

**Enduring transmission charging
arrangements for distributed generation**

A discussion document

September 2005

Summary

This document considers and invites views on whether the existing charging and contractual arrangements for distributed generation (also known as embedded or dispersed generation) are appropriate on an enduring basis. The arrangements are considered in light of recent developments in both the nature of connections to the electricity transmission and distribution networks and in the regulatory framework in Great Britain (GB).

In March 2005, the Authority approved National Grid Electricity Transmission plc's (NGET) proposals for a use of system charging methodology under the British Electricity Transmission and Trading Arrangements (BETTA). In developing its GB charging arrangements NGET noted that it was planning to undertake further work post-BETTA looking at the wider implications of distributed generation¹. This reflected the fact that the Government's Renewables Obligation (RO) has provided strong incentives to develop new renewable generation projects, creating a step change in the demand for connections to both the transmission and distribution networks. NGET noted that this was leading to a larger number of Grid Supply Points exporting onto the transmission system and expressed the view that the existing charging methodology and wider contractual framework were not sufficiently robust to address this change. Given the timescales for developing GB trading arrangements NGET noted that it did not intend to address these concerns within the initial GB methodologies for BETTA but that it may become necessary to consider developing the charging methodology and the wider commercial contractual arrangements in the short to medium term.

One consequence of these considerations was that in the interim Ofgem consulted on, and subsequently implemented through a new licence condition for NGET, a rebate for small (less than 100MW) transmission connected generators to address a specific arbitrary benefit to being distribution connected in England and Wales rather than transmission connected in Scotland. However, the discount was only set for a period of three years with a view to reviewing the charging arrangements and developing enduring arrangements for charging distributed generators.

¹ GB Transmission Charging: Final Methodologies Consultation – NGC, August 2004, p38
www.nationalgrid.com/uk/indinfo/betta/pdfs/GBChargingFinalMethodologieswithdiagramsfinalversion.pdf

In light of this the Authority considered that there would be merit in NGET, as GB system operator (GBSO), reviewing the appropriateness of its charging arrangements in relation to distributed generation at an early stage after the introduction of BETTA. As a first stage in this process Ofgem proposed to produce a document setting out the key issues and a consideration of possible options.

This discussion document is produced against the backdrop of a combination of factors, including but not limited to:

- different voltage definitions of transmission in England and Wales compared to Scotland - 132kV is defined as a distribution voltage in England and Wales but a transmission voltage in Scotland;
- the introduction, as an interim step not lasting more than three years, of a discount for small generators connected to the 132kV transmission network to ensure those generators were not unduly disadvantaged in relation to 132kV distribution connected generators under the GB charging arrangements;
- the Authority's approval of NGET's GB use of system charging methodology subject to five conditions, designed to ensure that future review of the methodology determines whether it could better meet NGET's relevant charging methodology objectives. NGET is currently progressing this review;
- a series of amendments being proposed to the Connection and Use of System Code (CUSC) relating to, among other things, the contractual requirements for small and medium distributed power stations and the flow of electricity from distribution systems into the transmission system;
- a Grid Code Review Panel (GCRP) Working Group being established to review the existing regional differences triggered by the current definition of small, medium and large power stations within the Grid Code; and
- Ofgem being in the process of conducting a review of the structure of charges for use of distribution networks.

Each of these areas has implications for, and is thus relevant to, a consideration of the enduring charging and contractual arrangements for distributed generators. However, Ofgem considers that the interactions mentioned above mean that it would be difficult for an individual licensee to adequately consider the full range of issues in the round. Thus, this discussion document seeks to set out a summary of these issues and consider

the treatment of distributed generation within the context of all these areas, such that respondents can comment on the arrangements, and potential refinements to the arrangements, as a whole. It suggests, and invites views on, a number of areas where Ofgem considers that potential amendments to the charging and contractual arrangements relating to distributed generation may, subject to further detailed consultation by relevant licensees, better facilitate licensees' relevant objectives and protect the interest of customers.

It is Ofgem's intention to publish a further document on distributed generation charging issues early in 2006. That document will, amongst other things, summarise responses to this document and consider the implications of different options for reviewing the existing charging arrangements.

The two documents are intended to stimulate debate and highlight areas in which respondents consider that changes could be made to existing arrangements. It is not the intention of either document to draw firm conclusions or prescribe a way forward. Ofgem expects both NGET as GBSO, distribution licensees and industry members to consider possible changes to the existing charging arrangements and wider changes necessary to better reflect the transmission network costs that are imposed by distributed generators. It will be for licensees, in tandem with industry, to develop any such proposals through the appropriate consultation and modification channels. Since in most instances Ofgem will have a role in approving modifications subsequently proposed, it would be inappropriate for Ofgem to prescribe particular answers to the issues raised. Ofgem's role at this stage is to facilitate debate in a co-ordinated manner.

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1. Rationale

- 1.1. Ofgem's principal responsibility is to protect the interests of consumers, wherever appropriate through the promotion of effective competition. In the context of network charging, Ofgem considers that consumer interests are best served by developing cost reflective charging arrangements, i.e. ensuring that parties face the costs they impose on the system. Cost-reflective charges contribute to the efficient use of the network, the efficient trade off of costs and benefits when deciding on connection sites and thus the lowest cost solution for all parties who pay transmission charges. Consumers ultimately benefit from cost effective decision making in the amount they pay in utility bills.
- 1.2. In carrying out its functions the Authority is also required to have regard to the effects on the environment of activities connected with the generation, distribution, transmission or supply of electricity. Ensuring that all generators, both distribution and transmission connected, face appropriate network charges can be expected to promote the efficient use of the network, which in turn can have environmental benefits. The pattern of generation and demand connected to the network determines the amount of energy that is lost through the transmission of electricity. Inefficient network use can result in an unnecessary amount of lost energy. Further, encouraging efficient network use can reduce the number of unsightly transmission circuits needing to be built. Finally, greater consistency in charging arrangements might be expected to have particular relevance to renewable generation connected to the 132kV transmission circuits in Scotland. This could ensure more equitable treatment of this class of generator in comparison to other classes of renewable generator, thereby promoting greater efficiency in the development of renewable generation as a whole.
- 1.3. Recent developments in regulatory arrangements and incentives to connect, particularly renewable generation technologies, to transmission and distribution networks has meant that the traditional pattern of network usage has altered and is likely to continue to do so. In light of the changes that are already being seen, Ofgem considers that it is appropriate to review the adequacy of the existing regulatory and charging arrangements.

- 1.4. One of the key factors increasing demand for network capacity, at both transmission and distribution level, is from distributed generation plant. Distributed generation (also known as embedded or dispersed generation) is electricity generation that is connected to a distribution network, rather than the transmission network. The voltage definition of distribution networks differs across GB. In England and Wales circuits up to and including the 132kV network form part of the distribution network while in Scotland 132kV circuits form part of the transmission network, and thus only voltages below 132kV are defined as distribution.
- 1.5. Distributed generation is already an important feature of the GB power system and networks and its importance is set to grow, particularly if offshore transmission infrastructure connects to distribution networks. It is expected that increasingly Grid Supply Points (GSPs) will export power from the distribution system to the high voltage transmission network at some times rather than import power from it at all times. An enduring transmission network charging framework, taking full account of the costs arising as a consequence of the connection and actions of distributed generators, needs to be robust to the changing physical background. The historical treatment of distributed generation has, in essence, ignored the impact of much distributed generation on the transmission network. While this was defensible in the context of relatively small amounts of distributed generation, the approach would appear to be less appropriate in circumstances where the amount of distributed generation is large and growing.
- 1.6. A number of areas of work being undertaken by both Ofgem and industry participants, which are discussed in detail later in this document, can be expected to have implications for the charging and/or contractual arrangements relating to distributed generation. These include: the distribution structure of charges review; the conditions imposed by the Authority in approving NGET's initial GB charging methodology; various Connection and Use of System Code (CUSC) Amendment Proposals; and future Grid Code change proposals being developed by NGET with the assistance of the Grid Code Review Panel (GCRP).
- 1.7. Given the multiple work streams with the potential to impact on distributed generation, the recent introduction of new contractual arrangements for

embedded exemptible large power stations (EELPS) as part of the British Electricity Transmission and Trading Arrangements (BETTA), and increasing discussion within the industry about the issues which an increased penetration of distributed generation may give rise to, Ofgem considers it appropriate to issue a document:

- ◆ outlining current charging and contractual arrangements
- ◆ discussing interrelated issues
- ◆ setting out a range of possible approaches to amending the existing arrangements, and
- ◆ inviting views on these options.

- 1.8. Following consideration of responses to this document, Ofgem intends to issue a further document summarising respondents' views and highlighting areas where respondents consider that amendments to current arrangements could aid competition or better facilitate the relevant objectives of codes, licences or charging methodologies. However, it is not Ofgem's intention to prescribe solutions or mandate amendments to industry documents. In the first instance it will be for NGET as GB system operator (GSO) to consider possible changes to the existing transmission charging arrangements to better reflect the costs imposed by distributed generators on the network, and for licensees, or signatories to industry codes, to raise modifications to appropriate documents.

Legal framework

- 1.9. The Electricity Act 1989 (the "Act") sets down the legislative structure under which the electricity industry operates including the roles and duties of the Authority. Sections 3A to 3C set out the Authority's principal objective and statutory duties.
- 1.10. The Authority's principal objective is "to protect the interests of consumers ... wherever appropriate by promoting effective competition". In addition the Act places a number of other duties on the Authority including carrying out its functions in a manner which is best calculated to secure a diverse and viable long term energy supply and having regard to the effect on the environment of

activities connected with the generation, transmission, distribution or supply of electricity.

- 1.11. On 5 October 2004 the Authority became subject to two additional statutory duties under the Energy Act 2004. These relate to contributing to the achievement of sustainable development and having regard to the principles of best regulatory practice. In carrying out its duties the Authority must also have regard to any additional guidance issued by the Secretary of State in relation to social or environmental policies.
- 1.12. In addition to the regulatory framework set out under the Act, the electricity industry is also subject to European law and competition law. Section 3D of the Act confirms that the obligations imposed on the Authority under Sections 3A to 3C of that Act do not override contradictory duties or obligations under European law including Directive 2003/54/EC concerning common rules for the internal market in electricity and Directive 2001/77/EC concerning the promotion of electricity from renewable sources in the internal market.
- 1.13. Finally, Ofgem has concurrent powers with the Office of Fair Trading ('OFT') to apply the Competition Act 1998 to the gas and electricity sectors in GB. Ofgem's principle objective and duties do not apply to the concurrent exercise of powers under the Competition Act. The Competition Act contains two prohibitions. Chapter 1 prohibits agreements between undertakings, decisions by associations of undertakings and concerted parties that have as their object or effect the restriction, distortion or prevention of competition with the United Kingdom. Chapter 2 prohibits abuse of a dominant position by an undertaking within the United Kingdom.

