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Review of Electricity and Gas System Operator Role, Functions and Incentives: Initial Thoughts

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Overview:

National Grid Electricity Transmission (NGET) is the System Operator (SO) for the electricity transmission system in Great Britain (GB), and National Grid Gas (NGG) is the SO for the gas transportation system. The consultation document and these supplementary appendices set out our initial thoughts on the review of gas and electricity system operator functions and incentives.

These appendices are part of the document inviting views from interested parties on a number of questions relating to the activities of the SOs, and their current incentive schemes. It is important that the incentives on the SOs create the conditions for the efficient and economical operation of the system so as to minimise the costs that gas and electricity customers pay. Following consideration of respondents' views, we will issue a further consultation paper, setting out our views on the scope of the changes that we will implement before April 2008, and those changes that we will implement from April 2009.

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Context

This project is part of our work to regulate markets effectively. In both gas and electricity we consider that it is important that the roles of the system operators are correctly identified and that they have the appropriate tools available to them to undertake these roles. Any interventions in the market by the system operators can lead to costs being incurred, both directly by the system operator and more widely by the market as a whole. Since customers ultimately bear these costs it is important to keep them as low as possible. Based on our experience over the past years, we remain of the view that the best way to achieve the lowest costs to customers is to provide the system operators with commercial incentives whereby they share some of the gains (losses) from cost reductions (increases).

Associated Documents

- Review of Electricity and Gas System Operator Role, Functions and Incentives: Initial Thoughts, Ofgem 8 August 2007
- National Grid Electricity Transmission and National Grid Gas System Operator Review, Ofgem, 18 May 2007
- National Grid Gas System Operator Incentives from 1 April 2007: Final proposals and statutory licence consultation, Ofgem, 21 March 2007
- National Grid Electricity Transmission System Operator incentives from 1 April 2007: Final proposals and statutory licence consultation, Ofgem, 27 February 2007

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Appendix 5 - Terms of Reference

The terms of reference that will guide our review are as follows:

- Have previous SO incentive schemes been effective in ensuring that NGET and NGG as SOs have:
    - operated the electricity and gas transmission systems in an efficient and economic manner?
    - managed the external costs of operating the system effectively?

- Is the current scope of the incentive schemes appropriate? For example, should the scope be expanded to include other important transmission issues (such as gas quality)? Are there elements that are currently included in the schemes which should be taken out?

- Are there areas in which previous SO incentive schemes could be enhanced to improve further the incentives on NGET and NGG to operate the electricity and gas networks in an efficient and economic manner, manage the external costs of operating the system more effectively and ensure that the risk and rewards involved in the incentive schemes are proportionate and effective?

- Do the current roles and functions of the SOs ensure that they are able to operate the electricity and gas transmission systems in the most efficient and economic manner?

- Would longer term SO incentive schemes provide greater opportunities for investment that ought over the longer term result in greater net efficiencies in SO costs?

- If we were to consider longer term SO incentive schemes, what are the key drivers of SO costs that would need to be considered over the longer period?

- Is it desirable for SO incentive schemes in electricity and gas to be consistent? Do the physical characteristics of electricity and gas transmission and SO activities limit the extent to which SO incentive arrangements in electricity and gas can be harmonised?

- Do the emerging policy directions in the European Union and/or Great Britain potentially impact the operation of the high-voltage electricity and national gas transmission systems, and therefore impact the roles and functions of the SOs?

- Have the payments to and from NGET and NGG in performing their SO roles appropriately reflected the risks faced by NGET and NGG in performing their respective roles and the capital invested by each in providing SO services?

- Is there sufficient transparency surrounding the SO incentives both in terms of the process for setting the incentive parameters and in terms of the information on costs provided by NGET and NGG?

- Is it appropriate for participants (including NGET and NGG) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs?

- Is the form and scope of the gas reserve incentive appropriate (including a consideration of the volume and source of gas reserve NGG considers necessary for the safe operation of the network, the contestability and locational nature of some of these requirements and the price at which it is efficient for these bookings to be made)?

Appendix 6 – Electricity Market Legislative and Regulatory Obligations

Legislative framework

1.1. The Energy Act amended the Electricity Act 1989 (the Electricity Act) to enable the introduction of BETTA and the separation of system operation and transmission ownership activities. Section 4 of the Electricity Act (prohibition on unlicensed supply etc.) was amended such that the list of prohibited activities included "participates in the transmission of electricity for that purpose". Section 4 was also amended such that a person who participates in the transmission of electricity is a person who "co-ordinates, and directs, the flow of electricity onto and over a transmission system by means of which the transmission of electricity takes place" (i.e. system operation), or "makes available for use for the purposes of such a transmission system anything which forms part of it" (i.e. transmission ownership).

1.2. There are currently three companies that participate in the transmission of electricity and therefore hold transmission licences. Within the transmission licence there are separate sections that relate to the requirements of a System Operator (SO) and those that relate to a Transmission Owner (TO). Further, during the recent transmission price control review consultation process it was decided that it would be appropriate to remove the linkage that still remained between the two areas of the transmission licence in certain areas, relating to the TO's price control and the SO's incentive scheme. The licence conditions that are most relevant in relation to this review are outlined below.

System Operator and Transmission Owner

1.3. **Standard Licence Condition B12 "System Operator - Transmission Owner Code"** requires the licensee, in common with all other transmission licensees to which the condition applies, to have in place a System Operator - Transmission Owner Code (STC). The STC defines the high level relationship between the GB SO and the TOs in Great Britain. The STC is supported by a number of procedures (STC procedures (STCPs)) that set out in greater detail the roles, responsibilities, obligations and rights of the GB SO and the TOs.[1]

System Operator

1.4. **Standard Licence Condition C2 "Prohibited activities"** provides that (except with the written consent of the Authority), the SO may only buy or sell

[1] Further details relating to the STC and the STC itself are available from the electricity codes section of NGET's website at http://www.nationalgrid.com/uk/Electricity/Codes/

electricity for the procurement or use of balancing services in connection with co-ordinating and directing the flow of electricity onto and over the GB transmission system and doing so economically and efficiently.

1.5. **Standard Licence Condition C3 "Balancing and Settlement Code (BSC)"** requires the licensee to have in force (and comply with) at all times a BSC, which sets out, amongst other things, the terms of the balancing and settlement arrangements.

1.6. **Standard Licence Condition C10 "Connection and Use of System Code (CUSC)"** requires the licensee to prepare (and comply with) a connection and use of system code which sets out, amongst other things, the terms for arrangements for connection and use of the transmission system

1.7. **Standard Licence Condition C12 "Limits on the level to which transmission services are provided"** requires the licensee not exceed any technical levels that apply to the provision of any transmission services.

1.8. **Standard Licence Condition C14 "Grid Code"** requires the licensee to have in force at all times and comply with the Grid Code which covers all material technical aspects relating to connections to and the operation and use of the GB transmission system.

1.9. **Standard Licence Condition C16 "Procurement and use of balancing services"** requires the licensee to co-ordinate and direct the flow of electricity onto and over the GB transmission system in an efficient, economic and co-ordinated manner. The licensee is also required (having taken into account relevant price and technical differences) not to discriminate between any persons or classes of persons in its procurement or use of balancing services. Under Standard Licence Condition C16, the licensee is also required to have four statements in place relating to its purchasing of Balancing Services, these are outlined further below.

