transmission access right zones that capture the majority of expected transmission constraints without using a large number of zones.[50] Thus, further consideration needs to be given as to whether some form of nodal definition of rights, along with other mechanisms to facilitate trading should be employed;

- **symmetry of locational resolution**: Ofgem's initial view is that, if the geographical definition of entry rights is on the basis of a few large zones, then exit rights should be based on the same geographical definition. However, if a geographic delineation based on nodes or a large number of zones is adopted, the possibility of using an asymmetric definition of entry and exit rights (in which exit rights were defined to cover a larger area than entry rights) should be considered. Such an asymmetry might allow demand side participation whilst taking into account the relative ability of participants on the two sides of the market to respond to locational signals. Nevertheless, we continue to believe that, all other things being equal, it would be desirable to define entry and exit zones on the same basis, and that there are economic benefits (for example consistency of price signals between generation and demand) that accrue from doing so. However, these benefits need to be weighed against the complexity and cost of estimating load on a basis

[50] NGC's analysis indicates that at least 31 zones would be required to guarantee that greater than 75% of the expected volume of constraints could be captured, whilst a nodal definition of rights would provide for closer to 100% constraint capture.

other than GSP groups in particular in assessing its impact in other areas of the arrangements; and

- **temporal definition:** Our initial view is that access rights should be defined on a half hourly basis. Any more aggregate a definition would substantially decrease the effectiveness of access right trading as a means of resolving transmission constraints.

Determination of the volume of access rights and the means of their primary allocation

5.17 We remain of the view that auctioning transmission access rights is an efficient and non-discriminatory form of primary allocation. Thus, one option would be to employ auctions for both entry and exit rights, with secondary trading being used by participants as well as the SO to fine tune their positions and an access imbalance regime designed to incentivise participants to match their physical positions to their access right holdings.

5.18 However, a possible alternative would be to rely entirely upon secondary trading to deliver market based locational signals. Some simple allocation of firm access rights would be made to all participants for which they would pay a (possibly locational) access charge. The SO would then use secondary trading to resolve transmission constraints. One possibility would be for the SO to rely on option contracts to achieve this by selling options to constrain on generators or consumers and purchasing options to interrupt their intended use of the transmission system. The options would be bilateral contracts between NGC and participants, specifying the rights and obligations of each party, the payment terms and the penalties in the event of non-delivery. Appropriate non-delivery charges would ensure the "firmness" of the rights and obligations and there might be no need for a complex access imbalance settlement system. The effect in terms of price signals should be broadly the same as the auction approach (although auctions might give more detailed half-hourly price signals).

5.19 A range of intermediate approaches would also be possible. For example, the approach of auctioning entry rights but allocating exit rights has been proposed for the GB gas market.

5.20 In general, Ofgem's initial view is that if it is uncertain that liquid secondary trading will develop then the use of auctions as the primary allocation mechanism becomes more important to ensure locational market based price signals emerge. If primary auctions form part of the new access arrangements, our initial views on some key issues can be summarised as follows:

- **the extent of SO involvement in access volume determination**: Two broad approaches can be taken to the extent of central involvement in determining access volumes. First, the SO could determine the absolute volume of entry and exit rights that will be sold in any auction. This requires taking views on the patterns of generation, demand and transmission availability. Second, the SO could simply determine the capability of the transmission system to transport electricity from one location to another (transfer capabilities). The volume of entry rights available at a particular location would then depend on how many exit rights were sold because it is the difference between the two that defines the allocated transfer. There are advantages in terms of efficiency and consistency with NETA in opting for an approach which involves central determination of transfer capabilities only, and which does not require centralised forecasting of demand and generation in order to determine absolute access volumes. However, further consideration will need to be given to the potential loss of transparency under this approach as a result of the absolute volume of rights available not being known with certainty prior to the primary allocation process. It is likely that the choice of zonal or nodal definition of rights (as discussed in Appendix 1) will be of relevance here, as forecasting absolute entry/exit volumes rather than just transfer capabilities between locations may be less consistent with a nodal regime;

- **the definition of the volume of access rights to be allocated**: Further consideration needs to be given to exactly how to define transmission capability. However, in principle Ofgem believes that any allocation process should make available the maximum possible volume of access rights (given the transmission network) through a combination of the primary allocation mechanism and appropriate incentives on NGC to release further capacity in secondary markets. The granting of firm access rights necessitates the introduction of so-called “use it or lose it” provisions to prevent participants from hoarding rights in order to restrict access to the system or drive up the costs of resolving constraints.

- **the nature of the primary price auction**: Our initial view is that a simple auction format should be chosen in order to maximise transparency and to enable participants to make a clear link between the bids they have placed and the allocation they have received. However, (as discussed above) we also recognise that there are merits in facilitating the efficient allocation of access rights through the primary auction if it is likely that secondary trading will be illiquid. Consideration will therefore need to be given to the trade-offs between simplicity in auction design and the efficiency of the allocation. Ofgem believes that reserve prices may be appropriate to mitigate the effects of market power in primary auctions for access rights in areas with limited competition and could play a role in ensuring that the SO is able to cover its short-run avoidable costs and, to the extent necessary, the costs of investments required to make the capacity available (they may also have a role in relation to the pricing of transmission losses). However, given the potential for reserve prices to distort market outcomes and prevent markets clearing, careful consideration should be given to their use; and

- **the bundling of rights in the primary allocation process**: Ofgem’s initial view is that the underlying rights need to be defined on a half-hourly basis. While bundling of half hourly rights in the primary allocation process would simplify the auction process, we consider that the degree of bundling incorporated should principally be determined by the preferences and requirements of market participants. We see advantages in keeping the products sold via the primary allocation relatively simple, and relying on the secondary markets to unbundle primary rights, when participants will be better able to judge their half-hour by half-hour requirements. However, as with the question of the volume of rights, consideration will need to be given to the trade off between product simplicity and the efficiency of long term price signals.

Nature of secondary trading of access rights, including the role of the System Operator

5.21 There are a number of issues that need to be considered in relation to the role and form of secondary trading of access rights, and in relation to the role of participants and the SO in such secondary trading. Below we outline our initial views on each of these issues:

- **need for SO facilitation of secondary trading**: Ofgem's general preference would be for a variety of secondary markets to develop in response to the needs of market participants. However, we recognise that, depending on other choices made in relation to the design of the regime (in particular, whether the primary allocation method involves auctioning or allocating rights), secondary trading may need to be facilitated by NGC. Indeed, any form of nodal regime would be likely to require SO facilitation to allow competition to evolve between participants in different nodes;

- **extent to which the SO should release products other than firm rights**: Ofgem continues to believe that interruptible rights can play a role in preventing the hoarding[51] of access rights and ensuring that the maximum volume of capacity is made available to participants. Owners of firm rights should be required to 'use them or lose them' and this would be achieved by allowing the SO to sell interruptible rights. Ofgem also considers that it may be worth considering auction processes that allow the SO to buy options to interrupt demand or generation and sell options to constrain-on generation and demand for, say, a specified number of occasions or during specified periods; and

- **SO incentivisation**: As we have already made clear, Ofgem believes that access rights released by the SO should be firm in the sense that the SO is obliged to repurchase these rights at market prices if they cannot be delivered. Ofgem believes that it will be important that effective SO incentive arrangements, encompassing the new access regime, are implemented at the same time as the new arrangements. Such incentive arrangements will have an important role to play in ensuring that NGC makes all capacity available to the market and effectively manages the costs of resolving constraints. We believe that NGC should face a consistent access, electricity balancing and system balancing incentive scheme, with this being linked via defined and transparent output measures (entry and exit capacities) to the Transmission Price Control.

The interaction between the access regime and the electricity balancing arrangements under NETA

5.22 There are two main issues in relation to how the transmission access regime might interact with NETA. Ofgem's view in respect of these issues is as follows:

- **treatment of access rights for Balancing Mechanism bids and offers:** Given the significant implications that the treatment of access rights in the BM will have for imbalance prices, it is important that further detailed consideration is given to this issue once other elements of the access regime have been decided. The option of allocating access rights to participants whose offers are accepted may have merits, in that it avoids participants or NGC purchasing rights they may not require but this could also be achieved by allowing the trading of access rights to continue after Gate Closure.

- **interactions with forward electricity prices:** Ofgem accepts that there may be some advantages in specifying a national balancing point around which participants can price their access right bids and offers but believes that further consideration needs to be given as to the overall desirability of such an approach, particularly if locational reserve prices are adopted for auctions. If it is adopted, it will be important that the national balancing point does not coincide with a physical node on the network since access at this point will by definition be free for the period for which rights are allocated, irrespective of whether, as the pattern of supply, demand and transmission availability changes, the nominated location becomes constrained.

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[51] Whether hoarding is likely to occur will depend on other aspects of the regime, notably the access imbalance settlement arrangements.

The access imbalance settlement regime

5.23 Ofgem's initial views in respect to each of the key issues surrounding an access imbalance settlement regime can be summarised as follows:

- **rules based regime versus imbalance settlement mechanism:** Ofgem's initial view is that participants' holdings of transmission access rights would be best incentivised through an appropriate access right imbalance and settlement mechanism rather than a rules based regime. However, if secondary trading is restricted to the SO selling constrained-on options and buying interruption options, then, as discussed above, penalties for non-delivery (failing to reduce output or demand in interruption options and failure to maintain output or demand in constrained-on options) in the option contracts could take the place of an access imbalance settlement system;

- **nature of the access imbalance regime:** our initial view is that a two-sided cash-out regime is not appropriate for access imbalance. Instead, when participants have paid to acquire access rights they should be subject solely to over-run charges. Conversely, when participants have been paid to provide a service (including when they have been paid to take access rights), we consider they should be subject solely to under-run charges for failing to deliver the service.

- **determination of access imbalance volumes:** Our initial view is to prohibit netting off of entry and exit imbalances, since it could unduly discriminate in favour of vertically integrated participants. By definition, netting-off would not occur if the imbalance regime related to failures to meet contractual obligations;

- **determination of access imbalance prices:** Overall, Ofgem believes that there is strong merit in relating access imbalance prices to the costs incurred by the SO in resolving transmission access. With regard to whether imbalance prices should be locational or national, we consider that it would not be possible to provide participants with appropriate cost signals if a national imbalance price were used.

The interaction of the access regime with the Transmission Price Control and transmission charges

5.24 It is expected that TNUoS charges will continue to be required for NGC to recover the costs of building and maintaining the transmission network (i.e. its allowed revenue under its Transmission Price Control). Together, the proposals for trading firm access rights (including, potentially, their auctioning) and charging losses on a marginal basis are expected to result in net revenue surpluses. However, it is likely that there will be a difference between these surpluses and the allowed Transmission Price Control revenue and hence some form of TNUoS charge will still be needed in order to account for this difference.

5.25 Under the proposed new regimes for pricing transmission access and transmission losses, participants may see short run locational cost signals based on the costs of transmission constraints and marginal transmission losses. In this environment, the use of locational TNUoS charges based on NGC's Investment Cost Related Pricing (ICRP) methodology (as at present) might overstate locational incentives and hence could lead to inefficient investment decisions. Some adjustments to the locational nature of TNUoS are therefore likely to be in order, although the ICRP methodology might still have a role to play in calculating the minimum prices at which NGC might be willing to offer incremental access rights on a longer-term basis. The ICRP mechanism could, for example, form the basis for setting reserve prices in primary access right auctions. Moreover, if the primary allocation mechanism does not involve auctions, it is particularly likely that there will be a need for some form of locational access charge.

5.26 In addition, since participants will face short run marginal signals for all periods, including the system peak, there may be a case for no longer linking charges to use of the system at times of system peak. In addition, it is for consideration whether generators and suppliers should share equally the costs of TNUoS.

5.27 It is important that NGC is properly incentivised to ensure that all transmission capacity is made available and to expand capacity where it is efficient to do so. Prices from the primary and secondary access markets can help to signal the need for new capacity. However, to ensure NGC provides the appropriate capacity, it will be necessary for NGC to face consistent and co-ordinated incentives across the Transmission Price Control, the SO incentive scheme and any incentive scheme for access rights. The access, electricity and system balancing incentives that NGC faces should be linked via defined and transparent output measures to the Transmission Price Control.

Summary and Views Invited

5.28 Views and comments are invited on the key building blocks and the key options within them discussed in this chapter: particularly:

- the two proposed options for the treatment of losses;
- the specification of access rights;
- the extent of participation in the access regime;
- the locational and temporal resolution of exit and entry access rights;
- the volume of rights to be allocated and the extent of central involvement in volume determination;
- the nature of the primary allocation mechanism and whether this should be the same for entry and exit rights;
- the need for SO facilitation of the secondary trading process;
- the extent to which SO should release products other than firm access rights;
- the treatment of access rights for BM bids and offers; and
- the nature of the access imbalance regime, including the determination of access imbalance volumes and prices.

6. A possible approach

Introduction

6.1 Chapter 5 laid out the key issues that need to be considered in defining new transmission access and losses arrangements and presented a broad overview of Ofgem's thinking in each individual area. This chapter presents a summary of one possible approach that combines the various building blocks in a consistent manner. Whilst the approach presented reflects Ofgem's initial views on transmission access and losses, the primary purpose of this chapter is to outline a coherent set of proposals against which participants can consider the merits of alternative approaches to the various elements.

Transmission losses

6.2 Ofgem believes that enduring arrangements for transmission losses should be designed to expose participants to the costs of locational marginal losses. We accept that this could be achieved in different ways. However, of the approaches considered in this document, we believe that Option 1, which involves adjusting participants' metered volumes using estimates of average zonal loss factors with a separate financial payment or levy to reflect the difference between estimated marginal loss factor and the average loss factors used to adjust metered volumes, would best meet the objectives set out in Chapter 3. Under this approach, effective short term signals would be sent to all participants as to the costs of transmission losses. This approach also fits well with the framework for traded wholesale electricity markets established by NETA, since participants would have the opportunity to manage their exposure to the costs of transmission losses.

A market in firm tradable access rights

6.3 Ofgem believes that without new transmission access and pricing arrangements, we will continue to see inefficiencies in both the short term operation and long term development of the electricity market. On the direction of reform, we have argued that a new regime based around a market in tradable firm access rights for CUSC signatories will offer the most transparent, non-discriminatory and effective means of valuing and pricing transmission access in the short and long term.

Defining and allocating entry and exit rights

6.4 Rights made available to participants to use the transmission system (access rights) should be well defined and the linkages between the requirement to pay use of system charges, the ability to impose costs on NGC from using the system and the entitlement to compensation for the curtailment of access rights should be consistently applied to all participants. In this context, Ofgem believes that there is strong merit in two sided transmission access arrangements, which allow the demand side to play an active role, but we accept that it may be appropriate to treat the two sides of the market differently in some respects.

6.5 With respect to the generation (entry) side of the market, Ofgem believes that access rights should be sold in a simple and transparent price auction. Based on NGC's analysis, Ofgem considers that it may be necessary for these entry rights to be split between a relatively large number of zones (around 30) in order that the SO can resolve the most constraints via the trading of access rights. Whilst ultimately these rights would relate to individual half hourly periods (for access imbalance settlement purposes), they could be sold for significantly longer durations (five years and more). As far as possible, Ofgem considers that the discretion that the SO has in determining the volume of access rights made available in the entry right auctions should be kept to a minimum.

6.6 Although we accept that reserve prices can distort the market if they are set at an inappropriate level, we consider that they may have a role to play in mitigating the effects of market power in primary auctions for access rights in areas with limited competition. Reserve prices could also be used to ensure that the SO is able to cover its short-run avoidable costs (in the absence of constraints, these are likely to be low) and, to the extent necessary, the costs of investments required to make the capacity available.[52]

[52] For example, a reserve price related to the SO's short-run avoidable costs could be applied in respect of transmission capacity that already exists but a higher reserve price could apply if participants sought to acquire access rights which would require the SO to reinforce or extend the network.

6.7 We believe that the allocation process should make available the maximum possible volume of access rights (given the transmission network in place) through a combination of the primary allocation mechanism and appropriate incentives on NGC to release further capacity in the short term (including close to real time) and invest in further capacity, where efficient and economic, in the long term.

6.8 With respect to the demand (exit) side of the market, Ofgem believes that whilst auctions could also be used here to allocate firm rights, it may not be necessary to use auctions to make the primary allocation of access rights. The extent to which the demand side as a whole can help to resolve constraints may be limited as compared to the generation side of the market, particularly if it is considered impractical to adapt their meter registration and data collection (the Supplier Volume Allocation System, known as Stage 2 under the Electricity Pool) to allow for greater regional differentiation of access rights on the demand side.[53] Nonetheless, individual large customers or groups of customers may have a valuable role (for example, by agreeing to be interrupted on instruction from NGC). Hence, Ofgem considers that it may be better to concentrate on arrangements for the demand side that facilitates this kind of approach. We believe an alternative and preferable approach to auctioning would be to allocate firm exit rights to all consumers in return for payment of a locationally varying access charge, possibly set on the basis of the prices emerging from the primary auction of entry rights. Participants who have been allocated exit rights would be free to choose whether or not to participate in secondary trading (either via options contracts or more directly). In this way, participants who did not wish actively to trade their access rights would face a simple system with transaction costs comparable to those under the initial NETA arrangements.

[53] If these systems were not to be adapted and hence the contribution of the demand-side to constraint resolution was limited, we accept that the transactions costs associated with a primary auction of access rights may not be justified.

Secondary trading

6.9 Having sold firm entry rights and firm exit rights, participants would be able to trade these firm rights in secondary markets. In addition, NGC should use secondary markets to buy and sell firm access rights, as required, to resolve transmission constraints, to release further firm capacity as additional capacity becomes available and to procure interruptible (and potentially constrained on) services, particularly from customers, via tenders or auctions for option contracts. It will be important that NGC is properly incentivised to trade efficiently in secondary markets and release further capacity where this is possible.

6.10 Ofgem believes that secondary markets should develop in response to the needs of market participants, but we recognise that it may be necessary to have some SO facilitation both for its own trading and to encourage liquidity in trading between participants. We also consider that the granting of firm access rights will necessitate the introduction of "use it or lose it" provisions to prevent participants from hoarding rights. One method of implementing such provisions would be for the SO to sell interruptible access rights at, say, the day-ahead stage. The volume made available would reflect the SO's view of the quantity of rights that had been allocated but were unlikely to be used. If, in the event, a participant used rights that the SO had assumed would be available then the SO would exercise its option to interrupt participants who had purchased interruptible access rights (or sold interruptible option contracts).

Interactions with NETA

6.11 The interactions between the access regime and the electricity balancing arrangements under NETA will influence the success of the new access regime in addressing the NETA related issues outlined in Chapter 3. Ofgem believes that the treatment of access rights for BM acceptances should be consistent with the arrangements in the gas market so that interactions between the two markets are efficient. Thus, we believe that the SO (and perhaps other participants) should be able to continue to buy and sell access rights after Gate Closure as required in order to accept BM bids and offers. If Gate Closure is moved closer to real time in the near future, the issue of access rights for BM acceptances will become less significant, as NGC will predominantly be buying and selling access rights and electricity in short-term forward markets rather than the BM.

6.12 With respect to whether a NBP needs to be defined, Ofgem considers that this is primarily a matter for market participants. Nonetheless, we believe that if the national balancing point is specified it should not be a physical node on the network i.e. it should be a notional node.

Imbalance charges

6.13 Ofgem believes that all participants should face the right commercial incentives in relation to the costs imposed by over or under running against firm access rights. Therefore, Ofgem believes that all participants should face imbalance charges of some form that maintain the ‘ticket to ride’ principle and ensure that participants purchase firm rights before generating or consuming electricity.

6.14 Our view is that a half-hourly imbalance settlement regime based on one sided access imbalance charges is appropriate. Thus, when participants have paid to acquire access rights they should be subject solely to over-run charges. Conversely, when participants have been paid to provide a service (including when they have been paid to take access rights), they should be subject solely to under-run charges for failing to deliver the service. In practice, we expect this to mean that holders of exit rights are unlikely to face a significant exposure to access imbalance charges unless they participate in secondary trading (including buying option contracts from NGC or selling them to NGC).

6.15 Over and under run charges should be related to the costs incurred by the SO in resolving transmission constraints through the secondary trading of access rights. In order to provide effective signals to participants these imbalance prices will need to be locational. For the reasons outlined in Chapter 5, we do not believe that the netting of entry and exit imbalances should be allowed.

6.16 Holders of firm exit rights and those customers that have contracted with NGC to provide an interruptible or constrained on service should face similar incentives. Ofgem believes that penalties for failure to deliver these services should be set out in the contracts to ensure that it is always in a customer’s commercial interest to deliver the service when called to do so by NGC.

Interactions with the Transmission Price Control and transmission charges

6.17 It will be important that, over time, NGC faces complementary incentives with respect to constraint alleviation through a link between transmission output measures defined as part of the Transmission Price Control and the incentives on day to day management of constraint alleviation under the SO incentive scheme. Equally, the SO incentive scheme will need to deliver consistent signals with regard to NGC's actions in electricity balancing, system balancing and access right trading. Ofgem considers that NGC should be exposed to the (opportunity) costs of constraints as determined in secondary markets where it fails to deliver entry and exit capacity output measures agreed as part of the Transmission Price Control and should be allowed to earn additional revenues where it exceeds them. In this way, NGC should be incentivised to invest in the transmission network to meet customers' needs where it is efficient to do so. Such an approach would be consistent with the long term investment regime proposed for Transco's National Transmission System in gas.

6.18 With respect to the form and structure of transmission charges after the introduction of new transmission access and pricing and losses arrangements, Ofgem believes that some adjustment to the basis for calculating TNUoS charges is likely to be required. Specifically, a mechanism to deal with any financial surplus or shortfall, relative to allowed revenues under the price control, will be required. In addition, we consider that, on the generation side of the market at least, if auctions for firm entry rights are introduced with reserve prices related to the long run marginal costs (or some proportion thereof of the transmission system, TNUoS charges should no longer be locationally differentiated. If there were to be separate locationally differentiated access charges relating to the initial allocation of exit rights, then equally there would be a case for having uniform demand TNUoS charges. Finally, Ofgem believes that there may be a case for no longer linking charges to use of the system at times of system peak and to move to charging on a per MWh basis.

Assessment against objectives

6.19 In Chapter 3, we outlined four main objectives for reform to overcome deficiencies in the initial NETA arrangements:

- **NETA related issues**, to separate the pricing of electricity from the pricing of transmission access and to ensure transparency in the actions of all participants;
- **short and long term efficiency issues:** to establish a framework to target the costs imposed on the system by the locational patterns of generation and demand;
- **NGC investment signals and incentives:** to provide effective signals and incentives on NGC related to making transmission capacity available and appropriately investing in the transmission network; and
- **gas –electricity market interactions**: to provide a framework for effective and efficient interactions.

6.20 In this chapter, we have argued that any enduring arrangement for transmission losses should be designed to expose participants to the costs of locational marginal losses. With respect to transmission access arrangements, we have argued that a new regime based around a market in tradable firm access rights (which nonetheless recognises the practical difficulties of treating generation and demand in an identical fashion) will offer the most transparent, non-discriminatory and effective means of valuing and pricing transmission access in the short and long term.

6.21 Ofgem believes that the firm access rights regime described in this chapter would address the deficiencies in the initial NETA arrangements, and meet the objectives of reform since:

- the pricing and trading of access and energy would be separated and the potential gains to participants from exploiting locational market power would be reduced through increased transparency and better defined rights and obligations;

- transmission related costs and benefits would be revealed in traded capacity markets and be better targeted to those that cause and create them through the allocation of firm access rights and the imposition of imbalance charges. All participants would receive effective short and long term signals of transmission related costs through auctions of firm entry rights, and the secondary trading of both entry and exit rights (including option contracts for the interruption or constraining on of participants) and charges for locational, marginal transmission losses. Participants would be given the means to manage their exposure to transmission costs through tradable access rights and by being able to meet their own losses obligations;

- NGC would face effective signals to make an efficient level of capacity available in the short and long term through an appropriate incentive mechanism. It would have an incentive to operate the system efficiently day to day and invest in new capacity, where economic, given the signals provided by the buyback and sale of transmission access rights; and

- the arrangements described above are consistent with those implemented and proposed for the gas market. Participants, existing and prospective, would, therefore, face consistent price signals and incentives between the two markets.

7. Way forward and summary of views invited

Introduction

7.1 Ofgem believes the process for developing and implementing new transmission access and losses arrangements should be open to all interested and affected parties. In addition, we recognise that significant industry resource is currently focused on the implementation of the CUSC and adapting to trading under NETA.

7.2 Against this background, this chapter describes Ofgem's initial views on the way forward in relation to new transmission access and losses arrangements and summarises the key issues on which views have been invited elsewhere in the document.

Transmission losses

7.3 Depending upon the approach selected,[54] it may be possible to implement a more cost reflective regime for transmission losses independently of the implementation of transmission access arrangements. For example, if the use of locational loss factors to adjust metered volumes coupled with an additional BSUoS charge for the difference between marginal and average loss factors (option 1 from Appendix 8) were felt to be the most appropriate way forward, this could be implemented prior to changing the access arrangements, using the provisions for locational transmission loss factors included in the BSC, along with appropriate amendments to BSUoS charges. In contrast, if marginal loss charging was to be achieved via reserve prices for access auctions (option 2), this could only be implemented at the same time as the new access arrangements. It would also be possible to move from option 1 to option 2 following the implementation of the access arrangements.

7.4 The route taken in relation to the implementation of enduring transmission losses arrangements, along with the responsibility for implementation, will therefore be dependent upon the option adopted. Nevertheless, it is likely that

[54] The changes required to implement option 1 do not depend on the introduction of new transmission access arrangements whereas those for option 2 do.

under either approach, changes will be required to a number of regulatory and contractual documents, including:

- CUSC (particularly if option 1 were adopted since this would be bound up with the modifications required to implement new transmission access arrangements);

- NGC's Transmission Licence (particularly if option 2 were adopted because of the changes to BSUoS and hence the SO incentive scheme, but more generally if the basis for setting TNUoS charges were to change. Consequent on changes to NGC's licence, changes would be required to its charging methodology statements);and

- the BSC (both options represent a change to the current methodology).

Transmission access arrangements

7.5 As noted elsewhere in the document, the implementation of enduring arrangements for transmission access is likely to represent a significant undertaking. Below we outline briefly the approach envisaged for taking forward the initial design work in relation to the regime, and for the implementation phase, once the design of the arrangements themselves has been finalised.

Design and implementation phases

7.6 Following publication of this document, Ofgem will consider the responses received. It is then intended that we would issue a further paper, setting out our views on these responses, and our subsequent thinking on the issues raised in this consultation paper and on the general direction of the overall design.

7.7 Following the publication of this further paper, the next step will be a design phase for new transmission arrangements to be led by NGC, in consultation with all interested parties. To ensure a high level of industry engagement in the consideration of options and issues outlined in this document and the development of detailed proposals for implementation, NGC will be using a relevant industry forum to consult with the industry during the design phase of the new arrangements. Ofgem expects substantial progress on the design phase to have been made by the end of 2001 and hence we anticipate the publication of a progress report at this time.

7.8 We envisage that modifications to the CUSC will be the main vehicle through which new transmission access arrangements will be implemented, which Ofgem will need to approve. Thus, following completion of the design phase, detailed modifications to the CUSC to implement the new regime will need to be proposed, drafted and submitted for approval via the CUSC governance arrangements. At this stage, it will be necessary to consider any alternative proposals that may be raised as part of the modification process. In addition, changes are likely to be required to NGC's Transmission Licence and its charging methodologies. Some, less substantive, modifications may need to be raised in respect of the BSC.

7.9 During the design phase, further thought will need to be given as to the most appropriate way to manage the implementation process for the new arrangements, particularly given the likely impact of the new regime on market participants and other industry organisations. It should also be possible for NGC to begin the initial stages of systems scoping and development. For example, it will be possible to ask for initial expressions of interest from potential IT system developers.

7.10 Ofgem considers that it is important in determining the timetable to balance the need for reform and the need to give careful consideration to a range of difficult issues. In particular, there is a need to keep to a minimum the period during which the new electricity trading arrangements are operating without consistent and efficient transmission access and losses arrangements. Moreover, given the essential linkages to the BETTA project, it is important that implementation of new arrangements occurs as soon as is practicable.

Interactions with BETTA

7.11 In parallel with the consultation on the design of the new arrangements, Ofgem will consider the implications for trading and transmission arrangements in Scotland. This will be taken forward in conjunction with the BETTA steering group and associated workstreams. Thus, it will be important that, during the design phase, the issues and options considered are robust to GB wide transmission access arrangements.

Summary of views invited

7.12 Ofgem invites views generally on the issues and proposals raised in this report (although it is likely that the detailed questions raised in the Appendices to this document could more sensibly be discussed as part of the design and implementation phase of the new regime). The most significant questions and proposals that have been raised in the preceding chapters are summarised below.

The need for reform

- the weaknesses of the initial NETA arrangements;
- the scope of the problem; and
- the objectives and benefits of reform.

The key building blocks of a new transmission access and losses regime

- the introduction of a marginal losses regime;
- the specification of access rights;
- the extent of participation in the access regime;
- the locational and temporal resolution of exit and entry access rights;
- the volume of rights to be allocated and the extent of central involvement in volume determination;
- the nature of the primary allocation mechanism and whether this should be the same for entry and exit rights;
- the need for SO facilitation of the secondary trading process;
- the extent to which SO should release products other than firm access rights;

- the treatment of access rights for BM bids and offers; and

- the nature of the access imbalance regime, including the determination of access imbalance volumes and prices.

Ofgem's possible approach

- a marginal losses regime based around adjusting participants' metered volumes using estimates of average zonal loss factors with a separate financial payment or levy to reflect the difference between the full marginal loss factor and the average loss factors used to adjust metered volumes;

- a transmission access regime based around a market in firm tradable access rights, involving both sides of the market but probably with separate locational definitions for entry and exit rights;

- the use of auctions for entry access rights (possibly with reserve prices), with exit rights allocated in return for the payment of a locational access charge. Rights would be allocated on a "use it or lose it" basis;

- an allocation process that makes the maximum possible volume of rights available (given the transmission network) through a combination of the primary allocation mechanism and incentives on the SO to release further rights if they become available in the short term and to invest in further capacity, where efficient and economic, in the long term;

- secondary markets that develop in response to the needs of participants and the SO, recognising that this may involve some degree of SO facilitation. These markets would remain open after Gate Closure to allow participants to acquire access rights to back their BM bids and offers;

- all participants facing imbalance charges of some form that maintain the 'ticket to ride' principle and ensure that they purchase firm rights before using the system; and

- locational over and under-run charges related to the costs incurred by the SO in resolving transmission constraints through the secondary trading of access rights. Participants who had paid to acquire rights should face an over-run charge whilst those who had been paid to take rights (or to be interrupted) should face under-run charges for failing to deliver the agreed service.

