

February 2002

**Transmission access and losses
under NETA**

Revised proposals

Summary

Ofgem has a duty to protect the interests of customers, through the promotion of competition and the effective regulation of network monopolies. Ofgem remains concerned that the current arrangements for access to and pricing of National Grid Company's (NGC) high voltage electricity transmission system are not in customers' long-term interests.

The need for reform

The current arrangements provide poor signals to generators and large customers about the transmission costs associated with locating at different points on the network. The lack of firm, long-term rights adds additional risk and costs to generators and customers that are difficult to hedge and limits the access choices on offer (for example the choice to pay more for a firm service or less for an interruptible service). Moreover, the current arrangements for charging transmission losses do not encourage efficient use of the transmission system as the costs are averaged nationally across all users. This leads to cross-subsidies between generators, and between customers, that harm competition and distort wholesale electricity trading.

Given typical investment and planning lead times of a number of years, the current arrangements do not provide NGC with reliable signals of rising demand or emerging bottlenecks on the system and, in the absence of price signals, it is difficult to provide NGC with appropriate investment incentives. Instead, NGC uses its forecasts of demand and generation changes to identify where the transmission network may need to be reinforced. As a consequence, new generators and demand sites may have to wait some time to be connected if their requirements were not foreseen in NGC's planning process. In extreme cases, insufficient transmission capacity, resulting from poor signals, can threaten security of supply and lead to power cuts for customers. A number of countries, including the USA (California) and Norway have recently experienced these problems.

The transmission system is relatively unconstrained at present with constraint costs for England and Wales that are of the order of £25m per annum. There are, however, a number of developments in the market that suggest that costs could rise and patterns of demand and supply could change relatively rapidly in the near future. These include

developments in continental Europe, where liberalisation is leading to significant changes in the patterns of flows between countries, plans for new interconnectors from Norway and the Netherlands to the UK (and from Scotland to England) and more active trading of electricity between member states. Relatively modest changes in the patterns of demand and supply on existing or new interconnections could lead to significant increases in the incidence of constraints.

In the absence of reform, this could lead to a rapid escalation in constraint costs, which are ultimately paid for by customers. Recent experience in the gas market demonstrates the problems. Rising demand for system capacity to allow exports of gas to continental Europe in the summer has led to constraint costs of several hundred million pounds per annum.

Ofgem and its predecessor organisation, OFFER, has been highlighting the need for reform since before privatisation of the Electricity Supply Industry in 1990.

Unfortunately, attempts to reform the current arrangements have been hampered by the governance arrangements for the Pool (the wholesale market arrangements in place between 1990 and 2001) and NGC's Master Connection and Use of System Agreement (MCUSA).

The Pool did attempt to reform charges for transmission losses to ensure that they more accurately targeted costs to system users. However, OFFER's decision in favour of the proposals, following an appeal, was the subject of a Judicial Review in 1996. As a result of the announcement of the Review of Electricity Trading Arrangements (RETA), the Judicial Review was never heard, and the proposed scheme was not implemented.

At the start of the RETA many companies and customer representatives highlighted the importance of reform of the transmission access and losses arrangements. However, Ofgem decided at the time, given the scale of the changes to the energy trading arrangements being undertaken, to address these issues separately and to a slower timetable. This decision was widely welcomed.

The current arrangements are also inconsistent with the arrangement in gas and this would, in the absence of reform, lead to inefficient interactions that could threaten supply security. For example, Transco may contract to interrupt certain gas-fired generators to avoid the need for costly transportation investment. NGC does not, under the current arrangements, have an incentive to offer firm, long-term rights (via a

'constrained on' contract) to signal to the generator the value NGC places on its generation being available. Hence, there is no signal of the relative values that Transco and NGC place upon being able to control the output of the plant.

Process to date

Ofgem first published a consultation document dedicated to these issues in December 1999. This document highlighted the need to change the existing contractual framework, to enable the implementation of new arrangements and to allow transmission and losses arrangements to develop in the light of experience of operating under NETA. Ofgem proposed replacing the MCUSA with a Connection and Use of System Code (CUSC). We suggested that the CUSC should have similar governance arrangements to the Balancing and Settlement Code (BSC) and Transco's Network Code. In September 2001, following extensive consultation and discussion with all interested parties, the CUSC was implemented by the Secretary of State.

In May 2001, we published a second document setting out the need for reform, the objectives of the reforms and possible approaches to reform consistent with these objectives. We presented, to stimulate discussion, a 'possible approach' for new transmission access arrangements and two approaches to transmission losses, with our favoured approach involving exposing participants to the costs of locational marginal losses.

A number of respondents, whilst expressing concerns about Ofgem's specific proposals, continued to express strong support for reforming the current access and losses arrangements.

To address the concerns raised by respondents, Ofgem has considered whether the policy objectives of providing effective short and longer-term locational signals can be met through less complex and costly approaches.

Proposed reforms

Ofgem's proposed reforms will initially apply only in England and Wales. However, it is Ofgem's current intention, subject to primary legislation, to extend the new arrangements to Scotland. Ofgem intends, through the British Electricity Trading and Transmission Arrangements (BETTA) project, to create a new GB-wide electricity market.

Ofgem's proposed reform of transmission access is based on the creation of financially firm, tradable rights for use of the transmission system for both generators and customers. The introduction of firm rights will bring immediate benefits to system users as it will reduce the risks associated with failures of the transmission system to users. It will also enable the creation of appropriate incentives on NGC to invest in system reliability. Finally, it will promote greater choice and innovation in the services that NGC offers users (by enabling the development of, for example, interruptible use of system rights).

Trading of these firm rights should lead to the emergence of forward price signals that will improve the information available to NGC. NGC will be able to use these emerging market-based signals when planning network reinforcement or expansion. Rising forward prices, indicative of rising demand, should emerge in sufficient time to allow NGC to respond, given typical investment lead times. This will lead to lower constraint costs over time and will ensure that security of supply is maintained.

It is a further objective of the reform that participants should be able to acquire long-term access rights. This will reduce risks and uncertainty and help to underpin new investment decisions in both large demand sites and new generation.

The reform to the charging of transmission losses should help to promote competition and protect customers' interests by more accurately targeting the costs of losses at different locations on the network. They will unwind the existing cross-subsidies between customers and between generators. This will produce short-term efficiency benefits by lowering the costs of losses. In the longer-term, it will ensure that new load and generation factor in the cost of losses when considering the location of new generation and large demand sites.

The reforms are directly analogous to, and complimentary with, Ofgem's new NTS capacity investment incentives for Transco's National Transmission System (NTS) in gas. These new incentives are due to be introduced as part of Transco's system operator (SO) incentive arrangements from April 2002.

Preferred approach

During the consultation process, Ofgem sought participants' views on how to best achieve the transmission reform policy objectives, and also asked respondents to

comment on several different approaches. In response to this consultation, many participants raised concerns over the proposal to auction transmission access rights. In particular, they were concerned that an access rights auction would be overly complex and costly to implement and impose a large burden on participants. Having considered these views, we believe that the policy objectives can be met without auctioning transmission access rights. Instead, we believe that firm access rights could be allocated to participants in return for payment of an access charge. Given that transmission constraints are generally transient, it seems likely that strong price signals will only develop via secondary trading close to real time and hence the primary allocation mechanism is relatively unimportant. Allocating rather than auctioning access rights could therefore reduce the complexity and cost of transmission access reforms without compromising their effectiveness.

It is envisaged that there would be secondary trading of the access rights. This will include resolving constraints through constraint management contracts with generators and customers. We still believe that it is important that the costs of resolving constraints are better targeted to provide all market participants with better locational signals.

There are still, however, a number of issues of detailed design that will need to be discussed and addressed. For example, it will be important to ensure that the demand side is fully incorporated into this simpler model and to consider the treatment of embedded generators. It will also be important to ensure that measures to facilitate trading of access rights are incorporated.

Ofgem has also reconsidered its views on transmission losses as a result of concerns raised during the consultation. A number of respondents argued that charging for losses on the basis of locational marginal losses would provide unduly strong and potentially unstable price signals to participants and would overstate the actual costs of transmission losses. In light of these concerns, Ofgem have examined whether the scaled marginal loss approach proposed by the Pool might be more appropriate than the full marginal loss treatment proposed in the May document. The Pool spent a considerable amount of time developing this scheme and the proposals were subsequently approved by OFFER.

The Pool's scheme, which can be thought of as an average zonal losses approach, overcomes the issues associated with how to deal with revenue over-recovery under a

full marginal losses approach (marginal losses are approximately twice actual losses) whilst retaining most of the cost signalling benefits. Ofgem now believes that the Pool proposals should form the starting point for discussions on reform of losses charging.

Ofgem also accepts, in the light of concerns raised by respondents, that it will be important that generators and customers will be able to understand the possible evolution of losses and access charges over time, as the system develops and patterns of demand and generation change over time. This will enable participants to consider hedging risks associated with changes in losses charges over time, as the system develops. Ofgem therefore believes that NGC should make publicly available its losses and cost models for the network in a simple and user-friendly format. This will make the arrangements more consistent with gas, where Transco publishes Transcost on its website.

Ofgem's proposed transmission access and losses reforms offer a number of potential environmental benefits. These benefits have always been recognised by Ofgem and, in light of our environmental obligations under the Utilities Act 2000, we believe it is important to highlight this aspect of the transmission access and losses reforms. Our proposals should reduce the level of transmission losses both in the short-term (through more efficient use of existing generation) and in the longer-term (by influencing the location of new generation). Reductions in the level of losses will see less electricity generated to meet demand, thereby reducing emissions.

Ofgem's proposals to use better cost targeting to influence the location of new generation should also encourage more local, embedded and on-site generation (such as CHP) as they will face relatively lower transmission costs.

Finally, Ofgem's proposals should, over time, lead to a more efficient level of transmission investment by encouraging efficient locational decisions and better use of existing assets. This will reduce the resources consumed in electricity transmission and the visual intrusion caused by new overhead transmission lines.

Way forward

Ofgem has set out, at a high level, our current preferences for new access and losses arrangements to facilitate discussions, including under the new CUSC governance

arrangements. These discussions will allow all interested parties to make representations and shape the proposals.

Ofgem expects that detailed discussions will begin immediately. Proposals for reform will ultimately be implemented through changes to NGC's licence, modification proposals to the BSC and amendment proposals to the CUSC and NGC's Use of System Charging Methodology. Ofgem believes that new losses arrangements, based on the Pool scheme, could be implemented in a matter of months as the NETA central systems were designed to accommodate such changes. Transmission access reform may take longer, as there are more detailed discussions to be held to resolve design issues. There will also be longer lead times associated with developing NGC's systems and contractual framework.

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1. Introduction

Purpose of this document

- 1.1 This document sets out Ofgem's revised proposals for reform of the arrangements for electricity transmission access and losses charges in England and Wales. We summarise the background to these issues, including Ofgem's two previous consultation documents and respondents' views on Ofgem's proposals. We then set out our latest thinking, in the light of these responses, to facilitate industry and customer debate.

Outline of this document

- 1.2 The document is arranged as follows:
- ◆ Chapter 2 outlines the background to the current proposals;
 - ◆ Chapter 3 explains the rationale for the proposed reforms;
 - ◆ Chapter 4 states Ofgem's view on reforms to the transmission access arrangements;
 - ◆ Chapter 5 outlines respondents' alternative approaches to transmission access;
 - ◆ Chapter 6 states Ofgem's view on reforms to the transmission losses arrangements; and
 - ◆ Chapter 7 outlines the process going forward and the 'next steps' that have been identified.
- 1.3 The appendices are arranged as follows:
- ◆ Appendix 1 sets out the legal and regulatory framework for the electricity supply industry in England and Wales;
 - ◆ Appendix 2 provides details of how a transmission losses charging system based on scaled zonal marginal ('average zonal losses') losses might work;

- ◆ Appendix 3 lists respondents to our May 2001 consultation document¹;
- ◆ Appendix 4 provides a summary of the submissions (except those marked confidential); and
- ◆ Appendix 5 sets out a more comprehensive history of previous proposals to reform transmission losses charging in England and Wales.

Related consultations

NGC transmission asset owner (TO) price control

- 1.4 The National Grid Company (NGC) both owns the national electricity transmission grid in England and Wales and operates it to ensure that, subject to generation being available, all reasonable demands for electricity are met. Thus, it fulfils the roles of both transmission asset owner (TO) and system operator (SO). The TO function relates to the maintenance and longer-term development of and investment in the transmission system, whilst the SO function covers all the short-term operational activities required to keep the system balanced and operating within safe limits.
- 1.5 Ofgem published final proposals for NGC's TO price control in September 2000², which were implemented, with NGC's consent, from 1 April 2001. NGC's TO price control runs for five years and provides NGC with an allowed revenue based on an assessment of the efficient capital and operating expenditure necessary for NGC to fulfil its role as TO. At the time that the TO control was set, Ofgem asked NGC to provide details of the baseline outputs (in terms of transmission capacity) that the TO price control was funding.
- 1.6 We indicated that these output measures would provide the baseline for any enhanced investment incentives that might be introduced, as part of transmission access reform. This is analogous to the arrangements for Transco's new system operator incentive scheme, to be put in place from April 2002 (discussed in more detail below).

¹ 'Transmission Access and Losses under NETA. A consultation document', Ofgem, May 2001

² 'The transmission price control review of the National Grid Company from 2001, Transmission owner. Final proposals', Ofgem, September 2000

NGC SO incentive scheme from April 2002

- 1.7 NGC has a set of incentive arrangements that relate to its SO function and hence to the day-to-day operation of the transmission system. The SO incentives cover both internal costs (the costs of NGC's own staff, buildings and control systems) and external costs (those associated with NGC's purchases and sales of electricity and other services for electricity and system balancing purposes).
- 1.8 NGC's existing SO incentives are of the sliding scale type. NGC is set a cost target. If actual costs are below the target, it keeps a proportion of the difference (defined by a sharing factor), subject (where appropriate) to a cap on the maximum gain it can make. If costs are above the target, it pays a proportion of the difference, again subject (where appropriate) to a collar on the maximum loss NGC can make.
- 1.9 NGC's internal costs targets have been set for five years, consistent with the TO price control. NGC's external cost targets and the sharing factors and caps and collars under the incentive scheme were set initially for the period from 27 March 2001 (NETA Go Live) to 31 March 2002. This reflected the uncertainty associated with the likely level of some of these costs, ahead of the introduction of NETA.
- 1.10 At the beginning of February 2002, Ofgem published its final proposals in relation to the NGC external SO incentive scheme for the period 1 April 2002 to 31 March 2003³, which NGC has accepted, subject to formal consultation on the modification of NGC's licence. The proposals effectively roll over the existing scheme for one year, but with some specific adjustments including a revised target for external SO costs of £460 m, reflecting the fact that the costs of NGC balancing the transmission system have substantially reduced since 27 March 2001. If the costs fall below this level, NGC can retain 60% of the benefits up to the maximum of £60 m. If the costs exceed the target, NGC must share 50% of the additional costs up to a maximum loss of £45 m.
- 1.11 In line with the gas SO incentive scheme recently agreed with Transco (see below), Ofgem intends to implement enhanced investment incentive arrangements for investing in NGC's transmission system, through changes to

the SO incentive arrangements at the time that new transmission access arrangements are introduced. It may also be necessary to reconsider the internal cost allowances if there are additional net costs, that were not anticipated or could not be quantified at the time that the targets were agreed, associated with implementing and operating the new arrangements.

British Electricity Trading and Transmission Arrangements (BETTA)

- 1.12 In December 1998, OFFER published a consultation document⁴ outlining the need for reform of the electricity trading arrangements in Scotland. OFFER argued that distortions in the electricity prices in Scotland are of particular concern. These distortions are caused by a number of factors, including administered wholesale trading arrangements, the lack of non-discriminatory arrangements for the cashing out of top-up and spill imbalances, the lack of transparent non-discriminatory arrangements for access to the transmission system and the lack of transparent interconnector access and pricing arrangements.
- 1.13 In August 2000, Ofgem published a consultation document outlining interim proposals for the reform of electricity trading arrangements for Scotland.⁵ Ofgem suggested that trading arrangements should be developed for the whole of Great Britain (GB) by the creation of a single GB wholesale electricity market. There was strong support for this proposal from respondents.
- 1.14 Ofgem published a further BETTA document in December 2001.⁶ As set out in that document, Ofgem is of the opinion that it is now appropriate and timely to implement market based wholesale trading arrangements in Scotland as a matter of priority. Furthermore, there are compelling reasons why a solution based on the creation of GB balancing and settlement mechanisms, GB transmission access and pricing arrangements and a GB SO is the most appropriate way of achieving this. A GB market will open up the benefits of competition in England and Wales to customers in Scotland, ensure that the GB wholesale forward markets are as liquid as possible, reduce concerns over generator market power

³ 'NGC system operator incentive scheme from April 2002. Final Proposals', Ofgem, February 2002

⁴ 'Scottish trading arrangements. Consultation paper', OFFER, December 1998

⁵ 'Interim proposals for the reform of Scottish Trading Arrangements: British Electricity Trading and Transmission Arrangements (BETTA)', Ofgem, August 2000

in Scotland and allow all participants in Great Britain access to the same markets on equal terms. It will change the role of the transmission companies in GB, as one of its principal elements is the creation of a GB SO. There are also a number of practical benefits associated with governance and cost effectiveness achieved by implementing a single set of GB-wide arrangements, based on the principles underpinning the current England and Wales model.

