nationalgrid

Stage 05: Draft CUSC Modification Self-governance Report

Connection and Use of System Code

CMP193 Housekeeping modifications to Section 14 of the Connection and Use of System Code (CUSC)

What stage is this document at?

01	Initial Written Assessment
02	Workgroup Consultation
03	Workgroup Report
04	Code Administrator Consultation
05	**Draft CUSC Modification Report**
06	Final CUSC Modification Report

This proposal seeks to modify the CUSC to make a number of non-material changes to Section 14 in order to better incorporate the Charging Methodology Statements into the main body of the CUSC. This proposal is linked with CMP194 which makes consequential non-material changes to Section 11 of the CUSC to incorporate the definitions previously described in Section 14 and which are proposed to be removed from Section 14 through this proposal.

Published on: 19 May 2011
Date of Self-governance Vote 27 May 2011

National Grid view:
That CMP193 should be implemented as it better facilitates Applicable CUSC objective (a).

High Impact:
None

Medium Impact:
None

Low Impact:
Existing signatories to the CUSC.
National Electricity Transmission System Operator (NETSO)

Contents

Any Questions?
Contact:
Steven Lam

Code Administrator

steven.lam@uk.ngrid.com

01926 653534

Proposer:
Andy Wainwright

National Grid Electricity Transmission Plc

About this document

This is a draft of the CUSC Modification Self-governance Report which contains responses to the Code Administrator Consultation and has been prepared and issued by National Grid under the rules and procedures specified in the Connection and Use of System Code (CUSC) as designated by the Secretary of State. Its purpose is to assist the CUSC Modifications Panel in their decision whether to implement CMP193.

Document Control

Version	Date	Author	Change Reference
0.1	03/05/11	National Grid	Version for Industry comment following closure of CA Consultation
0.2	19/05/11	National Grid	Draft for Panel Self-governance Vote

1 Executive Summary

1.1 Following the implementation of CUSC Amendment Proposal 188 (Code Governance Review: Governance of Charging Methodologies) in December 2010, it was recognised that there would be a subsequent requirement to undertake further non-material alterations to Section 14 of the CUSC in order to ensure consistency of this section with the main body of the CUSC.

1.2 This modification proposal seeks to make a number of non-material changes to Section 14 of the CUSC to better incorporate the Charging Methodology Statements into the main body of the CUSC.

1.3 This modification proposal is linked to a second proposal, CMP194 - Housekeeping modifications to Section 11 of the Connection and Use of System Code (CUSC), which proposes consequential definition changes to Section 11 of the CUSC to incorporate definitions previously described in Section 14, and which are proposed to be removed from Section 14 through this proposal.

CUSC Modifications Panel view

1.4 At the CUSC Modifications Panel meeting on 25th March 2011, the Panel agreed that CMP193 should proceed directly to the Code Administrator Consultation for a period of three weeks. The Panel also determined that the proposal should follow the Self-governance route.

National Grid's View

1.5 National Grid supports the implementation of CMP193 as it better facilitates the applicable CUSC objective(s) by improving the clarity of both Use of System and Connection Charging Methodologies within the CUSC.

Self Governance

Self-governance is a process which may be followed in the CUSC which allows the CUSC Panel to approve or reject a modification to the CUSC without approval from the Authority.

However the Authority will have veto rights over the decision to progress a proposal as Self-governance

2 Purpose & Introduction

2.1 This document describes the CMP193 Modification Proposal and incorporates a summary of all representations received in response to the Code Administrator Consultation. The full responses can be found in Annex 3 of this report.

2.2 This CUSC Modification Self-governance Report has been prepared in accordance with the Terms of the CUSC. An electronic copy can be found on the National Grid Website, www.nationalgrid.com/uk/Electricity/Codes/, along with the CUSC Modification Proposal Form.

2.3 CMP193 was proposed by National Grid Electricity Transmission plc and submitted to the CUSC Modifications Panel for their consideration on 17 March 2011. The Panel determined that the proposal should be sent to the Code Administrator Consultation phase and that it would be progressed through the Self-governance route. The Panel also agreed that the proposal would report back to the CUSC Modifications Panel in May 2011 whereby the Panel would undertake the vote to approve or reject the proposal.

2.4 The Panel agreed that the proposal satisfied the Self-governance criteria as set out below as the changes proposed by CMP193 were housekeeping in nature.

2.5 A CUSC Modification Proposal that, if implemented,

(a) is unlikely to have a material effect on:

(i) existing or future electricity consumers; and

(ii) competition in the generation, distribution, or supply of electricity or any commercial activities connected with the generation, distribution or supply of electricity; and

(iii) the operation of the National Electricity Transmission System; and

(iv) matters relating to sustainable development, safety or security of supply, or the management of market or network emergencies; and

(v) the CUSC's governance procedures or the CUSC's modification procedures, and

(b) is unlikely to discriminate between different classes of CUSC Parties

3 Description of Proposed Modification

3.1 This proposed modification seeks to make a number of non-material changes to Section 14 of the CUSC to better incorporate the Charging Methodology Statements into the main body of the CUSC. This is linked with a second proposed modification, CMP194, which seeks to make consequential non-material changes to Section 11 of the CUSC to incorporate the definitions previously described in Section 14 and which are proposed to be removed from Section 14 through this proposed modification.

3.2 On 30 December 2010 National Grid implemented CUSC Amendment Proposal 188 bringing the Charging Methodologies under the CUSC. As a result, Section 14 of the CUSC was created containing the methodologies as set out in the Statement of the Use of System Charging Methodology and the Statement of the Connection Charging Methodology. This was achieved without amendment to the content of the Methodology statements, and it was recognised that there was a further requirement to review the Methodology Statements to ensure consistency with the CUSC.

3.3 The proposed changes were initially discussed at the Transmission Charging Methodologies Forum on 26 January 2011. Subsequently an open letter was circulated to the industry for comment which contained the proposed drafting of the legal text required for the changes to Section 14 and Section 11 of the CUSC. Following a review period to incorporate the received comments from the industry, CMP193 was raised as an official modification and was presented to the CUSC Modifications Panel on Friday 25 March 2011.

3.4 At the CUSC Modifications Panel meeting, a CUSC Panel Member noted the need for additional non-material changes to be made. The Panel agreed that as the comments were non-material in nature, they should be incorporated into the final legal text before the consultation was issued. These, and other subsequent non-material referential alterations, have been made and are included in the proposed legal text in Annex 2.

3.5 Due to the non material nature of the changes, the Panel agreed that the proposal should progress through the Self-governance route, as opposed to the standard CUSC Modifications route. Therefore, the Panel would carry out the determination on the proposal rather than the Authority.

4 Impact and Assessment

Impact on the CUSC

4.1 CMP193 requires amendments to the following parts of the CUSC:

- Section 14 - Charging Methodologies

4.2 The text required to give effect to this proposal is contained in Annex 2 of this document.

Impact on Core Industry Documents

4.3 The proposer has not identified any impacts on Core Industry Documents.

Impact on other Industry Documents

4.4 The proposer has not identified any impacts on other Industry Documents.

Assessment against Applicable CUSC Objectives

4.5 The proposer considers that CMP193 would better facilitate the following Applicable CUSC Objective(s);

Use of System Charging Methodology

(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

This proposal satisfies objective (a), in that it improves the clarity of the Use of System Charging Methodology, and therefore better facilitates industry understanding of the Statements which will better facilitate competition.

Connection Charging Methodology

(a) that compliance with the connection charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

This proposal satisfies objective (a), in that it improves the clarity of the Connection Charging Methodology within the CUSC, and therefore better facilitates industry understanding of the Statement and so facilitates competition.

5 Proposed Implementation

5.1 National Grid proposes that, once the Panel has made their determination through the Self-governance vote, CMP193 should be implemented 10 working days after the Self-governance appeal window has closed.

Appeals Window

A party may raise an appeal against the Panel decision on a Self-governance proposal by notifying the Authority within 15 working days after the Panel vote takes place.

6 Recommendations

National Grid View

6.1 National Grid supports the implementation of CMP193 as it better facilitates the applicable CUSC objective(s) by improving the clarity of both Use of System and Connection Charging Methodologies within the CUSC, and therefore better facilitating industry understanding of the Statements and so facilitates competition.

7 Responses

7.1 The following table provides a summary of the responses received to the Code Administrator Consultation. The full responses can be found in Annex 3.

Reference	Company	Supportive?	Comments
CMP193-CR-01	Scottish and Southern Energy, Southern Electric, Airtricity Developments (Scotland) Limited, Airtricity Developments (UK) Limited, Clyde Wind Farm (Scotland) Limited, Greenock Wind Farm (Scotland) Limited, Griffin Wind Farm Limited, Keadby Developments Limited, Keadby Generation Limited, Medway Power Limited, Slough Energy Supplies Limited, SSE (Ireland) Limited, SSE Energy Limited and SSE Generation Limited.	Yes	• Agree that CMP193 better facilitates Applicable Use of System Charging Methodology Objective (a) • Agree that CMP193 better facilitates Applicable Connection Charging Methodology Objective (a) • Support the proposed implementation arrangements • Agree with the decision to progress CMP193 as Self-governance • Minor formatting error in Section 14 whereby the National Grid logo on page 14 should be removed
CMP193-CR-02	EDF Energy	Yes	• Agree that CMP193 better facilitates Applicable CUSC Objective (a) • Support the proposed implementation arrangements • Agree with the decision to progress CMP193 as Self-governance
CMP193-CR-03	E.ON UK	Yes	• Agree that CMP193 better facilitates Applicable CUSC objective (a) in respect of the Use of System and

			Connection Charging Methodologies • Support the proposed implementation arrangements • Agree with the decision to progress CMP193 as Self-governance

CUSC Modification Proposal Form (for Charging Methodology proposals)	CMP193

Title of the CUSC Modification Proposal: *(mandatory by proposer)*
Housekeeping modifications to Section 14 of the Connection and Use of System Code (CUSC)

Submission Date *(mandatory by Proposer)*
17th March 2011

Description of the CUSC Modification Proposal: *(mandatory by proposer)*
This proposal seeks to make a number of non-material changes to Section 14 of the CUSC to better incorporate the Charging Methodology Statements into the main body of the CUSC. This is linked with a second proposed CMP which makes consequential non-material changes to Section 11 of the CUSC to incorporate the definitions previously described in Section 14 and which are proposed to be removed from Section 14 through this proposed CMP.

Description of Issue or Defect that the CUSC Modification Proposal seeks to Address: *(mandatory by proposer)*
On 30th December 2010 National Grid implemented CUSC Amendment Proposal 188 bringing the Charging Methodologies under the CUSC. As a result, Section 14 of the CUSC was created containing the methodologies as set out in the Statement of Use of System Charging Methodologies and the Statement of Connection Charging Methodology. This was achieved without amendment to the content of the Methodology statements, and it was recognised that there was a further requirement to review the Methodology Statements to ensure consistency with the CUSC.

Impact on the CUSC: *(this should be given where possible)*
The proposed modifications are non-material in nature, and therefore there are only cosmetic changes to section 14 of the CUSC and, through the proposed linked CMP, to section 11 of CUSC.

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes/No *(assessed in accordance with Authority Guidance – see guidance notes for website link)*
No

Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information: *(this should be given where possible)*

BSC ☐

Grid Code ☐

STC ☐

Other ☐
(please specify)

None

Urgency Recommended: Yes / No *(optional by Proposer)*
No

Justification for Urgency Recommendation *(mandatory by Proposer if recommending progression as an Urgent Modification Proposal)*
N/A

Self-Governance Recommended: Yes / No *(mandatory by Proposer)*
Yes

Justification for Self-Governance Recommendation *(mandatory by Proposer if recommending progression as Self-governance Modification Proposal)*
Changes are non-material, and have already been circulated to industry for comment. Hence formation of a working group would be inefficient.

Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews? *(mandatory by Proposer in order to assist the Panel in deciding whether a Modification Proposal should undergo a SCR Suitability Assessment)*
There are no ongoing Significant Code Reviews

Impact on Computer Systems and Processes used by CUSC Parties: *(this should be given where possible)*
None

Details of any Related Modifications to Other Industry Codes (including related CUSC Modification Proposals): *(where known)*
Modifications to Section 11 of the Connection and Use of System Code (CUSC)

Justification for CUSC Modification Proposal with reference to Applicable CUSC Objectives: *(mandatory by proposer)*

Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

☒ (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

☐ (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

☐ (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

Full justification:

This proposal satisfies objective (a), in that it improves the clarity of the Use of System Charging Methodologies, and therefore better facilitates industry understanding of the Statements which will better facilitate competition.

Connection Charging Methodology

☒ (a) that compliance with the connection charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

☐ (b) that compliance with the connection charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

☐ (c) that, so far as is consistent with sub-paragraphs (a) and (b), the connection charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;

☐ (d) in addition, the objective, in so far as consistent with sub-paragraphs (a) to (c) above, of facilitating competition in the carrying out of works for connection to the national electricity transmission system.

Full justification:
This proposal satisfies objective (a), in that it improves the clarity of the Connection Charging Methodology within the CUSC, and therefore better facilitates industry understanding of the Statement and so facilitates competition.

Details of Proposer: (Organisation's Name)	National Grid Electricity Transmission Plc
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party, "National Consumer Council" or Materially Affected Party)	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Andrew Wainwright National Grid Electricity Transmission Plc 01926 655944 andy.wainwright@uk.ngrid.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	William Kirk-Wilson National Grid Electricity Transmission Plc 01926 655424 william.kirkwilson@uk.ngrid.com
Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:** Appendix 1 – CUSC Section 14 – Proposed legal text	

Formatted: Underline

CUSC - SECTION 14

CHARGING METHODOLOGIES

CONTENTS

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Annex 2 – Proposed Legal Text

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Formatted: Font: (Default) Arial, 12 pt

Annex 2 – Proposed Legal Text

CUSC v~~1.1~~

Annex 2 – Proposed Legal Text

CUSC - SECTION 14

CHARGING METHODOLOGIES

14.1 Introduction

14.1.1 This section of the CUSC sets out the statement of the Connection Charging Methodology and the Statement of the Use of System Methodology.

Formatted: Font: (Default) Arial

Formatted: CMS Head L4

Formatted: CMS Head L5, No bullets or numbering

Formatted: Bullets and Numbering

Formatted: Font: (Default) Arial

Annex 2 – Proposed Legal Text

~~CUSC SECTION 14~~

Formatted: Font: Arial Bold, Strikethrough

~~THE CHARGING METHODOLOGIES~~

~~PART I~~

~~THE STATEMENT OF THE CONNECTION CHARGING METHODOLOGY~~

Annex 2 – Proposed Legal Text

CUSC v~~1.1~~

~~CUSC SECTION 14~~

~~THE CHARGING METHODOLOGIES~~

~~PART II~~

~~THE STATEMENT OF THE USE OF SYSTEM CHARGING METHODOLOGY~~

Formatted: Strikethrough

~~Issue~~	~~Revision~~
~~6~~	~~0~~

Formatted: Strikethrough

~~The Statement of the Connection Charging Methodology~~

~~Effective from 1 April 2010~~

nationalgrid

~~About this Document~~

~~This document describes the methodology that National Grid Electricity Transmission plc (National Grid), employs to levy charges for connection to the transmission system in Great Britain (GB) on behalf of National Grid Electricity Transmission plc, Scottish Power Transmission Ltd and Scottish Hydro-Electric Transmission Ltd. This document is one of a suite of three documents that describe the charges levied by The Company and the methodologies behind them. The other documents are:~~

Deleted: ~~National Grid~~

- **~~The Statement of the Use of System Charging Methodology~~**
- **~~The Statement of Use of System Charges~~**

~~These are available on our Charging website at:~~

~~http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/~~

~~This Statement of the Connection Charging Methodology Issue 6, Revision 0 is effective from the 1 April 2010.~~

~~This document has been published by The Company in accordance with Condition C6 of The Company's Transmission Licence. The methodology was developed as part of the GB charging consultation process originally approved by the Authority[1] in December 2004 and also includes any subsequently approved modifications following industry consultation.[2]~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

~~If you require further details about any of the information contained within this document or have comments on how this document might be improved please contact our **Charging Team**, preferably by email at:~~

~~charging.enquiries@uk.ngrid.com~~

~~or at:~~

~~National Grid House~~
~~Warwick Technology Park~~
~~Gallows Hill~~
~~Warwick~~
~~CV34 6DA~~

~~Telephone 01926 654633~~

[1] ~~NGC's proposed electricity transmission charging methodologies: The Authority's Decisions – December 2004~~
[2] ~~http://www.nationalgrid.com/uk/Electricity/Charges/modifications/ccmc/~~

Formatted: Strikethrough

Deleted: 2

~~Contents~~

Deleted: April 2010 . Th ... [1]
Formatted ... [2]
Deleted: 5
Deleted: ~~National Grid~~ ... [3]
Deleted: 6
Deleted: 8
Deleted: 9
Deleted: 9
Deleted: 9
Deleted: 11
Deleted: 11
Deleted: 11
Deleted: 12
Deleted: 12
Deleted: 13
Deleted: 14
Deleted: 14
Deleted: 14
Deleted: 15
Deleted: 16
Deleted: 17
Deleted: 17
Deleted: 18
Deleted: 18
Deleted: 18
Deleted: 19
Deleted: 19
Deleted: 19
Deleted: 19
Deleted: 20
Deleted: 21
Deleted: 21
Deleted: 22
Deleted: 22
Deleted: 23
Deleted: 23
Deleted: 24
Deleted: 24
Deleted: 26
Deleted: 27
Deleted: 28
Deleted: 28
Deleted: 30
Deleted: 33
Deleted: 33
Deleted: 34
Deleted: 34
Deleted: 34
Deleted: 35
Deleted: 35
Deleted: 35
Deleted: 35
Deleted: 3

Deleted: The Statement of the Connection Charging Methodology . April 2010

Deleted: 36

Deleted: 42

Deleted: 2

~~General Introduction~~

The Company~~'s Licence Obligations~~

~~1 As the holder of Transmission Licences in Great Britain, the GB transmission licensees are required by the Electricity Act 1989, as amended by the Utilities Act 2000 and the Energy Act 2004, to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the generation and supply of electricity. The transmission licensees are also required by Schedule 9 of the Electricity Act to have regard for the effects of its activities on the environment.~~

2 The Company~~'s Transmission Licence Conditions were changed by the Secretary of State through the Energy Act 2004 as part of the implementation of BETTA. Consequently~~ The Company ~~is responsible for the determination and implementation of a GB connection charging methodology that has effect from the BETTA Go-Live date of 1 April 2005. Following the changes, Licence Condition C6 of the~~ The Company ~~Transmission Licence states that:~~

~~*The Licensee (National Grid) shall as soon as practicable after the date this Condition comes into effect prepare a statement approved by the Authority of the connection charging methodology in relation to charges, including charges:*~~

~~*a. for the carrying out of works and the provision and installation of electrical lines or electrical plant or meters for the purposes of connection (at entry or exit points) to the GB transmission system;*~~

~~*b. in respect of extension or reinforcement of the GB transmission system rendered (at the discretion of a transmission licensee where the extension or reinforcement is of that licensee's transmission system) necessary or appropriate by virtue of the licensee providing connection to or use of system to any person seeking connection;*~~

~~*c. in circumstances where the electrical lines or electrical plant to be installed are (at the discretion of a transmission licensee where the electrical lines or electrical plant which are to be installed will form part of that licensee's transmission system) of greater size than that required for use of system by the person seeking connection;*~~

~~*d. for maintenance and repair (including any capitalised charge) required of electrical lines or electrical plant or meters provided or installed for making a connection to the GB transmission system; and*~~

~~*e. for disconnection from the GB transmission system and the removal of electrical plant, electrical lines and meters following disconnection.*~~

3 The Company ~~is also required by the Transmission Licence:~~

- ~~*to offer terms for connection to and use of the GB system or for the modification of an existing connection within three months of application;*~~

- ~~*to offer terms for use of the GB system only within 28 days of application;*~~

Deleted: April 2010 . The Statement of the Connection Charging Methodology

Deleted: National Grid

Formatted: Strikethrough

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm

Deleted: National Grid

Formatted: Strikethrough

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm

Deleted: National Grid

Formatted: Strikethrough

Deleted: National Grid

Formatted: Strikethrough

Formatted: Indent: Left: 1.25 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.27 cm, List tab + Not at 0.63 cm + 1.89

Formatted: Indent: Left: 1.25 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.27 cm, List tab + Not at 0.63 cm + 1.89

Formatted: Indent: Left: 1.25 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.27 cm, List tab + Not at 0.63 cm + 1.89

Formatted ... [4]

Formatted ... [5]

Deleted: National Grid

Formatted ... [6]

Formatted: Strikethrough

Formatted ... [7]

Formatted ... [8]

Deleted: 3

~~not to discriminate between any persons or class or classes of persons in providing use of the GB system or in carrying out works for connection.~~

4 ~~Licence Condition C11 also requires~~ The Company ~~no later than 31 May 2005 for the financial year ending 31 March 2005 and by 31 March in each financial year thereafter, to prepare a statement in a form approved by the Authority showing in respect of each of the seven succeeding financial years circuit capacity, forecast power flows and loading on each part of the GB transmission system and fault levels for each transmission node, together with:~~

~~a. such further information as shall be reasonably necessary to enable any person seeking use of system to identify and evaluate the opportunities available when connecting to and making use of such system;~~

~~b. a commentary prepared by the licensee indicating those parts of the GB transmission system most suited to new connections and transport of further quantities of electricity; and~~

~~c. such other matters as shall be specified in directions issued by the Authority from time to time for the purposes of this condition.~~

~~Relevant Objectives~~

~~5 As part of Licence Condition C6~~ The Company ~~has to ensure that the Connection Charging Methodology meets the relevant licence objectives as specified in C6(5) and C6(11) in relation to connection charges. The relevant objectives are set out as follows:~~

~~a. That compliance with the Connection Charging Methodology facilitates effective competition in the generation and supply of electricity and (so far as consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;~~

~~b. That compliance with the Connection Charging Methodology results in charges which reflect, as far reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by licensees in their transmission businesses; and~~

~~c. That so far as is consistent with the sub-paragraphs (a) and (b), the Connection Charging Methodology, as far as is reasonably practicable, properly takes account of the developments in the transmission licensees' transmission Businesses;~~

~~d. In so far as consistent with sub paragraphs (a), (b) and (c) of facilitating competition in the carrying out of works for connection to the GB transmission system.~~

~~In interpretation of the above objectives, Standard Condition C1 of~~ The Company~~'s Transmission License shall prevail in its definition of connection charges and use of system charges in respect of the GB transmission system.~~

~~6 The Licence states that~~ The Company ~~must keep the Connection Charging Methodology under review at all times for the purpose of ensuring that the methodologies meet the relevant objectives outlined above.~~

Deleted: The Statement of the Connection Charging Methodology . April 2010

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Deleted: ~~National Grid~~

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 4 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Formatted: Indent: Left: 1.27 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at:

Formatted: Indent: Left: 1.27 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at:

Formatted: Indent: Left: 1.27 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at:

Formatted: Indent: Left: 1.27 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at:

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: 2

~~7 The Company may make modifications to the Methodology as may be required for the purpose of better meeting the relevant objectives above.~~

~~8 Before making any modifications, unless it has been agreed otherwise with the Authority, The Company will consult with CUSC parties for a period of at least 28 days on the proposed change to the Connection Charging Methodologies where written representations can be made.~~

~~9 A report will then be issued to the Authority by The Company setting out the terms of the modification, representations made, any change to the terms of the modification, how the modification better meets the relevant objectives and a timetable and date for implementation of the modification.~~

~~10 Unless the Authority has, within 28 days of the report being furnished to it, given a direction that the modification may not be made, or that an impact assessment will be undertaken, The Company will make the modification to the Connection Charging Methodology. In the event that an impact assessment is deemed necessary, the Authority will undertake a consultation process, thus extending the decision period by a maximum of three months.~~

~~11 Once a modification is made The Company will issue a revised statement showing the changed Connection Charging Methodology. The revised Connection Charging Methodology statement will supersede all previous statements from the date of its issue.~~

Deleted: April 2010 . The Statement of the Connection Charging Methodology

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: 3

~~The Contractual Framework~~

~~12 The Connection and Use of System Code (CUSC) is a multi-party document creating contractual obligations among and between all Users of the transmission system, parties connected to the GB transmission system and National Grid. Persons wishing to use and/or connect to the GB transmission system will be required to accede to the CUSC by signing the Framework Agreement and to enter into a Bilateral Agreement with The Company.~~

~~13 The Company continues to request that Small Power Stations make a formal application for use of the system. The Company can then assess the potential impact on the transmission system and consider what form of agreement, if any, may be required.~~

~~14 The CUSC and individual User's Bilateral Agreements set out the terms and conditions applicable for use of and/or connection to the transmission system. In particular, they set out the User's obligations to:~~

- ~~pay all use of system and connection charges;~~
- ~~comply with the provisions of the Grid Code;~~
- ~~sign on to the Balancing and Settlement Code (BSC);~~
- ~~enter into an appropriate Mandatory Services Agreement.~~

~~15 Additionally, each Bilateral Agreement details the information on which the User's connection charges are based:~~

- ~~Appendix A of each Bilateral Agreement lists the connection assets by description and age to the User;~~
- ~~Appendix B identifies the connection charges;~~

~~16 If a User fails to fulfil their obligations, their entitlement to use and/or be connected to the GB transmission system will cease. The User will be liable for all charges that may arise up to the end of the current Financial Year and, for connection, the appropriate termination sum.~~

~~17 When a User applies for a new connection to the system or to modify an existing connection they may be required to enter into a Construction Agreement. Within the Construction Agreement there will be provisions for site-specific elements such as Consents and Final Sums.~~

Deleted: The Statement of the Connection Charging Methodology April 2010

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Deleted: ~~National Grid~~

Formatted: Strikethrough

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Deleted: 2

Part 1 - The Statement of the Connection Charging Methodology

14.2 Principles

Costs and their Allocation

14.2.1 Connection charges enable The Company to recover, with a reasonable rate of return, the costs involved in providing the assets that afford connection to the National Electricity Transmission System.

14.2.2 Connection charges relate to the costs of assets installed solely for and only capable of use by an individual User. These costs may include civil costs, engineering costs, and land clearance and preparation costs associated with the connection assets, but for the avoidance of doubt no land purchase costs will be included..

14.2.3 Connection charges are designed not to discriminate between Users or classes of User. The methodology is applied to both connections that were in existence at Vesting (30 March 1990) and those that have been provided since.

Connection/Use of System Boundary

14.2.4 The first step in setting charges is to define the boundary between connection assets and transmission system infrastructure assets.

14.2.5 In general, connection assets are defined as those assets solely required to connect an individual User to the National Electricity Transmission System, which are not and would not normally be used by any other connected party (i.e. "single user assets"). For the purposes of this Statement, all connection assets at a given location shall together form a connection site.