Appendix 1 Defining transmission access rights

Introduction

1.1 In Chapter 3, we outlined a number of objectives that new transmission access and pricing arrangements should seek to achieve. These included providing appropriate economic signals to all participants of the long-term and short-term value of generation and demand in different locations so as to encourage efficient use of resources.

1.2 With these objectives in mind, this appendix discusses how transmission rights might be appropriately defined in the context of an access rights regime. In considering the various options for the definition of access rights, there are a number of important trade-offs to consider. The decisions made in this regard will have a significant impact on the value of access rights, the way in which price signals are sent to all participants and the usefulness of the regime in resolving transmission constraints. Although at the highest level the issues discussed in this appendix would be relevant whatever form of access right regime was introduced, the more detailed discussions are most relevant if the regime includes a primary allocation involving auctions, subsequent participant-to-participant trading and a full access imbalance settlement regime.

1.3 Ofgem has been in continuing discussions with NGC on the definition of rights and related issues and these discussions are reflected in this and later appendices.

The December Consultation

1.4 Ofgem argued that an efficient transmission access regime would include appropriate economic signals regarding both the short and long term value to market participants of transmission capacity in different locations, thus providing an appropriate mechanism for allocating and pricing access to and use of the transmission network.

1.5 In the December Consultation, Ofgem noted that defining access rights more clearly would be an important first step in the design of new transmission access arrangements. Moreover, Ofgem argued that access rights must be locationally defined. At its most detailed, this could involve defining rights for individual nodes. However, given the size and complexity of the England and Wales transmission system and the systems in place for domestic supply competition, Ofgem suggested that this might not be feasible. Thus, access rights might need to be based around groups of nodes i.e. zones. Ofgem argued that an appropriate definition of zones would be needed to ensure that the value of access rights could be discovered via the combination of a primary allocation mechanism and trading in secondary markets. The December Consultation also argued that access rights should be defined on the basis of entry/exit to the transmission system rather than as location to location (point to point) rights.

NGC's views

1.6 In its response to the December Consultation, NGC agreed that an access regime based on the trading of firm entry and exit rights had the potential to send appropriate economic signals to market participants. It also agreed that a market in access rights would align more closely with NETA than other possible options.

1.7 NGC stated that full constraint resolution would require rights to be defined nodally but noted that for there to be liquid unfacilitated secondary trading,[55] rights would have to be defined zonally with the zones being sufficiently large for there to be enough competing buyers and sellers. NGC's view was that acceptable compromises with regard to zonal definition might be possible, but these would depend on the solution to practical problems, such as the Stage 2 settlement limitation that half hourly demand data by supplier is only available at the Grid Supply Point (GSP) Group level (discussed later).

1.8 Since the December Consultation, NGC has developed its thinking on how a market in firm access rights might operate. NGC has told us that whilst a market on the lines suggested by Ofgem would, of necessity, be fairly complex it does not believe that such complexity necessarily challenges the feasibility of the proposed approach.

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[55] By "unfacilitated trading", we mean direct bilateral trading between participants that does not involve the SO as a "market making" intermediary.

Other respondents' views

1.9 Twelve respondents to the December Consultation commented on issues concerning the temporal and spatial definition of access rights. Most of the respondents voiced concerns about the potential for significant complexity in the design of a market in firm access rights. Several participants argued that the cost of such a regime could outweigh any benefits it might have and that a less rigorous approach might be more appropriate by virtue of its simplicity. Several respondents also suggested that changes to the current system of access rights might add undue risk and uncertainty and threaten existing and future investments.

1.10 A number of respondents supported the objective of separating the pricing and trading of energy from the pricing and trading of transportation, but suggested that the new capacity regime in gas was not directly transferable to the electricity sector. One respondent warned about the limited effectiveness of an auction process if there is only one bidder involved, as might arise if there were a large number of zones.

1.11 Of the respondents who welcomed a new regime based on firm access rights, the majority advocated a zonal approach. One respondent believed that transmission access zones would need to be fixed and coincidental with GSP Groups because of the Stage 2 settlement arrangements.

The August Transmission Access Workshop

1.12 At the August Workshop, Ofgem emphasised the importance of definitional issues in the overall design of a new transmission access and pricing regime. In particular, the debate focused on the spatial definition of access rights and the trade-offs involved in arriving at an appropriate definition. Ofgem noted four main trade-offs that need to be considered in defining both the access rights themselves and the volume to make available:

- liquidity in secondary trading;
- effectiveness in resolving constraints;

- competition and market power; and
- incentives on all participants.

1.13 We suggested that the way in which these were resolved would strongly influence the effectiveness of the access rights market in terms of resolving constraints before Gate Closure and/or in encouraging the development of liquid trading in access rights. Ofgem also noted that the trade-offs would need to be considered in the context of wider objectives and principles.

1.14 NGC carried out some analysis highlighting the severity of the trade-off between constraint capture and zonal competition under a number of different zonal scenarios. A number of participants highlighted approaches taken in other markets including the use of transmission rights based on access to so called "flow-gates" or rights to flow across multiple congested paths.

Responses to the August Workshop

1.15 Several respondents to the August Workshop commented on issues relating to the definition of access rights. A concern expressed by many respondents was the potentially high level of complexity that could arise from decisions made with regard to the definition of access rights particularly in relation to access right imbalance and settlement. A further concern was that the level of constraint capture under the zonal definitions of access rights presented by NGC was, on average, only around 40%-50%.

1.16 On the question of whether entry and exit zones should be defined on the same spatial basis, several demand-side participants argued that a one sided (generator only) market should be considered. Under such an approach, only entry zones would need be defined and used for the allocation and trading of rights by generators whilst a locationally differentiated TNUoS charge could remain for the demand side of the market. These participants argued that this simplification would reduce the cost and complexity of any new regime. One respondent also stated that it was not convinced that GSP Groups could easily be split to allow for both demand side participation and effective constraint capture. A number of demand side participants also argued that it was unclear how active the demand side might be in any new transmission access and pricing arrangements since demand is not generally price elastic in the short term.

1.17 Overall, respondents appreciated that the definition of access rights, and for that matter the design of new transmission access and pricing arrangements, would involve a compromise between a set of conflicting trade-offs. One participant suggested that the next stage of the process should be to prioritise the objectives of the regime before discussing the issues in further depth.

Discussion

1.18 In light of the responses received to the December Consultation, feedback from the August Workshop and ongoing discussions with NGC, Ofgem has developed its thinking on the core issues surrounding the definition of transmission access rights. The discussion below describes the issues and potential options in relation to five key aspects of defining transmission access rights:

- **specifying the access product**: should access rights be defined in relation to location – entry or exit rights for specific locations, or rights between locations (termed here "flowgate" rights)?
- **participation in the access right regime:** should both the generation and demand side participate in the regime?
- **locational resolution***:* what should be the locational resolution of rights?
- **symmetry of locational resolution:** should the locational resolution of generation and demand rights be the same?
- **temporal definition***:* should rights be specific to a particular time of day?

Specifying the access product

1.19 Below we consider two potential access right regimes:

- **Entry and exit rights**: the holder of an entry right would have the right to inject power into the transmission system at a specified location for a particular time period, whilst the holder of an exit right would have the right to take power out of the system at a specified location for a particular time period. Injections or offtakes above the level of rights held by a participant could result in an access imbalance charge liability as could injections or offtakes below a participant's holding of rights if the participant had been paid to take rights; and

- **"flowgate" rights**: the holder of a flowgate right would have the right to flow power over a particular circuit or circuits (the flowgate) for a specified time period. Flows of power through a flowgate above or below the level of rights holding by a participant could result in an imbalance charge liability (or potentially receipt). Given the need for participants to be able to determine the flowgates through which their power will be deemed to flow, and the need to relate rights back to measurable metered inputs and offtakes for settlement purposes, a set of "participation" factors would be needed. These participation factors would specify, for a 1 MW injection or offtake at a particular location and time, and the assumed MW flows through each flowgate. The factors would probably need to be calculated *ex ante*, in order that participants had some certainty over the portfolio of flowgate rights they would require. If the actual factors were calculated *ex post*, at the very least indicative factors would be required *ex ante*.

1.20 Both forms of access regime would be capable of delivering the correct locational signals to participants. However, Ofgem believes that there are some significant drawbacks with the flowgate approach:

- **reliance on stable network configuration**: the calculation of the participation factors described above would probably need to be carried out centrally by the SO prior to the primary allocation process. Given that the participation factors would determine the relationship between inputs/offtakes and flowgate use, and would be used in the imbalance settlement process, the factors for any given half-hour settlement period would need to remain constant following the primary allocation. If this were not the case, for any given output or consumption level, participants would be faced with a moving target whilst attempting to determine whether their holding of flowgate rights was adequate. Since the participation factors depend principally upon the configuration of the transmission system, the effectiveness with which a flowgate market represents the physical characteristics of the transmission system in real time will depend on the stability of network configuration from the time of the primary auction. The stability of the network's configuration will be only partly within the SO's control – and if it is not sufficiently high, the effectiveness of a flowgate market could be significantly reduced. In contrast, in an entry/exit rights market, participants are not attempting to trade to a target portfolio based on an *ex ante* definition of network topology – the SO therefore has a greater ability to influence locational holdings of rights;

- **number of flowgates required**: given the intermeshed nature of the England and Wales transmission system, it is likely that a significant number of flowgates would need to be defined in order to ensure effective constraint resolution. Indeed, since an entry/exit zone can have multiple boundaries, the number of separate products required to achieve the same constraint resolution effectiveness could be significantly higher under a flowgate access regime than under entry/exit based rights.[56] This would unnecessarily increase the transactions costs of participants; and

- **difficulty of valuation of flowgate rights**: more information is required to form a basic valuation of individual flowgate rights than is required for entry/exit rights.[57] [58] While participants will know the aggregate portfolio of flowgate rights that they require, valuation of the individual flowgate rights within that portfolio is more difficult. Their value is derived from modelling of the change in overall despatch costs as a result of an increment in the capacity of the particular flowgate. However, to arrive at this value, it is necessary to take a view on the capability of all transmission lines and the likely behaviour of all market participants on

[56] Even if many of these flowgates subsequently proved to be unconstrained, it would still be necessary for participants to purchase access rights for them.
[57] At a minimum, the information required would relate to capability of transmission lines, the level of the national energy price and own and regional competitors' cost estimates.
[58] This problem could be addressed in part by combining individual flowgate rights into a "path" to a given point. The aggregate products should be easier for participants to value – they would be more akin to rights to or from a national balancing point.

the system – a more onerous requirement than that required to value entry or exit rights. Hence, whilst it would be possible to provide the information needed to carry out a valuation of flowgate rights, the transaction and participation costs in a market based on flowgate rights is likely to be high. This in turn may give an unfair advantage to larger participants.

1.21 For these reasons, Ofgem continues to believe that a new transmission access regime based on entry/exit rights may be preferable to one based on flowgate rights.

Participation in the access rights regime

1.22 In the December Consultation and at subsequent industry seminars and workshops, Ofgem stated an initial preference for a two sided transmission access and pricing regime based around the trading of firm entry and exit rights (i.e. with demand and generation both actively involved in trading rights). We have argued that a two sided market would provide the correct signals to all participants and is consistent with an underlying NETA design principle, namely to encourage active demand side participation in the electricity market. However, a number of respondents to the August Workshop argued that there is merit in considering the value of a one sided or "entry only" access rights regime as a way of reducing the complexity and cost of new transmission access and pricing arrangements.[59]

1.23 A number of arguments could be made for new transmission access and pricing arrangements based around the trading of entry (generation) access rights only. For example:

- it may be that generators are more likely to be able and willing to respond to short-term locational signals than demand side participants. A new transmission access regime based on entry rights only would mean that the resolution of transmission constraints would continue to

[59] Before the introduction of NETA, the Pool arrangements for resolving transmission constraints were effectively one-sided. Although demand side participants paid for the costs of transmission constraints through the Transmission Services Use of System (TSUoS) charges, they had little or no ability to influence the cost of constraint management. Furthermore, there was little incentive for the demand side to respond in the short term to the costs of resolving constraints, since TSUoS charges were levied on a nationwide basis, proportional to each participant's metered load.

be achieved predominantly through actions on the generation side of the market; and

- the use of transmission exit rights could lead to more complicated transmission access and pricing arrangements than would otherwise be necessary, thus imposing additional costs and risks on participants. For example, at present, many suppliers have little control over their customers' load, making it difficult for them to forecast exit right requirements and leaving them with little ability to adjust the electricity consumption of their customers in response to changes in the value of exit rights.

1.24 Thus, it could be argued that if active or effective demand side participation is unlikely then developing transmission access and pricing arrangements that include active trading of exit rights could introduce additional complexity without significantly increasing efficiency and effectiveness.

1.25 However, there are a number of arguments which suggest that more active two-sided arrangements of some form are desirable in order to provide the correct incentives to all participants and to increase the effectiveness of transmission access and pricing arrangements overall:

- **demand side competition to generators.** Although there was little demand side participation in the Electricity Pool, this was in part due to the lack of incentives on demand-side participants to forecast and control their day to day load requirements. The introduction of NETA has placed more responsibility on the demand-side to predict accurately their requirements as well as providing incentives for them to match their physical positions to these forecasts.[60] It could be argued that the sharper incentives to manage their electricity requirements brought about by NETA combined with new access incentives will encourage suppliers to find innovative ways to manage their load and thus compete with generators to resolve transmission constraints;

[60] Under the Pool, demand-side participants actively managed their energy requirements to varying degrees. Several large customers had (and continue to have under NETA) contracts with NGC to provide reserve and response services and many suppliers attempted to manage their peak load requirements in order to limit their exposure to transmission charges based on the demand Triad. Triad demand is broadly defined as the average demand in three half-hours of highest system demand peak.

- **efficient entry and exit right signals.** There are clear linkages between the levels of entry and exit rights available. For example, in any given location, the total volume of entry rights available should equal the total volume of exit rights sold plus the net transfer capability out of the region (after accounting for losses). An increase in demand for exit rights at any given location would mean that more entry rights could be made available at that location and vice versa. Thus, although NGC's planning standards mean that, at the highest level, exit capacity is not generally scarce, the way in which it is allocated has implications for the volume of entry rights that can be made available. If the demand side were unable even to signal their willingness to forego their exit rights i.e. to be interrupted, it will be impossible to achieve an efficient allocation of transmission capacity overall. Thus, at least to this extent it is important to have a two sided regime;

- **consistency of demand and generation price signals:** Efficient transmission access and pricing arrangements would result in entry and exit access prices at the same location that were equal in magnitude but opposite in sign, so that when the access and energy prices are considered together, demand and generation face the same effective locational "value" of electricity. Therefore, even if the treatment of generation and demand is not identical, signals of the locational value of access rights would need to be passed on to the demand side in some way (in order to ensure that all participants in a given location face the same signals).

1.26 Finally, the *de minimis* limits to the requirement to participate in new transmission access and pricing arrangements need to be considered i.e. whether particular classes of small participants are exempted from any part of the arrangements, how "generation" and "demand" is mapped to imports and exports (and/or production and consumption under the BSC) and how Trading Units (as defined in the BSC) are affected by the arrangements. This issue is not dealt with in this document, but will need to be considered carefully as the detailed design work is taken forward.

Locational resolution

1.27 The effectiveness of a transmission access regime in relieving constraints and sending efficient locational signals will depend on the capability of the arrangements to expose participants to the costs they impose on the system (including transmission related costs) so that their commercial decisions are made on a truly cost-reflective basis. In order for transmission access rights to be useful in resolving transmission constraints, it is necessary for the spatial definition of rights to take into account, as far as possible, the location of actual transmission constraints. While it may be possible to capture all constraints (via a nodal definition), such an approach will require trade-offs against other objectives of new transmission access and pricing arrangements. Below, we examine:

- the key trade-offs involved in defining the geographical delineation of access rights; and
- the results of initial analysis by NGC on the effectiveness of particular zonal definitions.

Key trade-offs in relation to geographical delineation of rights

1.28 In determining the geographical delineation of rights (e.g. the size of zones, or the decision between a nodal or zonal definition of rights), there will be a trade-off between a number of competing objectives. The key trade-offs are:

- **effectiveness of constraint resolution versus competition and liquidity in secondary markets**: whilst actions taken at one node of the transmission system will have effects on the electricity flows between all other nodes, actions taken at several different nodes could have the same effect on the resolution of transmission constraints. Rights defined on a nodal basis would in such circumstances give the SO the ability to resolve all pre-Gate Closure[61] transmission constraints via the transmission access regime. However, there will typically be only one

[61] Constraints which occur after Gate Closure may not, depending on the Balancing Mechanism arrangements, be captured by the access regime.

participant (at least in the case of generation) connected to each transmission node, and participants would (in the absence of information from the SO) be uncertain of the relative exchangeability of rights between nodes. Hence, the extent to which bilateral participant-to-participant trading for rights developed could be limited (the possibility of secondary markets facilitated by the SO is discussed further in Appendix 3). Grouping together similar nodes into access right zones *ex ante* would allow all participants within a zone to compete for access rights with participants in the same zone – effectively, all rights in a zone would be defined as equivalent products. However, this means that constraints that occurred within a zone could not be resolved via the access regime. While such a market might provide the environment for liquid secondary trading of access rights to develop, it would not be as effective as a nodal regime in resolving constraints;

- **effectiveness of constraint resolution versus the complexity of the arrangements required to implement the access regime**: this trade-off relates specifically to the current design of the Stage 2 settlements system. Under this system, suppliers are allocated half-hourly demand volumes for their non-half hourly metered customers at the GSP Group (PES area) level – it is not possible with the current system to derive demand volumes with a finer locational resolution. *Prima facie,* this means that it is not possible to measure the demand of individual suppliers on a nodal basis, or on any zonal basis where the zonal boundaries are not coincident with those of GSP Groups. Thus, access right imbalances could only be calculated for the demand side (with the current Stage 2 systems) if the access right zones were coincident with the GSP Groups. Therefore, whilst adopting a different zonal definition (or a nodal definition) might be significantly more effective in terms of constraint resolution, it would also be likely to increase the cost of the arrangements required to implement the access regime. For example, it might involve making amendments to the Stage 2 settlements systems themselves to allow for greater locational "tagging" of some or all demand or creating a nodal or zonal allocation system that would take existing zonal Stage 2 data and produce nodal or zonal demands using estimated “allocation factors”. The extent to which these considerations are relevant will depend partly on whether entry and exit rights are treated in an identical fashion or whether the demand side’s main route to participation in the access regime is via options contracts with specific loads; and

- **simplicity of the access regime versus stability of locational definitions over time**: a zonal definition of access rights, it could be argued, might make participation in the regime simpler, as there would be a reduced number of products and prices to consider. However, since the pattern of generation and demand can change significantly over time, any fixed definition of zones might gradually become less useful to the SO in resolving constraints. Thus, in a zonal market there might be a need, over time, to change the geographical definition of access rights; whilst in a nodal market, since there are no fixed assumptions about the location of key transmission constraints, such a need would not arise. Therefore, while a zonal market might be simpler in some senses, it would potentially be accompanied by less stability and certainty regarding locational definitions.[62]

Initial analysis by NGC on the effectiveness of particular zonal definitions

1.29 In a zonal market, the basis for the definition of zonal boundaries is clearly critical. Ideally, zones should be defined such that their boundaries coincide with the transmission circuits most likely to become constrained. NGC has carried out some preliminary analysis on the effectiveness of using a variety of different zonal definitions in terms of resolving transmission constraints. It should be noted that in carrying out this analysis NGC made a number of simplifying assumptions, notably it:

[62] It is worth noting that, even if access rights are defined in a way consistent with GSP Group boundaries initially, they may need to be changed in the medium term to reflect changes in the pattern of constraints.

- did not incorporate any contribution from the demand side in resolving constraints; and

- based its analysis on the current disposition of generation and demand and the merit order prevailing at the time it made its calculations (mid – 2000).

1.30 Further details of the methodology used for this analysis are included in Attachments 1 and 2. The zonal definitions examined by NGC were:

- **generation tariff zones** (the 16 zones that formed the basis for generation use of system charges in 2000/01): these zones broadly related to the 11 critical system boundaries which, amongst other things, are used in determining the need for transmission reinforcement and investment. SO studies indicate that such a zonal definition would allow at most *two-thirds* of constraints to be resolved via the access market. Amalgamating some of these zones to form 6 "supra-zones" in order to maximise secondary market liquidity would make it unlikely that more than *half* of expected transmission constraints could be resolved;

- **GSP Groups** (the 12 PES Areas)**:** NGC has estimated that zones based around the GSP Groups could be expected to allow the resolution of approximately *half* of the total volume of transmission constraints prior to Gate Closure. While this zonal definition would have a similar effectiveness in resolving constraints to the generation supra-zones, the trade-off against liquidity would be greater as there would be twelve zones instead of six. Again, several GSP Groups could be combined to form more competitive access right zones. Preliminary studies by NGC indicate that amalgamating the GSP Groups to form six regions (not equivalent to the 6 generation supra zones discussed above) would still potentially enable close to *half* of the expected transmission constraints to be resolved prior to Gate Closure; and

- **customised zones:** NGC has looked at zonal definitions which are defined to maximise constraint resolution. Specifically, it has looked at the outcome with 24 zones and 31 zones. On the basis of the “system snapshots” examined, the 24 zone definition resulted in resolution of a minimum of 75% of constraints, and the 31 zone definition resolved a minimum of 88% of constraints. However, 4 out of the 24 zones had only one generator in them, as did 9 out of the 31 zones.

Symmetry of locational resolution

1.31 As we have previously indicated, although it is important that the demand side can participate in the access regime, this does not necessarily mean that the treatment of generation and demand have to be identical. Consequently it is worth considering whether the locational definitions for entry and exit rights need to be the same or whether different zones for generation and demand (as currently exist for TNUoS charging) would be acceptable.

1.32 The main advantage in defining separate locational maps for generation and demand is that it might enable a larger volume of constraints to be captured, as compared to having identical zones for generation and demand, at a reduced cost of implementation for the regime as a whole. Thus, in practical terms there are some advantages to defining separate locational maps for generation and demand. Against this must be weighed the loss of potential competition in constraint resolution from suppliers competing directly with generators, consistency of entry and exit price signals and the incentives to develop innovative demand side response products.

1.33 It would be possible, if separate generation and demand locational definitions were considered desirable, for access rights for entry to the transmission system to be based on nodes or a zonal definition which captures the majority of transmission constraints, whilst exit rights could be based around GSP Groups (or amalgamations thereof).

1.34 It is important to note that this approach might not remove the need for some approximation of the level of demand in each location defined for generation rights when determining the quantity of entry rights available. This is because participants would only be able to trade exit with entry rights (for example, by the creation of “matched pairs” discussed in Appendix 2) if the relationship between each node’s entry access price for generation was related to the zonal exit right prices for demand. For example, if a demand zone covered three generation nodes with access priced at 7, 8 and 9 it would be necessary to know the weighting of zonal demand to each node in order to calculate an appropriate price to offer for exit rights. If the weightings were say 25%, 25% and 50% respectively, the price for exit rights should be $(0.25*(-7)+0.25*(-8)+0.5*(-9))$ or –8.25. Note that even if an explicit entry-exit "matching" system were not to be developed in order to permit such trading, the SO would have to develop an implicit one to consider the relative merits of, for example, buying back entry or exit rights to relieve a constraint.

1.35 If this approach were to be taken, it would be important to consider whether uncoupling the direct link between entry and exit rights in this way would have knock-on implications elsewhere in the access arrangements. For example, the potential arrangements (considered later) in which additional demand could "sell" an additional "matched pair" entry right to generation might become more complex, since the access rights registration system might need to verify that the demand right had been split up among generation nodes in the correct proportions).[63]

Temporal duration of access rights

1.36 Given the structure of the electricity market, if access rights are to be used to resolve constraints, then the SO must be able to buy and sell rights on a half-hourly basis. Thus, access rights must be capable of being broken down into half-hourly blocks for secondary trading and ultimately access rights will need to be capable of settlement on a half hourly basis, even if they are initially allocated and/or traded in longer duration blocks.

Ofgem's initial views

1.37 Having considered the views of respondents to the December Consultation and the August Workshop, we set out below Ofgem's initial views on each of the key areas identified as important in the definition of transmission access rights:

- **participation in an access right regime:** Ofgem's initial view is that there is strong merit in a transmission access regime that enables the demand side to play an active role. However, this does not necessarily mean that

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[63] It is likely, however, that the same effect could be achieved via contracts without the need to complicate the access rights registration system in this way.

the two sides of the market need be treated identically in all respects. As well as retaining consistency with the treatment of electricity trading under NETA, there are clear advantages to encouraging demand-side participation in a new transmission access and pricing regime. Not only would it enable the demand-side to contribute to the resolution of transmission constraints, but it would also enable account to be taken of demand side participants' actual requirements and capabilities rather than central forecasts (for example with regard to interruptions);

- **specifying the access product:** Our initial view is that the definition of access rights should be based on an entry and exit, rather than a flowgate approach. There are a number of drawbacks to defining access rights in relation to flowgates on an intermeshed transmission system such as exists in England and Wales. These drawbacks include the need for a stable network topology, the potentially large number of access right products required and the complexity in valuation of rights. Taken together these drawbacks suggest that an entry/exit market may be preferable;

- **locational resolution:** Ofgem's initial view is that a definition of access rights based on a relatively small number of zones would be desirable since it would facilitate liquid secondary trading. However, it seems likely that it will not be possible to create transmission access right zones that capture the majority of expected transmission constraints without using a large number of zones.[64] Thus, further consideration needs to be given as to whether some form of nodal definition of rights, along with other mechanisms to facilitate trading should be employed;

[64] NGC's analysis indicates that at least 31 zones would be required to guarantee that greater than 75% of the expected volume of constraints could be captured, whilst a nodal definition of rights would provide for closer to 100% constraint capture.

- **symmetry of locational resolution**: Ofgem's initial view is that, if the geographical definition of entry rights is on the basis of a few large zones, then exit rights should be based on the same geographical definition. However, if a geographic delineation based on nodes or a large number of zones is adopted, the possibility of using an asymmetric definition of entry and exit rights (in which exit rights were defined to cover a larger area than entry rights) should be considered. Such an asymmetry might allow demand side participation whilst taking into account the relative ability of participants on the two sides of the market to respond to locational signals. Nevertheless, we continue to believe that, all other things being equal, it would be desirable to define entry and exit zones on the same basis, and that there are economic benefits (for example consistency of price signals between generation and demand) that accrue from doing so. However, these benefits need to be weighed against the complexity and cost of estimating load on a basis other than GSP groups, in particular in assessing its impact in other areas of the arrangements; and

- **temporal definition:** Our initial view is that access rights should be defined on a half hourly basis. Any more aggregate a definition would substantially decrease the effectiveness of access right trading as a means of resolving transmission constraints.

Summary and views invited

1.38 There are a wide range of possible options for the definition of access rights. Selecting from these options involves trade-offs between the usefulness of access rights in resolving transmission constraints, competitiveness in initial and secondary trading, and the complexity of the new arrangements. Ofgem believes that the primary goal should be to define rights in such a way that they can be used to resolve the majority of transmission constraints whilst creating the conditions under which competition for access to the transmission system and the trading of access rights can develop. However, given that another of our objectives for new transmission access arrangements is that they should be transparent, it is important to note that the more complex the arrangements become the less transparent they will be.

1.39 Views are invited on all the issues discussed in this appendix. In particular, views are invited on:

- whether new transmission access and pricing arrangements should be two sided;
- whether the locational definition of access rights should be based on:
  - zones derived from GSP Groups;
  - customised zones, designed to achieve greater constraint resolution;
  - transmission system nodes; and
- whether the locational resolution of entry and exit rights should be symmetrical.

Appendix 2 Determination of the volume of rights and primary allocation

Introduction

2.1 Appendix 1 discussed the issues surrounding how transmission access rights should be defined. In this appendix, we consider ways in which transmission access rights could be initially allocated amongst participants (the primary allocation mechanism), the definition of the volume of access rights to be made available through this mechanism, and the possible ways in which the need for access rights to be ultimately capable of definition and settlement on a half hourly basis can be reconciled with the need for the primary allocation mechanism to be relatively simple and transparent.

December Consultation

2.2 The December Consultation considered two options for the primary allocation of firm access rights. The first was the “grandfathering” of rights by allocating them to existing users of the transmission system on the basis of current usage, the rationale being that this would protect the value of current system users’ long term investments. The second option presented was the use of auctions. Ofgem expressed an initial preference for this form of allocation, citing the fact that auctions were commonly used in other markets as a means of efficiently allocating a finite resource in a non-discriminatory and transparent manner. Auctions have the additional advantage that, unlike grandfathering, they allow for price discovery.

2.3 The use of reserve prices in a primary auction was also considered as a means of protecting against localised power in any auction of transmission access rights. Ofgem argued that it might be difficult to set an appropriate reserve price without introducing distortions. We suggested that it might be more appropriate to attempt to define any transmission access auction to mitigate the impact of localised market power.

2.4 The December Consultation also considered the length of time for which primary access rights should be allocated and noted that there are competing objectives between allocative efficiency, long term certainty and transaction costs. It was noted that in other countries where an auction of access rights for the transmission of gas and electricity has been adopted, the duration of rights sold is normally between one month and a year.