- 1.15 Ofgem's BETTA proposals will require primary legislation to be implemented. Ofgem's current plan, contingent on legislation being passed in the 2002/3 Parliamentary session, is to introduce the new arrangements from April 2004. Ofgem will consult, as part of the BETTA programme, on the development of SO incentive arrangements for the GB SO from the BETTA implementation date.

Transco TO price control and SO incentive schemes

- 1.16 Interactions between the electricity and gas transmission networks are becoming more important. Gas-fired power stations now account for one third of the installed generation capacity and are responsible for about 40% of demand on Transco's National Transmission System (NTS). Recent increases in the wholesale price of gas and decreases in the price of electricity have led to increasingly converging prices as companies arbitrage between the two markets on a daily basis. Companies re-sell gas in the wholesale market on days when it is more profitable than generating electricity. Conversely, those gas-fired generators who have a degree of flexibility increasingly change their generation (and therefore their gas consumption) in response to movements in electricity prices within day.
- 1.17 These interactions can have a significant impact on both SOs. The need to take balancing actions and the costs associated with those actions are driven, in part, by price movements in both markets. Decisions taken by one SO can also have a significant impact on the other. One obvious example is the interruption of gas-fired power stations by Transco to deal with constraints on the NTS. Interruptions of gas-fired generators can lead to NGC having to take corresponding actions for energy balancing or for system balancing purposes (for

⁶ 'The Development of British Electricity Trading and Transmission Arrangements (BETTA). A consultation paper', Ofgem, December 2000

example to deal with a constraint on its system as a result). Against this background, it is increasingly important to have consistent incentives on the TOs and SOs in both markets.

Transco TO price control

- 1.18 In September 2001, Ofgem published final proposals for Transco's TO price controls.⁷ Three separate TO price controls were proposed covering the high pressure NTS, the lower pressure Local Distribution Zones (LDZ) and metering/meter reading activities. Transco's allowed revenues over the five-year period will be £13.62 billion (2000 prices), of which £2.15 billion relates to the NTS price control. For comparison, NGC's allowed TO revenues for the current price control period are £0.8 billion.
- 1.19 For the first time, Transco's NTS allowed revenues were derived by estimating the efficient costs of providing a baseline level of outputs for entry capacity, exit capacity and linepack (the capacity to store gas in the pipeline system).
- 1.20 Transco accepted Ofgem's final proposals for the TO price control, subject to agreement on its SO incentives (discussed below) and the detailed licence drafting. Both the TO price control and the SO incentives are due to be implemented from 1 April 2002.

Transco SO incentive scheme

- 1.21 Ofgem published final proposals for Transco's SO incentive scheme⁸ in December 2001. At the end of January 2002, Transco accepted Ofgem's final SO incentive scheme proposals, subject to the detailed drafting of the necessary modifications to Transco's licence.
- 1.22 Transco's SO incentive scheme covers four main areas: entry capacity investment, exit capacity investment, the costs of day-to-day system operation and Transco's internal costs for its SO function.

⁷ 'Review of Transco's Price Control from 2002. Final proposals', Ofgem, September 2001

⁸ 'Transco's National Transmission System System Operator incentives 2002-7. Final Proposals', Ofgem, December 2001

Entry and exit capacity incentives

- 1.23 The entry and exit capacity incentives are designed to improve Transco's incentive to invest to meet changing customer demand in a timely and efficient manner. They seek to build on the incentives provided under RPI-X regulation. At entry, they provide Transco with the opportunity to earn additional returns, above its regulated cost of capital, where it invests to deliver outputs greater than the baseline outputs in response to changing customer demand.
- 1.24 Transco will introduce firm, long-term entry capacity rights. These rights will be financially firm, as Transco will have to buy-out rights at market prices in the event that the rights are physically unavailable. Companies will be free to trade entry rights and will be able to purchase entry rights through a series of rolling auctions or in secondary markets. The price signals emerging from the trading of these rights will provide additional signals to Transco about future demand for capacity. This should provide Transco with better information of rising demand sufficiently far in advance to allow it to respond, given typical investment lead times of two to three years.
- 1.25 At exit, the incentives are designed to encourage Transco to consider alternatives to pipeline investment (such as the use of interruptible contracts and local storage) where it is more efficient to do so and to provide more flexibility in access terms.

Day-to-day incentives and internal costs

- 1.26 The day-to-day SO incentives and those relating to Transco's internal costs are directly analogous to NGC's SO incentives. The incentives are of a similar form to NGC's SO incentives, with cost targets being set and profit sharing through caps, collars and sharing factors. The day-to-day incentive schemes proposed for Transco relate to similar cost drivers to NGC: (residual) gas balancing, system balancing (including shrinkage (losses) and system reserve), entry capacity buy-backs and contracting for interruption at exit (constraints).

2. Background

2.1 This chapter presents the background to the reform of the arrangements for transmission access and losses. It discusses how transmission access and losses arrangements developed under the Pool, summarises the consultations prior to NETA on the need for reform, outlines the transmission access and losses arrangements in place from NETA Go-Live, and discusses the consultations after NETA's implementation.

Transmission access and losses development under the Pool

2.2 The Pool came into effect on 1 April 1990 (Vesting day) as part of the arrangements introduced by the Government in privatising the electricity industry. The Pool was governed by the Pooling and Settlement Agreement (PSA), which included a schedule of those arrangements that needed further development post Vesting, and transmission losses were included in that schedule.

2.3 Before the Pool was implemented, OFFER indicated, in its 1989 Annual Report, that there should be locational pricing for the use of NGC's transmission system and made it clear that it envisaged that transmission losses should include locational signals. The issue was again highlighted in OFFER's 1990 and 1991 Annual Reports. The 1991 Annual Report made it clear that reform to the transmission access arrangements was required to provide incentives to locate generation nearer to centres of demand.

2.4 To this end, NGC introduced revised Transmission Network Use of System (TNUoS) charges in April 1993 based on Investment Cost-Related Pricing (ICRP) and in 1994 the Pool took forward work on the introduction of locational signals in the allocation of transmission losses.

2.5 In effect, ICRP estimates the long run marginal costs of adjusting the network to meet changes in the pattern of electricity flows around the country. Consequently, it provides signals of the longer-term need for generation and demand in different locations.

- 2.6 The work undertaken by the Pool in relation to transmission losses led to proposals, accepted by a majority of Pool members, to introduce scaled zonal loss factors from 1 April 1997. The scaled zonal loss factors were to be calculated by estimating marginal zonal loss factors, on the basis of historic load flows, and then scaling them back so as to recover the cost of actual losses. However, this decision was appealed to OFFER on grounds including that the proposals would unfairly prejudice a group of Pool members. In May 1997 OFFER rejected the appeal.
- 2.7 Subsequently Teesside Power and Humber Power sought a Judicial Review of OFFER's decision. They argued that the Pool's proposals went beyond the terms of the agreed PSA Work Schedule.
- 2.8 The review of the trading arrangements based on the Pool, and the subsequent abolition of the Pool on the introduction of NETA, effectively pre-empted the Judicial Review, and it was formally withdrawn in December 2001.

Consultations before NETA on the need for reform

- 2.9 As part of the review of electricity trading arrangements during 1998 and 1999, Ofgem consulted on whether transmission issues needed to be addressed as well as the wholesale electricity trading arrangements. A consensus emerged that transmission arrangements should be reviewed but at a later date, to prevent the introduction of new wholesale trading arrangements being delayed.
- 2.10 In December 1999, Ofgem issued a consultation document⁹ (the December consultation) setting out our initial thoughts on a number of issues relating to new transmission access and losses arrangements under NETA. Issues covered included the need for, and possible approaches to, new transmission access and pricing arrangements and enduring arrangements for the treatment of transmission losses. 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.

⁹ 'NGC System Operator Incentives, Transmission Access and Losses Under NETA. A Consultation Document', Ofgem, December 1999

2.11 In the December consultation, Ofgem argued that, in keeping with the principles underlying NETA, new transmission access arrangements should create a framework for the creation 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.

2.12 Ofgem's initial preference was for the 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.

2.13 Under these arrangements the access rights would be financially firm. NGC would buy-back access rights at market prices 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. Therefore, we suggested that access rights that had been purchased but remained unused should be made available to other participants. 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.

2.14 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 electricity 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.

- 2.15 Given the locational signals emerging from the proposed transmission access and losses regimes, Ofgem suggested that it might be necessary for NGC to consider reviewing the structure of its TNUoS charges.

Industry workshops

- 2.16 The issues raised in Ofgem's December consultation were discussed in seminars at the Charging Principles Forum of the Transmission Users Group (TUG-CPF) in February and June 2000 and at the NETA Seminar in June 2000.
- 2.17 In addition, 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 computer and other systems requirements for the proposed transmission access regime.
- 2.18 NGC and other participants made valuable contributions to these debates. They also reiterated the view that reform of the transmission access and losses arrangements should be delayed until after NETA was implemented, since they did not have the resources to consider the issues at the same time as preparing for NETA.

Initial arrangements for transmission access and losses under NETA

Transmission access

- 2.19 Charges relating to the use of the transmission system are split between TNUoS and Balancing Services Use of System (BSUoS) charges, broadly relating to NGC's TO and SO roles respectively. Both generators and suppliers pay both of these charges. The allowed revenues that NGC recovers from TNUoS charges (together with its revenues from pre-Vesting connection charges) are determined by its TO price control. This is set and reviewed by Ofgem on a regular basis and, as discussed in Chapter 1, the current price control began on 1 April 2001. The BSUoS charge allows NGC to recover the costs it incurs, as SO, in

balancing the system, subject to an incentive scheme that allows for a sharing of profits or losses for performance that exceeds or falls short of target values. NGC's current and future SO incentive schemes were also discussed in Chapter 1.

- 2.20 As under the Pool, TNUoS is currently an annual charge differentiated by a participant's location (on a zonal basis) based on ICRP. At present, 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 NGC's Connection Charging Methodology Statement under supplementary standard condition C7B).
- 2.21 A locational transport problem (or constraint) occurs if the desired pattern of flows would breach the voltage, stability or thermal limits on any part of the system¹⁰, in the event of one of a defined list of contingencies (including, for example, double circuit failure). Managing such a transport constraint requires a re-balancing of the power flows in the locality of the constraint.
- 2.22 Currently, NGC primarily manages constraints by accepting bids and offers in the Balancing Mechanism¹¹. The costs of constraint actions, along with the other costs that NGC incurs in balancing the system (other Balancing Mechanism costs and balancing services contract¹² costs), are recovered from all participants via the BSUoS charge on the basis of their metered volumes.

¹⁰ The voltage and stability limits arise from the obligations for the SO to maintain the stability of the transmission network by managing the voltage and reactive power flows and by ensuring the satisfactory dynamic performance of generators. The thermal limits are a function of the capability of the plant and equipment forming the transmission network.

¹¹ The Balancing Mechanism is a close to real time market in which NGC is the counter-party to all trades. It was established to enable NGC to balance the system and effectively no bilateral trades for a settlement period can take place after the Balancing Mechanism for that period has opened.

¹² Balancing services contracts cover contracts for the provision of ancillary services e.g. frequency response, reserve, reactive power and black start, and any forward energy contracts that NGC may sign.

2.23 The current transmission access arrangements do not give generators and directly connected customers firm financial rights to use the system. In the event of transmission failures, they are exposed to potentially large financial risks that cannot be hedged. NGC does not have any long-term market based signals as to where new investment should occur. Changes in electricity flows or delays in transmission system investment can result in enduring transmission constraints. A recent example of this is the restriction of flows from Scotland to England as a result of delays in building the second Yorkshire line. Enduring constraints of this nature can impose large costs and inefficiencies on the system.

Transmission losses

2.24 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;
- ◆ participants are responsible for purchasing transmission losses, in the sense that their electricity imbalance volumes are adjusted for transmission losses.¹³

2.25 The metered volumes of all Balancing and Settlement Code¹⁴ (BSC) parties are adjusted in each settlement period to reflect the actual losses incurred in that 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.¹⁵

2.26 This averaging of losses provides poor signals to generators and customers of the costs of locating at different points on the network and also leads to inefficient use of the existing system. The difference between the percentage of electricity

¹³ In addition, NGC is incentivised to reduce the volume of losses through its SO incentive scheme.

¹⁴ The BSC governs the central arrangements of NETA. Its scope and governance is described in Appendix 1.

¹⁵ The rationale for this 45:55 split (rather than a 50:50 split), is due to the differences in the Defined Meter Point for demand and generation connections. In general, metering for generation connections is on the high voltage side of the supergrid transformer whilst the metering for demand connections is on the low voltage side of the supergrid transformer. Consequently, the measured losses include losses in supergrid transformers for demand connections but exclude them for generation connections.

that is actually lost in transmission as an average across the whole system and the percentage of losses that can be attributed to a particular region can be large (up to 9% for a generator in the North of England against average losses of approximately 2%).

- 2.27 The present arrangements also involve significant cross-subsidies. Relative to the actual costs they impose on the system, 'Northern' generators pay too little and 'Southern' generators pay too much. We estimate that compared with the actual costs imposed, Northern generators pay £23m too little and generators in and around Greater London pay £11m too much¹⁶. Conversely, 'Northern' customers pay too much relative to 'Southern' customers. Our estimates suggest that 'Northern' customers pay £19m more than the actual cost of losses they impose on the system whilst consumers in and around Greater London pay £7m too little¹⁷.

Consultations since NETA on the need for reform

May 2001 Consultation

- 2.28 Ofgem's May consultation sought to clarify the rationale for reform and to consider in more detail, and in the light of responses to the December consultation and the August 2000 workshop, the key building blocks that would be required to implement new transmission access and losses arrangements.

The need for reform

- 2.29 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 can be distorted by inappropriate transmission arrangements. There is potential for electricity prices to be influenced by transmission effects in ways that could reduce market liquidity and may effectively lead to market

¹⁶ Here we refer to Northern generators as being those generators connected to the transmission system in TNUoS charging zones 1 to 5, while generation in and around Greater London refers to generation TNUoS zones 7, 9, 10, 11, 12 and 13.

¹⁷ Demand TNUoS zones 1, 2, 3 and 4 have been used to represent consumers in the North and zones 7, 9, 10 and 11 refer to consumers in and around Greater London.

segmentation. This, in turn, could give rise to increased opportunities for locational market power to be exercised;

- ◆ participants do not receive appropriate economic signals related to short-term transmission losses, transmission constraints and locational decisions for major new connections and disconnections. This is particularly relevant for 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 does 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.

2.30 Consequently, the May consultation identified four main objectives that needed to be achieved by any reform of the initial NETA arrangements for transmission access and losses:

- ◆ **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. This necessitates separating the pricing of electricity from the pricing of transmission capacity as far as possible, 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 and electricity interactions:** to provide the framework for efficient and effective interactions between the gas and electricity markets in the short and long-term.

2.31 Ofgem considered that the best means of achieving these objectives would be the establishment of a market in firm tradable access rights and appropriate charging for transmission losses.

Transmission access reforms in the May consultation

2.32 There are a number of different ways in which a transmission access regime based on firm tradable rights could be introduced, but Ofgem suggested that the implementation of a system based on firm entry and exit access rights has considerable merits. We noted that it would 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's initial view was that there might be merit in auctioning entry (generation) access rights but that it might be preferable to allocate firm exit rights to all customers in return for the payment of a locationally varying access charge.

2.33 To ensure participants purchase sufficient rights to match the amount of electricity they wish to transmit across the transmission system, Ofgem suggested that some form of imbalance regime could be needed. Equally importantly, the establishment of firm financial rights for users of the transmission system means that NGC would be required to buy-back from participants at market prices any rights that it had allocated but could not deliver. Ofgem believed that the maximum possible volume of access rights (given the transmission network in place) should be made available. This would be achieved 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 it would be efficient and economic to do so, in the long-term.