14.2.6 Connection assets are defined as all those single user assets which:

a) for Double Busbar type connections, are those single user assets connecting the User's assets and the first transmission licensee owned substation, up to and including the Double Busbar Bay;

b) for teed or mesh connections, are those single user assets from the User's assets up to, but not including, the HV disconnector or the equivalent point of isolation;

c) for cable and overhead lines at a transmission voltage, are those single user connection circuits connected at a transmission voltage equal to or less than 2km in length that are not potentially shareable.

14.2.7 Shared assets at a banked connection arrangement will not normally be classed as connection assets except where both legs of the banking are single user assets under the same Bilateral Connection Agreement.

14.2.8 Where customer choice influences the application of standard rules to the connection boundary, affected assets will be classed as connection assets. For example, in England & Wales The Company does not normally own busbars below 275kV, where The Company and the customer agree that The Company will own

Deleted: April 2010 . The Statement of the Connection Charging Methodology
Formatted: Font: Arial Bold, 16 pt, Not Strikethrough
Formatted: Font: Arial Bold, 16 pt, Not Strikethrough
Formatted: Font: Arial Bold, 16 pt, Font color: Auto, Not Strikethrough
Deleted: Chapter 1:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: GB
Deleted: t
Deleted: s
Formatted: Bullets and Numbering
Comment [a1]:
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: GB
Deleted: t
Deleted: s
Formatted: Bullets and Numbering
Deleted: 1.7 .
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: National Grid
Deleted: National Grid
Deleted: 3

the busbars at a low voltage substation, the assets at that substation will be classed as connection assets and will not automatically be transferred into infrastructure.

14.2.9 The design of some connection sites may not be compatible with the basic boundary definitions in 14.2.6 above. In these instances, a connection boundary consistent with the principles described above will be applied.

Deleted: The Statement of the Connection Charging Methodology . April 2010

Deleted: 1.9 .

Formatted: Bullets and Numbering

Deleted: 1

Deleted: 2

14.3 The Calculation of the Basic Annual Connection Charge for an Asset

Pre and Post Vesting Connections

14.3.1 Post Vesting connection assets are those connection assets that have been commissioned since 30 March 1990. Pre Vesting connection assets are those that were commissioned on or before the 30 March 1990.

14.3.2 The basic connection charge has two components. A non-capital component, for which both pre and post vesting assets are treated in the same way and a capital component for which there are slightly different options available for pre and post vesting assets. These are detailed below.

Calculation of the Gross Asset Value (GAV)

14.3.3 The GAV represents the initial total cost of an asset to the transmission licensee. For a new asset it will be the costs incurred by the transmission licensee in the provision of that asset. Typically, the GAV is made up of the following components:

Construction Costs - Costs of bought in services
Engineering - Allocated equipment and direct engineering cost
Interest During Construction – Financing cost
Liquidated Damages Premiums - Premium required to cover Liquidated Damages if applicable.

Some of these elements may be optional at the User's request and are a matter of discussion and agreement at the time the connection agreement is entered into.

14.3.4 The GAV of an asset is re-valued each year normally using one of two methods. For ease of calculation, April is used as the base month.

- In the Modern Equivalent Asset (MEA) revaluation method, the GAV is indexed each year with reference to the prevailing price level for an asset that performs the same function as the original asset;
- In the RPI revaluation method, the original cost of an asset is indexed each year by the Retail Price Index (RPI) formula set out in paragraph 14.3.6. For Pre Vesting connection assets commissioned on or before 30 March 1990, the original cost is the 1996/97 charging GAV (MEA re-valued from vesting). The original costs of Post Vesting assets are calculated based on historical cost information provided by the transmission licensee's.

14.3.5 In the MEA revaluation method, the MEA value is based on a typical asset. An MEA ratio is calculated to account for specific site conditions, as follows:

- The outturn GAV (as calculated in paragraph 14.3.4 above) is re-indexed by RPI to the April of the Financial Year the Charging Date falls within;
- This April figure is compared with the MEA value of the asset in the Financial Year the Charging Date falls within and a ratio calculated;

Deleted: April 2010 . The Statement of the Connection Charging Methodology
Deleted: Chapter 2:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.6 cm
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Deleted: 2.6
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Deleted: 2.3
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Deleted: 3

- If the asset was commissioned at a Connection Site where, due to specific conditions, the asset cost more than the standard MEA value, the ratio would be greater than 1. For example, if an asset cost 10% more to construct and commission than the typical asset the MEA ratio would be 1.1. If, however, the asset was found only to cost 90% of the typical MEA value the ratio would be 0.9;

- The MEA ratio is then used in all future revaluations of the asset. The April GAV of the asset in any year is thus the current MEA value of the asset multiplied by the ratio calculated for the Financial Year the Charging Date falls within.

14.3.6 The RPI revaluation method is as follows:

- The outturn GAV (as calculated in paragraph 14.3.4 above) is re-indexed by RPI to the April of the Financial Year the Charging Date falls within. This April GAV is thus known as the Base Amount;

- The Base Amount GAV is then indexed to the following April by using the RPI formula used in The Company's Price Control. April GAVs for subsequent years are found using the same process of indexing by RPI.

  i.e. $GAV_n = GAV_{n-1} * RPI_n$

- The RPI calculation for year n is as follows:

$$RPI_n = \frac{[\text{ May to October average RPI Index }]_{n-1}}{[\text{ May to October average RPI Index }]_{n-2}}$$

Calculation of Net Asset Value

14.3.7 The Net Asset Value (NAV) of each asset for year n, used for charge calculation, is the average (mid year) depreciated GAV of the asset. The following formula calculates the NAV of an asset, where A_n is the age of the asset (number of completed charging years old) in year n:

$$NAV_n = GAV_n * \frac{\text{Depreciation Period} - (A_n + 0.5)}{\text{Depreciation Period}}$$

14.3.8 In constant price terms an asset with an initial GAV of £1m and a depreciation period of 40 years will normally have a NAV in the year of its commissioning of £0.9875m (i.e. a reduction of 1.25%) and in its second year of £0.9625m (i.e. a further reduction of 2.5% or one fortieth of the initial GAV). This process will continue with an annual reduction of 2.5% for each year of the asset's life.

Capital Components of the Connection charge for Post Vesting Connection Assets

14.3.9 The standard terms for a connection offer will be:

- 40 year life (with straight line depreciation);

- RPI indexation

Deleted: The Statement of the Connection Charging Methodology . April 2010

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Bullets and Numbering

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Deleted: 2.3

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Deleted: National Grid

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.9 cm, List tab + Not at 0.63 cm

Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.9 cm, List tab + Not at 0.63 cm

Deleted: 2

14.3.10 In addition a number of options exist:

- a capital contribution based on the allocated GAV at the time of commissioning will reduce capital. Typically a capital contribution will include costs to cover the elements outlined below and charges are calculated as set out in the equations below;

  - Construction costs
  - Engineering costs (Engineering Charge x job hours)
  - Interest During Construction (IDC)
  - Return element (6%)
  - Liquidated Damages Premium (LD) (if applicable)

  General Formula:

  Capital Contribution Charge = (Construction Costs + Engineering Charges) x (1+Return %) + IDC + LD Premium

- MEA revaluation which is combined with a 7.5% rate of return, as against 6% on the standard RPI basis;

- annual charges based on depreciation periods other than 40 years;

- annuity based charging;

- indexation of GAVs based on principles other than MEA revaluation and RPI indexation. No alternative forms of indexation have been employed to date.

14.3.11 For new connection assets, should a User wish to agree to one or more of the options detailed above, instead of the standard connection terms, the return elements charged by the transmission licensee may also vary to reflect the re-balancing of risk between the transmission licensee and the User. For example, if Users choose a different indexation method, an appropriate rate of return for such indexation method will be derived.

Capital Components of the Connection charge for Pre Vesting Connection Assets

14.3.12 The basis of connection charges for GB assets commissioned on or before 30 March 1990 is broadly the same as the standard terms for connections made since 30 March 1990. Specifically charges for pre vesting connection assets are based on the following principles:

- The GAV is the 1996/97 charging GAV (MEA re-valued from vesting) subsequently indexed by the same measure of RPI as used in The Company's Price Control;

- 40 year life (with straight line depreciation);

- 6% rate of return

14.3.13 Pre-vesting 1996 MEA GAVs for Users' connection sites are available from The Company on request from the **Charging Team**.

Non-Capital Components - Charging for Maintenance and Transmission Running Costs

14.3.14 The non-capital component of the connection charge is divided into two parts, as set out below. Both of these non-capital elements will normally be identified in the charging appendices of relevant Bilateral Agreements.

Part A: Site Specific Maintenance Charges

14.3.15 This is a maintenance only component that recovers a proportion of the costs and overheads associated with the maintenance activities conducted on a site-specific basis for connection assets of the transmission licensees.

14.3.16 Site-specific maintenance charges will be calculated each year based on the forecast total site specific maintenance for NETS divided by the total GAV of the transmission licensees NETS connection assets, to arrive at a percentage of total GAV. For 2010/11 this will be 0.52%. For the avoidance of doubt, there will be no reconciliation of the site-specific maintenance charge.

Part B: Transmission Running Costs

14.3.17 The Transmission Running Cost (TRC) factor is calculated at the beginning of each price control to reflect the appropriate amount of other Transmission Running Costs (rates, operation, indirect overheads) incurred by the transmission licensees that should be attributed to connection assets.

14.3.18 The TRC factor is calculated by taking a proportion of the forecast Transmission Running Costs for the transmission licensees (based on operational expenditure figures from the latest price control) that corresponds with the proportion of the transmission licensees' total connection assets as a function of their total business GAV. This cost factor is therefore expressed as a percentage of an asset's GAV and will be fixed for the entirety of the price control period. For 2010/11 this will be 1.45%.

14.3.19 To illustrate the calculation, the following example uses the average operating expenditure from the published price control and the connection assets of each transmission licensee expressed as a percentage of their total system GAV to arrive at a GB TRC of 1.45%:

Example:

Connection assets as a percentage of total system GAV for each TO:

Scottish Power Transmission Ltd	15.1%
Scottish Hydro Transmission Ltd	8.6%
National Grid	12.5%

Published current price control average annual operating expenditure (£m):

Scottish Power Transmission Ltd	29.1
Scottish Hydro Transmission Ltd	11.3
National Grid	295.2

Deleted: The Statement of the Connection Charging Methodology April 2010

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: GB

Deleted: GB

Deleted: 2.17

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: 2.19

Formatted: Bullets and Numbering

Formatted: Indent: Left: 1.6 cm

Formatted: Indent: Left: 0.33 cm

Formatted Table

Formatted: Indent: Left: 0.33 cm

Formatted Table

Deleted: 2

Total GB Connection GAV = £2.12bn

GB TRC Factor = (15.1% x £29.1m + 8.6% x £11.3m + 12.5% x £295.2m) / £2.12bn

GB TRC Factor = 1.99%

Net GB TRC Factor = Gross GB TRC Factor – Site Specific Maintenance Factor*

Net GB TRC Factor = 1.99% - 0.54% = 1.45%

*** Note – the Site Specific Maintenance Factor used to calculate the TRC Factor is that which applies for the first year of the price control period or in this example, is the 2007/8 Site Specific Maintenance Factor of 0.54%.**

The Basic Annual Connection Charge Formula

14.3.20 The charge for each connection asset in year n can be derived from the general formula below. This is illustrated more fully by the examples in **Appendix 2: Examples of Connection Charge Calculations.**

Annual Connection Charge$_n$ = D_n (GAV_n) + R_n (NAV_n) + SSF_n ($RPIGAV_n$) + TC_n (GAV_n)

Where:

For n = year to which charge relates within the Depreciation Period

n = year to which charge relates
GAV_n = GAV for year n re-valued by relevant indexation method
$RPIGAV_n$ = GAV for year n re-valued by RPI indexation
NAV_n = NAV for year n based on re-valued GAV_n
D_n = Depreciation rate as percentage (equal to 1/Depreciation Period) (typically 1/40 = 2.5% of GAV)
R_n = real rate of return for chosen indexation method (6% for RPI indexation, 7.5% for MEA Indexation)
SSF_n = Site Specific Factor for year n as a % (equal to the Site Specific Cost/Total Site GAV)
TC_n = Transmission Running Cost component for year n (other Transmission Owner Activity costs).

For n = year to which charge relates beyond the Depreciation Period

n = year to which charge relates
GAV_n = GAV for year n re-valued by relevant indexation method
$RPIGAV_n$ = GAV for year n re-valued by RPI indexation
NAV_n = 0
D_n = 0
R_n = real rate of return for chosen indexation method (6% for RPI indexation, 7.5% for MEA Indexation)
SSF_n = Site Specific Factor for year n as a % (equal to the Site Specific Cost/Total Site GAV)

Deleted: April 2010 . The Statement of the Connection Charging Methodology
Formatted: Indent: Left: 0.33 cm
Formatted: Indent: Left: 1.6 cm
Formatted: Indent: Left: 0.33 cm
Formatted: Indent: Left: 1.6 cm
Formatted: Indent: Left: 0.33 cm
Formatted: Indent: Left: 1.6 cm
Deleted: 2.20
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.25 cm
Formatted: Indent: Left: 1.25 cm
Formatted: Indent: Left: 2.5 cm
Formatted: Indent: Left: 2.5 cm
Formatted: Indent: Left: 2.5 cm
Formatted: Indent: Left: 2.5 cm
Deleted: 3

Deleted: The Statement of the Connection Charging Methodology April 2010

TC_n = Transmission Running cost component for year n (other Transmission Owner Activity costs).

14.3.21 Note that, for the purposes of deriving asset specific charges for site-specific maintenance, the RPI re-valued GAV is used. This is to ensure that the exact site charges are recovered from the assets at the site. The site costs are apportioned to the assets on the basis of the ratio of the asset GAV to total Site GAV.

Deleted: 2.21

Formatted: Bullets and Numbering

Adjustment for Capital Contributions

14.3.22 If a User chooses to make a 100% capital contribution to The Company towards their allocation of a connection asset then no capital charges will be payable and hence the connection charges for that asset would be calculated as follows:

Deleted: 2.22

Formatted: Bullets and Numbering

Deleted: National Grid

$$\text{Annual Connection Charge}_n = SSF_n\ (RPIGAV_n) + TC_n\ (GAV_n)$$

Formatted: Indent: Left: 1.27 cm

14.3.23 If a User chooses to make a partial capital contribution to The Company towards their allocation of a connection asset, for example PCCF = 50%, then the connection charges for that asset would be calculated as follows:

Deleted: 2.23

Formatted: Bullets and Numbering

Deleted: National Grid

$$\text{Annual Connection Charge}_n = D_n\ (GAV_n{*}PCCF) + R_n\ (NAV_n{*}PCCF) + SSF_n\ (RPIGAV_n) + TC_n\ (GAV_n)$$

Formatted: Indent: Left: 1.6 cm

PCCF = Partial Capital Contribution Factor

Formatted: Indent: Left: 0.33 cm

Formatted: Indent: Left: 1.27 cm

Modification of Connection Assets

14.3.24 Where a modification to an existing connection occurs at the User's request or due to developments to the transmission system, their annual connection charges will reflect any additional connection assets that are necessary to meet the User's requirements. Charges will continue to be levied for existing assets that remain in service. Termination charges as described in **Chapter 5** below will be charged for any existing connection assets made redundant as a result of the modification.

Deleted: 2.24

Formatted: Bullets and Numbering

Deleted: 2

14.4 Other Charges

14.4.1 In addition to the basic annual connection charges set out above, the User may pay The Company for certain other costs related to their connection. These will be set out in the Bilateral and Construction Agreements where appropriate and are described below.

One-off Works

14.4.2 To provide or modify a connection, the transmission licensee may be required to carry out works on the transmission system that, although directly attributable to the connection, may not give rise to additional connection assets. These works are defined as "one-offs". Liability for one-off charges is established with reference to the principles laid out below:

- Where a cost cannot be capitalised into either a connection or infrastructure asset, typically a revenue cost
- Where a non-standard incremental cost is incurred as a result of a User's request, irrespective of whether the cost can be capitalised
- Termination Charges associated with the write-off of connection assets at the connection site.

Consistent with these principles and in accordance with Connection Charging Methodology modification GB ECM-01, which was implemented on 1 December 2005, a one-off charge will be levied for a **Category 1 Intertripping Scheme** or a **Category 3 Intertripping Scheme**. A one-off charge will **not** be levied for a **Category 2 Intertripping Scheme** or a **Category 4 Intertripping Scheme**.

14.4.3 The one-off charge is a charge equal to the cost of the works involved, together with a reasonable return, as shown in 14.4.4 below.

14.4.4 For information, the general formula for the calculation of the one-off charge for works is outlined below.

One-off Charge = (Construction Costs + Engineering Charges) x (1 + Return %) + IDC + LD Premium

Where: Engineering Charges = "Engineering Charge" x job hours
Return % = 6%
IDC = Interest During Construction
LD Premium = The Company Liquidated Damages Premium (if applicable)

14.4.5 The calculation of the one-off charge for write-off of assets is outlined below:

Write-off Charge = 100% of remaining NAV of redundant assets

14.4.6 One-offs are normally paid on an agreed date, which is usually upon completion of the works. However, arrangements may be agreed between the transmission licensee and the User to pay the charge over a longer period. If a one-off is paid over a longer period it is termed a Transmission Charge. It is usually a depreciating

Deleted: April 2010 . The Statement of the Connection Charging Methodology
Deleted: Chapter 3:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm
Formatted: Bullets and Numbering
Deleted: 3
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: 3

finance charge or annuity based charge with a rate of return element and may include agreement on a schedule of termination payments if the agreement is terminated before the end of the annuity period. The charge is usually inflated annually by the same RPI figure that is used to inflate GAVs, though Users can request alternative indexation methods.

Miscellaneous Charges

14.4.7 Other contract specific charges may be payable by the User, these will be set out in the Bilateral and Construction Agreements where appropriate.

Rental sites

14.4.8 Where The Company owns a site that is embedded within a distribution network, the connection charge to the User is based on the capital costs and overheads but does not include maintenance charges.

Final Metering Scheme (FMS)/Energy Metering Systems

14.4.9 Charges for FMS metering are paid by the registrant of the FMS metering at the connection site. It is charged on a similar basis as other Connection Assets. The electronic components of the FMS metering have a replacement and depreciation period in line with those advised by the transmission licensees, whilst the non-electronic components normally retain a 40 year replacement and depreciation period (or a User specified depreciation period as appropriate).

Deleted: The Statement of the Connection Charging Methodology April 2010

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: National Grid

Formatted: Bullets and Numbering

Deleted: 2

14.5 Connection Agreements

Indicative Agreement

14.5.1 The standard connection agreement offered by The Company is an indicative price agreement. From the Charging Date as set out in the User's Bilateral Connection Agreement, the User's initial connection charge is based on a fair and reasonable estimate of the expected costs of the connection.

Outturning the Indicative Agreement

14.5.2 Once the works required to provide a new or modified connection are completed and the costs finalised, the connection scheme is "outturned". The Company reconciles the monies paid by the User on the indicative charge basis against the charges that would have been payable based on the actual costs incurred in delivering the project together with any relevant interest. This process involves agreeing a new charging GAV (The Base Amount) with the User in line with the elements stated in paragraph 14.3.3 and then calculating connection charges with this GAV.

14.5.3 In addition, for Users that have chosen MEA revaluation their MEA ratios are agreed at outturn and this ratio is used for MEA revaluation in subsequent years.

14.5.4 In the case of connection asset replacement where there is no initiating User, the outturn is agreed with the User at the site.

Firm Price Agreement

14.5.5 In addition to the options stated in paragraph 14.3.10 above, firm price agreements are also available. Typically with this option the charges to be incurred, and any indexation, are agreed between The Company and the User and connection charges are not recalculated once outturn costs are known. A typical example of a firm price agreement is:

- Capital Contribution
- Firm Price GAV
- Running Costs (based on a firm price GAV)
- Fixed Schedule of Termination Amounts

14.5.6 When a User selects a firm price agreement some or all of the above elements can be made firm. Any elements of the agreement that have not been made firm will be charged on an indicative basis in accordance with this statement.

14.5.7 Final Sums and Consents costs are never made firm in a Firm Price Agreement. Details of both are set out in the Construction Agreement.

Deleted: April 2010 . The Statement of the Connection Charging Methodology
Deleted: Chapter 4:
Formatted: Font: 14 pt
Formatted: Font: 14 pt
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: 2.3
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: 2.10
Deleted: National Grid
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: 3

Deleted: The Statement of the Connection Charging Methodology . April 2010

Monthly Connection Charges

14.5.8 The connection charge is an annual charge payable monthly.

Formatted: Bullets and Numbering

14.5.9 If the initial Charging Date does not fall within the current Financial Year being charged for and there are no revisions to charges during the year, the monthly connection charge will equal the annual connection charge divided by twelve.

Formatted: Bullets and Numbering

14.5.10 For the Financial Year in which the Charging Date occurs (as set out in the User's Bilateral Agreement) or for any Financial Year in which a revision to charges has occurred during the Financial Year, for each complete calendar month from the Charging Date (or effective date of any charge revision) to the end of the Financial Year in which the Charging Date (or charge revision) occurs, the monthly connection charge shall be equal to the annual connection charge divided by twelve.

Formatted: Bullets and Numbering

14.5.11 For each part of a calendar month, the charge will be calculated as one twelfth of the annual connection charge prorated by the ratio of the number of days from and including the Charging Date to the end of the month that the Charging Date falls in and the number of days in that month.

Formatted: Bullets and Numbering

14.5.12 For example, say the annual connection charge for Financial Year 2010/11 is £1.2m and the Charging Date falls on the 15th November 2010, the monthly charges for the Financial Year 2010/11 would be as follows:

Formatted: Bullets and Numbering

• November = £1,200,000/12 * (16/30)	=	£53,333.33
• Dec 10, Jan 11, Feb 11, Mar 11	=	£1,200,000/12
	=	£100,000.00

Formatted: Indent: Left: 1.6 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 0.96 cm, List tab + Not at 0.63 cm

14.5.13 The above treatment does not apply to elements such as Miscellaneous Charges (as defined in 14.4.7) and Transmission Charges (annuitised one-offs, as defined in 14.4.6). If the Charging Date falls within a Financial Year, then the full annual charge will remain payable and will be spread evenly over the remaining months. This is because these payments are an annuitisation of charges that would normally be paid up-front as one-off payments.

Formatted: Bullets and Numbering

Deleted: 3.7

Deleted: 3.6

Deleted: 2

14.6 Termination Charges

Charges Liable

14.6.1 Where a User wholly or partially disconnects from the transmission system they will pay a termination charge. The termination charge will be calculated as follows:

- Where the connection assets are made redundant as a result of the termination or modification of a Bilateral Connection Agreement, the User will be liable to pay an amount equal to the NAV of such assets as at the end of the financial year in which termination or modification occurs, plus:

- The reasonable costs of removing such assets. These costs being inclusive of the costs of making good the condition of the connection site

- If a connection asset is terminated before the end of a Financial Year, the connection charge for the full year remains payable. Any remaining Use of System Charges (TNUoS and BSUoS) also remain payable

- For assets where it has been determined to replace upon the expiry of the relevant Replacement Period in accordance with the provisions set out in the CUSC and in respect of which a notice to Disconnect or terminate has been served in respect of the Connection Site at which the assets were located; and due to the timing of the replacement of such assets, no Connection Charges will have become payable in respect of such assets by the User by the date of termination; the termination charges will include the reasonable costs incurred by the transmission licensee in connection with the installation of such assets

- Previous capital contributions paid to The Company will be taken into account

14.6.2 The Calculation of Termination amounts for financial year n is as follows:

$$\text{Termination Charge}_n = UoS_n + C_n + NAV_{an} + R - CC$$

Where:

UoS_n = Outstanding Use of System Charge for year (TNUoS and BSUoS)
C_n = Outstanding Connection Charge for year
NAV_{an} = NAV of Type A assets as at 31 March of financial year n
R = Reasonable costs of removal of redundant assets and making good
CC = An allowance for previously paid capital contributions

14.6.3 Examples of reasonable costs of removal for terminated assets and making good the condition of the site include the following:

- If a circuit breaker is terminated as a result of a User leaving a site, this may require modifications to the protection systems.

- If an asset were terminated and its associated civils had been removed to 1m below ground then the levels would have to be made up. This is a common condition of planning consent.

Deleted: April 2010 . The Statement of the Connection Charging Methodology
Deleted: Chapter 5:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Formatted: Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm
Deleted: 3

Repayment on Re-Use of Assets

14.6.4 If any assets in respect of which a termination charge was made to The Company are re-used at the same site or elsewhere on the system, including use as infrastructure assets, The Company will make a payment to the original terminating User to reflect the fact that the assets are being re-used.

14.6.5 The arrangements for such repayments for re-use of Assets are that The Company will pay the User a sum equal to the lower of:

i.) the Termination Amount paid in respect of such Assets; or

ii.) the NAV attributed to such Assets for charging purposes upon their re-use

less any reasonable costs incurred in respect of the storage of those assets.

14.6.6 The definition of re-use is set out in the CUSC. Where The Company decides to dispose of a terminated asset where it is capable of re-use, The Company shall pay the User an appropriate proportion of the sale proceeds received.

Valuation of Assets that are re-used as connection assets or existing infrastructure assets re-allocated to connection

14.6.7 If an asset is reused following termination or allocated to connection when it has previously been allocated to TNUoS, a value needs to be determined for the purposes of connection charges. In both instances the connection charge will be based on the standard formula set out in paragraph 14.3.20. The Gross Asset Value will be based on the original construction costs and indexed by RPI. Where original costs are not known a reasonable value will be agreed between The Company and the User based on similar types of asset in use. The Net Asset Value will be calculated as if the asset had been in continuous service as a connection asset from its original commissioning date taking into account the depreciation period.

14.6.8 Where an asset has been refurbished or updated to bring it back into service a new value and an appropriate replacement period will be agreed between The Company and the User. This will be based on the value of similar types of asset in service and the costs of the refurbishment.

Deleted: The Statement of the Connection Charging Methodology April 2010
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Indent: Left: 1.27 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1.27 cm + Indent at: 0 cm
Formatted: Indent: Left: 1.25 cm, Hanging: 1.27 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1.27 cm + Indent at: 0 cm
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: 2
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

14.7 Contestability

Deleted: Chapter 6:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Formatted: Bullets and Numbering

14.7.1 Some connection activities may be undertaken by the User. The activities are the provision, or construction, of connection assets, the financing of connection assets and the ongoing maintenance of those assets. While some Users have been keen to see contestability wherever possible, contestability should not prejudice system integrity, security and safety. These concerns have shaped the terms that are offered for contestability in construction and maintenance.