1.10. **Standard Licence Condition C17 "Transmission system security and quality of service"** requires the licensee to coordinate and direct the flow of electricity onto and over the GB transmission system in accordance with the GB Security and Quality of Supply Standard (GBSQSS), STC and Grid Code.

1.11. **Special Licence Conditions AA5A, AA5E and Schedule A** relate to the Balancing Services Revenue Restrictions, i.e. it is via these licence conditions that the SO incentive schemes are incorporated within the SO's transmission licence.

Transmission Owner

1.12. The Transmission licences are the means by which the transmission companies are bound by their price controls set by the Gas and Electricity Markets Authority.

The price controls determine how much revenue the company is permitted to recover, generally over a five year period.

1.13. The price controls are a key part of ensuring that we regulate network monopolies effectively by implementing provisions so that the companies can finance their activities and by providing the companies with the right set of financial incentives to act in the interests of consumers.

Standard Condition C16 Statements

1.14. Standard Condition C16 requires the SO to have in place four documents relating to its purchasing of Balancing Services. These documents are:

- The **Procurement Guidelines (PGs);** which sets out the principles used in the SO's procurement of Balancing Services, the kinds of Balancing Services that the SO may be interested in purchasing and the mechanisms by which the SO may purchase such services;
- The **Balancing Principles Statement (BPS);** which defines the broad principles and criteria by which NGET will determine, at different times and in different circumstances, which balancing services it will use to assist in the operation of the transmission system;
- The **Balancing Services Adjustment Data (BSAD) Methodology Statement;** which sets out the information on the Relevant Balancing Services that are taken into account under the BSC for the purposes of determining Imbalance Prices; and
- The **Applicable Balancing Services Volume Data (ABSVD) Methodology Statement;** which sets out any Balancing Services volume data is determined by reference to the volumes of energy associated with the provision of applicable Balancing Services.

1.15. These statements may only be modified in accordance with the process set out in Standard Condition C16, under which only the licensee is able to propose modifications.

Appendix 7 - Services available to the Electricity System Operator

Ancillary Services

1.1. Ancillary services are described in Connection Condition 8 of the Grid Code and are categorised as mandatory, necessary or commercial. The Ancillary Services procured under the category of Mandatory or Necessary are procured for system balancing purposes whilst those categorised as Commercial Ancillary Services include variants of the services used for system balancing as well as services specifically used for energy balancing such as Reserve. Each of these services and the category that they are procured under are described in the following sections.

Mandatory System Services

1.2. Mandatory System Ancillary Services are those services which are required for system reasons and which all licensed generators are required to provide in accordance with the Connection Conditions of the Grid Code unless they seek and receive derogation from the condition. These services are Reactive Power and Frequency Response. Details of the two Mandatory System Ancillary Services are given below together with a brief outline of how the SO currently procures the service.

Reactive Power

1.3. The requirement for Reactive Power is primarily driven by the interaction of real power flows on the transmission system with the complex independencies of the various elements that make up the network together with the demand at the lower voltage system interfaces. The SO is required to maintain the reactive power balances between sources of generation and points of demand. Unlike system frequency, which is consistent across the network, voltages experienced at points across the system form a 'voltage profile', which is uniquely related to the prevailing real and reactive power supply and demand. Without the appropriate injections of reactive power at correct locations, the voltage profile of the transmission system will go outside statutory planning and operational limits.

1.4. The SO procures Reactive Power via the established reactive power market, the arrangements for which are set out in Schedule 3 of CUSC. The Reactive Power market enables the SO to invite tenders for alternative payment arrangements for reactive capability and tenders for the provision of an enhanced Reactive Power Service which is discussed later in this document under Commercial Ancillary Services. Invitations to tender are issued every six months with contract start dates on 1 April and 1 October. Contracts are awarded for a minimum of 12 months duration with six month increments. The two main components of the Reactive Power markets are:

- market agreements whereby generators and the SO can enter into a market based contract on mutually agreed terms. The agreements can cover the Obligatory Reactive Power Service or the Enhanced Reactive Power Service; and
- default arrangements whereby, in the absence of a market agreement, payment is made to generators for reactive utilisation with 50% of the price of Reactive indexed to the wholesale power price.

Frequency Response

1.5. System frequency is a continuously changing variable that is determined and controlled by the balance between system demand and total generation. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises. The SO has a statutory obligation to maintain system frequency within the limits specified in the Electricity Safety, Quality and Continuity Regulations 2002[2] (+/- 1% of nominal system frequency 50.00Hz) except in abnormal or exceptional circumstances. The SO must therefore ensure that sufficient generation and/or demand side response is held in automatic readiness to manage all securable frequency change contingencies.

1.6. In order to ensure that frequency can be managed satisfactorily in all circumstances, all large generators must be capable of contributing to frequency control. This obligation is required by the Grid Code and is a condition of connection to the transmission network.

1.7. The SO maintains system frequency using a range of frequency response services provided under mandatory and commercial ancillary services by mainly generators and to a lesser extent demand side response. The SO calls on the volume of response necessary to meet system requirements by selecting Balancing Mechanism Units (BMU) based on technical and commercial criteria.

1.8. In November 2005 CAP047[3] replaced the administrative price setting mechanism for Mandatory Frequency Response holding prices with a market mechanism whereby generators submit prices for their individual BMU on a month-ahead basis. Holding prices and utilised volumes of mandatory Frequency Response are published monthly on the National Grid website.[4]

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[2] Statutory Instrument 2002 No. 2665 see http://www.opsi.gov.uk/si/si2002/20022665.htm
[3] Amendment to the Connection and Use of System code (CUSC) 047 "Introduction of a competitive process for the provision of Mandatory Frequency Response".
[4] Further details of the information provided on the National Grid website are provided in the section on information and transparency later in this chapter.

Necessary System Services

1.9. Necessary System Ancillary Services are those services required for system reasons which must be provided by some generators where they have agreed to provide them under a Bilateral Agreement with the SO. Grid Code Connection Condition 8.1 part 2 gives a non-exhaustive list of necessary system Ancillary Services:

- Frequency control by means of Fast Start (Fast Start Capability);
- Black Start Capability; and
- System to Generator Operational Intertipping.

Fast Start Capability

1.10. Fast start is the ability of Open Cycle Gas Turbine (OCGT) plant to start rapidly from a standstill condition and to deliver its rated power output, automatically within five minutes following initiation of a Low Frequency (LF) relay, or within seven minutes of a manual instruction via an Electronic Data Log from the SO. Fast Start is required by the SO to minimise the risk of further system frequency degradation after an incident involving an abnormal or exceptional imbalance between generation and demand.

1.11. Fast Start Capability is procured by the SO by means of bilateral contracts entered into pursuant to the CUSC. These are typically of five to 10 years duration.

Black Start Capability

1.12. Black Start is the procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. In general, all power stations need an electrical supply to start up: under normal operation this supply would come from the transmission or distribution system; under emergency conditions Black Start stations receive this electrical supply from alternative sources, normally small auxiliary generators located on-site.