2.34 Ofgem considered that, as part of an expanded SO incentive scheme, NGC should be exposed to the costs of constraints where it fails to invest to deliver output measures agreed as part of its TO price control and should be allowed to earn additional revenues where it exceeds them. In this way, NGC would have

strong financial incentives 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 SO investment regime proposed and agreed for Transco's NTS in gas (see Chapter 1).

- 2.35 With respect to the form and structure of transmission charges after the introduction of new transmission access and pricing and losses arrangements, Ofgem believed that some adjustment to the basis for calculating TNUoS charges is likely to be required. Specifically, we suggested that it may be appropriate for NGC to review whether to reduce or remove the locational differentiation in TNUoS charges and to move to a per MWh charging arrangement for all generation and demand.
- 2.36 The May consultation also outlined a 'possible approach', which was designed to provide a coherent set of arrangements against which participants could consider the merits of alternative approaches to the various elements. The key features of the possible approach were:
- ◆ an entry/exit approach to defining transmission access rights;
 - ◆ differing primary allocation mechanisms for entry and exit rights, with entry rights being auctioned and exit rights being allocated;
 - ◆ a variety of secondary trading mechanisms, including the use of constraint option contracts;
 - ◆ 'use it or lose it' provisions;
 - ◆ trading of access rights continuing after Gate Closure¹⁸ in order to allow NGC (and perhaps other participants) to trade access rights to back Balancing Mechanism acceptances; and
 - ◆ a half-hourly imbalance settlement regime based on one sided access imbalance charges i.e. participants who paid to acquire access rights would only be subject to over-run charges, whilst those who had been paid to take rights would face under-run charges.

¹⁸ Gate Closure is the point at which bilateral trading stops and the Balancing Mechanism opens. Currently, it occurs 3.5 hours before the start of the settlement period.

Transmission losses reforms in the May consultation

- 2.37 Ofgem believed that an enduring scheme for transmission losses should incorporate more efficient arrangements for the charging of transmission losses including the use of locational marginal loss factors. Ofgem suggested an approach involving adjusting participants' metered volumes using estimates of average zonal loss factors in combination with a separate financial payment or levy as part of the BSUoS charge, calculated to reflect the difference between estimated marginal loss factors and the average factors used to adjust metered volumes.
- 2.38 Ofgem pointed out that this approach might make it possible to implement a more cost reflective regime for transmission losses independently of the implementation of transmission access arrangements.

Respondents' views

- 2.39 Ofgem received 54 non-confidential responses to the May consultation. Four main themes could be identified from the responses:
- ◆ Ofgem needs to set out a clear business case before proceeding with both the transmission access and transmission losses reforms;
 - ◆ the proposed transmission access reforms were too complex and costly (especially in terms of necessary systems) with the possibility that the cost of reforms may outweigh any benefits;
 - ◆ a concern that the move to charge for transmission losses on a locational basis will result in windfall gains for some at the expense of others; and
 - ◆ the gas model has not worked properly and should therefore not be adopted for the electricity markets.
- 2.40 A number of respondents, whilst expressing concerns about Ofgem's specific proposals, recognised that the current arrangements for transmission access and transmission losses need reform to ensure that participants are exposed to the correct economic signals, both in the short and long-term.

- 2.41 Two respondents outlined alternative models. Both models aim to achieve the objectives of reform with less complexity than the 'possible approach' in the May consultation. These models are described in more detail in Chapter 4.
- 2.42 Respondents who were concerned that a move to locational charging of transmission losses would lead to windfall gains at the expense of others argued that generators would be excessively penalised for historic investment decisions.
- 2.43 Respondents who were opposed to aligning the arrangements with those in the gas sector also argued that the differences between these sectors does not warrant a 'one fits all' approach.

3. Rationale for reform

- 3.1 Ofgem remains of the view that the current transmission access and losses arrangements need reform. Ofgem continues to believe that a system of firm tradable access rights should be introduced along with a move to locationally differentiated transmission loss factors. However, we acknowledge participants' concerns over the implementation costs of a complex regime.
- 3.2 In this chapter we discuss why Ofgem remains convinced of the need for reform. We also outline developments in our thinking on simpler approaches to new transmission access and losses arrangements that would still deliver the key benefits of reform.

The need for reform

- 3.3 From the evidence of the previous sections a number of weaknesses with the current arrangements for transmission losses and transmission access can be identified. In particular:
- ◆ investment in new load and generation is likely to be inefficient as the costs of transmission are not properly signalled and targeted;
 - ◆ the lack of firm, long-term rights adds additional risk to generators that they cannot effectively hedge. These risks take the form of exposure to energy imbalances as a result of failures in the transmission system. Furthermore, the absence of firm, long-term rights limits the opportunities for system users to negotiate interruptible use of system arrangements in return for lower charges;
 - ◆ the lack of long-term tradable rights provides poor signals to users and NGC of rising demand for system use in particular locations. Therefore, the planning process undertaken by NGC to determine the need for new investment will not fully reflect the needs and intentions of system users. This could reduce the overall efficiency of the system and pose a risk to security of supply;

- ◆ NGC does not have appropriate incentives to invest in the transmission system in a timely manner to meet rising demand in particular locations and also to improve system reliability;
- ◆ trading under NETA may be distorted through a lack of cost targeting of transmission related costs; and
- ◆ the present arrangements are inconsistent with the arrangement in gas and this would, in the absence of reform, lead to inefficient interactions that could threaten supply security.

3.4 At the highest level, a more accurate targeting of locational costs should reduce the overall costs of operating the system as participants respond to these signals and the transmission system is used more efficiently. Thus, although charges for some participants will increase in the short-term, over the longer-term, charges for all participants should be lower than they would otherwise have been. For example, as a result of locational signals of the high costs associated with additional northern generation there may be a greater tendency for new plant to be built in the south rather than the north-east. This would reduce the likelihood of north-south constraints and the associated costs to participants, and additionally might remove or reduce the need for NGC to reinforce the network. This, in turn, would result in an overall reduction in transmission costs for all participants due to lower infrastructure costs as well as a reduction in the constraint costs faced by northern generators and southern consumers.

3.5 It is Ofgem's principal objective to protect the interests of consumers, wherever appropriate by promoting effective competition. Subject to this principal objective, Ofgem is also required to promote efficiency in the generation and supply of electricity. In addition, NGC is obliged under the terms of its electricity transmission licence to operate its transmission system in a way consistent with ensuring effective competition in the generation and supply of electricity. We believe that the significant cross-subsidies that currently exist between participants in different locations distort competition across the system through discriminating against customers in the north and generators in the south and inhibit system efficiency. Ofgem therefore believes that these cross-subsidies need to be addressed sooner rather than later.

Main considerations

3.6 The May consultation listed four major objectives for reform, whilst recognising a number of other supplementary objectives. Ofgem now believes that the importance of several of these supplementary objectives has increased and therefore the main considerations associated with the reform of transmission access and losses arrangements should be:

- ◆ short and long-term efficiency issues;
- ◆ NGC investment signals and incentives;
- ◆ NETA related effects;
- ◆ gas and electricity interactions;
- ◆ interactions with Europe; and
- ◆ environmental effects.

3.7 Each of these is discussed in more detail below.

Short and long-term efficiency issues

3.8 Ofgem continues to believe that there is scope for improving both the short and long-term efficiency of the transmission system and ensuring that the system costs of transmission losses, transmission constraints and locational decisions for major new connections and disconnections are appropriately targeted and incentivised.

3.9 There is a great deal of uncertainty surrounding future patterns of electricity flows and hence the short and long-term costs that will be imposed on the system. A number of market factors such as the introduction of new interconnectors and changes in the relative levels of gas, coal and electricity prices can have a significant effect on generation patterns of plant and hence electricity flows. It is already the case that under NETA typical patterns of generation have changed. For example, combined cycle gas turbines (CCGTs) typically operated at baseload under the Pool but are now operating in a more flexible manner and in some cases are actively participating in the Balancing

Mechanism. It is also possible that the competitiveness of different types of generation technology could change in the future. Powergen has announced its intention from 1 April 2002 to mothball a unit at its northern gas-fired plant, Killingholme, and bring back a unit at its southern coal/oil plant, Tilbury. Additionally, over the next ten years, many of the long-term contracts that the early CCGT plants entered into will come to an end, potentially changing the way these generators participate in the market.

- 3.10 Without appropriate access arrangements and proper locational signals, there is a risk that the system will not be used efficiently in the short-term and that long-term system development will not be targeted effectively.

NGC investment signals and incentives

- 3.11 As the electricity market becomes more dynamic, the use of an administered planning process, such as that involved in the current TO price control reviews, will become more problematic. In an evolving market, it will become increasingly difficult for a centralised planning process to accurately forecast where and when investment would be required in the transmission system. Furthermore, the typically long planning and investment lead times mean that the effects of investment decisions will be felt by participants several years after the decisions are taken. We believe that, as much as possible, these investment decisions should be based on the value placed on transmission capacity by participants.
- 3.12 Ofgem believes that a regime such as that to be implemented for gas (described in Chapter 1) has considerable merits. Applied to NGC, the TO price control revenues would relate to the delivery of baseline levels of transmission capacity. The baseline levels would be supplemented by incentive arrangements to encourage movements away from these in response to signals emerging from the market.
- 3.13 We accept that there are differences between the gas and electricity regimes, most notably that NGC has greater control over the timing of introduction of new generation than Transco has over the commissioning of new gas fields. However, we believe that the general approach is as valid in the electricity market as it is in the gas market. Consider, for example, the trade-offs that

Transco will be able to make between investing in greater exit capacity, entering into more interruptible transportation agreements and purchasing more local reserves of gas. NGC has exactly the same options open to it¹⁹ and hence the same types of incentives are appropriate.

- 3.14 Equally, the current price control regime requires NGC and Ofgem to 'second guess' generators' decisions with regard to the operation of their plant whether it be to delay or advance closure, bring back a mothballed plant or to alter investment plans. Providing that new access arrangements give rise to long-term market signals, this should provide a better basis for NGC's investment decisions.

NETA related effects

- 3.15 Ofgem continues to believe that it is important to ensure that the market and price for traded electricity is separated as much as possible from the price of transmission capacity. Ofgem agrees that the current arrangements are leading to participants being unfavourably exposed to imbalance prices in the event of transmission failures.
- 3.16 Ofgem accepts that it is not possible to separate completely electricity and transmission prices. However, by separating these prices as much as possible, Ofgem believes that market transparency will be improved, making it easier to identify and deal with any locational market abuse. In addition, Ofgem believes that failure to separate the prices will result in distortions to the wholesale electricity markets, which in turn could lead to reduced levels of liquidity in these markets. The effects of this could include price increases and reduced competition with the subsequent negative implications for consumers' interests.
- 3.17 To the extent that imbalance or spot prices affect the prices at which electricity is traded more generally, there are potentially high pay-offs to be gained from exercising local market power. Separating, as far as possible, the price of traded electricity from capacity will reduce the level of distortions in the traded electricity price and reduce incentives on participants to exercise local market power.

¹⁹ In electricity terms, interruptible transportation agreements might be options to constrain down participants.

- 3.18 Ofgem recognises that NETA has only recently been introduced and that some participants argue for delaying the reform of the transmission access and losses arrangements until NETA is more established. However, Ofgem believes that the interests of consumers will be better served by the industry taking forward the reform of these arrangements as soon as practically possible.
- 3.19 As experience from the gas market shows, it is important not to wait to introduce appropriate locational access signals until problems arise, because such a delay can significantly increase the constraint costs that participants face and prolong the period for which constraints persist. For example, the lack of appropriate access arrangements in the gas market contributed to the situation that developed at St Fergus whereby a lack of incentives on Transco to reinforce the network in a timely manner led to significant constraints arising. Although the gas access arrangements have now been reformed and the need for more capacity has been apparent for several years, entry costs at St Fergus remain high for those months when constraints are most likely to occur because of the lead times associated with reinforcing the gas transportation network.

Gas and electricity interactions

- 3.20 Ofgem continues to believe that it will be important to consider the interactions between the gas and electricity markets when designing enduring transmission access and losses arrangements. This is of particular importance given the growing significance of gas-fired generation within the plant mix. Consistency in the approach between the two markets will ensure that incidences of inefficient or perverse decisions and short-term trading distortions are minimised.
- 3.21 As an example, consider the situation where a CCGT enters into an interruptible gas transportation contract, potentially lasting several years. This CCGT might prove to be vital to NGC for short-term balancing of the system. However, NGC might not be able to alter the output of the plant due to the interruptible gas transportation contract that is in place. Aligning the electricity and gas systems so that the relative value of a particular asset to the two systems is apparent would increase the security of both systems. This does not mean that the two systems have to be identical. Technical differences between the two systems

may mean that this is not appropriate. However, it is important that the approaches are consistent. In the example above, it would not be necessary for interruptible contracts for electricity and gas to be offered at the same time. It is sufficient that NGC is incentivised to make decisions on interruptions in time for it to be able to buy out the interruptible gas transportation agreement, if this proves to be necessary.

- 3.22 Over the longer-term, consistent arrangements between gas and electricity should ensure that efficient investment decisions are made with regard to the location of plant in relation to both the gas and electricity transportation networks. There is inevitably a balance to be struck between gas and electricity transportation costs since locations that are favourable from an electricity perspective may not be favourable from a gas perspective. Consequently, it is important that the two access regimes allow this trade-off to be made appropriately and that differences between them do not lead to distortions in investment signals.

Interactions with Europe

- 3.23 We believe that robust arrangements need to be in place in advance of possible developments in the pattern of European wide electricity flows that could have significant consequences for the level of constraints in England and Wales. New interconnectors from Norway and the Netherlands to the UK, and from Scotland to England, are being discussed that might substantially alter the pattern of flows in England and Wales. Moreover, it is also possible that flows on the French interconnector could, particularly at times of peak, reverse direction over time given the increasing age of some of the marginal French oil and coal stations. Ofgem has not taken any particular view on how electricity flows will develop. However, it is our view that the increased uncertainty associated with such developments requires efficient transmission access arrangements to be introduced to ensure that participants and NGC receive appropriate signals to respond to changing circumstances in a timely fashion.
- 3.24 Experience in the UK gas market provides a good example of how changes in the wider market can change system flows and alter the value that participants place on transmission access. Prior to the commissioning of the interconnector

between the UK and continental Europe, demand by participants to access Transco's NTS was highest over the winter months, reflecting the greater UK demand for gas during these months. However, since the opening of the interconnector, the commercial opportunities to flow gas through the NTS and into Europe over the summer months have led to increased demand for access to the NTS over the summer. Due to the seasonal nature of NTS entry capacity availability, the auctions for summer capacity in both 2000 and 2001 were heavily over-subscribed.²⁰ Under Transco's new SO incentive schemes, Transco will have the ability to respond to these signals by making additional capacity available where it is economic to do so.

Environmental effects

- 3.25 Under the Utilities Act 2000, Ofgem has certain obligations, as set out in the Environmental Action Plan²¹, with regard to the environmental effects of our work and the industries we regulate. We believe that the proposed reforms to transmission access and losses arrangements offer a number of potential environmental benefits.
- 3.26 One of the key aims of the reforms to transmission losses arrangements is to reduce the overall level of losses. We believe that, by better reflecting the costs of transmission losses on participants, existing generation will be used more efficiently in the short-term and participants will face long-term incentives to take transmission losses into account when making investment decisions. Any reduction in overall transmission losses will mean less energy is required to meet electricity demand and hence would mean an overall reduction in emissions.
- 3.27 Better targeting of transmission costs also has the potential to encourage more local, embedded and on-site generation schemes as they will be able to capture greater benefits from reducing overall transmission costs. Over time there is also potential for this better cost targeting to reduce the need for investment in additional transmission assets. This will reduce the resources consumed in

²⁰ This arose partly because of incentives caused by oil linked gas prices in Europe during 2000 and partly because higher oil production was creating greater volumes of associated gas.

²¹ 'Environmental Action Plan', Ofgem, August 2001

electricity transmission and the visual intrusion caused by new overhead transmission lines.

- 3.28 Ofgem recognises that many renewable technologies are dependent on fixed natural resource eg wind or river flows, and therefore do not have locational flexibility. However, cost reflective pricing for transmission will help to promote efficient investment decisions between alternative technologies and projects.
- 3.29 Clearly, a number of factors other than the transmission access and losses arrangements will influence the operational and investment decisions of participants and NGC. For example, local planning regulations and the potential introduction of tradable emissions rights for generators could both be significant factors for participants to take into account. However, greater transparency in transmission costs would enable participants to balance these factors appropriately.