Contestability in Construction

Formatted: Bullets and Numbering

14.7.2 Users have the option to provide (construct) connection assets if they wish. Formal arrangements for Users exercising this choice are available and further information on User choice in construction can be obtained from the **Customer Services Team** at:

National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Telephone 01926 654634

Deleted: 3

14.8 Asset Replacement

14.8.1 Appendix A of a User's Bilateral Connection Agreement specifies the age (number of complete charging years old), for charging purposes, of each of the NETS connection assets at the Connection Site for the corresponding Financial Year. Connection charges are calculated on the assumption that the assets will not need to be replaced until the charging age has reached the duration of the asset's Replacement Period.

If a connection asset is to be replaced, The Company will enter into an agreement for the replacement with the User. Where replacement occurs before the original asset's charging age has reached the duration of its Replacement Period, The Company will continue to charge for the original asset and make no charge to the existing User for the new asset until the original asset's charging age has reached the duration of its Replacement Period.

Where the replacement occurs after the original asset's charging age has reached the duration of its Replacement Period, The Company will charge on the basis of the original asset until replaced and on the basis of the new asset on completion of the works.

14.8.2 When the original asset's charging age has reached the duration of its Replacement Period the User's charge will be calculated on the then Net Asset Value of the new asset. The new asset begins depreciating for charging purposes upon completion of the asset replacement.

The Basic Annual Connection Charge Formulae are set out in **Chapter 2: The Basic Annual Connection Charge Formula.**

Asset Replacement that includes a change of Voltage

14.8.3 There are a number of situations where an asset replacement scheme may involve a change in the voltage level of a User's connection assets. These replacement schemes can take place over a number of years and may involve a long transitory period in which connection assets are operational at both voltage levels.

14.8.4 These situations are inevitably different from case to case and hence further charging principles will need to be developed over time as more experience is gained. Set out below, are some generic principles. This methodology will be updated as experience develops.

14.8.5 The general principles used to date are to ensure that, in the transitory period of an asset replacement scheme, the User does not pay for two full transmission voltage substations and that the charges levied reflect the Replacement Period of the original connection assets. In addition, in line with paragraph 14.8.1 above, charges will only be levied for the new assets once the original assets would have required replacement.

14.8.6 For example, a transmission licensee in investing to meet a future Security Standard need on the main transmission system, may require the asset replacement of an existing 275kV substation with a 400kV substation prior to the expiry of the original assets' Replacement Period. In this case, The Company will seek to recover the connection asset component via connection charges when the assets replaced were due for asset replacement. Prior to this, the User should not see an increase

Deleted: The Statement of the Connection Charging Methodology . April 2010

Deleted: Chapter 7:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Deleted: 7.1 .

Formatted: Bullets and Numbering

Deleted: GB

Deleted: National Grid

Deleted: National Grid

Deleted: National Grid

Deleted: 7.2 .

Formatted: Bullets and Numbering

Deleted: 7.3 .

Formatted: Bullets and Numbering

Deleted: 7.4 .

Formatted: Bullets and Numbering

Deleted: 7.5 .

Formatted: Bullets and Numbering

Deleted: 7

Deleted: 7.6 .

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

in charges and therefore the investment costs would be recovered through TNUoS charges.

In addition, if in the interim stage the User has, say, one transformer connected to the 275kV substation and one transformer connected to the 400kV substation, the charge will comprise an appropriate proportion of the HV assets at each site and not the full costs of the two substations. Note that the treatment described above is only made for transitory asset replacement and not enduring configurations where a User has connection assets connected to two different voltage substations.

Deleted: 3

14.9 Data Requirements

14.9.1 Under the connection charging methodology no data is required from Users in order to calculate the connection charges payable by the User.

Deleted: The Statement of the Connection Charging Methodology April 2010

Deleted: Chapter 8

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Deleted: :

Formatted: Font: 14 pt, Font color: Auto

Deleted: 8.1

Formatted: Bullets and Numbering

Deleted: 2

14.10 Applications

14.10.1 Application fees are payable in respect of applications for new connection agreements and modifications to existing agreements based on the reasonable costs transmission licensees incur in processing these applications. Users can opt to pay a fixed price application fee in respect of their application or pay the actual costs incurred. The fixed price fees for applications are detailed in the **Statement of Use of System Charges**.

14.10.2 If a User chooses not to pay the fixed fee, the application fee will be based on an advance of transmission licensees' Engineering and out-of pocket expenses and will vary according to the size of the scheme and the amount of work involved. Once the associated offer has been signed or lapses, a reconciliation will be undertaken. Where actual expenses exceed the advance, The Company will issue an invoice for the excess. Conversely, where The Company does not use the whole of the advance, the balance will be refunded.

14.10.3 The Company will refund the first application fee paid (the fixed fee or the amount post-reconciliation) made under the Construction Agreement for new or modified existing agreements. The refund shall be made either on commissioning or against the charges payable in the first three years of the new or modified agreement. The refund will be net of external costs.

14.10.4 The Company will not refund application fees for applications to modify a new agreement or modified existing agreement at the User's request before any charges become payable. For example, The Company will not refund an application fee to delay the provision of a new connection if this is made prior to charges becoming payable.

Deleted: April 2010 . The Statement of the Connection Charging Methodology

Deleted: Chapter 9:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: National Grid

Deleted: National Grid

Formatted: Bullets and Numbering

Deleted: National Grid

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: 3

Deleted: The Statement of the Connection Charging Methodology . April 2010

14.11 Illustrative Connection Charges

Deleted: Appendix 1:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

2010/11 First Year Connection Charges based on the RPI Method (6% rate of return)

The following table provides an indication of typical charges for new connection assets. Before using the table, it is important to read through the notes below as they explain the assumptions used in calculating the figures.

Calculation of Gross Asset Value (GAV)

The GAV figures in the following table were calculated using the following assumptions:

- Each asset is new
- The GAV includes estimated costs of construction, engineering, Interest During Construction and Liquidated Damages premiums

For details of the Calculation of the Gross Asset Value, see Chapter 2 of this Statement.

Calculation of first year connection charge

The first year connection charges in the following table were calculated using the following assumptions:

- The assets are new
- The assets are depreciated over 40 years
- The rate of return is assumed to be 6% for RPI indexation
- The connection charges include maintenance costs at a rate of 0.52% of the GAV
- The connection charges include Transmission Running Costs at a rate of 1.45% of the GAV

For details of the Basic Annual Connection Charge Formula, see Chapter 2 of this Statement.

Please note that the actual charges will depend on the specific assets at a site. Agreement specific NAVs and GAVs for each User will be made available on request.

Notes on Assets

The charges for Double and Single Busbar Bays include electrical and civil costs.

Transformer cable ratings are based on winter soil conditions.

In this example, transformer charges include civil costs of plinth and noise enclosure and estimated transport costs, but not costs of oil dump tank and fire trap moat. Transport costs do not include hiring heavy load sea transportation or roll-on roll-off ships.

Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

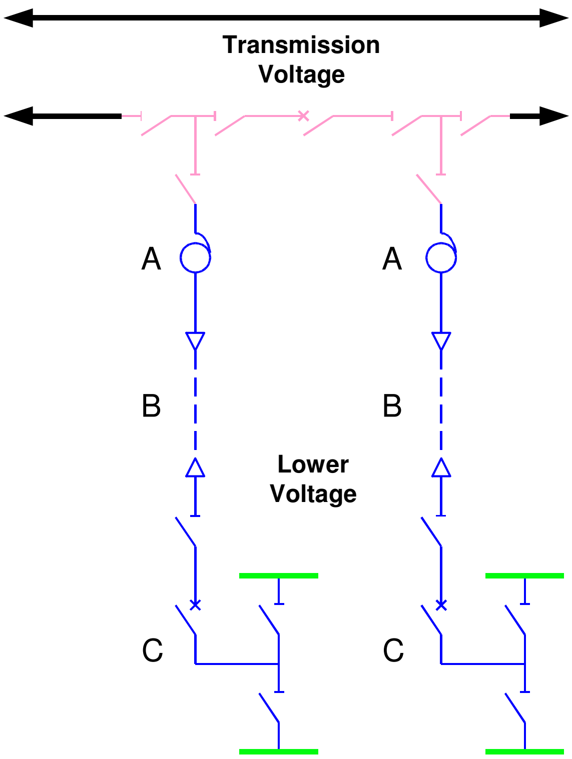
	£000's					
	400kV		275kV		132kV	
	GAV	Charge	GAV	Charge	GAV	Charge
Double Busbar Bay	2300	239	1890	197	630	65
Single Busbar Bay	1830	190			460	50
Transformer Cables 100m (incl. Cable sealing ends)						
120MVA			970	100	310	30
180MVA	1480	150	970	101	320	30
240MVA	1520	158	980	102	355	37
750MVA	1540	160	1135	118		
Transformers						
45MVA 132/66kV					1060	110
90MVA 132/33kV					102 0	106
120MVA 275/33kV			2110	219		
180MVA 275/66kV			2560	266		
180MVA 275/132kV			2180	227		
240MVA 275/132kV			2630	273		
240MVA 400/132kV	3180	340				

Deleted: 3

Connection Examples

Example 1

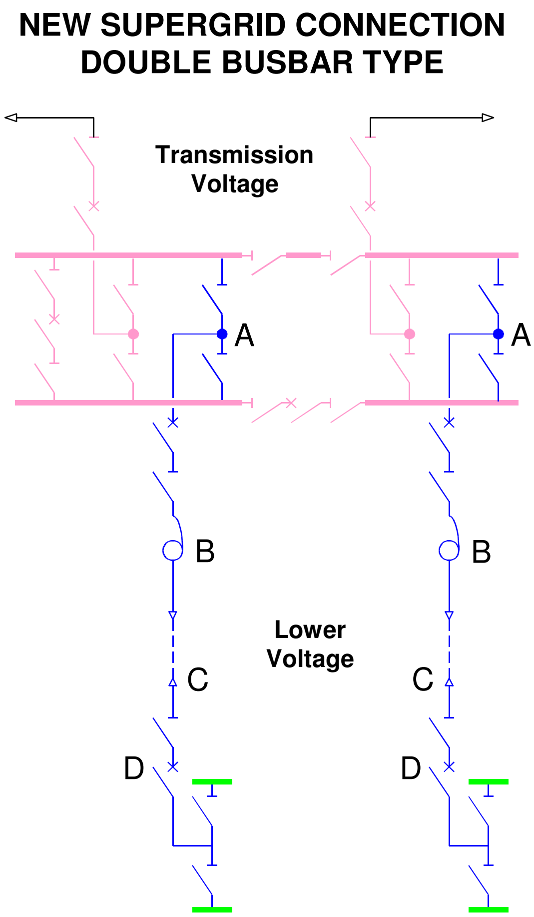
NEW SUPERGRID CONNECTION
SINGLE SWITCH MESH TYPE



KEY:
- Existing Transmission Assets (infrastructure)
- New Transmission Assets (infrastructure)
- New connection assets wholly charged to customer
- Customer Assets

SCHEDULE FOR NEW CONNECTION				
	132/33kV		**400/132kV**	
Ref	Description	First Year Charges (£000s)	Description	First Year Charges (£000s)
A	2 x 90MVA Transformers	212	2 x 240MVA Transformers	680
B	2 x 100m 90MVA Cables	20	2 x 100m 240MVA Cables	72
C	2 x Double Busbar Transformer Bays	20	2 x Double Busbar Transformer Bays	130
	Total	**252**	**Total**	**882**

Example 2



KEY:

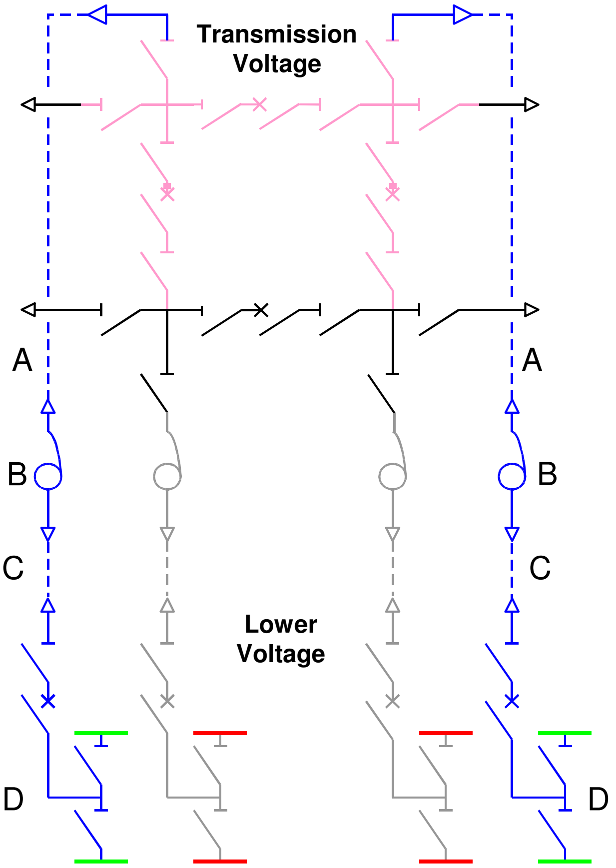
- Existing Transmission Assets (infrastructure)
- New Transmission Assets (infrastructure)
- New connection assets wholly charged to customer
- Customer Assets

SCHEDULE FOR NEW CONNECTION

Ref	132/33kV Description	132/33kV First Year Charges (£000s)	400/132kV Description	400/132kV First Year Charges (£000s)
A	2 x Double Busbar Transformer Bays	130	2 x Double Busbar Transformer Bays	478
B	2 x 90MVA Transformers	212	2 x 240MVA Transformers	680
C	2 x 100m 90MVA Cables	20	2 x 100m 240MVA Cables	74
D	2 x Double Busbar Transformer Bays	20	2 x Double Busbar Transformer Bays	130
	Total	**382**	**Total**	**1362**

Example 3

EXTENSION OF SINGLE SWITCH MESH TO FOUR SWITCH MESH (extension to single user site)



KEY:	
Black line	Existing Transmission Assets (infrastructure)
Pink line	New Transmission Assets (infrastructure)
Blue line	New connection assets wholly charged to customer
Grey line	Existing connection assets wholly charged to another user
Green line	Customer Assets
Red line	Other Users Assets

SCHEDULE FOR NEW CONNECTION				
	132/33kV		400/132kV	
Ref	Description	First Year Charges (£000s)	Description	First Year Charges (£000s)
A	2 x 100m 240MVA Cables	74	2 x 100m 240MVA Cables	316
B	2 x 90MVA Transformers	212	2 x 240MVA Transformers	680
C	2 x 100m 90MVA Cables	20	2 x 100m 240MVA Cables	74
D	2 x Double Busbar Transformer Bays	20	2 x Double Busbar Transformer Bays	130
	Total	**326**	**Total**	**1200**

Deleted: April 2010 . The Statement of the Connection Charging Methodology

14.12 Examples of Connection Charge Calculations

Deleted: Appendix 2:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

The following examples of connection charge calculations are intended as general illustrations.

Example 1

This example illustrates the method of calculating the first year connection charge for a given asset value. This method of calculation is applicable to indicative price agreements for new connections, utilising the RPI method of charging, and assuming:

i) the asset is commissioned on 1 April 2010
ii) there is no inflation from year to year i.e. GAV remains constant
iii) the site specific maintenance charge component remains constant throughout the 40 years at 0.52% of GAV
iv) the Transmission Running Cost component remains constant throughout the 40 years at 1.45% of GAV
v) the asset is depreciated over 40 years
vi) the rate of return charge remains constant at 6% for the 40 year life of the asset
vii) the asset is terminated at the end of its 40 year life

For the purpose of this example, the asset on which charges are based has a Gross Asset Value of £3,000,000 on 1 April 2010.

Charge	Calculation	
Site Specific Maintenance Charge (0.52% of GAV)	3,000,000 x 0.52%	£15,600
Transmission Running Cost (1.45% of GAV)	3,000,000 x 1.45%	£43,500
Capital charge (40 year depreciation 2.5% of GAV)	3,000,000 x 2.5%	£75,000
Return on mid-year NAV (6%)	2,962,500 x 6%	£177,750
TOTAL		£311,850

The first year charge of £311,850 would reduce in subsequent years as the NAV of the asset is reduced on a straight-line basis.

This gives the following annual charges over time (assuming no inflation):

Year	**Charge**
1	£311,850
2	£307,350
10	£271,350
40	£136,350

Based on this example, charges of this form would be payable until 31 March 2050.

Deleted: 3

Example 2

The previous example assumes that the asset is commissioned on 1 April 2010. If it is assumed that the asset is commissioned on 1 July 2010, the first year charge would equal 9/12th of the first year annual connection charge i.e. £233,887.50

This gives the following annual charges over time:

Year	Charge
1	£233,887.50 (connection charge for period July to March)
2	£307,350
10	£271,350
40	£136,350

Example 3

In the case of a firm price agreement, there will be two elements in the connection charge, a finance component and a running cost component. These encompass the four elements set out in the examples above. Using exactly the same assumptions as those in example 1 above, the total annual connection charges will be the same as those presented. These charges will not change as a result of the adoption of a different charging methodology by The Company, providing that the connection boundary does not change.

Deleted: National Grid

Example 4

If a User has chosen a 20-year depreciation period for their Post Vesting connection assets and subsequently remains connected at the site beyond the twentieth year their charges are calculated as follows.

For years 21-40 they will pay a connection charge based on the following formula:

Annual Connection Charge$_n$ = SSF$_n$ (RPIGAV$_n$)+ TC$_n$ (GAV$_n$)

The NAV will be zero and the asset will be fully depreciated so there will be no rate of return or depreciation element to the charge.

Deleted: The Statement of the Connection Charging Methodology April 2010

Deleted: 2

14.13 Nominally Over Equipped Connection Sites

14.13.1 This chapter outlines examples of ways in which a connection site can be considered as having connection assets that exceed the strict, theoretical needs of the individual Users at the connection site. These can be described as:

Historical

14.13.2 This is where the connection assets at the connection site were installed to meet a requirement of the Users for connection capacity that no longer exists. An example would be where a User, at one time, had a requirement for, say, 270 MW. This would allocate three 240 MVA 400/132kV transformers to the User. Due to reconfiguration of that User's network only 200 MW is now required from the connection site. The lower requirement would only allocate two transformers, but all the transformers are kept in service. The connection assets will continue to be assigned to the User's connection, and charged for as connection, until the User makes a Modification Application to reduce the historical requirement. In some cases the Modified requirement will mean that Termination Payments will have to be made on some connection assets.

Early Construction

14.13.3 If a User has a multi-phase project, it may be necessary to install connection assets for the latter phases at the time of the first phase. These connection assets could be charged from the first phase charging date.

Connection site Specific Technical or Economic Conditions

14.13.4 In circumstances where the transmission licensee has identified a wider requirement for development of the transmission system, it may elect to install connection assets of greater size and capacity than the practicable minimum scheme required for a particular connection. In these circumstances, however, connection charges for the party seeking connection will normally be based on the level of connection assets consistent with the practicable minimum scheme needed to meet the applicant's requirements.

14.13.5 There may be cases where there are specific conditions such that the practicable minimum scheme at a site has to be greater than the strict, theoretical interpretation of the standards. In these cases all assets will still be assigned to connection and connection charges levied.

14.13.6 A practicable minimum scheme is considered in terms of the system as a whole and may include a change in voltage level.

Deleted: April 2010 . The Statement of the Connection Charging Methodology

Deleted: Chapter 10:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: 3

Deleted: The Statement of the Connection Charging Methodology April 2010

~~Glossary~~

Formatted: Strikethrough

~~The following definitions are intended to assist the reader's understanding of this document. In the event of conflict with definitions given elsewhere, those used in the Electricity Act 1989 (as amended by the Utilities Act 2000), Transmission Licence, Grid Code, Balancing and Settlement Code and Connection and Use of System Code take precedence.~~

~~Act~~	~~The Electricity Act 1989 as amended by the Utilities Act 2000 and the Energy Act 2004~~
~~Authority~~	~~The Gas & Electricity Markets Authority (Ofgem)~~
~~Balancing and Settlement Code (BSC)~~	~~As defined in the Transmission Licence~~
~~Bilateral Agreement~~	~~Means, in relation to a User, a Bilateral Connection Agreement or a Bilateral Embedded Generation Agreement between~~ ~~The Company~~ ~~and the User, as defined in Standard Condition 1 of the~~ ~~The Company~~ ~~Transmission Licence~~
~~Category 1 Intertripping Scheme~~	~~A System to Generator Operational Intertripping Scheme arising from a Variation to Connection Design following a request from the relevant User which is consistent with the criteria specified in the Security and Quality of Supply Standard.~~
~~Category 2 Intertripping Scheme~~	~~A System to Generator Operational Intertripping Scheme which is:~~ ~~i) required to alleviate an overload on a circuit which connects the Group containing the User's Connection Site to the GB Transmission System; and~~ ~~ii) installed in accordance with the requirements of the planning criteria of the Security and Quality of Supply Standard in order that measures can be taken to permit maintenance access for each transmission circuit and for such measures to be economically justified, and the operation of which results in a reduction in Active Power on the overloaded circuits which connect the User's Connection Site to the rest of the GB Transmission System which is equal to the reduction in Active Power from the Connection Site (once any system losses or third party system effects are discounted).~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

~~**Category 3 Intertripping Scheme**~~	~~A System to Generator Operational Intertripping Scheme which, where agreed by NGC and the User, is installed to alleviate an overload on, and as an alternative to, the reinforcement of a third party system, such as the Distribution System of a Public Distribution System Operator.~~
~~**Category 4 Intertripping Scheme**~~	~~A System to Generator Operational Intertripping Scheme installed to enable the disconnection of the Connection Site from the GB Transmission System in a controlled and efficient manner in order to facilitate the timely restoration of the GB Transmission System.~~
~~**Charging Date**~~	~~As defined in the Construction Agreement of the Connection and Use of System Code (CUSC)~~
~~**Commissioned**~~	~~In respect of Plant and Apparatus commissioned before the Transfer Date means Plant and Apparatus recognised as having been commissioned according to the commissioning procedures current at the time of commissioning and in respect of Plant and Apparatus commissioned after the Transfer Date] means Plant and/or Apparatus certified by the Independent Engineer as having been commissioned in accordance with the relevant Commissioning Programme~~
~~**Connection boundary**~~	~~Shall be the boundary defined by Paragraph~~ 14.2.6 ~~in this document~~
~~**Connection Entry Capacity (CEC)**~~	~~As defined in the Connection and Use of System Code~~

Deleted: ~~1.6~~

~~**Consents**~~	~~In relation to any Works:-~~ ~~a) all such planning and other statutory consents; and~~ ~~b) all wayleaves, easements, rights over or interests in land or any other consent; or for commencement and carrying on of any activity proposed to be undertaken at or from such Works when completed~~ ~~c) permission of any kind as shall be necessary for the construction of the Works~~
~~**Construction Agreement**~~	~~An agreement entered into pursuant to Paragraph 1.3.2 of the CUSC~~
~~**CUSC**~~	~~The Connection and Use of System Code~~
~~**Customer Services Team**~~	~~The Customer Services Team manages the commercial interface with parties connected to the transmission network. Team Phone: 01926 654634~~
~~**Demand**~~	~~Electricity consumed at sites or by equipment not owned and operated by the transmission licensees~~

Deleted: 3

Deleted: The Statement of the Connection Charging Methodology . April 2010

~~**Depreciation Period**~~	~~In relation to a transmission licensees Asset for a particular User, the period which commences on the asset's initial effective charging date, and which expires after the appropriate duration, which unless otherwise agreed upon connection is 40 years excluding FMS Metering Electronics that are agreed between the User and~~ The Company~~.~~
~~**Directly-Connected Customer**~~	~~A large, usually industrial, consumer of electricity who is directly connected to the GB transmission system~~
~~**Disconnect or Disconnection**~~	~~(a) permanent physical disconnection of the [User's Equipment] at the site of connection to the Distribution System;~~ ~~(b) permanent physical disconnection of a User's Equipment at any given Connection Site which permits removal thereof from the Connection Site or removal of all transmission licensees Assets therefrom (as the case may be);~~ ~~(c) permanent physical disconnection of the User's Equipment or Equipment for which the User is responsible (as defined in Section K of the Balancing and Settlement Code) at the site of connection to the Distribution System~~
~~**Distribution voltage**~~	~~A voltage of 132kV or below in England & Wales. A voltage of below 132kV in Scotland. Generally taken to be voltages lower than those defined as transmission voltages~~
~~**Embedded**~~	~~Having a direct connection to a User system or the system of any other User to which Customers and or Power Stations are connected, such connection being either a direct connection or a connection via a busbar of another User or of a Transmission Licensee (but with no other connection to the Transmission System).~~
~~**Engineering Charge**~~	~~As set out in the Statement of Use of System Charges from time to time~~
~~**Exempt generator**~~	~~Any generator who, under the terms of the Electricity (Class Exemptions from the Requirement for a Licence) Order 2001, is not obliged to hold a generation licence~~
~~**Final Sums**~~	~~As defined in the Construction Agreement~~
~~**Financial Year**~~	~~The period of 12 months ending on 31st March in each calendar year~~

Deleted: ~~National Grid~~

Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

~~**GB Transmission System**~~	~~The system consisting (wholly or mainly) of high voltage electric lines owned and operated by transmission licensees and used for the transmission of electricity from one Power Station to a substation or to another Power Station or between substations or to or from any External Interconnection and includes any Plant and Apparatus and meters owned by and operated by transmission licensees in connection with the transmission of electricity but does not include any Remote Transmission Assets~~
~~**Generator**~~	~~A person who generates electricity under licence or exemption under the Act~~
~~**Generating Unit**~~	~~Unless otherwise provided in the Grid Code, any Apparatus which produces electricity.~~
~~**Grid Code**~~	~~A document prepared by~~ The Company ~~in accordance with Standard Condition 7 of the Transmission Licence setting out the technical parameters for the operation and use of the transmission system and of plant and apparatus connected to the transmission system~~
~~**Grid Supply Point (GSP)**~~	~~A point of delivery from the GB Transmission System to a distribution system or Non-Embedded User~~
~~**Interconnector**~~	~~Means apparatus, connected to the Total System from or to an External System~~
~~**Licence standards**~~	~~Standards listed in Condition AA2 of the Transmission Licence or otherwise registered with the Authority in accordance with which transmission licensees are required to plan, develop, operate and maintain the transmission system~~
~~**Licensable Generation**~~	~~Generating plant where the party generating electricity at that generating plant is required to hold a Generation Licence~~
~~**Liquidated Damages**~~	~~The sums specified in the Construction agreement~~
~~**Mandatory Services Agreement**~~	~~An agreement between~~ The Company ~~and a User to govern the provision of and payment for Mandatory Ancillary Services~~
~~**Modification**~~	~~Any actual or proposed replacement, renovation, modification, alteration, or construction by or on behalf of a User or~~ The Company ~~to either that CUSC Party's Plant or Apparatus or the manner of its operation which has or may have a Material Effect on another CUSC Party at a particular Connection Site~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Deleted: 3