1.13. Not all power stations are obliged to provide a Black Start service because in an emergency neither the SO nor the local distribution networks could manage restoration from all power stations simultaneously with the implication that there would be a great deal of redundancy. Instead the SO contracts with generators that it considers to be particularly effective at strategic locations on the system to provide the Black Start service. Approximately a third of Power Stations with a capacity greater than 300MW have a Black Start Capability.

1.14. Black Start Capability is procured by the SO by means of bilateral contracts entered into pursuant to the CUSC. In order to provide the Black Start service, power stations require auxiliary plant to enable the main generating plant to start up independently from on-site power supplies. The costs involved in providing a Black

Start capability predominantly arise from the capital outlay on the auxiliaries (and various other associated set up costs). It is generally not economic to generate energy from such auxiliary plant for trading in the energy market alone, and therefore such plant are generally only installed if generators expect to recover a significant proportion of costs through a Commercial Services Agreement (CSA) with the SO.

1.15. The Black Start plant may be installed solely to provide a Black Start Service or alternatively it can be used for other energy-related services. A significant proportion of a provider's income will consist of a Black Start Availability Payment, paid through the CSA together with a smaller revenue from the Balancing Mechanism if used for other energy related services . Further payments are made when the service is utilised both for testing purposes and in the event of a Black Start.

System to Generator Operational Inter-tripping

1.16. Some Generators are required to have in place operational intertrip schemes as a condition of connection to the transmission system under the CUSC. System to Generator Operational Intertrips are required as an automatic control arrangement whereby generation or demand may be reduced or disconnected following a system fault event in order to relieve localised transmission network flows, system instability and / or system voltage constraints.

1.17. Inter-tripping schemes fall under several categories which defined under section 4.2.A of the CUSC along with the compensation arrangements relating to each scheme with some schemes entitling the service provider to payments for arming (capability fee) and utilisation of the service.

1.18. In addition to the System to Generator Operational Inter-tripping schemes discussed above the SO is also able to enter into commercial intertrip schemes to manage system issues these are discussed below under Commercial Ancillary Services.

Commercial Ancillary Services

1.19. In addition to the mandatory and necessary Ancillary Services the SO also enters into commercial arrangements for the provision of services to enable it to carry out its system balancing duties. The terms of commercial arrangements including prices are freely negotiated between the SO and the provider or are subject to a tender process. The main commercial Ancillary Services currently provided are listed below, according to whether the service is used for energy balancing, system balancing or both, followed by a description of the service and a brief outline of how it is procured by the SO.

Commercial Services for Energy Balancing

1.20. There is currently only one commercial ancillary service that the SO uses solely for energy balancing.

Short Term Operating Reserve (formerly Standing Reserve and Supplementary Standing Reserve)

1.21. At certain times of the day the SO requires additional power in the form of either increased generation or demand reduction in order to deal with demand and supply imbalances, for example, as a result of actual demand being greater than forecast demand or actual generation being less than forecast because of the breakdown of plant. This requirement is met from synchronised and non-synchronised sources. The SO procures part of this requirement by contracting for Short Term Operating Reserve (STOR), provided by a range of service providers including short notice generating units and demand reduction. The STOR service replaced Standing Reserve (SR) and Supplementary Standing Reserve (SSR) on 1 April 2007. STOR is procured through a tender process of which there are three a year with market participants able to tender for up to two years of provision.

Commercial Services for System Balancing

1.22. There are currently four commercial ancillary services that the SO uses for system balancing, although in limited cases these services may also contribute to energy balancing. These are:

- Enhanced Reactive Service;
- Frequency Response;
- Intertrip Arrangements; and
- Transmission Related Agreements.

Enhanced Reactive Service

1.23. The Enhanced Reactive Service comprises a range of Ancillary Services delivering a Reactive Power capability which is capable of being made available to, and utilised by the SO for the purpose of voltage support on the transmission system. This service is in addition to the capability provided through the Obligatory Reactive Power Service and is procured through the Reactive Power Market arrangements discussed above.

Frequency Response

1.24. The SO can enter into Commercial Frequency Response arrangements with providers where it considers there is a technical or commercial advantage in doing so. Commercial Ancillary agreements are negotiated between the parties both in terms of the form of the contract and the prices. Generators can provide both the mandatory and commercial services such as firm frequency response. Large electricity consumers who are prepared to interrupt their demand automatically for short periods can also provide occasional frequency services.

Intertrip Arrangements

1.25. In addition to the System to Generator Operational Inter-tripping schemes discussed above the SO is also able to enter into commercial intertrip schemes to manage system issues. Commercial intertrips are negotiated bilaterally between the SO and the provider and are an automatic control arrangement where by generation or demand may be reduced or disconnected following a system fault event in order to relieve transmission network flows, system instability and/or system voltage constraints.

Transmission Related Agreements

1.26. The requirement for transmission related agreements arises where the connection arrangement of a generator results in a requirement for that generator's output to be constrained in the event that certain situations arise which impact on the transmission system. In this event the SO will agree a commercial arrangement for provision with the generator concerned.

Commercial Services for both Energy and System Balancing

1.27. There are currently four commercial ancillary services that the SO may use for both energy and system balancing. These are:

- Fast Reserve;
- BM Start Up Service (formerly Warming);
- System to System Services (SO-SO); and
- Maximum Generation Service.[5]

Fast Reserve

1.28. Fast Reserve is the rapid and reliable delivery of active power provided as an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from the SO. Active power delivery must start within 2 minutes of the despatch instruction at a delivery rate in excess of 25MW/minute, and the reserve energy should be sustainable for a minimum of 15 minutes. Fast Reserve is used to control frequency changes that

[5] Maximum Generation is non-firm emergency service which is only used as a last resort in order to prevent demand control.

might arise from sudden, and sometimes unpredictable, changes in generation or demand. The SO has a 24-hour requirement for Fast Reserve.

1.29. The Fast Reserve contracting process has three key stages:

- Pre-qualification - where potential providers are invited to fill in a questionnaire about their plant capabilities. Success at this stage allows a party to enter into a framework agreement and offer an optional and/or a firm service to the SO.
- Optional service - where, upon successful pre-qualification, a framework agreement is entered into which puts no obligation on either party but allows optional despatch of Fast Reserve when available. Ancillary Services payments are made only when used.
- Firm service - where, upon successful pre-qualification and facilitated by the same framework agreement as for the optional service, providers have the opportunity to tender (on a monthly basis) to provide guaranteed availability of their plant to be in a state of readiness to provide Fast Reserve for subsequent despatch as required. Ancillary Services payments are made subject to tender acceptance.

BM Start-Up Service (formerly Warming)

1.30. The BM Start-Up Service provides the SO with on-the-day access to additional generation BMUs that would not otherwise have run, and which are not made available in Balancing Mechanism timescales. The service contains two elements, BM Start-Up and Hot Standby. BM Start-Up deals with bringing a BM Unit to a state where it can synchronise within BM timescales. Hot Standby deals with holding the BMU in this state of readiness to synchronise. The BM Start-Up Service replaced the Warming and Hot Standby Service on 1 November 2006. The service is procured through a Commercial Services Agreement.