Structure of this document

- 1.14. The remainder of this document is structured as follows.
 - ◆ Chapter 2 sets out additional detail on the background to this document; including further information on the relevant aspects of BETTA and other key related issues applying to distributed generation. In addition, it summarises the existing contractual and charging arrangements for distributed generators.

- ◆ Chapter 3 provides details of relevant areas of work which are ongoing, including: work by NGET in addressing its five conditions; work of the GCRP; the distribution structure of charges project and a number of CUSC amendments currently at working group stage.
- ◆ Chapter 4 outlines some of the key issues posed by the existing charging and contractual treatment of distributed generators which have informed Ofgem's analysis of the relative merits of the options discussed in Chapter 5.
- ◆ Chapter 5 sets out potential options for addressing those issues and developing enduring charging arrangements for distributed generation.
- ◆ Finally chapter 6 provides details of how to respond, the issues on which Ofgem invites views and the way forward.
- ◆ Two appendices are also attached to this document. Appendix 1 sets out relevant information on the treatment of distributed generation internationally. Appendix 2 contains a pictorial representation from NGET's approved transmission use of system charging methodology statement² setting out the parties liable for Transmission Network Use of System (TNUoS) charges.

Responding to this document

1.15. Ofgem intends this document to give rise to discussion and therefore invites views on any of the issues raised. However, views are sought in particular on:

- ◆ the extent to which the current charging and contractual arrangements relating to distributed generation are appropriate/ inappropriate
- ◆ the need for refinement of the existing charging and contractual arrangements, and
- ◆ the options for refinement of the existing arrangements outlined in Chapter 5.

²www.nationalgrid.com/uk/indinfo/charging/pdfs/UOSCM11R1-GBFinalAugust2005.pdf

- 1.16. Views are invited by Friday 9 December 2005. Where possible, responses should be sent electronically to:

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- 1.17. All responses will be held electronically in Ofgem's Research and Information Centre. They will normally be published on the Ofgem website unless they are clearly marked confidential. Consultees should put confidential material in appendices to their responses where possible. Ofgem prefers to receive responses electronically so that they can easily be placed on the website.
- 1.18. Should you have any questions regarding the issues raised in this document please contact Mark Copley (e-mail: mark.copley@ofgem.gov.uk, telephone 0207 901 7410) or Grant McEachran (e-mail: grant.mceachran@ofgem.gov.uk, telephone 0141 332 5647).

2. Background - existing contractual and charging arrangements

Contractual arrangements between NGET and distributed generators

- 2.1. In England and Wales, the key concept underlying the contractual arrangements that apply to distributed generators is that only power stations located on distribution networks that were sufficiently large to be licensable should be contractually obligated to NGET. This principle has remained broadly stable since vesting.
- 2.2. The basic rule adopted in England and Wales was a simplifying assumption that licensable plant above the size limit of 100MW, which corresponds to the England and Wales threshold for defining a large power station as set out in the Grid Code, uses the transmission system. It must therefore contract for an appropriate level of transmission capacity and pay use of system charges. Conversely plant below the limit does not pay use of system charges, and because it is assumed to improve the overall capability of the transmission system, through netting off against demand, receives a transmission payment.
- 2.3. Arrangements in Scotland before the introduction of BETTA were different in each transmission licensee's area. In one area, unlicensed distributed generators netted off against supply and in the other area charges were based on an assessment carried out on a case-by-case basis to determine how much use an individual generator was deemed to make of the transmission system. The result was that some distributed generation paid transmission charges on the same basis as transmission-connected generators on a deemed proportion of their capacity.
- 2.4. In developing BETTA, Ofgem/DTI recognised that due to the relatively high number of large³ distributed power stations in Scotland, a number of which

³ See paragraph 2.13

were eligible to be exemptible from the need to hold generation licences, in order to maintain the reliability and security of the GB transmission system, it was necessary for those parties to have an appropriate relationship with the GBSO to ensure compliance with appropriate sections of the Grid Code. In essence, a contractual framework was required to replace the framework of bilateral agreements between the generator and the Scottish transmission and distribution licensees. Ofgem/ DTI consulted on the treatment of EELPS in July 2004⁴. In its conclusions published in November 2004 Ofgem set out the view that EELPS should be required to either enter into a bilateral agreement based upon the form of the existing Bilateral Embedded Generation Agreement (BEGA) in the CUSC or enter into a new Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA).

BEGA

- 2.5. A BEGA must be signed by a distributed party greater in size than 100MW or a party which is defined as large in the Grid Code and requires transmission system access rights, and may be entered into by other generators. Parties entering into a BEGA are required to comply fully with the Grid Code (insofar as it applies to them) and are required to register the generators as Balancing Mechanism Units (BMU) in accordance with the Balancing and Settlement Code (BSC). A BEGA provides firm rights to access the transmission system, subject to the payment of transmission charges as calculated in accordance with the use of system charging methodology. It should be noted that the use of system charging methodology currently stipulates that only directly connected parties or distributed generators greater in size than 100MW are liable for transmission charges.

BELLA

- 2.6. An EELPS which does not wish to become a party to the BSC may choose to sign a BELLA. The principle differences for parties entering into a BELLA would be:

⁴ Treatment of embedded exemptible large power stations under BETTA: An Ofgem/DTI mini-consultation document – Ofgem/DTI, July 2004 #161/04
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- ◆ the BELLA would not allocate any use of system rights or Transmission Entry Capacity (TEC) to the EELPS
- ◆ the EELPS would not be required to become a BSC party as the power station metering may be registered in the BSC supplier meter registration service (SMRS) by a supplier, and
- ◆ the EELPS would generally be required to comply with the provisions of the Grid Code applying to large power stations. However, certain elements of the Grid Code would not be applicable including, unless required by NGET, the requirement to provide physical notifications.

Licence Exempt Generation Agreement (LEGA)

- 2.7. When a medium power station applies for licence exemption, the DTI will consult NGET (among others). To date NGET has identified a number of technical requirements that it considers should be a condition of the licence exemption which it has set out in a LEGA with the generator seeking licence exemption.
- 2.8. The LEGA deals with technical issues and is outside the BSC, CUSC, Grid Code and charging methodology. It is recognised that the LEGA is an interim arrangement and that the industry is developing proposals for an enduring solution within the Grid Code, Distribution Code and CUSC governance.

NGET's contractual framework

- 2.9. NGET's transmission licence places obligations on NGET, which establish the legal framework for dealing with all transmission system users. NGET must have in place:
- ◆ a Grid Code dealing with material technical aspects relating to connections to and use of the transmission system
 - ◆ a BSC dealing with how half-hourly imbalances of wholesale traded electricity are settled, and which among other matters in effect establishes the basis for accrual of some embedded benefits

- ◆ a CUSC dealing with contractual issues relating to connection to and use of the transmission system, and
- ◆ statements of charging methodologies and of charges.

2.10. Each of these documents is summarised below.

Grid Code

- 2.11. NGET's Grid Code defines technical obligations on NGET and users of the transmission system (including those parties who are connected to and/or are impacting on the transmission system). The Grid Code defines many generator obligations on the basis of power station size and the Grid Code includes definitions of small, medium and large power stations which impact on the type of contractual agreement which a generator must enter into with NGET.
- 2.12. Many distributed generators are not directly required to comply with the Grid Code but, where NGET considers that a generator can impact on the system, it will attempt to establish a contractual arrangement in order to oblige compliance with some or all aspects of the Grid Code, as described previously.
- 2.13. The Grid Code includes a number of regional differences between areas of the transmission system owned by different parties reflecting technical differences between these parts of the network. One example is the thresholds for defining small, medium and large power stations. At present the thresholds are as follows:
- ◆ large power station - a power station in NGET's transmission area with a registered capacity of 100MW or more, a power station in SP Transmission Ltd (SPT)'s transmission area with a registered capacity of 30MW or more, or a power station in Scottish Hydro Electric Transmission Ltd (SHETL)'s transmission area with a registered capacity of 5MW or more
 - ◆ medium power station – a power station in NGET's transmission area with a registered capacity of 50MW or more, but less than 100MW, or a power station in SPT's transmission area with a registered capacity of 5MW or more, but less than 30MW, and

- ◆ small power station – a power station in NGET’s transmission area with a registered capacity of less than 50MW, or a power station in SPT’s or SHETL’s transmission area with a registered capacity of less than 5MW.

2.14. In developing the Grid Code as part of BETTA it was acknowledged that it would not be possible to harmonise all arrangements across the transmission areas for BETTA Go-Live (1 April 2005). However, to ensure that work on harmonisation continued post-BETTA the duties of the GCRP were amended to include an obligation to consider and identify changes to the Grid Code to remove any unnecessary differences in the treatment of issues across GB. As noted in paragraph 3.32, NGET has proposed that to address this obligation a GCRP Working Group is formed to review the relevance of the existing definitions of small, medium and large power stations.

Balancing and Settlement Code (BSC)

2.15. The BSC deals with electricity trading between BSC parties. Only a BSC party can register the metering at a connection point for use in electricity settlements. Typically, distributed generators trade in the BSC through a third party, most often a supplier, therefore any BSC impacts will typically be seen indirectly through the contract with their supplier. However, distributed generators who choose to sign a BEGA must also accede to the BSC.

CUSC

2.16. The CUSC sets the contractual framework for connection to and use of the transmission system. Since 1 April 2005, the CUSC arrangements have been applicable GB wide and all commercial arrangements with transmission-connected parties are now administered by NGET in its role as GBSO.

2.17. Distributed power stations that impact on the transmission system are required to comply with the requirements set out in the CUSC. Section 3 of the CUSC determines rights and conditions for use of the GB transmission system. The conditions focus on the requirements to have a use of system agreement in place and on payment of the associated access charges. Another such condition is that a qualifying distributed generator must have entered into a BEGA or BELLA with NGET and have a distribution agreement with the

Distribution Network Operator (DNO). There is no explicit definition in the CUSC of the level at which a distributed generator may have an impact on the transmission system; this has to be decided on a case by case basis by the appropriate DNO and NGET.