2.5 The December Consultation pointed out that the allocation of a portion of longer-term rights would provide holders with greater certainty when planning investments, but that it might be more difficult to define accurately the volume available. Thus, the December Consultation indicated that there might be some merit in selling a combination of long and short-term rights. An efficient and liquid secondary market would also provide confidence that participants should be able to purchase the rights that they require whatever duration of primary access rights is chosen.[65]

2.6 Finally, the December Consultation included a brief discussion on how the volume of rights to be allocated might be determined. In theory, any volume could be allocated, although more practically the choice falls within the range between the maximum physical capacity of the system (for example the sum of capacities defined under connection agreements[66]), normally referred to as the top-down approach, and a minimum level that can always be reasonably guaranteed to be available (a bottom-up approach). Ofgem argued that the top-down approach has merit since it has the potential to ensure that as much transmission capacity as possible is released to the market, thus mitigating any market power and/or information advantage that the SO might have in an access rights market The implication of a top-down approach is that NGC would rarely sell additional rights and would need to buy-back rights in secondary markets in order to resolve transmission constraints.[67]

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[65] Ofgem has applied this principle in the sale of BG storage capacity at both Rough and Hornsea. Access to these storage facilities for both one year and five years was auctioned. For details see ‘Review of the supply of gas storage and related services, Decision Document,’ Ofgas, February 1999.

[66] Other measures of maximum physical capacity are also possible. For example, the capacity of nodes on the network could be much greater than the total capacity of participants connected behind a given node.

[67] Arguably, the top-down approach may overstate the level of grandfathered rights preserved if a solution that retained such rights were adopted. Under the Pool for example, the quantity of access rights a generator received in an export constrained zone was not equal to the capacity stated in its connection agreement. In order to be paid compensation for denial of access, the generator needed to be scheduled in the unconstrained schedule (so the aggregate amount of rights in any half-hour was limited to forecast demand). Furthermore the rate of compensation for denial of access was also limited (negative bid prices were not, for example, permitted under the Pool).

NGC's views

2.7 NGC indicated that it believed an initial allocation via an auction process would be workable. It suggested that there were a number of ways in which a bidding process could be managed.

2.8 NGC noted that, in relation to profiling of products in the primary auction, there would be a trade off between simplicity and the volume of constraints likely to be relieved by the market. However, it also suggested that a sophisticated product may make the allocation process more complex.

2.9 With regard to the duration of access rights, NGC suggested following precedents in other markets such as the gas market. Access rights could be allocated for between six to twelve months. NGC argued that, over time, it saw no reason why products of different durations could not be allocated, subject to there being sufficient competition to ensure that the different products were priced efficiently.

2.10 In response to the December Consultation, NGC stated that it believed that it would be inappropriate to use reserve prices in the primary auction (other than perhaps in relation to losses) as this might prevent access prices from reaching an equilibrium.

Other respondents' views

2.11 Eight respondents supported the use of auctions as the method of primary allocation of transmission access rights, although opinion on the specifics of the auction designs were diverse. Several participants expressed concerns about the potential complexity involved, stating that an emphasis should be placed on simplicity as a design criterion.

2.12 Several respondents noted that consideration needed to be given to the contractual rights of existing users as established through their connection and use of system agreements. A small number of generators argued that substantial investments in new generation have taken place over the last 10 years on the basis of firm access to the transmission system (i.e. entitlement to "constrained-off" payments). They believe that any significant change to the existing arrangements that ignores historical investment decisions will undermine the basis on which the investments had been financed, since allocating access via auctions could strand assets as a result of a change in the cost base that some participants would face. Several respondents commented that the requirement to purchase access rights would add to the risks they faced.

2.13 In general, those participants who opposed the auctioning of firm access rights suggested an allocation mechanism based on historical use of the transmission system. They argued that grandfathering of access rights would address their concerns regarding previous long-term investment signals. They also argued that grandfathering of rights should not be seen as a barrier to entry as access rights could be purchased in secondary markets.

2.14 There was no consensus on the issue of the duration of rights to be allocated, with preferences being expressed for periods ranging from 6 months to 40 years. A number of respondents argued that consistency between gas and electricity markets was important and that this should be taken into account in determining the length of rights.

2.15 Of the 11 respondents who commented on the volume of rights that should be sold, 6 were in favour of top-down arrangements. The general feeling was that this approach could result in the volume of available access rights remaining broadly the same as under the current transmission access arrangements. One supplier favoured the use of a bottom-up approach as it felt that the costs of excess capacity required for system security should be borne by the transmission network owner rather than customers. Two generators were opposed to the use of a bottom up approach and the remainder of respondents commented that more detail was required before they could make a judgement.

The August Transmission Access Workshop

2.16 At the August Workshop, Ofgem reiterated that there was merit in considering a primary auction of access rights with subsequent trading taking place in secondary markets. NGC presented an overview of how such arrangements might work and highlighted the interactions between the primary allocation mechanism and the nature of secondary trading.

Responses to the August Workshop

2.17 Several respondents expressed concern regarding the potential costs and complexities involved in establishing and running the proposed access rights regime, especially in light of the significant investments already being made in new systems for NETA. One respondent calculated that the total potential cost to the industry, including both central and participants' systems, could be up to £200m.[68]

2.18 With regard to the issue of existing rights, one generator argued that investments in generation and load were made according to economic activity at the time of the investment decision. It suggested that although gas fired power stations could have been sited nearer to the load centres, this did not necessarily mean that they were in the wrong place. Hence, it argued that existing generators should not be penalised for siting decisions that were justified given the set of arrangements in place at the time they were made. Another generator commented that it had invested on the basis that access was guaranteed under various agreements and it was of the view that generators had a fundamental right to access. Three other respondents suggested that under new transmission access and pricing arrangements it would not be necessary to take away existing access rights from users and that the rights of existing participants could be preserved under the new arrangements. One suggestion made by two participants was for generators to be allocated access rights by virtue of having paid the TNUoS charge (in the past). It would then be for the generators to decide whether to trade these rights in secondary markets.

2.19 A Combine Heat and Power (CHP) operator voiced concern that, because it must produce electricity in order to meet its commitments to provide steam, it requires long term security of transmission rights but risks becoming a distressed buyer of rights in the secondary markets if it cannot secure a sufficient quantity of rights in the primary allocation. Being a small participant, the generator also commented that it had limited resources to dedicate to trading effectively in secondary markets.

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[68] Based on the ratio of central NETA systems to participant costs estimated by Ofgem and presented in the July 1999 NETA document applied to the estimate of costs for implementing new transmission and pricing arrangements of £15m to £30m presented by NGC.

2.20 Finally, two respondents argued that the market design should take into account the potential conflict of interests resulting from NGC having a key role in the design process of a new regime, and being an active trader of rights in the secondary market.

Discussion

2.21 The rights of access to the transmission system of participants are currently not well defined under the NETA arrangements (nor were they under the Electricity Pool). The access rights of generators are limited in their Supplemental Agreements to the MCUSA to their notified Maximum Export Capacities (pre-Vesting connections) or Registered Capacities (post-Vesting connections). Suppliers do not have specific access limits although the access of distribution network operators is limited to their notified Connection Site Demand Capabilities and this provides an upper bound on the aggregate access limits of all the suppliers within a distribution network. However, these limits can be reduced if NGC is prevented from transporting electricity due to transmission constraints that could not have been avoided by the exercise of Good Industry Practice.[69] Thus, NGC's connection agreements i.e. the Supplemental Agreements, do not confer fully firm access rights.

2.22 However, under the P&SA, the unconstrained day-ahead schedule determined generators' effective access rights. The Pool compensated generators participants for their forgone profits i.e. SMP – bid, as a result of being constrained off, but only up to their unconstrained scheduled generation (subject to the plant not subsequently redeclaring downward), and with a minimum permissible bid price of zero. The costs of this compensation, plus the costs of providing replacement generation to meet demand, were recovered from all demand side participants.

[69] Good Industry Practice requires the exercise of appropriate skill, diligence, prudence and foresight but does not require an unconstrained transmission system.

2.23 Under NETA, participants self-schedule their plant and load. In Chapter 3, we noted that NETA may result in a greater potential for participant actions to increase the volume and cost of constraints compared to the Electricity Pool, and that it is possible for the equivalent of constraint payments to be made to the demand side under NETA. We also noted that key objectives of the new access regime included providing appropriate locational signals to participants and ensuring that electricity markets are not unduly distorted by transmission related costs. A new transmission access and pricing regime must therefore address how to allocate and charge for the rights to use the transmission system when it is constrained.

2.24 Below we provide some thoughts on the objectives of the primary allocation process, and outline some of potential allocation mechanisms. In the light of our initial views, we then discuss some of the more detailed aspects of the way in which the primary allocation of rights could be carried out.

Objectives for the primary allocation process

2.25 The approach taken to the primary allocation of access rights will not be critical in terms of achieving the overall objectives of the arrangements if liquid secondary trading of access rights develops, since the desired price signals will emerge from the secondary trading of access rights if they are not provided by the primary allocation. However, if liquid secondary trading does not develop then the choice of primary allocation mechanism becomes more important. Thus, the primary allocation mechanism should aim to:

- continue to allow for non-discriminatory access to the transmission system for both existing and new participants;
- provide long term price signals as to the impact of siting (and retiral) decisions of generation and load;
- assist in producing an economically efficient allocation of transmission capacity between participants; and
- assist in providing, to the greatest extent possible, price signals of the need for, and value to participants of, transmission reinforcement.

Options for the primary allocation process

2.26 There are many potential designs for the primary allocation process which are of varying complexity and which address these objectives to a greater or lesser extent. Below we set out three potential options for the allocation mechanism, in order to highlight the nature of the design considerations involved. The options we consider are:

- **"grandfathering"**: Under this approach, access rights would be allocated to current participants in accordance with their historical usage of the system. The SO would have to compensate participants for any curtailment of these rights and new entrants would (at least in the short term) have to purchase access rights from existing holders and/or the SO (to the extent that there was spare capacity on the network following the new connection);

- **access charges**: In return for the payment of a locational access charge, this approach would give existing and new participants the option of exercising access rights up to the level of their connection agreements. The SO would have to purchase rights from participants who could not use them due to system constraints. Additional access rights would be created and allocated to new entrants upon connection as system expansion allowed. This approach has features in common with the arrangements under the Electricity Pool; and

- **auctions**: The system operator would make available access rights corresponding to a measure of existing physical transmission capacity (and imminent expansion plans). All participants, including new entrants, would have to compete to acquire these rights in the primary auction.

2.27 Each of these approaches has different implications in terms of meeting the objectives of a new transmission access and pricing regime and these are discussed below. The implications of each of the three approaches are discussed below.

Grandfathering transmission access rights

2.28 This approach would partially address participants' concerns over the risks of having to acquire rights but it takes little account of the value that participants place on transmission capacity now or in the future. Although efficient trading in secondary markets should result in access rights being reallocated to the participants who value them most, the original access right holders would realise windfall gains as a result of a scarcity in these rights. This may favour incumbent portfolio generators and/or vertically integrated firms over new entrants and could harm competition.

2.29 Grandfathering of rights could also form a barrier to entry if any new entrant was to be required to buy transmission access rights from an incumbent through illiquid secondary markets. It is not clear for how long new entrants would continue to be required to purchase rights from existing participants, nor a non-discriminatory basis on which this would be decided. In addition, upon closure of existing stations, it is not clear how their rights should be allocated amongst existing or new participants.

2.30 Furthermore, determining the volume of rights to grandfather is not straightforward if usage patterns are changing rapidly, as they are to some extent in the England and Wales market. For example, would the access rights of existing participants decline if their load factor declined over time?

2.31 Some participants have argued that they have paid for the historical fixed cost of the transmission system and therefore they own the rights to use it. Ofgem does not accept these arguments. Connection charges only confer a right to be connected, not a right to use the system, and payments in respect of use of the system relate to use made to date, and not to future use.

Access charge approach

2.32 The greatest advantage of an access charge approach would be its relative simplicity to implement. In return for paying a locational access charge, participants would receive access rights up to their maximum connection agreement capacity or some other measure of capacity. Participants would be free to use or to sell on rights that they have been allocated. It would be the responsibility of the SO to repurchase rights as required in order to resolve transmission constraints.

2.33 The key distinctions between this and the grandfathering approach outlined above are that:

- there is an explicit link between the allocation of access rights and the payment of an access charge; and
- both existing and new entrants would be allocated rights on an equal footing.

2.34 While the access charge approach may address some of the problems in relation to discrimination between existing players and new entrants under the grandfathering approach, it does not address the problems in relation to market-based long term investment or plant closure signals. As participants would not compete for access rights in the primary allocation process, the market value of long-term access rights would not be signalled. However, if access rights are not scarce then the potential disadvantages identified above would cease to be an issue because no allocation mechanism would provide investment or closure signals.

Access right auctions

2.35 Auctions have a number of advantages over other means of allocating a scarce resource. As well as treating all participants on an equal, non-discriminatory basis, auctions would reveal the value placed on rights. Participants in an auction have an opportunity to signal the value they place on transmission access and receive the rights for which they are willing to pay. The primary allocation of rights is then made on the basis of these valuations rather than according to participants' previous use of the system or their earlier investment decisions. Auctions can therefore send efficient long- and short-term signals to participants.

2.36 Auctioning transmission access rights would raise revenue as well as providing locational long-term investment signals – these revenues could be used to offset TNUoS charges. Participants would then face locational signals via the cost of transmission access rights purchased in the auctions, and a residual TNUoS charge designed to ensure that NGC was able to recover its allowed Transmission Price Control revenues. This change in charging arrangements could result in either an increase or decrease in the total use of system costs (including payments for access rights purchased) faced by individual participants. Most importantly though, it would provide a better signal of locational value of access to the transmission system, through combining the payments by the participant for access rights and the revenues received for wholesale electricity, participants would overall be paid or charged at the value of electricity at the location at which they generated or took demand. A change in the overall level of use of system costs paid by an individual participant would indicate that the previous charging structure did not accurately reflect the value they derived from access to the transmission system.

2.37 More fundamentally, in the absence of certainty about the extent to which the network, given changing patterns of demand and supply, is genuinely constrained, the auction approach is the best option. If the auctions reveal the network to be relatively unconstrained, the prices realised in the auctions would be likely to be close to zero (in the absence of reserve prices). Incumbents would simply continue to pay TNUoS charges for their access rights, as they would under the other two options and would receive the same volume of rights. However, these rights would be firm and in the event of a transmission failure, participants would be entitled to compensation at market prices.

2.38 Moreover, the auction system would, unlike the alternatives, provide signals of the value of transmission rights if parts of the network were constrained without providing windfall gains to incumbents and/or raising barriers to new entry.

Ofgem's initial views

2.39 Ofgem remains of the view that, when transmission capacity is a scarce commodity, auctioning transmission access rights can have considerable merits. However, auctioning of firm access rights would inevitably lead on to a requirement for some form of secondary trading and an access imbalance settlement regime. Thus, taken as a package, this system would be relatively complex and expensive to implement (see, for example, Appendix 9) and would increase the trading costs of participants. We therefore believe that it may be appropriate also to consider whether simpler approaches, on one or both sides of the market could deliver broadly comparable locational cost signals.

2.40 Possibly the simplest approach would be to adopt the access charge approach to primary allocation of both entry and exit rights and limit secondary trading to the SO selling option contracts to constrain participants on and buying options contracts to interrupt/reduce the generation or consumption of participants. By exercising these options, the SO should be able to resolve all pre-Gate Closure constraints. Such an approach would remove the need for a full-blown access imbalance settlement regime since the necessary incentives on participants could be achieved via penalty clauses in the option contracts. However, it would be likely to reduce the extent to which very short-term signals of the costs of transmission constraints were available. It would also mean that the firmness of access rights, in terms of participants' obligations, would vary between those participants who had bought and/or sold option contracts and those who had not.

2.41 A somewhat more complex approach, proposed for the GB gas market, would be to auction entry rights but allocate, under an access charge approach, exit rights. Both generators and customers could assist in resolving constraints either via the purchase/sale of option contracts or via direct secondary trading of their access rights, and an access imbalance regime would be required that could accommodate both production and consumption imbalances. This approach would be to allow the full involvement (including in access imbalance settlement) of consumers with half hourly meters whilst using the allocative method for non-half hourly metered demand (and hence reducing their transaction costs).

2.42 Ofgem does not believe that grandfathering of access rights is a valid alternative to the access charge approach or an auction based allocation process. As well as being a distortionary form of allocation, grandfathering access rights to a constrained network can, in practice, lead to windfall gains for incumbents and barriers to new entry.

Nature of an auction based allocation process

2.43 In the discussion that follows, we explore the issues that would need to be resolved if it were decided that auctions should form part of the primary allocation process (whether just for entry rights or for both entry and exit rights). We consider:

- the extent of central involvement in volume determination;
- the definition of the volume of rights to be allocated;
- the nature of the price auction mechanism; and
- the bundling of half hourly rights in primary allocation.

SO involvement in volume determination

2.44 Prior to considering the volume of rights to be sold under any auction mechanism, or the way in which that mechanism would operate, it is important to consider how the volume of rights to be made available is defined. If exit rights are not auctioned, it follows that the volume of exit rights to be allocated must be centrally determined. There are then two options by which the volume of entry rights to auction could be determined:

Absolute volumes

2.45 Under this approach, all the access right volumes to be auctioned would be determined centrally – this could either involve a central forecast by the SO of the patterns of demand and generation and the transfer capabilities of the network, or some more simple and transparent approach to volume determination. This might be seen as undesirable, since the process by which these volumes were determined would not be transparent. However, the approach would mean that the total volume of entry and exit rights was known prior to the primary auction and this might allow a more accurate valuation by participants of such rights.

Transfer capabilities

2.46 Under this approach, the total transfer capability between locations is determined prior to the primary auction, but not the absolute volume of entry (and possibly exit) rights at each location. The absolute volumes available are defined as part of the auction process and the volume available at any location will depend on the volumes available at all other locations.

2.47 If both entry and exit rights were to be auctioned, the concept of "matched pairs" of entry and exit rights might be useful. Given that it is only the transfer volume that is fixed, it is only the difference between the volume of entry and exit rights in a location that is important – the absolute volumes are irrelevant for purposes of resolving constraints. Therefore, participants could be allowed to adjust the overall volume of entry and exit rights in the market consistent with the maximum transfer volumes. Indeed, it is likely that such transactions would occur anyway (via secondary trading or financial contracts if the explicit creation of matched pairs were not allowed) provided that market participants have a clear understanding of the system capacity and can be certain that the SO will release all the available capacity to the market eventually (either through the primary allocation or the secondary markets). Thus, it may be appropriate to consider explicitly allowing participants to create additional entry rights providing they can find a counterparty to accept a matching volume of exit rights at the same location (and vice versa). A potential disadvantage of this approach is, however, that the absolute volume of entry and exit rights available would not be so transparent and this could lead to difficulties in valuation of the rights.

Volume of rights to be allocated

2.48 The volume of access rights allocated in the primary allocation mechanism should relate in some way to the underlying physical capabilities of the transmission system – the system's ability to transfer power from one location to another. Over the medium and long term, the volume of transmission capacity available will be heavily influenced by network investments and hence by the Transmission Price Control. However, given a fixed network, the capability of the transmission system to transfer power across boundaries will depend on the voltage capability,[70] the stability capability[71] and the thermal capability[72] of boundaries. All of these capabilities depend on a number of assumptions including the distribution of generation and demand around the system.

2.49 Because of this linkage between physical capacity and the generation and consumption decisions of participants, defining the capacity of the transmission system is not a simple task. There is no clear definition of system capability on which the primary allocation of rights can be based. Possible definitions range from the "theoretical maximum capability", where the system's transfer capabilities are in some sense maximised to some objective and predefined measure, through an "estimate of actual capacity" that includes some allowance for likely constraints, to an "estimate of maximum certain" capacity where the volume made available can be guaranteed to be available. Defining the capacity to be released in the primary auction will be a case of choosing the assumptions that best reflect the objectives of the regime.

2.50 If the rights released in the primary allocation do not reflect the underlying capabilities of the network, the SO will need to buy-back rights or release additional rights in secondary trading. If the "theoretical maximum" volume of rights is released through the primary allocation mechanism, then the SO will be predominantly repurchasing transmission capability in secondary markets. Conversely, if a volume of rights consistent with worst case capability is released, the SO will predominantly be releasing further capability.

2.51 At Gate Closure, participant to participant trading and release / buy-back by the SO should ensure an efficient allocation of rights, and hence an efficient set of self-scheduled physical notifications (given the information available prior to the opening of the BM) irrespective of the volume of rights allocated initially. In this sense, the volume of rights made available in the primary allocation mechanism is not important from an short-term efficiency viewpoint.

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[70] The overall voltage capability of a boundary is the maximum transfer which provides both compliant voltage levels and sufficient robustness against the risk of voltage instability.

[71] The overall stability of a boundary is the maximum transfer across it which can take place without one or more synchronouse generating units losing synchronism with the remainder of the system, or poor damping of electromechanical oscillations of generating units under certain transmission system faults.

[72] The thermal capability of a boundary is the maximum power transfer across the boundary which can be tranferred without exceeding the capacity of any of the circuits when certain circuits are out of service (because of an unplanned outage).

2.52 However, only in the case of perfect knowledge among market participants will this also be true for signals regarding long term investment and plant closure. For example, consider the situation in which more rights are auctioned in an export constrained area than the transmission system is capable of delivering. With perfect knowledge of transfer capabilities and the value of electricity at different locations on the system, the price paid for such rights in the primary auction will accurately reflect the revenue which would accrue to the holder as a result of the SO having to repurchase the right in secondary trading. Participants will not make windfall gains as a result of the buy-back of rights, as this will be factored in to primary auction prices.

2.53 In the absence of such perfect knowledge, the price paid for rights in the primary allocation is unlikely to reflect fully the revenue accruing from secondary trading, as participants will not know with certainty whether rights will be bought back. In this instance, as a result of overselling relative to system capability, generators in the export constrained area may indeed secure windfall gains. As a result, the signals from the primary auction related to long term investment in capacity and plant closure would be distorted.

2.54 On the other hand, auctioning an “estimate of actual capability” is not straightforward. Given that system capability depends on assumptions regarding dispersion of generation and load, the basis of such an estimate may not be transparent, and would be likely to rely heavily on judgements taken by the SO as to the likely outcome of trading in the various electricity markets. This lack of transparency may create an opportunity for the SO to select a set of assumptions, and hence an “estimate of actual capability”, which is beneficial to it under its incentive arrangements. For example, for any given target under an incentive regime for the buyback/release of access rights, the SO will have an incentive to reduce the volume of rights available through the primary auction since this would reduce the potential need for buy-back and increase the scope for the profitable release of further rights. In any event, it would be necessary to link the incentive arrangements of the SO to the quantity of rights released in the primary auction.

2.55 In summary, all measures of transmission capability will inevitably involve subjective judgements and assumptions on demand and generation. From the viewpoint of achieving the objectives of the regime in relation to long term price signals, an "estimate of actual" view of system capability would be preferable. However, moving towards a primary allocation volume at the "theoretical maximum" end of the possible range of capacities may reduce the scope for the SO to exploit this need for subjectivity to optimise against its incentive scheme and define the volume available to its advantage.

2.56 Ofgem has previously argued that the SO should be incentivised against its performance in delivering appropriate capability on the transmission system. It will therefore also be important to ensure that the volume of rights made available through the primary allocation is consistent with any output measures in NGC's Transmission Price Control. There may need to be arrangements put in place to ensure that costs incurred under the SO incentive regime as a result of operating and investment decisions by the TO business are treated in an appropriate and consistent way.

Nature of the price auction mechanism

2.57 The extent to which the SO is involved in determining the volume of access rights will influence the available options in relation to the price auction mechanism. If absolute volumes of rights are determined by the SO, the volume of rights in each location on the system will be known prior to the primary auction. Rights could then be sold via a series of separate price auctions – one for each entry (and possibly exit) location, for example. If such an approach were adopted, a relatively simple auction process could be envisaged, although its design would need further consideration.

2.58 If only transfer capabilities are determined *ex ante*, then a simultaneous clearing mechanism (as suggested by NGC – see Attachment 3) would be required. Under this approach, the SO would announce maximum transfer capabilities between locations prior to the auction. Participants would submit bids for entry (and possibly exit) access rights at the various locations and these would then be allocated taking account of the valuations revealed through the bids until the maximum transfer limit in respect of each boundary was reached or until participants' requirements were satisfied. Alternatively, (as discussed above) it would be possible to auction only the transfer capacity and to allow participants freely to create additional matching pairs of rights. Thus, the total volume of entry (and possibly exit) rights available in each location as well as their price would be determined by the auction process. This approach would ensure that capacity is allocated efficiently, taking into account interactions between constraints on the network. In effect, participants would be competing for access rights, not only with other participants at the same location, but to the extent that they influence constraints elsewhere on the system, with participants at a range of other locations. The auction algorithm would clearly need to be transparent and auditable. Further details of this approach are included in Attachment 4 (the system described in the attachment assumes that both entry and exit rights would be auctioned).

2.59 The simultaneous clearing approach ensures an efficient treatment of such interactions, but at the cost of increased complexity and potentially reduced transparency in the auction process itself. For example, participants would not be aware of the absolute volume of access rights to be allocated in each location until after the allocation process was complete.

2.60 Other issues that would require consideration include: should there be more than one round in the auction to aid price discovery, should it be a "sealed bid" auction or some more transparent mechanism be used, should the auction pricing be pay as bid or uniform.

2.61 In a GB context, the choice of approach might also have an institutional dimension. For example, a system-wide auction process across GB might need to be carried out by a single auction facilitator.

Role of reserve prices

2.62 Ofgem has previously expressed concerns over the use of reserve prices, as they may prevent markets from clearing and thus distort pricing signals. For example, if a constraint is not active in a given time period, there should be no difference in access prices "either side" of it – reserve prices may create an inappropriate price differential.

2.63 It is for consideration whether the use of reserve prices would be required to ensure successful auction outcomes. In the gas entry capacity regime, reserve prices have been used as a means of dealing with lack of competition at specific entry terminals e.g. Barrow where there is just one shipper of gas. Even if there were to be several participants within zones for electricity transmission access, reserve prices could be used to mitigate the affect of market dominance (by ensuring that dominant players do not secure valuable rights at unduly low prices).

2.64 A further rationale for the use of reserve prices would be to signal the need for new transmission system investment over and above that provided for in the Transmission Price Control. Consideration should be given to setting reserve prices related to investment costs for capacity made available in excess of the output measures defined in the Transmission Price Control. Such an approach would provide incentives for NGC to expand transmission capacity to meet customers' needs where it is efficient to do so. Reserve prices could also be used to signal the short run costs of transmission losses – this is discussed in more detail in Appendix 8.

Bundling of half hourly rights

2.65 Given the structure of the electricity market, access rights must ultimately be defined and settled on a half hourly basis. However, it is not necessary and may not be desirable for the primary allocation mechanism to involve such granularity. For example, participants could be allocated or could bid for strips of rights covering all settlement periods for a specified period of time or rights separately covering peak/off-peak periods, weekdays/weekends, potentially on a seasonal or monthly basis.

2.66 As in other areas, there are clearly trade-offs to be made. A finer resolution of the primary product(s) will tend to allow for a better match between the primary allocation of rights and the expected availability of transmission capacity, and should provide greater flexibility to participants to match purchases in the primary allocation to actual requirements. On the other hand, auctioning a wide range of different products will increase the complexity and the transactions costs of the process and may reduce its transparency.

2.67 Related to the temporal definition of primary access rights is the question of how far into the future it should be possible to obtain an allocation of access rights. Since, in the longer term, the intention is to link the volume of rights that the SO makes available to the output measures in the Transmission Price Control, it would seem sensible that at least some rights should be allocated for the period for which investment decisions are being made in the Transmission Price Control. The use of longer term auctions, in combination with an appropriate incentive scheme, should ensure that network investments in response to signals from customers.

2.68 Due to these trade-offs, there could be advantages in allocating rights of different durations in the primary auction in order to meet the differing needs of participants. This should be possible within a framework of independent price auctions for access at separate locations across the system, but it is for further consideration whether it would be possible under the simultaneous clearing mechanism.

Ofgem's initial views

2.69 Below we set out our initial views in relation to each of the issues we have discussed regarding auctions of access rights as a primary allocation mechanism:

- **the extent of SO involvement in access volume determination**: Two broad approaches can be taken to the extent of central involvement in determining access volumes. First, the SO could determine the absolute volume of entry and exit rights that will be sold in any auction. This requires taking views on the patterns of generation, demand and transmission availability. Second, the SO could simply determine the capability of the transmission system to transport electricity from one location to another (transfer capabilities). The volume of entry rights available at a particular location would then depend on how many exit rights were sold because it is the difference between the two that defines the allocated transfer. There are advantages in terms of efficiency and consistency with NETA in opting for an approach which involves central determination of transfer capabilities only, and which does not require centralised forecasting of demand and generation in order to determine absolute access volumes. However, further consideration will need to be given to the potential loss of transparency under this approach as a result of the absolute volume of rights available not being known with certainty prior to the primary allocation process. It is likely that the choice of zonal or nodal definition of rights (as discussed in Appendix 1) will be of relevance here, as forecasting absolute entry/exit volumes rather than just transfer capabilities between locations may be less consistent with a nodal regime;

- **the definition of the volume of access rights to be allocated**: Further consideration needs to be given to exactly how to define transmission capability. However, in principle Ofgem believes that any allocation process should make available the maximum possible volume of access rights (given the transmission network) through a combination of the primary allocation mechanism and appropriate incentives on NGC to release further capacity in secondary markets. The granting of firm access rights necessitates the introduction of so-called "use it or lose it" provisions to prevent participants from hoarding rights in order to restrict access to the system or drive up the costs of resolving constraints.

- **the nature of the primary price auction**: Our initial view is that a simple auction format should be chosen in order to maximise transparency and to enable participants to make a clear link between the bids they have placed and the allocation they have received. However, (as discussed above) we also recognise that there are merits in facilitating the efficient allocation of access rights through the primary auction if it is likely that secondary trading will be illiquid. Consideration will therefore need to be given to the trade-offs between simplicity in auction design and the efficiency of the allocation. Ofgem believes that reserve prices may be appropriate to mitigate the effects of market power in primary auctions for access rights in areas with limited competition and could play a role in ensuring that the SO is able to cover its short-run avoidable costs and, to the extent necessary, the costs of investments required to make the capacity available (they may also have a role in relation to the pricing of transmission losses). However, given the potential for reserve prices to distort market outcomes and prevent markets clearing, careful consideration should be given to their use; and

- **the bundling of rights in the primary allocation process**: Ofgem's initial view is that the underlying rights need to be defined on a half-hourly basis. While bundling of half hourly rights in the primary allocation process would simplify the auction process, we consider that the degree of bundling incorporated should principally be determined by the preferences and requirements of market participants. We see advantages in keeping the products sold via the primary allocation relatively simple, and relying on the secondary markets to unbundle primary rights, when participants will be better able to judge their half-hour by half-hour requirements. However, as with the question of the volume of rights, consideration will need to be given to the trade off between product simplicity and the efficiency of long term price signals.