System to System Services (SO-SO)

1.31. System to System (SO-SO) services are services provided by other Transmission System Operators connected to the GB system via interconnectors. SO-SO services are typically used to manage interconnector transfer profiles and to increase or reduce power flows across an interconnector to resolve transmission constraints or provide Emergency Assistance if required. The provision of SO-SO services is undertaken on a reciprocal basis and procurement of services is undertaken as required via bilateral contracts with the relevant SO.

1.32. Emergency Assistance is a specific interconnector service where additional active power support is provided by one electrical grid system to another to manage emergency events such as extreme or major unforeseen circumstance. This system to system service can result in one or both grid systems being operated beyond their normal security standards. This service is therefore used as a measure in extreme circumstances and historically, its use has been extremely rare. An SO receiving a request for Emergency Assistance is obliged to meet the request, unless this would require a demand or security reduction on its own system.

Balancing Mechanism

1.33. The Balancing Mechanism provides a tool where the SO can accept offers of electricity (generation increases and demand reductions) and bids for electricity (generation reductions and demand increases) at very short notice. Bids and offers can be submitted to the Balancing Mechanism by BSC Parties, although they are not obliged to do so. A bid or offer specifies the price that the BSC Party wishes to be paid (or is willing to pay) to move away from its Final Physical Notification (FPN) and the volume by which it is prepared to move.

Other Services

1.34. These are commercial services that can be entered into with any party whether or not they are an Authorised Electricity Operator. Other services that are not classified as Ancillary Services or as Balancing Mechanism Offers and Bids include any service provided by parties that are not signatories to the Balancing and Settlement Code. Services in this category may be procured for system balancing purposes as well as energy balancing purposes and comprise:

- Reactive Power;
- Frequency Response;
- Standing Reserve;
- Fast Reserve; and
- Demand Intertrip.

1.35. The category of Other Services also includes energy related products. There are three general categories of energy related products that the SO currently procures:

- Power Exchange Trades;
- Over the Counter (OTC) Trades; and
- Energy Balancing Contracts.

Appendix 8 - Industry developments that may affect future electricity SO costs

Generation and transmission

Carbon emissions

1.1. A key goal of energy policy is to tackle the threat of climate change by reducing greenhouse gas emissions. The recent Energy White Paper set out a number of elements to the Government's strategy for developing low carbon energy supplies.

1.2. The EU Emissions Trading Scheme (EU ETS) encourages the establishment of a carbon price, ensuring that companies investing in new power stations take account of the costs of their carbon emissions. These costs will be passed through into the wholesale price of power and thus will feed through into Balancing Costs.

Large Combustion Plant Directive

1.3. In addition to the EU ETS, the Large Combustion Plant Directive (LCPD, 2001/80/EC) will have significant implications for generation availability from January 2008 onwards. Combustion plants must meet the Emission Limit Values (ELVs) stipulated in the LCPD, with limited exemptions available for "existing plants" (those in operation prior to 1987).

1.4. The LCPD will have a significant impact on the way in which generators operate. Member States can choose to meet the obligations either by operating within a "National Plan" that would set an annual national level of emissions, or by seeking an exemption by submitting a written declaration to the competent authority. Unless the generator meets the new build standard for ELVs, the operating permit for any plant using this exemption will be revoked after 20,000 hours of operation or at the end of 2015, whichever comes first.

1.5. The Directive favours less carbon-intensive technologies such as renewables and gas-fired combined cycle plant and may lead to a reduction in the output of existing coal plant. This may have an impact on wholesale power prices which would feed into Balancing Costs.

Renewable generation

1.6. As part of its policy, the Government is committed to stimulating growth in renewable energy sources and is aiming for renewable generation to provide 10% of electricity supplies by 2010, with an aspiration for this level to double by 2020.

1.7. The increase in renewable generation is likely to have two separate impacts on the costs incurred by the SO. Firstly, significant volumes of renewable generation are likely to be located at the extremities of the transmission system (including offshore) predominantly located in Scotland. Transmission of generation from these extremities to demand centres could lead to higher transmission losses and additional transmission constraints all of which would impact on SO costs. Secondly, the technical characteristics of renewable generation are somewhat different to nuclear and fossil fuel generation (e.g. reliability of wind). For example, the characteristics of wind, wave and other renewable generation technology are subject to greater fluctuations and unpredictability than conventional generation. It is expected that balancing costs could increase as the wind portfolio increases as a result of the need for more System Reserve to be held and also increased procurement of services to manage frequency on the system.

Distributed generation

1.8. The increased volume of proposed new renewable generation connections includes a significant proportion planning to connect to the distribution system; i.e. distributed or decentralised generation. Combinations of new and existing technologies are also opening up new possibilities for carbon reduction by producing and using heat and electricity at a local level. This includes micro-generation, district heating schemes, combined heat and power and biomass fuelled heating at community and industry scale.

1.9. Any increase in energy from distributed generation may potentially have an effect on the costs incurred by the SO in operating the transmission system. This development might therefore have the effect of increasing transmission losses and constraint costs, and may also impact on transmission investment.

1.10. In July 2006 Ofgem established an industry working group - the Transmission Arrangements for Distributed Generation (TADG) working group - to develop options for the appropriate development of transmission arrangements to reflect the impact of distributed generation on the transmission network. The TADG Working Group Report was published on 30 July 2007[6] and included the Group's assessment of the issues with the existing arrangements and of four strawman options for change to those arrangements. In its covering letter to the report, Ofgem stated that it is now for the industry to consider whether to take forward any particular changes, whether based on any of the strawman models developed by the Group, or indeed any other new models, through change proposals to relevant industry codes or other documents.

[6] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=57&refer= Networks/Trans/Elec TransPolicy/TADG/

Offshore transmission

1.11. As discussed above, a large part of the new generation to be built to meet the Government's target for electricity from renewable sources is intended to come from offshore windfarms. An offshore electricity transmission regulatory regime is being implemented in order to allow renewable generation located offshore to connect to the existing onshore networks. NGET has been appointed designate SO for the UK offshore transmission networks by the Secretary of State.

1.12. As offshore generation and transmission is developed, it is likely that this will result in incremental costs to the SO for the development and implementation of additional commercial and operational arrangements.

System access and constraint issues in Scotland

1.13. There are a number of tools that the SO can use to manage the impact of constraints, both in terms of network configuration and through constraining generation and demand. Currently, as a result of the split of SO and TO in Scotland, the financial consequences of using the alternative options are different to those in England and Wales. NGET has suggested that the incentives surrounding the management of network constraints in Scotland can be better aligned and that these should be investigated further by a Working Group established under the STC Committee. NGET is in discussions with the Scottish Transmission Operators to take this forward.

Transmission access framework

1.14. In the 2007 Energy White Paper the government announced a review led by Ofgem and DTI to examine the technical, commercial and regulatory arrangements through which new renewable generation acquires connection and access to the grid. This will include, inter alia, consideration of the ways in which access to the network can best be shared between different forms of generation, and the extent to which the existing mechanisms for system and energy balancing remain appropriate. The latter will include consideration of the role constraint costs play in the transmission system. Some of the changes either considered under the current incremental developments or to be examined under the medium to long term review, could potentially impact on the costs incurred by the SO, especially in respect of constraints.