- 2.18. CUSC section 6.5 (1-4) prevents a DNO from energising a connection until requirements to enter the appropriate contracts with NGET are met. This process is designed to ensure that any transmission system short circuit, thermal, voltage and stability limitations are identified and addressed.
- 2.19. The CUSC amendments panel oversees the assessment of all amendment proposals to the CUSC, according to prescribed timescales. Any changes have to be assessed against specified applicable objectives set out in standard condition C10 of the transmission licence and include the efficient discharge of obligations imposed under the Act and the licence and to facilitate effective competition, where appropriate, in the generation and supply of electricity.

Charging arrangements

Principles of TNUoS charges

- 2.20. The primary purpose of a transmission system is to transport bulk energy via high voltage lines and cables from generators to centres of demand. The amount of transmission infrastructure needed is determined by the extent to which generation and demand are disparate. In GB there is a surplus of generation in the north, and a relative excess demand in the south. Therefore, the prevailing direction of flows over the GB transmission network is north to south.
- 2.21. NGET has adopted a locational charging methodology. This means that charges vary depending on where a generator is putting energy on to the network, and depending on where a supplier is taking energy from the transmission network. The basic premise behind locational charging is that generators furthest away from centres of demand (and suppliers furthest away from centres of generation) make most use of the transmission system – and therefore should make a larger contribution to the total costs of the transmission system.

- 2.22. Charges are based on the forward looking long run marginal cost of providing incremental capacity at different points on the network, adjusted for voltage, and security. The charges reflect the fact that, because of the existing pattern of power flows over the network and prevailing pattern of demand and generation, locating in some places will cause higher reinforcement costs than at others. Indeed locating at certain points may reduce or defer the need for reinforcement and therefore reduce the total costs of the network.
- 2.23. The TNUoS charges are themselves comprised of two elements. The first, as described above, is a locational element. However, in addition the charges include a non-locational (or residual) charge which is the same in every zone and is set to ensure NGET recovers its total allowed revenue as determined by Ofgem during price controls.

Governance

- 2.24. The GBSO is responsible for setting charges on a GB basis and for developing and maintaining the GB charging methodologies and statements. There are three statements which the GBSO must have in place and which must be approved annually by Ofgem. These are:
- ◆ the **Statement of the Use of System Charging Methodology**, which details the methodology used to calculate use of system charges
 - ◆ the **Statement of Use of System Charges** which details the use of system charges, and
 - ◆ the **Connection Charging Methodology**, which sets out the methodology by which connection charges will be calculated.
- 2.25. NGET is required to keep its charging methodologies under constant review and make such changes as may be required for the purpose of better achieving the relevant objectives. Proposed changes must be consulted upon by the licensee and approved by the Authority. The relevant objectives are:
- ◆ to facilitate effective competition where appropriate in the generation and supply of electricity and facilitate competitiveness in the sale, distribution and purchase of electricity

- ◆ to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses, and
- ◆ to properly take account of the developments in transmission licensees' transmission businesses.

2.26. In addition there is a further objective in the connection charging methodology requiring NGET to facilitate competition in the carrying out of works for connection to the transmission system.

Types of charge

2.27. The GBSO levies three types of charge to recover the costs of network assets and costs incurred in balancing and operating the transmission system:

- ◆ **TNUoS charges** recover the costs of infrastructure assets which are, or have the potential to be, used by more than one user. Circa £1.1bn is currently recovered annually via TNUoS charges
- ◆ **Balancing Services Use of System (BSUoS) charges** recover the costs incurred by NGET in balancing supply and demand on the transmission network from BSC parties. This includes, for example, the costs of bids and offers accepted in the balancing mechanism, reserve contracts and constraint payments, and
- ◆ **Connection charges** recover the costs of assets provided specifically for the purpose of connecting an individual user to the transmission network which do not have the potential to be used by another user. Around £100m is currently recovered in connection charges.

Liability for TNUoS charges

2.28. The statement of the use of system charging methodology sets out charging liability and the method by which charges are calculated. Appendix 2, transposed from the statement, provides a pictorial representation of those parties liable for both generation and demand TNUoS charges.

2.29. The following CUSC parties are currently liable for generation charges:

- ◆ parties of generators that have a Bilateral Connection Agreement (BCA) with National Grid
- ◆ parties of licensable generation that have a BEGA with NGET and are greater than 100MW in size, and
- ◆ interconnector asset owners that have a BCA with NGET and/or interconnector asset owners of interconnectors capable of exporting 100MW or more to the total system.

- 2.30. It should be noted that while a BEGA contains provisions requiring parties to pay TNUoS charges in accordance with the statement of the use of system charging methodology, the current drafting of the methodology means that parties which are defined as being large but are smaller than 100MW in size have no liability for TNUoS.
- 2.31. A user's transmission access rights and liability for charges are defined by their TEC. TEC gives a generator a right to export power up to the chosen level of capacity at any point during the charging year. Following the introduction of CAP048⁵ this capacity is firm and a generator will be compensated in the event of temporary physical disconnection.
- 2.32. A directly connected party or a party with a BEGA will, on an annual basis, decide on their chosen level of entry capacity. The purchase of TEC in one charging year conveys an option to renew that capacity in the subsequent year, subject to the payment of TNUoS charges, unless the user makes an application to NGET to reduce their TEC. If TEC is reduced, then any subsequent request by the user to increase its TEC will be treated by NGET as a new application for TEC, and the sought capacity could be dependent on whether other parties are also seeking TEC in that area of the network. Consequently, the TEC might only be available upon completion of specified additional works.

⁵ See <http://www.nationalgrid.com/uk/indinfo/cusc/pdfs/CAP048D.pdf>

3. Interrelated areas of work

BETTA and transmission charging

- 3.1. On 30 September 2004 following nine months of extensive industry consultation, NGET submitted proposals for both a GB transmission connection charging methodology and a GB transmission use of system charging methodology to the Gas and Electricity Markets Authority (the “Authority”) for approval⁶. Ofgem published an impact assessment and consultation in respect of the September proposals in October 2004⁷.
- 3.2. Having assessed the proposals against the relevant objectives, the Authority decided to approve NGET’s proposed connection charging methodology but did not approve NGET’s proposed use of system methodology, as it considered that further work in a number of specific areas had the potential to better facilitate the relevant objectives⁸.
- 3.3. In the light of those decisions, NGET developed and consulted on revised proposals for a GB use of system methodology and submitted a revised methodology to the Authority for approval in January 2005⁹. Following the publication of a further impact assessment¹⁰ and having regard to other relevant information, the Authority was satisfied that NGET had addressed appropriately and proportionately the areas of weakness which it had identified in rejecting the September proposals. The Authority published its decision approving NGET’s proposed use of system charging methodology in March 2005¹¹.

⁶ GB Transmission Charging: Final Methodologies Conclusion Report to the Authority – NGET, September 2004

⁷ The proposed transmission charging methodologies of the GB system operator: An Ofgem consultation and Impact Assessment – Ofgem, October 2004 #241/04

⁸ NGET’s proposed GB electricity transmission charging methodologies: the Authority’s decisions – Ofgem, December 2004 #275/04

⁹ Use of system charging methodology revised proposals: Conclusions report to the Authority – NGET, January 2005

¹⁰ The proposed transmission use of system charging methodology of the GB system operator: An Impact Assessment – Ofgem, February 2005 #25/05

¹¹ NGET’s proposed GB electricity transmission use of system charging methodology: The Authority’s decisions – Ofgem, March 2005 #80/05

3.4. The Authority attached a number of conditions to its approval of the use of system charging methodology. The conditions relate to future actions by NGET which the Authority considered might reasonably be expected to promote further the attainment of the relevant objectives of NGET's methodology. Five conditions were attached to the approval¹². Three conditions relate primarily to ensuring as far as practicable that the methodology results in charges which reflect costs. Two conditions relate primarily to the facilitation of effective competition. Those conditions were:

- ◆ Condition 1: To invite views and to consult on alternative methods of addressing the issue of negative demand charges
- ◆ Condition 2: To identify, review and assess further the technical basis for a range of alternative methods of estimating, and reflecting in locational charges, the incremental costs of capacity
- ◆ Condition 3: To review, invite views and to consult on alternative methods of treating intermittent generation
- ◆ Condition 4: To invite views and to consult on methods of enabling transmission users to choose to contract for rights to use the transmission system with TNUoS charges fixed at a specified level for periods of more than one year, and
- ◆ Condition 5: To publish information at least once a year on the forecast future (at least five years) path of tariffs under a range of credible generation and demand scenarios.

3.5. Ofgem attached a timescale of between 1 and 2 years in which it expects NGET to review these areas and, where it identifies potential improvements in its charging methodology, to bring forward proposals to modify that methodology¹³.

3.6. Furthermore, the Authority noted that the conditions listed above do not detract in any way from NGET's enduring licence obligation to keep its charging

¹² Full details of the conditions are available at: www.nationalgrid.com/uk/indinfo/charging/mn_TNUoS.html

¹³ An indicative timeline for addressing the conditions is available at: www.nationalgrid.com/uk/indinfo/charging/pdfs/Approval_Conditions_Workplan.pdf

methodologies under review at all times and to bring forward modifications where it considers that such changes would in its view result in the methodologies better meeting the relevant objectives. Charges calculated using the approved methodology were introduced from 1 April 2005.

- 3.7. Ofgem is mindful of the ongoing work of NGET in addressing the commitments imposed on it by the Authority and in particular notes that conditions relating to the treatment of intermittent generators and, to some extent, negative demand charges will be of direct interest to distributed generators.
- 3.8. NGET has recently issued a charging consultation (ECM 02)¹⁴ consulting on a number of options for eliminating negative demand charges. These include, amongst other things, amending the prescribed share of total revenue recovered from generators relative to the share recovered from suppliers and large users, the so-called G/D split, and constraining tariff differentials. Constraining tariff differentials may alter the percentage of allowed revenue recovered via the locational element of TNUoS charges and hence affect the value of the rebate for small generators, discussed below.
- 3.9. On the issue of intermittent generation NGET recently published a questionnaire seeking industry views on possible ways to reflect the impact of intermittent generation within its charging model. In the light of the feedback to that questionnaire it is anticipated that NGET will publish further thoughts shortly.