Deleted: The Statement of the Connection Charging Methodology . April 2010

~~**Non-Embedded Customer**~~	~~A Customer in Great Britain, except for a Network Operator acting in its capacity as such, receiving electricity direct from the GB Transmission System irrespective of from whom it is supplied.~~
~~**Power Station**~~	~~As defined in the Grid Code as:~~ ~~"an installation comprising one or more Generating Units (even where sited separately) owned and/or controlled by the same Generator, which may be reasonably considered as being managed as one Power Station."~~
~~**Public Distribution System Operator**~~	~~Any holder of a distribution licence who was the holder, or is a successor to a company which was the holder of a Public Electricity Supply Licence relating to the distribution activities in GB on the CUSC Implementation Date~~
~~**Reasonable Charges**~~	~~Reasonable cost reflective charges comparable to charges for similar services obtainable in the open market~~
~~**Replacement Period**~~	~~In relation to a transmission licensees Asset, the period commencing on the date on which such transmission licensees Asset is or was originally Commissioned, after which it is assumed for accounting purposes such a transmission licensees Asset will need to be replaced, which shall be 40 years unless otherwise agreed between the parties to a Bilateral Agreement and recorded in the relevant Bilateral Agreement~~

Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

~~**Retail Price Index**~~	~~Means the general index of retail prices published by the Office for National Statistics each month in respect of all items or:~~ ~~(a) if the said index for any month in any year shall not have been published on or before the last day of the third month after such month such index for such month or months as the parties hereto agree produces as nearly as possible the same result shall be substituted or in default of the parties reaching agreement within six weeks after the last day of such three month period then as determined by a sole Chartered Accountant appointed by agreement by both parties or in the absence of agreement on the application of either party by the President of the Electricity Arbitration Association who shall act as an expert and whose decision shall be final and binding on the parties; or~~ ~~(b) if there is a material change in the basis of the said index, such other index as the parties agree produces as nearly as possible the same result shall be substituted or in default of the parties reaching agreement within six weeks after the occurrence of the material change in the basis of the said index then as determined by the sole Chartered Accountant appointed by agreement by both parties or in the absence of agreement on the application of either party by the President of the Electricity Arbitration Association who shall act as an expert and whose decision shall be final and binding on the parties~~
~~**Security Standard**~~	~~GB Transmission System Security and Quality of Supply Standard~~
~~**Small Power Station**~~	~~As defined in the Grid Code~~
~~**Supplier**~~	~~A holder of an electricity supply licence~~
~~**Total System**~~	~~Has the meaning given to that expression in the Electricity Generation Licence i.e. "…the transmission and distribution systems of all authorised electricity operators which are located in GB"~~
~~**Trading Party**~~	~~As defined in the Balancing and Settlement Code~~
~~**Transfer date**~~	~~31st March 1990~~
~~**Transmission Licences**~~	~~The licences granted to National Grid, Scottish Power Transmission Ltd and Scottish Hydro Electric Transmission Ltd under Section 6(1)(b) of the Act~~

Deleted: 3

~~Transmission Licensees Assets~~	~~The Plant and Apparatus owned by Transmission Licensees necessary to connect the User's Equipment to the GB Transmission System at any particular Connection Site in respect of which The Company charges Connection Charges (if any) as listed or identified in [Appendix A] to the Bilateral Agreement relating to each such Connection Site~~
~~Transmission Owner Activity~~	~~The function of a transmission licensees Transmission Business as defined in the Transmission Licence~~
~~Transmission voltage~~	~~Voltages above 132kV in England and Wales - usually 275kV and 400kV. In Scotland, voltages of 132kV and above.~~
~~User~~	~~A party that connects to or makes use of the GB Transmission System~~
~~User System~~	~~Any system owned or operated by a User comprising:-~~ ~~a) Generating Units; and/or~~ ~~b) Systems consisting (wholly or mainly) of electric lines used for the distribution of electricity from Grid Supply Points or Generating Units or other entry points to the point of delivery to Customers, or other Users;~~ ~~And Plant and/or Apparatus connecting:-~~ ~~c) The system as described above; or~~ ~~d) Non-Embedded Customers equipment;~~ ~~To the GB Transmission System or to the relevant other User System, as the case may be.~~ ~~The User System includes any Remote Transmission Assets operated by such User or other persons and Plant and/or Apparatus and meters owned or operated by the User or other person in connection with the distribution of electricity but does not include any part of the GB Transmission System.~~
~~Utilities Act 2000~~	~~Electricity Act 1989, as amended by the Utilities Act 2000~~

Deleted: The Statement of the Connection Charging Methodology April 2010

Deleted: ~~National Grid~~

Formatted: Indent: Hanging: 3.16 cm, Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 2.52 cm + Tab after: 3.16 cm + Indent at: 3.16 cm

Formatted: Indent: Left: 0.04 cm, Hanging: 1.25 cm, Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 2.52 cm + Tab after: 3.16 cm + Indent at: 3.16 cm, Tabs: Not at 3.16 cm

Formatted: Indent: Hanging: 3.16 cm, Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 2.52 cm + Tab after: 3.16 cm + Indent at: 3.16 cm

Deleted: 2

Deleted: April 2010 . The Statement of the Connection Charging Methodology

~~Index to the Statement of the Connection Charging Methodology (Issue 5) Revisions~~

~~Issue 6~~	~~Modifications~~	~~Changes to Pages~~
~~Revision 0~~	~~New Issue~~	

Deleted: 3

Page 2: [1] Deleted	andy.wainwright	01/02/2011 13:45:00

April 2010 The Statement of the Connection Charging Methodology

Page 3: [2] Formatted	andy.wainwright	31/01/2011 17:51:00

Strikethrough

Page 3: [3] Deleted	andy.wainwright	31/01/2011 18:04:00

~~National Grid~~

Page 3: [3] Deleted	andy.wainwright	17/03/2011 13:33:00

~~5~~

Page 5: [4] Formatted	andy.wainwright	17/03/2011 12:57:00

Indent: Left: 1.25 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.27 cm, List tab + Not at 0.63 cm + 1.89 cm

Page 5: [5] Formatted	andy.wainwright	17/03/2011 12:57:00

Indent: Left: 1.25 cm, Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.27 cm, List tab + Not at 0.63 cm + 1.89 cm

Page 5: [6] Formatted	andy.wainwright	17/03/2011 12:57:00

Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm

Page 5: [7] Formatted	andy.wainwright	17/03/2011 12:57:00

Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

Page 5: [8] Formatted	andy.wainwright	17/03/2011 12:57:00

Indent: Left: 1.27 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm

~~Issue~~	~~Revision~~
~~6~~	4

~~The Statement of the Use of System Charging Methodology~~

~~Effective from 1 April 2010~~

Formatted

~~About this Document~~

~~This document describes the methodology that National Grid Electricity Transmission plc (National Grid) employs to levy charges for use of the transmission system in Great Britain on behalf of National Grid Electricity Transmission plc, Scottish Power Transmission ltd (SPTL) and Scottish Hydro-Electric Transmission ltd (SHETL). This document is one of a suite of three documents that describe the charges levied by~~ The Company ~~and the methodologies behind them. The other documents that are available are:~~

Deleted: ~~National Grid~~

- **~~The Statement of the Connection Charging Methodology~~**
- **~~The Statement of Use of System Charges~~**

~~These are available on our Charging website at:~~

~~http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/~~

~~This Statement of the Use of System Charging Methodology Issue 6 Revision 4 is effective from the 1 April 2010.~~

~~This document has been published by~~ The Company ~~in accordance with Standard Conditions C4 and C5 of~~ The Company~~'s Transmission Licence and is approved by the Gas and Electricity Markets Authority (the Authority).~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

~~This document is in three parts:~~

- ~~A General Introduction~~
- ~~The Statement of the Transmission Network Use of System Charging Methodology~~
- ~~The Statement of the Balancing Services use of System Charging Methodology~~

~~If you require further details about any of the information contained within this document or have comments on how this document might be improved please contact our~~ ~~**Charging Team**~~~~, preferably by email at:~~

~~charging.enquiries@uk.ngrid.com~~

~~Or at:~~

~~National Grid House~~
~~Warwick Technology Park~~
~~Gallows Hill~~
~~Warwick~~
~~CV34 6DA~~

~~Telephone 01926 654633~~

~~Contents~~

Deleted: 6
Deleted: National Grid... [1]
Deleted: 6
Deleted: 8
Deleted: 8
Deleted: 10
Deleted: 13
Deleted: 13
Deleted: 13
Deleted: 14
Deleted: 15
Deleted: 15
Deleted: 17
Deleted: 17
Deleted: 21
Deleted: 21
Deleted: 22
Deleted: 24
Deleted: 24
Deleted: 24
Deleted: 26
Deleted: 26
Deleted: 27
Deleted: 29
Deleted: 30
Deleted: 30
Deleted: 31
Deleted: 32
Deleted: 32
Deleted: 32
Deleted: 33
Deleted: 34
Deleted: 34
Deleted: 34
Deleted: 34
Deleted: 35
Deleted: 37
Deleted: 37
Deleted: 37
Deleted: 37
Deleted: 37
Deleted: 38
Deleted: 38
Deleted: 39
Deleted: 39
Deleted: 39
Deleted: 40
Deleted: 40
Deleted: 40
Deleted: 42
Deleted: 42
Deleted: 42
Deleted: 42
Deleted: 2

Deleted: 44
Deleted: 44
Deleted: 45
Deleted: 46
Deleted: 46
Deleted: 46
Deleted: 47
Deleted: 49
Deleted: 52
Deleted: 55
Deleted: 58
Deleted: 58
Deleted: 58
Deleted: 59
Deleted: 59
Deleted: 61
Deleted: 63
Deleted: 63
Deleted: NATIONAL ... [2]
Deleted: 66
Deleted: 67
Deleted: 68
Deleted: 68
Deleted: 70
Deleted: 70
Deleted: 70
Deleted: 72
Deleted: 73
Deleted: 74
Deleted: 74
Deleted: 75
Deleted: 75
Deleted: 75
Deleted: 75
Deleted: 76
Deleted: 77
Deleted: 78
Deleted: 79
Deleted: 81
Deleted: 81
Deleted: 81
Deleted: 81
Deleted: 81
Deleted: 81
Deleted: 82
Deleted: 83
Deleted: 87
Deleted: 87
Deleted: 87
Deleted: 94
Deleted: 98
Deleted: 102

Deleted: ~~109~~

Deleted: 2

~~General Introduction~~

~~The Company's Licence Objectives~~

Deleted: ~~National Grid~~

1 ~~As the holder of Transmission Licences in Great Britain, the GB transmission licensees are required by the Electricity Act 1989, as amended by the Utilities Act 2000 and the Energy Act 2004, to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the generation and supply of electricity. The transmission licensees are also required by Schedule 9 of the Electricity Act to have regard for the effects of its activities on the environment.~~

2 ~~The Company's Transmission Licence Conditions were changed by the Secretary of State through the Energy Act 2004 as part of the implementation of the British Electricity Trading and Transmission Arrangements (BETTA). Consequently, The Company is responsible for the determination and implementation of a GB Use of System charging methodology post the BETTA go-live date of 1 April 2005.~~

Deleted: National Grid

Deleted: National Grid

~~Relevant Objectives~~

3 ~~The GB Use of System Charging Methodology has the following objectives as set out in Licence Condition C5 which requires:~~

(a) ~~that compliance with the Use of System Charging Methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;~~

(b) ~~that compliance with the Use of System Charging Methodology results in charges which reflect, as far as reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses; and~~

(c) ~~that, so far as is consistent with sub-paragraphs (a) and (b), the Use of System Charging Methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.~~

~~In interpretation of the above objectives, Standard Condition C1 of The Company's Transmission Licence shall prevail in its definition of connection charges and Use of System charges in respect of the Great Britain (GB) transmission system.~~

Deleted: National Grid

4 ~~The Licence notes that The Company must keep the Use of System Charging Methodology under review at all times for the purpose of ensuring that the methodology meets the relevant objectives outlined above.~~

Deleted: National Grid

5 ~~The Company may make modifications to the methodology as may be required for the purpose of better meeting the relevant objectives above.~~

Deleted: National Grid

~~Modification Process~~

6 ~~Before making modifications, unless it has been agreed otherwise with the Authority, The Company will consult with CUSC parties for a period of at least 28 days on the~~

Deleted: National Grid

~~proposed change in the Use of System Charging Methodology. The consultation will seek views on:~~

- ~~details of the proposed modification;~~
- ~~the timetable for implementation;~~
- ~~the justification of the proposal against the Relevant Objectives; and~~
- ~~the impact on other industry documents.~~

~~7 The consultation will, where appropriate, indicate how the proposed changes will impact existing tariffs or where a new charge is created an indication what tariffs might be.~~

~~8 The timetable for implementing methodology changes will seek to avoid introducing changes to tariffs within a charging year where this would affect the charges paid by existing Users. There may, however, be circumstances where this will not be possible, and in these circumstances~~ ~~The Company~~ ~~will seek views from Users on the issues this might raise. Against this background, methodology changes to existing tariffs will generally be implemented from the following 1 April, although later dates may be considered where this could be expected to better facilitate competition in generation or supply of electricity.~~

Deleted: ~~National Grid~~

~~9 There may also be instances where additional industry consultation may be beneficial. For example:~~

- ~~where a proposal is likely to have a significant impact on a large number of transmission Users and an additional consultation will enable these Users to better prepare for a formal modification and / or highlight specific implementation issues that should be taken into account.~~
- ~~where a methodology change is consequential to other framework changes and an early additional consultation will expedite the formal charging process, the framework change, or reduce uncertainty for Users.~~
- ~~where there are several options for change that could each better facilitate the Relevant Objectives and an additional consultation will expedite the formal charging process.~~

~~10 In these instance and where time permits, an "Initial Thoughts" consultation will be prepared to consult Users in advance of commencing the formal process for modifying the Use of System Charging Methodology. It is anticipated that an additional 28 day consultation would be allowed for.~~

~~11 Following consultation with Users, a report will be issued to the Authority by~~ ~~The Company~~ ~~setting out the terms of the modification, the representations made, any changes to the terms of the modification, how the modification better meets the relevant objectives and a timetable and date for implementation of the modification.~~

Deleted: ~~National Grid~~

~~12 Unless the Authority has, within 28 days of the report being furnished to it, given a direction that the modification may not be made, or that an impact assessment will be undertaken,~~ ~~The Company~~ ~~will make the modification to the Use of System Charging Methodology. In the event that an impact assessment is deemed~~

Deleted: ~~National Grid~~

Deleted: 2

~~necessary, the Authority will undertake a consultation process, thus extending the decision period by a maximum of three months.~~

~~13 If the proposed change in the Use of System Charging Methodology would result in changes to the GB Transmission Network Use of System charges,~~ The Company ~~must give, except where the Authority consents to a shorter period, 150 days notice of a proposal to change the GB Transmission Network Use of System charges to the Authority together with a reasonable assessment of the effect of the proposal on those charges.~~ The Company ~~will notify Users of the proposal at the same time as the Authority.~~

~~14 In addition, with the approval of the Authority,~~ The Company ~~may alter the form of the statements from time to time and also revise the statements such that the information set out is accurate in all material respects.~~

~~The Connection/Transmission Use of System Boundary~~

~~15 In order to calculate Transmission Network Use of System charges and Connection charges,~~ The Company ~~must apportion its assets to one of two charging categories. The apportionment methodology between Connection and Transmission Network Use of System used by~~ The Company ~~is on a shallow basis as described by~~ The Company ~~in its GB Transmission Charging Final Methodology document of 30 September 2004. Further details are provided in the~~ ~~**Statement of the Connection Charging Methodology.**~~

~~The Contractual Framework~~

~~16 The Connection and Use of System Code (CUSC) is a multi-party document creating contractual obligations among and between all Users of the GB transmission system, parties connected to the GB transmission system and~~ The Company~~. Persons wishing to use and/or connect to the GB transmission system will be required to accede to the CUSC by signing the Framework Agreement and to enter into a Bilateral Agreement with~~ The Company~~.~~

~~17~~ The Company ~~continues to request that Small Power Stations should make a formal application for use of the system to~~ The Company~~.~~ The Company ~~can then assess the potential impact on the GB transmission system and consider what form of agreement, if any, may be required.~~

~~18 The CUSC and individual User's Bilateral Agreements set out the terms and conditions applicable for use of and/or connection to the GB transmission system. In particular, they set out the User's obligations to:~~

- ~~pay all use of system and connection charges;~~
- ~~comply with the provisions of the Grid Code;~~
- ~~sign on to the Balancing and Settlement Code (BSC);~~
- ~~enter into an appropriate Mandatory Services Agreement.~~

~~19 Additionally, each Bilateral Agreement details the information on which the User's connection charges are based.~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Formatted: Indent: Left: 0 cm, Hanging: 1.27 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.27 cm, List tab + Not at 0.63 cm

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.25 cm, List tab + Not at 0.63 cm

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.25 cm, List tab + Not at 0.63 cm

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.25 cm, List tab + Not at 0.63 cm

Formatted: Indent: Hanging: 0.02 cm, Bulleted + Level: 1 + Aligned at: 0.63 cm + Tab after: 1.27 cm + Indent at: 1.27 cm, Tabs: 2 cm, List tab + Not at 1.27 cm

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: Not at 0.63 cm

- ~~Appendix A of each Bilateral Agreement lists the connection assets by description, age and allocation to the User;~~

- ~~Appendix B identifies the connection charges;~~

20 ~~If a User fails to fulfil their obligations, their entitlement to use and/or be connected to the GB transmission system will cease. The User will be liable for all charges that may arise up to the end of the current Financial Year and, for connection, the appropriate Termination Amount.~~

21 ~~When a User applies for a new use of system agreement or to modify an existing use of system agreement they may be required to enter into a Construction Agreement. Within the Construction Agreement there will be provisions for site-specific elements such as Consents and Final Sums.~~

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.25 cm, List tab + Not at 0.63 cm

Formatted: Indent: Left: 0 cm, Hanging: 1.25 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 15 + Alignment: Left + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 1.25 cm, List tab + Not at 0.63 cm

Formatted: Centered

Deleted: 2

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)**".

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented the following proposals:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand of 27% and 73% respectively.

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.26 has been determined as 21.

vii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.14.6 The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.7 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' Transmission Entry Capacities (TECs) accommodated. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system at the time of peak demand. The charging methodology therefore recognises this peak element in its rationale.

Formatted: Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Formatted: Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Formatted: Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Formatted: Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Formatted ... [4]

Formatted ... [5]

Deleted: 2

Deleted: 17

Formatted ... [6]

Deleted:

Formatted ... [7]

Formatted ... [8]

Deleted: National Grid

Formatted ... [9]

Formatted ... [10]

Deleted: GB

Deleted: t

Formatted ... [11]

Deleted: s

Formatted ... [12]

Deleted: National Grid

Deleted: GB

Deleted: t

Formatted ... [13]

Deleted: s

Formatted ... [14]

Deleted: National Grid

Deleted: 1.8

Formatted ... [15]

Deleted: 2

14.14.8 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.9 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.10 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

Deleted: 1.9
Deleted: National Grid
Formatted: Indent: Left: 1.25 cm
Deleted:
Formatted: Indent: Left: 2.5 cm, Tabs: 3.25 cm, List tab + Not at 2 cm
Formatted: Indent: Left: 2.5 cm, Tabs: 3.25 cm, List tab + Not at 2 cm
Formatted: Indent: Left: 2.5 cm, Tabs: 3.25 cm, List tab + Not at 2 cm
Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 9 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm, Tabs: Not at 2.54 cm
Deleted: National Grid
Deleted: National Grid
Deleted: National Grid
Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 9 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm, Tabs: Not at 2.54 cm
Deleted: National Grid

14.15 Derivation of the Transmission Network Use of System Tariff

Deleted: Chapter 2:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

Formatted: Bullets and Numbering

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of three separate components. A wider component reflects the costs of the wider network, and the combination of a local substation and a local circuit component reflect the costs of the local network. Accordingly, the wider tariff represents the combined effect of the wider locational tariff component and the residual element; and the local tariff represents the combination of the two local locational tariff components.

Formatted: Bullets and Numbering

14.15.3 The process for calculating the TNUoS tariff is described below.

The Transport Model

Model Inputs

Formatted: Bullets and Numbering

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

Formatted: Bullets and Numbering

14.15.5 The transport model requires a set of inputs representative of peak conditions on the transmission system:

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The ratio of each of 132kV overhead line, 132kV cable, 275kV overhead line, 275kV cable and 400kV cable to 400kV overhead line costs to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data
- Identification of a reference node

Formatted: Bullets and Numbering
Deleted: GB
Deleted: GB
Deleted: 2

14.15.6 For a given charging year "t", the nodal TEC figure at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

Deleted: GB

14.15.7 Nodal demand data for the transport model will be based upon the GSP demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

Formatted: Bullets and Numbering

14.15.8 Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

Formatted: Bullets and Numbering

Deleted: GB

Deleted: GB

Deleted: National Grid

14.15.9 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

Formatted: Bullets and Numbering

14.15.10 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) cabled routes and overhead line routes, (ii) 132kV and 275kV routes, (iii) 275kV routes and 400kV routes, and (iv), uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically 400kV cable, 275kV overhead line, 275kV cable, 132kV overhead line and 132kV cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

Formatted: Bullets and Numbering

14.15.11 A reference node is required as a basis point for the calculation of marginal costs. It determines the magnitude of the marginal costs but not the relativity. For example, if the reference point were put in the North of Scotland, all nodal generation marginal costs would likely be negative. Conversely, if the reference point were defined at Land's End, all nodal generation marginal costs would be positive. However, the relativity of costs between nodes would stay the same. For information purposes the reference node for 2010/11 is East Claydon 400kV (ECLA40).

Formatted: Bullets and Numbering

Model Outputs

14.15.12 The transport model takes the inputs described above and firstly scales the nodal generation capacity uniformly such that total national generation (sum of contracted TECs) equals total national ACS Demand. The model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity. Then it calculates the resultant total network MWkm, using the relevant circuit expansion factors as appropriate.

Formatted: Bullets and Numbering

14.15.13 Using this baseline network, the model calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MWkm of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The marginal km cost for demand at each node equal and opposite to this nodal marginal km for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.14 Using a similar methodology, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake at the reference node. In this model, any circuits identified as local assets to a node will have the local circuit expansion factors are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.15 An example is contained in 14.21 Transport Model Example.

Calculation of local nodal marginal km

14.15.16 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.17 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.18 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.19 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.20 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

Calculation of zonal marginal km

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: Appendix TN-1:

Formatted: Font: Not Bold

Formatted: Font: Not Bold

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: GB

Deleted: T

Deleted: s

Deleted: GB

Deleted: t

Deleted: s

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: 2

14.15.21 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.26. The number of generation zones set for 2010/11 is 20.

Formatted: Bullets and Numbering

Deleted: 2.2

Deleted: 5

14.15.22 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

Formatted: Bullets and Numbering

14.15.23 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

Formatted: Bullets and Numbering

14.15.24 Generators will have a zonal tariff derived from the wider nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets. The zonal marginal km for generation is calculated as:

Formatted: Bullets and Numbering

$$WNMkm_j = \frac{NMkm_j * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j$$

Where

Gi	=	Generation zone
j	=	Node
NMkm	=	Wider nodal marginal km from transport model
WNMkm	=	Weighted nodal marginal km
ZMkm	=	Zonal Marginal km
Gen	=	Nodal Generation from the transport model

14.15.25 The zonal marginal km for demand zones are calculated as follows:

Formatted: Bullets and Numbering

$$WNMkm_j = \frac{-1 * NMkm_j * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di} = \sum_{j \in Di} WNMkm_j$$

Where

Di	=	Demand zone
Dem	=	Nodal Demand from transport model

14.15.26 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zones should contain relevant nodes whose wider marginal costs (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/- £1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.27 The process behind the criteria in 14.15.26 is driven by initially applying the nodal marginal costs from the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs for guidance.

14.15.28 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.29 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.30 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security**

Factor (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

The Expansion Constant

14.15.31 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

Formatted: Bullets and Numbering

14.15.32 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.60 – 14.15.65, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.81.

Formatted: Bullets and Numbering

Deleted: 2.60

Deleted: 2.76

14.15.33 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

Formatted: Bullets and Numbering

Deleted: National Grid

14.15.34 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.42 – 14.15.47. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

Formatted: Bullets and Numbering

Deleted: 2.35

14.15.35 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

Formatted: Bullets and Numbering

400kV OHL expansion constant calculation					
MW	**Type**	**£(000)/km**	**Circuit km***	**£/MWkm**	**Weight**
A	B	C	D	E = C/A	F=E*D
6500	La	700	500	107.69	53846
6500	Lb	780	0	120.00	0
3500	La/b	600	200	171.43	34286
3600	Lc	400	300	111.11	33333
4000	Lc/a	450	1100	112.50	123750

5000	Ld	500	300	100.00	30000
5400	Ld/a	550	100	101.85	10185
Sum			**2500 (G)**		**285400 (H)**
				Weighted Average (J= H/G):	**114.160 (J)**

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.36 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

Formatted: Bullets and Numbering

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.37 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

Formatted: Bullets and Numbering

Deleted: National Grid

14.15.38 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

Formatted: Bullets and Numbering

14.15.39 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

Formatted: Bullets and Numbering

400kV OHL expansion constant calculation	**Ave £/MWkm**
OHL	114.160
Annuitised	7.535
Overhead	2.055
Final	**9.589**

14.15.40 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.45, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.50.

Formatted: Bullets and Numbering

Deleted: 2.

Deleted: 35

Deleted: offshore TO

Deleted: (OFTO)

Deleted: 2

Deleted: 2

14.15.41 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

Formatted: Bullets and Numbering

Deleted: National Grid

Onshore Wider Circuit Expansion Factors

14.15.42 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

Formatted: Bullets and Numbering

14.15.43 In calculating the onshore cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

Formatted: Bullets and Numbering

14.15.44 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

Formatted: Bullets and Numbering

14.15.45 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

Formatted: Bullets and Numbering

14.15.46 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

Formatted: Bullets and Numbering

14.15.47 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Formatted: Bullets and Numbering

Scottish Hydro Region

400kV cable factor:	22.39
275kV cable factor:	22.39
132kV cable factor:	27.79
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor:	2.24

Scottish Power & National Grid Regions

400kV cable factor:	22.39
275kV cable factor:	22.39
132kV cable factor:	30.22
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor:	2.80

Onshore Local Circuit Expansion Factors

14.15.48 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.49 In addition, the 132kV onshore overhead line circuit expansion factor is sub-divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

400kV cable factor:	22.39
275kV cable factor:	22.39
132kV cable factor:	30.22
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor (single; <200MVA):	10.00
132kV line factor (double; <200MVA):	8.32
132kV line factor (single; >=200MVA):	7.13
132kV line factor (double; >=200MVA):	4.42

Offshore Circuit Expansion Factors

14.15.50 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.51 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

CRevOFTO1	=	The offshore circuit revenue in £ for Year 1
L	=	The total circuit length in km of the offshore circuit
CircRat	=	The continuous rating of the offshore circuit

Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: OFTO
Deleted: OFTO
Deleted: OFTO
Deleted: OFTO
Formatted: Bullets and Numbering
Deleted: 2

14.15.52 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

Formatted: Bullets and Numbering

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

AvCRevOFTO	=	The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control
L	=	The total circuit length in km of the offshore circuit
CircRat	=	The continuous rating of the offshore circuit

14.15.53 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be re-calculated at the start of each price control when the onshore expansion constants are revisited.