Summary and views invited

2.70 This appendix has discussed some of the key issues and objectives surrounding the primary allocation of transmission access rights, and several mechanisms by which transmission access rights could be allocated. We have also discussed more detailed issues in relation to the determination of the volume of rights available.

2.71 Views are invited on all the issues raised in this appendix. In particular we would welcome responses to the following key consultation issues:

- the relative merits of different access right allocation mechanisms and, in particular, whether different allocation mechanisms should be used for entry and exit rights;
- Participants' views on the impact of the quantity of rights auctioned on the rights of existing participants;
- the appropriate extent of SO involvement in the determination of access right volumes;
- the appropriate approach to the definition of the volume of rights to be allocated;
- the preferred mechanism for price auctions (for entry rights);

- the role of reserve prices; and
- the most appropriate bundling of half hourly rights in the primary allocation process.

Appendix 3 Secondary trading of access rights

Introduction

3.1 In this appendix, we consider the possible role and form of secondary markets for access rights in new transmission access arrangements, the role of the SO in secondary trading, and the way in which the SO may be incentivised in relation to such trading.

December Consultation

3.2 The December Consultation noted that secondary markets for transmission access were likely to be required. These would be used by market participants to manage and refine their holdings of access rights. They would also be used by the SO to buy-back allocated capacity or to release additional capacity in order to reflect changing conditions on the network, such as changes in flows and network outages.

3.3 The December consultation also considered the need for “use-it-or-lose-it” provisions to prevent participants hoarding firm access rights. It was suggested that one method of implementing use-it-or-lose-it provisions would be for the SO to sell interruptible transmission rights.

NGC's views

3.4 NGC, at a presentation to TUG-CPF,[73] has commented on the likely nature of secondary market trading. In addition to its participation in the secondary markets by releasing extra rights or buying back rights, NGC also expects the secondary markets to allow participants to unbundle the rights they have acquired in the primary allocation to enable them better to match their access rights to their requirements.

Other respondents’ views

3.5 A number of respondents expressed the view that the development of secondary markets would be central to the success of a transmission access rights regime.

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[73] ‘Possible Transmission Access Arrangements’ A Presentation by NGC to TUG-CPF 99/00-18.

3.6 Of the seven participants who expressed a view on use-it-or-lose-it provisions, opinion was divided, with four participants agreeing with the need for use-it-or-lose-it provisions and three disagreeing. One participant commented that it would be undesirable to sell interruptible capacity in an electricity market, though no specific reasons were given.

The August Transmission Access Workshop

3.7 At the August Workshop, NGC presented an overview of the potential interactions between the primary allocation and the nature of secondary trading. It suggested that unfacilitated secondary trading would only be possible if access rights were defined on the basis of a few large zones. If however, access rights were defined on a nodal basis, then NGC believed that it would be necessary for it to facilitate centrally secondary trading. Given offers and bids from the participants to sell or buy access rights at each node on the system, NGC would determine the volume of each offer and bid to take in line with its updated expectation of the inter-nodal capabilities. Following each round of secondary trading, NGC would publish prices at each node.

Responses to the August Workshop

3.8 Responses to the August Workshop mainly focused on the additional trading resources that would be required to effectively participate in the access market so as to avoid exposure to access imbalance cash-out. Some participants voiced concern that small players may have limited resources to dedicate to such trading.

Discussion

3.9 We discuss below a number of issues around the role and nature of secondary trading in the access regime and the extent of participation in trading activities. The key areas we cover are:

- the need for secondary trading;
- the nature of secondary trading;
- the need for SO facilitation of secondary trading;

- the role of interruptible capacity; and

- SO incentives in relation to secondary trading.

Need for secondary trading

3.10 Secondary trading in access rights will be critical to ensuring that new transmission access and pricing arrangements result in the efficient allocation of rights between participants and that production and consumption decisions are based on a full appreciation of the costs of producing or consuming at different locations. However, as discussed in Appendix 2, the type of secondary trading that is required will depend on the overall form of the regime. Hence, whilst secondary markets could serve a range of functions, at the very least they will need to provide:

- the SO with the opportunity to resolve transmission constraints either via the release and buy-back of access rights or via the sale and purchase of option contracts; and

- up to date price signals as to how the relative value of electricity in different locations around the system is changing over time.

3.11 It will thus be important to incentivise the SO to manage the costs of buying back rights (and to make all capacity available to market on non-discriminatory terms) in a similar way to its incentive to reduce system operator costs. This will be facilitated if there is a liquid market in which the SO can carry out these activities.

3.12 In addition, secondary trading may provide participants with the opportunity to unbundle and rebundle access right products from the primary allocation process in order to match their holdings of access rights with their evolving expected requirements.

Nature of secondary trading

3.13 It is clearly the case that the SO will need to be able to buy and sell entry and exit rights at all locations. The issue with regard to the nature of secondary trading is thus how participants can trade between themselves and in particular:

- are participants restricted to trading access rights within zones or are they able to trade rights between zones; and

- can direct trading occur between entry and exit rights?

3.14 In practice, whatever decisions are made on these issues with regard to their treatment in central systems (access right registration and access imbalance settlement), participants may well be able to extend their trading opportunities via contracts written around the physical trades.

3.15 A further consideration will be whether the SO should be allowed to hold auctions to buy option contracts to interrupt/reduce generation or consumption and sell option contracts to constrain participants on. Again, as discussed in Appendix 2, whether this is considered necessary or desirable will depend on the overall structure of the transmission access arrangements. However, if such option contracts were traded, it would be important that they were of short duration (weekly or monthly) if they were to form the basis of providing short-run signals of the costs of transmission constraints. In effect, holder of rights who sold interruptible option contracts to the SO would be swapping firm rights for interruptible ones (a subject which is considered further later in this Appendix).

SO facilitation of secondary trading

3.16 It might be possible to rely on unfacilitated trading, with no central mechanisms run by the SO. In this case, secondary trading of access rights would take place on a bilateral over-the-counter basis, via exchanges, or through bulletin boards established on a commercial basis because of a perceived demand for such services. However, such unfacilitated trading might lead to concerns about liquidity and transparency in the secondary markets (particularly about the trading undertaken by the SO). If this were the case, it might be desirable to introduce some form of central facilitation by the SO. If secondary trading is restricted to the SO buying and selling option contracts then, by definition, all secondary trading will be centrally facilitated. Thus, in the discussion which follows, we concentrate upon the situation where participants (whether on one or both sides of the market) are able to trade access rights between themselves.

Complete SO facilitation

3.17 In a regime under which there are a small number of large zones, unfacilitated trading of rights between participants is likely to develop since access rights have value through their hedging properties (i.e. they reduce or hedge exposure to access imbalance liabilities arising from a forecast physical position). Thus, within each zone, there should be a significant number of participants interested in trading rights for this reason alone (i.e. even before considering any participants trading on a purely speculative basis). Therefore, zonal price discovery should be possible through the trading of rights for each zone. As discussed above, the SO will also need to trade rights across zones in order to ensure the geographic dispersion of rights matches the capabilities of the transmission system.

3.18 In contrast, if there are a large number of zones or a nodal definition of rights is adopted, there may not be a sufficient number of participants interested in the physical hedging properties of access rights in each defined location to ensure a liquid secondary market and price discovery for each access product. For example, with a nodal definition, on the generation side of the market there will typically only be one participant connected at each node. In the absence of any other options, participants would then be restricted to trading with either the SO, or those interested in rights for speculative reasons. Furthermore, in practice, there may be few such speculators, since:

- access right valuations in each location will depend upon the level of electricity prices and local generation cost (or demand opportunity cost) conditions. The participants with whom a speculator would trade might be viewed as having a significantly better view of local cost conditions than anyone else (as they may be the sole local participant), and this information asymmetry may discourage “third party” speculation in relation to the expected value of the rights; and

- upon the creation of an open position, speculators would only have two counterparties with whom they could trade to close the position – the participant with whom they traded originally, and the SO. This contrasts to a significantly greater number of participants in a regime with a few large zones . If speculators were concerned about their ability to close their positions, this might discourage them from trading. Whether or not there would be a concern of this nature would also be dependent upon the access rights imbalance cash-out arrangements.

3.19 If liquid secondary trading within zones or at nodes does not develop, then the only realistic way to increase liquidity may be to allow participants to trade rights between locations (zones or nodes). However, this requires some method of determining how volumes of rights can be exchanged between locations as participants will not themselves be in a position to know *ex ante* the exchangeability of rights in different locations. Hence, the SO would need to facilitate trading by assessing the exchangeability of rights between locations, and act as the counterparty to all access rights trades in secondary markets. This would be in addition to undertaking trades to align access rights with the capabilities of the network. We explain this further below.

3.20 The exchangeability of rights between locations will depend upon the relative effectiveness of increments or decrements in demand or generation at each location in resolving transmission constraints. For example, consider two nodes, *a* and *b*, and two constraints, *k* and *j,* and suppose node *a* is particularly effective at resolving constraint *k* whilst node *b* is effective at resolving constraint *j*. Only by considering the situation on the system as a whole and the extent to which constraint *k* and/or *j* is binding, can the relative exchangeability of access rights at nodes *a* and *b* be determined.

3.21 Only the SO will be in a position to estimate the relative exchangeability of different access rights, and it can only do this via a full system analysis – it cannot provide a set of fixed *ex ante* information to participants to indicate relative exchangeability. Therefore, unless a regime with a few, large, zones is adopted, efficient secondary trading of access rights between participants (which will involve trading between different locations), is likely to require an explicit, central mechanism operated by the SO.

3.22 There are a number of options for the design of such a mechanism. For example, the SO could quote prices for access at each node or zone, reflecting a forecast of the supply and demand for access rights. Trading access rights between participants would consist of the SO purchasing rights from one participant at a given location and selling rights to other participant(s) in different location(s). The prices quoted by the SO could be adjusted over time to reflect the relative exchangeability of rights between nodes and improved information on the likely demand and supply of access rights. The SO could continue to adjust prices until there was no further access right trading taking place.

3.23 An alternative approach would be for the SO to receive bids and offers from participants, and then to optimise the allocation of rights between participants on the basis of the bids and offers submitted and the physical capabilities of the transmission network. The SO could then publish the volumes to be exchanged and relative prices derived from this optimisation process.

3.24 Under any mechanism, it will be important to ensure that the facilitated secondary trading mechanism could be understood by market participants, and that the SO undertook its activities on a consistent and clear basis, without exploiting its position as market maker or its information advantages.

Partial SO facilitation

3.25 Even in a regime with rights defined according to relatively large zones, where liquid secondary trading could develop without central involvement, there may be a role for some looser SO facilitation of secondary trading in order to improve transparency.

3.26 For example, while trading between participants on a bilateral over-the-counter (OTC) basis might develop without SO facilitation, the view may be taken that OTC trading would not provide sufficient transparency and assurance of non-discrimination in relation to the SO's trading activities. Such a view may be held because of the perceived importance of the trading undertaken by the SO (i.e. buying back or releasing rights to reflect the actual physical capability of the transmission system), or because of the potential information advantages available to the SO.

3.27 In this situation, it may be desirable to establish an exchange or a bulletin board system which could be used on a voluntary basis by participants but which the SO was obliged to use when buying back or releasing capacity. Whilst it would not be necessary for the SO to operate the exchange/bulletin board, it would be facilitated by the SO in the sense that the obligation on the SO to use it for trading would provide a focus for trading and hence encourage liquidity.

3.28 Irrespective of whether or not there is SO facilitation of secondary trading, the SO will clearly have a key role to play in the secondary markets and it will be important that its activities are transparent and that it releases adequate data given the information advantage it holds over other participants.

Role of interruptible capacity

3.29 The sale of interruptible capacity would be one mechanism by which the SO could resolve transmission constraints. It would also allow the SO to reallocate rights that it believed participants would not use (so-called “use it or lose it”) without being obliged to repurchase them in the event the firm rights holders do utilise them fully. This may be desirable in order to prevent hoarding of firm rights by some participants.

3.30 For example, the SO could make an assessment of the access rights it expects to be unutilised at the day-ahead stage, and then sell interruptible access rights equal to this volume. The value placed on these rights by participants would depend upon the expected probability of interruption and hence on the volume released. Care would need to be taken to ensure that the original right holder still had the ability to exercise the rights – in this event, the interruptible rights would need to be cancelled (interrupted) by NGC without payment to the holder(s).

3.31 The treatment of interruptible capacity in a regime with a nodal definition of access rights (or a zonal definition with a large number of zones) may be more complex, given that the participant directly interested in the purchase of interruptible capacity at a particular location might also be the holder of the firm rights. In such a situation, in order to make the release of interruptible capacity effective, it would be necessary for the SO to release interruptible rights elsewhere across the system, taking into account an estimate of the relative exchangeability of rights in different locations.

3.32 Whether interruptible rights would be required might, in part, depend on the arrangements put in place regarding access imbalance calculations and the access rights associated with BM offers and bids. For example, the sale of interruptible rights might be particularly desirable if participants had to back their BM bids/offers with access rights or face exposure to access imbalance cash-out. If the acceptance of a participants' bids/offers in the BM automatically allocated the necessary access rights to participants, then interruptible rights might be of less value. We discuss possible treatments of access rights within the BM further in Appendix 4.

System Operator incentives under new transmission access arrangements

3.33 NGC, as the SO, currently faces a unified incentive regime in relation to electricity and system balancing costs. Following the implementation of the transmission access regime, we believe it will be desirable for the SO to face a consistent incentive mechanism for its trading operations in the energy and access regimes.

3.34 Secondary trading in access rights by the SO will be related to system balancing (i.e. the resolution of transmission constraints). However, any incentive scheme should ensure that the SO has an incentive both to:

- ♦ maximise the volume of access rights available to the market given the latest information on the capability of the transmission network; and
- ♦ resolve transmission constraints as well as any energy imbalances in the most cost effective way, whether that is through *ex ante* trading of access rights, striking electricity forward or option contracts, or through buying and selling electricity through the BM after Gate Closure.

3.35 The costs incurred (or revenues earned) through NGC's secondary access trading activities will depend critically on the volume of rights issued in the primary allocation - for example:

- ♦ the generation / demand assumptions which underlie the estimate of the transmission network's capabilities i.e. the decision between allocating in the primary auction the theoretical maximum capability of the transmission system, some estimate of the system's actual capability (with some allowance for likely constraints), or an estimate of the maximum certain capability (discussed in Appendix 2);

- the extent to which the products in the primary allocation are profiled to reflect the network's capabilities; and
- whether planned transmission outages are taken account of in the primary allocation of rights (if they are not, NGC will need to buy-back rights to cover the occasions on which the network's capability is reduced as a result of planned outages).

3.36 Particularly in relation to the determination of the volume of access rights made available in the primary allocation, it will be important that the SO faces consistent access, electricity and system balancing incentives as part of a bundled SO incentive scheme linked via defined and transparent output measures to the Transmission Price Control.

Ofgem's initial views

3.37 The above discussion has set out a number of issues in relation to the role and form of secondary trading of access rights, and in relation to the role of participants and the SO in that secondary trading. Below we outline our initial views on each of these issues:

- **need for SO facilitation of secondary trading**: Ofgem's general preference would be for a variety of secondary markets to develop in response to the needs of market participants. However, we recognise that, depending on other choices made in relation to the design of the regime (in particular, whether the primary allocation method involves auctioning or allocating rights), secondary trading may need to be facilitated by NGC. Indeed, any form of nodal regime would be likely to require SO facilitation to allow competition to evolve between participants in different nodes;
- **extent to which the SO should release products other than firm rights**: Ofgem continues to believe that interruptible rights can play a role in

preventing the hoarding[74] of access rights and ensuring that the maximum volume of capacity is made available to participants. Owners of firm rights should be required to 'use them or lose them' and this would be achieved by allowing the SO to sell interruptible rights. Ofgem also considers that it may be worth considering auction processes that allow the SO to buy options to interrupt demand or generation and sell options to constrain-on generation and demand for, say, a specified number of occasions or during specified periods; and

- **SO incentivisation**: Ofgem believes that access rights released by the SO should be firm in the sense that the SO is obliged to repurchase these rights at access market prices if they cannot be delivered. Ofgem believes that it will be important that effective SO incentive arrangements, encompassing the new access regime, are implemented at the same time as the new arrangements. Such incentive arrangements will have an important role to play in ensuring that NGC makes all capacity available to the market and effectively manages the costs of resolving constraints. We believe that NGC should face a consistent access, electricity balancing and system balancing incentive scheme, with this being linked via defined and transparent output measures (entry and exit capacities) to the Transmission Price Control.

Summary and views invited

3.38 This appendix has considered the role and form of secondary trading in access rights and the role that NGC should play in these markets. Views are invited on all the issues raised in this appendix - in particular we would welcome responses to the following key consultation issues:

- the types of secondary markets that will be required and whether these should be created or allowed to develop naturally;

- the role the NGC should play in the secondary markets for transmission access;

[74] Whether hoarding is likely to occur will depend on other aspects of the regime, notably the access imbalance settlement arrangements.

- the role of interruptible rights and how interruptible rights may be sold and traded; and

- the nature of the incentive arrangements on NGC as SO with the introduction of new transmission access arrangements.

Appendix 4 Interactions with NETA

4.1 This appendix discusses a number issues associated with the interactions between transmission access and energy trading arrangements under NETA. The topics that are covered are only relevant if, on at least one side of the market, there is a fully traded access regime including an access imbalance settlement system.

Discussion

4.2 The transmission access regime seeks to encourage participants to trade under NETA so that, at Gate Closure, a participant's intended output and/or consumption is consistent with the prevailing physical capabilities of the network. In this way, it should (in theory at least) only be necessary for NGC to make constraint-relieving acceptances in the BM (and then subsequently smear the cost of these over the market) when constraints arise after Gate Closure. Moreover, the combined trading and transmission access arrangements should aim to deliver signals to participants of the value of electricity at their location. We have set out in previous appendices some of the mechanisms through which this can be achieved.

4.3 The SO will, of course, continue to use the BM in the period between Gate Closure and real time. If, as anticipated Gate Closure is reduced from the current 3 ½ hours, NGC's actions in the BM might increasingly reflect system rather than electricity balancing actions. Given this, it will be necessary to ensure that treatment of transmission access in BM acceptances is consistent with that for similar trades conducted in other markets. Failure to do so could lead to distortions between the BM and other markets. Moreover, given that BM acceptances are used to set energy imbalance prices, prices emerging from the BM may influence the level and volatility of prices in other *ex ante* markets. It is, however noted that actions in the BM may still be required for other system balancing reasons, for example placing plant in a position to provide frequency response or reactive power.

4.4 In this appendix we examine how the transmission access regime would interact with the electricity trading arrangements under NETA:

- first, we examine the interactions between the access regime and the BM and put forward a number of possible ways by which locational considerations can be removed from the determination of energy imbalance prices; and

- second, we consider the location of energy trades under NETA. We discuss whether it is necessary or desirable to define a specific National Balancing Point (NBP) i.e. a physical rather than a notional point, at which energy is traded (in power exchanges and other markets) and at which imbalance prices (for energy and access) are calculated.

The transmission access regime during BM timescales

4.5 As noted earlier, the purchase of transmission access rights bestows upon the holder the right to inject a given amount of electricity onto or extract a given amount of electricity from the transmission system at a given location and in a given time period without incurring transmission access imbalance charges. The design of the transmission access regime therefore seeks to ensure that participants are incentivised to align their purchases of access rights to their intended physical positions (through the access imbalance and settlement process – see Appendix 5). In turn, the energy imbalance and settlement regime under NETA provides incentives for participants to align their intended energy position with their sales and purchases of energy undertaken in *ex ante* markets.

4.6 However, as well as trading in forward markets, a participant may also sell (or buy) energy, albeit only to (or from) the SO, after Gate Closure in the BM. Therefore, the design of the transmission access regime needs to consider whether:

- a seller of energy to or buyer of energy from the SO in the BM would need to have purchased access rights to cover these transactions (and equally, whether a participant who ends up with surplus rights as a result of BM transactions would be able to sell the surplus access rights in order to avoid access imbalance liabilities); or

- to ignore transmission access issues in the BM. In this case, the trading of transmission access rights would end at Gate Closure. Buyers and sellers of energy in the BM would simply trade with the SO without consideration of the implications for transmission access rights holdings (in a manner akin to the "bundling of access rights with BM energy" referred to in previous consultations).

4.7 Prima facie, the latter option appears the simpler and more practical arrangement. However, as we demonstrate below, completely ignoring the transmission access regime in the BM has undesirable consequences for the energy imbalance price calculation.

4.8 Under NETA, the energy imbalance prices are calculated from the price of bids and offers accepted by the SO in the BM. As the BM is a locational market (in the sense that the location of bids and offers will affect the SO's decision to accept them), tagging arrangements have been introduced in an attempt to remove constraint-related locational prices from the calculation of energy imbalance prices (more generally, tagging is intended to remove all system balancing trades). Hence, the tagging regime attempts to derive a "clean" electricity price that reflects the costs of producing an electricity balance for the overall system over the half-hour.

4.9 Tagging is recognised as a relatively crude method of removing locational considerations from imbalance prices and, all other things being equal, it would be desirable if the access arrangements removed the need for tagging. However, as noted above system balancing actions in relation to placing participants in a position to provide system services will still be required and hence some residual form of tagging might be necessary.

4.10 If tagging is to be removed, the transmission access regime cannot simply be ignored in BM timescales. As the BM is a locational market, if access right trading ended at Gate Closure, participants' offers and bids into the BM would continue to reflect the cost of taking actions at specific points on the network (i.e. they would reflect the constraints of the network). This would be true even if all constraints had been resolved by Gate Closure since participants' offers and bids would reflect their expectation of the value of energy at their location.

4.11 Without arrangements to correct for this, energy imbalance prices, when calculated from the offers and bids accepted by the SO, would reflect local considerations. For instance, suppose on two occasions the SO required an additional small amount of energy to ensure national balance. In one time period, the state of the network allowed it to take the energy from a northern generator, at a relatively low price. On the second occasion, because of a transmission constraint, the SO is forced to call on energy from a more expensive generator. Hence, if there is no consideration of transmission access issues in the BM, a change in the selection of locationally priced offers and bids accepted in the BM could change the energy imbalance price markedly. Thus locational considerations will impact upon the energy imbalance price, and relatively crude tagging mechanisms would continue to be required in an attempt to separate the locational (system balancing) aspect from the electricity balancing aspect of BM actions in determining energy imbalance prices. However, if it transpires that the materiality of the distortions involved in tagging are not large, further consideration may need to be given as to whether complex new arrangements to replace tagging would be necessary.

4.12 As noted above and in Chapter 3, an approach that removes the influence of location on energy imbalance prices without relying on the use of a relatively crude tagging methodology would be advantageous. By this we mean that energy imbalance prices should reflect the costs of energy at some NBP (either notional or physical). Thus, for example, low priced energy offers might be increased by high access right prices whilst highly priced energy offers might be reduced by negative access right prices so that both become equivalent in overall price terms at the NBP. Two approaches to the treatment of interactions between energy and access markets between Gate Closure and real time can be identified:

- a “**ticket to participate” approach**: Under this approach access rights and energy trades in the BM would be unbundled in the sense that participants would require access rights to support their offers and bids in the BM or else face exposure to access imbalance prices in the event that any of their bids or offers were accepted;

- the use of **proxy access right prices:** Under this approach, the acceptance of offers and bids in the BM would confer supporting access rights whose price would be centrally determined. These proxy access right prices would also feed into the calculation of energy imbalance prices.

4.13 We examine each option below.

"Ticket to participate" approach

4.14 Under this approach, participants could acquire access rights to cover their BM bids and offers in one of two main ways:

- **via pre Gate Closure trading:** participants wishing to submit BM offers and bids would have to acquire sufficient rights to back the offers or bids they submitted. To facilitate participation in the BM, NGC might make available very short term or interruptible rights before Gate Closure, perhaps at prices that reflected the uncertainty over whether the rights would be used or would be available. The access imbalance arrangements would, under such arrangements affect the incentives on parties to submit offers and/or bids into the BM without a guarantee of acceptance.

- **via a contemporaneous access right market**: trading in access rights would not end at Gate Closure, instead markets in access rights would run contemporaneously with the BM. Participants could, thus, reconcile their holdings of access rights with changes in their energy position caused by purchases or sales to the SO in the BM. The contemporaneous access right market could either be a continuation of the pre-Gate Closure secondary market(s) or a form of access right BM under which the acceptance of energy bids and offers by the SO would have to be linked to the purchase of corresponding access rights. Whilst the latter option would provide the "cleanest" energy imbalance prices, the complexity and system costs it involves are likely to make it an unattractive option.

4.15 Under both of these options, national energy imbalance prices could be calculated since the prices of participants' offers and bids into the BM would effectively include an allowance for access right costs.

Proxy access rights prices

4.16 Another approach, which would avoid the need for participants to acquire access rights to cover their offers and bids, would be to incorporate proxy access prices into the costs of bids and offers accepted by the SO for the purpose of calculating energy imbalance prices. In this way, it would be possible to impute "clean" energy imbalance prices whilst the BM would remain a locational market with the price of submitted bids and offers continuing to reflect locational variations.

4.17 To calculate energy imbalance prices, each accepted offer or bid for a BM Unit would have added to its price a proxy for the prevailing price of transmission access at the location of the BM Unit. A suitable proxy price might be the closing secondary market price (i.e. at Gate Closure) for access rights.[75] In terms of the prices paid to or by participants for accepted offers and bids, two approaches could be adopted:

- participants could be paid or pay their unadjusted prices but have their access right holdings adjusted to take account of their accepted offer and bid volumes for access imbalance settlement purposes. This would ensure that participants do not incur access rights imbalances on account of BM acceptances; or

- participants could be paid or pay their adjusted bid and offer prices. This would incentivise participants to include an expectation of this additional cost/benefit in their BM offer and bid prices. Hence, in access rights imbalance settlement, metered volumes associated with BM acceptances would need to be cashed out at the predefined proxy price. All other volumes of access rights imbalance would be cashed out at the prevailing access imbalance price.

[75] The methodology for calculating this price requires consideration. Clearly, the ability for participants to distort the price in the run up to Gate Closure would need to be assessed.

Analysis of options

4.18 Of the two options under a “ticket to participate” approach presented above, the pre-Gate Closure trading option has the advantage of simplicity and transparency. However, it may lead to some mismatches between access rights holdings at Gate Closure and the rights needed to cover offers and bids submitted in the BM. If most constraints were to be resolved prior to Gate Closure then this might not be important. The contemperous markets option improves the ability of participants to match their holdings of access rights to what they actually require, taking into account actual bid and offer acceptances. However, it cannot be guaranteed that there will be sufficient liquidity in a contemperous access rights market for participants to be confident that if they have a bid or offer accepted by the SO they will be able to adjust appropriately their access right holdings at a reasonable price.

4.19 Using closing access prices as a proxy price for access will be less accurate than a solution involving a contemporaneous access rights market since the “true” value of access rights may change after the proxy prices have been determined. For example, if a large transmission constraint suddenly developed, the value of access rights on either side of the constraint would normally be expected to change. The extent to which the use of proxy prices distorts energy imbalance prices will depend, amongst other things, on the volume of constraints (including intra half-hour constraints) that have to be resolved in the BM. Also, liquidity problems in *ex ante* access markets would effect the extent to which reliable proxy prices could be set.

4.20 To the extent that the implementation of the transmission access regime allows Gate Closure to be brought nearer to real time, the loss of accuracy from proxy pricing would be reduced. However, the same reasoning would suggest that, in these circumstances, the retention of the simple tagging mechanism might not unduly distort energy imbalance prices.

National Balancing Point

4.21 Given that, currently, in *ex ante* trading there is no need for participants to consider the actual capabilities of the transmission network, the price of energy for any given period should reflect the “unconstrained” price of energy. Hence, for each settlement period, market expectations of the cost of the marginal source of generation required to meet system demand will influence the price of electricity for the system as a whole. Generation with lower operating costs than this marginal source of generation are likely to seek contracts with load at a price reflecting the costs of this expected marginal generator, without regard to the location of the marginal generator. Generators with higher costs may exclude themselves from the market for this given settlement period.

4.22 Until a new access regime is introduced, it is the SO's role, amongst others, to adjust the "unconstrained" physical notifications submitted by participants to achieve a constraint compliant schedule, by accepting bids and offers in the BM. The cost of these constraint related acceptances form a component of the costs that are recovered through BSUoS charges.

4.23 With the introduction of new transmission access and pricing arrangements under NETA, participants will, to a greater extent, be incentivised to recognise constraints in their electricity trading prior to Gate Closure since they will have acquired access rights which should, at least partially, reflect the capabilities of the transmission network. Hence, some less expensive generation in export constrained areas may, for example, be excluded from the electricity market via operation of the access rights market. Therefore, the results of forward electricity trading, as represented by the submission of physical notifications, should be closer to being constraint compliant.

4.24 An important issue is whether trading in the forward electricity markets will be on the basis of bundled prices, incorporating both energy and access components (as in the gas market) or whether it will be on the basis simply of the energy component. In the former case, by definition, trading will take place at some form of NBP. From the perspective of providing locational signals, it makes no difference if the maximum and minimum access right prices are +80 and 0 or +40 and –40. However, market prices in the former case will be higher by 40 than in the latter case, although this difference should be largely offset, by lower or negative residual TNUoS charges. Nonetheless, it might be considered desirable to steer the market towards the +40/-40 type of spread by explicitly defining a physical NBP, at which the price of access is fixed. With one access price fixed, the appropriate relativities for all other points on the transmission system can be calculated.