4. Ofgem's views on transmission access

Overview

- 4.1 In the May consultation, Ofgem presented a 'possible approach' for new transmission access arrangements that covered the key issues for any new arrangements. The primary purpose of this was to outline a coherent set of proposals against which participants could consider alternative approaches to various elements.
- 4.2 The general concern raised by participants in response to Ofgem's initial proposals was the complexity and potential cost of the proposals (in terms both of implementation and ongoing costs for NGC and participants) in comparison to the likely benefits that could be achieved.
- 4.3 Ofgem agrees with the majority of respondents that, in considering reforms to the transmission access regime, it is important to take account of the likely costs of the reforms as well as their benefits. We accept that the set-up and transaction costs associated with a full-blown tradable regime may be significant. Therefore, while Ofgem continues to believe that the introduction of firm, tradable access rights is desirable, we accept that there may be merit in exploring a simpler approach. To this end, in the May consultation, we outlined at a very high level the features that a simpler regime might incorporate and these have been more fully developed in a number of responses, as discussed in Chapter 5.
- 4.4 We consider that an approach along the broad general lines of an initial allocation of rights followed by trading of rights (either via tenders for constraint options or via some form of access adjustment mechanism) might provide an appropriate way forward. There are, of course, a number of outstanding issues that would need to be resolved if such an approach were to be adopted.
- 4.5 In this chapter, we outline the features that we consider would be essential in any new transmission access regime to ensure that it addressed the issues discussed in Chapter 3 on the need for reform.

Definition of transmission access rights and their locational resolution

- 4.6 Ofgem continues to believe that a regime based on entry and exit rights is preferable to one based on flowgates²² for the England and Wales system. Ofgem considers that an entry/exit right regime would be simpler than flowgates in terms of defining initial allocations of rights and their subsequent trading. One essential feature of such transmission access rights would be their firmness: once rights have been allocated, the SO would only be able to withdraw them by buying them back. This approach would automatically mean that participants would be compensated for a lack of access in the event of transmission failures.
- 4.7 If, as seems sensible, an initial allocation of entry rights for generators were to be based on Registered Capacities then this would essentially be a nodal approach. However, the charges for the rights could be zonally defined in which case generators would be free to trade rights with other generators subject to the same access charge.
- 4.8 Ofgem considers that the issue of how such zones should be defined can only be resolved in consideration with decisions on a number of other design features, notably the range of tools that the SO is able to use to resolve constraints. For example, if in addition to buying and selling transmission access rights directly, the SO is able to tender with individual participants for constraint option contracts, then the use of larger zones may be possible since the option contracts would give the SO the finer control needed to resolve constraints.
- 4.9 On the demand side, we believe that the most straightforward way of allocating exit rights would be to define them in relation to GSP Groups given that this corresponds to the current zonal definition for metered volumes.

Primary allocation mechanism for transmission access rights

- 4.10 As Ofgem pointed out in the May consultation, the key to a successful access regime is to ensure that appropriate locational signals emerge. Whilst using

²² The concept of flowgates was highlighted in the May consultation. 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).

auctions to effect a primary allocation of rights is one way of achieving such signals, it is by no means the only way. Subsequent trading of rights that are initially allocated in some administered way can equally well deliver appropriate signals. Several respondents to the May consultation voiced concerns about the cost and complexity of auctions. In light of this, Ofgem accepts that a simple primary allocation mechanism may be preferable on practical and cost grounds to an auction of rights.

- 4.11 Another highly desirable feature of any new access regime would be that it allows rights to be allocated for several years at a time. Participants would then guarantee to pay access charges for that period and if they subsequently decided that they no longer required some of these rights (for example, if they closed a unit), they would still be required to pay the access charges. They would, however, be able to sell on their rights and hence effectively avoid the access charges. It is for this reason that Ofgem believes that it is desirable for firm access rights to be tradable amongst participants.

Secondary trading of access rights

- 4.12 As discussed above, Ofgem considers that the secondary trading of access rights is likely to be a feature of any successful transmission access rights regime. At the very least, it will be essential that the SO can resolve transmission constraints by trading access rights or access right derivatives, e.g. constraint option contracts. However, Ofgem considers that it would also be desirable for participants to trade access rights between themselves both to reflect short-term changes in expected output and consumption and to enable efficient market entry and exit. In this respect, the views of participants with regard to facilitating secondary trading are particularly important.
- 4.13 Our initial view is that tenders for constraint options might be a simple and inexpensive method of resolving transmission constraints. It would also be consistent with the arrangements in gas whereby the equivalent of constraint options (interruptible transportation contracts) are agreed for a year at a time.
- 4.14 If the methodology for recovering NGC's TO allowed revenues were to change, constraint contracts would also be a way of reproducing the effect of the Triad charging methodology in respect of TNUoS charges for half-hourly metered

customers.²³ Currently, many large customers seek to avoid TNUoS charges by reducing their demand in half-hours that might be counted as one of the three Triad periods. Typically, this involves them in reducing their demand in around 20 half-hours. Customers could, in principle, achieve a similar effect by agreeing an option contract with NGC that gave it the right to reduce their demand in 20 half-hours. Whether the value that NGC placed on such contracts would be equal to the costs that customers have avoided in the past would depend on the extent to which a guarantee of the ability to reduce demand would enable NGC to avoid undertaking network reinforcement.

Transmission access imbalance and settlement

- 4.15 It is likely that a significant proportion of the costs of an access rights regime will be associated with the development and operation of some form of access rights imbalance system. Clearly, the decisions taken with regard to access right trading will have an impact on the complexity, and therefore cost, of dealing with access imbalance. It will be necessary to weigh the benefits of greater freedom in access right trading against the costs of a more complicated imbalance system.
- 4.16 If possible, Ofgem would be in favour of solutions that allow for some degree of participant to participant trading without the need for a full-blown access imbalance system. The use of constraint options might be one method of reducing the costs of managing access imbalances since the penalties for failure to perform in accordance with the contract would be dealt with under negotiated contract terms.
- 4.17 Another essential feature of any access regime will be a locational allocation of the costs incurred by the SO in resolving constraints. Only in this way will appropriate signals of the varying locational values of generation and demand be apparent and hence enable participants to price their access right trades and/or option contracts with NGC appropriately.

²³ TNUoS demand charges for half-hourly metered customers are based on the average of metered consumption volumes in the three winter half-hours of highest demand in a year that are separated from one another by 10 days.

- 4.18 It will also be important to involve both sides of the market so that all benefits can be realised. For example, to resolve a particular constraint NGC may call a constraint contract to decrease a generator or to increase the consumption of a large demand site.

Interactions with NETA

- 4.19 The issue of who should be responsible for ensuring that accepted Balancing Mechanism bids and offers are backed by appropriate access rights holding may be less important under a simplified approach, in which participants are allocated access rights. This would be particularly true with regard to entry rights if generators' allocations are based on their Registered Capacities since then, by definition, they should always have sufficient rights to back their offers and bids. Even if they had traded their rights to another generator in the same access charge zone, the overall level of access rights in that zone would not have changed and hence should be sufficient to accommodate any offers and bids that might be submitted.

Interaction with transmission price control

- 4.20 As discussed in Chapter 3, one of the benefits of a reform of the transmission access arrangements should be to provide better incentives on NGC with regard to investments. This requires long-term market signals of the value that participants place on access to the transmission system to be visible and reinforces the need for access rights to be allocated for, at least, several years at a time and for the SO to be able to sign long-term constraint options.
- 4.21 The access charges that participants pay for their transmission access rights should, at least in part, cover NGC's allowed TO price control revenues. A capacity-linked access charge i.e. £/kW would seem an obvious approach but it would differ from the current TNUoS charges in that the access charges could not be avoided, except by entering into constraint options. Therefore, the scope of the access charges needs to be considered. Should the access charges be set to cover all of NGC's allowed revenues or should there be a combination of access and commodity (£/MWh) charges?

4.22 As for Transco, we would expect that market-related investment revenues and costs would form part of NGC's SO incentive regime. One possibility, therefore, would be for these costs/revenues to be included in the BSUoS charge, although it is for consideration whether a £/MWh charge is appropriate for investment related costs/revenues. Equally, the recovery of constraint costs could be accomplished via a locationally differentiated element to the BSUoS charges.

Greater demand side participation

4.23 Tradable firm access rights would facilitate greater demand side participation in managing transmission constraints. Although the Triad charging methodology provides some incentive for demand side participation to manage their consumption during system peaks, participants do not know *a priori* which periods will make up the Triad and hence the value of any demand side management is always uncertain. In some cases, participants will curtail demand during periods when there is sufficient transmission capacity, while in other cases the SO may use generation to manage transmission constraints when demand side actions would be more efficient. With firm transmission access rights, demand side participants will have much more scope to participate in resolving transmission congestion, either through selling access rights back to the SO or by agreeing interruptible terms with it.

4.24 Ofgem expects that any new transmission access regime will fully incorporate demand side participation.

Summary

4.25 Ofgem continues to believe that reform of the transmission access regime to introduce firm, tradable access rights is desirable. We accept that there may be merits in adopting a simpler approach than that outlined as the 'possible approach' in the May consultation.

4.26 Ofgem considers that there are a number of key elements to any transmission access regime. These are as follows:

- ◆ Firmness: once allocated, access rights can only be interrupted by the SO buying back the rights. Equally, participants who have been allocated

rights will be committed to paying for them for the length of time for which they have been allocated.

- ◆ Duration: it would be desirable for access rights to be allocated for several years at a time in order to ensure that signals of the need for new transmission capacity can emerge.
- ◆ Trading: for market signals to emerge, some form of trading will be necessary. Tenders for constraint contracts would be one such form of trading but it would be desirable for participants also to be able to trade between themselves.
- ◆ Cost-signalling: to inform participants' trading decisions, it will be important that they are exposed to the locational costs that NGC incurs in resolving constraints.
- ◆ Linkage to SO incentives on investments: the access regime should enable the SO to be incentivised to respond to market signals of the need either for new transmission capacity in excess of that agreed as part of the TO price control or for intended investments to be delayed.

4.27 These essential elements provide an outline for the form of transmission access arrangements going forward, however, there are many detailed design issues that will still need to be worked through. It is intended that these issues will be addressed by industry working groups as part of the BSC modification and CUSC amendment processes required to implement the new arrangements.

5. Alternative transmission access approaches proposed by respondents

Introduction

- 5.1 As mentioned in Chapter 2, a number of respondents expressed concerns over the complexity and potential cost of the 'possible approach' to transmission access arrangements outlined by Ofgem in the May consultation. However, in the May consultation we also indicated that there may be merit in exploring simpler approaches and outlined at a very high level the features that such a simplified regime might incorporate. Two respondents to this consultation have further investigated simplified approaches and have proposed alternative transmission access models.
- 5.2 Both these models show strong similarities to the simple approach that Ofgem outlined in the May consultation in that access rights are allocated rather than auctioned. The models would still enable two of the concerns Ofgem raised - removing distortions to energy prices and introducing more efficient short-term locational signals – to be resolved and hence merit consideration as possible ways forward. This chapter outlines the key features of both models and raises a number of issues concerning them.

Defining and allocating entry and exit rights

Model 1

- 5.3 Under this model, a simple allocation of firm access rights would be made to all participants, for which they would pay an access charge. Each participant would receive the right to operate up to a 'natural' limit. For generators, this limit would be their Registered Capacity and entry rights would therefore be defined on a nodal basis. Given the limitations of the Supplier Volume Allocation (SVA) arrangements for those without half-hourly meters, it would be most practical for exit rights to be allocated on a GSP Group basis. Consequently, the upper limit for a GSP Group as a whole would be the GSP Group Demand, but it is unclear how these rights would be split between

suppliers within the GSP Group. The limits would be enforceable under existing codes or contracts, for example connection agreements.

Model 2

- 5.4 Model 2 also envisages allocation rather than auctioning of both entry and exit rights. The allocation of rights would take place through performance agreements, akin to the current connection agreements. However, there would be a guaranteed entitlement to subscribe for a specified volume of access rights in return for a fee. As in Model 1, generators would be entitled to access rights equal to their Registered Capacity. On the demand-side, suppliers could request exit rights for a GSP Group up to a forecast of their maximum demand in the zone.
- 5.5 The performance agreement would also cover such matters as compensation terms in event of transmission failures and could also cover other quality of supply criteria.

Trading of access rights and resolving constraints

Model 1

- 5.6 Trading under Model 1 would be restricted to the signing of constraint contracts (both fixed and option contracts) between NGC and participants. Generally, NGC would be entering into short-term constraint contracts with durations perhaps as short as a week or less. However, NGC might tender for contracts several months to a year in advance and might also enter into longer-term contracts where constraints are more persistent.
- 5.7 Participants who have entered a constraint contract would be required to notify their intended physical position to NGC prior to Gate Closure (Initial Physical Notifications²⁴ could potentially be used for this purpose). In the case of a fixed constraint contract, the physical notification would have to be consistent with the constraint contract. NGC could choose to call option contracts by requiring that the contracted participant behaves in a specified way. This could include a requirement to follow its physical notification or to adjust its physical

²⁴ By 11 am each day, generators and suppliers are required to provide an Initial Physical Notification to the system operator setting out their expected operating levels throughout the following day.

notification in a specified way. To the extent that a participant was required to alter its intended physical position, it should be able to adjust its contract position accordingly by trading in the period up until Gate Closure.

- 5.8 Since these options would be called some time prior to Gate Closure, participants would not directly be put into energy imbalance as a result of the exercise of these contracts. Hence, they should not have to factor imbalance costs into the contract prices they offer.
- 5.9 Resolving a possible transmission constraint at a given location could require NGC to exercise a number of constraint contracts held with different generators. For any given constraint there might be a number of generators capable of resolving it. In theory, NGC could exercise just one constraint option contract with a single generating unit to reduce generation behind the constraint. However, NGC's action to resolve the constraint could be undone through further trading by other generators. In such circumstances, NGC would need to ensure that changes in the intended physical positions of other generators would not serve to 'recreate' the transmission constraint. It is for this reason that Model 1 allows NGC to exercise option contracts that require participants to remain at their physical notifications.

Model 2

- 5.10 Under this model, a distinction is made between those activities carried out by the TO and those carried out by the SO. The TO would be responsible for the initial allocation of rights and for setting a transmission plan with associated circuit availabilities for each day. The TO might choose to buy-back rights that it had already allocated or make additional rights available when creating this transmission plan.
- 5.11 The transmission plan would be handed over to the SO at, say, the day-ahead stage. The SO would then be responsible for ascertaining whether it needed to take any action to resolve constraints on the basis of participants' access right holdings and an initial indication of their intended physical positions (Initial Physical Notifications could again fulfil this role). It is likely that the TO would need to compensate the SO if circuit availability decreased for any reason after the hand-over had occurred.

- 5.12 Instead of constraint option contracts, Model 2 includes an Access Adjustment Market that the SO would use to resolve constraints in a similar way to that in which it uses the Balancing Mechanism to resolve energy imbalances. Participants would also be able to use the Access Adjustment Market. For example, suppliers who gained or lost customers after they had been allocated their exit rights could use the market to adjust their holdings accordingly. The TO would also be able to participate in the Access Adjustment Market if it could provide additional circuit availability.
- 5.13 Participants are under a Grid Code obligation to use reasonable endeavours to follow their Final Physical Notifications²⁵. It is envisaged that participants in the Access Adjustment Market would be placed under a similar obligation to follow the physical positions that they notified when the market started. As discussed below, participants would be penalised for varying from the physical positions they had notified at the start of the Access Adjustment Market. There is no similar penalty in the current arrangements in the Balancing Mechanism (although the information imbalance charge could provide such a penalty).

Interactions with NETA

Model 1

- 5.14 Under Model 1, NGC would be free to trade-off the costs of entering in to constraint contracts against those of taking actions in the Balancing Mechanism to resolve constraints. Consequently, NGC would need to be incentivised to make efficient trade-offs between constraint and Balancing Mechanism actions and the current tagging mechanism would need to be retained under this model. The tagging mechanism seeks to separate out bids and offers that are accepted for system balancing actions from the calculation of energy imbalance prices.
- 5.15 Access rights would be granted automatically when a bid or offer is accepted in the Balancing Mechanism, even though this might result in some locational effects continuing to influence energy imbalance prices.

²⁵ By gate closure for each half hour trading period, generators and suppliers are required to submit a Final Physical Notification of their proposed operating levels.

Model 2

- 5.16 Under this model, participants are expected to be in balance in terms of their energy and access position at Gate Closure. This could be enforced by checking participants' FPNs and Maximum Export and Import Limits against their access right holdings and, if necessary, applying a penalty for any discrepancy.
- 5.17 After Gate Closure, no access right trading would take place. To avoid free rider problems, Model 2 envisages that some form of matching process might be required for Balancing Mechanism acceptances.