Other industry developments

Cash out arrangements

1.15. The cash out (or imbalance) arrangements are important in providing commercial incentives for market participants to balance their market positions. The electricity cash out arrangement are currently subject to review. To date, the review has resulted in two modification proposals, both of which are currently being considered by the Modification group. Modification proposal P211 "Main imbalance price based on ex-post unconstrained schedule" has been raised by EDF Energy and Modification P212 "Main imbalance price based on Market Reference Price" has been raised by Bizz Energy. Any changes to these arrangements could alter the incentives on market participants to balance and hence influence the overall level of balancing costs that the SO faces.

Frequency response

1.16. Frequency Response costs have been one of the key components driving increases in Balancing Costs in 2006/07 and the later part of 2005/06. Costs increased from just over £66 million in 2005/06 to nearly £125 million in 2006/07 following the Implementation of CAP047[7] in November 2005. The implementation of CAP107[8] in December 2006 has to date not had any impact on post CAP047 Frequency Response Holding price.

1.17. In April 2007, NGET invited the CUSC Amendment Panel to agree to reconvene the Balancing Services Standing Group (BSSG) to consider the procurement of Mandatory Balancing Services under the CUSC. At the time, NGET was most concerned with the costs it was incurring in the procurement of frequency response following the implementation of CUSC Amendments CAP047 and CAP107.

1.18. The outcome of the BSSG discussions may include a recommendation for a modification proposal to be taken forward for changes to the Frequency Response Market which may have significant implications for procurement of Frequency Response and for SO costs. For example, currently the SO procures more volumes of High Frequency Response than is required because the Grid Code bundles High Frequency Response with Primary and Secondary Response. Alternatively the outcome may be a number of minor changes aimed at improving the efficiency of the Frequency Response Market.

[7] Amendment to the Connection and Use of System code (CUSC) 047 "Introduction of a competitive process for the provision of Mandatory Frequency Response". Following this change generators were able to price freely this aspect of their Mandatory Frequency service. For further details see Ofgem's Connection and Use of System Code Proposed Amendment CAP047: "Introduction of a competitive process for the provision of mandatory frequency response" Impact Assessment, August 2004, (reference 210/04).

[8] CAP 107 had the effect of amending the Response Energy Payment component of the payment for the provision of mandatory frequency response such that it is based on the Market Index Price adjusted by defined multipliers, as a proxy for the System Buy Price and the System Sell Price.

Transmission Losses

1.19. The BSC sets out the rules for how users of the transmission network pay for transmission losses. Under the current rules, these costs are recovered from generators and suppliers on a uniform basis.

1.20. Four Modification Proposals (and two alternatives) have been raised to modify the BSC in relation to the treatment of transmission losses. The overriding principle of all of the proposals is to allocate transmission losses to BSC Parties on a 'zonal' basis through the application of locationally varying Transmission Loss Factors (TLFs). The principle behind this approach is that losses are allocated to parties according to the extent to which they give rise to variable losses. It is the Authority's intention to publish its final decision by 20 September 2007.

1.21. One issue raised by respondents to the Impact Assessment, and which was highlighted in the minded to document, was the effect of SO actions on the level of losses. Some parties also suggested that there may be some interaction between a zonal losses scheme, which would provide signals to market participants in relation to their impact on variable losses, and the SO incentives arrangements put in place by Ofgem to encourage the SO to take account of the impact of its actions on overall transmission losses.

Appendix 9 - Transparency and information provision for electricity operations

Introduction

1.1. In this appendix we outline the provision of information in relation to the role of the electricity SO. There are two different types of information: market data and commercial information associated with actions undertaken by the SO.

Sources of information

1.2. This range of information is currently supplied through five different sources:

- National Grid Balancing Services website;
- the Balancing Mechanism Reporting System (BMRS) website (managed by Elexon[9]);
- the Elexon website;
- System Operator Notification and Reporting System (SONAR); and
- National Grid Operational Forum meetings.

1.3. The type of information provided by each of these sources is discussed below.

National Grid Balancing Services website

1.4. The National Grid Balancing Services website is the main source of information on Balancing Services. There are three broad categories of information available:

- **Reference material:** C16 statements, service descriptions and criteria;
- **Market updates:** Consultations, tenders, reports, procurement data and use of Balancing Services; and
- **Operational information:** for example, reserve related information, to assist market participants in understanding the likelihood of the SO needing additional reserve on the day.

[9] ELEXON is the Balancing and Settlement Code Company (BSCCo) established under the provisions of the BSC. The BSC contains the rules and governance arrangements for electricity balancing and settlement in Great Britain, and ELEXON is responsible for ensuring its proper, effective and efficient implementation. ELEXON is wholly owned, but not controlled by NGET. ELEXON's independence of NGET is established by the BSC.

BMRS website

1.5. The BMRS website provides near real time and historic data about the Balancing Mechanism. Data is provided close to real-time, down to a half hourly resolution. The key data provided includes:

- 2-52 week ahead and 2-14 day ahead national and zonal margin information, including forecast generation, demand and surplus;
- Market summary data –market length, prices, index, Balancing Services Adjustment Data;
- Demand outturn;
- BMU level data – including Physical Notification, Bid Offer Acceptance and dynamic parameters; and
- System warnings and other messages (PGBTs, SO-SO prices).

Elexon website

1.6. The Elexon website provides key market data relating to areas such as:

- credit default;
- pricing; and
- BMU specific physical and static data.

1.7. Project Isis is being run to enable Elexon to ensure that the settlement systems continue to operate in a robust manner meeting the BSC requirements beyond the expiry of the current contract with existing service providers.

1.8. The objective of the project, which is being run with Industry involvement, includes the development of the necessary contracts and specifications of the systems and processes to be used from the start of any service beyond the current contract expiry date.

SONAR

1.9. This source of information has been developed as a flexible medium for the SO to publish SO related notifications to the market in real time. It currently provides notifications when PGBTs are procured and when the BM Start-up service is used, availability of additional GTs, and general messages.

NGET Operational Forum

1.10. NGET holds regular meetings with its customers to discuss the operation and performance of the system and energy balancing regimes. The web pages are used to display the presentation material used at these meetings.

Appendix 10 - Gas Market Legislative and Regulatory Framework

The Gas Act

1.5. The Gas Act (as amended) sets out the way in which the GB gas industry is regulated (including enabling the separate licensing of gas transporters (‘GTs’), gas shippers and gas suppliers).

1.6. Section 34(1) of the Gas Act places a duty on the Authority, as far as it appears to the Authority to be practicable, to keep under review the carrying on both within and outside Great Britain licensed activities and relevant ancillary activities. It is also the duty of the Authority, as far as it appears to the Authority to be practicable, to collect information on the activities of GTs, gas shippers, gas suppliers and ancillary services, in relation to matters with respect to which its functions are exercisable.