Interim discount for small generators connected at 132kV in Scotland

- 3.10. In November 2003 Ofgem/DTI consulted on small generator issues under BETTA¹⁵. The purpose of the document was to consider the position of small generators (in this context defined as generators with a total connected capacity of less than 100MW) across the piece under the proposed set of reforms as part

¹⁴ ECM02 was issued on 3 Aug 2005: See

http://www.nationalgrid.com/uk/indinfo/charging/pdfs/GB_ECM_02_Neg_Demand_Tariffs_FINAL.pdf

¹⁵ The document is available at:

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5125_Small_Generators_issues_20nov03.pdf

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of BETTA. The document highlighted one particular area of concern relating to transmission charging and small transmission-connected generators in Scotland.

- 3.11. The specific problem was, what appeared to be, an arbitrary benefit (i.e. not reflecting differences in costs or other objective criteria) of being distribution connected as opposed to transmission connected, associated with the ability of small distribution connected generators to 'net off' demand and thereby enable suppliers to reduce their liability for demand charges. Prior to the introduction of BETTA there were no generators with a total connected capacity of less than 100MW connected to the transmission system in England and Wales. However, in Scotland there are a number of generators with capacities lower than 100MW connected to the 132kV transmission network.
- 3.12. Ofgem's proposed remedial measure was an interim (i.e. not more than three years) discount against NGET's use of system charges for small transmission connected generators. Ofgem also undertook to progress work in the medium term to address this discrepancy on an enduring basis. The interim nature of the proposal recognised that an enduring solution could not be delivered in time for the BETTA Go-live date (1 April 2005), and that implementing a short-term measure appeared to be a proportionate policy response given the potential for small transmission-connected generators being commercially disadvantaged and for investment decisions to be distorted in the short term.
- 3.13. The interim discount is given effect through a stand-alone licence condition for NGET. It is not, formally, part of NGET's charging methodology. The new licence condition, standard condition C13 (Adjustments to use of system charges (small generators)), was designated to give effect to the measure as part of the BETTA reforms. The adjustment requires NGET to discount charges for eligible generators by a set amount and to recover the revenue shortfall from demand users non-locationally based on peak demand.

- 3.14. The Authority determined that the discount would be calculated to reflect the benefit that small distribution connected generators gain from netting-off demand¹⁶ which is not available to small transmission connected generators. In charging year 2005/06 this gives a discount of £3.61/kW. The Authority further determined that the discount would stay in place for a maximum period of three years, while retaining its right to issue a direction at any time stating that, with effect from the beginning of the subsequent charging year, the discount could be set to zero.
- 3.15. The discount for transmission connected generators is scheduled to expire in 2008. Further, it is not Ofgem's view that the extension of the discount is a desirable option. The discount was only introduced as an interim measure to address a discrepancy in the charging arrangements until an enduring solution could be found. Therefore, an enduring solution to this issue must be introduced within this timescale. This represents the absolute minimum that a review of the charging arrangements for distributed generation should address.

Embedded benefits

- 3.16. Embedded benefits can be summarised as the benefits arising as a consequence of a generator being distribution rather than transmission connected and relate to the ability to avoid certain transmission and trading-related charges associated with reducing power flows on the transmission system.
- 3.17. Generators and suppliers directly connected to the transmission network are liable for TNUoS charges. As signatories to the BSC they also incur other related charges including BSUoS charges and the costs incurred by Elexon in managing the centralized trading system, including transmission losses and trading charges. However, small generators connected to the distribution networks that are not signatories to the BSC are not subject to these charges, and indeed can have the effect (through bilateral contracts) of reducing the liability for such charges for other BSC parties. The output of a distributed generator will frequently be used to offset the amount of energy which a supplier needs to offtake from the transmission network, reducing its liability

¹⁶ The ability for a supplier to contract with a small distribution connected generator for output as a result both parties avoid using the transmission network and consequently paying TNUoS charges.

for TNUoS charges. It is likely that the distributed generator will realise a percentage of this saving via its contract with the supplier.

- 3.18. In addition, a distributed generator registered as a Balancing Mechanism Unit (BMU), will be paid by NGET depending on its output over the Triad period¹⁷. This is because its output is considered to offset the levels of demand offtake from the transmission network and hence aid system security. The distributed generator receives the demand tariff for the zone in which it is connected.
- 3.19. The manner in which BSUoS charges apply to licence-exempt distributed generators which are signatories to the BSC changed on 5 November 2003, when BSC Modification P100 was implemented. It allows for licence-exempt distributed generators who are signatories to the BSC and have registered meter(s) in the central meter registration service (CMRS) to have the opportunity to receive directly from NGET the benefit of reducing the BSUoS charge as well as receiving other benefits relating to the Balancing and Settlement Code Company (BSCCo) costs and transmission losses.
- 3.20. The level of embedded benefits varies by location across GB but will include the inverse of the locational demand charge (reflecting the impact on transmission costs) plus the full value of both the demand and generation residual charges (not reflecting any cost impact). Further, the value of the benefits accruing to distributed generators will depend on the outcome of the contractual negotiation that generator has with the supplier.

Distribution charging

- 3.21. In December 2000 Ofgem initiated a review of the structure of distribution charges. This review was driven by concerns over the divergence of charging arrangements between the DNOs and recognition that the existing arrangements needed to be reviewed in the light of an expected increase in distribution-connected generation.

¹⁷ The Triad is the collective term for the three half hourly periods, separated by at least 10 days, between November and February where the highest levels of demand are recorded.

- 3.22. In its initial decision paper published in November 2003¹⁸, Ofgem proposed that by April 2005:
- i. there should be a common connection boundary for demand and generation
 - ii. generators should no longer pay deep connection charges and should face use of system charges, and
 - iii. DNOs should determine connection and use of system charging methodologies.
- 3.23. The paper also proposed that further consideration should be given to the development of long-term charging arrangements to be in place, at the latest, by 2010.
- 3.24. On 1 June 2004 the Authority gave notice of its intention to change standard licence condition 4 of the distribution licence requiring that the DNOs determine use of system and connection charging methodologies and gain approval for these by 1 April 2005. DNOs submitted draft use of system and connection charging methodologies to Ofgem in September 2004. Following consultation and revision the Authority approved final charging methodologies, some conditionally, in February 2005¹⁹.
- 3.25. One of the key elements of the new arrangements was the introduction of a generation use of system charge (GDUoS), in place of the previous deep connection charging regime. The GDUoS tariffs cover the costs of network reinforcement not captured within connection charges under the apportionment rules.
- 3.26. With the interim charging arrangements in place, Ofgem has issued initial thoughts on the development of longer term charging arrangements for electricity distribution networks, explaining the work that has been carried out by Ofgem, the industry and three groups of academics earlier in 2005²⁰. The document outlines and discusses the various options for distribution charge

¹⁸ Structure of Electricity Distribution Charges – Ofgem, 14 November 2003 #142/03

¹⁹ Ofgem approves new charges for high voltage network: Press Release – Ofgem, 25 February 2005 #R/12

²⁰ The document is available at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/11417_13505.pdf
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setting models, and also notes some of the issues associated with the development of use of system charges for demand and generation.

- 3.27. Ofgem expects to publish conclusions on these topics later in 2005, with the intention of providing a platform for the development of longer term and enduring charging arrangements by the DNOs and the industry. Ofgem expects that the development of the longer term arrangements will be predominantly led by the DNOs and industry in accordance with the methodology modification process.

Grid Code modification proposals

- 3.28. In May 2003 the GCRP²¹ and Distribution Code Review Panel (DCRP) set up a joint working group to consider, in the light of changes to the licence exemption regime, how existing technical requirements in the Grid Code can be applied to Licence Exempt Embedded Medium Power Stations (LEEMPS) in a robust manner without such stations requiring an enduring agreement with NGET.
- 3.29. Having discussed a wide range of issues the group agreed that a framework whereby the Grid Code obligations were passed through to the host DNO, with the DNO in turn placing those obligations on the generator through the Distribution Code, would be the most appropriate approach. The joint working group then reviewed the drafting of both the Grid Code and the Distribution Code with a view to establishing the proposed mechanism.
- 3.30. In July 2005 the joint working group submitted a final report for the GCRP and DCRP. This recommended that the draft changes to the Grid and Distribution Codes developed by the working group should be taken forward to the consultation stage. NGET²² and the DCRP²³ are currently consulting on these proposed changes.

²¹ For information on the work of the GCRP see http://www.nationalgrid.com/uk/indinfo/grid_code/mn_gcrp_business.html

²² NGET's consultation on proposed Grid Code changes is available at: http://www.nationalgrid.com/uk/indinfo/grid_code/pdfs/cp_d05.pdf

²³ The DCRP's consultation on proposed Distribution Code changes is available at: http://www.energynetworks.org/dcode/pdfs/050823_LEEMPS_Consultation_package.zip

- 3.31. The group also identified the need for complementary changes to the CUSC and duly referred the matter to the CUSC panel. An amendment (CAP097) has now been proposed to the CUSC panel in relation to the contractual framework for LEEMPS. This is discussed in more detail below.
- 3.32. A GCRP working group has also been established to review the definitions of small, medium and large as part of its work streams for the latter part of 2005. This work has been requested by a number of industry participants and is in accordance with the GCRP's obligations "to consider and identify changes to the Grid Code to remove unnecessary differences in the treatment of issues in Scotland from their treatment in England and Wales"²⁴. Ofgem understands that this work may consider whether the existing Grid Code definitions are appropriate in light of operational experience under BETTA.
- 3.33. General Condition 15 of the Grid Code allows relaxation of the requirement to apply the Grid Code in relation to EELPS and EEMPS in Scotland for a time limited period. This relaxation was considered necessary for the implementation of the BETTA arrangements and was directed by Ofgem. NGET has recently submitted a report to the Authority proposing a Grid Code change to extend the defined time limit for a further 12 months on the basis that it is likely that the relevant obligations for a significant number of generators will be affected by the output of the working group's review of the definitions of small, medium and large power stations.
- 3.34. This review is directly relevant to the enduring charging arrangements for distributed generators as any changes to the Grid Code definitions are likely to have implications for the contractual arrangements to which distributed generators would need to be subject, and potentially the number of generators who would be liable for TNUoS charges.

CUSC modification proposals

- 3.35. A series of amendments have been proposed to the CUSC which either directly concern or have implications for the treatment of distributed generation. The three relevant proposals are:

²⁴ Grid Code, General Conditions, GC 4.2(f).
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- i. CAP093: Enabling the Flow of Electricity from Distribution Systems into the Transmission System at Grid Supply Points
- ii. CAP094: Limited Duration Transmission Entry Capacity, and
- iii. CAP097: Revision to the Contractual Framework for Small and Medium Power Stations.