Deleted: OFTO

Formatted: Bullets and Numbering

The Locational Onshore Security Factor

14.15.54 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

Formatted: Bullets and Numbering

14.15.55 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

Formatted: Bullets and Numbering

14.15.56 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

Formatted: Bullets and Numbering

Deleted: National Grid

Local Security Factors

14.15.57 Local onshore security factors are generator specific and are applied to a generators local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

Formatted: Bullets and Numbering

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.58 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:
NetworkExportCapacity = the total export capacity of the network
k = the generation connected to the offshore network

14.15.59 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

Initial Transport Tariff

14.15.60 First an Initial Transport Tariff (ITT) must be calculated. For Generation the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff:

$$ZMkm_{Gi} \times EC \times LSF = ITT_{Gi}$$

Where
$ZMkm_{Gi}$ = Zonal Marginal km for each generation zone
EC = Expansion Constant
LSF = Locational Security Factor
ITT_{Gi} = Initial Transport Tariff (£/MW) for each generation zone

14.15.61 Similarly, for demand the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff:

$$ZMkm_{Di} \times EC \times LSF = ITT_{Di}$$

Where
$ZMkm_{Di}$ = Zonal Marginal km for each demand zone
EC = Expansion Constant
LSF = Locational Security Factor
ITT_{Di} = Initial Transport Tariff (£/MW) for each demand zone

14.15.62 The next step is to multiply these initial transport tariffs by the expected metered triad demand and generation capacity to gain an estimate of the initial revenue recovery. Both of these latter parameters are based on forecasts provided by Users and are confidential.

$$\sum_{Gi=1}^{21} (ITT_{Gi} \times G_{Gi}) = ITRR_G \quad \text{and} \quad \sum_{Di=1}^{14} (ITT_{Di} \times D_{Di}) = ITRR_D$$

Where
$ITRR_G$ = Initial Transport Revenue Recovery for generation

Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: 2

G_{Gi}	=	Total forecast Generation for each generation zone (based on confidential User forecasts)
$ITRR_D$	=	Initial Transport Revenue Recovery for demand
D_{Di}	=	Total forecast Metered Triad Demand for each demand zone (based on confidential User forecasts)

14.15.63 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. This has been determined to be 27:73 by the Authority for generation and demand respectively. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

Formatted: Bullets and Numbering

$$\sum_{Gi=1}^{21}\left[\left(ZMkm_{Gi}+C\right)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{14}\left[\left(ZMkm_{Di}-C\right)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p\left(CTRR_G + CTRR_D\right)$$

Where

CTRR	=	"Generation / Demand split" corrected transport revenue recovery
p	=	Proportion of revenue to be recovered from demand
C	=	"Generation /Demand split" Correction constant (in km)

14.15.64 The above equations deliver corrected (£/MW) transport tariffs (CTT).

Formatted: Bullets and Numbering

$$\left(ZMkm_{Gi}+C\right)\times EC\times LSF = CTT_{Gi}$$

$$\left(ZMkm_{Di}-C\right)\times EC\times LSF = CTT_{Di}$$

So that

$$\sum_{Gi=1}^{21}\left(CTT_{Gi}\times G_{Gi}\right)=CTRR_G \quad \text{and} \quad \sum_{Di=1}^{14}\left(CTT_{Di}\times D_{Di}\right)=CTRR_D$$

Deriving the Final Local Tariff (£/kW)

Local Circuit Tariff

14.15.65 Generation with a local circuit tariff is calculated by multiplying the nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

Formatted: Bullets and Numbering

$$\sum_{k}\frac{NLMkm_{Gj}{}^{L}\times EC\times LocalSF_{k}}{1000}=CLT_{Gi}$$

Where

k	=	Local circuit k for generator
$NLMkm_{Gj}{}^{L}$	=	Nodal marginal km along local circuit k using local circuit expansion factor.
EC	=	Expansion Constant
$LocalSF_{k}$	=	Local Security Factor for circuit k
CLT_{Gi}	=	Circuit Local Tariff (£/kW)

Onshore Local Substation Tariff

14.15.66 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

Formatted: Bullets and Numbering

Deleted: 2

14.15.67 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

Formatted: Bullets and Numbering

Substation Rating (b)	**Connection Type** (c)	**Substation Voltage** (a)		
		132kV	**275kV**	**400kV**
<1320MW	No redundancy	0.133	0.081	0.065
<1320MW	Redundancy	0.301	0.192	0.155
>=1320MW	No redundancy	n/a	0.257	0.208
>=1320MW	Redundancy	n/a	0.417	0.336

14.15.68 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

Formatted: Bullets and Numbering

14.15.69 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

Formatted: Bullets and Numbering

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
ELT_{Gi} = Effective Local Tariff (£/kW)
SLT_{Gi} = Substation Local Tariff (£/kW)

14.15.70 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

Formatted: Bullets and Numbering

ELT_{Gi} = LT_{Gi}
Where
LT_{Gi} = Final Local Tariff (£/kW)

14.15.71 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

Formatted: Bullets and Numbering

$$LT_{Gi} = \frac{12 \times \left(ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.72 For the purposes of charge setting, the total local charge revenue is calculated by:

Formatted: Bullets and Numbering

$$\mathrm{LCRR}_G = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery

G_j = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on confidential information received from Users)

Offshore substation local tariff

14.15.73 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

Formatted: Bullets and Numbering

14.15.74 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

Deleted: OFTO

Formatted: Bullets and Numbering

Deleted: OFTO

Deleted:

Deleted: OFTO

Deleted:

14.15.75 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

Deleted: OFTO

Formatted: Bullets and Numbering

Deleted: OFTO

14.15.76 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

Formatted: Bullets and Numbering

14.15.77 Offshore substation tariffs shall be inflated by RPI each year and reviewed every price control period.

Formatted: Bullets and Numbering

14.15.78 The revenue from the offshore substation local tariff is calculated by:

Formatted: Bullets and Numbering

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left(SLT_k \times \sum_k Gen_k \right)$$

Where:

SLT_k = the offshore substation tariff for substation k

Gen_k = the generation connected to offshore substation k

The Residual Tariff

14.15.79 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges (TRR_t) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

Formatted: Bullets and Numbering

Deleted: 2

$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

TRR_t = TNUoS Revenue Recovery target for year t

R_t = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

Deleted: National Grid

Deleted: National Grid

PVC_t = Forecast Revenue from Pre-Vesting connection charges for year t

SG_{t-1} = The proportion of the under/over recovery included within R_t which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

Deleted: National Grid

14.15.80 In normal circumstances, the revenue forecast to be recovered from the corrected transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

Formatted: Bullets and Numbering

14.15.81 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the corrected transport tariffs so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

Formatted: Bullets and Numbering

$$RT_D = \frac{(p \times TRR) - CTRR_D}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - CTRR_G - LCRR_G}{\sum_{Gi=1}^{21} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

Final £/kW Tariff

14.15.82 The effective Transmission Network Use of System tariff (TNUoS) can now be calculated as the sum of the corrected transport wider tariff, the non-locational residual tariff and the local tariff:

Formatted: Bullets and Numbering

$$ET_{Gi} = \frac{CTT_{Gi} + RT_G}{1000} + LT_{Gi} \quad \text{and} \quad ET_{Di} = \frac{CTT_{Di} + RT_D}{1000}$$

Where
ET = Effective TNUoS Tariff expressed in £/kW

14.15.83 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi} \quad \text{and} \quad FT_{Di} = ET_{Di}$$

14.15.84 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left(ET_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left(ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

14.15.85 If the final demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore,
$$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
RFT_{Di} = Revised Final Tariff (£/kW)

14.15.86 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: 2

14.15.87 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.88 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.89 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

14.15.90 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

14.15.91 The factors which will affect the level of TNUoS charges from year to year include the forecast level of peak demand on the system, the Price Control formula (including the effect of any under/over recovery from the previous year), the expansion constant, the locational security factor, changes in the transmission network and changes in the pattern of generation capacity and demand.

14.15.92 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

Stability & Predictability of TNUoS tariffs

14.15.93 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.28.

Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.25 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 2 cm, List tab + Not at 0.63 cm
Formatted: Indent: Left: 1.25 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 2 cm, List tab + Not at 0.63 cm
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: GB
Deleted: network
Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: GB
Formatted: Bullets and Numbering
Deleted: Appendix TN-8

14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

£/kW Tariff = The £/kW Effective Demand Tariff (£/kW), as calculated previously, for the GSP Group concerned.

$NHHD_F$ = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

FL_G = Forecast Liability incurred for the GSP Group concerned.

$NHHC_G$ = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the relevant annual TNUoS £/kW tariff. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

FT	=	Final annual TNUoS Tariff expressed in £/kW
Gi	=	Generation zone
STTEC Period	=	A period applied for in days as defined in the CUSC

Deleted: Chapter 3:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 1.27 cm
Formatted: Indent: Left: 1.27 cm
Deleted: National Grid
Deleted: National Grid
Deleted: 3.3
Formatted: Indent: Left: 1.25 cm
Deleted: .
Formatted: Indent: Left: 1.27 cm
Formatted: Indent: Left: 2.27 cm
Deleted: 2

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where FT is the final annual TNUoS tariff expressed in £/kW;
G_i is the generation TNUoS zone; and
P is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

Formatted: Indent: Left: 1 cm
Deleted: 3.4
Deleted:
Deleted: 3
Formatted: Indent: Left: 1.25 cm
Deleted: 3.5
Deleted:
Formatted: Indent: Left: 1.25 cm
Deleted: 3.6
Formatted: Indent: Left: 1.27 cm
Deleted:
Deleted: National Grid
Deleted: 3.7
Formatted: Indent: Left: 1.27 cm
Deleted:
Deleted: 3.8
Formatted: Indent: Left: 1.27 cm
Deleted:
Deleted: National Grid

14.17 Demand Charges

Parties Liable for Demand Charges

14.17.1 The following parties shall be liable for demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 14.25 Classification of parties for charging purposes provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

Basis of Demand Charges

14.17.3 Demand charges are based on a de-minimus £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable Demand Capacity is the value of Triad demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of demand tariffs within a charging year, the Chargeable Demand Capacity is multiplied by the relevant demand tariff, for the calculation of demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of demand tariffs are applicable within a single charging year, demand charges will be calculated by multiplying the Chargeable Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = Chargeable\ Demand\ Capacity \times \left(\frac{(a \times Tariff\ 1) + (b}{12} \right.$$

where:

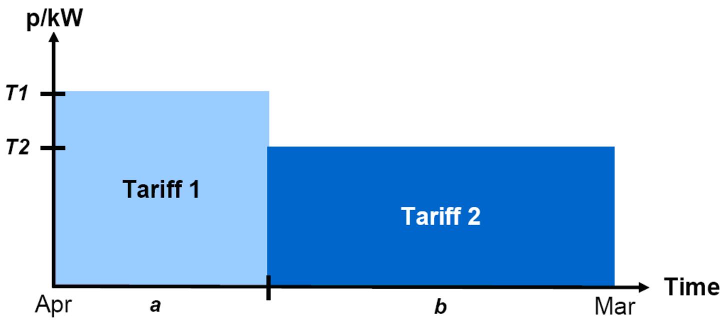
Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

Deleted: Chapter 4
Formatted: Font color: Auto
Deleted: :
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Formatted: Indent: Left: 2.54 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 2.54 cm, List tab + 2.63 cm, List tab + Not at 0.63 cm + 2 cm
Formatted: Indent: Left: 2.54 cm
Formatted: Indent: Left: 2.54 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 2.54 cm, List tab + 2.63 cm, List tab + Not at 0.63 cm + 2 cm
Formatted: Indent: Left: 1.27 cm
Formatted ... [16]
Deleted: Appendix TN-5:
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 2.54 cm
Deleted: 2



14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.54 cm

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

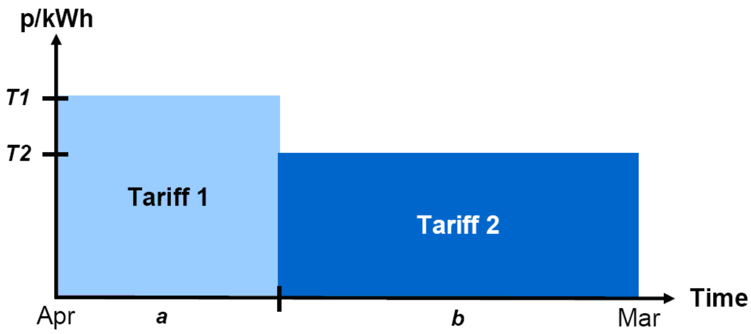
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.



Supplier BM Unit

14.17.9 A Supplier BM Unit charges will be the sum of its energy and demand liabilities where::

Formatted: Bullets and Numbering

- The Chargeable Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered demand during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

Formatted: Indent: Left: 2.5 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.14 cm, List tab + Not at 0.63 cm

Formatted: Indent: Left: 2.48 cm

Formatted: Indent: Left: 2.48 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.12 cm, List tab + Not at 0.63 cm + 1.89 cm

Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement

14.17.10 The Chargeable Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the net import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

Formatted: Bullets and Numbering

Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement

14.17.11 The Chargeable Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered volume of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

Formatted: Bullets and Numbering

Small Generators Tariffs

14.17.12 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB demand tariffs.

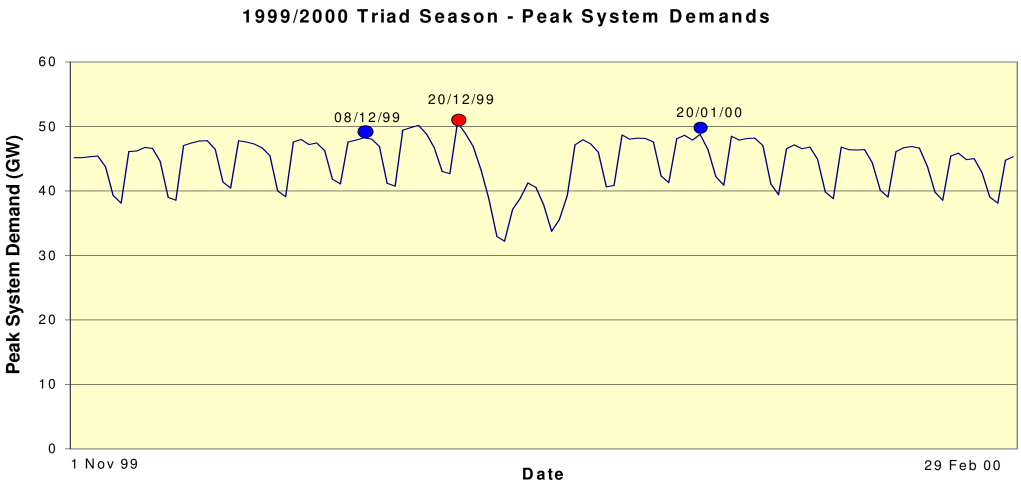
Formatted: Bullets and Numbering

The Triad

14.17.13 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak demand. An illustration is shown below.

Formatted: Bullets and Numbering

Deleted: 2



Half-hourly metered demand charges

14.17.14 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered volume over the Triad results in an import, the Chargeable Demand Capacity will be positive resulting in the BMU being charged. If the average half-hourly metered volume over the Triad results in an export, the Chargeable Demand Capacity will be negative resulting in the BMU being paid. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for a negative demand credit.

Netting off within a BM Unit

14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.

Monthly Charges

14.17.16 Throughout the year Users' monthly demand charges will be based on their forecasts of:

- half-hourly metered demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: National Grid

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.54 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.29 cm, List tab + Not at 0.63 cm

Formatted: Indent: Left: 2.56 cm

Formatted: Indent: Left: 2.54 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.29 cm, List tab + Not at 0.63 cm

Formatted: Indent: Left: 2.56 cm

Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing an import from the system) will be accepted.

14.17.17 Users should submit reasonable demand forecasts in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User’s Triad demand for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) demand in the Financial Year to date is compared to the equivalent average demand for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH demand at Triad in the preceding Financial Year to derive a forecast of the User's HH demand at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) demand over the last complete month for which The Company has settlement data is calculated. Total system average HH demand for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH demand at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH demand for weekday settlement period 35 over the last month to derive a forecast of the User's HH demand at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a

Deleted: National Grid

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: National Grid

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 2.87 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1 cm + Indent at: 1 cm, Tabs: 2.62 cm, List tab + Not at 1 cm + 2.25 cm

Deleted: National Grid

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 2.87 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 2 + Alignment: Left + Aligned at: 0 cm + Tab after: 1 cm + Indent at: 1 cm, Tabs: 2.62 cm, List tab + Not at 1 cm + 2.25 cm

Formatted: Indent: Left: 2.89 cm

Formatted: Indent: Left: 2.87 cm

Formatted ... [17]

Deleted: National Grid

Formatted: Indent: Left: 2.87 cm

Formatted ... [18]

Deleted: National Grid

Deleted: 2

percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.18 14.27 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

Deleted: Appendix TN-7:

Deleted: Example:

Deleted: National Grid

Formatted: Bullets and Numbering

Formatted: Font: Not Bold

Deleted: National Grid

Formatted: Bullets and Numbering

Reconciliation of Demand Charges

14.17.19 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

Initial Reconciliation of demand charges

14.17.20 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

Formatted: Bullets and Numbering

Initial Reconciliation Part 1– Half-hourly metered demand

14.17.21 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: National Grid

14.17.22 Initial outturn charges for half-hourly metered demand will be determined using the latest available data of actual average Triad demand (kW) multiplied by the zonal demand tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly demand.

Formatted: Bullets and Numbering

Initial Reconciliation Part 2 – Non-half-hourly metered demand

14.17.23 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

Formatted: Bullets and Numbering

Final Reconciliation of demand charges

14.17.24 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data).

14.17.25 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

Reconciliation of manifest errors

14.17.26 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in a Users TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.28 will be in accordance with Sections 14.17.20 to 14.17.25. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.27 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.28 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or
b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.29 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

Further Information

14.17.30 14.24 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for demand and consumption for half-hourly and non-half-hourly metered demand respectively.

14.17.31 **The Statement of Use of System Charges** contains the £/kW zonal demand tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

Formatted: Bullets and Numbering
Deleted: 4.28
Deleted: 4.20
Deleted: 4.25
Formatted: Indent: Left: 3.81 cm
Formatted: Indent: Left: 2.54 cm
Deleted: Appendix TN-4:
Formatted: Font: Not Bold
Deleted: 2

14.17.32 14.26 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

Deleted: Appendix TN-6

Deleted: :

Formatted: Bullets and Numbering

Formatted: Font: Not Bold

14.18 Generation charges

Parties Liable for Generation Charges

14.18.1 The following CUSC parties shall be liable for generation charges:

i) Parties of Generators that have a Bilateral Connection Agreement with The Company.

ii) Parties of Licensable Generation that have a Bilateral Embedded Generation Agreement with The Company.

14.18.2 14.25 Classification of parties for charging purposes provides an illustration of how a party is classified in the context of Use of System charging and refers to the relevant paragraphs most pertinent to each party.

Structure of Generation Charges

14.18.3 Generation Charges are comprised Wider and Local Charges, the latter of which contains a substation element and may also contain a circuit element. Specifically, all transmission connected generation will be liable to pay a local substation charge, with some of these also being liable to pay a local circuit charge. For the avoidance of doubt, embedded generation has a zero local tariff.

14.18.4 The intention of the charging rules is to charge the same physical entity only once.

14.18.5 The basis of the generation charge for Power Stations is the Chargeable Capacity and the short-term chargeable capacity (as defined below for positive and negative charging zones).

14.18.6 If there is a single set of Wider and Local generation tariffs within a charging year, the Chargeable Capacity is multiplied by the relevant generation tariff to calculate the annual liability of a generator.

14.18.7 If multiple sets of Wider and Local generation tariffs are applicable within a single charging year, the Chargeable Capacity is multiplied by the relevant tariffs pro rated over the entire charging year, across the months that they are applicable for.

$$Annual\ Liability = Chargeable\ Capacity \times \left(\frac{a \times Tariff\ 1 + b \times Tariff\ 2}{12} \right)$$

where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

Deleted: Chapter 5:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.87 cm, Hanging: 1.27 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1.27 cm + Indent at: 0.63 cm, Tabs: 4.14 cm, List tab + Not at 1.27 cm

Deleted: National Grid

Formatted: Indent: Left: 1.6 cm

Formatted: Indent: Left: 2.87 cm, Hanging: 1.27 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1.27 cm + Indent at: 0.63 cm, Tabs: 4.14 cm, List tab + Not at 1.27 cm

Deleted: National Grid

Deleted: Appendix TN-5:

Formatted: Font: Not Bold

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

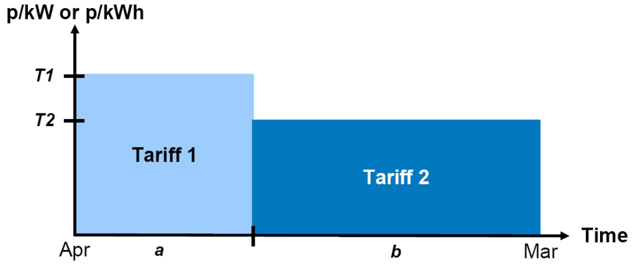
Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.54 cm

Deleted: 2

b = Number of months over which the revised tariff is applicable.



14.18.8 For the avoidance of doubt if there are multiple sets of Wider and Local generation tariffs applicable within a single charging year and a tariff changes from being positive to negative or vice versa, the Chargeable Capacity for the entire charging year will be determined based on the net position of the pro rated tariffs for each affected generator.

Formatted: Bullets and Numbering

Basis of Wider Generation Charges

Generation with positive wider tariffs

14.18.9 The Chargeable Capacity for Power Stations with positive wider generation tariffs is the highest Transmission Entry Capacity (TEC) applicable to that Power Station for that Financial Year. A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity, STTEC). For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

Formatted: Bullets and Numbering

14.18.10 The short-term chargeable capacity for Power Stations situated with positive generation tariffs is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as appropriate.

Formatted: Bullets and Numbering

14.18.11 For Power Stations, the short term chargeable capacity for LDTEC with positive generation tariffs referred to in Paragraph 14.18.10 will be the capacity purchased either on a profiled firm[2] or indicative[3] basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term

Formatted: Bullets and Numbering

Deleted: 5.10

[2] where an LDTEC Block Offer has been accepted (Profiled Block LDTEC) and a firm profile of capacity has been purchased.

[3] where an LDTEC Indicative Block Offer has been accepted (Indicative Profiled Block LDTEC) and a right to future additional capacity up to a requested level has been purchased, the availability of which will be notified on a weekly basis in accordance with the CUSC.

chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second of 50MW. Further examples are provided in 14.16.6.

Deleted: on Pages 36 and 37 of this document

Generation with negative wider tariffs

14.18.12 The Chargeable Capacity for Power Stations with negative wider generation tariffs is the average of the capped metered volumes during the three settlement periods described in 14.18.13 below, for the Power Station (i.e. the sum of the metered volume of each BM Unit associated with Power Station in Appendix C of its Bilateral Agreement). A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity). If TEC is exceeded, the metered volumes would each be capped by the TEC for the Power Station applicable for that Financial Year. For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

Formatted: Bullets and Numbering

Deleted: 5.13

14.18.13 The three settlement periods are those of the highest metered volumes for the Power Station and the two half hour settlement periods of the next highest metered volumes which are separated from the highest metered volumes and each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive. These settlement periods do not have to coincide with the Triad.

Formatted: Bullets and Numbering

<u>Example</u>

If the highest TEC for a Power Station were **250MW** and the highest metered volumes and resulting capped metered volumes were as follows:

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 3.6 cm

Formatted: Indent: Left: 2.87 cm

Formatted Table

Date	19/11/08	13/12/08	06/02/09
Highest Metered Volume in month (MW)	**245.5**	**250.3**	**251.4**
Capped Metered Volume (MW)	**245.5**	**250.0**	**250.0**

Then, the chargeable Capacity for the Power Station would be:

$$\left(\frac{245.5 + 250 + 250}{3}\right) \textbf{ = 248.5 MW}$$

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 2.85 cm

Formatted: Indent: Left: 3.6 cm

Note that in the example above, the Generator has exceeded its TEC on 13 December 2007 and 6 February 2008 and would therefore be in breach of the CUSC unless the generator had an approved STTEC or LDTEC value. (The STTEC and LDTEC charge for negative zones is currently set at zero).

Formatted: Indent: Left: 1.6 cm

Formatted: Indent: Left: 1.6 cm

14.18.14 The short-term chargeable capacity for Power Stations with negative generation tariffs is any approved STTEC or LDTEC applicable to that

Formatted: Bullets and Numbering

Deleted: 2

Power Station during a valid STTEC Period or LDTEC Period, as applicable.

14.18.15 For Power Stations with negative generation tariffs, the short-term chargeable capacity for LDTEC referred to in Paragraph 14.18.14 will be the capacity purchased either on a profiled firm or indicative basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second at 50MW.

Formatted: Bullets and Numbering

Deleted: Error! Reference source not found.

Deleted:

14.18.16 As noted above, a negative LDTEC tariff in negative generation charging zones is set to zero. Accordingly no payments will be made for use of LDTEC (in any of its forms) in these zones.

Formatted: Bullets and Numbering

Basis of Local Generation Charges

14.18.17 The Chargeable Capacity for Power Stations will be the same as that used for wider generation charges, except that each component of the local tariff shall be considered separately as to whether it is a positive or negative tariff component. This means that where a local circuit tariff is negative, the final charging liability for this element will be based on actual metered output as described in Paragraph 14.18.12.