1.7. Section 35 of the Gas Act provides the Authority with the powers to publish advice or information, related to the conveyance of gas through pipes, where it would promote the interests of existing and future consumers. In publishing the advice or information the Authority must have regard to the need for excluding information, so far as that is practicable, which relates to an individual or body if, in the Authority's opinion, publication of the information would or might seriously and prejudicially affect that individual or body's interests. Before deciding to publish advice or information in relation to a particular individual or body, the Authority must consult that individual or body.

1.8. In the event that the Authority considers any licensee is contravening (or is likely to contravene) any licence condition or relevant obligation (as defined in the Gas Act), the Authority may then take enforcement action (by issuing an enforcement order against the licensee under section 28 of the Gas Act). Section 30A of the Gas Act then outlines the provisions by which the Authority can impose penalties on a licence holder where it contravenes its obligations.

NGG's gas transporter licence

1.9. GTs have a duty, under section 9 of the Gas Act, to develop and maintain an efficient and economical pipeline system for the conveyance of gas and, so far as it is economical to do so, to comply with any reasonable request to connect to that system and convey gas by means of that system to any premises or to connect to that system a pipeline system operated by an authorised transporter. It is also the duty of GTs to facilitate competition in the supply of gas.

1.10. GTs have a further duty to avoid any undue preference or discrimination in the connection of premises or pipeline system operated by an authorised transporter to any pipeline system operated by it, or in the terms on which it undertakes the conveyance of gas by means of such a system.

1.11. Standard special condition A6 of NGG's GT licence requires it to conduct its transportation business in the manner best calculated to ensure that neither the GT nor any affiliate, nor any gas shipper nor gas supplier, nor DN Operator obtains any unfair commercial advantage.

1.12. Standard special condition A9 sets out certain gas security standards to which NGG must plan and develop its pipeline system. In essence, these standards require the pipeline system to be capable of meeting a peak aggregate daily demand that is only likely to be exceeded in one year in every 20 years.

1.13. Special condition C5 relates to the system management services and requires the licensee to operate the NTS in an efficient, economic and co-ordinated manner. The SO is required not to discriminate between any persons or classes of persons in its procurement or use of system management services. The system management services relate to the balancing of gas inputs to and gas offtakes from the NTS including balancing trades and balancing trades derivatives and constraint management services. Special condition C5 further requires the licensee to establish the following two documents:

- **The UK Transmission System Management Principles Statement** which sets out the principles and criteria for deploying system management services; and
- **Procurement Guidelines** set out types of system management services which the SO may be interested in purchasing along with the mechanisms by which the SO envisages purchasing such services.

1.14. Standard special condition A7 requires NGG only to enter into transportation arrangements, which are in conformity with any relevant provisions of the network code. This would include any obligations in the network code to disclose information relating to the operation of NGG's pipeline system or any market relating to NGG's pipeline system.

Uniform Network Code (UNC)

1.15. The original network code was put in place in March 1996. This was replaced by the UNC in May 2005 (following the sale by National Grid of four of its gas distribution network (GDN) businesses).

1.16. While each GT, including NGG, is still required to produce its own network code under their GT licence, to prevent fragmentation the substantive provisions of these Codes are incorporated by reference to a common document known as the Uniform Network Code (UNC). The UNC is therefore the code around which the gas industry operates, setting out the legal and contractual framework relating to the supply and transportation of gas through the GB network.

1.17. The UNC is required to meet a set of relevant objectives defined in the GT licence. These are:

- (a) the efficient and economic operation by the licensee of its pipeline system;
- (b) so far as is consistent with (a) above, the coordinated, efficient and economic operation of the pipeline system and/or the pipeline system of one or more other relevant gas transporters;
- (c) so far as is consistent with (a) and (b) above, the efficient discharge of the licensee's obligations under its licence;
- (d) so far as is consistent with (a) to (c) above, the securing of effective competition between relevant shippers, and/or between relevant suppliers, and/or between DN operators and relevant shippers;
- (e) so far as is so consistent with the provisions of (a) to (d) above, the provision of reasonable economic incentives for relevant suppliers to secure that the domestic supply security standards (as defined) are satisfied as respects the availability of gas to their domestic customers; and
- (f) so far as is consistent with (a) to (e) above, the promotion of efficiency in the implementation and administration of the UNC.

1.18. The mechanism by which the UNC can be modified is set out in condition A11(13)-(19) of NGG's GT licence (as well as in the UNC modification rules). Under these rules, shippers, NGG and third party participants are able to propose modifications. Ofgem is not itself able to propose modifications (although the implementation of all modifications requires the consent of the Authority).

1.19. The Authority may only direct that the UNC should be modified if, in its opinion, the proposed modification would, as compared with the existing provisions of the network code or any alternative proposal, better facilitate the achievement of the relevant objectives as set out in the GT licence. In making such a direction, the Authority is required to have regard to its statutory duties.

Appendix 11 – Gas balancing arrangements

Introduction

1.1. In its role as residual energy balancer, the SO is responsible for:

- ensuring that demand and supply are balanced on a daily basis;
- managing the physical consequences of any significant changes in demand until the market is able to respond to such a change; and
- managing the physical consequences of any unexpected changes in supply (and/or demand) until the market is able to respond to such a change.

1.2. The gas balancing arrangements provide shippers with commercial incentives to balance their inputs to and offtakes from the NTS at the end of the gas day. If a shipper is out of balance at the end of any given day, any imbalance volume is cashed-out at prices determined by trades on the OCM. Note that, unlike in the electricity market, the SO does not buy gas in forward markets.

1.3. In the gas arrangements, there is no equivalent concept to that of "Gate Closure" in electricity. As such, market participants can continue trading gas throughout each gas day to ensure their positions are balanced. In addition, participants are permitted to trade out their imbalance volumes for up to 15 days after the end of the month in which the relevant gas day occurs.[10]

1.4. Since imbalance charges are intended to provide incentives on shippers to balance their gas inputs and outputs, a shipper's imbalance volume is the difference between its inputs to and offtakes from the NTS (net of the impact of any ex-post trading).

Gas cash out

1.5. The gas cash out rules are designed to ensure that the imbalance prices reflect the costs that the SO incurs in buying / selling gas for residual balancing purposes. The cash out rules therefore set out the prices that are paid / received by shippers for any imbalance between their metered inputs and offtakes over the gas day.

1.6. Different imbalance prices apply depending on whether the shipper is short or long gas. A shipper that is short gas **pays** the system marginal buy price (SMP buy) which is the higher of:

[10] Although participants have to notify their intended inputs and offtakes ahead of time.

- the highest price of any trade to which the SO is a party on the OCM, excluding any trades that it makes for locational reasons; and
- the average price of gas traded on the OCM (SAP) plus a fixed value set at 0.0287p/kWh.[11]

1.7. Conversely, a shipper that is long gas **is paid** the system marginal sell price (SMP sell) which is the lower of the lowest price of:

- any trade to which the SO is a party on the OCM, excluding any trades that it takes for locational reasons; and
- SAP minus a fixed value set at 0.0324p/kWh, which is based on the price for delivering gas from the Hornsea storage site in 2000.

1.8. These arrangements were designed so that, on days when the SO does not take balancing actions on one (or both) side(s) of the market, cash out prices better reflect the costs of imbalances and encourage shippers to balance their portfolios by buying or selling gas on the OCM.