Settlement

Model 1

- 5.18 There would be no general access imbalance settlement but only settlement of constraint contract imbalances under Model 1. These imbalances and their associated charges would arise if a participant failed to comply with the instructions it had been given under its constraint contract. This would occur if it either failed to adjust its position as requested or it changed its position when it had been instructed not to. The terms of these imbalance charges would be set as part of the negotiation of the constraint contract.

Model 2

- 5.19 This model includes an imbalance settlement process that would cover both imbalances relating to Access Adjustment Market acceptances and more general imbalances (those arising from a difference between a participant's access rights holdings and its physical position). For general imbalances, the imbalance charge would only arise if a participant's physical position exceeded its access right holdings. Given the volume of access rights that would be allocated, it is envisaged that general imbalances would not be very frequent. Access Adjustment Market imbalances could result from either:
- ◆ a participant failing to follow an agreed level of output/demand; or
 - ◆ a participant varying from a notified level when no variation had been requested.

Recovery of constraint costs

Model 1

5.20 Although a general access imbalance regime is not required under this model, all participants would be exposed to the costs of resolving transmission constraints. This would include not only the net costs of constraint option contracts (option fees and utilisation fees) but also any net constraint-related Balancing Mechanism costs. It is envisaged that these costs would be recovered via an extension to the current BSUoS charges. This could be achieved by:

- ◆ maintaining the existing non-locational charge-out of the costs of constraints based on participants' metered volumes;
- ◆ introducing a locational charge where the costs incurred in calling options would be allocated to zones; or
- ◆ introducing locational marginal price signals based on the options that NGC had called.

Model 2

5.21 Under Model 2, the SO can use the Access Adjustment Market to buy back and sell transmission capacity to resolve constraints. The options that exist for recovering the cost of transmission constraints under this model are similar to the first two options under Model 1, namely:

- ◆ continue to charge the cost of constraints on a non-locational basis according to participants metered volumes; or
- ◆ introduce locational charges based on the costs of managing constraints through the Access Adjustment Market.

Interactions with the transmission price control and transmission charges

Model 1

- 5.22 As discussed above, Model 1 incorporates an access charge approach although the form of the access charge is left for further consideration. However, if the access charge were locational²⁶, it might not be necessary to give additional locational signals to participants through transmission losses charges or constraint charges. Alternatively, the access charge could be non-locational i.e. a postage stamp charge, if short-term locational signals were provided through a transmission loss charge and/or constraint charge.

Model 2

- 5.23 Under this model, NGC would recover its allowed TO revenues through a combination of £/kW access charges and £/MWh commodity charges. As discussed for Model 1, the degree of locational differentiation in the access charges under Model 2 would depend on the extent to which locational signals are provided through charges for transmission losses and the recovery of constraint costs.

Ofgem's view on the two models

- 5.24 Ofgem considers that there is considerable merit in the general approaches outlined above. Both models incorporate firm, tradable access rights in a system that provides appropriate short-term locational signals whilst minimising the set-up and transaction costs for both central systems and participants. However, the two models raise a number of issues which would need to be resolved if they, or some variant of them, were to be taken forward.
- 5.25 Both models assume that generators will be allocated entry rights equal to their Registered Capacities and that the SO will buy back rights to resolve transmission constraints. This suggests that very little participant-to-participant trading of entry rights will occur, unless access rights are allocated for several years at a time. Ofgem is strongly of the opinion that any long-term, firm

²⁶ For example, in a similar form to the current ICRP based charge.

transmission access rights should be tradable. With tradable long-term rights, participants wishing to close or mothball plant could sell their access rights to other participants. Similarly, new entrants should be able purchase rights from incumbents. This would facilitate efficient market entry and exit decisions and help to avoid the present situation whereby decisions are influenced by the annual use of system charging process. It will also be important to ensure that market signals of the value of capacity at different locations of the transmission system will emerge from some combination of the long-term allocation of rights, tenders for constraint contracts (or prices from an Access Adjustment Mechanism) and the locational targeting of the recovery of constraint costs.

- 5.26 The methodology for allocating access rights to the demand side has not been fully developed in either model. Assuming that access rights would be allocated on a GSP Group basis, it is unclear how the total rights available for the GSP Group would be allocated between suppliers. To the extent that subsequent participant-to-participant trading is facilitated, the choice of initial allocation mechanism may be of less importance. Suppliers and customers would be able to adjust their initial allocations in line with their actual requirements, subject only to an overall cap on the number of rights available for each GSP Group.
- 5.27 The models envisage that participants who wish to participate in resolving constraints (either by entering into constraint contracts or by submitting bids and offers to the Access Adjustment Market) will have to fix their physical positions in advance of Gate Closure. This runs counter to the general principle underlying NETA of allowing participants as much freedom as possible. Moreover, such systems would only work if liquid within-day trading develops so participants can adjust their contract positions in the light of adjustments to their physical positions for constraint resolution purposes. So far fully liquid within-day trading is yet to develop, but, Ofgem is supportive of efforts to remove barriers to within-day trading. Participants are also considering ways to facilitate trading close to real time. For example, a BSC modification proposal has been put forward to improve the information that participants receive with regard to their short-term contract positions.²⁷

²⁷ Currently, the last report that participants receive on their contract position is published between 18:00 and 20:00 day-ahead. Without reassurance that subsequent trades have been correctly logged by the

- 5.28 Ofgem accepts that the possibility exists for NGC's constraint resolution actions to be undone by other participants (or other units of the same participant) adjusting their positions. However, we are concerned that Model 1 could effectively re-introduce central despatch if most large generators signed constraint contracts with NGC.
- 5.29 Model 2 envisages that a general imbalance settlement regime might be required but anticipates it would be simpler than that outlined in the May Consultation. However, Ofgem's understanding is that at least part of the complexity of the system's requirements relates to the need to identify access right holdings on a locational basis. Locational identification would be required under Model 2; indeed, it might need to be performed at Gate Closure to check participants' FPNs against their access right holdings. Consequently, Ofgem is not convinced that the settlement process would be significantly simplified.
- 5.30 In Chapter 3 we explained that Ofgem believes it is important to ensure the SO can respond to market signals and adjust investment in the network away from the agreed baseline output measures when the market signals it is appropriate to do so. Neither of these models would enable this to happen because both models envisage that rights would only be allocated for a year at a time. Thus, no long-term signals would emerge to encourage the SO to undertake additional investment or defer planned investment. However, there is potential to explore allocating rights for significantly longer periods under these models, given that, at least on the generation side, rights would be allocated in accordance with Registered Capacities.
- 5.31 We believe that the recovery of constraint costs should be targeted as far as possible to those who are responsible for them. Therefore, Ofgem does not agree that the costs of constraints should continue to be charged equally over all participants based on a flat, national BSUoS tariff. Instead, we favour an approach where the costs of constraints are charged back on a locational basis.
- 5.32 Finally, we also believe a locational charge in exchange for firm access rights merits further consideration. Other locational charges, such as a possible

central systems, participants are unwilling to trade on the day since they view the risk of inadvertently incurring imbalance charges as too great. Modification Proposal P4 to the BSC entitled 'Dual Energy Contract Notification' seeks to rectify this deficiency.

locational transmission losses charge, should be considered in conjunction with a locational access charge. A process of auctioning access rights for parts of the transmission system should also be considered if constraints become more common in the future.

6. Ofgem's views on transmission losses

Overview

- 6.1 In the May consultation, we expressed the view that an enduring scheme for transmission losses should incorporate more efficient losses charging, including the use of locational loss charges. We then went on to outline two general approaches to achieve this. Option 1 was based around an adjustment of participants' metered volumes to reflect average locational loss factors and a financial levy on participants to reflect marginal losses. Option 2 was based around the use of marginal loss factors to set the reserve prices in any auction of transmission access rights.
- 6.2 Many respondents to the May consultation were opposed to the transmission losses proposals and in particular to the introduction of marginal loss factors. The main arguments put against the proposals were the potential costs of reform outweighing the possible benefits, the potential for some participants to receive windfall gains/losses and that the proposals will lead to excessive penalties being placed on participants for historic investment decisions.
- 6.3 Ofgem remains of the view that a move to locational charging for transmission losses has considerable merits and will promote customers' interests. We continue to believe that the present system of averaging transmission losses across the system leads to inefficient investment and operational decisions and gives rise to significant cross-subsidies. However, our thinking in terms of the details of how locational losses charges might be implemented has moved on since the May consultation. We now accept that there may be merit in investigating alternatives to the full marginal loss factor approach. In addition, given that we now accept that an initial allocation of transmission access rights might be preferable to auctioning them, it follows that Option 2 from the May consultation is no longer a viable proposal.

Determining transmission loss factors

- 6.4 The main development in Ofgem's thinking relates to the level of locational differentiation that is required. In the May consultation, we argued in favour of the use of full marginal transmission loss factors. However, the use of marginal

loss factors would result in an over-recovery of the cost of transmission losses (since marginal losses are approximately double average losses). These over-recovered revenues would have to be returned to participants via some route. Where possible, Ofgem would like to avoid situations of cost over-recovery as in some cases, such as the auctions for gas entry capacity, refunding these revenues cannot be achieved without producing discriminatory outcomes. In addition, several respondents to the May consultation expressed the view that a process using marginal loss factors would be overly complex and increase the risks on participants by providing unstable price signals. Because of these reasons, we now believe that it might be more appropriate to use a mechanism that does not recover more than the cost of average losses.

- 6.5 Thus, Ofgem believes that consideration should be given to implementing a variant of Option 1 from the May consultation in which average zonal loss factors are calculated by scaling back marginal loss factors so that the overall volume of losses allocated equals the average volume of losses. Appendix 2 provides a more detailed description of how a scheme based on average zonal transmission loss factors might work. Such a scheme would essentially amount to implementing the zonal scheme proposed by the Pool but in a NETA context. This scheme was thoroughly explored and debated by Pool members and proposed as the best way to reflect locational losses. The scheme was approved by a majority of Pool members but, as discussed in Chapter 2, was not implemented since it became subject to a Judicial Review on a point of process.
- 6.6 It is recognised that it will be important for participants to be able to forecast transmission losses in order to hedge effectively their exposure to energy imbalances. Therefore, we would expect that the models or methodology used to estimate transmission loss factors would be made publicly available.

Benefits of reform

- 6.7 Ofgem understands the concerns of many respondents to the May consultation over the potential costs associated with changing the transmission access and losses arrangements. However, Ofgem believes that many of the costs related to these reforms would be associated with the initial proposals for transmission access and, as outlined in Chapter 4, we have modified our views on the

appropriate form of transmission access arrangements, partly in response to these concerns. Ofgem believes that the costs of implementing locational loss charging arrangements would not be prohibitive, particularly if a scheme along the lines outlined in this chapter and Appendix 2 were to be used. NGC has estimated that the benefits of introducing locational loss signals could be of the order of £3 m per year, even before taking into account any demand-side effects. An approach based on average zonal loss factors should not require new central IT systems as the current systems have the functionality to charge according to average zonal losses. Indeed, it is not clear that there would be any significant central costs. However, we accept that participants might incur costs in adapting their trading systems to accommodate zonal loss factors.

- 6.8 Ofgem does not accept that there will be windfall losses and gains resulting from the implementation of Option 1. As set out in Chapter 2, OFFER has consistently indicated since before the Pool was introduced that it would like to see locational pricing introduced for losses. Reference was made to this objective as long ago as OFFER's 1989 Annual Report and it was mentioned in the prospectus for the privatisation of the Regional Electricity Companies in 1990 and British Energy in 1996. A chronology of public information relating to the introduction of locational pricing for losses is included as Appendix 5.
- 6.9 Investors in the electricity industry should have been fully aware of Ofgem's and OFFER's intention to introduce locational pricing for losses. Therefore, we do not accept that any alteration in the prices paid by generators and customers represents windfall gains or losses, nor that locational signals should only apply to new generation and demand (with the current arrangements being retained for existing players). Indeed, one could argue that because of the delay in reforming the pricing of transmission losses that the generators and customers who would pay more under a locational losses scheme have been receiving a windfall gain for a number of years. If locational pricing for losses is not introduced, southern generators and northern customers will continue to cross-subsidise northern generators and southern customers.

Impact on participants

6.10 Ofgem has analysed the potential impact on generators and customers of a move to a regime like that outlined above. Based on estimated loss factors and zonal generation and demand data provided by NGC, we have estimated the impact on generators and customers of moving to a loss charging system based on average zonal losses. This analysis is presented in Table 6.1 for generators and Table 6.2 for customers. Generally speaking, 'Northern' generators would be exposed to higher transmission losses than they are under current arrangements and 'Southern' generators would be exposed to lower losses. The opposite would be true for consumers, with 'Northern' customers benefiting from a better targeting of transmission losses, whilst 'Southern' consumers would be subject to higher losses.

6.11 The figures used in this analysis do not take into account the overall benefits to the system that would occur as a result of better targeting of transmission costs. Furthermore, as has already been discussed in Chapter 4, reforms to the transmission access and losses arrangements may result in significant changes to the current TNUoS charging structure. These changes could partly offset the impact on participants.

Table 6.1: Change in attributed loss volumes and estimated effect for generators

Zone	Generation (TWh)	Losses under average zonal approach (TWh)	Losses under current approach (TWh)	Change in loss volumes (TWh)	Estimated effect of change in loss volume @ 20 £/MWh (£ million)
North	31.998	0.775	0.266	0.509	10.182
Humberside	67.274	1.043	0.560	0.483	9.655
N Yorks & N Lancs	20.999	0.338	0.175	0.163	3.255
S Yorks & S Lancs	38.074	0.300	0.317	-0.017	-0.333
North Wales	2.137	0.017	0.018	0.000	-0.007
West Midlands	17.155	-0.041	0.143	-0.184	-3.672
Rest of Mids & Anglia	26.265	0.172	0.219	-0.047	-0.938
South Wales	12.580	-0.138	0.105	-0.243	-4.864
Wiltshire	5.721	-0.047	0.048	-0.095	-1.894
Greater	23.362	-0.057	0.194	-0.251	-5.025

London					
Estuary	36.711	0.154	0.306	-0.152	-3.040
Inner London	0.002	0.000	0.000	0.000	-0.001
South Coast	1.137	-0.007	0.009	-0.016	-0.322
Wessex	8.507	-0.079	0.071	-0.149	-2.987
Peninsula	0.014	0.000	0.000	0.000	-0.010

Table 6.2: Change in attributed loss volume and estimated effect for demand

Zone	Demand (TWh)	Losses under average zonal approach (TWh)	Losses under current approach (TWh)	Change in loss volumes (TWh)	Estimated effect of change in loss volume @ 20 £/MWh (£ million)
Northern	16.479	-0.205	0.171	-0.376	-7.514
Norweb	25.311	0.057	0.262	-0.206	-4.114
Yorkshire	29.374	0.040	0.305	-0.264	-5.284
Manweb	24.455	0.131	0.254	-0.122	-2.442
East Midlands	26.609	0.309	0.276	0.033	0.658
Midlands	33.607	0.619	0.348	0.271	5.417
Eastern	33.691	0.287	0.349	-0.062	-1.245
Swalec	13.065	0.298	0.135	0.163	3.251
Seeboard	20.740	0.269	0.215	0.054	1.072
London	24.126	0.366	0.250	0.116	2.311
Southern	29.007	0.555	0.301	0.254	5.089
South Western	10.074	0.244	0.104	0.140	2.801

6.12 Appendix 2 provides more details of the analysis we have conducted to estimate the impact on participants.

Summary

6.13 Ofgem continues to believe that the introduction of locational charging for transmission losses has considerable merits and will promote the interests of customers. However, we accept that the use of full marginal transmission loss factors may increase the risks on participants and would result in an over-recovery of the cost of transmission losses, the return of which could result in a distortion to locational signals. It is our view that an approach based on average zonal losses would help to address these concerns.

6.14 Over-recoveries would be avoided under the average zonal losses approach as, by definition, the loss factors used would be adjusted so that the volume of

losses allocated to participants equals the overall losses (these overall losses could either be pre-set or equal the actual losses incurred in each trading period). Average zonal losses could also address participants' concerns over the uncertainty caused by locational loss factors. In addition to being less volatile than true marginal prices, under the approach outlined in Appendix 2, it may be possible to set loss factors, or at a least reasonable estimates of them, sufficiently far in advance of Gate Closure to give participants some certainty over their exposure to transmission losses.

- 6.15 It is Ofgem's view, therefore, that there would be considerable merit to implementing a locational losses scheme based on the average zonal losses approach.