4.25 If energy only trading occurs (so-called “station gate” trading), it may be more important explicitly to define a NBP to ensure that “headline” electricity prices do not increase and to prevent undue volatility developing in both the access and electricity markets. With access right arrangements, the energy only price may be higher than when trading is done on an unconstrained basis because, as discussed, if there are active constraints that are reflected in the level of available access rights, some less expensive generation will be removed from the market and have to be replaced by more expensive generation. Once again the issue arises as to what the overall level of prices will be, which will be dependent on the extent to which negative access right prices at the location of the more expensive generation offset the higher energy prices. Thus, again it may be advantageous to define a NBP, with zero access prices, from which appropriate access prices in other locations can be defined to ensure that the +40/-40 type of spread rather than the +80/0 spread evolves.

4.26 With station gate trading, another advantage of defining a NBP if prices are set on an energy only basis would be that, where a local transmission problem arose, it would cause the price of access in that region to change but would reduce the extent to which energy prices would change. Without such an explicit definition, both energy and access prices might change quite markedly in response to small changes in demand or the availability of generation.

4.27 Defining a NBP would not mute the signals that the transmission access regime sends since the relative level of access prices would be preserved. For each participant, the outcome would be the same as that when the most expensive plant on the system set the electricity price. By fixing the price of access at a particular location, more expensive plant in areas where generation is relatively scarce would demand an additional payment to generate. Hence, in some locations (specifically, where generating costs are more expensive than generating costs in the location where access is zero priced) the price of entry access would be negative.

Determining a NBP

4.28 If it is decided that it is desirable to define a NBP, there are a number of issues that need to be resolved. The first issue is whether the location of the NBP should be centrally determined or whether participants should agree on its definition. If the NBP is centrally determined then, in order to enforce its use, it would be necessary for the SO to price all its access trades with reference to the NBP and to set access imbalance prices in relation to it.

4.29 Allowing participants to agree a point with reference to which they would value access rights might facilitate liquid trading in forward electricity markets since it would enable energy to be traded at the location which was most convenient for participants. However, there is no guarantee that it would be possible for all participants to reach agreement on where the NBP should be located.

4.30 The second issue relates to the allocation of rights at the NBP. Access rights at the NBP would not be price rationed in the same way as at other locations since, by definition, the price of access rights there would be fixed irrespective of the volume of rights demanded. Thus, only the maximum physical capacity of the transmission grid would limit access[76] and the signals deterring excess generation or demand locating at this point would be blunted. This problem could be overcome by defining the NBP to be a point where no physical injections or offtakes can take place.

4.31 A further issue for consideration is that the appropriateness of any given NBP might reduce over time as network topology and the dispersion of generation and demand changes over time. This would restrict, to an extent, the length of time for which rights could be sold in any primary allocation of access rights and could lead, moreover, to participants facing basis risk.[77]

[76] In a regime where there is no national balancing point, the most expensive generator on the system sets the energy price and at that location access is priced at zero. Access is physically rationed at this point by total system demand for energy, rather than the access regime. With establishment of a national balancing point other than at the site of the most expensive generator on the system, system demand will no longer be effective at rationing access at this new balancing point.

[77] In financial terms, basis risk occurs when there is a difference between the asset for which a hedge is required and the asset underlying the futures contract used in the hedge.

Ofgem's initial views

4.32 Ofgem's view in respect of the two main issues discussed above is as follows:

- **treatment of access rights for Balancing Mechanism bids and offers:** Given the significant implications that the treatment of access rights in the BM will have for imbalance prices, it is important that further detailed consideration is given to this issue once other elements of the access regime have been decided. The option of allocating access rights to participants whose offers are accepted may have merits, in that it avoids participants or NGC purchasing rights they may not require but this could also be achieved by allowing the trading of access rights to continue after Gate Closure.

- **interactions with forward electricity prices:** Ofgem accepts that there may be some advantages in specifying a national balancing point around which participants can price their access right bids and offers but believes that further consideration needs to be given as to the overall desirability of such an approach, particularly if locational reserve prices are adopted for auctions. If it is adopted, it will be important that the national balancing point does not coincide with a physical node on the network since access at this point will by definition be free for the period for which rights are allocated, irrespective of whether, as the pattern of supply, demand and transmission availability changes, the nominated location becomes constrained.

Summary and views invited

4.33 In this appendix we have outlined how the transmission access regime might interact with NETA. We have explained why it is important that the interactions identified are carefully considered. We have outlined a number of options for treating the interactions between NETA and transmission access arrangements to facilitate the objective (for new transmission access arrangements) that energy imbalance prices should be as free as possible from the influence of transmission constraint and other transmission related costs. In addition, we have discussed why it might be beneficial to establish a specific NBP at which energy would be traded and relative to which access prices would be valued and established.

4.34 Views are invited on all the issues raised in this appendix and in particular:

- whether the interactions between access right trading and the BM should be captured through a “ticket to participate” approach or a proxy price approach. In addition, views are invited on which of the two options under a “ticket to participate” approach has most merit; and
- whether it is desirable to design the transmission access regime to create a specific NBP or whether such a point can be expected to emerge from the allocation and trading of access rights as a point at which most (if not all) participants are willing to trade.

Appendix 5 Transmission access imbalance and settlement

Introduction

5.1 In order for the benefits of a new transmission access and pricing regime to be realised, participants need to be incentivised to produce and consume in a manner consistent with their holdings of transmission access rights and the physical capabilities of the network. To the extent that participants' physical generation or demand is not consistent with these holdings (i.e. to the extent that they have access imbalances), and they impose costs on the system, these costs could be targeted at them. This appendix sets out the issues surrounding the treatment of these access imbalances. We consider the basis for calculating imbalance volumes and how imbalance prices might be determined and applied.

5.2 The extent to which an explicit access imbalance settlement regime will be required will heavily depend on the method of access right trading used to resolve constraints. For example, if constraints are resolved via the use of contracts then the settlement regime is reduced to a penalty system for failing to deliver on contractual obligations (for example, the failure to interrupt when instructed to do so by NGC under the terms of any transmission access interruptible contracts). However, most of this appendix is concerned with the issues that would need to be considered if a "full-blown" access imbalance regime, similar to that in place for energy imbalances, was considered desirable.

December Consultation

5.3 The December Consultation said relatively little on the possible design of transmission access imbalance and settlement. Nevertheless, in the context of a market in firm access rights, it was suggested that over-run charges would be required to discourage participants from generating or consuming in excess of the firm access rights they had purchased. Furthermore, the possible need to apply under-run charges in some instances was also discussed.

NGC's views

5.4 At a presentation to TUG-CPF[78] subsequent to the publication of the December Consultation, NGC suggested that it would be essential for transmission access and pricing arrangements based on firm access rights to be supported by an access imbalance settlement mechanism. In NGC's view, participation in primary auctions and secondary markets for access rights will only take place if electricity producers and consumers face a risk in not matching their metered volumes to their holdings of access rights.

5.5 NGC felt that it would be necessary for access products to impose obligations as well as rights on participants e.g. the holders of entry rights would face access imbalance charges for both under- and over-generating against their access right holdings. This is because to resolve a constraint NGC might, for example, require extra generation in a particular zone. Unless the sale of additional rights results in additional generation, it will not assist NGC in resolving the constraint. To encourage extra output in the right location, it may be necessary for NGC to pay a generator to acquire additional access rights, i.e. the prices for entry rights would be negative. NGC believed that imposing under-run as well as over-run charges on access rights would effectively impose obligations on participants with regard to the use of access rights.

5.6 NGC has also argued that access imbalance settlement would have to operate on a half hourly basis in order to allow access rights to be used to manage transmission constraints. This half-hourly resolution, and the fact that imbalances would need to be calculated for each access zone (or node), would in NGC's view mean that significant systems development would be required in order to calculate and settle transmission access imbalances.

5.7 Finally, NGC argued that the use of dual imbalance prices, as under NETA, would be likely to incentivise market participants appropriately. However, NGC expressed a general concern that any move away from cost reflective pricing of access rights could create inefficient incentives for participants.

[78] 'Possible Transmission Access Arrangements' A Presentation by NGC to TUG-CPF 99/00-18.

Other respondents' views

5.8 A number of respondents to the December Consultation provided specific comments on the issues surrounding transmission access imbalance and settlement. One large portfolio generator suggested that participants should only be able to notify energy quantities up to the level of access rights they hold. Another large vertically integrated energy company pointed out the complexity in assessing and imposing access imbalance charges. It also suggested that participants would arbitrage to find the best combination of energy and access imbalance prices. One independent generator pointed out that the trading of access rights and the need to balance access as well as energy positions would be a greater burden on small independent power producers than larger participants.

Discussion

5.9 In this section, we discuss a number of issues around the nature of access imbalance settlement. The key areas we cover are:

- the need for an imbalance regime;
- a rules based imbalance regime versus an imbalance settlement mechanism;
- an overview of an access imbalance settlement mechanism;
- the determination of access imbalance volumes; and
- the determination of access imbalance prices.

Need for an imbalance regime

5.10 Participants need to be incentivised to match their locational generation and demand to their access right holdings (or at least to take account of the cost to the system as a whole of not so doing) in order for new transmission access arrangements to meet their objectives.

5.11 It is envisaged that participants will hold, as a result of a primary allocation of rights and secondary trading, transmission access rights related to their expected electricity flows for each trading period. However, the actual metered flows of participants, and hence their access rights requirements, may vary from the level of access rights they hold. This could, for example, arise because of:

- uncontrollable events on the participant's side such as an unplanned outages of generation plant or uncertainty in the demand of suppliers' customers; and/or
- controllable events on the participant's side such as the participant wishing to exploit favourable market conditions e.g. high electricity prices, without purchasing associated rights.

5.12 Discrepancies between participants' metered volumes and their access rights may result in the SO having to take more actions in the BM in order to manage constraints than would be the case if there were no mismatches. This could undermine the effectiveness of the new transmission access and pricing arrangements and result in the trading and pricing of energy in electricity markets being unduly influenced by transmission constraints. Thus, ensuring that participants are appropriately incentivised is the role of the access imbalance regime – without it, the access regime will not correctly influence participants' behaviour either in terms of physical production or consumption plans, or in terms of the *ex ante* trading of access rights.

An imbalance settlement mechanism versus a rules based imbalance regime

5.13 The development of a full transmission access imbalance and settlement mechanism could be expensive and time consuming. It is therefore worthwhile considering other means of enforcing the firmness of transmission access rights on participants – for example, using legal obligations.

5.14 One possibility is that, if the SO were to rely on exercising option contracts to resolve constraints then the inclusion of penalty clauses in the contracts for failure to deliver the contracted service might be an adequate form incentive against access right imbalance. Thus, for example, if a consumer had agreed (or been instructed) to be interrupted for a particular settlement period but continued to consume electricity, a financial penalty would be levied on the excess electricity that it consumed.

5.15 An alternative would be to insert appropriate conditions in participants' generation or supply licences, the CUSC or the Grid Code. Such conditions could specify that participants' physical position at each location on the network must be consistent with the volume of access rights they hold.

5.16 A rules-based approach to enforcing firm access rights has the advantage of being potentially simpler and less expensive to implement than a settlement mechanism but does suffer from a number of drawbacks. In order for a rule based approach to be effective it would still be necessary to monitor participants' physical positions relative to their access right holdings. A random sampling approach could be used in order to decrease the burden of monitoring. However, given the potentially large number of positions from which a random sample would have to be chosen, an effective monitoring process may still involve considerable effort. Even with a random monitoring process, a system for registering participants' access right holdings would be required – this alone might require significant systems development.

5.17 Furthermore, assuming an appropriate method of monitoring can be devised, consideration would need to be given to the types of penalties to be used in order to encourage participants to achieve a balance in their access positions. If variable financial penalties are to be used then a basis for their calculation would need to be devised although such an arrangement may be tantamount to implementing a full access rights imbalance cash-out regime in any case (because both prices and volumes are determined). Alternatively, it might be possible to apply simpler, fixed fines (for example, such fines could be based on the application of information imbalance charges).

Overview of an access imbalance settlement mechanism

5.18 If an access imbalance settlement mechanism is to be implemented, its design should ensure that the incentives on participants are consistent with the effects that their actions would have on the resolution of transmission constraints.

5.19 Participants would have an imbalance if they had:

- **over-run**: their physical generation or demand was greater than their access right holdings; or

- **under-run**: their physical generation or demand was less than their access right holdings.

5.20 There are two ways in which such imbalances could be treated:

- **access rights as rights *or* obligations**: access rights would be interpreted as conferring the right for the holder to generate or consume up to a certain level if they had paid for the rights *or* the obligation for the holder to generate or consume at a certain level if they had been paid to take the rights. Thus, it is likely that entry rights in export constrained regions (and possibly exit rights in import constrained regions) would be rights whilst entry rights in import constrained regions (and possibly exit rights in export constrained regions) would be obligations. Participants would face imbalance charges if they either exceed their rights or failed to meet their obligations; and

- **access rights as obligations**: under this approach, participants would always be exposed to access imbalance prices if their metered volumes differed from their access right holdings. However, in some locations access imbalance prices might be negative for entry (or exit) and hence participants might be paid for undergenerating (or overconsuming).

5.21 As noted above, the impact on the transmission system of a participants' failure to produce or to consume in accordance with their access right holdings will vary depending on the prevailing system conditions. If there are no transmission constraints affecting the region in which a participant is located, neither over-runs nor under-runs should effect the system. However, if the region is constrained then there will be an impact. Table 5.1 summarises the various possibilities with a "negative" impact representing an action that leads to an increase in the transmission constraint and a "positive" impact one which helps to relieve the transmission constraint.

Table 5.1 – Impact of over-runs and under-runs on system constraints

Nature of imbalance	Export constrained area	Import constrained area
Generation over-run	Negative impact	Positive impact
Generation under-run	Positive impact	Negative impact
Demand over-run	Positive impact	Negative impact
Demand under-run	Negative impact	Positive impact

5.22 Given that the costs that access imbalances impose on the system vary by location, it is important that access imbalance prices also vary by location. It follows that an access imbalance regime with imbalance charges and payments based on (although not necessarily equal to) the best available estimate of real time access prices (i.e. those emerging from secondary markets) will provide appropriate incentives for participants (see below for a more detailed discussion of the derivation of these prices).

5.23 For example, consider a situation in which there are two locations, A and B. A has an entry price of £3 (and an exit price of -£3) and B has an entry price of -£2 (and an exit price of £2). If these are the market clearing prices for access in each location, there is clearly an active constraint between A and B, and £3 and £2 respectively are the best real time estimates of the cost to the system as a whole of incremental injections at location A and incremental offtakes at location B. To the extent that participants have access imbalances, the incentives sent by the imbalance charges or payments should be based on these valuations. Thus, the imbalance prices associated with the constraint exacerbating over-runs and under-runs in each zone should be as set out in the table below.

Table 5.2 - Worked example of imbalance prices

Nature of imbalance	Location A Entry price = £3 Exit price = -£3	Location B Entry price = -£2 Exit price = £2
Generation over-run	Charge based on £3	
Generation under-run		Charge based on £2
Demand over-run		Charge based on £2
Demand under-run	Charge based on £3	

5.24 The question would then remain as to the imbalance prices for over-runs and under-runs that relieved the constraints. Broadly speaking there appear to be three options:

- **Option 1**: a regime under which an imbalance price equal in magnitude to prevailing access prices is applied to constraint relieving imbalances.[79] For example, generation over-runs in location A in the example above would be paid £3;

- **Option 2**: a regime under which an imbalance price at a premium to prevailing access prices (to create a disincentive to being out of balance) is applied to constraint relieving imbalances. For example, generation under-runs in location A in the example above might be paid £2.50. This option provides a greater incentive for participants to balance their access position than option 1; and

- **Option 3**: zero access imbalance prices for constraint relieving imbalances. This would be the outcome if access rights were considered as rights or obligations rather than always obligations (see discussions above).

5.25 The first option simply applies access imbalance prices with a single value to access imbalances in both directions. The second and third options provide increasingly strong incentives for participants to balance their access position (in

[79] Attachment 4 contains some worked examples by NGC of the imbalance charges that would apply in various circumstances under this option.

one direction at least). Whether this is necessary given dual energy imbalance prices is a matter for further consideration.

Determination of imbalance volumes

5.26 The basic principle behind the determination of the imbalance volume position of each participant should be to compare, for each trading period and for each location, the level of access rights held with the actual metered volume of that participant.

5.27 As noted in Appendix 1, it is not possible with the current Stage 2 settlement systems to obtain information on individual suppliers' demands at a locational resolution below the GSP Group level. If zonal definitions of access rights are adopted which are not consistent with the current GSP Group boundaries, then consideration will need to be given as to how imbalance volumes for demand are calculated.

5.28 There are a number of potential ways in which a finer locational resolution for the demand-side could be achieved. They range from amendments to the geographic resolution of metering point registration in the Stage 2 systems to allow the calculation of demand side information on a finer level of locational resolution for some or all demand, to using existing Stage 2 data in combination with geographic "allocation factors" to produce finer zonal or nodal demand information. These "allocation factors" could be derived on the basis of historic or a forecast estimates of the geographic dispersion of demand within GSP Groups. An allocation of this sort could be conducted largely independently of the current Stage 2 settlement process. While the former approach is clearly likely to be more accurate in its allocation of GSP Group demand information to finer zonal or nodal demand information, the relative complexities and cost of such a change might suggest consideration should be given to other solutions at least for the short term. The use of allocation factors, therefore, may provide a useful interim solution.

5.29 Even if exit rights are defined in terms of GSP Groups, a finer resolution of demand data may still be desirable if entry rights are defined on a different zonal basis or nodally. For example, suppose entry rights were defined nodally, and exit rights were defined on the basis of GSP Groups. Demand side imbalance quantities could be derived from the existing Stage 2 systems. However, the access imbalance price to apply would ideally take into account the dispersion of demand within GSP Groups. This is because, conceptually, the relationship between exit and entry prices in these circumstances should be such that the price of an exit right should be the negative of the demand weighted nodal entry right prices within the exit zone.

5.30 A final issue to be considered is whether imbalance volumes should be calculated and settled separately for entry right and exit right imbalances at each location or whether it should be possible for entry and exit rights at a given location to be netted off for imbalance settlement purposes. If netting off were allowed, this would mean that all a participant's access imbalances at a particular location would be added together to give a single net access imbalance for which the access imbalance charge (if applicable) would be calculated. Thus, if a participant over-generated by 10 MWh but also over-consumed by the same amount, it would have no net access imbalance volume (although it would, of course have two energy imbalance quantities).

5.31 From a technical perspective, it is only the net flows into or out of an area that are important and hence allowing netting off would not affect the ability of the SO to resolve constraints. For example, consider a participant with both generation and demand at a given point from which the SO was attempting to limit the net flow in order to manage a constraint. It could be argued that a participant who over-delivers on an exit obligation to the same extent that it exceeds its entry rights at the same location is not actually creating incremental net flow and hence is not imposing additional costs on the system. Because the participant is offsetting its own position at the same location, the SO would not need to take additional actions to limit the flows out of the area.

5.32 However, a net entry and exit imbalance approach would be inconsistent with the equivalent arrangements under NETA for the purposes of energy imbalance settlement where separate accounts will be used for production and consumption. In the case of energy imbalances, the argument for separate production and consumption accounts related to the potential discrimination between different types of participants that might result from allowing netting of imbalances. Vertically integrated companies with generation and demand at the same location might be able to offset their access imbalances, and therefore their incentive to trade access rights prior to gate closure in order to remain in access balance would be reduced. This could be seen as unduly disadvantaging participants that are not vertically integrated. The encouragement of vertical integration (including by contracts) would be general and might lead to consolidation of the market at its lower end, with control passing to a small number of 'lead parties'. Whilst the effects of this on competition overall are unclear, it would represent a structural distortion of the market.

Determination of access imbalance prices

5.33 The basis for determining access imbalance prices will be crucial in providing the correct economic incentives on participants. The general principle underlying access imbalance settlement should be that, to the extent that participants' *ex ante* purchases of access rights do not match their physical generation or consumption and this imposes costs on the system, participants should be exposed to these costs.

5.34 Cost reflective pricing of access imbalances implies an imbalance price for each location related to the costs of the SO resolving imbalances at that location. Conceptually, there are two bases for determining these costs:

- **access prices prevailing at Gate Closure:** It would be possible to use access prices prevailing at, or just before, Gate Closure as a basis for access imbalance prices.[80] These would not be fully cost-reflective if constraints arise between Gate Closure and real time. However, in the absence of other reliable real time prices, and particularly if Gate Closure moves closer to real time, Gate Closure access prices may provide a sufficiently accurate and relatively simple method for setting access imbalance prices. A further refinement of this approach might be just to use the average of the prices of the access trades undertaken by the SO (rather than the average of all trades). This refinement would better reflect the costs to the system of participant's imbalances; and

[80] To avoid the potential for undue manipulation by market participants, it may be felt desirable to use a measure derived from the average price of trades for a specified period (e.g. 1 hour) prior to Gate Closure.

- **access prices imputed from the BM:** Under this approach, access imbalance prices would be calculated from the prices of constraint related acceptances made by the SO in the BM. This would more directly reflect the real time costs incurred by the SO in resolving residual access imbalances but would ignore the costs of any actions taken in advance by the SO in anticipation of residual access imbalances (analogous to ignoring the forward electricity contract costs in setting energy imbalance prices).

5.35 It would also be possible to use some combination of the two basic approaches to include both real time and short term costs in access imbalance prices.

Ofgem's initial views

5.36 Below, we set out our initial views in relation to each of the key issues discussed in this appendix:

- **rules based regime versus imbalance settlement mechanism:** Ofgem's initial view is that participants' holdings of transmission access rights would be best incentivised through an appropriate access right imbalance and settlement mechanism rather than a rules based regime. However, if secondary trading is restricted to the SO selling constrained-on options and buying interruption options, then, as discussed above, penalties for non-delivery (failing to reduce output or demand in interruption options and failure to maintain output or demand in constrained-on options) in the option contracts could take the place of an access imbalance settlement system;

- **nature of the access imbalance regime:** our initial view is that a two-sided cash-out regime is not appropriate for access imbalance. Instead, when participants have paid to acquire access rights they should be subject solely to over-run charges. Conversely, when participants have been paid to provide a service (including when they have been paid to take access rights), we consider they should be subject solely to under-run charges for failing to deliver the service;

- **determination of access imbalance volumes:** Our initial view is to prohibit netting off of entry and exit imbalances, since it could unduly discriminate in favour of vertically integrated participants. By definition, netting-off would not occur if the imbalance regime related to failures to meet contractual obligations; and

- **determination of access imbalance prices:** Overall, Ofgem believes that there is strong merit in relating access imbalance prices to the costs incurred by the SO in resolving transmission access. With regard to whether imbalance prices should be locational or national, we consider that it would not be possible to provide participants with appropriate cost signals if a national imbalance price were used.

Summary and views invited

5.37 The discussion above has covered a number of areas related to the need for and form of an imbalance regime, including some more detailed aspects of the potential operation of a full access imbalance settlement mechanism. Ofgem continues to believe that an access imbalance settlement process will be required to ensure the effectiveness of new transmission access and pricing arrangements and to provide appropriate price signals to all participants.

5.38 Views are invited on all the issues raised in this appendix. In particular we would welcome responses to the following key consultation issues:

- the need for a full blown access imbalance and settlement regime versus a rule based imbalance regime;

- the calculation of demand side information including possible changes to Stage 2 settlement systems;

- the basis for determining access imbalance volumes;

- the proposal not to allow the netting of entry and exit right imbalances; and

- the basis for determining access imbalance prices.

Appendix 6 Treatment of transmission failures

Introduction

6.1 In Appendix 3, we discussed the issue of NGC releasing and buying back rights in secondary markets ahead of real time to resolve constraints and to reflect new information on the expected status of the transmission network for each settlement period. In this appendix, we discuss the separate but related issue of the treatment of transmission failures, specifically the rights of participants in circumstances where it is not possible for participants to exercise the access rights they hold as a result of a failure of the transmission network.

The August Transmission Access Workshop

6.2 Four respondents to the August Workshop expressed concerns regarding the treatment of transmission failures under NETA. It was pointed out that in the event of a transmission failure, generators are exposed to significant energy imbalance risk and that this issue needs to be addressed since it was both unfair and unacceptable over the long-term. Two respondents also pointed out the need to ensure consistency between the national transmission system and distribution networks, especially since a great deal of generation over the next decade is likely to be embedded in distribution networks.

Discussion

6.3 In the event of a failure on part of the transmission system that influences the overall supply/demand balance or stability of the system, NGC will need to take immediate remedial action(s) to ensure the system remains secure and stable. This is likely to be achieved through a combination of accepting BM bids and offers, the use of commercial interruption tools such as inter-trips[81] with specific generators and demand sites, and ultimately forced disconnection of generation and load.

[81] NGC has the ability to utilise a set of commercial and non-commercial inter-trips in order to maintain system security. This involves the use of automatic equipment to disconnect or “trip” generation or loads in response to system emergencies. Broadly speaking, commercial inter-trips are needed to meet operational standards, whereas non-comercial inter-trips are needed to meet planning standards.

6.4 However, to the extent that transmission failures occurring after Gate Closure force participants out of balance in relation to their contracted energy position, there is currently no means for them to redress their imbalance and they will be exposed to energy imbalance prices. Ofgem agrees with the view that this is not a desirable long term position. Participants should not be exposed to disproportionate risks as a result of being unable to deliver on physical positions due to a transmission system failure.

6.5 In the case of a planned outage, NGC can contract with participants before the outage to limit their use of specific transmission assets for the period of the outage (for example, by buying back access rights). This mechanism should ensure that participants are appropriately compensated for the reduction in the capability of the system affecting them. In contrast, with a transmission failure, NGC cannot contract in this way, as the failure is, by definition, not anticipated.

6.6 Following a transmission failure, conceptually NGC is failing to deliver on firm access rights held by the affected participant(s), but, depending on whether trading in access rights is allowed after Gate Closure, NGC might not be able explicitly to buy-back the access rights that the participants(s) now cannot use. To mitigate the risks imposed on participants and to provide NGC with an incentive to minimise the incidence, duration and impact of transmission failures, Ofgem continues to believe that NGC should be required to pay compensation for the failure to deliver on firm access rights. As transmission failures occur during, or close to, real time, the level of such compensation would need to be calculated *ex post*.

6.7 In considering how such compensation payments should be determined, there are two key issues:

- the duration of the compensation period for the transmission failure; and
- the calculation of the level of compensation.

6.8 We discuss each of these issues in turn.

The duration of the compensation period

6.9 The compensation period could be related to:

- **the duration of the failure**: participants could be entitled to compensation for the entire duration of the failure itself. While this may be appropriate for relatively short failures, it may discourage more innovative contracting between participants and NGC in relation to failures lasting for more significant time periods (i.e. when NGC would have an opportunity to contract forward on secondary markets); or

- **the duration of the failure, subject to a maximum duration**: to address the issue raised above, a maximum period for compensation could be defined. Under this option, compensation would not be payable for periods in which NGC should be able to via the normal secondary markets buy-back access rights; or

- **the flexibility of plant or demand on the system**: the compensation period could also be related to the flexibility of generation plant or demand on the system. For example, if particularly inflexible plant or demand are disconnected from the system for even a short period of time, it may take a long time for them to regain their pre-failure level of output/consumption. It may therefore be considered appropriate for compensation to take this time lag into account.

The level of compensation

6.10 There are two elements to the level of compensation payments: the volume of rights on which compensation is paid, and the price for such compensation.

6.11 Participants should be compensated for the difference between the volume of transmission rights they have purchased and the volume that they are actually able to utilise (that arises as a direct result of the transmission failure). However, consideration might need to be given to whether a link should be made with how much a participant actually intended to use its access rights (for example, a link with contract notifications). Moreover, if the period for which compensation was payable following a transmission failure were to extend to periods for which Gate Closure had not occurred, then further consideration might need to be given to the definition of compensation volumes. This is because, with a zonal definition of access rights, a portfolio generator, for example, could respond to one of their stations being tripped due to a transmission failure by increasing output from another station in the same zone. The generator could still be using all its zonal access rights but would have been deprived of the option of using them at a particular node within the zone to which the rights apply.

6.12 A further issue for consideration is the price that should be used to determine compensation levels. Potential options include:

- using a pre-determined price;
- using a price emerging from the prices paid in primary access right auctions (if these occur);
- using prices emerging from secondary markets for access rights in the relevant zone; or
- basing the prices on energy or access imbalance prices.

6.13 Ideally a price which reflects the market value of the access rights curtailed would be desirable.[82] If access markets close at Gate Closure, for the first 3.5 hours of a compensation period there will be no new market based access prices. During this period, the most appropriate compensation price might therefore be a price based on access prices at Gate Closure for the relevant half

[82] In the gas regime a capacity outage at a particular terminal may be managed by Transco in a number of ways. First, Transco may reduce the amount of capacity made available by exercising its right of interruption on any interruptible rights sold to participants. If this still leaves an excess of rights on the system and Transco cannot provide the allocated firm capacity it must pay compensation for denial of access . The compensation paid depends on the actions Transco takes in the event that there are insufficient interruptble rights to manage the situation. The next option available to Transco is to buy-back rights at the going rate in the secondary market by purchasing the lowest cost offers. Finally, Transco has the right to scale-back access rights at the terminal which is facing an access imbalance. Scale-back takes place on a pro-rata basis for all relevant participants but the compensation scheme in place ensures that the cost to Transco of scaling back capacity is always greater than the cost of buying back in the secondary market. The costs of buying back and scaling capacity are 20% borne by Transco, with the remaining 80% of the costs of buying back or scaling back smeared across the holders of monthly capacity at all major beach terminals subject to an annual cap and collar set at +/- £5 million. Thus, Transco is incentivised to take remedial action as early as possible. This encourages use of the secondary market to buy-back rights, where the price paid is reflective of the market value of the rights curtailed.

hour. Alternatively, a price based on access imbalance prices or a combination of Gate Closure and imbalance prices might be appropriate.