3.36. Each of these is summarised in further detail below.

CAP093

- 3.37. CUSC Amendment Proposal 93²⁵ (CAP093) aims to recognise the flow of electricity from distribution systems into the transmission system at GSPs by altering the CUSC definitions of GSP and Distribution System, and by making any necessary consequential changes to the CUSC.
- 3.38. The proposed amendment is relevant to consideration of the enduring arrangements for distributed generation as it recognises that in light of targets for increased distributed generation it is likely that many more GSPs will be required to accommodate two-way flows in the future. The intention of CAP093 is to clarify that GSPs may export power onto the transmission system.
- 3.39. CAP093 is currently at the working group stage.

CAP094

- 3.40. The basis of CUSC Amendment Proposal 94²⁶ (CAP094) is to introduce a new access product to enable transmission users to purchase TEC for a limited period.
- 3.41. The new product would enable capacity to be provided in circumstances where capacity is available within year but NGET cannot grant enduring TEC rights due to the time taken to analyse a proposal, future rights having been

²⁵ The CAP093 Amendment Proposal is available at:
<http://www.nationalgrid.com/uk/indinfo/cusc/admin/scripts/uploads/CAP093%20-%20Enabling%20the%20Flow%20of%20Electricity%20from%20Distribution%20Systems%20into%20the%20Transmission%20System%20at%20GSPs%20%20%20.pdf>

²⁶ The CAP094 Amendment Proposal is available at:

allocated to a future connectee or a generator only requiring access for part of the financial year.

- 3.42. The proposal has potential implications for distributed generation as limited duration TEC could represent an appropriate access product where a distributed generator is only using, or is more likely to use, the transmission network during specific periods. It is therefore appropriate to recognise its potential impact in considering the form of enduring charging arrangements for distributed generation.
- 3.43. CAP094 is also currently at the working group stage.

CAP097

- 3.44. CUSC Amendment Proposal 97²⁷ (CAP097) is intended to revise and clarify the processes to be followed by NGET and DNOs regarding the energisation of distributed power stations recognising that not all distributed generators will enter into a bilateral agreement with NGET.
- 3.45. The amendment proposal notes that specific exemptions have been granted for distributed generators of up to 100MW in size, and that should exemption be granted by the Secretary of State, then there are no direct obligations for the distributed generator to accede to the CUSC.
- 3.46. The intention of CAP097 is to ensure that the CUSC processes are consistent with the proposed changes to the Grid and Distribution Codes associated with the LEEMPS proposals discussed previously which are based on there being no direct relationship between NGET and the embedded medium power station. However, NGET considers that CAP097 (initiated by NGET) could be implemented independently of the LEEMPS Grid and Distribution Code changes. NGET would still need to assess and address the impact of certain distributed generators on the transmission system, CAP097 seeks to clarify the obligation on DNOs to provide relevant information to NGET about technical

<http://www.nationalgrid.com/uk/indinfo/cusc/admin/scripts/uploads/CAP094%20%20Limited%20Duration%20Transmission%20Entry%20Capacity%20.pdf>

²⁷ The CAP097 Amendment Proposal is available at:

<http://www.nationalgrid.com/uk/indinfo/cusc/admin/scripts/uploads/CAP097%20-%20CUSC%20changes%20for%20Medium%20Power%20Stations%20associated.pdf>

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distributed generator connections so that any transmission system implications can be identified (and where necessary remedied) prior to connection.

- 3.47. CAP097 is currently at the working group stage.

Access to the GB Transmission System

- 3.48. In parts of the transmission network, predominantly Scotland and northern England, the demand for transmission capacity exceeds the existing capability of the network. Parties wishing to connect in these areas may therefore be unable to connect for some time while contingent reinforcement works are carried out. The procedures by which offers are determined and issued, and the amount of reinforcement which a party is required to provide financial security against during the construction period, are calculated in accordance with a methodology established by NGET in accordance with standard licence condition C18 (Requirement to offer terms for connection or use of the GB transmission system during the transition period) in relation to applications before 1 April 2005 and in accordance with standard licence condition C8 (Requirement to offer terms) for applicants who applied after 1 April 2005.

Views invited

- 3.49. Ofgem welcomes respondents views on any of the issues highlighted in this chapter and in particular:
- i. whether the chapter has captured the full range of interrelated subject areas
 - ii. whether any interactions have been overlooked, and
 - iii. the implication of those interactions for developing enduring charging arrangements for distributed generators.

4. Issues to be addressed

- 4.1. This chapter highlights issues which parties have raised with Ofgem and which Ofgem considers constitute some of the key issues which are required to be addressed in developing enduring charging arrangements for distributed generators. Ofgem has considered these issues in developing and analysing the options set out in chapter 5.

Exporting GSPs without access rights

- 4.2. The issue of GSPs which may from time to time (or more regularly) export power from a distribution system onto the transmission system has been widely discussed. Indeed, the rationale for CAP093 (which was raised by Central Networks plc) is to clarify the arrangements in relation to such GSPs. It is recognised that there are cases where the actions of a single distributed generator or the cumulative effect of multiple generators (which have not been required to sign a BEGA or a BELLA with NGET) can result in export from a GSP to the transmission system.
- 4.3. There are two main aspects to this issue which could be characterised as:
- ◆ NGET has operational concerns in relation to its rights to collect information about, and the lack of control over, the amount of power flowing onto the transmission system from a distribution network connection. In addition, where parties have signed a BELLA, there is no requirement to provide mandatory ancillary services and NGET is unable to control their operation, as they are not BSC parties, in the event that, for example, they contribute to constraints. Such operational concerns may be expected to increase the total level of balancing costs which are met by all BSC parties but are unlikely to be faced by the parties causing these costs, and
 - ◆ some parties do not pay for the use that they are making of the transmission network. The costs of this “free riding” are paid by other parties (e.g. the directly connected generation and the demand charging base) who have contractual relationships with NGET and whose charges are consequently likely to be higher than the cost-reflective or

economically efficient level. This may be expected to have anti-competitive effects and increase the perverse incentives for generators to connect at distribution voltages. This is discussed in further detail later in this chapter.

- 4.4. It is worth considering whether the fact that a GSP may export power to a transmission network is a directly relevant issue in considering charging arrangements. The impact of a single incremental MW on flows across the transmission network is the same, regardless of the voltage at which the generator that produces the power connects. If the distributed generator locates in the south of the country, where demand charges are highest and generation charges are negative, it should receive a benefit for reducing the excess demand. If a distributed generator connects in the north of the country it will reduce demand, and increase flows down the transmission system, imposing an increased cost which, in a cost reflective charging system, it should face. A directly connected power station of the same size locating at the same point will increase power flows by the same amount.

Cost reflectivity

- 4.5. Where a user has an impact on the transmission network for which it does not pay, the costs or benefits it provides to the system will, by definition, fall to all other users. Assuming that in aggregate system use by non paying parties creates a cost; charges to paying parties are higher than efficient. This is likely to lead to a situation where parties that currently pay transmission charges are paying charges that may be higher than the efficient level as they are meeting a proportion of costs that are imposed by other network users. This may be considered not to facilitate competition in generation and could be seen as discriminatory.
- 4.6. It should also be noted that, where parties are not facing charges which reflect the costs they impose, inefficient decisions are likely to be made. This can be expected to lead to the inefficient development of the transmission network, the cost of which is ultimately paid for by customers.

Perverse incentives – voltage and location

- 4.7. It has been suggested that the differential charging arrangements for distribution and transmission connected generators can lead to perverse incentives when deciding where, and at which voltage, to connect.
- 4.8. As an example of the possible impact of the locational incentive, consider a party who wishes to connect a large power station. Assuming that there is available capacity on both the transmission and distribution networks, the party has to decide whether to connect directly to the transmission network and pay relevant transmission charges (or risk incurring a liability for charges at a later date) or to connect to a distribution network, sign a BELLA (assuming that there is no requirement for the generator to seek TEC e.g. that there is sufficient GSP demand to net off the generator's export) and pay GDUoS charges. The relative magnitude of GDUoS and connection charges compared to TNUoS charges will be a major factor in this decision and could lead to an overall inefficient investment decision. It is likely that in offsetting GSP demand, the distributed generator would give rise to transmission system costs for which it would not be liable. Indeed it would receive (a portion of) the value related to the residual element of transmission charges which bears no relation to the costs that the generator imposes on the transmission network. Such perverse incentives can also be expected to lead over time to increased costs to consumers and inefficient system development.
- 4.9. It is also worth considering the potential influence that the regional differences in the definitions of small, medium and large power stations in the Grid Code may have on a generator's locational decision. One area where the scope for perversity becomes clear is in the charging zones which span the border between NGET and SPT's transmission areas. There are two zones which span the border – zones 9 and 11. If a 50MW plant were considering connecting to the 132kV network in either of these zones, it could face the full TNUoS charge²⁸, as it would be transmission connected, in the SPT operated part of the zones, while if it connected in NGET's area, to United Utilities plc or Northern

²⁸ At present being 50MW in size in SPT's area would involve no liability for TNUoS. However, a BEGA includes provision for charges to be paid in accordance with the statement of the use of system charging. Were the charging methodology to change, the party with the BEGA could become liable for charges.

Electric Distribution Limited's network, it would face GDUoS charges but could be able to avoid paying the same level of TNUoS charge.

Perverse incentives - size

- 4.10. The existing definitions of small, medium and large power stations in the Grid Code, and to some extent the supporting contractual frameworks, could be characterised as providing a number of perverse incentives. Inevitably, given size definitions are relevant to the liability for TNUoS charges, any absolute threshold will provide incentives to size plant marginally below them. For example, the current arrangements would levy charges to a single distributed generator exporting more than 100MW, but would not levy charges on a 99MW generator, or indeed a collection of smaller generators, with a cumulative export capacity (e.g. 4 x 25MW units) of over 100MW. The presence of 99MW generation schemes indicates that this effect is real, given that there are no obvious engineering reasons for sizing generation plant at 99MW rather than 100MW.
- 4.11. However, in considering whether and how thresholds should be altered, it is important to find an enduring solution to the issue rather than simply allowing the problem to occur at a lower size/voltage level.
- 4.12. As discussed previously, where parties use the transmission system but do not face the costs they impose on that transmission system, investment decisions are more likely to be inefficient and parties who are liable for transmission charges will pay a proportion of the costs imposed by those who do not pay TNUoS charges. This situation may be likely to increase the perverse incentive to commission projects of sizes which avoid the liability for charges.