7. Process and next steps

Introduction

- 7.1 Ofgem believes that the various consultations, seminars and workshops on the issues of transmission access and losses have initiated a process of debate and consideration. This has allowed all interested parties to become familiar with the principles likely to be involved and to develop an appreciation of possible approaches that would satisfy these principles. Accordingly, we believe that the next step in the process of reforming the current transmission access and losses arrangements should be for modifications to the BSC and amendments to the CUSC and NGC's Use of System Charging Methodology to be proposed that would lead to the introduction of revised arrangements.
- 7.2 After the various proposals have completed their respective consultation processes, they will be presented to the Authority for decision. The Authority will be required to reach a decision on whether they will, or can be expected to, better facilitate achievement of the relevant objectives. The relevant objectives for BSC modifications, CUSC amendments and changes to NGC's charging methodology are set out in Appendix 1.
- 7.3 If the Authority decides that the modifications and amendments in respect of changes to transmission access and losses can be expected to better facilitate achievement of the relevant objectives (as appropriate), it will direct NGC to implement the modifications/amendments.

BSC changes

Transmission access

- 7.4 Ofgem envisages that changes to the transmission access regime would primarily be implemented by amendments to the CUSC and NGC's transmission licence and Use of System Charging Methodology Statement. However, depending on the regime proposed, it is possible that new variables and new data flows (from central settlement to NGC) might be required in order for access imbalance settlement calculations to be performed. Any party to the BSC, including NGC and energywatch, can propose modifications to the BSC.

Transmission losses

- 7.5 The BSC is drafted on the basis that the adjustment to participants' metered volumes – their Transmission Loss Multiplier (TLM) – is the sum of two terms: a Transmission Losses Adjustment (TLMO) and a Transmission Loss Factor (TLF). Section T2 of the BSC defines both the TLM and the TLMO. Currently, separate TLMO's are calculated for generation and demand for each settlement period but they are not Balancing Mechanism Unit specific. They are defined to provide the current 45:55 split of actual losses. The TLFs are, in principle, defined by Balancing Mechanism Unit and by settlement period. TLFs were included to allow for the introduction of zonal loss factors but they are currently set to zero.
- 7.6 An approach based on a zonal losses adjustment to metered volumes would require a BSC modification to define non-zero TLF's. It would also be necessary to set the TLMO's to zero if the BSC losses adjustment were to be solely based on zonal loss factors set in advance. Changes to the central systems might be required to provide the data flows necessary to accommodate zonal TLFs and, if required, to provide TLMOs that provide appropriate scaling.

CUSC changes

Transmission access

- 7.7 New arrangements for transmission access could be implemented via an amendment proposal to the CUSC. Any BSC Party, CUSC Party or NGC can raise an amendment proposal to the CUSC.
- 7.8 Once an amendment proposal to the CUSC has been raised the proposal will go through the normal consultation process. Alternative amendment proposals may be raised during this consultation process. The CUSC Amendment Panel could also draw up terms of reference for a Standing Group to consider further the reform of the transmission access arrangements.

Transmission losses

- 7.9 It is envisaged that changes to the transmission losses arrangements will mainly require changes to the BSC.

Changes to NGC's licence

- 7.10 Changes to the BSC or CUSC may require changes to NGC's transmission licence. Changes to NGC's transmission licence can be made by the Secretary of State and the Authority.
- 7.11 A BSC modification on transmission losses would have to specify how the TLM's should be calculated. Their calculation would depend on a series of load flow analyses. If NGC were to carry out these calculations, a change to its transmission licence may be necessary.
- 7.12 Just as NGC is required by its transmission licence to publish a statement regarding its methodology for calculating the Balancing Services Adjustment Data, it would seem appropriate for it to be obliged under its licence to publish a statement describing the methodology that it would adopt if NGC were to be responsible for calculating the zonal TLM's. It is for consideration whether these calculations should also be subject to an independent audit.

Other changes

- 7.13 It is likely that both TNUoS and BSUoS charges will change if new transmission access and losses arrangements are introduced. This would involve changes to NGC's Use of System Charging Methodology Statement and hence NGC would have to go out to consultation, including via the Transmission Charging Methodologies Forum, on these changes, which would be subject to approval by the Authority.

Summary

- 7.14 Ofgem has set out, at a high level, our current preferences for new access and losses arrangements to facilitate discussions that will begin, including under the new CUSC governance arrangements. These discussions will allow all

interested parties to make representations and shape the proposals and Ofgem expects that detailed discussions will begin immediately.

Appendix 1 Regulatory and legal framework

The legal framework

The Electricity Act 1989 and the Utilities Act 2000

- 1.1 The Electricity Act 1989 (as amended by the Utilities Act) provides the framework for the functions of the Gas and Electricity Markets Authority ('the Authority'), and for the licensing to enable the generation, transmission, supply and distribution of electricity.
- 1.2 The Utilities Act 2000 (the Utilities Act), which received Royal Assent on 28 July 2000, inserted a section into the Electricity Act 1989, which allows the Secretary 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.
- 1.3 The Utilities Act introduced other reforms to the gas and electricity markets and the regulation of these markets including:
 - ◆ the transfer of the functions of the Director General of Electricity Supply and the Director General of Gas Supply to the Authority²⁸ which took place on 20 December 2000;
 - ◆ the introduction of a new principal objective on the Authority in carrying out its functions '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;

²⁸ The Authority determines strategy and decides on major policy issues. It is made up of non-executive and executive members.

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

The electricity transmission licence

- 1.4 Under section 9(2) of the Electricity Act 1989, holders of transmission licences are 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.
- 1.5 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 distributors' local distribution networks and to customers connected directly to the transmission system. It has an obligation under its licence not to discriminate in its terms for using the transmission system and the interconnectors with Scotland and France or for carrying out works to connect participants to the transmission system. In addition, special condition AA5A of NGC's licence sets restrictions on the revenues that NGC is allowed to earn.
- 1.6 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 (special condition AA4(1));
 - ◆ publish a statement in a form approved by the Authority, setting out the basis upon which charges for connection (supplementary standard

condition C7B(4)) and use of system (supplementary standard condition C7(2)) will be made²⁹;

- ◆ maintain the security and quality of electricity supplies (special condition AA2);
- ◆ offer terms for connection and use of system (supplementary standard condition C7D);
- ◆ to operate the system within prescribed frequency and voltage limits³⁰ (special condition AA2 and the Grid Code); and
- ◆ implement and comply with a Grid Code (standard condition 7(1), which sets out the detailed technical aspects of connection to and the operation and use of the licensee's transmission system.

1.7 NGC has also been made responsible for having in place and maintaining a Balancing and Settlement Code (supplementary standard condition C3) and for preparing, complying with, and operating the amendment procedures of the Connection and Use of System Code (supplementary standard condition C7F).

1.8 In relation to its use of system charging methodology, NGC can only modify it if it better achieving the relevant objectives, which are that compliance with the use of system charging methodology:

- ◆ facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
- ◆ results in charges which reflect, as far as is reasonably practicable, the costs incurred by the licensee in its transmission business; and
- ◆ so far as is consistent with the previous objectives and as far as is reasonably practicable, properly takes account of the developments in the licensee's transmission business.

²⁹ Section 2.14.1 and 3.9.1 of the CUSC as well as supplementary standard condition C7B(6) and supplementary standard condition C7B(7) of the Electricity Transmission Licence places an obligation on NGC to charge in accordance with these statements.

³⁰ These limits are defined and prescribed in the Electricity Supply Regulations 1988.

Industry codes

The Balancing and Settlement Code

- 1.9 The BSC's scope is defined in general terms in the transmission, generation and supply licences. As discussed above, the BSC is maintained by NGC. The BSC 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.
- 1.10 A BSC 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).³¹ 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.
- 1.11 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. Modifications to the BSC can only be made at the direction of the Authority following receipt of a report after the modification procedures have been completed. The Authority will direct the modification to be implemented if it better facilitates achieving the applicable BSC objectives, which are:

³¹ The BSCCo was named Elexon Limited on 7 June 2000.

- ◆ the efficient discharge by NGC of the obligations imposed upon it by its transmission licence;
- ◆ the efficient, economic and co-ordinated operation by NGC of its transmission system;
- ◆ promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity; and
- ◆ promoting efficiency in the implementation and administration of the balancing and settlement arrangements.

1.12 In reaching its decision, the Authority must comply with the principal objective and its other duties under sections 3A-C of the Electricity Act 1989.

1.13 Any decision by the Authority to modify the BSC, following the completion of the BSC Modification Procedures, takes the form of a direction to NGC to make a modification. Under supplementary standard condition C3(5)(b) of its transmission licence, NGC must modify the BSC upon receipt of a direction to do so from the Authority.

1.14 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.

1.15 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. Before taking this step, the Authority must have given notice to the Panel and/or Elexon to comply with the BSC Modification Procedures within a specified time period and they must 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).

- 1.16 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. The Authority can exercise this power if 'there is a substantial disruption to the implementation and/or operation' of NETA or that 'urgent action is necessary to prevent such disruption'.

Connection and Use of System Code

- 1.17 Following extensive consultation with the industry and other interested parties over the last year, the Secretary of State exercised the powers granted to her under the Utilities Act to implement the Connection and Use of System Code (CUSC) on 18 September 2001.
- 1.18 The CUSC is the contractual framework governing connection to and use of NGC's system. It sets out terms and conditions for connection to, and use of, the transmission system, the provision of mandatory balancing services by connected parties and the rules for commercial balancing services. These terms and conditions include: payment methods; metering; modifications to a connection site; amendment procedures; and dispute resolution. It also introduces more flexible governance arrangements than under the previous contractual framework, the Master Connection and Use of System Code Agreement (MCUSA).
- 1.19 The new, more flexible governance arrangements are designed to enable arrangements for connection to and use of NGC's transmission system to develop over time in the light of experience of operating under NETA. For example, the governance procedures would allow new transmission access arrangements to be introduced.
- 1.20 A separate Bilateral Agreement is in place between NGC and each party connected to and/or using the transmission network other than suppliers,

interconnector users and Interconnector Error Administrators.³² These agreements contain the site-specific terms for connection to or use of NGC's system. In addition, there are Mandatory Services Agreements between NGC and each generator that is required to provide mandatory ancillary services under the Grid Code, and Construction Agreements covering the site specific assets required to connect participants to the grid. The agreements also include some of the charging rules for both connection to and use of the transmission system and the provisions whereby NGC can revise its charges.

- 1.21 The governance arrangements for the CUSC are similar in many respects to those for the BSC and Transco's Network Code. An Amendments Panel, chaired by an NGC appointed representative, considers all amendment proposals. The Panel, in addition to the Chairman, consists of 2 NGC representatives, 7 members appointed by the industry and an energywatch representative. The Authority has power to appoint one additional member to represent the interests of any class whose interests are not reflected in the Panel membership. The Chairman and industry elected Panel members are required to act independently.
- 1.22 Amendments can be put forward by any CUSC party, a BSC party and energywatch. NGC is responsible for appointing a Panel secretary to undertake the administration of the Amendments Panel and the amendments procedures. Amendments to the CUSC can only be made at the direction of the Authority following receipt of a report after the amendment procedures have been completed. The amendment will only be approved if it better facilitates achieving the applicable CUSC objectives, which are:
- ◆ the efficient discharge by NGC of the obligations imposed upon it under the Electricity Act (as modified by the Utilities Act) and its Transmission Licence (supplementary standard condition C7F(1)(a)); and
 - ◆ facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity (supplementary standard condition C7F(1)(b)).

³² The terms and conditions for these categories of transmission network user are covered in the CUSC itself.

1.23 In reaching its decision, the Authority must comply with the principal objective and its other duties under sections 3A-C of the Electricity Act 1989.

Parties directly connected to the transmission system and embedded generators have Bilateral Agreements.

Appendix 2 A scaled marginal loss approach

Outline

- 2.1 In Chapter 6, we indicated that there may be merit in investigating a loss charging approach based on scaling back marginal loss factors to reflect the overall volume of transmission losses. This appendix explains how such an approach might work in practice and gives an indication of the effect that average zonal loss factors could have on participants.
- 2.2 A scaled marginal loss approach would require the ex-ante estimation of Transmission Loss Factors (TLFs). This could be achieved, as under the Pool scheme, by taking snapshots of demand and generation spot values for all nodes throughout a year to obtain representative values for the flows on the system at different times of the day and the year (the Pool proposed to use 624 snapshots). These snapshots would be included in NGC's load flow model, which would then be run so that an increment in demand at one node is met by a suitable increase in generation spread across all nodes. The process would be repeated for each node so that the load flow model produces nodal marginal TLFs for each snapshot.
- 2.3 The snapshot nodal TLFs (equal and opposite for generation and demand) would need to be scaled back so that the total volume of estimated losses equals the actual losses for the snapshot period. To ensure that generation and demand losses at the same node remain equal and opposite, whilst the 45:55 split of losses between generation and demand is maintained, would require both a scaling factor (α) and an offset (β) so that the Adjusted Transmission Loss Factors (ATLFs) would be given by:
$$\text{ATLF} = \alpha\text{TLF} + \beta$$
- 2.4 These ATLFs would be averaged (weighted by demand) to produce zonal ATLFs and these, in turn, would be averaged across the snapshots to produce annual zonal ATLFs.
- 2.5 Since the adjustment to average zonal losses is done on the basis of historic losses data and patterns of generation and demand, there is no guarantee that

when the ATLFs are used they will generate loss volumes equal to the actual losses on the system in any half-hour. It is for consideration, therefore, whether any further adjustment should be made to 'true-up' losses in each half-hour by the use of additional balancing factors. For example, the Pool scheme used separate generation and demand balancing factors to ensure that the volume of losses to which participants overall were exposed equalled actual losses in each half-hour. Alternatively, any differences between actual losses and those calculated from ATLFs could be charged across participants at an administered price on the basis of their metered volumes.

- 2.6 The final ATLFs would be applied to participants' metered volumes to alter the physical positions against which they are cashed-out. The functionality for including zonal loss factors is already included in the BSC and central systems. Thus, the cost or remuneration for losses will depend on how participants choose to contract ahead to anticipate and cover their share of losses. Depending on their choices, participants with the same ATLFs might have to pay for their losses at the System Buy Price, be paid at the System Sell Price or have no exposure.

Analysis of its impact

- 2.7 Ofgem has analysed the potential impact on generators and customers of a move to a regime like that outlined above. We asked NGC to calculate what this year's scaled marginal loss factors would be and it calculated these on the basis of actual generation volumes in 2000/01 and forecast demand volumes for 2001/02. The method that NGC adopted was slightly different to that outlined above in that it calculated zonal marginal loss factors³³ (by TNUoS zones for generators and by GSP Group for customers) on the basis of 'variable' losses i.e. those caused by the pattern of electricity flows, halved these values to provide zonal average loss factors and then applied separate offsets³⁴ to the demand and generation factors to scale them to account both for fixed losses e.g. corona losses, and to preserve the 45/55 split of losses between generation and demand. The resulting loss factors are shown in Table A2.1.

³³ The zonal loss factors were calculated by averaging the nodal loss factors in each zone.

³⁴ The offsets were 0.55% for generation losses and 0.40% for demand losses.

Table A2.1: NGC's estimates of average loss factors for 2000/01

Generation loss factors		Demand loss factors	
TNUoS zone	Average Loss Factor	GSP Group	Average Loss Factor
North	2.4%	Northern	-1.2%
Humberside	1.6%	Norweb	0.2%
N Yorks & N Lancs	1.6%	Yorkshire	0.1%
S Yorks & S Lancs	0.8%	Manweb	0.5%
North Wales	0.8%	East Midlands	1.2%
West Midlands	-0.2%	Midlands	1.8%
Rest of Mids & Anglia	0.7%	Eastern	0.9%
South Wales	-1.1%	Swalec	2.3%
Wiltshire	-0.8%	Seeboard	1.3%
Greater London	-0.2%	London	1.5%
Estuary	0.4%	Southern	1.9%
Inner London	-0.5%	South Western	2.4%
South Coast	-0.6%		
Wessex	-0.9%		
Peninsula	-2.6%		

2.8 On the basis of the loss factors and the generation and demand data by zone provided by NGC, we have estimated the impact on the costs of generators and customers of moving to the average zonal losses approach. This analysis is presented in Table A2.2 for generators and Table A2.3 for customers.