6.14 For situations in which a transmission failure occurs whilst access rights markets are still open, the appropriate access price is likely to depend upon whether access rights are defined nodally or zonally:

- with a **nodal definition**, there may be a very limited number of participants at each node (typically, there will only be one generation participant). There may not therefore be an access price at the disconnected node to use in calculating compensation. Hence, it may be appropriate to continue to use a price based on access prices at Gate Closure, access imbalance prices or some combination of the two. This might, however, result in some loss of accuracy, particularly for long compensation periods; and

- with a **zonal definition**, trading in the rights will continue between other participants despite the transmission failure and an access right price for the zone might therefore be available. However, it may still be appropriate to use a price based on *ex ante* access prices and/or imbalance prices in calculating compensation, in order to reduce the possibility of participants with portfolios of generation or load within the zone attempting to manipulate access prices in order to increase their compensation payments.

Ofgem's initial views

6.15 Ofgem remains of the view that participants should receive compensation for the involuntary removal of their access rights as a result of transmission failures.

6.16 In accordance with the general principle of reducing, as far as possible, administered mechanisms, Ofgem is inclined towards the view that explicit compensation should only be payable for periods for which secondary trading of access rights has already ended when the transmission failure occurs. Thereafter, participants should be able to sell their access rights to participants or the SO and thus indirectly receive compensation.

Summary and views invited

6.17 We have highlighted some of the key issues involved in compensating participants for transmission failures. Views and comments are invited on all of the issues discussed in this appendix. In particular views are invited on:

- the approach to determining the length of the compensation period; and
- the appropriate derivation of compensation volume and price under a zonal or nodal definition of access rights.

Appendix 7 Interaction with Transmission Price Control

Introduction

7.1 In this appendix, we consider the interaction of the proposed transmission access regime, as outlined in the previous sections, with the Transmission Price control. Specifically, we consider how NGC's allowed TO revenues should be funded under the new regime. We also briefly discuss the issue of transmission investment and retiral.

December Consultation

7.2 The December Consultation considered how NGC's allowed revenue under the Transmission Price Control should be funded under a transmission access rights regime. Ofgem's initial view was that the value of energy at different locations on the transmission network would be signalled by the proposed new transmission access and pricing (and losses) arrangements. Given this, Ofgem suggested that it would not remain appropriate to levy TNUoS charges on a locational basis and that consideration should be given to replacing it with a flat rate charge which covered the difference between the net revenues that NGC earned from the access regime and its allowed TO revenue.

NGC's views

7.3 NGC believed that it would be inappropriate to link revenues from an access market to the income required by NGC to plan, develop, construct and maintain the transmission system i.e. its allowed revenue under the Transmission Price Control. NGC argued that the access market will reveal the short-run costs of constraints and losses (assuming that losses are included in the access regime) but that its capital expenditure should continue to be based on meeting its planning and security standards and its revenue requirement set by price reviews. Thus, NGC argued that there will still be a requirement for TNUoS charges under the proposed regime.

7.4 NGC also noted that a well designed and competitive access market would deliver short-run locational marginal prices that should incentivise efficient investment decisions by participants. NGC believed additional locational signals through TNUoS charges would distort the signals to participants and hence it agreed that, if an access market is introduced, TNUoS charges should become non-locational.

Other respondents' views

7.5 Six respondents to the December consultation raised concerns over how the construction and maintenance of the transmission system would be funded under new transmission access and pricing arrangements. Most comments were of a general nature suggesting that TNUoS charges should be reduced to reflect the costs that participants would face in purchasing access rights. However, one large integrated energy company believed that the price for access rights should encompass both the costs of long-term transmission system development and the costs of short-run congestion. This respondent believed that both long and short-run signals would be required to give the correct economic valuation of system access and that cost recovery through a combination of access right charges and use of system charges would not be appropriate.

7.6 Four respondents commented on whether NGC should retain any revenues generated by the trading of access rights to offset against other transmission charges. Of these, two respondents were against NGC retaining these revenues whilst a group representing consumers was in favour.

Discussion

7.7 In this section, we consider the most appropriate methodology for participants to fund NGC's allowed revenue under the Transmission Price Control to cover the costs of the transmission system. We also discuss the issue of transmission investment and retiral. Specifically, we consider:

- the financial surplus that may arise with a market in firm transmission access rights;
- the continued need for TNUoS charges; and
- transmission investment and retiral under the new regime.

Financial surplus under a transmission access regime

7.8 Operation of any access right trading regime with locationally differentiated prices may will result in a financial surplus when there is a constrained transmission system. This can most easily be seen in the case where both entry and exit rights are auctioned. In this case, a financial surplus may arise because, in export constrained locations, the volume of positively priced entry access rights sold is greater than the volume of negatively (equal in magnitude but negative in sign) priced, exit access rights. Similarly, in import constrained locations, more positively priced exit rights may be sold than negatively priced entry rights. The revenue associated with the sale of the surplus entry and exit rights respectively will create the financial surplus. The same logic holds even if exit rights are allocated rather than auctioned , providing the method by which exit access charges are calculated does not unduly distort the market.

7.9 Should all constraints cease to be active, access prices would be the same across the system, and since the aggregate volume of entry rights sold would equal that of exit rights, there would be no financial surplus. Hence, it is the presence of transmission constraints in a regime with locationally differentiated market prices that leads to the accrual of a financial surplus.[83] Financial surpluses from the primary allocation mechanism would also be unlikely if the volume of access rights to allocate was calculated using the "maximum theoretical capability" of the system.

7.10 It would be inappropriate to leave this financial surplus with the SO if doing so would incentivise the SO to judge lines to be constrained in order to increase the surplus. However, it would be appropriate if the retention by the SO of any surplus formed part of an overall framework designed to encourage efficient investment in the network to meet customers' needs. For example in the gas market, to ensure that Transco faces efficient long term investment signals, Ofgem has proposed that Transco should be:

[83] A financial surplus would arise in an unconstrained system were reserve prices to be applied. A further source of a financial surplus would be if losses were to be charged on a purely marginal basis.

- exposed to the full costs of buying back from participants, at market prices, firm access rights initially made available in line with the output measures agreed for its price control, which Transco was subsequently unable to deliver or decided not to deliver;

- allowed to retain any surplus associated with making available rights in line with those agreed for its price control for the purpose of accelerating the depreciation of its assets and, hence, reducing future transportation charges;

- allowed to retain any additional revenue associated with rights sold over and above the output measures agreed for its price control; and

- required to buy-back any incremental capacity that it had sold but failed to make available.

7.11 Such an approach could equally well be adopted in the electricity market. If, however, it is decided that any surplus should not be retained by the SO, the issue then arises as to how the surplus should be returned to participants. There are broadly two options: to smear it back to participants on the basis of their access right holdings or to use it to reduce TNUoS charges. The distributional effects of the two approaches would be different because the charging bases would not be the same.

TNUoS charges

7.12 There is no reason why the revenues from an access trading regime should match NGC's allowed Transmission Price Control revenues. For this reason, Ofgem believe that TNUoS charges will continue to be required to fund the difference between the transmission access surplus and NGC's allowed revenue.

7.13 In this section we consider other aspects of the TNUoS charging methodology and examine, in turn:

- the geographic differentiation of TNUoS charges;

- the basis for TNUoS charging; and

- the split of TNUoS charges between generation and demand.

Geographic differentiation of TNUoS charges

7.14 The current Investment Cost Related Pricing (ICRP) mechanism determines locationally differentiated TNUoS charges. These are broadly based on the long run costs of providing the network assets required to deal with forecast incremental levels of generation and demand at various locations throughout the transmission system.

7.15 Under the proposed new regime for transmission losses and a traded access right regime, participants will be exposed to short run locational cost signals based on the costs of marginal transmission losses and transmission constraints. Under these circumstances, the combined price of energy and access will reflect the costs of generation and consumption at each location given the capabilities of the transmission network. Participants' expectations of the future levels of these costs should form the basis of long run investment decisions in generation and demand, and the value that participants place on access should influence NGC's investment decisions.

7.16 In this environment, the use of locational TNUoS charges based on an ICRP methodology (as at present) might overstate locational incentives and hence could lead to inefficient investment decisions. In these circumstances, some adjustments could therefore be in order (for example, a move towards charging for TNUoS on a non-locational flat rate or "postage stamp" basis). However, the ICRP methodology might still have a role to play in calculating the minimum prices at which NGC might be willing to offer incremental access rights on a longer-term basis. It might, for example, be used to set reserve prices in auctions for access rights incremental to those associated with the current capabilities of the system.

7.17 If, however, the access right regime were to follow the access charge/option contract approach, then locationally differentiated access charges would still be required and it is for consideration whether these should be separate from TNUoS charges. (If this approach was only adopted on the demand-side of the market, the questions raised above would still be relevant with regard to generation). It would still be appropriate to consider whether the ICRP methodology should be changed. For example, participants would still be exposed to the locational costs of marginal losses, which they do not currently face.

The basis for charges

7.18 Currently, TNUoS charges are levied for generation on installed MW capacity, for half-hourly metered demand on Triad[84] demand and for non half-hourly metered demand on actual electricity consumption over defined periods of the year. The rationale behind this basis for charging is that the capacity of the transmission system is set by the requirements for transmission capacity at system peak. Therefore, participants should contribute to its costs in relation to their use at system peak. Non half-hourly metered demand is charged on the basis of consumption over the year to overcome the allocation problems associated with customers switching suppliers at different points during the year.

7.19 Under the proposed access regime, however, participants may face access (and losses) signals that reflect the short run value of electricity, given the transmission network at that time, for all periods, including the system peak. There may, therefore, be a case for no longer linking charges to use of the system at times of system peak, as the charges for access will reflect the scarcity of transmission capacity in all time periods. For example, it might be more appropriate to charge for TNUoS simply on the basis of a flat per MWh unit charge. The majority of consumption TNUoS charges are already levied on a £/MWh basis (although not on all MWh[85]) so the question relates primarily to the treatment of generation TNUoS charges. This question is probably not relevant if TNUoS charges are used as access charges for entry rights.

Split of charges between generation and load

7.20 Currently, TNUoS charges are split 27:73 between generation and load. It is for consideration whether this split should be retained if TNUoS charges are changed. In this context, it will be relevant to take account of European Union

[84] Triad is defined as the three half-hours between November and February (inclusive) in any financial year which comprise the half-hour of system demand peak, and two other half-hours of highest system demand which are separated from system demand peak and each other by at least ten days.
[85] Suppliers' final charges for half-hourly metered demand are based on the average of the actual demand supplied during the Triad. Suppliers' final charges for non-half-hourly metered demand are based on their actual energy consumption over the period 16:00hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38 inclusive) over the year (1 April 2000 to 31 March 2001 inclusive).

initiatives with regard to harmonising the split between generation and demand transmission charges as a means of facilitating cross-border trading.

Transmission investment

7.21 The proposed regime for transmission access will expose participants to the short run value of electricity at their location i.e. the value of electricity at their location *given* the configuration of transmission network at that time. In the long term, signals are required to encourage load to locate in low priced areas and generation in high priced areas - at least to the extent that regional differentials in other costs do not overshadow access price differences. In turn, this may reduce variations in locational prices. However, as well as investment by generation and demand, investment in transmission assets also has the potential to affect the variations in locational prices.

7.22 Investment in transmission that relieves a constraint will reduce access prices in an export constrained area and increase access prices in an import constrained area. This occurs because relieving a constraint increases the supply of access rights in the export constrained area and decreases the demand for access rights in the import constrained area.[86] Thus, changes to the configuration of the transmission network will directly affect the prices to which generators and demand are exposed. This is different to the current NETA situation where, for the most part (with the main exception of generation plant who have offers accepted for constraint resolution in import constrained regions), the impact of transmission investment is only indirectly felt via changes in BSUoS and TNUoS costs,[87] which are spread over all participants.

7.23 Therefore, it will be the case that, upon adoption of the transmission access proposals, transmission investment and retiral will become more important to industry participants than to date. The issue of the basis on which investment decisions are made under the proposed regime is not, however, straightforward. At least three possible bases for investment decisions could be envisaged under the new arrangements:

[86] The demand for access rights in import constrained areas reduces because expensive local generation is replaced by cheaper generation from the previously export constrained region.
[87] Those participants who, before the investment, were constrained on or off but are not after the investment face a more direct exposure to the impact of transmission investment.

- **security standards approach**. The default approach would be to continue to use the present security standards to set NGC's level of transmission investment and retiral over a price control period. This would have the benefit of allowing participants to respond, in terms of locating new generation and load, to a fixed plan of the topology of the transmission network over a given time horizon. A disadvantage of this approach is, however, that it may be less efficient as investment would be made irrespective of the value participants placed on it and the costs of the investment then imposed on them;

- **market based transmission owner investment.** Under this approach, the transmission owner would invest in additional assets should access prices suggest it beneficial to do so. The transmission owner would continue to recover a regulated revenue stream from the additional assets. Under this approach the costs of the investment could be visited on those participants that gain (through lower prices) as a result of the additional transmission capability; or

- **market-based investment by third parties.** An alternative market-based approach would be for investment in transmission to be undertaken by third parties in response to different access price signals at various locations on the network. Transmission investment would occur to the extent that it bestowed benefits on the builders of transmission wires. Whilst perhaps conceptually attractive, this approach raises a host of problems associated with capturing all of the externalities associated with investment in long lived transmission assets as well as its interaction with existing transmission assets.

Ofgem's initial views

7.24 The above discussion has set out a number of issues in relation to the structure of transmission charges under the access regime. We believe that the treatment of any financial surplus should be considered in the context of the overall framework on NGC to make efficient investments to meet customers' needs. We consider that an approach which allows NGC to retain any surplus both to allow for faster depreciation of existing assets and to fund customer driven investments incremental to those agreed for the Transmission Price Control is likely to be superior to one in which any surplus is smeared back across participants. It would allow NGC to invest in incremental capacity where the price signals emerging from the auctions indicated that it would be efficient to invest. If additional investment is required, Ofgem would expect that excess demand for the available level of access rights would increase prices above long run marginal costs, triggering an evaluation within NGC as to whether further investment would be efficient. In subsequent price controls, a decision could then be taken as to whether the additional investment should be included in NGC's regulatory value but we consider that such a market based approach would lower the risk to NGC of 'stranding' new investment when compared to the current regime.

7.25 As there is no reason for the revenues from the transmission access regime necessarily to equate to the amount of revenue required to fund NGC's allowed revenue, Ofgem believe that TNUoS charges will continue to be required to be levied on participants.[88] Our initial views on TNUoS charges are:

- **geographic differentiation of charges**: we believe that, under an access rights regime, there may be less need for additional locational signals to be sent through TNUoS charges; and
- **the basis for charges**: if the proposed regime results in a price for access at each location that reflects the scarcity of tranmission capacity in all time periods, our initial view is that there is no need to charge for TNUoS on some basis of usage of transmission at "peak". Instead, it might be preferable to charge on a per MWh basis. It is for consideration whether generators and suppliers should share equally the costs of TNUoS.

Summary and views invited

7.26 Where possible and appropriate, Ofgem would like NGC to make the maximum volume of access rights available to participants. To achieve this, it will be necessary for NGC to face consistent and co-ordinated incentives across the

[88] Were the financial surplus to exceed the amount of revenue required to fund NGC's revenue requirement, then TNUoS charges would be negative.

Transmission Price Control, the SO incentive scheme and any incentive scheme for access rights. The access, electricity and system balancing incentives that NGC faces should be linked via defined and transparent output measures to the Transmission Price Control.

7.27 Views are invited on all the issues raised in this appendix. In particular, we seek views on:

- the appropriate geographic differentiation of charges;
- the appropriate basis for levying TNUoS charges;
- the equal sharing of costs between generation and demand; and
- how transmission investment and retiral should be treated for the current Price Review Period under the proposed transmission access regime.

Appendix 8 The enduring treatment of transmission losses

8.1 Transitional arrangements for the treatment of transmission losses have been put in place for the start of NETA. This appendix presents Ofgem's current thinking on enduring arrangements for the treatment and charging of transmission losses.

Background

8.2 Under the Electricity Pool, transmission losses in England and Wales were charged on a uniform basis across the vast majority of electricity purchased in the Electricity Pool. The metered demand of all suppliers, in each settlement period, was scaled up such that the total demand through the Electricity Pool was equal to total metered generation. Thus, the cost of actual losses was recovered only from suppliers.

8.3 In accordance with Schedule 12 of the P&SA,[89] set up at Vesting, the Pool's Transmission Steering Group, in March 1996, considered the issue of locational charging for losses and suggested a more cost reflective zonal approach to charging for losses on both generators and suppliers. Subsequent to Pool member approval and the Director General upholding the Pool's resolution in an appeal for determination, the Pool Executive Committee set out in July 1996 a timetable to implement a differential Transmission Loss Factor (TLF) scheme in November 1997. A challenge by Teeside Power and Humber Power led to a judicial review as to the compliance of the proposed scheme with Schedule 12 of the P&SA, which prevented the scheme from being implemented.

December Consultation

8.4 In the December Consultation, Ofgem argued that changes to transmission losses arrangements should be designed to provide appropriate signals as to the value of generation and demand at different locations. The document presented several specific objectives for the treatment and charging of transmission losses including that any charging regime should:

[89] Schedule 12, Section 11, Paragraph (B) states that the arrangements for transmission losses should be "Review(ed) and, if agreed, implement changes in the arrangements for allocating the costs of transmission losses on the supergrid, e.g. to reflect: (i) electrical location of generation and demand; and/or (ii) contractual arrangements between Generators, Suppliers and NGC; and/or (iii) incentives for investment in supergrid facilities.

- help to promote the efficient short-run matching of generation and demand;

- provide signals for the location of new investments for generation and demand; and

- help to signal the need for, and appropriate location of, network expansions i.e. it should provide long-term investment signals.

8.5 The December Consultation also raised a number of issues to be considered in the design and application of any transmission loss charging regime. Specifically Ofgem said consideration would need to be given to:

- **whether charges for transmission losses should be defined on a zonal or nodal basis:** a change in load or generation at any node will affect the flows of power, and hence losses, across the system. This can be reflected by a mechanism which reflects different loss factors between nodes. Alternatively, to simplify the arrangements, groups of nodes with similar loss factors can be grouped together into zones, with each zone having a single (e.g. weighted average) loss factor;

- **whether predetermined or actual flows should be used to calculate loss factors**: to provide wholly accurate signals in relation to losses, charges should reflect actual system flows. However, under a regime which determined losses in real time or *ex post*, participants would not know the loss charges which they would face *ex ante*. Participants would, therefore, be unable to manage fully the uncertainty which they faced in relation to transmission losses (additionally, the level of losses charges would not only depend upon participants' actions as a whole, but also on actions in relation to the configuration of the system taken by NGC). The alternative, therefore, is to base losses charges on a centrally determined *ex ante* forecast of flows, which will inevitably be inaccurate (and could result in the need for a small losses "uplift" to recover the costs of differences between actual losses and *ex ante* forecasts losses), but which will allow participants to manage their exposures;

- **whether marginal or average losses should be used to determine charges**: losses charges can in principle be based on either average or marginal losses but prices reflecting marginal losses provide more efficient economic incentives than average pricing. However, if charges are based on marginal losses, an over-recovery of costs occurs and a mechanism for the return to participants of this surplus revenue needs to be introduced; and

- **whether responsibility for purchasing losses should be with participants or NGC as SO**: The responsibility for purchasing losses can be either allocated to market participants or centrally co-ordinated via the SO. The main advantage of the first approach is that it allows market participants greater freedom to enter into innovative arrangements to share the risks and costs attributable to transmission losses. Alternatively, the purchasing of losses can be viewed as part of the task of achieving an overall electricity balance and, therefore, properly part of the function of the SO as electricity balancer.

Ofgem's initial views

8.6 Ofgem proposed that losses should be charged by scaling the metered volumes of both generators and suppliers prior to settlement on the basis of predetermined (ex ante) locational marginal loss factors. These loss factors would be based on historic data. Ofgem believed that this arrangement would provide the most appropriate and efficient economic signals to generators and suppliers as well as providing them with considerable commercial freedom to manage their exposure to transmission losses. The December Consultation went on to present a detailed proposal for a loss charging arrangement under NETA based on a scheme originally devised for use under the Electricity Pool trading arrangements. The functionality to implement the broad mechanics of this scheme has already been included in the BSC.

8.7 The December Consultation also suggested that the surplus revenues that would accrue from the use of marginal rather than average loss factors should be offset against other transmission charges. Furthermore, Ofgem argued that with the introduction of locational loss charges it might be appropriate to consider changes to the way that TNUoS charges are calculated so as not to overexpose participants to locational signals (a point already raised in Appendix 7).

NGC's views

8.8 NGC was supportive of the objective of establishing an efficient regime for the treatment and charging of transmission losses. Although it agreed that locational marginal loss factors could provide appropriate economic signals to market participants, it felt that there were important implementation issues to do with the correct calculation of these factors, the efficient collection of any revenue surplus that might arise and the interaction with other locational charges. Foremost of NGC's concerns was that the adjustment of participants' metered volumes on the basis of marginal Transmission Loss Factors (TLFs) would be likely to result in a physical electricity surplus rather than a financial revenue surplus.

8.9 NGC argued that, under NETA, the majority of participants would seek to stay in balance by matching their contract volumes with their loss-adjusted metered volumes. Consequently the use of marginal loss adjustments would result in an overall electricity surplus, as participants' actions would over compensate for the level of actual system losses, i.e. the average level of losses. This in turn would result in the SO always having to purchase more bids than offers. NGC argued that it is unclear to what degree this would result in a revenue surplus to them which could then be retained to offset all participants transmission charges, as opposed to a subset of participants in the BM and imbalance settlement.

8.10 NGC also raised a number of points associated with the interaction between the treatment and charging of transmission losses and any potential new transmission access and pricing arrangements. It agreed that nodal charging for demand was impractical since the demand of non-half-hourly metered customers can only be measured at the GSP Group level. However, NGC felt that it would be beneficial for transmission loss charging zones to be compatible with the zones used in defining firm access rights.

8.11 NGC discussed the effect that transmission constraints would have on the calculation of locational loss factors. It argued that, in order for the correct locational signals to be sent to participants, it would be desirable to consider the treatment of access and losses together both in terms of the time frames under which they are purchased and in the determination of an appropriate reference point to ensure an equitable sharing of costs between generation and demand.

8.12 NGC have also argued that there is an important interaction between transmission constraints and marginal losses – specifically that the correct marginal loss signal in relation to transfers across an active transmission constraint is zero, since no additional power can flow over the constraint. Hence, NGC argued that using unconstrained marginal loss factors alongside a transmission access regime would overstate locational signals in the event of constraints.

Other respondents' views

8.13 Thirty respondents to the December Consultation commented on issues related to the treatment of transmission losses under NETA. Of these, the majority supported the need for reform to the treatment of losses. However, a few noted that more detail would be required before they felt able to comment on the proposals. Several participants expressed a concern to ensure that due process is observed in debating proposals, particularly given the judicial review of the Electricity Pool's proposed loss scheme.

8.14 A majority of respondents had reservations over the introduction of marginal losses, especially if this was to occur at the same time as the introduction of NETA. However, most respondents were in favour of both sides of the market (i.e. generation and demand) being charged for losses.

8.15 Views were evenly divided on whether zonal loss factors should be varied by season and time of day with many respondents taking the view that this additional level of complexity (at least initially) might hamper participants ability to come successfully to grips with the new trading arrangements. On the whole, respondents were not supportive of the SO retaining any surplus resulting from a marginal loss charging regime.

Possible long-term mitigating arrangements

8.16 A group of generators were concerned that the scope of issues considered in the December consultation was incomplete and, in particular, that insufficient attention had been paid to the issue of whether the proposed scheme would serve to increase efficiency. They have since argued that it is not necessary to withdraw what they describe as their existing rights with regard to transmission losses in order to achieve efficient cost signals, and that withdrawing existing rights without good reason would damage efficiency rather than improve it.

8.17 They suggested that for a predetermined period existing generators should only be exposed to transmission loss signals to the extent that their output changed from what they had produced at some pre-determined time (for example, during 1999/00 or an average of historic output levels) since transmission loss signals need only apply to marginal generation decisions. These mitigating arrangements would be effected through the creation of long term contracts for differences between NGC and participants[90] for pre-determined volumes (perhaps declining over time) that refunded any difference between the costs of transmission losses in the future and current loss charges faced by participants for transmission losses (in the case of generation under the Electricity Pool this reference cost would be zero). These contracts would be tradable and it would be for further consideration whether contracts would be made available for new entrants albeit for an option fee.

8.18 They further maintained that without such an arrangement the proposed change in the arrangements for transmission losses would lead to unjustified windfall gains and losses, and increased costs for the industry as a whole since the cost of capital would increase in response to a perceived increase in regulatory risk as a result of what they argued was an unjustified change in the treatment of losses.

Discussion

8.19 As discussed in Ofgem's April 2001 Consultation[91] and August 2000 Initial Proposals documents,[92] Ofgem accepted the concerns raised by NGC and other respondents to the proposals in the December Consultation with regard to attempting to implement a full locational marginal loss factor scheme for the

[90] For the demand side the suggestion was that CfDs should be struck with distributors with the costs passed on to consumers.
[91] 'NGC System Operations under NETA: transitional arrangements, A consutation document', Ofgem, April 2000.
[92] 'Initial proposals for NGC's System Operator incentive scheme under NETA, A consultation document and proposed licence modifications; Ofgem, August 2000.

start of NETA. Thus, for a transitional period under NETA, adjustments for transmission losses are being made on actual (i.e. average) losses across the system (i.e. with no locational element) and are being uniformly recovered on the basis of metered volumes. Participants' metered volumes are adjusted for losses before imbalance volumes are calculated with 45% of the loss volume being allocated to generators and 55% to the demand-side. Nonetheless, Ofgem continues to believe that the enduring scheme for transmission losses should incorporate more efficient arrangements for the charging of transmission losses including the use of locational marginal loss factors.

8.20 Ofgem accepts that simply adjusting participants' metered volumes by marginal loss factors could distort trading in the BM and hence imbalance prices. We have also noted NGC's arguments in relation to the interaction between transmission constraints and marginal losses.

8.21 Below we discuss our initial views on possible enduring arrangements and the long-term mitigating arrangements suggested by some generators. We are currently considering two general options for enduring transmission losses charging arrangements.

- **Option 1** would be to adjust participants' metered volumes using estimates of average zonal loss factors. A separate financial payment or levy, calculated to reflect the difference between the full marginal loss factor and the average factors used to adjust metered volumes, would be included in BSUoS charges; and

- **Option 2**, originally proposed by NGC, would be to use estimates of the costs of marginal locational losses to set loss related reserve prices in any auctions for access rights.

8.22 We discuss each of these in further detail below.

Option 1: Metered volume adjustment plus BSUoS charge

8.23 The broad thrust of this approach is that participants' metered volumes would be adjusted using estimates of average zonal loss factors and a separate financial payment or levy would be applied to reflect the difference between the full marginal loss factor and the average factors used to adjust metered volumes.

8.24 Adjusting generation and consumption metered volumes by marginal loss factors scaled downwards to equal average system losses should mean that there would be no systematic need for NGC to accept bids in the BM. This approach alone would not send the full marginal losses signal to participants – to achieve this, an additional adjustment is required. This would need to be in the form of a financial payment or levy, in order to avoid distorting total *ex ante* contracted electricity volumes. An obvious mechanism would be to include this additional payment or levy in BSUoS charges.

8.25 To calculate this marginal loss-related payment or levy, it would be necessary to calculate the difference between the full marginal loss factors and the average-scaled loss factors applied to participants' metered volumes. A charge equal to these locational "difference" factors multiplied by an appropriate electricity price would then be added to the BSUoS charges. It is for consideration whether this price should be the System Buy Price (on the grounds that this is the price at which the SO would have to purchase any losses) or whether it should be taken from a power exchange or price index. It would be important that the chosen reference price is consistent with other electricity related reference prices used, for example, the reference prices used in the SO incentive scheme under NETA.

8.26 Overall, this arrangement would mean that participants would be responsible for purchasing losses. The SO would be responsible for charging the difference between marginal and total losses. Participants could choose to provide for average losses themselves by adjusting their contractual position accordingly. Alternatively, participants who did not contract ahead, or adjust their consumption/production position to account for average losses, would face an energy imbalance charge and hence would effectively be buying average losses at the appropriate imbalance price.

8.27 Within this general methodology, two main approaches are possible depending on whether or not it is considered desirable to define participants' loss factors in advance of Gate Closure.

Approach One: Ex ante metered volume adjustment using unconstrained loss factors

8.28 Under this approach, participants' metered volumes would be adjusted using *ex ante* estimates of unconstrained marginal loss factors which have been scaled down to equal expected average losses (and possibly adjusted for expected transmission constraints). The match between actual losses and those calculated from participants loss factors will not be perfect due to the use of an *ex ante* estimate of loss factors, and due to uncertainties in the level of participants' generation or demand. However, the use of pre-determined loss factors would make it simpler for participants to judge how to contract so as to avoid energy imbalance charges.

8.29 In order to attempt to reflect the interaction between transmission constraints and marginal losses, the average locational loss factors calculated under this approach could be adjusted to reflect an *ex ante* forecast of the incidence of transmission constraints. This approach will be unlikely to capture correctly the interaction between constraints and marginal losses, as it cannot reflect accurately the real time incidence of constraints.

Approach Two: Constraint updated metered volume adjustment

8.30 The difference between this approach and Approach One is that the loss factors used to adjust participants' metered volumes would not be set in advance but would be calculated at Gate Closure on the basis of physical notifications made to the SO. Thus, the loss factors would reflect the prevailing market expectation of active transmission constraints. If this approach were adopted, it would be important that, prior to Gate Closure, participants had sufficient information to be able to estimate their loss factors given their expectation of the likely incidence of transmission constraints.

8.31 A set of unconstrained marginal loss factors would be calculated and published *ex ante* as in Approach One. Participants would also be given information as to the way in which the incidence of transmission constraints in various locations would change the loss charges (effectively, participants would be provided with a way of calculating constrained marginal loss factors from a set of unconstrained loss factors given their own expectation of constraints). Using forward access prices (or their own expectations of access prices), participants would therefore be able to estimate the “constrained” loss charges, and contract to cover these charges.

8.32 At Gate Closure, the loss factors for use in settlement would be adjusted for active constraints, using closing access right prices as the market’s best estimate of the location of active constraints, and scaled down to anticipated average losses. As under Approach One, these loss factors would then be applied to participants’ metered volumes in calculating energy imbalances.