Interaction with current access issues

- 4.13. As noted in paragraph 3.48 it is not always possible for a party to secure access at the time they would ideally desire because of an excess demand for transmission capacity in parts of the network. Applications for new transmission connections are handled on a first-come-first-served basis. In considering the options in chapter 5, particularly those which consider amending or formalising access arrangements for distributed generators, it will

be important to consider the interactions with the process for issuing GB offers. For example, were it considered appropriate for all distributed parties to purchase a level of TEC, thought would need to be given to how this TEC would be allocated to distributed generation and how this would interact with parties who are currently seeking access to the transmission network under the transitional and enduring access arrangements²⁹ to the transmission network.

Trade offs

- 4.14. Ofgem acknowledges that the recent reforms as part of the BETTA project introduced a fundamental overhaul of regulatory arrangements relating to electricity transmission and is mindful that relevant work is already being progressed in a number of areas, as referenced in chapter 3. Ofgem recognises that a balance is required between the objectives of improving the efficiency of the existing arrangements and those of avoiding increased complexity and uncertainty.
- 4.15. The options discussed in the next chapter are arranged in order of the relative magnitude of change associated with each option. Ofgem is seeking respondents' views on the level of benefit that could be expected and the implications in terms of cost, uncertainty and complexity associated with the introduction of each of the options discussed in chapter 5

Ease of implementation and implementation costs

- 4.16. Ofgem additionally urges respondents to consider how onerous or indeed easy the different options could be to implement, and the associated implementation costs.

²⁹ Standard licence condition C8 sets out NGET's requirement to offer terms of connection on enduring basis while standard licence condition C18 sets out the requirement to offer terms during the transition period. On 12 September Ofgem published an open letter informing the industry that in some instances offers of terms for connection may be made by NGET within longer timescales than set out in the licence. This is available on the Ofgem website at:

www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/12310_20005.pdf

Views invited

- 4.17. Ofgem welcomes respondents' views on any of the issues highlighted in this chapter and in particular:
- i. whether the full range of issues that need to be addressed in developing enduring charging arrangements for distributed generators are identified, and
 - ii. any additional issues that have not been considered.

5. Options for an enduring charging framework for distributed generation

- 5.1. This chapter presents a number of possible options for amending transmission network charging and contractual arrangements to better reflect the impact on the transmission network of distributed generation.
- 5.2. The relative magnitude of change associated with the options varies and, as such, they are arranged in this order; beginning with those options which would require limited change to existing arrangements and ending with options which could lead to fundamental changes. It is unlikely that the options involving multiple changes to frameworks could be implemented in their entirety in the short term. Ofgem therefore encourages respondents to consider the relative merits of options from both a short and long term perspective. Ofgem also urges respondents to consider whether combinations of the suggested options could lead to enduring solutions. Ofgem invites views on the advantages and disadvantages of the models, as well as on other alternative approaches not identified.
- 5.3. The chapter provides a summary of each option before providing details of the:
- i. magnitude of change to existing arrangements necessary to implement the option
 - ii. impact, if any, on who is liable for TNUoS charges
 - iii. expected impact, if any, on the level of charges, and
 - iv. relative advantages and disadvantages of the option, in part based on the extent to which the option has the ability to address the issues identified in the previous chapter.

Option 1: Do nothing

- 5.4. The first option would involve making no amendments to the existing arrangements applying to distributed generation, with the exception of the

Authority making a decision on CAP093 and providing clarity over the ability of a distribution network to flow power on to the transmission network.

- 5.5. Parties currently liable for TNUoS charges would continue to be so, with charges calculated in accordance with the use of system charging methodology and there would be a minimal impact on existing arrangements.
- 5.6. A do nothing option may be considered appropriate if it is considered that the effect of distributed generators on the transmission system is captured within existing arrangements. For example, if it is considered that the driver for transmission network investment is behaviour at system peak and that this is captured by a suppliers TNUoS charge being based on their offtake, net of distributed generation, during the Triad, it could be considered that flows across a GSP, in either direction, at other times of the year are not a relevant consideration.
- 5.7. However, given that TEC corresponds to generator access rights that define the maximum export level from a power station at any point during a year (which may or may not correspond to system peak), it may be considered appropriate for transmission charging arrangements to take account of distributed generators using the system, and not paying for this usage, at any point during a charging year.
- 5.8. A do nothing approach would fail to improve the cost reflectivity of charging arrangements relating to distributed generation. Indeed, as it is likely that the number of distributed generators will increase, and that this in turn will impact on transmission system costs, it is likely that the cost reflectivity of charges will diminish over time. This could be expected to have a disproportionate effect on those parties currently liable for transmission charges.
- 5.9. In addition, a do nothing option would also provide no enduring solution to the issue of the rebate for small generators connected to the 132kV transmission network in Scotland, and in the absence of other changes this discount would fall away in 2008. As noted previously it is not Ofgem's view that the extension of the discount is a desirable option. The discount was only intended as an interim measure until an enduring solution was found to address the discrepancy in the charging arrangements.

Option 2: De-energise plant that spills

- 5.10. Section 5.2.1 of the CUSC contains the right for NGET to de-energise equipment or request that the owner of a distribution system de-energise a user's equipment if it poses a threat to the transmission system. It has been suggested that the issue of exports from GSPs to the transmission system by parties which have not procured a level of TEC could be addressed using this condition. In the first instance it would be likely that NGET could request that flows are managed such that exports cease with de-energisation providing a last resort.
- 5.11. While such an approach would be likely to involve minimal change to existing arrangements, and would not affect the range of parties liable for transmission charges or the charging methodology, it may be viewed as disproportionate. It is likely that establishing responsibility for an export from a GSP point, particularly if multiple plants with a combination of firm and non firm access rights were located behind it, would prove difficult and legally challenging. It may not be considered appropriate to prevent a plant from generating because of what could be a relatively small export onto the transmission network, which may be caused largely by circumstances beyond that generators control. Equally, given that the requirements in the CUSC apply only to CUSC parties, it may not be possible for a non-CUSC party to be de-energised.
- 5.12. While this option may go some way to addressing incentives for parties which will use the transmission network to enter into BELLAs, it is unlikely to address any of the wider concerns identified in chapter 4.

Option 3: Amendments to the charging model

- 5.13. The discount for small transmission connected generators was introduced because of concerns over discrepancies between the charges faced by transmission connected small generators in Scotland and those faced by their counterparts connected to distribution networks in England and Wales. It may be considered that amendments to the parameters of NGET's DC Load Flow model, used in calculating transmission tariffs, could better reflect the conditions on the 132kV network and hence improve the cost reflectivity of charges and render the discount obsolete.

- 5.14. The process for modifying the charging model is, in itself, relatively straightforward and would involve minimal change to the existing arrangements. However, in the absence of changes to charging thresholds, amendments to NGET's charging model would not extend the liability for charges but rather would only serve to change the allocation of charges between existing paying parties.
- 5.15. Unless changes to charging thresholds were implemented concurrently to amendments to the transport model, any such change would result in a zero sum game and would only serve to change the allocation of charges between existing paying parties, which may increase uncertainty. Therefore, while refinements to the transport model may eliminate the need for a discount for small generators connected to the 132kV transmission network in Scotland, it would not affect distributed generators or address any of the issues highlighted in chapter 4. This option could therefore have a similar effect as consolidating the 132kV discount on an enduring basis in the charging methodology.

Option 4: Extend the DCLF ICRP model to parts of the distribution network

- 5.16. It would be possible to harmonise transmission and high voltage distribution network charges by applying the DCLF model used by NGET (or a similar variant) to appropriate distribution voltages in addition to the existing transmission voltages. The total costs of both the transmission network and appropriate sections of distribution network would be recovered from system users by applying a consistent model and deriving locationally varying charges reflective of the costs that individual users impose. Such an approach could introduce a consistent set of locational signals to transmission and distribution networks. This option would need to be considered in tandem with the distribution structure of charges review discussed previously and the interaction between TNUoS and GDUoS charges fully considered.
- 5.17. This approach represents a potentially significant change to existing charging arrangements. In order to implement it, it might be necessary to consider how the costs of the relevant sections of the distribution network could be

determined for the purposes of determining the total level of revenue to be recovered using the model.

- 5.18. It would appear likely that amendments to the charging methodology would be required alongside the implementation of this approach in order to maximise the potential benefits associated with it. Liability for transmission charges could be extended to parties connected to the 132kV (or other voltages deemed appropriate) distribution networks as calculated in accordance with the charging methodology. Charging arrangements could differ from current arrangements where distributed generators receive the negative demand tariff based on their production over the Triad and all generators, regardless of the voltage of connection could have a liability for generation charges, with the transmission charge reflecting the cost or benefit that a plant imposed on the transmission network.
- 5.19. Extending the model could be expected to lead to a change in charges to all users as allowed revenues were redistributed amongst a larger number of users. Charges would continue to be calculated in accordance with the statement of the use of system charging methodology and it may be appropriate in such circumstances for NGET to consider whether the existing parameters and assumptions within the transport model were appropriate and able to produce cost reflective charges across the additional voltage levels, consistent with their requirement to keep charging methodologies under review.
- 5.20. It could be considered that there are fundamental differences between transmission and distribution networks (e.g. the cost drivers differ) and that it is not therefore appropriate to harmonise arrangements. It is possible that this option would simply provide incentives for parties to locate at lower distribution voltages and it could be seen as discriminating between distribution network users.
- 5.21. However, by providing a consistent method of charging between transmission and distribution networks this approach could be expected to remove perverse incentives to connect at distribution as opposed to transmission voltages. This consistent treatment would render the rebate for 132kV connected generation obsolete. Were it progressed alongside amendments to charging thresholds, all users of high voltage sections of distribution networks would face cost

reflective use of system charges. In turn, this would be expected to improve the cost reflectivity of charges, particularly for existing users, as more costs were targeted at those that caused them. This could be expected to facilitate competition.