1.9. In addition to an imbalance charge, the cash out arrangements include a scheduling charge (designed to give shippers an incentive to make accurate input and output nominations). If a shipper's actual inputs or offtakes differ from final nominations, it will pay scheduling charges.[12]

1.10. The money that is paid to (or paid by) the SO as a result of imbalance charges, scheduling charges and purchases and sales of gas on the OCM is returned to (or paid by) shippers via the balancing neutrality charge. The aggregate system payments are returned to (or paid by) shippers on the basis of their throughputs (the sum of their inputs and outputs).

[11] This was derived from the price for injecting gas into the Hornsea storage site in 2000. At the time the current methodology was introduced, it was felt that the use of prices from the Hornsea storage site represented a suitable proxy for system flexibility.
[12] So long as the difference is greater than a specified tolerance.

Appendix 12 – Quality of service measures

1.1. There are two main sets of quality of service measures for the Gas Transporters (GTs) and Gas Distribution Network Operators (GDNs). These are the Guaranteed Standards of Performance and the Overall Standards of performance. The Gas Act 1986 allows the Authority to make regulations for guaranteed standards of performance and to determine overall standards of performance for GTs. These standards of performance have been in place since April 2002.

Guaranteed Standards of Performance

1.2. Guaranteed standards of performance applicable to GTs relate to specific measurable services that must be met in each individual case. If a GT fails to provide the guaranteed level of service, it must make a payment to the customer affected, subject to certain exemptions defined for each standard separately. These standards are set out in the Gas (Standards of Performance) Regulations 2005 (SI no.1135). In addition, Standard Special Licence Condition D10 (Provision of connections information) is associated to guaranteed standards relating to connections (standards 4 through 11 below) and requires GDNs to meet 90% performance targets in these service areas for all customers.

1.3. The table below provides information on each guaranteed standard and the minimum level of compensation and any cap to the level of compensation, payable to customers by GTs in the event of a failure to meet the guaranteed standard.

Standard	Definition	Payment
Restoring domestic customers' supplies after an unplanned interruption	GTs should restore domestic customers' supplies within 24 hours following unplanned interruptions on their networks. If a GT fails to achieve this, a fixed compensation payment will be paid to the customer affected. Further compensation will be paid for each additional period of 24 hours until the customer's supply is restored. This standard does not apply where the event originated on another GTs network.	£30 Cap per customer of £1,000
Reinstatement of customers' premises	On completion of GT initiated work to re-lay service pipes on a customer's premises, the premises will be reinstated within 10 working days. If the GT fails to achieve this, a fixed compensation payment will be made. Further compensation will be paid for each additional period of 5 working days until the premises are reinstated	£50 (domestic) £100 (non-domestic)

Provision of alternative heating and cooking facilities to priority domestic customers	If a priority customer's gas supply is discontinued because of a planned interruption, the GT shall provide alternative heating and cooking facilities within 4 hours. If the supply to a priority customer's premises or gas fittings at those premises is discontinued because any other event (e.g. a gas emergency or unplanned interruption) where fewer than 250 customers are affected, the GT shall provide alternative heating and cooking facilities within 4 hours of it becoming aware that the customer has been affected. Where 250 or more customers are affected, the GT shall provide alternative heating and cooking facilities within 8 hours of it becoming aware that the customer has been affected.	£24
Provision of standard connection quotations	GTs shall provide a standard quotation for providing a new or altering an existing connection up to and including 275 kWh /hr within 6 working days. Where a GT fails to achieve this, a fixed payment shall be made in respect of the initial failure and each additional day during which the failure continues. Where a quotation is later found to be inaccurate it shall be treated as if it wasn't provided on time.	£10 Cap per customer is the lesser of £250 or the quotation sum
Provision of non-standard connection quotations ≤ 275 kWh/hr	GTs shall provide a non-standard quotation for providing a new or altering an existing connection up to and including 275 kWh /hr within 11 working days. Where a GT fails to achieve this, a fixed payment shall be made in respect of the initial failure and each additional day during which the failure continues. Where a quotation is later found to be inaccurate it shall be treated as if it wasn't provided on time.	£10 Cap per customer is the lesser of £250 or the quotation sum
Provision of non-standard connection quotations >275 kWh/hr	GTs shall provide a non-standard quotation for providing a new or altering an existing connection greater than 275kWh /hr within 21 working days. Where a GT fails to achieve this, a fixed payment shall be made in respect of the initial failure and each additional day during which the failure continues. Where a quotation is later found to be inaccurate it shall be treated as if it wasn't provided on time.	£20 Cap per customer is the lesser of £500 or the quotation sum
Accuracy of quotations	Where a customer challenges a quotation under the GT's published accuracy scheme and the quotation is found to be inaccurate the GT shall refund any overcharge that has been made.	N/A

Response to land enquiries	A GT shall respond to a land enquiry in respect of a new connection or alteration of an existing connection within 5 working days. Where a GT fails to achieve this, a fixed payment will be made in respect of the initial failure and each additional day during which the failure continues.	£40 Cap per customer: £250 for a new connection or altering an existing connection up to 275kWh/hr and £500 for>275 kWh/hr
Offering a date for commencement and substantial completion of connection work (≤ 275 kWh/hr)	Where a customer has accepted a quotation, the GT shall offer a date for commencement of the work and substantial completion within 20 working days. Where a GT fails to achieve this, a fixed payment will be made in respect of the initial failure and each additional day during which the failure continues.	£20 Cap per customer is the lesser of £250 or the contract sum
Offering a date for commencement and substantial completion of connection work (>275 kWh/hr)	Where a customer has accepted a quotation, the GT shall offer a date for commencement of the work and substantial completion within 20 working days. Where a GT fails to achieve this, a fixed payment will be made in respect of the initial failure and each additional day during which the failure continues.	£40 Cap per customer is the lesser of £500 or the contract sum
Completion of the work on the agreed date	Where a GT fails to substantially complete a connection on the date agreed with the customer, a payment will be made in respect of the initial failure and each additional day during which the failure continues.	Depending on the value of contract, £20 - £150. The cap varies between £200, 25% of the contract up to £9,000.
Notifying customers and making payments owed under the standards	GTs shall write to the relevant customer/shipper and make payment within 20 working days. Where a GT fails to achieve this level of service, a fixed compensation payment will be made.	£20

Overall Standards of Performance

1.4. The standards set minimum average levels of performance for a 12 month period in areas where it is not necessary appropriate to put in place guarantees for individual customers. They are determined separately for each GT by the Authority.

The following table summarises the overall standards showing the target level of performance which all GTs are expected to achieve in respect of the standard.