Formatted: Bullets and Numbering

Deleted: 5

Small Generators Charges

14.18.18 Eligible small generators' tariffs are subject to a discount of a designated sum defined by Licence Condition C13 as 25% of the combined residual charge for generation and demand. The calculation for small generators charges is not part of the methodology however, for information the designated sum is included in **The Statement of Use of System Charges.**

Formatted: Bullets and Numbering

Monthly Charges

14.18.19 Initial Transmission Network Use of System Generation Charges for each Financial Year will be based on the Power Station Transmission Entry Capacity (TEC) for each User as set out in their Bilateral Agreement. The charge is calculated as above. This annual TNUoS generation charge is split evenly over the months remaining in the year. For positive final generation tariffs, if TEC increases during the charging year, the party will be liable for the additional charge incurred for the **full** year, which will be recovered uniformly across the remaining chargeable months in the relevant charging year (subject to Paragraph 14.18.20 below). An increase in monthly charges reflecting an increase in TEC during the charging year will result in interest being charged on the differential sum of the increased and previous TEC charge. The months liable for interest will be those preceding the TEC increase from April in year t. For negative final generation tariff, any increase in TEC during the year will lead to a recalculation of the monthly charges for the remaining chargeable months of the relevant charging year. However, as TEC decreases do not become effective until the start of the financial year following approval, no

Formatted: Bullets and Numbering

Deleted: 5

recalculation is necessary in these cases. As a result, if TEC increases, monthly payments to the generator will increase accordingly.

14.18.20 The provisions described above for increases in TEC during the charging year shall not apply where the LDTEC (in any of its forms) has been approved for use before the TEC is available, which will typically mean the LDTEC has been approved after the TEC increase has been approved. In such instances, the party shall commence payments for TEC during the LDTEC Period for LDTEC purchased up to the future level of TEC and LDTEC Charges will only apply to LDTEC that is incremental to the TEC increase. For the avoidance of doubt, where TEC has been approved after LDTEC in a given year, these provisions shall not apply and the LDTEC shall be considered additional to the TEC and charged accordingly.

Formatted: Bullets and Numbering

Ad hoc Charges

14.18.21 For each STTEC period successfully applied for, a charge will be calculated by multiplying the STTEC by the tariff calculated in accordance with Paragraph 14.16.3. The Company will invoice Users for the STTEC charge once the application for STTEC is approved.

Formatted: Bullets and Numbering

Deleted: 3

Deleted: National Grid

14.18.22 For Power Stations utilising LDTEC (in any of its forms) the LDTEC Charge for each LDTEC Period is the sum of the charging liabilities associated with each incremental level of short term chargeable capacity provided by LDTEC within the LDTEC Period (assessed on a weekly basis). The charging liability for a given incremental level of short term chargeable capacity is the sum of:

Formatted: Bullets and Numbering

i) the product of the higher tariff rate (calculated in accordance with Paragraph 14.16.6) and capacity purchased at this increment for the first 17 weeks in a Financial Year (whether consecutive or not); and

Deleted: 3

ii) the product of the lower tariff rate (calculated in accordance with Paragraph 14.16.6) and capacity purchased at this increment in any additional weeks within the same Financial Year (whether consecutive or not).

Deleted: 3

14.18.23 For each LDTEC Period successfully applied for, the LDTEC Charge will be split evenly over the relevant LDTEC Period and charged on a monthly basis. LDTEC charges will apply to both LDTEC (in any of its forms) and Temporary Received TEC held by a User. For the avoidance of doubt, the charging methodology will not differentiate between access rights provided to a generator by LDTEC or through Temporary Received TEC obtained through a Temporary TEC Exchange (as defined in the CUSC).

Formatted: Bullets and Numbering

Example

Formatted: Indent: Left: 2.87 cm

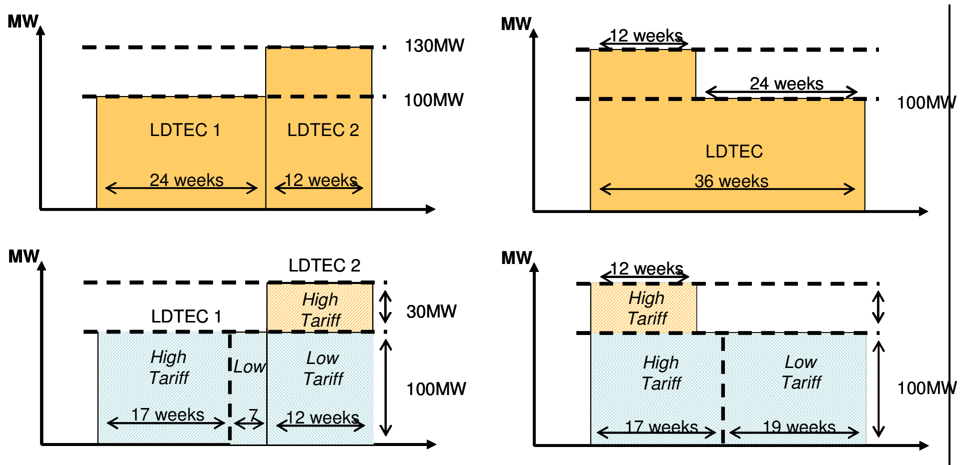
Formatted: Indent: Left: 1.6 cm

The diagrams below show two cases where LDTEC has been purchased: in Case A, two LDTEC Periods have been purchased; and in Case B one LDTEC Period has been purchased. The total capacity purchased in both cases is the same. The top diagrams illustrate the capacity purchased, while lower diagrams illustrate the incremental levels of short term chargeable capacities of LDTEC and the tariff rate that would apply to that capacity.

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 1.6 cm

Deleted: 2



Case A **Case B**

In both cases, the total amount charged for the LDTEC would be the same:

Capacity charges at the higher tariff rate:	Capacity charges at the lower tariff ra
• 17 weeks at the 100MW increment • 12 weeks at the 30MW increment	• 19 weeks at the 100MW increment

Embedded Transmission Use of System Charges "ETUoS"

14.18.24 The ETUoS charges are a component of Use of System charges levied on offshore generators whose offshore transmission connection is embedded in an onshore distribution network. The charge relates to the provision and use of the onshore distribution network.

14.18.25 The main purpose of ETUoS charges is to pass through the charges that are levied by the DNO on the NETSO to the offshore generator(s). This charge reflects the charges levied by the DNO for the costs of any works on and use of the DNO network in accordance with the DNO's charging statements and will include, but is not limited to, upfront charges and capital contributions in respect of any works as well as the ongoing and annual Use of System charges for generation connected to the distribution network.

14.18.26 In the case of some relevant transitional offshore generation projects, ETUoS will also be used to pass through historic DNO capital contributions forming part of the Offshore Transmission Owner tender revenue stream.

14.18.27 The specific nature of the ETUoS charge and the payment profile for these will depend upon the charging arrangements of the relevant DNO and reference should be made to the relevant DNO's charging statement. In terms of applicable transitional offshore generation projects the ETUoS payment profile will be consistent with the recovery of the Offshore Transmission Owner revenue stream.

14.18.28 Where a DNO's charge relates to more than one offshore generator, the related ETUoS charge will represent a straight pass through of the distribution charge specific to each relevant offshore generator. Where

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 1.6 cm

Formatted Table

Formatted: Indent: Left: 0 cm, Hanging: 0.44 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 0.44 cm, List tab + Not at 0.63 cm

Formatted: Indent: Left: 0 cm, Hanging: 0.47 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 0.47 cm, List tab + Not at 0.63 cm

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: OFTO

Formatted: Bullets and Numbering

Deleted: OFTO

Formatted: Bullets and Numbering

specific information is not available, charges will be pro-rated based on the TEC of the relevant offshore generators connected to that offshore network.

14.18.29 Invoices for ETUoS charges shall be levied by the NETSO on the offshore generator as soon as reasonably practicable after invoices have been received by the NETSO for payment such that the NETSO can meet its payment obligations to the DNO. The initial payments and payment dates will be outlined in a User's Construction Agreement and/or Bilateral Agreement.

14.18.30 As the ETUoS charges reflect the DNO charges to the NETSO, such charges will be subject to variation when varied by the DNO. Where the User disputes regarding the ETUoS charge please note that this will result in a dispute between the NETSO and DNO under the DCUSA.

Reconciliation of Generation Charges

14.18.31 The reconciliation process is set out in the CUSC and in line with the principles set out above.

14.18.32 In the event of a manifest error in the calculation of TNUoS charges which results in a material discrepancy in a User's TNUoS charge as defined in Sections 14.17.27 to 14.17.29, the generation charges of Users qualifying under Section 14.17.28 will be reconciled in line with 14.18.19 and 14.18.24 using the recalculated tariffs.

Further Information

14.18.33 **The Statement of Use of System Charges** contains the £/kW generation zonal tariffs for the current Financial Year.

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: 4.27

Deleted: 4.29

Deleted: 4.28

Deleted: 5.19

Deleted: 5.24

Formatted: Bullets and Numbering

Deleted: 2

14.19 Data Requirements

Data Required for Charge Setting

14.19.1 Users who are Generators or Interconnector Asset Owners provide to The Company a forecast for the following Financial Year of the highest Transmission Entry Capacity (TEC) applicable to each Power Station or Interconnector for that Financial Year. For Financial Year 2008/9 Scottish Generators or Interconnector Asset Owners provide to The Company a forecast of the equivalent highest 'export' capacity figure. This data is required by The Company as the basis for setting TNUoS tariffs. The Company may request these forecasts in the November prior to the Financial Year to which they relate, in accordance with the CUSC.

14.19.2 Users who are owners or operators of a User System (e.g. Distribution companies) provide a forecast for the following Financial Year of the Natural Demand attributable to each Grid Supply Point equal to the forecasts of Natural Demand under both Annual Average Cold Spell (ACS) Conditions and a forecast of the average metered Demand attributable to such Grid Supply Point for the National Grid Triad. This data is published in table 2.4 of the Seven Year Statement and is compiled from week 24 data submitted in accordance with the Grid Code.

14.19.3 For the following Financial Year, The Company shall use these forecasts as the basis of Transmission Network Use of System charges for such Financial Year. A description of how this data is incorporated is included in 14.15 Derivation of the Transmission Network Use of System Tariff.

14.19.4 If no data is received from the User, then The Company will use the best information available for the purposes of calculation of the TNUoS tariffs. This will normally be the forecasts provided for the previous Financial Year.

Data Required for Calculating Users' Charges

14.19.5 In order for The Company to calculate Users' TNUoS charges, Users who are Suppliers shall provide to The Company forecasts of half-hourly and non-half-hourly demand in accordance with paragraph 14.17.14 and 14.17.15 and in accordance with the CUSC.

Deleted: Chapter 6:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: National Grid
Deleted: National Grid
Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: Chapter 2
Formatted: Font: Not Bold
Deleted: :
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: National Grid
Deleted: 4
Deleted: 4

14.20 Applications

14.20.1 Application fees are payable in respect of applications for new Use of System agreements; modifications to existing agreements; and applications for short-term access products or services. These are based on the reasonable costs that transmission licensees incur in processing these applications.

Applications for short-term access

14.20.2 Application fees for short-term access products or services are fixed and detailed in the **Statement of Use of System Charges**. These are non-refundable except for the following limited instances:

- Where a User (or Users) withdraw their application in accordance with any interactivity provisions that may be contained within the CUSC; or
- Where the application fee covers ongoing assessment work that is contingent on the acceptance of the offer.

14.20.3 In either case, the refunded amount will be proportional to the remaining assessment time available.

14.20.4 To ensure that application fees for short-term access are cost reflective, fees may be comprised of a number of components. For instance, the LDTEC Request Fee is comprised of a number of components and the total fee payable is the sum of those components that apply to the type(s) of LDTEC Offer(s) requested. For example:

- The LDTEC Request Fee for an LDTEC Block Offer is the basic request fee.
- The LDTEC Request Fee for an LDTEC Indicative Block Offer is the sum of the basic request fee and the additional rolling assessment fee.
- The LDTEC Request Fee payable for a combined LDTEC Block Offer and LDTEC Indicative Block Offer is the sum of the basic request fee, the additional rolling assessment fee, and the additional combined application fee.

Applications for new or modified existing Use of System Agreements

14.20.5 Users can opt to pay a fixed price application fee in respect of their application or pay the actual costs incurred. The fixed price fees for applications are detailed in the **Statement of Use of System Charges**.

14.20.6 If a User chooses not to pay the fixed fee, the application fee will be based on an advance of transmission licensees' Engineering and out-of pocket expenses and will vary according to the size of the scheme and the amount of work involved. Once the associated offer has been signed or lapsed, a reconciliation will be undertaken. Where actual expenses exceed the advance, The Company will issue an invoice for the excess. Conversely, where The Company does not use the whole of the advance, the balance will be returned to the User.

Deleted: Chapter 7:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 2.87 cm, Hanging: 0.63 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0 cm + Indent at: 0 cm, Tabs: Not at 1.9 cm
Formatted: Indent: Left: 4.14 cm
Formatted: Indent: Left: 2.87 cm, Hanging: 0.63 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0 cm + Indent at: 0 cm, Tabs: Not at 1.9 cm
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 2.87 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.62 cm, List tab + Not at 0.63 cm
Formatted: Indent: Left: 2.87 cm
Formatted: Indent: Left: 2.87 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.62 cm, List tab + Not at 0.63 cm
Formatted: Indent: Left: 2.87 cm
Formatted: Indent: Left: 2.87 cm, Hanging: 0.75 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 3.62 cm, List tab + Not at 0.63 cm
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: National Grid
Deleted: 2

14.20.7 The Company will refund the first application fee paid (the fixed fee or the amount post-reconciliation) and consent payments made under the Construction Agreement for new or modified existing agreements. The refund shall be made either on commissioning or against the charges payable in the first three years of the new or modified agreement. The refund will be net of external costs.

14.20.8 The Company will not refund application fees for applications to modify a new agreement or modified existing agreement at the User's request before any charges become payable. For example, The Company will not refund an application fee to delay the provision of a new connection if this is made prior to charges becoming payable.

Deleted: National Grid

Formatted: Bullets and Numbering

Deleted: National Grid

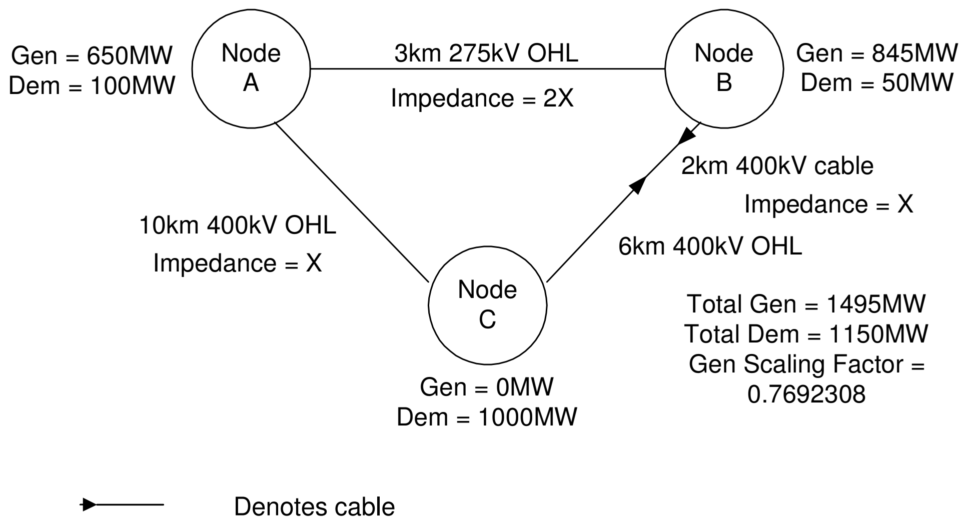
Formatted: Bullets and Numbering

Deleted: National Grid

14.21 Transport Model Example

For the purposes of the DCLF Transport algorithm, it has been assumed that the value of circuit impedance is equal to the value of circuit reactance.

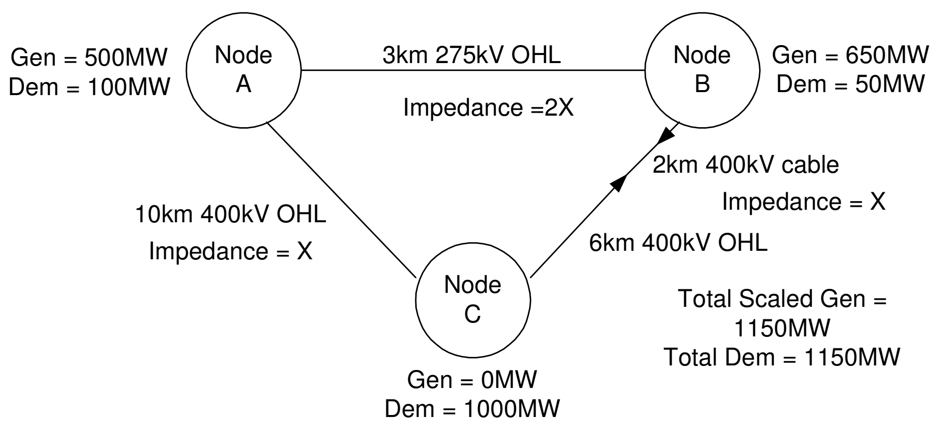
Consider the following 3-node network:



The first step is to match total demand and total generation by scaling uniformly the nodal generation down such that total system generation equals total system demand.

Node A Generation = 1150/1495 * 650MW = 500MW
Node B Generation = 1150/1495 * 845MW = 650MW

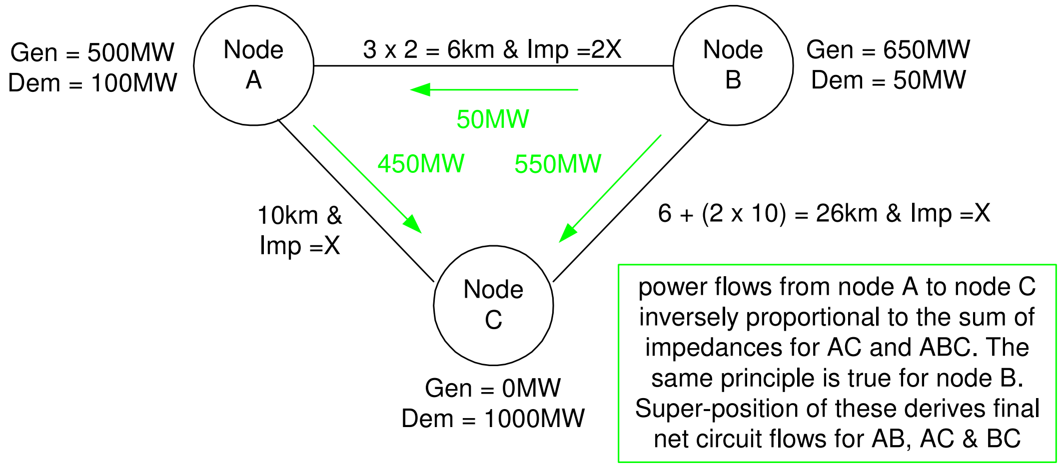
This gives the following balanced system:



Deleted: Appendix TN-1:
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto

Deleted: 2

Assuming Node A is the reference node, each circuit has impedance X the 400kV cable circuit expansion factor is 10 and the 275kV overhead line circuit expansion factor is 2, the DCLF transport algorithm calculates the base case power flows as follows:



Nodes A and B export, whilst Node C imports. Hence the DCLF algorithm derives flows to deliver export power from Nodes A and B to meet import needs at Node C.

Step 1: Net export from Node A is 400MW; route AC has impedance X and route AB-BC has impedance 3X; hence 300MW would flow down AC and 100MW along AB-BC

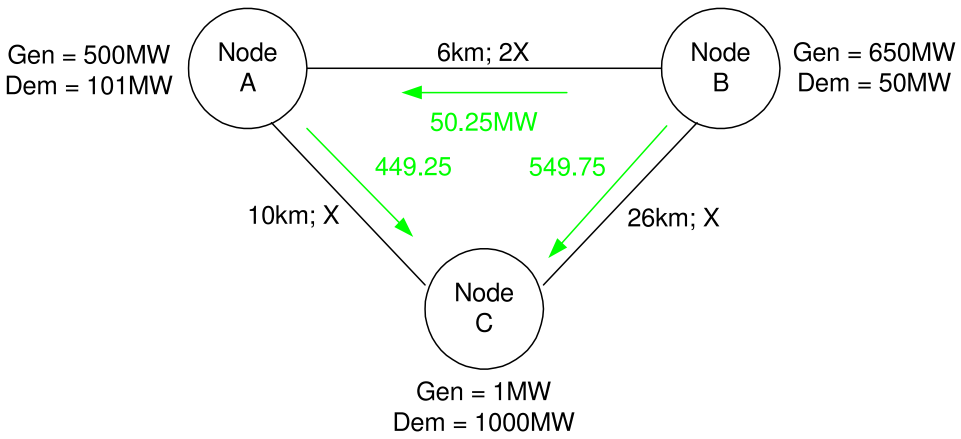
Step 2: Net export from Node B is 600MW; route BC has impedance X and route BA-AC has impedance 3X; hence 450MW would flow down BC and 150MW along BA-AC

Step 3: Using super-position to add the flows derived in Steps 1 and 2 derives the following;

Flow AC	= 300MW + 150MW	=	450MW
Flow AB	= 100MW – 150MW	=	-50MW
Flow BC	= 100MW + 450MW	=	550MW

Total cost = (450 x 10) + (50 x 6) + (550 x 26) = 19,100 MWkm
(base case)

We then 'inject' 1MW of generation at each node with a corresponding 1MW offtake (demand) at the reference node and recalculate the total MWkm cost. The difference in cost from the base case is the marginal km or shadow cost. This is demonstrated as follows:



To calculate the marginal km at node C:

Total Cost = (449.25 x 10) + (50.25 x 6) + (549.75 x 26) = 19,087.5 MWkm

Thus the overall cost has reduced by 12.5 (i.e. the marginal km = -12.5).

Deleted: 2

14.22 Example: Calculation of Zonal Generation Tariff

Deleted: Appendix TN-2:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Let us consider all nodes in generation zone 4: Western Highland.

The table below shows a sample output of the transport model comprising the node, the wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

Genzone	Node	Wider Nodal Marginal km	Scaled Generation
4	LAGG1Q	1113.41	0.00
4	CEAN1Q	1133.18	54.41
4	FASN10	1143.82	38.50
4	FAUG10	1100.10	0.00
4	FWIL1Q	1009.79	0.00
4	FWIL1R	1009.79	0.00
4	GLEN1Q	1123.82	43.52
4	INGA1Q	1087.40	16.74
4	MILL1Q	1101.55	0.00
4	MILL1S	1106.76	0.00
4	QUOI10	1123.82	15.07
4	QUOI1Q	1120.49	0.00
4	LOCL1Q	1082.41	0.00
4	LOCL1R	1082.41	0.00
		Totals	168.24

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For zone 4 this would be as follows:

Genzone	Node	Wider Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Wider Nodal Marginal km
4	CEAN1Q	1133.18	54.41	366.48
4	FASN10	1143.82	38.50	261.75
4	GLEN1Q	1123.82	43.52	290.71
4	INGA1Q	1087.40	16.74	108.20
4	QUOI10	1123.82	15.07	100.67
		Totals	168.24	

i.e. $\frac{1087.40 \times 16.74}{168.24}$

(ii) sum the generation weighted wider nodal shadow cost to give a zonal figure. For zone 4 this would be:

(366.48+ 261.75 +290.71 + 108.20 + 100.67) km = **1127.81km**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split of revenue recovery between generation and demand is retained.

For zone 4 this would be say:

1127.81km + (-239.60 km) = **888.21 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

(iv) calculate the wider transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 4 and assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.8:

$$\frac{888.21\text{ km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£16.10/kW}}$$

(v) If we assume (for the sake of this example) that the generation connecting at CEAN1Q connects via 10km of 132kV 100MVA rated single circuit overhead line from the nearest MITS node, with no redundancy, the substation is rated at less than 1320MW, and there is no other generation or demand connecting to this circuit, then:

Deleted: has a

Deleted: redundant connection

a) referencing the table in paragraph 14.15.67, the local substation tariff will be £0.133/kW; and

Deleted: 2

Deleted: 1

Deleted: charge

Deleted: 5

b) running the transport model with a local circuit expansion factor of 10.0 applied to the 10km of overhead line connecting CEAN1Q to the nearest MITS node and the wider circuit expansion factors applied to all other circuits, gives a local nodal maginal cost of 100MWkm. This is the additional MWkm costs associated with the node's local assets. Applying the expansion constant of £10.07/MWkm and local security factor of 1.0 and dividing by 1000 gives a local circuit tariff of £1.007/kW.

(vi) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from generation (calculated as c.27% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the generation transport tariffs divided by total expected generation.

Deleted: National Grid

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from generation would be (27% x £1067m) = £288m. Assuming the total recovery from both wider generation transport and local generation tariffs is £70m and total forecast chargeable generation capacity is 67000MW, the Generation residual tariff would be as follows:

Deleted: 2

$$\frac{£288 - £70m}{65000MW} = \underline{£3.35/kW}$$

(vii) to get to the final tariff for a generator connecting at a particular node, we simply sum the generation residual tariff calculated in (vi), the wider zonal transport tariff calculated in (iv), the local substation tariff calculated in (v(a)) , and the local circuit tariff calculated in (v(b)). In this example:

For CEAN1Q : £16.10/kW + £3.35/kW + £0.135/kW + £1.007/kW = **£20.592 /kW**

To summarise, in order to calculate the generation tariffs, we evaluate a generation weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that our revenue recovery split between generation and demand is correct, multiply by the security factor, then we add a constant (termed the residual cost) to give the overall tariff.

14.23 Example: Calculation of Zonal Demand Tariff

Let us consider all nodes in demand zone 14: South Western.

The table below shows a sample output of the transport model comprising the node, the marginal km of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation = total national demand and the demand sited at the node.

Demand Zone	Node	Nodal Marginal km	Demand (MW)
14	ABHA4A	-381.25	148.5
14	ABHA4B	-381.72	148.5
14	ALVE4A	-328.31	113
14	ALVE4B	-328.31	113
14	AXMI40_SWEB	-337.53	117
14	BRWA2A	-281.64	92.5
14	BRWA2B	-281.72	92.5
14	EXET40	-320.12	357
14	HINP20	-247.67	4
14	HINP40	-247.67	0
14	INDQ40	-401.28	450
14	IROA20_SWEB	-194.88	594
14	LAND40	-438.65	297
14	MELK40_SWEB	-162.96	102
14	SEAB40	-63.21	352
14	TAUN4A	-273.79	0
14	TAUN4B	-273.79	97
		Totals	3078

Deleted: Appendix TN-3:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Deleted: 2

In order to calculate the demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For zone 14 this would be as follows:

Demand zone	Node	Nodal Marginal km	Demand (MW)	Demand Weighted Nodal Marginal km
14	ABHA4A	-381.25	148.5	-18.39
14	ABHA4B	-381.72	148.5	-18.42
14	ALVE4A	-328.31	113	-12.05
14	ALVE4B	-328.31	113	-12.05
14	AXMI40_SWEB	-337.53	117	-12.83
14	BRWA2A	-281.64	92.5	-8.46
14	BRWA2B	-281.72	92.5	-8.47
14	EXET40	-320.12	357	-37.13
14	HINP20	-247.67	4	-0.32
14	INDQ40	-401.28	450	-58.67
14	IROA20_SWEB	-194.88	594	-37.61
14	LAND40	-438.65	297	-42.33
14	MELK40_SWEB	-162.96	102	-5.40
14	SEAB40	-63.21	352	-7.23
14	TAUN4B	-273.79	97	-8.63
		Totals	3078	287.99

(ii) sum the demand weighted nodal shadow cost to give a zonal figure. For zone 14 this is shown in the above table and is 287.99km.