Option 2: Auction reserve price

8.33 In order to capture fully the interaction between constraints and marginal losses, NGC has argued that losses and constraints should be treated via an integrated approach.

8.34 NGC has suggested using an estimate of unconstrained marginal loss factors, along with a reference electricity price to set relative reserve prices for any primary access right auction. Thus, the minimum price that participants could pay to gain access rights would cover the expected costs of losses in the absence of constraints. In locations, where access is expected to be restricted due to transmission constraints, the primary auction should clear prices above the reserve price. The price signals would therefore correctly model the interaction of constraints and losses but only on the basis of an *ex ante* view of transmission constraints.

8.35 While this mechanism sends the appropriate signals with regard to marginal losses, it does not on its own result in energy being contracted to cover actual system losses. The key factor with this approach is the treatment of the funds raised by the auction reserve prices (i.e. those specifically related to losses). There are two ways in which the funds *could* be treated:

- they could be retained by the SO, and it could then purchase system losses (NGC's proposal); or
- they could be returned to participants (through BSUoS or TNUoS charges) and adjustments could be made to participants' metered volumes to incentivise them to purchase average losses. This adjustment would be non-locational.

8.36 Under either approach it would be important that any secondary trading of access rights also reflected the loss-related reserve prices. If this was not the case, the locational losses signals incorporated in the primary auction might subsequently be lost.

8.37 Under the first (NGC) approach above, revenues from reserve prices earned above any incentive regime target cost for losses would need to be passed back to participants. Under the second approach, all such revenues would need to be returned to participants.

Ofgem's initial views

8.38 Overall, Ofgem believes that Option 1 is preferable to Option 2. While option 2 allows for the interaction between expected constraints and marginal losses to be correctly modelled, and may be structured to place the responsibility for purchasing losses on participants, it requires the use of an administered reference price for electricity which may distort the price signals sent in relation to losses. Both determining an appropriate reference price and estimating loss factors for the reserve price calculation could be particularly problematic if long term access rights were to be sold. Moreover, it is not obvious that the reserve price approach would work unless both entry and exit rights were auctioned.

8.39 Ofgem considers that determining loss factors *ex ante* has advantages in terms of encouraging liquid trading. We accept that this can distort the interaction between constraints and losses but believe that this distortion may not be significant unless the volume of constraints increases substantially from its current level.

Possible long-term mitigating arrangements

8.40 Ofgem is not persuaded by the arguments made by some generators with regard to the need for long-term mitigating arrangements for existing participants for the following reasons.

8.41 First, we do not accept that the introduction of a marginal loss system will increase regulatory risk nor that it is a new initiative whose consequences were not understood at the time when investment decisions by existing players and new entrants to the industry were being made. The introduction of such a regime is not a wilful or unjustified act, it is one designed to increase the overall efficiency of the system and thus to facilitate the fulfilment of Ofgem's statutory obligations. The possibility of introducing a more cost-reflective arrangement for losses has been signalled since 1990. For example the Director General argued in May 1990, and confirmed in the Statement of October 1990,[93] that '(NGC) are keen to analyse their costs further and accept that in due course their charges should be more cost-reflective. Their charges should also encompass all the costs of transmission including transmission losses so that decisions on the location of generating plant and of demand are properly informed'. The need for more cost-reflective arrangements for losses has been signalled since Vesting through the inclusion of this issue in Schedule 12 of the Pooling and Settlement Agreement. Thus, the suggestion that changing to a locational marginal loss arrangement is likely to increase regulatory risk seems unfounded.

8.42 Second, the suggested mitigating arrangements to a marginal losses scheme proposed by some generators (discussed above) appear discriminatory and to some extent arbitrary. The arrangements would discriminate against new entrants (and indeed rely on this to ensure the effectiveness of the mitigating arrangements) who would be exposed to the full marginal loss scheme[94] thus raising the barriers to entry. This would act against consumers' interests. The proposed arrangements depend on taking the output that the plant produced in a given year or years as indicating the existing rights that the plant has acquired against which its exemption from the loss arrangements would be measured.

[93] 'Statement by the Director General of Electricity Supply: The regulatory system and duties of the DGES', October 1990.
[94] Even if contracts for differences were made available for new entrants, they would be hedges fixing their liability for marginal losses but not removing it (in contrast to the CfDs proposed for existing participants).

Depending on the year(s) chosen, the outcome could be very different and in this sense the arrangements proposed are arbitrary.

8.43 Third, we do not accept the argument that efficiency gains to be had as a result of charging participants for locational marginal losses only require the costs of marginal losses to be targeted to marginal producers. Marginal production is a dynamic concept and will vary over time in response to price and cost signals that participants face, entry and exit from the generation market and the pattern of generation and demand. In addition, a producer who is at the margin of a merit order that ignores losses may not be a marginal producer if loss factors are taken into account. Thus, to charge marginal losses only on the current marginal producers would arbitrarily discriminate against some participants and ignore the dynamic effects of marginal losses across the merit order. Hence, it is not possible to define what the marginal loss-adjusted production would be without first making adjustments to all participants positions.

Summary and views invited

8.44 In summary, Ofgem continues to believe that any enduring arrangement for transmission losses should be designed to expose participants to the costs of locational marginal losses. We accept that this could be achieved in different ways but are not convinced by the arguments in favour of long-term transitional arrangements. In addition, we believe that there is strong merit in allowing participants themselves to manage their exposure to transmission losses.

8.45 Views are invited on all the issues discussed in this appendix. In particular, views are invited on:

- the rationale for moving to arrangements based on locational marginal transmission losses;
- the mitigating arrangements proposed by some generators; and
- the relative merits of the alternative charging options for locational marginal losses discussed.

Appendix 9 Systems Requirements

Introduction

9.1 Earlier appendices have outlined the issues and options to be considered in developing new transmission access arrangements. This appendix discusses the processes and computer systems that might be required in order to support such arrangements, and based on some initial analysis conducted by NGC, the likely costs of such systems.

9.2 New transmission access and pricing arrangements described in this document would potentially require the development of systems in three main areas:

- **central systems**: new systems would be required to facilitate the allocation, trading and settlement of access rights;
- **NGC systems**: a number of NGC's internal systems could require development in light of the proposed arrangements; and
- **participant systems**: participants would require systems to allow them to participate fully in the new arrangements.

9.3 In this appendix, we focus on the first of these areas. However, NGC has conducted an initial analysis of the systems requirements for both central systems and its own systems and we present cost estimates for both these categories. We set out these estimates at the end of this Appendix.

Components of central systems requirements

9.4 Naturally, it is difficult fully to determine the exact requirements and level of sophistication required for these systems until the design of the trading arrangements they support has been more fully developed. However, it is possible to investigate the broad design requirements and identify where trade-offs may exist.

9.5 Broadly speaking, the central systems required to support trading in access rights will consist of three main parts:

- primary allocation systems;
- secondary trading systems; and
- registration and imbalance settlement systems.

9.6 We consider each of these components below.

Primary allocation systems

9.7 A range of possible primary allocation mechanisms were discussed in Appendix 2. The choices made with respect to the allocation process will determine the complexity of the systems required to support these functions. For example, a simple allocation procedure based on connection agreements would require little sophistication – essentially it would be a case of recording participants' generation or demand capacities. In contrast, an auction process might require electronic bid capture, an optimisation algorithm and an automatic notification process for each of the products being auctioned, e.g. notification of the entry rights at each location for each time period.

9.8 There is also likely to be an important trade-off between the complexity of the primary allocation mechanism adopted and the complexity of the secondary trading systems. The simpler the primary allocation of rights, the more secondary trading activity the SO (and possible participants) will need to undertake, and the more robust the secondary trading systems would need to be.

Secondary trading systems

9.9 As discussed in Appendix 3, the nature of secondary trading activity will depend amongst other things on whether a nodal or zonal definition of rights is chosen. Similarly, any systems required to facilitate secondary trading will be influenced by this choice. In terms of the systems requirements for each of the forms of secondary trading identified in Appendix 3:

- **complete SO facilitation**: systems would be required to allow NGC to facilitate all trading activity (whether by option contract or some more interactive system including participant to participant trading). These systems would almost certainly need to be operated by NGC, as they would rely on a significant amount of technical information on the status of the transmission system in order to operate effectively;

- **partial SO facilitation**: systems would be required to support NGC's buy-back and release of capacity, in much the same way that Transco uses its day ahead auction and within day capacity market to buy and sell gas entry capacity. The systems may also be used to facilitate more general participant to participant trading. They could be operated by a third party; and

- **no SO facilitation**: there would be no centrally designated operator of secondary markets, and hence no consequent need for centrally designed and procured trading systems. Secondary trading could take place over-the-counter, or via exchanges or bulletin boards established by third parties for commercial gain.

9.10 Where facilitation is required, there are a range of possible secondary market structures that could be adopted. For example, these could range from annual/monthly auctions of option contracts through to day ahead auctions of contracts and/or rights, to an access right exchange-based market. Each of these market structures would serve to fulfil different goals and potentially involve different levels of systems complexity. For example, the systems requirements for the sale and purchase of option contracts might be quite low. However, it would probably preclude participant to participant trading. In contrast, setting up a fully dedicated exchange would facilitate the buy-back and sale of rights by NGC and provide a means for participants to trade amongst themselves, but at the expense of greater systems complexity and costs.

Registration and imbalance settlement systems

9.11 If systems are required to register access right holdings and subsequently settle access right imbalances, they are likely to be the most complex part of the central systems. They would involve calculating an imbalance liability, requiring an imbalance volume and an imbalance price for each participant, for each half hour of the day, and for each defined location.

9.12 The calculation of imbalance payments and charges would involve a significant number of interfaces to other systems. These interfaces might include:

- registration of participants' access right holdings for each location for each half hour at Gate Closure;
- capture of participants' metered volumes (possibly including further geographic disaggregation of volume information from the Stage 2 settlement system;
- capture of the volume of BM energy bids/offers accepted;
- capture of access pricing information (the nature of which will be determined by the inputs to the imbalance price calculation – for example, access right prices at Gate Closure); and
- funds administration.

9.13 In addition, the access imbalance settlement system would need to take account of changes in demand side volume data through the Stage 2 reconciliation process.

Systems development costs

9.14 NGC has produced an estimate of the likely high level systems requirements arising from the form of transmission access and pricing arrangements described in the December Consultation. NGC, in conjunction with its consultants, has made an estimate of the costs of these systems requirements based on its previous experience of systems which have been developed in broadly comparable situations.[95]

9.15 Table 9.1 presents NGC's broad estimates of the minimum projected system costs to set up a zonal transmission access market based on GSP zones. The assumptions behind NGC's estimates and a more detailed presentation of its analysis are presented in Attachment 5.

[95] For example, the settlement roles and systems being developed for NETA, creation of traded exchanges and auction mechanisms.

Table 9.1 - Estimate of Possible One-Off Systems Development Costs[96]

System / Process	Cost (real 1999/00 prices)	Components
Primary Auction System	£1.5m to £3m	• Zonal auction system • Ticket allocation method • Auction settlement • Publication of results
Secondary Trading Mechanism	£2m to £4m	• Includes release/buyback system procurement (with option for bilateral trading)
Imbalance Settlement	£10m to £20m	• Assume 5 of 7 NETA roles are required (all except metered volumes and BM actions) • Aggregation needed at a zonal level • Rights Registration Agent included • Funds Administration included
TNUoS changes	£0.5m - £1.5m	• Includes NGC system changes for tariff and reconciliation
BSUoS changes	£0.5m to £1m	• Includes NGC system changes for algorithm and interfacing
Overall Program Management	£0.5m to £1.5m	• Managing overall implementation interfaces / legal contracts
Total	**£15m to £31m**	

9.16 Subsequent to providing the estimates in Table 9.1, NGC has provided a broad brush estimate of the potential implications of moving from a definition of access rights based on relatively large zones (i.e. a small number of zones) to a nodal definition (see Table 9.2). This estimate is not based on detailed analysis of systems requirements, but instead refers to variances from the cost ranges above based on a qualitative view of the likely systems changes required, and assumes that Stage 2 settlement is not re-opened.

[96] This table should be considered in the context of the supporting analysis in Appendix 6.

Table 9.2 - Implications of a nodal market

System / Process	Key changes	Cost Implications
Primary Auction System	• Nodal products would be sold, increasing the volume of products handled • May have little impact on systems if a simultaneous clearing mechanism is used	• *No significant impact on cost range – indeed it may actually be simpler (lower end of the cost range) as there would be no need to define zones* (£2m?)
Secondary Trading Mechanism	• More trades would have to be facilitated by the SO – the mechanism would have to cope with a larger volume • May require more reporting of nodal prices by the SO	• *System costs likely to be at top end of the range (£4m?)*
Imbalance Settlement	• Requires registration, pricing and settlement on a nodal basis (at least for generation) • Requires a method to allocate zonal GSP group demand to nodes • System Costs could be substantially higher if Stage 2 Settlement requires greater location resolution	• *System costs likely to be at upper end of range presented, and possibly higher depending on complexity of demand approximation method (£20m)*
TNUoS changes	• No significant change	£0.5m - £1.5m
BSUoS changes	• No significant change	£0.5m to £1m
Overall Program Management	• No significant change	£0.5m to £1.5m
Total Cost Estimates (real 1999/00 prices)		**£27.5 m to £30 m**

Summary and views invited

9.17 This appendix has outlined some of the issues surrounding the provision of systems to support the introduction of new transmission access arrangements. The implications of key market design factors such as the primary allocation mechanism, secondary market mechanisms, and access right imbalance and settlement have been highlighted in terms of the potential scope of the systems required.

9.18 Views are invited on all the issues discussed in this appendix. In particular, views are invited on:

- the degree to which synergies with existing and future systems under NETA could be exploited for developing systems for new transmission access arrangements; and
- the possible systems options and potential costs of implementing new arrangements.

Attachment 1: Assessing Volumes of Constraints Addressed Prior to Gate Closure in a Market for Firm Access rights

The following paper describes NGC's modelling of the volume of constraints it might be possible to capture under a market in firm tradable access rights.

Introduction

In line with the trade-offs outlined in the main text, indicative studies have been carried out in order to assess the effectiveness of a transmission access market at addressing constraints prior to Gate Closure hence removing the need to address them in the Balancing Mechanism (BM).

The studies have been limited to 6 snapshots of the system involving different assumptions on the dispersion of generation and demand, participants' bidding strategy and technical characteristics of the transmission network. In addition, the studies are based on some idealised assumptions and approximations and hence their results can be interpreted as at the 'best end' of a likely spectrum. In reality once these assumptions and approximations are no longer valid, the effectiveness of the access market may be reduced from results presented here.

These studies **do not** show the extent to which the total constraint **costs** seen by NGC will be saved as a result of the new transmission access market. This will be a function of how much cheaper constraints can be addressed in the forward access markets against being addressed through the Balancing Mechanism. Therefore it will depend on the liquidity of access zones, participants' valuation of risk and transparency of the market. It is extremely difficult to estimate the effect of this without prior knowledge / data from operation of NETA. In addition, the costs of 'constraints' addressed will depend on the volume of access tickets sold in the Primary Auction. If a 'maximum' method is used, participants may get rights above those that may be present without a transmission access market and hence create additional costs to NGC of buying back rights in the secondary markets. Conversely a 'minimum' method may depress the cost of constraints seen by NGC to be addressed.

This note first describes the study method used in the assessment exercise. It then describes an initial "Straw Man" design of the market based on the criteria and/or preferences set out in Ofgem's December Consultation Document, followed by a discussion of the assessment results of this design.

Straw Man Model Based on the December Document

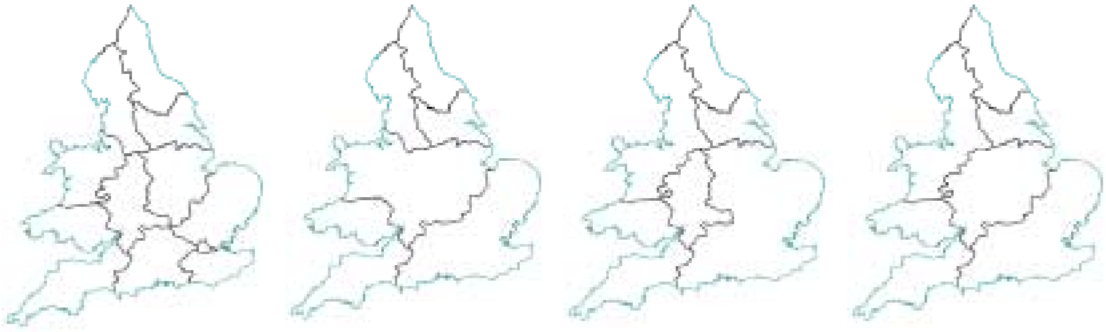
Ofgem indicated in their December Consultation Document that the transmission access market should be a **two-sided** and **competitive** market of **firm** access rights with **unfacilitated trading**. In response to that document, NGC constructed a Straw Man model under these criteria in order to assess the effectiveness and to scope the implementation of the access market.

This market model is based on an entry/exit right market design – with participants buying rights to inject power onto the transmission system (entry rights) and rights to take power off the system (exit rights) in given locations, both with reference to the same defined hub-point. These locations are defined by zones – each entry / exit point within a given zone is treated equally. To accommodate participation from the demand side under the restriction of the 1998 settlement metering arrangement, the following zonal definitions were examined:

- 12 GSP Group Areas (matching the 1998 settlement metering arrangements), and
- three different variants of 6 Supra GSP zones derived by amalgamating some of the 12 GSP groups based on the need for increased liquidity and/or defining sensible boundary constraint numbers.

Figure 1 shows these zonal definitions which are fixed for the whole year.

Figure 1 - Transmission Access Zonal Definition Based on GSP Groups



12 GSP   6 Supra GSP [1]   6 Supra GSP [2]   6 Supra GSP [3]

The transmission access market is assumed to comprise a Primary Auction of access rights and then secondary trading of these rights. Before the beginning of the Primary Auction, NGC agrees with Ofgem the absolute transfer capability of each boundary between zones, and makes these capabilities public. An auctioneer then facilitates a Primary Auction process for zonal rights for the forthcoming year, in which participants submit offer curves to buy or sell “bundles” of entry and exit rights within each zone.

The auctioneer operates a simultaneous clearing process across zonal access products, which determines clearing price and optimal volumetric allocations to participants based on their bids and the agreed transfer capabilities. The Primary Auction is subject to a set of relative loss adjustment factors, which set a minimum differential between access product prices to reflect the cost of unconstrained marginal losses.

Auction prices for each access right product are published. Surplus funds raised by this auction process partially support NGC’s TNUoS revenue.

Following this Primary Auction, participants fine tune their position by trading these rights on secondary markets (potentially down to the half hourly level). Via a Designated Exchange, NGC participates in secondary trading to the extent that its expectations of the inter-zonal boundary capabilities change – it is incentivised to maximise the revenue of any release of new right, and minimise the cost of any buy-back.[97] Clearly it will not be possible to resolve intra-zonal constraints via this market – these will be left to the Balancing Mechanism.

The access markets "close" at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

In each half hour, participants have a volumetric access imbalance exposure equal to the difference of their access right holdings in a given zone (adjusted for accepted BM bids/offers) and their metered output/demand in that zone. These imbalances are settled at a price derived (at least in part) from closing access prices in the secondary markets.

Study Methodology

Underlying Assumptions and Approximations

The assumptions and approximations made are as follows:

- Studies are based on a DC model hence approximate the constraints.
- With the market being two-sided the studies only deal with generation bidding for transmission access in the Primary Auction and then adjusting their position in secondary trading (i.e. the pattern of demand and total zonal demand is assumed constant throughout the market and in the Balancing Mechanism).
- NGC can perfectly predict the system constraints in line with the optimum nodal solution, so that a perfect "Best Estimate" can be made on the conditions governing the volumes of tickets available. It is further assumed that volumes of tickets sold in the Primary Auction reflect the "Best Estimate" conditions.

[97] In the assessment studies because it was assumed that the perfect total volume of tickets was sold in every zone, no such buying or selling needed to be modelled. The trading amongst the participants in a zone was simulated by re-distributing the tickets to generators strictly in order of their bid prices. This keeps the same amount of tickets in each zone but gives a different nodal allocation.

Input Data

For each of the six studies, one year's system and market operation was modelled, with each week represented by a single demand block with its own demand level and available generation pattern. Typical transmission availability was also included in the model. Sensitivities on generation bids were determined with reference to recent Pool bidding behaviour.

The temporal duration of the access rights was assumed to line up with the smallest unit of the simulation, i.e. one week, with each unit's rights being auctioned and traded as separate and independent products.

Primary Auction Simulation

For each temporal unit, a nodal allocation of transmission access was first derived from an optimisation algorithm which maximised the income from nodal auction bids while respecting all transmission constraints. This is equivalent to assuming that a perfect "Best Estimate" can be made on the conditions governing the volumes of rights available. Depending on the definition of the access rights (e.g. whether entry/exit or transfer type), this solution was converted to the appropriate volumes of rights sold, based on the assumption that the volumes of tickets sold in the Primary Auction perfectly reflect the "Best Estimate" conditions.

This simulation also gave the total system constraint volume.

Secondary Trading Simulation

In Secondary Trading, tickets of the same type can be traded amongst participants. The System Operator would not need to do any trading as the Primary Auction has already sold the perfect total volumes under the assumptions made for these studies. Assuming this process to be perfectly efficient, it would result in the rights of a particular type being held in accordance with an unconstrained merit order.

Calculation of Constraints left to be addressed in the BM

With the assumptions of a similar merit order of bids and offers in the BM and that Final Physical Notifications exactly match access rights held, the optimum BM solution would be the same as that in the Primary Auction simulation.[98] The BM action at each node would be defined as the difference between the rights allocated in the Secondary Trading and the BM solution. The sum of the absolute differences at all the nodes gave the total BM action volume to address remaining constraints.

Effectiveness Assessment

The results of the estimated level of constraints addressed before Gate Closure on the 6 snapshots are shown in the following table.

Table 1- Volume of Constraints Addressed by A Transmission Access Market Prior to Gate Closure (% of Total Constraint Volume)

Snapshot of System	Total Constraint Volume (TWh)	12 GSP	Supra GSP [1]	Supra GSP [2]	Supra GSP [3]
A	6.1	38%	29%	17%	33%
B	4.2	67%	37%	55%	54%
C	3.3	53%	35%	32%	43%
D	2.3	66%	43%	43%	60%
E	1.8	63%	39%	38%	57%
F	1.0	64%	44%	49%	49%

These results suggest that:

- Up to a maximum of two-thirds of the total constraint volume is likely to be addressed prior to Gate Closure in an access market based on the full 12 GSP Group (REC) zones.
- The scope for addressing constraints prior to Gate Closure would be reduced to below half of the total constraints volume if the requirement of market liquidity leads to the use of bigger zones (i.e. the combination of GSP groups into supra-GSP groups).
- Under certain scenarios the capture of constraints is much less than half. I.e. significant intra-zonal constraints may be present.

[98] Note that whilst this would approximately hold for volumes of constraints, it is less likely to hold for the costs as it is highly unlikely that the bid prices in the forward contracts will be equivalent to bids/ offers in the Balancing Mechanism. Hence the studies have been restricted to volumes addressed and not costs.

- These results are a “top estimate” as a number of the assumptions and approximations made in the studies, once relaxed, would be likely to bring the estimates down.

Attachment 2: Options for a Transmission Access Regime

At the industry workshop organised by Ofgem on the 7 August, the results of NGC's assessment of a "Straw Man" model of the transmission access market arrangements, based on the Ofgem's December 1999 consultation document, were presented. The Straw Man model was based on a zonal entry/exit rights approach with zones defined on the basis of the 12 GSP group boundaries. The participants at the workshop noted the limitations of this Straw Man access model to address transmission constraints prior to Gate Closure. After the workshop, Ofgem indicated that any transmission access market should aim to resolve at least 75% of total constraints prior to Gate Closure. NGC has subsequently examined alternative Straw Man models that are likely to deliver the required effectiveness. This involves relaxing some of the key assumptions made in the initial Straw Man model, based on 12 GSP group boundaries. NGC's considerations are summarised below.

Straw Man Models of Transmission access Arrangements

This note summarises, in turn, three additional Straw Man models of transmission access market arrangements which NGC have considered, and provides a brief analysis of the possible advantages and disadvantages of each.

The three Straw Man models considered are:

- **Straw Man 1**: Zonal entry/exit market;
- **Straw Man 2**: Nodal entry/exit market; and
- **Straw Man 3**: Flowgate market with nodal participation factors. (Note: could also be termed as a transfer rights market or a boundary rights market).

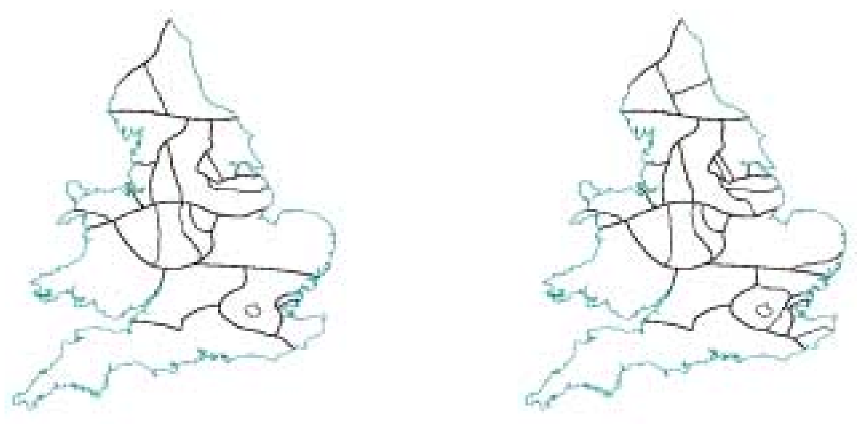
It should be noted that the descriptions of the market models below are at a high level, and are not complete in all aspects – they are intended to provide a context to the evaluation rather than a full description of the operation of the market.

Straw Man 1: Zonal entry/exit market

This market model is based on an entry/exit right market design – participants buy rights to inject power onto the transmission system (entry rights) and rights to take power off the system (exit rights) in given locations, both with reference to the same defined hub-point. These locations are defined by zones – zonal entry / exit rights confer equal injection / withdrawal rights to each entry / exit point in that zone. In order to resolve at least 75% of constraints in this market model, our analysis suggests it is likely that a minimum of 24 zones would be required, with zonal boundaries being non-coincident with GSP Group boundaries. Further analysis shows that 31 zones would be required for the transmission access market to address about 90% of total constraint volume. These two zonal definitions are shown below.

Figure 1 - Alternative Transmission Access Zonal Definitions

24 Zones 31 Zones



The table below shows the constraint capture levels of these two zonal definitions for the six studies considered in the initial Straw Man model.

Table 1 - Volume of Constraints Prior to Gate Closure (% of Total Constraint Volume)

Snapshot of	Total Constraint	24 Zones	31 Zones
A	6.1	82%	93%
B	4.2	92%	95%
C	3.3	75%	92%
D	2.3	84%	97%
E	1.8	78%	95%
F	1.0	80%	88%

NGC agrees with Ofgem the absolute transfer capability of each boundary between zones, and makes these capabilities public. An auctioneer then facilitates a primary auction process for zonal rights for the forthcoming year, in which participants submit offer curves to buy or sell “bundles” of entry and exit rights within each zone.

The auctioneer operates a simultaneous clearing process across zonal access products, which determines a clearing price and optimal volumetric allocations to participants based on their bids and the agreed transfer capabilities. The primary auction is subject to a set of relative loss adjustment factors, which set a minimum differential between access product prices to reflect the cost of unconstrained marginal losses.

Auction prices for each access right product are published. Surplus funds raised by this auction process partially support NGC’s TNUoS revenue.

Following this primary auction, participants fine-tune their position by trading these rights on secondary markets (potentially down to the half-hourly level). Via a Designated Exchange, NGC participates in secondary trading to the extent that its expectations of the inter-zonal boundary capabilities change – it is incentivised to maximise the revenue of any release of new right, and minimise the cost of any buy-back. Clearly it will not be possible to resolve intra-zonal constraints via this market – these will be left to the Balancing Mechanism.

The access markets “close” at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

In each half hour, participants have a volumetric access imbalance exposure equal to the difference of their access right holdings in a given zone (adjusted for accepted BM bids/offers) and their metered output/demand in that zone. These imbalances are settled at a price derived (at least in part) from closing access prices in the secondary markets.

As zonal boundaries are not coincident with GSP Group boundaries, a mechanism will be needed to allocate demand to zones. At least initially, this could be achieved by simply pro-rating GSP Group demand to the GSP nodes according to analysis of historical demand dispersion. These nodes can then be amalgamated into the access zones.

Straw Man 2: Nodal entry/exit market

This market model is based on an entry/exit right market design – participants buy rights to inject power onto the transmission system (entry rights) and rights to take power off the system (exit rights) in given locations, with reference to a defined hub-point. These locations are defined by nodes.

NGC agrees with Ofgem the capacity on the transmission system in the form of base constraint data. Participants submit offer curves for the volume of entry and exit rights which they require at each node.

Using these bids and an optimisation programme, NGC calculates the optimal allocation of rights given the agreed limitations of the transmission system. The optimisation is subject to the restriction of a set of minimum differentials between nodal prices set to reflect the cost of unconstrained marginal losses.

Auction prices at each node are published. Surplus funds raised by this auction process partially support NGC's TNUoS revenue.

Following the primary auction, participants fine-tune their position by trading these rights on secondary markets (potentially down to the half-hourly level). Given the bids from the participants for increments and decrements of entry and exit right volumes at each node on the system, NGC determines the volume of each bid to take in line with its updated expectation of the inter-nodal capabilities. NGC's trading would be subject to an incentive mechanism. Following each round of secondary trading, NGC would again publish prices at each node.

Although it is the characteristic which allows all constraints active prior to Gate Closure to be resolved, the fact that the information on the relative effectiveness of each node with respect to system constraints is variable and internal to NGC's optimisation means that participants cannot trade bilaterally (unless they are connected at the same node). The vast majority of trades must be with NGC.

The access markets "close" at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

In each half hour, participants have a volumetric access imbalance exposure equal to the difference of their access right holdings at a given node (adjusted for accepted BM bids/offers) and their metered output/demand at that node. These imbalances are settled at a price derived (at least in part) from closing access right prices in the secondary markets.