Table A2.2: Change in attributed loss volume and estimated effect for generators

Zone	Generation (TWh)	Losses under average zonal approach (TWh)	Losses under current approach (TWh)	Change in loss volumes (TWh)	Estimated effect of change in loss volume @ 20 £/MWh (£ million)
North	31.998	0.775	0.266	0.509	10.182
Humberside	67.274	1.043	0.560	0.483	9.655
N Yorks & N Lancs	20.999	0.338	0.175	0.163	3.255
S Yorks & S Lancs	38.074	0.300	0.317	-0.017	-0.333
North Wales	2.137	0.017	0.018	0.000	-0.007
West Midlands	17.155	-0.041	0.143	-0.184	-3.672
Rest of Mids & Anglia	26.265	0.172	0.219	-0.047	-0.938
South Wales	12.580	-0.138	0.105	-0.243	-4.864
Wiltshire	5.721	-0.047	0.048	-0.095	-1.894

Greater London	23.362	-0.057	0.194	-0.251	-5.025
Estuary	36.711	0.154	0.306	-0.152	-3.040
Inner London	0.002	0.000	0.000	0.000	-0.001
South Coast	1.137	-0.007	0.009	-0.016	-0.322
Wessex	8.507	-0.079	0.071	-0.149	-2.987
Peninsula	0.014	0.000	0.000	0.000	-0.010

Table A2.3: Change in attributed loss volume and estimated effect for demand

Zone	Demand (TWh)	Losses under average zonal approach (TWh)	Losses under current approach (TWh)	Change in loss volumes (TWh)	Estimated effect of change in loss volume @ 20 £/MWh (£ million)
Northern	16.479	-0.205	0.171	-0.376	-7.514
Norweb	25.311	0.057	0.262	-0.206	-4.114
Yorkshire	29.374	0.040	0.305	-0.264	-5.284
Manweb	24.455	0.131	0.254	-0.122	-2.442
E. Midlands	26.609	0.309	0.276	0.033	0.658
Midlands	33.607	0.619	0.348	0.271	5.417
Eastern	33.691	0.287	0.349	-0.062	-1.245
Swalec	13.065	0.298	0.135	0.163	3.251
Seeboard	20.740	0.269	0.215	0.054	1.072
London	24.126	0.366	0.250	0.116	2.311
Southern	29.007	0.555	0.301	0.254	5.089
South Western	10.074	0.244	0.104	0.140	2.801

2.9 It is likely that the main direct impact of changes to transmission losses charges will be felt by generators and larger electricity users, for whom such signals are important. There will, however, be a direct impact on domestic customers but this is likely to be relatively small. Ofgem estimates that the average impact on domestic customers would be a small increase or decrease (depending on location) in their electricity bill of approximately 0.5%. This could represent a change of up to £1.50 per annum for some customers.

Appendix 3 List of non-confidential responses to the May consultation

3.1 Ofgem received 54 non-confidential respondents to the May consultation document. Copies of these responses can be obtained from Ofgem's library. The non-confidential respondents were:

- ◆ Accord Energy
- ◆ Accordis Acetate Chemicals
- ◆ AES Drax Power
- ◆ AES Indian Queens Power
- ◆ Association of Electricity Producers
- ◆ Automated Power Exchange
- ◆ BNFL Magnox
- ◆ BOC
- ◆ BP Gas Marketing
- ◆ British Energy
- ◆ British Gas Trading
- ◆ Castle Cement
- ◆ Chemical Industries Association
- ◆ Cornwall Consulting
- ◆ Corus
- ◆ Derwent Cogeneration
- ◆ Eastern Shires Purchasing Organisation

- ◆ EdF Trading
- ◆ Edision Mission Energy
- ◆ Electricity Association
- ◆ Energy Intensive Users Group
- ◆ energywatch
- ◆ Enron Europe
- ◆ Entergy
- ◆ GS Marketing
- ◆ Headland Foods
- ◆ Humber Power
- ◆ Innogy
- ◆ Karsten Neuhoff (University of Cambridge)
- ◆ London Electricity
- ◆ Major Energy Users Council
- ◆ MH Gammie and Associates
- ◆ National Association of Licensed Opencast Operators
- ◆ National Grid Company
- ◆ Northern Electric and Gas Limited
- ◆ Northern Electric - Distribution
- ◆ Northern Electric Generation
- ◆ NRG Energy

- ◆ Powergen
- ◆ Richard Green (University of Hull)
- ◆ RMC Group
- ◆ Scottish and Southern Energy
- ◆ Scottish Power
- ◆ Seeboard
- ◆ SELCHP
- ◆ South Coast Power (Shoreham)
- ◆ South West of England Regional Development Agency
- ◆ Teesside Power
- ◆ Transco
- ◆ TXU Europe
- ◆ UK Coal Mining
- ◆ United Utilities
- ◆ UPM (Shotton Paper)
- ◆ Wisenergy

Appendix 4 Respondents' views

- 4.1 This appendix summarises respondents' views on the May consultation. Fifty-four non-confidential responses were received. A list of the respondents is given in Appendix 3.
- 4.2 This appendix is organised into four main sections:
- ◆ the need for reform;
 - ◆ transmission access;
 - ◆ transmission losses; and
 - ◆ further issues raised by respondents.

The need for reform

NGC's view

- 4.3 NGC acknowledged that transmission effects and actions could distort the operation of NETA markets. The current arrangements may not be sufficient to ensure independence of electricity imbalance prices from Balancing Mechanism costs incurred to relieve constraints. This may have implications for the forward energy price and lead to some participants favouring or avoiding certain NETA markets due to locational effects. Although there have been few constraints to date, NGC considered that developments aimed at relieving constraints outside the Balancing Mechanism merit consideration.
- 4.4 NGC agreed that current transmission charges and other market arrangements do not reflect the short-term effect that the location of market participants has on the level of transmission losses and constraints. NGC also recognised that there is scope for improving signals to encourage efficient use of the transmission network. NGC estimated that the potential reduction in total annual losses from generators responding to more efficient signals could be around 3%, or £3 m per annum³⁵.

³⁵ Assuming a total volume of losses of 5 TWh at an average cost of £20/MWh.

- 4.5 NGC's view was that the current arrangements deliver adequate investment signals. Developments relevant to the transmission network, such as construction of new power stations, are directly observable. Due to the construction lead-times of power stations, the robustness of planning data is less of a concern than in gas.
- 4.6 Any constraint costs that arise from inefficient investments would result in increased costs to NGC under its SO incentive scheme. NGC did not believe that introducing a linkage between capacity auction prices and the financing of new investments would improve its investment incentives. In fact, it considered that this might result in perverse incentives. For example, NGC suggested that the expectation of high auction prices could encourage it to defer investment.
- 4.7 NGC agreed that consistent network prices over relevant investment and operational time scales are required to ensure the efficient use and development of both the gas and electricity transmission networks. However, it did not believe that it was necessary or desirable to use identical market arrangements for the gas and electricity markets.

Respondents' views

- 4.8 Thirty-four respondents to the May consultation commented on the need for reform because of NETA related effects. Eight respondents agreed with Ofgem's views but eight respondents did not agree that there was scope for improvement on current NETA arrangements. Three of the disagreeing respondents argued that it is not possible to separate energy and transmission prices, and attempting to do so may lead to illiquid markets. Eighteen respondents accepted that there might be a need for limited reform but suggested that more time should be allowed to assess the impact of the introduction of NETA before further changes are introduced. There was general concern that the costs of implementing the reforms would outweigh any benefits.
- 4.9 Eighteen respondents commented on the issue of short and long-term efficiency. Five respondents thought that these issues are dealt with adequately under the current arrangements whilst thirteen respondents agreed with Ofgem's view that there is scope for improving the economic signals to users of the transmission network. Of these, two respondents thought that other factors, such as planning

standards and safety issues, should take precedence over economic locational signals.

- 4.10 Eight respondents supported the need for reform of NGC's investment signals whilst six opposed it. However, all fourteen respondents expressed concerns over the notion of removing planning standards from NGC's investment decision process. Three respondents were concerned that the proposals in the May consultation would result in NGC only being exposed to short-term investment signals since it would be inappropriate for NGC to base long-term investment decisions solely on short-term signals.
- 4.11 Twenty-six respondents to the May consultation commented on the issue of interactions between the gas and electricity markets. Twenty respondents thought it unnecessary to introduce similar arrangements for the two markets, five respondents thought that arrangements in the two markets needed to be aligned and one respondent offered comments but proffered no opinion.
- 4.12 The majority of respondents argued that the gas and electricity markets are inherently different and therefore should not necessarily have similar arrangements in place. A number of respondents also indicated that they did not believe that the reforms in the gas sector had been successful. In particular, they argued that the introduction of entry capacity auctions had increased prices. These respondents were concerned that the same problems as those experienced in the gas market would occur in the electricity market if similar arrangements were put in place.

Transmission access

Overview

- 4.13 The majority of respondents were not convinced that Ofgem had put forward a convincing case for the need for reform of the current transmission access arrangements. In particular, they were concerned that the considerable extra complexity and cost of introducing a fully tradable access right regime, including an access imbalance settlement mechanism, would not be justified by the benefits that would arise. Even those respondents who were in favour of reform

suggested that simpler mechanisms might deliver most of the potential benefits at a significantly reduced cost.

- 4.14 Two respondents put forward alternative proposals to the 'possible approach' described in the May consultation. These alternatives are described in some detail in Chapter 5.

Specific issues

- 4.15 The May consultation sought views on a wide range of specific issues related to the reform of the transmission access arrangements under NETA. The most important specific issues were:

- ◆ the definition of transmission access rights and their locational resolution;
- ◆ the primary allocation mechanism for access rights;
- ◆ the secondary trading of access rights;
- ◆ transmission access and imbalance settlement;
- ◆ interaction with the transmission price control; and
- ◆ systems requirements.

- 4.16 Respondents' views on these issues are presented in turn below.

Definition of transmission access rights and their locational resolution

- 4.17 In the May consultation, Ofgem suggested that transmission access rights could be defined as:

- ◆ the right to flow power over particular constrained boundaries, labelled 'flowgates'; or
- ◆ a right of entry to or exit from the network at a particular location (Ofgem's preference).

- 4.18 Ofgem's initial view was 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, we accepted that this conflicts with the requirement of capturing the majority of expected transmission constraints through the trading of access rights.³⁶ Ofgem invited views on whether a zonal framework would be appropriate or if some form of nodal definition of rights, along with other mechanisms to facilitate trading, should be employed.

- 4.19 Ofgem also expressed the view that if entry rights are to be based on a few large zones, then exit rights should be based on the same geographical definition. However, if entry rights were based on a large number of zones (or nodes), it might be advantageous to use an asymmetric definition of entry and exit rights with exit rights based on GSP Groups.

NGC's view

- 4.20 NGC agreed with Ofgem's view that the entry/exit type of rights would be a more practical choice for NGC's highly integrated system. It recognised, however, that flowgates would have the advantage of providing information on the effectiveness of each location in resolving a constraint but considered that flowgates also would be unduly complex for participants.
- 4.21 NGC concurred that there are trade-offs between the effectiveness of constraint resolution and liquidity and competitiveness in secondary trading of access rights. However, NGC did not offer an opinion on whether the new arrangements should prioritise constraint resolution or liquidity in secondary trading.
- 4.22 NGC agreed that an asymmetrical spatial approach to entry and exit zones might be advantageous. This approach would allow demand-side participation without unduly compromising the effectiveness of the regime for constraint resolution. However, NGC pointed out that the asymmetrical approach would necessitate more SO facilitation and noted that it would be important to ensure that no significant inefficient arbitrage opportunities for participants are created by an asymmetric spatial definition.

³⁶ 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 close to 100% constraint capture.

Respondents' views

- 4.23 Seventeen respondents to the May consultation commented on the definition of access rights and their locational resolution. Of these, eleven agreed that entry and exit rights were preferable to flowgates and only one argued for the use of flowgates. Five respondents commented on the issue without expressing an opinion.
- 4.24 Eight respondents favoured a zonal solution to a nodal one. Four respondents stated that thirty-one zones would lead to illiquid secondary markets in transmission access rights. One respondent preferred a nodal regime arguing that the ability to resolve constraints should take priority. A further eight respondents commented on the issue without expressing a firm opinion.
- 4.25 On the issue of whether entry and exit zones needed to be identical, five respondents favoured identical entry and exit zones. They argued this would ensure efficient arbitrage in the marketplace. Four respondents did not believe zones need to be identical.

Primary allocation mechanism for transmission access rights

- 4.26 Ofgem's view in the May consultation was that auctioning transmission access rights would be an efficient and non-discriminatory form of primary allocation. Three allocation options were outlined:
- ◆ auction both entry and exit rights followed by secondary trading so that participants and the SO can fine-tune their positions. There would also need to be an access imbalance regime to incentivise participants to match their physical positions to their access rights holdings;
 - ◆ employ a simple allocation of firm access rights to all participants in exchange for an access charge (which might be locational). Trading of these rights in secondary markets would provide market-based locational signals. It would also provide the SO with a tool to resolve transmission constraints; or
 - ◆ auction entry rights but allocate exit rights. This was the option included in the 'possible approach'.

NGC's view

- 4.27 NGC favoured a simple approach to allocating transmission rights. Firm access rights should be allocated to participants, for which they would pay an access charge. If no additional locational signals are given to participants, the access charge could be made locational, otherwise it could be a flat postage stamp charge.
- 4.28 If auctions were to be used to allocate rights, NGC argued that a simultaneous clearing approach should be adopted, based on realistic estimates of the transmission network's capacity. It would then be possible to take into account the close relationship between the volume of rights allocated at an individual node (or zone) and the rights available to be allocated at all other locations.

Respondents' views

- 4.29 Five respondents agreed with Ofgem's initial view that auctions would be a fair mechanism to use for allocating access rights whilst eighteen respondents were opposed to auctions as the primary allocation mechanism. One respondent commented on the issue without stating an opinion.
- 4.30 A minority of those opposed to auctions (four respondents) argued that auctions are arbitrary and can lead to windfall gains and losses as well as over-recovery of the costs associated with the transmission network. Any over-recovered costs would be difficult to redistribute fairly. A further eight respondents believed that auctions would be an unnecessarily complex allocation mechanism.

Secondary trading of access rights

- 4.31 In the May consultation, Ofgem emphasised the need for secondary trading and stated a preference for secondary markets to develop in response to the needs of market participants rather than being centrally organised. Ofgem also recognised that, depending on other choices made in relation to the design of the regime³⁷, secondary trading might need to be facilitated by the SO.

³⁷ For example, SO facilitation is likely to be required if entry and exit zones are different or if the number of zones created is very large.

4.32 Ofgem suggested that interruptible rights could be used to implement 'use it or lose it' provisions and thus prevent the hoarding³⁸ of access rights. We also considered that it may be worth considering auction/tender processes that allow the SO to buy options to interrupt demand or generation and sell options to constrain-on generation and demand. These option contracts could, for example, be exercised on a specified number of occasions or during specified periods.

NGC's view

4.33 NGC agreed that SO facilitation of trading in entry and exit rights would be necessary for trading between different zones or nodes, especially if rights were to be defined for a large number of zones or for nodes. It also commented that SO facilitation of trading between demand and generation would be needed if different spatial definitions were used for entry and exit rights.

4.34 NGC did not believe that interruptible products would be necessary if the access imbalance regime was designed effectively. If, in the light of experience, interruptible rights or other products would be a useful additional tool, then these would naturally emerge through the market arrangements.

Respondents' views

4.35 Nine respondents thought it likely that secondary markets would develop whilst four thought it unlikely. A further two commented on the issue without stating a firm opinion.

4.36 Eight respondents were in favour of some sort of facilitation of participants' secondary trading, two were firmly against and a further two offered comments but no opinion. Five respondents urged that it would be more appropriate to have an independent facilitator of secondary trading rather than the SO. One respondent considered that it would be important to develop proper incentives for NGC's trading role if NGC were to facilitate the trading process. Ten respondents were in favour of the SO releasing non-firm products such as interruptible rights. No respondent argued against non-firm products.

³⁸ Whether hoarding is likely to occur will depend on other aspects of the regime, notably the access imbalance settlement arrangements.

Transmission access imbalance and settlement

- 4.37 Ofgem's initial view was that an access imbalance settlement regime would be required, for example to incentivise participants not to generate or consume in excess of their access right holdings. Our initial preference was for a one-sided cash-out regime so that participants either face an over-run charge or an under-run charge but not both. We also considered that the netting off of entry and exit imbalances should not be allowed. This could unduly discriminate in favour of vertically integrated participants.
- 4.38 Ofgem argued that access imbalance prices should be related to the costs incurred by the SO in resolving transmission constraints as reflected in the prices emerging from its secondary trading. Furthermore, imbalance prices should be locationally differentiated to provide appropriate locational signals to participants.

NGC's view

- 4.39 NGC agreed with Ofgem that an access imbalance and settlement system would be necessary under the 'proposed approach'. This would ensure that participants have an effective incentive to align their physical position with the access rights they hold. It also agreed that imbalance prices should be locational and based on the SO's costs incurred in resolving constraints. NGC believed that the imbalance charges should reflect all the costs of relieving constraints and hence cover costs relating to primary trading of access rights and Balancing Mechanism costs as well as secondary trading costs.