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approximate) split of revenue recovery between generation and demand is retained.

For zone 14 this would be say:

287.99km - (-239.60km) = **527.59 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

(iv) calculate the transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For zone 14, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

$$\frac{527.59\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£9.56/kW}$$

(v) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the demand transport tariffs divided by total expected demand.

Deleted: National Grid

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from demand would be (73% x £1067m) = £779m. Assuming the total recovery from demand transport tariffs is £130m and total forecast chargeable demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £130m}{50000MW} = \underline{£12.98/kW}$$

(vi) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariff calculated in (iv)

For zone 14:

£9.56/kW + £12.98/kW = **<u>£22.54/kW</u>**

To summarise, in order to calculate the demand tariffs, we evaluate a demand weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that our revenue recovery split between generation and demand is correct, then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

Deleted: 2

14.24 Reconciliation of Demand Related Transmission Network Use of System Charges

Deleted: Appendix TN-4:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Deleted: National Grid

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

Monthly Charges

Suppliers provide half-hourly (HH) and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW and 1.20p/kWh, is as follows:

	Forecast HH Triad Demand HHD_F(kW)	HH Monthly Invoiced Amount (£)	Forecast NHH Energy Consumption $NHHC_F$(kWh)	NHH Monthly Invoiced Amount (£)	Net Monthly Invoiced Amount (£)
Apr	12,000	10,000	15,000,000	15,000	25,000
May	12,000	10,000	15,000,000	15,000	25,000
Jun	12,000	10,000	15,000,000	15,000	25,000
Jul	12,000	10,000	18,000,000	19,000	29,000
Aug	12,000	10,000	18,000,000	19,000	29,000
Sep	12,000	10,000	18,000,000	19,000	29,000
Oct	12,000	10,000	18,000,000	19,000	29,000
Nov	12,000	10,000	18,000,000	19,000	29,000
Dec	12,000	10,000	18,000,000	19,000	29,000
Jan	7,200	(6,000)	18,000,000	19,000	13,000
Feb	7,200	(6,000)	18,000,000	19,000	13,000
Mar	7,200	(6,000)	18,000,000	19,000	13,000
Total		72,000		216,000	288,000

As shown, for the first nine months the Supplier provided a 12,000kW HH triad demand forecast, and hence paid HH monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

Initial Reconciliation (Part 1)

The Supplier's outturn HH triad demand, based on <u>initial</u> settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff
= (9,000kW - 7,200kW) x £10.00/kW
= 1,800kW x £10.00/kW
= £18,000

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.

As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge $= \frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,000 (£18,000 - £12,000).

Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad demand and NHH energy consumption values were 9,500kW and 16,500,000kWh, respectively.

Final HH Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final NHH Reconciliation Charge $= \frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,400.

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Deleted: 2

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

Terminology:

HHD_A = The Supplier's outturn half-hourly metered Triad Demand (kW) for the demand zone concerned.

HHD_F = The Supplier's forecast half-hourly metered Triad Demand (kW) for the demand zone concerned.

$NHHC_A$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

$NHHC_F$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

£/kW Tariff = The £/kW Demand Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

p/kWh Tariff = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

14.25 Classification of parties for charging purposes

Deleted: Appendix TN-5
Deleted: :
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

SUPPLIER	
Supplier Use of System Agreement **Supplier BMU1** ..... **Supplier BMUn**	
Demand Charges See 14.17.9 **and** 14.17.14.	Generation Charges None.

Deleted: 4.5
Deleted: 4.11

POWER STATION WITH A BILATERAL CONNECTION AGREEMENT	
Bilateral Connection Agreement Appendix C **Gen Unit BMU1** ..... **Gen Unit BMUn** **Station Load BMU** **Additional Load BMU**	
Demand Charges See 14.17.10.	Generation Charges See 14.18.1 **i) and** 14.18.3 **to** 14.18.8 **and** 14.18.17. For generators in positive zones, see 14.18.9 **to** 14.18.11. For generators in negative zones, see 14.18.12 **to** 14.18.16.

Deleted: 4.6
Deleted: 5.1
Deleted: 5.3
Deleted: 5.4
Deleted: 5.5
Deleted: 5.8
Deleted: 5.
Deleted: 9
Deleted: 5.12

Deleted: 2

PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT	
Bilateral Embedded Generation Agreement Appendix C **Gen Unit BMU1** ..... **Gen Unit BMUn** | **Station Load BMU** | **Additional Load BMU**	
Demand Charges See 14.17.10, 14.17.11 and 14.17.14.	Generation Charges See 14.18.1 ii). For generators in positive zones, see 14.18.3 to 14.18.11 and 14.18.17. For generators in negative zones, see 14.18.3 to 14.18.8 and 14.18.12 to 14.18.17.

Deleted: 4.6

Deleted: 4.7

Deleted: 4.11

Deleted: 5.1

Deleted: 5.3 to 5.6.

Deleted: 5.3 to 5.4

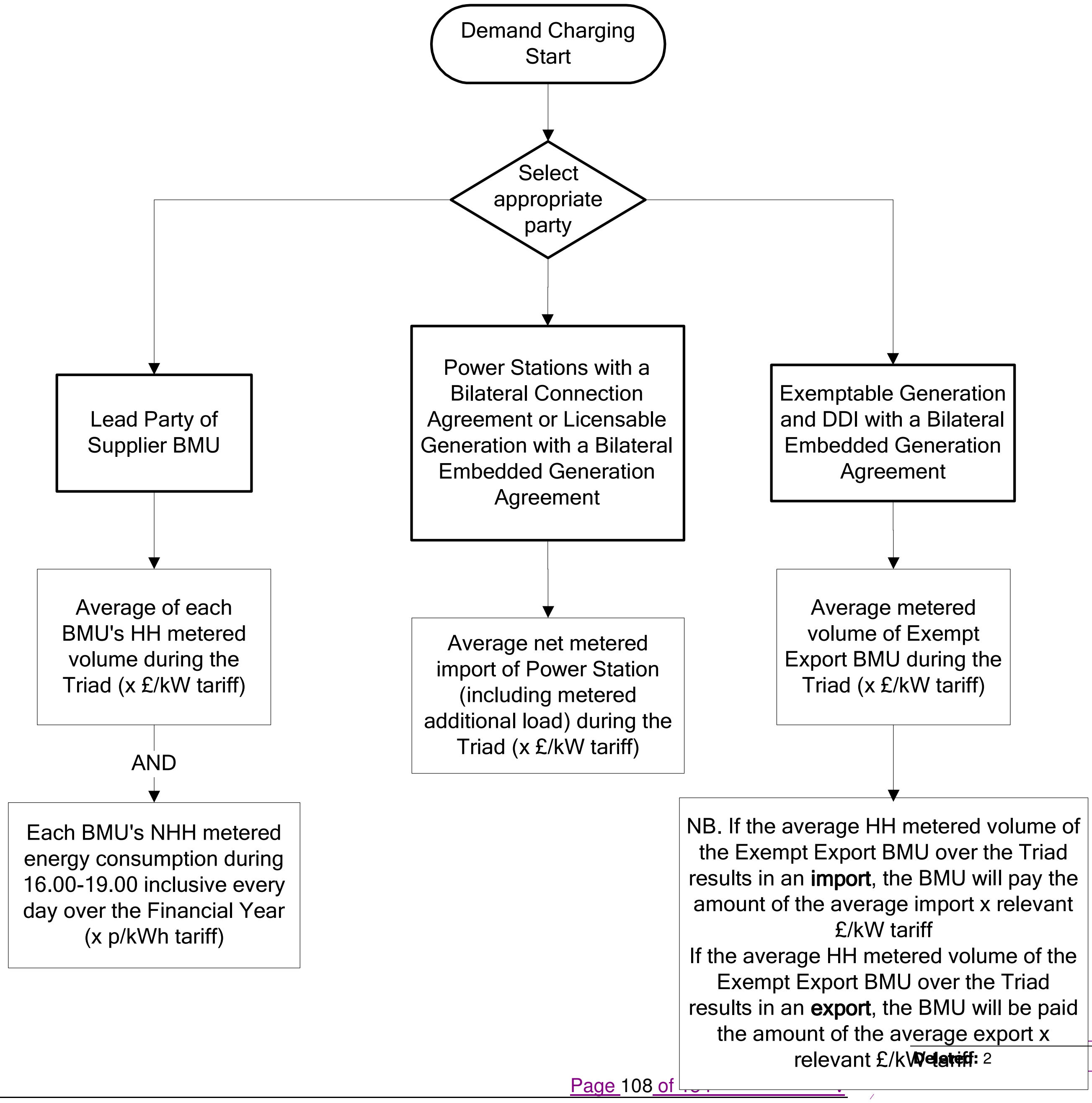
Deleted: 5.9 to 5.11.

14.26 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

Demand Charges



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = half hourly NHH = Non-half hourly

Deleted: Appendix TN-6:

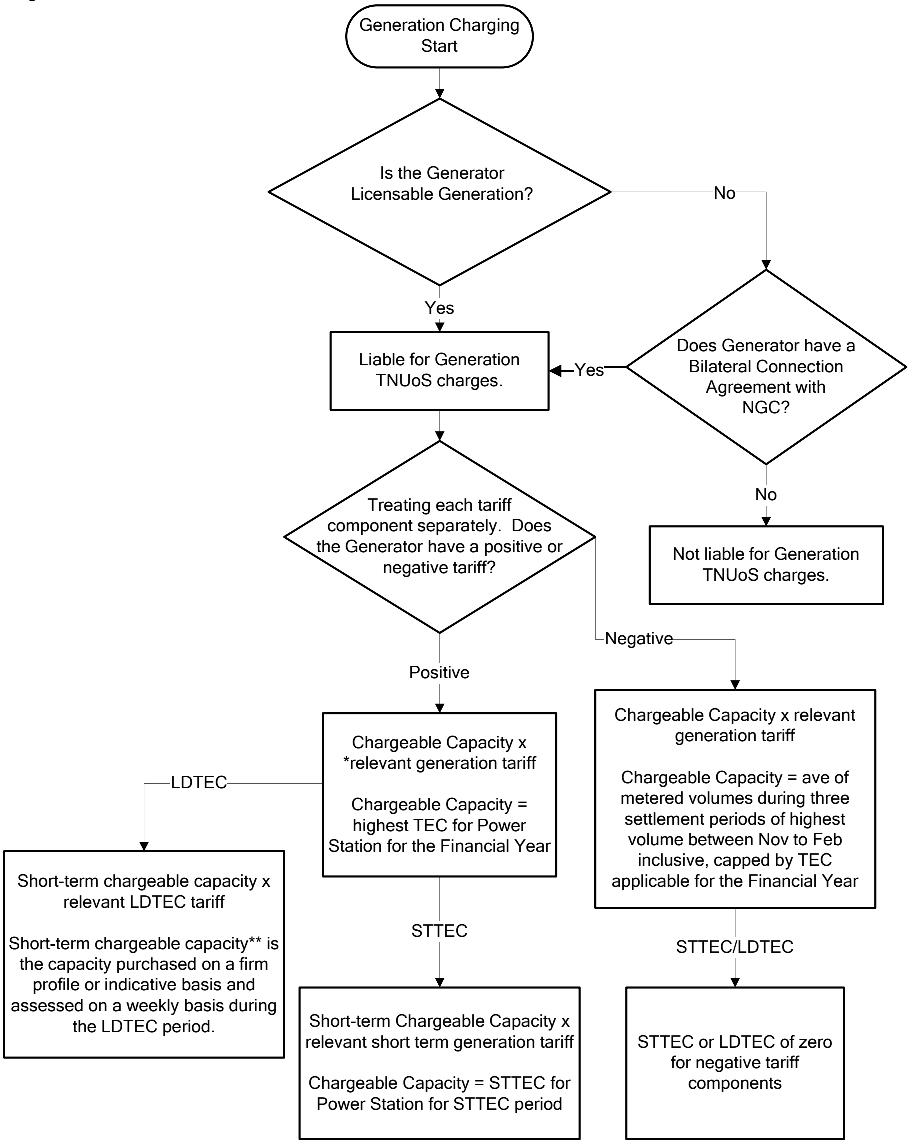
Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Deleted: 2

Generation Charges



Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

14.27 Example: Determination of The Company's Forecast for Demand Charge Purposes

Deleted: Appendix TN-7:
Deleted: National Grid
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

Deleted: National Grid

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

Deleted: National Grid
Deleted: National Grid

All values used with the examples are purely for illustrative purposes only.

i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

Deleted: National Grid
Deleted: National Grid

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

Deleted: National Grid

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH demand at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

Deleted: National Grid

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH demand at Triad in the preceding Financial Year

D = User's average half hourly metered demand in settlement period 35 in the Financial Year to date

P = User's average half hourly metered demand in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula

Deleted: National Grid
Deleted: National Grid
Deleted: 2

immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH demand at Triad in the Financial Year minus two

D = User's average half hourly metered demand in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered demand in settlement period 35 for the period corresponding to D in the Financial Year minus two

Example (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Deleted: National Grid

F = 10,000 * 13,200 / 12,000

F = 11,000 kWh

where:

T = 10,000 kWh (period November 2003 to February 2004)

D = 13,200 kWh (period 1st April 2004 to 15th February 2005#)

P = 12,000 kWh (period 1st April 2003 to 15th February 2004)

Latest date for which settlement data is available.

ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

Example:

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

Deleted: National Grid

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

Deleted: National Grid

iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered demand at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH demand at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

Example:

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Deleted: National Grid

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kWh

where:

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kWh (period November 2004 to February 2005)

W = 18,888,888 kWh (period 1st July 2004 to 31st July 2004)

iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

Deleted: 2

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

Example:

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

Deleted: National Grid

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

14.28 Stability & Predictability of TNUoS tariffs

Deleted: Appendix TN-8
Formatted: Font color: Auto
Deleted: :
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font: 14 pt, Font color: Auto

Stability of tariffs

The Transmission Network Use of System Charging Methodology has a number of elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity. This appendix seeks to highlight those elements.

Each node of the transmission network is assigned to a zone. The result of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation, demand, and network parameters. The criteria used to establish generation zones are part of the methodology and are described in Paragraph 14.15.26.

Deleted: 2
Deleted: 17

These zones are themselves fixed for the duration of the price control period. The methodology does, however, allow these to be revisited in exceptional circumstances to ensure that the charges remain reasonably cost reflective or to accommodate changes to the network. In rare circumstances where such a re-zoning exercise is required, this will be undertaken in such a way that minimises the adverse impact on Users. This is described in Paragraph 14.15.29.

Deleted: 2
Deleted: 0

In addition to fixing zones, other key parameters within the methodology are also fixed for the duration of the price control period or annual changes restricted in some way. Specifically:

- the expansion constant, which reflects the annuitised value of capital investment required to transport 1MW over 1km by a 400kV over-head line, changes annually according to RPI. The other elements used to derive the expansion constant are only reviewed at the beginning of a price control period to ensure that it remains cost-reflective. This review will consider those components outlined in Paragraph 14.15.31 to Paragraph 14.15.41.

Deleted: 2
Deleted: 24
Deleted: 2
Deleted: 32

- the expansion factors, which are set on the same basis of the expansion constant and used to reflect the relative investment costs in each TO region of circuits at different transmission voltages and types, are fixed for the duration price control. These factors are reviewed at the beginning of a price control period and will take account of the same factors considered in the review of the expansion constant.

- the locational security factor, which reflects the transmission security provided under the NETS Security and Quality of Supply Standard, is fixed for the duration of the price control period and reviewed at the beginning of a price control period.

Deleted: GB

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within The Company's Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

Deleted: National Grid
Deleted: National Grid
Deleted: National Grid
Deleted: National Grid

Deleted: 2

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

Deleted: National Grid

Deleted: National Grid

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[4] This analysis is based on data included within the Seven Year Statement. This report typically includes:

Deleted: National Grid

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

Deleted: National Grid

[4] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

~~The Statement of the Balancing Services Use of System Charging Methodology~~

Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs

Formatted: Not Strikethrough
Formatted: Font: Times New Roman, Not Strikethrough
Formatted: Normal
Deleted: Chapter 8:
Formatted: Font: 14 pt, Font color: Auto
Formatted: Font color: Auto
Formatted: Font: 14 pt, Font color: Auto
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Deleted: National Grid
Formatted: Bullets and Numbering
Deleted: National Grid
Formatted: Bullets and Numbering
Formatted: Bullets and Numbering
Formatted: Indent: Left: 2.87 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: 4.14 cm, List tab + Not at 2.54 cm
Deleted: National Grid
Formatted: Indent: Left: 1.6 cm

14.30 Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party∗ summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \left\{ \frac{BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right|} \right\}$$

For importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \left\{ \frac{-1 * BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right|} \right\}$$

Where:

$BSUoSTOT_j$ Total BSUoS Charge applicable for Settlement Period j

QM_{ij} BM Unit Metered Volume **

TLM_{ij} Transmission Loss Multiplier **

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code

∗ or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

Deleted: Chapter 9:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.54 cm

Formatted: Indent: Left: 3.87 cm

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 1.6 cm

Formatted: Indent: Left: 2.87 cm

Formatted: Indent: Left: 1.6 cm

Formatted: Indent: Left: 1.6 cm

Formatted: Indent: Left: 2.85 cm

Deleted: 2

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge. Note this includes the Interconnector BM Units that belong to the Interconnector Error Administrator.

Formatted: Bullets and Numbering

Interconnector BM Units

14.30.4 The Lead Party of an Interconnector BM Unit will be liable for BSUoS charges based on their proportion of the total BM Unit Metered Volume of each Settlement Period adjusted for Transmission Losses by the application of the relevant Transmission Losses Multiplier.

Formatted: Bullets and Numbering

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

14.30.5 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

Formatted: Bullets and Numbering

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period ($BSUoSEXT_{jd}$)

14.30.6 The External BSUoS Charges for each Settlement Period ($BSUoSEXT_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow ($CSOBM_j$) and Balancing Service Variable Contract Cost ($BSCCV_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

Formatted: Bullets and Numbering

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} + \left[\ (IncpayEXT_d + BSCCA_d + ET_d - OM_d)\right.$$

$$\left. * \left\{ \left|\sum{}^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum{}^{-}(QM_{ijd} * TLM_{ijd})\right| \right\} / \sum_{j \in d} \left\{ \left|\sum{}^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum{}^{-}(QM_{ijd} * TLM_{ijd})\right| \right\} \right]$$

Calculation of the daily External Incentive Payment ($IncpayEXT_d$)

14.30.7 In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme (ξk=1≡d-1IncpayEXTk):

Deleted: 9.7

Formatted: Bullets and Numbering

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

14.30.8 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayEXT_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

Deleted: ¶

Deleted: 9.8

Formatted: Bullets and Numbering

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

14.30.9 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

Formatted: Bullets and Numbering

Deleted: National Grid

14.30.10 The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

Deleted: 9.10

Formatted: Bullets and Numbering

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

14.30.11 The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate selection factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

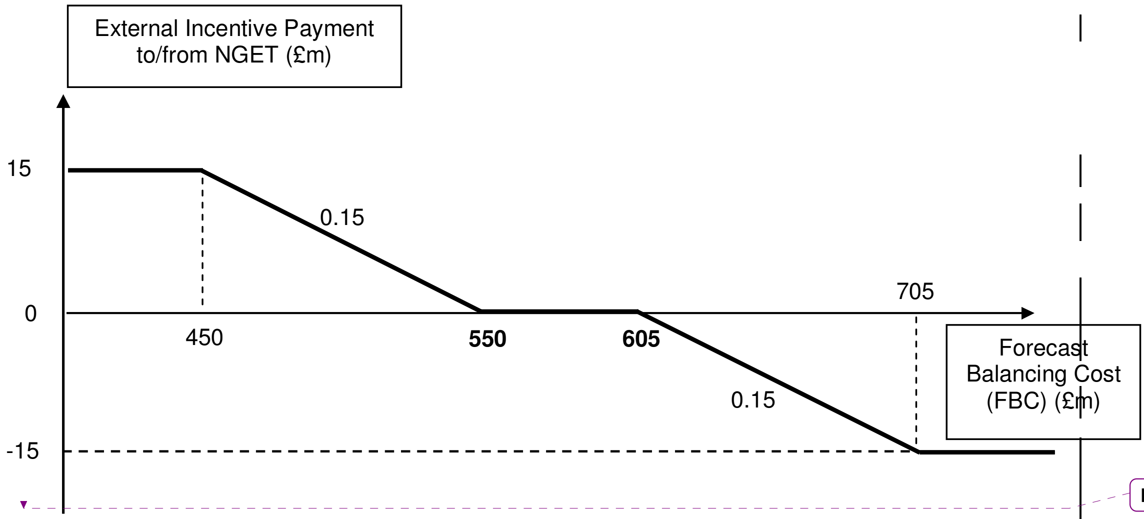
Deleted: 9.11

Formatted: Bullets and Numbering

Deleted: 2

Table 9.1

Forecast Balancing Cost (FBC)	M_t	SF_t	CB_t
£450,000,000 <	£0	0	£15,000,000
£450,000,000 <=FBC < £550,000,000	£550,000000	0.15	£0
£550,000,000 <=FBC < £605,000,000	FBC	0	£0
£605,000,000 <= FBC < £705,000,000	£605,000,000	0.15	£0
>= £705,000,000	£0	0	-£15,000,000



Deleted: Page Break

14.30.12 In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

Deleted: 9.12

Formatted: Bullets and Numbering

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS: Number of days in Scheme.

Formatted: Indent: Left: 2.54 cm

14.30.13 Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

Formatted: Bullets and Numbering

$$IBC_d = \sum_{j \in d} (CSOBM_{jd} + BSCCV_{jd} + NIA_{jd} + TLIC_{jd}) + BSCCA_d - OM_d - RT_d$$

Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{jd}$)

14.30.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.

Formatted: Bullets and Numbering

$$BSUoSINT_{jd} = (CSOC_d + IncpayINT_d + NC_d + IAT_d + IONT_d)$$

$$*\left\{ \left|\sum^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QM_{ijd} * TLM_{ijd})\right| \right\} / \sum_{j \in d} \left\{ \left|\sum^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QM_{ijd} * TLM_{ijd})\right| \right\}$$

Table 9.2 below summarises the annual SO Internal cost variables for Financial Year 20010/11 as set out in the Transmission Licence

Deleted: Page Break

Formatted: Indent: Left: 3.81 cm, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm, Tabs: 3.81 cm, List tab + Not at 1.27 cm

Table 9.2

Internal SO Cost Variable		Annual Cost Target (£m)
CSOC*	CSOOC	55.2
	CSOCEC	16.9
NC*	NSOC	1.6
	BI	3.2
	T	2.5
	P	15.0
	ON	1.0
IAT, IONT		0.0

[* in 2010/11 prices]

Formatted: Indent: Left: 3.81 cm

Formatted: Indent: Left: 2.54 cm

Formatted Table

Formatted: Indent: Left: 2.54 cm

Where

CSOC = CSOOC + CSOCEC

NC = (NSOC + BI + T + P + ON)

Calculation of the daily Internal Incentive Payment ($IncpayINT_d$)

14.30.16 In respect of each Settlement Day d, $IncpayINT_d$ is calculated as the difference between the overall total incentive payment ($FKIncpayINT_d$) due to that date and the overall incentive payment made up to the previous day ($\xi_{k=0\equiv d-1}IncpayINT_k$) plus the daily cost of Manifest Errors and Special Provisions:

Formatted: Bullets and Numbering

$$IncpayINT_d = \left(FKIncpayINT_d - \sum_{k=0}^{d-1} IncpayINT_k \right) + MESP_d$$

14.30.17 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayINT_d$) is calculated as the ratio of total forecast internal incentive payment across the duration of the scheme

Formatted: Bullets and Numbering

Deleted: 2

(FYIncpayINT): the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayINT_d = \frac{FYIncpayINT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

14.30.18 The Company daily Internal incentive payments ($IncPayINT_d$) are calculated by comparing the Daily Incentivised internal operating costs ($FSOINT_d$) against the Daily Internal Scheme Target (PTint) to set the Sharing Factor (SFint). Table 9.3 shows the respective values of these variables (in 2010/11 forecast prices).

Deleted: National Grid

Formatted: Bullets and Numbering

$$FYIncPayINT_d = (PT\,\mathrm{int} - FSOINT_d) * SF\,\mathrm{int}$$

Table 9.3

$FSOINT_d$ (£)	PTint (£)	SFint
$FSOINT_d$ < 55,262,715	55,262,715	0.15
$FSOINT_d$ => 55,262,715	55,262,715	0.15

14.30.19 In respect of each Settlement Day d, the forecast incentivised internal controllable System Operator operating cost ($FSOINT_d$) will be calculated as follows:

Formatted: Bullets and Numbering

$$FSOINT_d = \frac{\sum_{k=1}^{d} CSOOC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:
NDS: Number of days in Scheme.

Formatted: Indent: Left: 2.54 cm

14.30.20 The SO incentivised internal capital expenditure associated with balancing services activities (CSOCEC) is subject to fixed sharing factors at 15% upside and downside, to be applied each year to capital expenditure incurred which could then be added to the internal regulatory asset value (RAV).

Formatted: Bullets and Numbering

Inclusion of Profiling Factors

14.30.21 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme

Formatted: Bullets and Numbering

Deleted: National Grid

Manifest Errors and Special Provisions for IT system failures

14.30.22 The Company may, in certain circumstances, be required to pay compensation to BSC Parties as a result either of Manifest Errors or Special Provisions (collectively referred to as Contingency Provisions). For the avoidance of doubt charges for calling a manifest error are excluded.

Deleted: National Grid

Formatted: Bullets and Numbering

14.30.23 An incentivised cost-recovery mechanism for such costs has been included within the internal System Operator BSUoS charge element. This cost-recovery mechanism operates on a monthly basis and provides that The Company is exposed to 40% of any Contingency Provision costs invoiced to it in any month, subject to an overall monthly cap on its exposure of £250,000*.