- 5.22. An alternative though similar option, would involve the reclassification of the 132kV network in England and Wales as transmission, or the 132KV network in Scotland as distribution. However, such an amendment would require primary legislation and would appear inconsistent with the definition of transmission and distribution in the Act.
- 5.23. The definition of transmission in the Act reflects the physical purpose of lines. In Scotland, the 132kV network is predominantly used for the bulk transfer of electricity, and is hence classified as transmission. In England and Wales, this is not the case and the 132kV network is classified as distribution. Therefore, it may be considered inappropriate to harmonise arrangements for the assets which, while at the same voltage, have different uses. It is worth noting that this issue was also consulted on as part of the development of BETTA. This approach could additionally alter the pattern of cost recovery and may increase uncertainty.

Option 5: Amend use of size definitions as the basis for charging and contractual arrangements

- 5.24. Ofgem acknowledges that the GCRP has created a subgroup to consider the enduring appropriateness of the differing geographical definitions of small, medium and large power stations in the Grid Code. However, Ofgem considers it appropriate to discuss the potential advantages and disadvantages of amendments to the level at which size definitions are set.
- 5.25. Amending the size definitions in the Grid Code such that more parties are defined as being large, would mean more generators would be required to sign a BEGA, hence establishing a contractual relationship between themselves and NGET.
- 5.26. However, such a change would in itself have no impact on the liability for transmission charges. For charging liability to change, amendments would

have to be made in tandem to the use of system charging methodology. Consequently, if the threshold for the definition of a “large” generator were reduced and the charging methodology were subsequently amended to determine that all large generators were required to pay charges, then a greater number of parties would be obligated to pay transmission charges

- 5.27. It may be considered that, in a competitive GB market based on the principles of open competition, the rationale for thresholds which vary between geographic areas is unclear. One implication is that plants which may have a similar impact on the transmission network, but are located at different points, are subject to differing contractual and, potentially, charging arrangements. This may be viewed as discriminatory and it may be considered more appropriate for a threshold at which a generator has an impact on the transmission network to be based on, for example, network topology or likely levels of demand in the area in which it connects. An alternative approach would be to set de-minimis thresholds or indeed remove size thresholds altogether on the grounds that all parties, regardless of size impact on the network.
- 5.28. If the charging arrangements were to be revised to mandate payment by a larger number of generating stations this would be expected to reduce the extent to which parties are paying transmission network costs caused by other, non-paying, parties, increasing the cost reflectivity of charging arrangements. It may also reduce incentives to connect at distribution as opposed to transmission voltages. However, increasing the number of parties required to have a contractual relationship with NGET could increase the administrative burden on both parties.
- 5.29. This option may diminish the magnitude of the issues discussed in this document but is unlikely to provide an enduring solution. In effect, the same issues would simply be forced downwards and occur around different thresholds. The cost reflectivity of charging arrangements may be improved, but it is likely that the problems and perverse incentives highlighted in chapter 4 could be expected to persist. The approach would also involve extending the area of influence of NGET to a larger number of parties, which is likely to impose a greater administrative burden on both distributed generators and NGET.

Option 6: Creating a consistent liability for charges

- 5.30. From the perspective of not discriminating between users or classes of user, it could be considered that an additional MW of generation, regardless of the voltage of connection, imposes the same costs on the transmission system; by increasing flows or reducing offtake. Based on this logic the argument could be made for sending the same cost reflective charging message to all generators, regardless of the voltage at which they connect, i.e. they should face a locationally varying charge calculated in accordance with the statement of the use of the system charging methodology to signal the cost or benefit associated with locating at that point.
- 5.31. Were the charge setting process amended, such that the residual element of TNUoS charges did not form part of the final tariff (effectively decoupling the transport and tariff models), all parties would face a purely locational charge, based on the long run marginal cost of locating at a given point. As the effect of injecting a single MW of generation at a given node would be expected to be equal to that of removing a single MW of demand at the same node, generation and demand charges at every node would be equal and opposite. In this circumstance a directly connected generator, or party with a BEGA, would continue to pay the generation tariff, while distributed generators would continue to receive the inverse of the demand tariff, in accordance with the existing charging methodology. However, the inverse of the demand tariff would be the generation tariff and directly connected or embedded parties would pay the same amount, meaning that there was no discrimination based on a generator's size or voltage of connection. An existing contractual interface, such as that between NGET and suppliers, could then be used to recover the residual charge, with, for example, gross demand forming the basis for charging liability.
- 5.32. The option may lead to additional data requirements although it is likely that this would be on the same basis as distribution charges at present. It could be expected to result in all generators, regardless of their voltage of connection or size, facing a locational TNUoS charge calculated from the same methodology on the same cost base. It would remove the perceived anomaly in the present system whereby embedded generators (or their suppliers) are paid the residual

elements of transmission charges. This would be expected to render the discount for parties connected to 132KV in Scotland obsolete and to address distortions between transmission and distribution connected generators, ultimately facilitating competition.

- 5.33. The level of change to the existing arrangements would be far less than under the previous option of formalising contractual arrangements with all generators. However, changes to the charging methodology could be necessary to reflect the changing treatment of the residual charge.

Option 7: Agency models

- 5.34. At present, a distributed generator has a number of contractual relationships; with suppliers, DNOs and, in some cases, NGET. However an individual distributed generator is unlikely to have as much information about system conditions as the parties with which it contracts. This informational asymmetry may mean that it is not best placed to take efficient decisions about the level of access rights to secure. Therefore, models which involve the development of existing arrangements such that an intermediary can secure access rights on behalf of a portfolio of distributed generators and provide a contractual interface with the GBSO can be envisaged. These models may be considered particularly attractive if the fact that power is exported from a distribution system to the transmission network at certain times is viewed as the issue which needs addressing; as opposed to the fact that all distributed generators impose costs on the transmission network.
- 5.35. Agency models provide contractual interfaces through which, theoretically all, distributed generators could be charged, were this deemed appropriate and the charging methodology amended accordingly. The development of an agency model may be expected to facilitate competition by ensuring that all parties, regardless of the voltage to which they connect, face the same liability for charges, reflecting the fact that they impose identical costs (although once an interface is in place parties may consider it appropriate to develop alternative form of access arrangements to better reflect the needs of distributed generators). Additionally, it could be expected that perverse incentives to locate at distribution voltages would be much reduced. Ultimately, cost reflective messages to all generators may be expected to facilitate the efficient

development of networks which can be expected to lead to savings for customers. Agency models also avoid the need for NGET to enter into contracts with a greater number of distributed generators and may be viewed as reducing the administrative burden on parties.

- 5.36. In addition, agency models may provide an opportunity for agents to provide ancillary services to NGET on behalf of distributed parties (although it is acknowledged that at present DNOs are prevented from trading energy). This may allow distributed generators to enter markets in which they could not previously compete and allow customers to realise benefits associated with greater levels of competition in these markets.
- 5.37. In considering amendments to arrangements on the generation side of the market place, it will be necessary to consider whether there are parallels, interactions and developments which can be made on the demand side of the market place.
- 5.38. Within any agency model, it may be considered appropriate to introduce a system of overrun charges, designed to disincentivise the flow of power above the level of entry capacity purchased, with the exception of circumstances where an emergency instruction has been issued. This may be expected to provide strong incentives to manage flows and aid system security, although may not be seen as a proportionate measure. Indeed it may be considered that provisions within the CUSC, in which the concept of TEC is defined, provide sufficient powers to address the breach of an entry capacity right. An additional question would involve the development of the overrun charge. Given that such a charge would have a penal function; it may be difficult for it to be established in light of the charging methodology objective of charging on a cost reflective basis.
- 5.39. An additional question which would need to be considered were any of the agency options to be adopted, or indeed were any option which includes a requirement for parties that currently have no firm access rights to enter into an agreement which provides them such rights introduced, relates to the interaction with distribution or transmission connected parties which have received offers for connection but are yet to start generating. The way in which an access right was awarded e.g. based on historical data or via the same

application processes as are followed by distributed generators, could have wide ranging implications for both distributed generators and those awaiting connection.

- 5.40. There are various different agency models that can be envisaged. Three such subsets of models are set out below.

Supplier agency

- 5.41. At present a contractual interfaces exists between a supplier and DNO, a supplier and distributed generators and a supplier and NGET. Suppliers contract for the output of distributed generators, in part in order to avoid TNUoS charges. It may therefore be considered that they are best placed to judge whether their portfolio of contracted generation is likely to export on to the transmission network at any point or that the contract with the supplier represents the appropriate route through which to charge distributed generators. A range of supplier based agency models can be developed with the complexity and magnitude of change associated with each varying.
- 5.42. Suppliers currently have a liability for demand TNUoS charges based on their offtake over the Triad, so it would not be expected to be overly complex to develop the existing charging interface to also include a liability for generation TNUoS charges. This may involve decoupling production and consumption accounts and charging based on each, i.e. charging a supplier demand charges based on their demand offtake and generation charges based on their total contracted volume of distributed generation. Such an approach would recognise the impact that each incremental or decremental MW of generation has on flows on the transmission network and hence costs.
- 5.43. A relatively simple agency model could see any exporting demand BMU being liable for TNUoS charges. Thus any supplier which was responsible for the export of power onto the transmission network from a distribution network at any stage would be required to pay charges based on the expected level of capacity. A consideration within such a model would concern whether it had a disproportionate impact on smaller players or recent market entrants, which typically would have low levels of demand against which to net off their generation.

- 5.44. Were it possible to attribute cause to the export of a single GSP, a model would see each supplier which considered it likely that the cumulative effect of its contracted volumes of distributed generation would exceed levels of demand offtake at any stage during a charging year at a given GSP would need to purchase entry capacity equal to the level of any potential export. In effect, the maximum net flow from a distribution network in a given year would be treated as a substitute for directly connected generation or an interconnector.
- 5.45. Alternatively, were tracing flows and attributing cause at an individual GSP deemed overly complex, some form of arrangement could be developed whereby the export of a GSP was attributed to suppliers based on their contracted volume of demand offtake at the GSP group level, and an associated liability for charges levied. For example, a party responsible for 50% of demand offtake at GSP group level would face a liability for 50% of the total export to the transmission network at GSP group level. Such an approach may be viewed as arbitrary and may be considered to discriminate against parties with large volumes of demand offtake, typically established suppliers.