Respondents' views

- 4.40 Nine respondents believed that there would be a need for some form of settlement regime. One respondent provided comments but no opinion. Another respondent argued that there would be no need for an access and imbalance settlement regime if a less complex system based on access charges and constraint options were to be adopted.
- 4.41 On whether the imbalance regime should be one-sided or two-sided, four respondents believed that it should be one-sided and one respondent thought that it should be two-sided. The respondent in favour of a two-sided approach

argued that a one-sided regime might lead to distortions in bids and offers into the Balancing Mechanism and possibly to distortions in energy prices.

- 4.42 Only four respondents expressed views on whether entry and exit imbalance volumes should be netted off. Of these, three believed that it should not be allowed. The respondent in favour argued it would assist smaller participants.
- 4.43 One respondent suggested that imbalances should be settled at an administered price whilst one agreed with Ofgem that imbalance prices should be linked to prices in the secondary market. Four respondents supported locational imbalance prices. Two of these argued that GSP Groups could be used to define the charging areas on the demand side.

Interactions with NETA

- 4.44 The May consultation acknowledged that the treatment of access rights in the Balancing Mechanism will have significant implications for imbalance prices. Ofgem considered that allocating access rights to participants whose bids and offers are accepted in the Balancing Mechanism could have merits. This approach avoids participants or NGC purchasing rights they may not require. However, this could also be achieved by allowing the trading of access rights to continue after gate closure.

NGC's view

- 4.45 NGC's concern is to ensure that the Balancing Mechanism remains operable and effective. It was of the opinion that automatic granting of the necessary access rights for accepted Balancing Mechanism bids and offers would be the most pragmatic solution.

Respondents' views

- 4.46 Twelve respondents argued that the SO should be responsible for obtaining access rights to cover acceptances in the Balancing Mechanism whilst five respondents believed that this should be the responsibility of participants. A further two respondents commented on the issue without expressing an opinion.

4.47 Respondents who were in favour of participants being responsible for acquiring access rights for their Balancing Mechanism bids and offers argued that any other approach would lead to distortions in both the electricity and transmission access market. Those who believed that access rights should come bundled with the acceptance of bids and offers in the Balancing Mechanism emphasised the importance of having a workable, efficient Balancing Mechanism in place. They suggested that participants might be less willing to post offers and bids if they had to obtain access rights to cover their Balancing Mechanism position.

Interaction with the TO price control

4.48 The May consultation identified a number of issues in relation to the structure of transmission charges, particularly in relation to the possible auctioning of access rights. An auction could lead to NGC receiving more revenues than it is allowed under its TO price control. Ofgem suggested that any such surplus could be used to accelerate the depreciation of NGC's existing assets or to fund customer driven investments incremental to those included in the TO price control (in a fashion similar to the capacity investment incentives to be implemented for Transco as SO of the gas system).

4.49 On a related point, Ofgem accepted that there is no reason for the revenues from the transmission access regime necessarily to equate to NGC's allowed revenue. A residual TNUoS charge is, therefore, likely to continue to be required.

4.50 As a tradable access right regime will provide locational signals, we suggested that it might no longer be appropriate for the residual TNUoS charge to be locational in nature. In addition, we asked for views on whether TNUoS charges should continue to be charged on a peak usage basis, given that the value of access rights would reflect the scarcity of transmission capacity.

NGC's view

4.51 NGC commented that it was important for locational signals to be appropriate and not overstated. Hence, the interactions between any transmission loss charge, TNUoS charge and short-term constraint charge must be carefully considered.

- 4.52 NGC suggested that the issue of correct revenue recovery should be developed with regard to the relevant objectives in respect of its use of system charges (see Appendix 1). The Charging Methodology could be developed through consultations in the Transmission Charging Methodologies Forum.

Respondents' views

- 4.53 Only two participants responded specifically on whether NGC should be allowed to retain any surplus auction revenues. One was opposed to the idea and the other thought that it might be appropriate to allow NGC to retain some of any surplus. However, this respondent also thought that NGC should also be required to reduce TNUoS charges following a surplus from access auctions.
- 4.54 One respondent suggested that the TNUoS charge should be replaced by two separate charges: a locational £/kW access charge and a uniform £/MWh commodity charge. Another respondent voiced concern about losing negative TNUoS payments if the current form of TNUoS charges were to be abandoned. Three respondents suggested that locational TNUoS charges were the only way of ensuring that the 'user pays' principle was adhered to and free rider problems avoided. One respondent argued that the residual TNUoS charge should be uniform.
- 4.55 Eleven respondents thought that TNUoS charges should continue to be charged on a peak usage basis, arguing that this incentivises the demand-side to assist in relieving system constraints. Two respondents thought that the current TNUoS charging methodology was out of step with having forward energy markets.

System requirements

- 4.56 The May consultation included some initial analysis by NGC of the central system requirements for a transmission access regime such as that outlined in the 'possible approach'. NGC, and its consultants, estimated that the central development costs might be in the range of £15m to £31m for a zonal transmission access regime. The costs for a nodal regime could be between £27.5m and £30m.

NGC's view

- 4.57 NGC suggested that, in the light of the experience of NETA, the estimates that it had provided might be too low. As discussed above, it believed that these costs were likely to outweigh the benefits of moving to a fully tradable access regime, with auctions, secondary trading and imbalance settlement. Instead, NGC advocated a simpler approach.

Respondents' views

- 4.58 All thirteen responses on system requirements expressed the view that the costs involved would be high. One respondent (a generator) estimated that its set-up costs would be £1 m with annual costs of £100,000 thereafter.
- 4.59 On a related issue, thirty-five respondents suggested that a full cost-benefit analysis of the proposals should be undertaken before the process is taken forward. Some respondents were concerned that a proper regulatory impact assessment had not already been performed and pointed out that this was one of the key points in the efficiency review of regulators by WS Atkins.

Transmission losses

- 4.60 In the May consultation Ofgem stated that we continued to believe that the enduring scheme for transmission losses should incorporate more efficient arrangements for the charging of transmission losses. The enduring arrangements should include the use of locational marginal loss factors. Ofgem proposed two options on how to expose participants to the costs of locational marginal losses:
- ◆ **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.

NGC's view

- 4.61 NGC stated that it strongly believes that the costs of transmission losses should be included with other transmission costs for its management and optimisation. This would simplify their charge out and avoid ambiguities in the treatment of transmission losses associated with bids and offers in the Balancing Mechanism.
- 4.62 The costs could be charged to participants on a locational basis to expose participants to the locational effects of transmission losses. Charges could be levied on all metered volumes in a similar way to the current BSUoS charges. Spatially, the charge could be made on a:
- ◆ nodal level;
 - ◆ zonal level (possibly reflecting the GSP Group zones); or
 - ◆ a nodal level for generation and zonal level for demand.
- 4.63 It also suggested that further consideration should be given to whether average or marginal loss factors should form the basis for the charge.
- 4.64 NGC believed that Option 2 would most effectively meet the objectives if a firm tradable access rights regime were implemented. Option 2 would recognise interactions between constraints and losses, avoid distortions in the Balancing Mechanism that would otherwise be caused by the locational scaling of meter readings, and ensure consistent long and short-term incentives on the SO with regard to losses.

Respondents' views

- 4.65 Forty-seven respondents had comments to the May consultation on the treatment of transmission losses. Eighteen respondents were in favour of reforming the current arrangements and twenty-seven were opposed. Two respondents offered comments but no opinion.
- 4.66 The main arguments of the respondents disagreeing with the possible reform of the enduring treatment of transmission losses were that:
- ◆ the benefits are unlikely to exceed the costs of implementing the reform;

- ◆ there will be windfall losses and gains (generators in the north and customers in the south will be particularly disadvantaged); and
- ◆ the proposal will lead to excessive penalties being placed on generators for historic investment decisions.

4.67 In general, it was urged that Ofgem undertake a regulatory impact analysis before taking the proposal forward.

4.68 Of the eighteen in favour of the proposals, seven respondents urged that although they agree with the overall aims of the reform it is necessary to further assess the costs and benefits before going ahead. Three respondents were of the opinion that charging out transmission losses on a zonal basis would be more practical than a fully-fledged marginal transmission loss-charge.

4.69 None of the respondents favoured Option 2 whilst nine preferred Option 1. One respondent argued that locational signals should only apply to new generation and demand with the current scheme being retained for existing players.

Further issues raised by respondents

4.70 Respondents to the May consultation raised issues related to the reform of the transmission access and losses arrangements that were not specifically mentioned in the document. These issues included:

- ◆ the role of embedded generators, CHP and renewables;
- ◆ the role of interconnectors; and
- ◆ the interaction with the Government's review of energy policy.

The role of embedded generators, CHP and renewables

NGC's view

4.71 NGC's expectation was that embedded generators would continue to be able to net off their output from the demand of a supplier or suppliers in the same GSP zone without the need to acquire access rights. However, the access imbalance

risk that embedded generators imposed on their supplier counter-party would affect the energy contract prices they were offered. Zonal access imbalance arrangements would restrict the extent to which consolidation was possible, since aggregation to reduce access imbalance risk would only be available at the zonal level.

- 4.72 NGC believed it particularly important to assess the impact of a tradable access rights regime on small generators as quickly as possible. The assessment would clarify whether a tradable access rights regime would affect the Government's targets for CHP³⁹ and renewables⁴⁰.

Respondents' views

- 4.73 Thirteen respondents expressed concern over the fact that the role of embedded generators, CHP and renewables in the proposed new arrangements for transmission access and losses had not been addressed. They suggested that this issue needed to be considered as soon as practicable.
- 4.74 Respondents were particularly concerned that CHP generators would be distressed buyers of transmission rights (since they have to generate), and hence would be at a significant disadvantage. The disadvantage would apply both at the initial auction process and at subsequent secondary trading of access rights.
- 4.75 It was also pointed out that renewables, such as hydro and wind generators, are not flexible with regard to location. Thus, the appropriateness of locational signals for these types of plant should be considered carefully in the light of the Government's desire to encourage renewable energy resources.

The treatment of interconnectors

NGC's view

- 4.76 NGC pointed out that the role of interconnectors in a new transmission access regime needs to be considered. NGC identified five key issues:

³⁹ The Government strongly supports the development of CHP as a key contribution to sustainable development and promotes its use wherever economic. The Government has set a revised target for 10,000 MWe of CHP capacity to be installed by 2010.

⁴⁰ The Government has a target of 10 per cent of electricity to be supplied from renewable sources by 2010, as part of the broader Climate Change Programme subject to the costs being acceptable.

- ◆ how would loss factors be applied to interconnector users and how will this impact on interconnector flows and investments;
- ◆ who would be responsible for obtaining access rights – interconnector users or the interconnector asset owner;
- ◆ interactions between transmission access auctions and interconnection capacity auctions;
- ◆ co-ordination of secondary trading of transmission rights and interconnector access;
- ◆ the impact of developments in a number of European fora on cross-border charging proposals.

4.77 NGC also noted that the transmission access proposals for England and Wales would need to take account of the European developments, not least because any European Commission regulation will be directly applicable in the UK. Currently, cross border charging proposals are being considered by:

- ◆ the European Commission in their Draft Directive and Regulation on the completion of the internal market in energy;
- ◆ the Council of European Energy Regulators; and
- ◆ the association of European Transmission System Operators (ETSO).

Respondents' views

4.78 Five respondents also commented that the treatment of interconnectors needed to be considered as soon as possible. Two respondents pointed out the need to align the proposals for England and Wales with European developments.

Interaction with the Government review of energy policy

Respondents' views

4.79 Ten respondents to the May consultation commented on the potential interactions between the Ofgem proposals and the Government's review of energy policy. Five respondents urged that any further progress on new

transmission access and losses arrangements should be postponed until after the Government's review was completed. A further three suggested that the Ofgem proposals would need to be reconsidered in the light of the outcome of the review.

Appendix 5 History of transmission losses reform

5.1 The enduring treatment of transmission losses and the methodology with which to charge the associated costs have been under review for twelve years. Since 1989, the need for a cost reflective approach to charging out transmission losses has been put forward in various documents:

- ◆ OFFER's 1989 annual report, (pages six to eight):

'The National Grid Company (NGC) have proposed an initial structure for use of system charges for transmission. However they 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 location decisions are properly informed. Following Vesting NGC will, with my support, be analysing how best to achieve these changes.'

As regards those elements of cost presently covered by use of system charges, it has been agreed that NGC should work towards revised charges which could be phased in from April 1993. So far as transmission losses are concerned, the Pooling and Settlement Agreement provides for a review of the arrangements for allocating these costs. The timetable set out in that Agreement envisages a works programme submitted by December 1993, with implementation of approved changes within two years thereafter. In the light of NGC's review, it may also be appropriate then to review the charges for using the distribution system. On this basis I accept the initial structure of use of system charges for transmission and distribution.'

- ◆ OFFER's annual report in May 1990 again drew the attention to the relevance of cost reflective charging (page eleven);
- ◆ NGC's seven year statement in 1990 argued that the costs of losses could be reduced by southern siting of generators;
- ◆ the requirement to review arrangements for allocating costs of losses was incorporated in the original Pooling and Settlement Agreement 30 March 1990;

- ◆ OFFER's annual report in 1991 re-emphasised the opinions from the 1989 and 1990 annual reports arguing that stronger incentives should be given to site generation closer to demand;
- ◆ on 14 November 1995 OFFER's Director of Regulation and Business Affairs wrote to the Pool Chairman expressing concern over the lack of progress on locational issues and requested that the Pool move forward urgently. This issue was also discussed in the OFFER annual report for 1995/1996 as well as in the November 1995 OFFER consultation paper 'The transmission price control review of the National Grid Company';
- ◆ as a result of the letter, the Pool Executive Committee (PEC) constituted an expert group, whose recommendations formed the basis for a paper from what had become the Transmission Steering Group. The PEC voted on the proposals in the paper on 21 March 1996, but the resolutions were appealed to the meeting of Pool members on 8 May 1996;
- ◆ the 8 May 1996 meeting of Pool members voted on four different resolutions on how the arrangements for the charging out of transmission losses should be developed. The resolutions were referred to as Resolution 1a, 1b, 1c and 2. Resolution 1a was carried on a poll with 69% for and 31% against. Resolution 1a stated that: *'(Pool members) agree that in the pursuit of cost reflection differential transmission loss factors are implemented and that work continues on the development of the Project Brief'*. Resolutions 1b, 1c and 2 were not carried;
- ◆ Resolutions 1a, 1c and 2 were appealed, and the Director General of Electricity Supply (DGES) decided on 11 July 1996 that resolution 1a should have effect, whereas resolutions 1c and 2 should not have effect;
- ◆ further work on the proposals was undertaken and on February 3 1997 Pool members considered two different approaches. The resolution put forward by the works programme was carried by majority vote, whereas an alternative resolution by BNFL and Teesside Power was not carried. Subsequently, Teesside Power and Humber Power appealed the decision to the DGES who upheld the decision by the majority of Pool members

on February 3, 1997. Teesside Power then sought a Judicial Review of the DGES' decision;

- ◆ over the years cost reflective charging has been argued by the House of Commons Energy Committee, the Government's Energy Advisory Panel and the Energy Efficiency Policy Division of the Department of the Environment;
- ◆ the Government's Energy Report for 1995 suggests *'more transparent costing of infrastructure could lead to more decentralised production and better matching of electricity generation and consumer demand, leading to fewer large transmission lines and a reduction in the losses inherent in long-distance transmission;'*
- ◆ with the consultation process leading up to NETA the need for locational charging of transmission losses was re-emphasised. Evidence of this can be found in all Ofgem documents on the NETA process, starting with the 'July Document'⁴¹, followed by the 'October Document'⁴², then the 'December Document'⁴³ and 'April Document'⁴⁴; and
- ◆ finally, in May 2001 a consultation document⁴⁵ specifically aimed at developing the enduring arrangements for transmission access and losses under NETA was published.
- ◆ Further evidence of the industry's awareness of the view of the Regulator can be found in the Regional Electricity Companies Share Offers Main Prospectus of 21 November 1990. On page twenty seven, last paragraph it is stated: *'The pool output price is paid by suppliers on the basis of their metered demand, adjusted for transmission losses on the system and taking account of the demand associated with power stations. [...] The present Treatment of transmission losses is subject to review in accordance with the provisions of the Pooling and Settlement Agreement.'*

◆

⁴¹ 'The new electricity trading arrangements. Volume 1', Ofgem, July 1999

⁴² 'The new electricity trading arrangements. Ofgem/DTI Conclusions Document', October 1999

⁴³ 'NGC System Operator Incentives, Transmission Access and Losses Under NETA. A Consultation Document', December 1999

⁴⁴ 'NGC systems operations under NETA: transitional arrangements. A consultation document', April 2000

⁴⁵ 'Transmission access and losses under NETA. Consultation document', May 2001