As imbalance volumes are based on nodal injections / withdrawals, greater locational tagging of demand than is available within the Stage 2 settlement system would be required. As in Straw Man 1, this could be achieved by allocating GSP Group demand to individual Grid Supply Points on the basis of factors determined by analysis of historical demand dispersion.

Straw Man 3: Flowgate market

This market model is often also referred to as a transfer rights market or a boundary rights market. It is based on a definition of access as the right to transport power over specified flowgates rather than being defined in relation to injections to or withdrawals from areas "either side" of the flowgates. Again the rights are with reference to a defined hub point. In order to allow greater constraint resolution, the flowgates in question may be defined at least in part at the circuit level rather than as boundaries (combinations of circuits).

NGC defines the flowgates which will be traded (based upon expectations of where constraints will be active on the system), and agrees with Ofgem the volume of these flowgate rights which will be made available.

NGC also carries out studies to determine the participation factor of each node on the system for each defined flowgate. The participation factor for a node with respect to a flowgate represents the fraction of each MW injected or withdrawn at the node – with reference to a defined hub-point – which can be expected to be transported over it. NGC publishes this participation factor information – with *n* nodes and *k* defined flowgates, this publication would be in the form of an *n* x *k* matrix. In order to provide a firm basis for secondary trading, these participation factors remain unchanged from the primary auction through to imbalance settlement.

An auctioneer then facilitates a primary auction for access rights for the forthcoming year, in which participants submit offer curves to buy and sell “bundles” of rights in each flowgate. The auctions are independent of each other – there is no requirement for any simultaneous clearing process. The primary auctions are subject to loss related reserve prices, which set a minimum price for each access right to reflect the cost of unconstrained marginal losses.

Participants determine the volumes of each of the flowgates they require on the basis of their expected physical position at each node multiplied by the participation factor for each node in each defined flowgate. Participants with a physical position will need to trade to a target portfolio containing rights in a maximum of *k* flowgates.

Auction prices for each flowgate are published. Surplus funds raised by this auction process partially support NGC’s TNUoS revenue.

Following this primary auction, participants fine-tune their position by trading rights on secondary markets (potentially down to the half-hourly level). Through a Designated Exchange, NGC releases further flowgate volumes, or buys back volumes to reflect the evolving conditions on the transmission network, again under an incentive scheme.

Since the participation factors used in imbalance settlement are set at the primary auction and not updated to reflect evolving system conditions, it will not be possible for the market to efficiently resolve all constraints – some will be left to the Balancing Mechanism. However, in contrast to Straw Man 1, it is difficult to evaluate the likely extent of constraint resolution in this market model – such an analysis would need to map changes in network topology to changes in participation factors to (critically) changes in the extent of efficient constraint resolution.

The access markets “close” at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

Participants' volumetric imbalances are calculated separately for each defined flowgate by comparing volumetric holdings of individual flowgate rights with deemed use. Volumetric holdings are defined for each participant as holdings of each right adjusted (using the fixed participation factors) to reflect accepted BM offers and bids. The deemed volumetric use is defined as nodal metered injections or withdrawals multiplied by the set of participation factors for the node in the flowgate in question.

These imbalances are settled at a price derived (at least in part) from the closing prices of each flowgate right in the secondary markets.

As imbalance volumes are based on use of flowgate rights calculated by applying participation factors to nodal injections / withdrawals, greater locational tagging of demand than is available within the Stage 2 settlement system will be required. At least initially, this could be achieved by allocating GSP Group demand to individual Grid Supply Points on the basis of factors determined by analysis of historical demand dispersion.

Evaluation of market models

In all of the above Straw Man models, the efficiency of constraint resolution will depend upon NGC's ability to forecast accurately system capabilities and conditions at various points in time, and particularly at the primary auction (as this is when access rights are initially allocated). In Straw Man 1, therefore, effectiveness will depend in part upon the definition of the zonal boundaries and the estimation of each boundary transfer capability. In Straw Man 2, effectiveness will depend upon the accuracy of the base data for the optimisations. In contrast, in Straw Man 3, effectiveness will depend in part upon the initial definition of flowgates and the estimation of participation factors.

However, in addition to the general importance of forecasting across the market models, it is possible to identify further pros and cons of each of the models individually. In assessing these pros and cons, we make the assumption that NGC is able to perfectly forecast system conditions as required. Table 2 below summarises our evaluation.

Table 2 - Evaluation of Straw Man market models

Straw Man 1	Straw Man 2	Straw Man 3
Pros: • Valuation of access rights for participants is not complex • NGC is only involved in inter-zonal trading – no wider facilitation of trading is required	**Pros:** • All constraints active before Gate Closure will be solved • Valuation of access rights for participants is not complex	**Pros:** • Offers the possibility of solving a significant proportion of constraints with the potential of unfacilitated bilateral trading of transmission rights
Cons: • The number of zones required to capture a significant percentage of constraints is likely to restrict liquidity. A number of zones would have one single generator.	**Cons:** • (To the extent it is perceived as a con by market participants) NGC has to facilitate and act as counterpart to all inter-nodal participant trades	**Cons:** • Efficient constraint resolution is dependent upon a degree of stability of network topology • Valuation of access rights for participants is complex

Straw Man 1

The key advantages of this market model are:

♦ **valuation of access rights for participants is not complex**: participants are able to value the entry / exit access rights (as a minimum) on the basis of the difference between their expectations of the energy price at the national delivery point and their own costs – they do not necessarily need to engage in more complex analysis of other participants' behaviour in the access markets to value the rights; and

♦ **NGC is only involved in inter-zonal trading – no wider facilitation of trading is required**: for participants within the same zone, trading of entry and exit rights can take place bilaterally, either via over-the-counter or on-exchange trading – no facilitation by NGC is required. NGC's trading relates solely to changes in expected transfer capabilities between zones – for example buying back entry rights in one zone and selling additional entry rights in another.

In contrast, the main disadvantage of this model is that **the number of zones required to capture a significant percentage of constraints is likely to restrict liquidity.** As stated above, in order to solve at least 75% of constraints, it is likely that at least 24 zones would be needed. Since this reduces the number of different participants in each zone, it reduces the likelihood of liquid secondary markets developing – with 24 zones, a number might have only one generator participant.

Straw Man 2

The key advantages of this market model are that:

- **all constraints active before Gate Closure will be solved**: since the model is nodal in nature and allocations are the result of an optimisation process which takes into account changes to actual system conditions as they evolve, the market will be capable of solving all transmission constraints which are active before Gate Closure; and
- **valuation of access rights for participants is not complex:** as the market is based on entry / exit rights, as in Straw Man I, participants are able to come to a valuation of the entry / exit rights being traded (as a minimum) on the basis of the difference between their expectations of the energy price at the national delivery point and their own costs.

The principal disadvantage with this market model, to the extent that it is perceived as such by market participants, is that **NGC has to facilitate and act as counterparty to all participant trades** (save for nodes where there is more than one connected participant).

Straw Man 3

The key advantage of this market model is that it **offers the possibility of solving a significant proportion of constraints whilst allowing unfacilitated bilateral trading of individual access rights**. Since flowgates can be defined in relation to individual circuits and participation factors defined for each node in relation to each flowgate, it would theoretically be possible to resolve all constraints (provided participation factors did not change from the primary auction). Similar to Strawman 1, if approximations are made to the flowgates to increase liquidity or reduce complexity then some constraint capture will be lost.

There are, however, important disadvantages of this model:

- since imbalance settlement (and hence all *ex ante* trading) takes place on the basis of participation factors fixed at the time of the primary auction, trading *will not* take into account changes in network topology (which result in changes to the *actual* participation factors) despite the fact that they may create new constraints. As a result, **efficient constraint resolution is dependent on a degree of stability of network topology** – if topology changes frequently, the market will not be able to efficiently resolve all the actual constraints on the network; and

- the **valuation of access rights for participants is complex**. In an entry/exit market model, participants can price access rights (as a minimum) on the difference between their expectation of the energy price and their own costs. At an aggregate level, the same is still true under this model. Participants know that the unit price of their target portfolio of access rights should be equal to the difference between their expectation of the energy price and their unit costs. However, in contrast with the entry / exit model, this information is insufficient for each participant to price every individual access right. While a generator with a given output knows (from participation factors) the volume of each flowgate which they require, and knows their valuation of a unit of their total target portfolio, they cannot impute a value to each component access right in that portfolio without further information and analysis.

Summary

Three alternative Straw Man models of the transmission access market have been assessed and compared. The key points and important trade-offs are provided in the following table.

Market model	Definition of rights	Locational resolution	Constraint resolution under idealised condition (% of total volume)	NGC facilitation of trading?	Need to solve "GSP Group metering" problem?	Complexity for Market Participants to value the access rights
Straw Man 1	Entry / exit	Zonal (> 24 zones)	> 75% depending on zonal definition	Required for inter-zonal trading	Yes	Relatively simple
Straw Man 2	Entry / exit	Nodal	100%	Required for inter-nodal trading	Yes	Relatively simple
Straw Man 3	Transfer	Linked to Nodes by participati on factors	100% only with completely stable topology	None	Yes	Complex

Attachment 3: Simultaneous Clearing in Access Auctions and Losses Charges

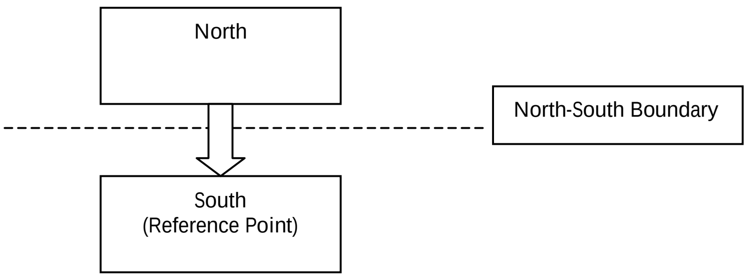
The following paper describes NGC's views on how transmission access rights in the form of entry and exit rights for different zones could be auctioned on the basis of a simultaneous clearing process. This paper also describes NGC's views on how this process could be extended to include provision for signalling marginal loss factors to participants.

Simultaneous Clearing – A Paper by NGC

Each constraint is defined as a limit on the total flow across a system boundary that divides the system into two areas. The boundary flow is represented by the difference between the total generation and total demand in the area which does not include the reference point. This can be termed the constrained area. In the case of generation exceeding demand in the constrained area, the transmission constraint sets a limit on the excess of total entry rights over total exit rights in that area. In the case of demand exceeding generation in the constrained area, the transmission constraint sets a limit on the excess of total exit rights over total entry rights in that area.

Within one single auction, after receiving market participants' bids and offers for entry and exit rights in all the zones, a simultaneous clearing of rights over all system boundaries will take place. This will release as many rights as possible which would maximise the total income of the auction while respecting the transmission constraints.

An example of a two-zone system is given below to illustrate how this process works.



Consider an auction for transmission capacity in a zone in the North of England. Suppose there is a North-South boundary and the reference point (ie energy exchange) is located in the South.

The clearing price in energy exchange is £20/MWh.

In North there are five generators each having 100MW capacity and all with production cost lower than the energy exchange price. They will be prepared to bid up to the difference between their production cost and the energy exchange price:

	Production cost £/MWh	(Max) bid for the right £/MWh
G1	19	1
G2	18	2
G3	17	3
G4	16	4
G5	15	5

There are also five demand blocks in North, each sized at 100MW and having the utility value listed below. Each block will consume only if it receives a transmission obligation payment at least equal to the difference between its utility value and the energy exchange price:

	Utility £/MWh	(Min) offer for the obligation £/MWh
D1	19	-1
D2	18	-2
D3	17	-3
D4	16	-4
D5	15	-5

Case 1 - Excluding Effect of Losses, System Constrained

The North-South boundary is constrained to a 100 MW maximum flow. The clearing process consists of accepting those bids and offers which yield the greatest auction income, while respecting the 100 MW constraint. Combinations which (just) satisfy the constraint are:

Bids/offers accepted	Auction income £/hr
G5	500
G5,G4,D1	800
G5,G4,G3,D1,D2	900
G5,G4,G3,G2,D1,D2,D3	800
G5,G4,G3,G2,G1,D1,D2,D3,D4	500

The auctioneer will arrive at the third combination, with a clearing price of £3/MWh set by G3 (highest bid taken) and D3 (lowest offer not taken).

Combining Relative Loss Adjustments to Clearing Process

A marginal charge for losses and the interaction between losses and constraints can be automatically allowed for in a loss adjusted access rights clearing process. In this process the "unconstrained Transmission Loss Factor (TLF)[99] times energy exchange price" is netted off all the bids and offers when they are ranked.

In the two-zone example, suppose the unconstrained TLF for the North is 8%. This gives a marginal loss cost at 8%*£20/MWh = £1.6/MWh. The bids and offers are adjusted in the clearing process.

Northern generation's bids:

	Original bid £/MWh	Marginal loss adjusted bid £/MWh
G1	1	-0.6
G2	2	0.4
G3	3	1.4
G4	4	2.4
G5	5	3.4

[99] For the generation in a particular zone this is the linear sensitivity of system losses to a marginal increase in generation in that zone which is balanced at the reference point, assuming no system constraint is present. The TLF for the demand is equal in magnitude and opposite in sign to the corresponding generation TLF.

Northern demand's offers:

	Original offer £/MWh	Marginal loss adjusted offer £/MWh
D1	-1	0.6
D2	-2	-0.4
D3	-3	-1.4
D4	-4	-2.4
D5	-5	-3.4

Case 2 - Loss Adjusted Clearing, System Unconstrained

Without any constraint on the North-South transfer, all the bids and offers which have positive TLF adjusted values are accepted, i.e. G5,G4,G3,G2 and D1. The total auction income would be £1300/hr. The clearing price is at £2/MWh, which is set by G2 (the lowest bid for entry accepted above marginal loss cost) and D2 (the highest offer for exit not accepted below marginal loss cost). It is expected that if the bid and offer curves are smooth, the clearing price for unconstrained transmission access will be at the marginal loss cost.

Case 3 - Loss Adjusted Clearing, System Constrained

If there is a North-South boundary constraint at 100 MW, then the combinations which just satisfy the constraint are:

Bids/offers accepted	Auction income £/hr	Auction income TLF adjusted £/hr
G5	500	340
G5,G4,D1	800	640
G5,G4,G3, D1,D2	900	740
G5,G4,G3,G2,D1,D2,D3	800	640
G5,G4,G3,G2,G1,D1,D2,D3,D4	500	340

The auctioneer will arrive at the third combination with a clearing price of £3/MWh, which is the same as Case 1.

Cases 2 and 3 show the interaction between losses and constraints and that the losses effect should not affect the clearing outcome where the system is constrained.

Attachment 4: Examples of the Calculation of Imbalance Charges

The following paper was developed by NGC to indicate some possible ways in which transmission access imbalance charges might be calculated.

Access Imbalance Pricing – A Paper by NGC

Overview of approach

Assume that buying an access 'ticket' imposes both a right and an obligation and that it is impossible to monitor what a party actually has paid for a 'ticket' through all trading mechanisms.

An imbalance price is required for two situations:

- **over-run**: if the market participant's demand or generation is *greater* than the number of tickets held; and
- **under-run**: if the market participant's demand or generation is *less* than the number of tickets held.

Imbalance prices relate to a zonal access price (ZAP) which could be calculated in any number of ways such as average/marginal price of NGC zonal trades in the secondary market or average/marginal price of bids accepted in the Primary Auction, or average/marginal price of bids accepted in the Balancing Mechanism. The exact calculation of the ZAP will need further consideration and could involve taking the maximum or average of a number of prices. The ZAP for entry rights is the negative of the ZAP for exit rights.

The ZAP can be adjusted up or down to form an over-run or under-run price in order to incentivise participants to balance. Indeed, the decision may be taken to set one of the prices to zero.

In this way, participants are purchasing both rights and obligations at the same time and there is no need to explicitly determine individually which type they have. The sign of the ZAP determines whether tickets relate to rights or obligations.

An imbalance liability calculation is detailed below. An allowance is made that access prices for entry and exit could be either positive or negative is allowed for, depending on the location of the reference point for access rights.

Calculation

There are four situations to consider. The access imbalance charge (AIC) is obtained by multiplying the Access Imbalance Price [(1+/-x)*ZAP] by the Imbalance Volume [M-BO-ZAT]:

Where:

x = Spread Factor

ZAP = Zonal Access Price (calculation method to be determined)

M = Zonal Metered Generation or Demand

BO = Zonal Bids/Offers accepted in the Balancing Mechanism

ZAT = Zonal Access Tickets Held

If the market participants' generation or demand is greater than the number of tickets held (i.e. an over-run, the imbalance volume (M-BO-ZAT) is positive, then the access imbalance charge (AIC) is as follows:

AIC = (1+x) * ZAP* (M - BO - ZAT) **if ZAP is positive**

AIC = (1-x) * ZAP * (M - BO - ZAT) **If ZAP is negative**

On the other hand, if market participants' actual generation or demand is less than the number of access tickets held (i.e. an under-run and (M-BO-ZAT) is negative) the AIC should be:

AIC = (1-x) * ZAP * (M - BO - ZAT) **If ZAP is positive**

AIC = (1+x) * ZAP * (M - BO - ZAT) **If ZAP is negative**

Example

Assume x = 0 for simplicity

Participant	Imbalance Volume (M-BO-ZAT) (1)	ZAP (2)	AIP (3) [=(2) as x=0]	AIC [= 1*3]
Generation	Positive / Over-run	Positive	Positive	Positive
	Positive / Over-run*	Negative	Negative	Negative
	Negative / Under-run*	Positive	Positive	Negative
	Negative / Under-run	Negative	Negative	Positive
Demand	Positive / Over-run	Positive	Positive	Positive
	Positive / Over-run*	Negative	Negative	Negative
	Negative / Under-run*	Positive	Positive	Negative
	Negative / Under-run	Negative	Negative	Positive

*The AIP could be set to zero if a 'use it or lose it' principle was to be adopted.

Numerical Example

Consider two zones, A in which the ZAP is +3 and B in which the ZAP is –3 (as noted above, another way to think of this is to consider the entry and exit rights respectively in the same zone). Suppose, for example, the spread factor was set as 50% and is applied symmetrically.

In zone A:

- the over-run price (which will be positive as it should represent a *charge to* participants) should be set higher than the positive ZAP to disincentivise over-runs. The over-run price should therefore be 4.5; and
- the under-run price (which will positive as multiplied by a negative imbalance volume it should represent a *payment to* participants) should be set lower than the positive ZAP to disincentivise under-runs. The under-run price should therefore be 1.5.

In contrast, in zone B:

- the over-run price (which should be negative, as it should represent a *payment to* participants – they would have been paid if they had bought an access right through *ex ante* trading) should be set higher than the negative ZAP to disincentivise over-runs. The over-run price should therefore be –1.5; and

- the under-run price (which should be negative, as when multiplied by a negative imbalance volume, it should represent a *charge to* participants – they would have to pay someone to take the access right off their hands in *ex ante* trading) should be set to higher than the negative ZAP, in order to disincentivise under-runs. The under-run price should therefore be -4.5.

Pulling this together gives the following matrix of imbalance prices:

	ZAP =3	**ZAP negative = -3**
Over-run @ 50% spread factor	Imbalance price = 4.5	Imbalance price = -1.5*
Under-run @ 50 % spread factor	Imbalance price = 1.5*	Imbalance price = -4.5

- These prices could be set to zero if it were decided not to apply the spread factor symmetrically. This would be the equivalent of a “use it or lose it” provision.

Attachment 5: Implementation of a Market In Transmission Access – Implications for Systems

The following paper was prepared by NGC to brief attendees at the workshop on transmission access issues on 7 August 2001 on the implications for systems of a market in firm tradable access rights.

Introduction

This document has been prepared to brief attendees at the workshops on transmission access issues on 7 August 2000.

It provides an outline of the likely high level systems requirements arising from the form of market that NGC understands Ofgem intends to be established. This is provided under the following major headings:

- background;
- assumptions for the new arrangements – a 'straw man';
- possible systems requirements; and
- implementation issues.

Background

The need for revised arrangements in transmission access has been known for some time, with initial thinking on possible arrangements being undertaken at the same time as early definition of requirements for NETA.

Ofgem has produced three documents related to transmission access:

- in its July 1999 NETA Document, Ofgem presented some initial thinking on the role of and incentives on NGC as System Operator and the development of new transmission access and pricing arrangements under NETA;
- the October 1999 NETA Document, published jointly by Ofgem and the DTI, discussed respondents' views on the initial thinking outlined in the July 1999 NETA Document; and

- Ofgem then issued a consultation document in December 1999, in which it indicated that its initial views were that transmission access and pricing arrangements need to reflect the value of transmission access and therefore to reflect the locational value of electricity.

The arrangements described in this document are based on NGC's current understanding of Ofgem's views on the form of transmission access market that should be established, as set out in the December 1999 consultation document.

NGC has been actively involved in the debate on transmission access, through discussions with Ofgem and industry participants, and through identifying in general terms the implications of introducing a market in transmission access rights along the lines set out in Ofgem's December 1999 consultation document. As part of this, NGC has made presentations to industry groups, including presenting a consideration of alternative approaches to implementing transmission access arrangements to the Charging Principles Forum (although Ofgem's December 1999 consultation document effectively closed down some of these alternatives).

More recently, NGC has undertaken work to identify in more detail the likely processes and systems that would be needed to facilitate new transmission access arrangements, and to understand the nature and scale of work that would be required to implement those arrangements.

The contents of this document are largely based on this recent work.

Assumptions for the new arrangements – a 'straw man'

The possible systems requirements set out in this document are based on a number of key assumptions which effectively define a 'straw man' for the transmission access market along the lines set out in Ofgem's December 1999 consultation document. The most important of these assumptions are:

- The market will be for firm physical entry and exit rights; The rights would be firm in the sense that if NGC, as the System Operator, is unable to deliver them, it would have to buy-back the rights. The definition of firm access rights would be locational to reflect the realities of the physical transmission system.

- The market will be two-sided. It is envisaged that both the generation and demand will participate in the access regime. In general, generators will acquire entry rights and suppliers (or large customers in their capacity as self-suppliers) will acquire exit rights.

- ♦ The market will be based on the use of zones based on GSP Groups. Demand side involvement has an important consequence for the definition of zones. As imbalance settlement will require metered volume data, zones must conform to GSP Groups as this is the finest level of locational tagging of consumption data available without any changes to the 1998 metering systems.

- ♦ There will be a primary auction to establish the initial allocations of access rights: Access rights will initially be auctioned by zone and by temporal product (e.g. peak, off peak etc) for one year. This will result in an initial allocation of rights to participants based on a broad view of the likely capabilities of the transmission system.

- ♦ There will be unfacilitated secondary trading of transmission access rights: Subsequent to the primary auction, both participants and NGC will wish to trade these rights via secondary markets, which will run from the primary auction up to Gate Closure (i.e. the opening of the Balancing Mechanism). Participants will trade to fine tune their access position with their expected physical position in order to minimise exposure to the access imbalance regime. Nearer real time, NGC would also participate in the secondary access markets, releasing additional rights or buying rights back as expectations of the transmission system's actual capacity changed.

- ♦ There will be a bundled energy and access Balancing Mechanism. Bids and offers accepted in the Balancing Mechanism will be deemed to include the appropriate entry or exit access rights to avoid participants being exposed to access imbalance charges on those volumes.

- ♦ There will be half-hourly zonal settlement of access imbalances. The access imbalance settlement process will occur after the delivery half-hour is finished. This process will compare generators' metered output and suppliers' metered/profiled consumption (adjusted for BM actions accepted) with the volume of access rights held by individual participants. Long (under-run) and short (over-run) access positions will result in imbalance liabilities or payments.

Given the criticality of these assumptions in defining the market, the 'straw man' on which this document is based should only be seen as one option for a transmission access market.

As the design of the arrangements progresses to greater levels of detail, these assumptions will be need to be reviewed and potentially changed. If the assumptions are changed, the outline systems requirements, and the scope of work required to implement those systems, are also likely to change.

Possible systems requirements

The direction set by Ofgem's December 1999 consultation document, and the assumptions listed above, lead to the following as a possible division of responsibilities with respect to the operation of the transmission access arrangements:

- NGC would be responsible for agreeing the key parameters of the auction arrangements in advance with Ofgem, for settlement of primary auction bids, for secondary trading activity to balance the system, and then for charging adjusted TNUoS and BSUoS tariffs;

- an Auctioneer would be responsible for offering products for sale in the primary auction, running the system that calculates equilibrium auction prices and volumes, and notifying participants (and potentially the market in general) of auction results;

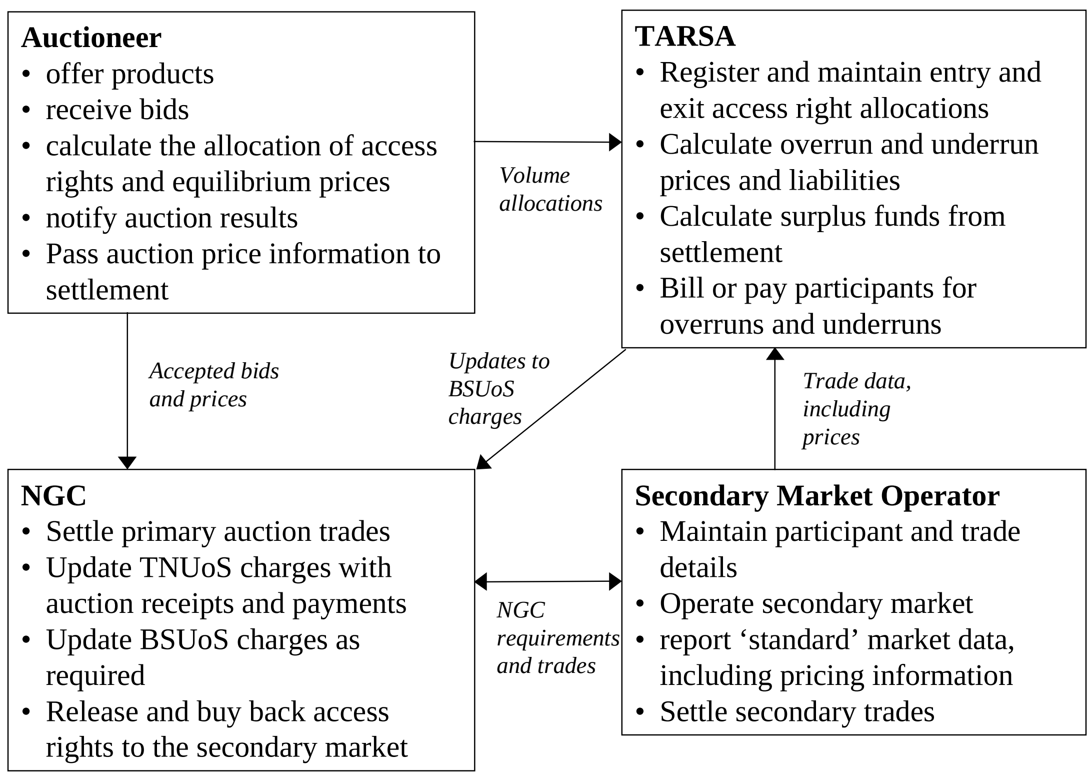
- a Secondary Market Operator would be responsible for operating a Designated Exchange (see below) and settling on-exchange trades; and

- a Transmission Access Registration and Settlement Agent (TARSA) would be responsible for registering access right allocations, and for calculating and settling imbalance liabilities with participants.

It has been assumed that there will be a Designated Exchange (as in the gas commodity regime), to provide the market with the assurance that there will always be a transparent, facilitated market on which NGC can make release and buy-back trades, and from which information can be derived in a transparent manner to be used potentially in the calculation of imbalance prices. It is assumed that the roles of Auctioneer, Secondary Market Operator and TARSA would be undertaken by bodies contracted to NGC, but not by NGC itself. It is therefore assumed that NGC will procure both the systems and the operational services required for these roles.

The possible systems requirements for the market are summarised in Figure 1. This figure indicates at a high-level the broad functionality that would be required in systems by each of the roles listed above, and the key interfaces between those roles.

Figure 1: Overview of transmission access systems requirements



Cost Estimate

At this stage, before agreement on the market design, it is not possible to estimate with any accuracy the likely costs of implementing systems to support a transmission access market. It is possible, however, to make rough estimates based on previous experience of systems which have been developed in broadly comparable situations. For example, the settlement roles and systems being developed for NETA, creation of trading exchanges and auction mechanisms.

It must be noted that where similar systems are needed (e.g. imbalance settlement), the scale and complexity of the projects and systems required will be of a similar magnitude to central NETA systems, thus requiring a similar time to design, develop, test and implement those systems. In addition, systems and operational services will be presumably be procured through an open tendering process, using a similar approach to NETA, through the issue of an OJEC notice inviting expressions of interest, followed by the issue of an Invitation to Tender (ITT) to selected suppliers. Hence, the 'delivery' of the market is likely to be an industry wide project involving many players where an overall programme management role will be critical.

Figure 2 shows broad estimates of the **minimum** projected system costs to set up a zonal transmission access market based on the assumptions listed above.

Figure 2

System / Process	Cost (real 1999/00 prices)	Components
Primary Auction System	£1.5m to £3m	• Zonal auction system • Ticket allocation method • Auction settlement • Publication of results
Secondary Trading Mechanism	£2m to £4m	• Includes release/buyback system procurement (with option for bi-lateral trading)
Imbalance Settlement	£10m to £20m	• Assume 5 of 7 NETA roles are required (all except metered volumes and BM actions) • Aggregation needed at a zonal level • Rights Registration Agent included • Funds Administration included
TNUoS changes	£0.5m - £1.5m	• Includes NGC system changes for tariff and reconciliation
BSUoS changes	£0.5m to £1m	• Includes NGC system changes for algorithm and interfacing
Overall Program Management	£0.5m to £1.5m	• Managing overall implementation interfaces / legal contracts
Total	£15m to £31m	

In the above, no consideration has been given to the ongoing annual costs of operation of the access market. This would include fulfilment of the Settlement System

Administrator role, running of the Secondary Market and the running of an annual auction as well as the trading activities of participants.

In addition, no allowance has been made for the costs involved with participants setting up their own trading processes and systems.