DNO agency

- 5.46. An alternative approach could see the DNO, as opposed to the supplier, providing the contractual interface between distributed generators and NGET. This option could be seen as an extension of the LEEMPS proposals which would (if implemented), remove the requirement for a contractual relationship between NGET and the distributed generator in many circumstances. The DNO would provide the interface between NGET and distributed generators which had not purchased their own firm access rights. The approach could be developed in two forms. Firstly, a DNO would take a decision, based on its expectation of total generation and demand, regarding the level of access rights to the transmission network which it required in a given charging year and would then formalise this in a contract with NGET; effectively taking a position to reflect its maximum net flow onto the transmission network in a given year. Secondly, arrangements could be developed such that a DNO could be charged based on the total level of generation capacity connected to its network. Under either of these options, charges could be passed through to

distributed generators in accordance with published charging methodologies approved by the Authority

- 5.47. Under such an approach the need for a BELLA is unclear. It would seem likely that the requirement for any party to enter into a BELLA would significantly reduce and, were a net flow approach adopted, the incentives to sign BEGAs may also reduce, as parties sought to gain firm access via an entry right purchased by the DNO because of their informational advantage.
- 5.48. However, implementing this model would place an administrative burden on the DNO. It is unclear whether the DNO has incentives to operate in such a capacity and whether some form of incentive arrangement may need to be designed.

An independent Distribution System Operator (DSO)

- 5.49. Alternatively, it may be deemed appropriate, perhaps to avoid any conflicts of interest, to have an independent party managing power flows on a distribution network. This model, which is complex and realistically is probably only practicable in the long term, could be similar in structure to the BETTA reforms. DNOs would have a similar role to Transmission Owners (TO) on the transmission network, owning assets, while an independent Distribution System Operator (DSO), similar to the GBSO, would take responsibility for the day to day operation of those parts of the distribution system which require active management. The relationship between the DSO and DNO would require formalising in a code, probably not dissimilar to the System Operator – Transmission Owner code (STC) introduced as part of BETTA. In addition if required, a relationship between the DSO and GBSO could also be formalised in a code.
- 5.50. The DSO would levy charges, either on a gross (all parties pay subject to thresholds in the grid code) or net (only the flow from distribution to transmission is paid for) basis, to distribution connected generators. If the TSO and DSO were the same party, it might be considered practicable to apply the same charging methodology to all actively managed sections of the network. This could result in all connected parties paying charges and may provide the most cost-reflective outcome.

- 5.51. The benefits of this model are similar to those of other agency arrangements, although it may be expected that overall system balancing costs, on both distribution and transmission networks could be reduced. These savings may be greater were the DSO the same party as the TSO.
- 5.52. On the negative side, implementing this option would require primary legislation and would be administratively complex; with changes to multiple codes, licences and legislation being necessary. However, it may be considered an appropriate development as distribution networks require more active management. Were such an option implemented in the short term, it may increase perceptions of regulatory risk, with a fundamental redefinition of market rules occurring shortly after the transition to a GB market.

Views invited

- 5.53. Ofgem welcomes respondents views on any of the issues highlighted in this chapter and in particular:
- i. the extent to which the options outlined are practicable and address the perceived defects
 - ii. if any of the options in chapter 5 are deemed practicable, the timescales within which it would be feasible to aim to amend existing charging and contractual arrangements, and
 - iii. any other options for change not contained within the document.

6. Views invited and way forward

Views invited

- 6.1. Ofgem intends this document to give rise to discussion and therefore invites views on any of the issues raised. In particular views are sought on:
- ◆ the extent to which the current charging and contractual arrangements relating to distributed generation are appropriate/ inappropriate
 - ◆ the extent to which the issues set out in chapter 4 represent concerns regarding the existing charging and contractual arrangements
 - ◆ the extent to which the options for refinement outlined in Chapter 5 are practicable and address the perceived defects
 - ◆ any other options for change not contained within the document, and
 - ◆ the appropriate way forward.

Way forward

- 6.2. Following consideration of responses to this document, Ofgem intends to publish a further document in early 2006 summarising responses, providing an update on the areas of work set out in chapter 3 and outlining Ofgem's provisional thoughts on a way forward. It is hoped that this document will inform NGET's paper, scheduled for April 2006, providing an update on progress against the five conditions imposed by the Authority when approving the GB charging methodology and setting out a way forward in addressing the remaining conditions.

Appendix 1: International precedents for charging distributed generation

- 1.1 In developing its thinking on enduring charging arrangements for distributed generation Ofgem commissioned a report by Cornwall Energy Associates³⁰. One of the key terms of reference for that piece of work was to provide analysis of international examples of distributed generation charging. This appendix briefly summarises the key findings of that report, a full copy is available by contacting the Ofgem library.

Basis of study

- 1.2 The study undertaken by Cornwall Energy Associates was principally based on a report commissioned by the European Commission in 2002³¹. It was supplemented by a recent study by the Irish regulator CER³² and with data from various markets outside of Western Europe using data trawled from various sources.

Key findings

- 1.3 The study identified that in the majority of systems considered including Argentina, Australia, California, New Zealand, Sweden and Spain, the charging structures do not specifically model the impact of distributed generators. Where they are recognised in the charging models distributed generators are often treated as negative loads which ultimately reduce transmission charges.
- 1.4 Two principle exceptions were identified in the report, the systems of Norway and Finland where there are significant generation beyond the main GSPs. The issue of distributed generation had been addressed in a similar way in both systems. The approach adopted involves a two-part grid charge. The first part is a “net charge” based on the power withdrawn from the grid which is reduced to

³⁰ Enduring charging arrangements for embedded generation – Cornwall Energy Associates, July 2005

³¹ http://europa.eu.int/comm/energy/electricity/publications/doc/bench_trans_tarif_en.pdf

³² www.cer.ie/CERDocs/cer04101.pdf

reflect distributed generation. The second part is a “gross charge” based on end-user consumption and losses beyond a GSP.

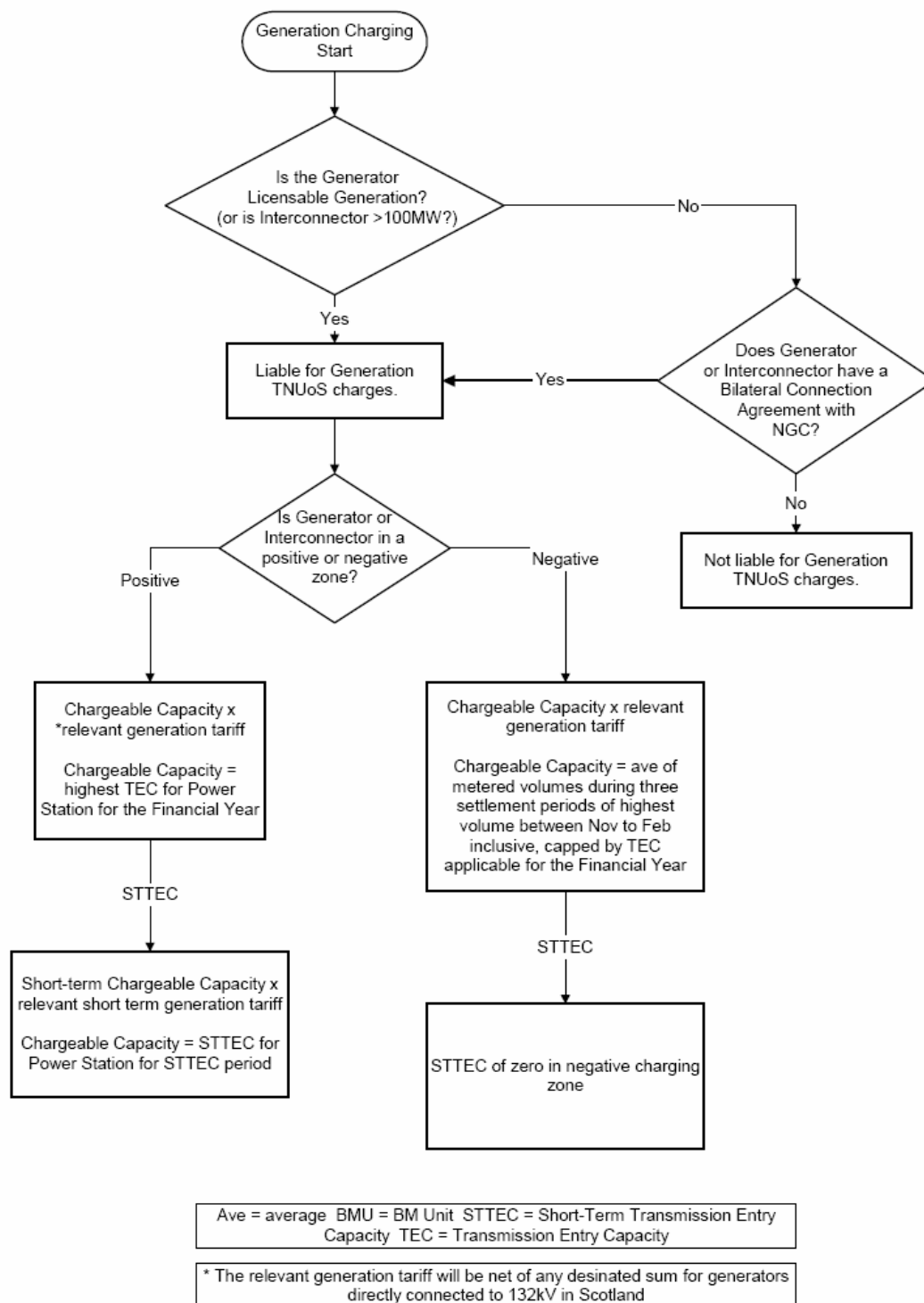
- 1.5 In the case of Finland, if the power taken from the grid is modest and thus the gross charge levied by the network operator Fingrid on end-user consumption is correspondingly modest then the charge for use of the grid will be low.
- 1.6 In Norway the relationship between the value of the access charge for generation capacity and consumption beyond a GSP and the power charge, based on the supply across a GSP during the regional peak demand, implicitly determines the benefit of distributed generation. As the power charge could be zero, if there is significant distributed generation there is a minimum power charge.

Conclusion

- 1.7 There are few international examples of charging regimes designed to reflect costs imposed by distributed generators on transmission networks. Most systems appear to charge based on the net flow of power out of the GSPs. Where there are examples of distributed generators being charged, in Finland and Norway, there is little in the way of economic analysis to consider how the charging regime could be structured and debates have ensued regarding the relative magnitude of charges.
- 1.8 In consequence there is little in the way of international precedence to draw on in developing enduring charging arrangements for distributed generation in GB.

Appendix 2: Existing liability for TNUoS charges

Generation Charges



Demand Charges