Standard	Definition	Target
Telephone calls (DNs only)	Telephone calls to the national emergency number (which operates 24 hours a day) will be answered by an individual within 30 seconds. Calls to the dedicated enquiry line and meter point reference number helpline (during the hours in which they operate) will be answered within 30 seconds.	90%
Notification of planned supply interruptions	For planned maintenance or replacement work, which involves interruption of the gas supply, the GT will provide written notification of the need for the interruption at least 5 working days before the expected interruption. The notice need not specify the date and time of the interruption. Its purpose is that it informs customers that an interruption may be required as a result of planned activities.	95%
Informing customers of when they are due to be reconnected	For unplanned supply interruptions or gas emergencies which are expected to last over 24 hours the GT or its contractor shall: (a) Where up to 250 customers are affected, notify individual customers that they have been interrupted and the expected programme for reconnection (including the expected date of reconnection) within 12 hours of the GT having knowledge of the interruption; (b) Where 250 or more customers are affected, provide public announcements (for example, using local public address broadcasts and local radio) throughout the area affected describing the expected programme for reconnection (including the expected date of reconnection) within 12 hours of the GT having knowledge of the interruption; and (c) Provide a progress report and revised information on the expected date of reconnection after each succeeding period of 24 hours from the original announcement or notification.	97%
Response to complaints	(a) GTs shall issue a written or verbal response to a written complaint within 5 working days of receipt of the complaint (where this is not a substantive response it will indicate when a substantive response may be expected); and (b) Where the initial response to a written or oral complaint is not a substantive reply the substantive response shall be provided within 10 days of receipt of the complaint (other than in exceptional circumstances)	90%

Gas emergencies (DNs only)	Where a report of a gas escape or other gas emergency, including a significant spillage of carbon monoxide or other hazardous situations relating to a company's DN is received on the emergency telephone service operated by Transco plc or by other means, it will attend as quickly as possible within the following timescales: (a) All uncontrolled gas escapes or uncontrolled gas emergencies within 1 hour of the call being received; and (b) All controlled gas escapes or other controlled gas emergencies within 2 hours of the call being received.	97%

Changes proposed under the Gas DPCR

1.5. As part of Gas DPCR Ofgem has reviewed the performance standards which GDNs are required to deliver and is proposing a number of changes. The effect of this package will be to provide a simpler range of measures for monitoring quality of service with tougher standards in some cases. It will also enable more effective enforcement in the event that GDNs fail to deliver.

1.6. Section 33BA of the Gas Act requires licensees to conduct their business in such a way that they can reasonably be expected to achieve overall standards of performance levels. In this way, a failure of an overall standard will not necessarily constitute a breach of the Act. We are proposing to migrate overall standards to licence conditions or guaranteed standards of performance. We consider that including precise performance levels in a licence condition, will enable the Authority to take more appropriate enforcement action against a licensee in the case the prescribed performance level is not met. Where the obligations become part of the guaranteed standards, individual consumers will receive a compensation payment in the event that the performance level is not met..

Associated documents

1.7. Guidance for reporting on Standards of Performance and Standard Special Licence Condition D10 For Gas Distribution Network Operators and Independent Gas Transporters, November 2005: http://www.ofgem.gov.uk/Networks/GasDistr/QoS/Documents1/12143-254_05.pdf

1.8. Gas Distribution Price Control Review Initial Proposals Document, Ofgem, 29 may 2007: http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/GDPCR%20Initial%20Proposals%20new%20template%20vfinal.pdf

Appendix 13 - Industry developments that may affect future gas SO costs

Changes in network flows

1.22. One of the most significant challenges facing the GB gas market over the coming years is the continued decline of gas supplies from the UK Continental Shelf (UKCS). Current estimates suggest that by 2012, output from UKCS will be around half the levels seen in 2000.

1.23. In response to this decline we have seen the growth in supplies from other sources in recent years, including imports from Norway (particularly through the Langeled pipeline, commissioned in Winter 2006/07), imports from the continent, and the growth of LNG imports. These changes are forecast to continue, with the development of new LNG importation facilities, as well as the commissioning of new gas storage facilities at a number of locations on the NTS.

1.24. These changes are likely to have significant implications for the way in which the SO operates the network and, as a consequence, the level and nature of costs incurred by the SO. For example, at present, the SO faces significant costs in transporting gas from point of entry at St. Fergus to areas of demand (located predominantly in the south of the country). To the extent that declining UKCS gas flows are substituted by flows that are located closer to demand, this may reduce the level of cost incurred by the SO. However, there also remains the possibility that exports of transit gas from the GB to the rest of Europe (potentially entering the GB market as LNG) could lead to an increase in compressor usage elsewhere on the NTS.

1.25. Changes in patterns of gas flows may also mean that the SO will consider it appropriate to make changes to the location and/or volume of gas reserves. In the event that new gas supplies are forecast to be available in areas where (relatively expensive) locational gas reserves have previously been required, this may lead to a reduction in the costs of the gas SO.

Improved information transparency

1.26. Recently there have been a number of initiatives that have led to enhanced information provision and increased transparency in the GB gas market. These include the implementation of UNC modification proposal 006 that led to the publication of real time flow data from NTS entry terminals, sub-terminals and storage sites[13]. This led to a step change in both the granularity and timeliness of

[13] Mod 006 was implemented on 3rd October 2006. In a bid to increase market efficiency it

gas market operational data. A number of modification proposals have also been raised that seek to improve the availability and transparency of demand side information[14].

1.27. UNC Review Group 140 was recently established to consider information provision on National Grid's Information Exchange. Amongst other things, the Group aims to assess the relevance of all the data currently being published on the information exchange, as well as to establish whether there are any additional data items which may be included on the website going forward.

1.28. In addition, in winter 2006/07 the SO undertook a number of initiatives to improve the quality of service of its website, specifically relating to the availability and timely delivery of key data. This led to significant improvements in website performance, particularly with regard to timely data delivery (discussed in more detail in the next section).

1.29. Gas market participants are therefore better informed about market conditions, enabling them to respond more quickly to unexpected changes in demand and supply. As a direct consequence of this improved transparency, we would expect that the volume of activity that the SO needs to undertake as residual balancer (either through trades in the OCM, or through management of linepack) should be reducing. We would therefore expect a commensurate fall in gas SO costs relating to residual balancing over time.

Contestable market for Operating Margins

1.30. In the context of the TPCR, NGG agreed to develop contestability in the market for OM services. This will mean that, once fully contestable, any provider of OM services should be capable of participating in the market on a competitive basis.

1.31. At present (and as discussed in more in this consultation document), a significant proportion of NGG's OM bookings are locational. As such, the development of a contestable market should increase the number of potential providers of OM across the network (including providers offering demand side services). In turn, we consider this should enable the SO to purchase OM at lower prices than at present, potentially leading to significant savings for customers.

required National Grid Gas NTS Plc to publish the volume of gas supplied to each eligible sub-terminal of NGG NTS' transportation network close to real time.

[14] These include Mod 97/97a (Release of information regarding pipeline interconnector offtake flows), Mod 101 (Amendment to demand forecasting timings in relation to the Gas Balancing Alert) and Mod 88 (Implementation of AMR meters to help commercial and industrial customers to manage their gas consumption during times of system stress).

Industry arrangements

Lastly, it is important to note that the industry arrangements within which the SO operates are of key importance to the nature and volume of activity that the SO is required to undertake. As discussed in Chapter 2, the ongoing review of electricity cash out arrangements may have implications for the levels of cost incurred by the SO in balancing the network. Although the gas cash out arrangements are out of scope of this current review, the review is a good example of a potential change that could have a significant impact on future SO cost.