Formatted: Bullets and Numbering

Deleted: National Grid

14.30.24 Thus, if the Contingency Provision costs incurred exceed £625,000* (£250,000*/0.4) in any month, The Company will be allowed to recover 60% of the costs it incurs up to £625,000*, and all the costs in excess of

Formatted: Bullets and Numbering

Deleted: National Grid

* Subject to the indexation provisions given in the Transmission Licence

Deleted: 2

£625,000*. If costs are less than £625,000* then The Company will recover 60% of these costs.

Deleted: National Grid

14.30.25 The Company will calculate any allowable revenue associated with Contingency Provisions based on the invoices received in any particular month. The monthly revenue will then be recovered equally over the days in the following month. An invoice for the final month of the incentive scheme will be recovered in via the following incentive scheme in the next Financial Year.

Deleted: National Grid

Formatted: Bullets and Numbering

14.30.26 The monthly cost associated with Manifest Errors and Special Provisions (CP_m) are subject to a monthly incentivised cost recovery mechanism based on a monthly Contingency Provision sharing factor (CSF_m) and an offset for Contingency Provisions (OS_m). The daily cost ($MESP_d$) is calculated as follows:

Formatted: Bullets and Numbering

$$MESP_d = \frac{(1 - CSF_m)(CP_m - OS_m)}{NDM}$$

NDM = Number of Settlement Days in the calendar month over which these costs are recovered.

Formatted: Indent: Left: 2.54 cm

The values for the 2010/11 scheme, in 2007/08 forecast prices as given in the Transmission Licence, are shown in the table below.

Table 9.4

Formatted: Indent: Left: 2.52 cm

Formatted: Indent: Left: 1.27 cm

Formatted Table

CP_m	**CSF_m**	**OS_m**
0 <= CP_m < £625,000	0.4	£0
CP_m > £625,000	0	£250,000

Formatted: Indent: Left: 1.27 cm

Formatted: Left

14.31 Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in Chapter 9 using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in Chapter 9 using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Deleted: Chapter 10:

Formatted: Font: 14 pt, Font color: Auto

Formatted: Font color: Auto

Formatted: Font: 14 pt, Font color: Auto

Formatted: Bullets and Numbering

Formatted: Indent: Left: 2.54 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 2.54 cm, List tab + 2.65 cm, List tab + Not at 0.63 cm + 2.01 cm

Deleted: National Grid

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: 10.4

Formatted: Bullets and Numbering

Deleted: National Grid

Deleted: National Grid

Deleted: National Grid

Deleted: National Grid

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm

Deleted: National Grid

Deleted: National Grid

Deleted: 2

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

Formatted: Bullets and Numbering

Deleted: National Grid

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

Deleted: National Grid

Formatted: Bullets and Numbering

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

Formatted: Indent: Left: 3.81 cm

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Forecast incentivised internal controllable System Operator cost	CSOC	£	As defined in the Transmission Licence
Forecast incentivised internal System Operator capital expenditure	CSOCEC	£	As defined in the Transmission Licence

Deleted: 2

EXPRESSION	ACRONYM	Unit	Definition
Forecast incentivised internal System Operator operating costs	CSOOC	£	As defined in the Transmission Licence
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
External Incentive payment to date	$FKIncpayEXT_d$	£	Total External Incentive Payment to date up to and including settlement day d
Internal Incentive payment to date	$FKIncpayINT_d$	£	Total Internal Incentive Payment to date up to and including settlement day d
Forecast incentivised internal controllable System Operator cost	$FSOint_d$	£	Forecast incentivised internal controllable System Operator cost for the duration of the incentive scheme as at settlement day d
Total Forecast External incentive payment	$FYIncpayEXT_d$	£	Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d
Total Forecast Internal incentive payment	$FYIncpayINT_d$	£	Total forecast Internal incentive payment for the entire duration of the incentive scheme as at settlement day d
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
Daily Incentivised Balancing Cost	IBC_d	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
Daily External incentive payment	$IncpayEXT_d$	£	External Incentive payment for Settlement Day d
Daily Internal incentive payment	$IncpayINT_d$	£	Internal Incentive payment for Settlement Day d
Outage Cost Adjustment	IONT	£	As defined in the Transmission Licence
Non-Incentivised Costs	NC	£	As defined in the Transmission Licence

Deleted: 9.13

EXPRESSION	ACRONYM	Unit	Definition
Net Imbalance Volume Cost	NI_j	£	Total Net Energy Imbalance Volume ($TQEI_j$)*Net Imbalance Reference Price ($NIRP_j$)
Net Imbalance Adjustment	NIA_j	£	As defined on the Transmission Licence
Net Imbalance Reference Price	$NIRP_j$		As defined in the Transmission Licence
Non-controllable System Operator cost	NSOC	£	As defined in the Transmission Licence
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Outage change allowance amount	ON	£	As defined in the Transmission Licence
Pension Cost Allowance	P	£	As defined in the Transmission Licence
Incentivised Balancing Cost daily profiling factor	PFT_d		The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d
Daily Internal Scheme Target	PTint	£	Target for the Internal Incentive scheme as agreed with Ofgem
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Internal Scheme sharing factor	SFint		Sharing Factor for the internal incentive scheme as agreed with Ofgem
Tax Allowance	T	£	As defined in the Transmission Licence
Net Cost of Transmission Losses	$TLIC_j$	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC

Deleted: 2

EXPRESSION	ACRONYM	Unit	Definition
Transmission Losses Reference Price	$TLRP_j$		As defined in the Transmission Licence
Transmission Losses Target Volume	TLT_j	MWh	As defined in the Transmission Licence
Transmission Losses Volume	TLV_j	MWh	$\sum_i QM_{ij}$ – Sum of BM Unit Metered Volume (QM_{ij}) over all BM units
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC

14.32 Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

Deleted: Appendix BS-1
Formatted: Font: 14 pt
Deleted: ¶
¶
Formatted: Font: 14 pt
Formatted: Font: 14 pt, Font color: Auto

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.

Day 1

Calculation of the Daily External SO Incentive Scheme Payment

The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 + TL_1 + NI_1 - OM_1 - RT_1$$

$$= £800k + £300k + £200k + £300k - £50k - £0k - £0k$$

$$= £1550k$$

Assuming that	$CSOBM_1$	=	£800k
	$BSCCA_1$	=	£300k
	$BSCCV_1$	=	£200k
	TL_1	=	£300k
	NI_1	=	-£50k
	OM_1	=	£0k
	RT_1	=	£0k

Deleted: 2

Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:

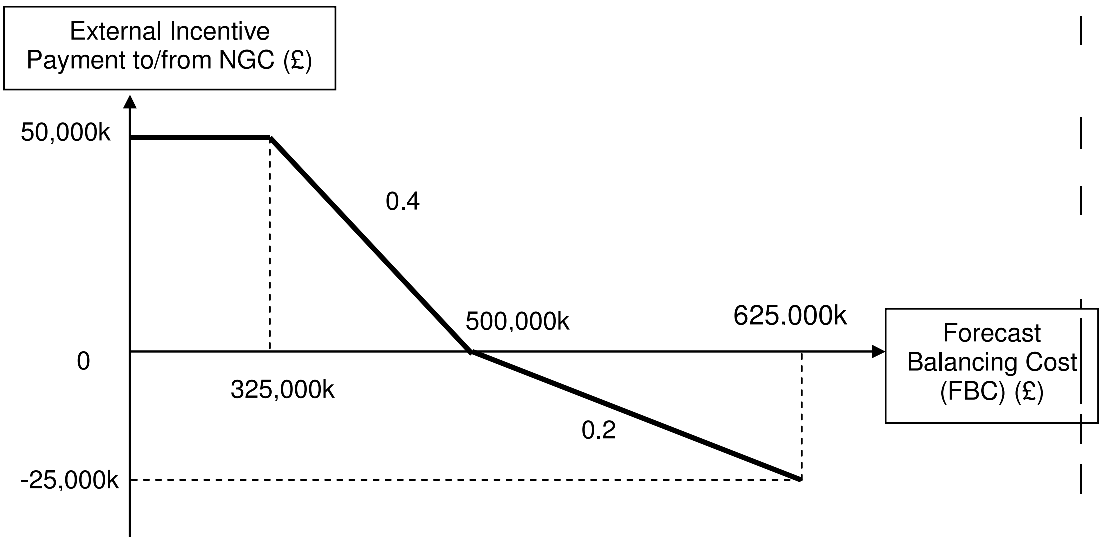
$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$
$$= \frac{£1550k}{1} * 365$$
$$= £565,750k$$

The values of SFext and OSext can now be read off table BS1 below. (These values are used purely for illustrative purposes). As FBC_1 is £565,750k, SFext is 0.2, OSext is £0 and BPext is £500,000k.

Table BS1

Forecast Balancing Cost (FBC_d)	BPext	SFext	OSext
£325,000,000 < FBC	£325,000,000	0	£50,000,000
£500,000,000 <= FBC > £325,000,000	£500,000,000	0.4	£0
£625,000,000 <= FBC > £500,000,000	£500,000,000	0.2	£0
FBC > £625,000,000	£625,000,000	0	£25,000,000

The table describes the external incentive scheme, which can also be illustrated by the graph below.



Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:

$$FYIncpayEXT_1 = SFext * (BPext - FBC_1) + OSext$$
$$= 0.2 * (£500{,}000k - £565{,}750k) + £0$$
$$= -£13{,}150k$$

In this case the incentive payment is negative (-£13,150k) i.e. a payment from The Company.

Deleted: National Grid

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$
$$= \frac{-£13{,}150K}{365} * 1$$
$$= -£36{,}027$$

Where:

NDS = Number of days in the external incentive scheme

The final step is to calculate today's external incentive payment ($IncpayEXT_1$ for day one), shown as follows:

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$
$$= -£36{,}027 - £0$$
$$= -£36{,}027$$

Calculation of the Daily Internal SO Incentive Scheme Payment

To carry this out, The Company will forecast monthly incentivised SO operating costs (CSOOC) and profile them to a daily basis. For this illustration, monthly costs for the first month of the scheme (April in our example) are assumed to be **£4,500k,** profiled down to a daily forecast of **£150k** (£450,000k divided by 30).

Deleted: National Grid

The calculation of the forecast SO internal operating cost for day one ($FSOINT_1$) is shown as follows:

$$FSOINT_1 = \frac{\sum_{k=1}^{d=1} CSOOC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$
$$= \frac{£150k}{1} * 365$$
$$= £54{,}750k$$

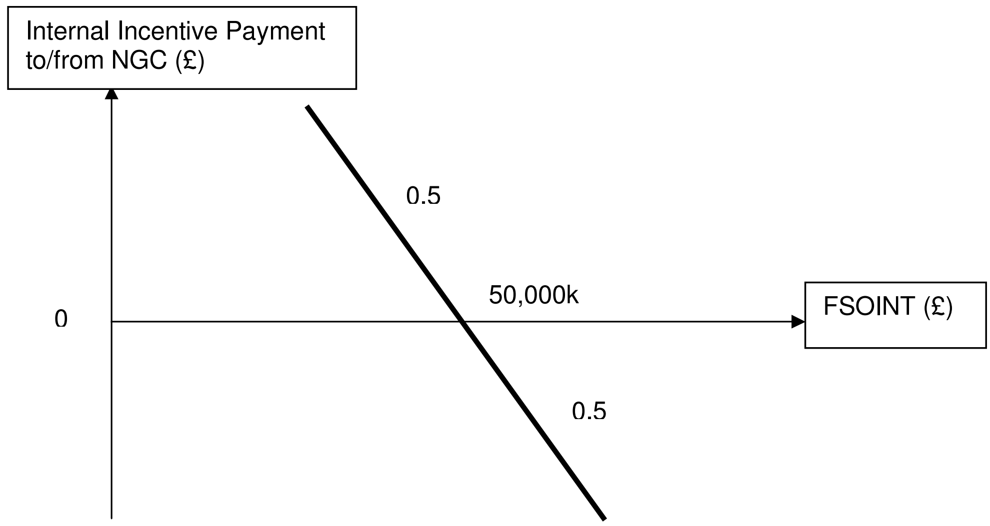
Deleted: 2

The relevant value of the **internal** incentive payment ($FYIncpayINT_1$) can then be calculated by reference to Table BS2 (figures shown for illustration only) and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast incentivised internal SO operating cost (FSOINT).

Table BS2

FSOINT	Ptint	SFint
FSOINT < £50,000k	£50,000k	0.5
FSOINT = £50,000k	£50,000k	0
FSOINT > £50,000k	£50,000k	0.5

The table describes the internal incentive scheme which can also be illustrated by the graph below.



Using the forecast internal operating cost for day one ($FSOINT_1$), the internal incentive payment for the duration of the scheme ($FYIncpayINT_1$) is calculated as follows:

$$FYIncPayINT_1 = (PT\text{int} - FSOINT_1) * SF\text{int}$$
$$= (£50{,}000k - £54{,}750k) * 0.5$$
$$= -£2{,}375k$$

The forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_1$) can then be used to calculate the forecast incentive payment to date ($FKIncpayINT_1$), shown as follows:

$$
\begin{aligned}
FKIncpayINT_1 &= \frac{FYIncpayINT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k \\
&= \frac{-£2{,}375k}{365} * 1 \\
&= -£6{,}507
\end{aligned}
$$

The final step is to calculate the Internal incentive payment ($IncpayINT_1$ for day one):

$$
\begin{aligned}
IncpayINT_1 &= (FKIncpayINT_1 - \sum_{k=0}^{d-1=0} IncpayINT_k) + MESP_1 \\
&= (£6{,}507 - £0) + £0 \\
&= -£6{,}507
\end{aligned}
$$

The costs associated with Manifest Errors and Special Provisions for day 1 ($MESP_1$) are assumed to be zero.

<u>Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:

$$
\begin{aligned}
BSUoSEXT_{11} = {} & CSOBM_{11} + BSCCV_{11} + [\ (IncpayEXT_1 + BSCCA_1 + ET_1 - OM_1) \\
& * \{ \left|\sum{}^{+}(QM_{i11} * TLM_{i11})\right| + \left|\sum{}^{-}(QM_{i11} * TLM_{i11})\right| \} / \sum_{j \in 1} \{ \left|\sum{}^{+}(QM_{ij1} * TLM_{ij1})\right| + \left|\sum{}^{-}(QM_{ij1} * TLM_{ij1})\right| \}\ ]
\end{aligned}
$$

For simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.

The illustration below shows the external BSUoS charge ($BSUoSEXT_{11}$) for Settlement Period one of Settlement Day 1.

The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_1 equation divided by 48 Settlement Periods).

CSOBM = £16,667
BSCCV = £4,167

Deleted: 2

The costs of the external SO Settlement Day variables are as follows:

IncpayEXT = £-36,027
BSCCA = £300k
ET = £0k
OM = £0k

$$
\begin{aligned}
BSUoSEXT_{11} &= £16{,}667 \;+ £4{,}167 \;+ \left[\; (-£36{,}027 + £300k + £0k \;- £0k\;)/48 \;\right] \\
&= £16{,}667 \;+ £4{,}167 \;+ £5{,}499 \\
&= £26{,}333
\end{aligned}
$$

Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can now be calculated using the following formula:

$$
BSUoSINT_{11} = (CSOC_1 + IncpayINT_1 + NSOC_1 + T_1 + P_1 + IAT_1 + BI_1 + ON_1 + IONT_1)
$$
$$
*\{\; \left|\sum^{+}(QM_{i11} * TLM_{i11})\;\right| + \left|\sum^{-}(QM_{i11} * TLM_{i11})\right| \;\}/\sum_{j\in 1}\{\; \left|\sum^{+}(QM_{i11} * TLM_{i11})\;\right| + \left|\sum^{-}(QM_{i11} * TLM_{i11})\right| \;\}
$$

As with the external BSUoS charge, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).

Table BS3 below shows the annual Internal SO costs assumed for this example:

Table BS3

Internal SO Cost Variable	Annual Cost (£m)
CSOOC	50
CSOCEC	9
T	4
NSOC	30
P	1
BI	4
ON	3
IAT, IONT	0

Income adjustments are assumed to be zero in this example for simplicity. If it is assumed that the incentivised internal SO operating costs (CSOOC) are £150k for day 1 and the incentivised SO capital expenditure costs (CSOCEC) (assumed on target) as well as the non-incentivised elements are recovered uniformly across the year (i.e. 1/365) then:

- CSOOC (incentivised Internal SO operating costs) = £150k
- CSOCEC (incentivised Internal SO capital expenditure) =£24, 657
- T (Tax allowance) = £13,699
- NSOC (Non controllable SO costs) = £82,192
- P (Pension allowance) = £2,740
- BI (BETTA preparation costs) = £32,876
- ON (Outage change allowance) = £8,219

$$\begin{aligned} BSUoSINT_{11} &= (£150k \; + (-£6507) + £24{,}657 + £13{,}699 \; + £82{,}192 \; + £2{,}740 \\ &\quad + £0 + £32876 + £0 + £0 + £8219 + £0 \;\;) / 48 \\ &= £6414 \end{aligned}$$

Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$\begin{aligned} BSUoSTOT_{11} &= BSUoSEXT_{11} + BSUoSINT_{11} \\ &= £26{,}333 + £5900 \\ &= £32{,}747 \end{aligned}$$

Deleted: 2

Day 2

Calculation of the Daily External SO Incentive Scheme Payment

Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 + TL_2 + NI_2 - OM_2 - RT_2$$

$$= £600k + £150k + £100k + £200k - £100k - £0 - £0$$

$$= £950k$$

Assuming that	$CSOBM_2$	=	£600k
	$BSCCA_2$	=	£150k
	$BSCCV_2$	=	£100k
	TL_2	=	£200k
	NI_2	=	-£100k
	OM_2	=	£0k
	RT_2	=	£0k

With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1550k + £950k)}{2} * 365$$

$$= £456{,}250k$$

The values of SFext, BPext and OSext can now be read off table BS1 given previously. As FBC_2 is £456,250k, SFext is now 0.4, BPext is £500,000k and OSext is 0, calculated as follows:

$$FYIncpayEXT_2 = SFext * (BPext - FBC_2) + OSext$$

$$= 0.4 * (£500{,}000k - £456{,}250k) + £0$$

$$= £17{,}500k$$

The external SO incentive payment for the entire duration of the incentive scheme ($FYincpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:

$$
\begin{aligned}
FKIncpayEXT_2 &= \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k \\
&= \frac{£17{,}500k}{365} * 2 \\
&= £95{,}890
\end{aligned}
$$

Where:

NDS = Number of days in the external incentive scheme

In this case the incentive payment is £95,890.

Again, the final step is to calculate today's external incentive payment ($IncpayEXT_2$ for day two), shown as follows:

$$
\begin{aligned}
IncpayEXT_2 &= FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k \\
&= £95{,}890 - -£36{,}027 \\
&= £131{,}917
\end{aligned}
$$

<u>Calculation of the Daily Internal SO Incentive Scheme Payment</u>

The first step is to calculate the forecast SO internal cost for day two ($FSOINT_2$). The same forecast of **£150k** for daily incentivised SO operating costs (CSOOC) used for day one is used for day two.

The calculation of the forecast SO internal cost ($FSOINT_2$) is shown as follows:

$$
\begin{aligned}
FSOINT_2 &= \frac{\sum_{k=1}^{d=2} CSOOC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS \\
&= \frac{(£150{,}000 + £150{,}000)}{2} * 365 \\
&= £54{,}750k
\end{aligned}
$$

Using the forecast SO internal cost ($FSOINT_2$), the forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_2$) can be calculated as follows (with reference to the values in Table BS2).

$$
\begin{aligned}
FYIncPayINT_2 &= (PT\text{int} - FSOINT_2) * SF\text{int} \\
&= (£50{,}000k - £54{,}750k) * 0.5 \\
&= -£2{,}375k
\end{aligned}
$$

The forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_2$) can then be used to calculate the forecast incentive payment to date ($FKIncpayINT_2$), shown as follows:

Deleted: 2

$$FKIncpayINT_2 = \frac{FYIncpayINT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$
$$= \frac{-£2,375k}{365} * 2$$
$$= -£13,014$$

The final step is to calculate the Internal incentive payment ($IncpayINT_2$ for day two).

$$IncpayINT_2 = (FKIncpayINT_2 - \sum_{k=0}^{d-1=1} IncpayINT_k) + MESP_2$$
$$= (-£13,014 - -£6,507) + £0$$
$$= -£6,507$$

The costs associated with Manifest Errors and Special Provisions for day 2 ($MESP_2$) are assumed to be zero.

As all of the internal cost variables are the same on day 1 as on day 2 the incentive payments for each of these days are identical.

<u>Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 of Settlement Day 2 can now be calculated using the following formula:

$$BSUoSEXT_{12} = CSOBM_{12} + BSCCV_{12} + [\ (IncpayEXT_2 + BSCCA_2 + ET_2 - OM_2)$$
$$* \{ \left|\sum{}^{+}(QM_{i12} * TLM_{i12})\ \right| + \left|\sum{}^{-}(QM_{i12} * TLM_{i12})\right| \} / \sum_{j \in 2} \{ \left|\sum{}^{+}(QM_{ij2} * TLM_{ij2})\ \right| + \left|\sum{}^{-}(QM_{ij2} * TLM_{ij2})\right| \}\ ]$$

As with day one, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).

The costs of the external SO Settlement Period variables are as follows:

CSOBM = £12,500
BSCCV = £2,083

The costs of the external SO Settlement Day variables are as follows:

IncpayEXT = £131,917
BSCCA = £150k
ET = £0k
OM = £0k

$$BSUoSEXT_{12} = £12,500 + £2,083 + [\ (£131,917 + £150k + £0k - £0k)/48\ ]$$
$$= £12,500 + £2,083 + £5,873$$
$$= £20,456$$

Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The Internal Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on Settlement Day 2 can now be calculated using the following formula:

$$BSUoSINT_{12} = (CSOC_2 + IncpayINT_2 + NSOC_2 + IAT_2 + BI_2 + ON_2 + IONT_2)$$
$$*\{ \left|\sum^{+}(QM_{i12} * TLM_{i12})\right| + \left|\sum^{-}(QM_{i12} * TLM_{i12})\right| \} / \sum_{j\in 2}\{ \left|\sum^{+}(QM_{i12} * TLM_{i12})\right| + \left|\sum^{-}(QM_{i12} * TLM_{i12})\right| \}$$

As with the external BSUoS charge, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day (1/48).

The Settlement Day 2 costs of the internal SO cost variables assigned to Settlement period 1 (based on values from Table BS3) are as follows:

$$BSUoSINT_{12} = (£150k \ + (-£6507) + £24{,}657 + £13{,}699 \ + £82{,}192 \ + £2{,}740 \ + £0 + £32876 + £0 + £0 + £82$$
$$= £6414$$

Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{12}$) for Settlement Period 1 on Settlement Day 2.

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}456 + £6414$$
$$= £26{,}870$$

Deleted: 2

Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

<u>Calculation of the Daily External SO Incentive Scheme Payment</u>

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} + TL_{365} + NI_{365} - OM_{365} - RT_{365}$$

$$= £700k + £\,200k + £150k + £200k - £50k - £0 - £0$$

$$= £1{,}200k$$

Assuming that	$CSOBM_{365}$	=	£700k
	$BSCCA_{365}$	=	£200k
	$BSCCV_{365}$	=	£150k
	TL_{365}	=	£200k
	NI_{365}	=	-£50k
	OM_{365}	=	£0k
	RT_{365}	=	£0k

With $\sum_{364} IBC_d$ assumed to be £432,000k for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000k + £1{,}200k}{365} * 365$$

$$= £433{,}200k$$

The values of SFext, BPext and OSext can now be read off table BS1. As FBC_{365} is £433,200k, SFext is now 0.4, BPext is £500,000k and OSext is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SFext * (BPext - FBC_{365}) + OSext$$

$$= 0.4 * (£500{,}000k - £433{,}200k) + £0$$

$$= £26{,}720k$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculated the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$

$$= \frac{£26{,}720k}{365} * 365$$

$$= £26{,}720k$$

Where:

NDS = Number of days in the external incentive scheme

In this case the incentive payment is positive (£26,720k) i.e. a payment to The Company. As this is the last day of the scheme this represents the overall incentive payment due to The Company i.e. with reference to the graph with Table BS1 40% of the difference between £500,000k and £433,200k.

Deleted: National Grid

Deleted: National Grid

Again, the final step is to calculate today's external incentive payment ($IncpayEXT_{365}$ for day 365), shown as follows:

It has been assumed that the total incentive payments for the previous 364 days ($\xi_{k=0\equiv364} IncpayEXT_k$) is £26,237,400.

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$

$$= £26{,}720{,}000 - £26{,}237{,}400$$

$$= £482{,}600$$

Calculation of the Daily Internal BSUoS Charge

Again, the first step is to calculate the forecast SO internal cost for day 365 ($FSOINT_{365}$).

To carry this out, The Company will forecast monthly incentivised SO operating costs (CSOOC) and profile them to a daily basis. For this illustration, monthly costs for the final month of the scheme (March in our example) are assumed to be **£4,000k,** profiled down to a daily forecast of **£129,032** (£4,000k divided by 31).

Deleted: National Grid

If $FSOINT_{364}$ is assumed to be £52,000k, the calculation of the forecast SO internal operating cost ($FSOINT_{365}$) is shown as follows:

$$FSOINT_{365} = \frac{\sum_{k=1}^{d=365} CSOOC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£52{,}000k + £129{,}032}{365} * 365$$

$$= £52{,}129{,}032$$

Using the forecast SO internal operating cost ($FSOINT_{365}$), the forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_{365}$) can be calculated as follows:

Deleted: 2

$$FYIncPayINT_{365} = (PT\text{int} - FSOINT_{365}) * SF\text{int}$$
$$= (£50{,}000{,}000 - £52{,}129{,}032) * 0.5$$
$$= -£1{,}064{,}516$$

The forecast internal SO incentive payment for the duration of the scheme ($FYIncpayINT_{365}$) can then be used to calculate the forecast incentive payment to date ($FKIncpayINT_{365}$), shown as follows:

$$FKIncpayINT_{365} = \frac{FYIncpayINT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$
$$= \frac{-£1{,}064{,}516}{365} * 365$$
$$= -£1{,}064{,}516$$

In this case the incentive payment is negative (-£1,065k) i.e. a payment from The Company. As this is the last day of the scheme this represents the overall incentive payment due from The Company i.e. with reference to the graph with Table BS2 50% of the difference between £50,000k and £52,129k.

Deleted: National Grid

Deleted: National Grid

The final step is to calculate the Internal incentive payment ($IncpayINT_{365}$ for day 365). It has been assumed that the total incentive payments for the previous 364 days ($\xi_{k=0\equiv364} IncpayINT_k$) is £1,056,145.

$$IncpayINT_{365} = (FKIncpayINT_{365} - \sum_{k=1}^{d-1=364} IncpayINT_k) + MESP_{365}$$
$$= (-£1{,}064{,}516 - -£1{,}056{,}145) + £0$$
$$= -£8{,}371$$

The costs associated with Manifest Errors and Special Provisions for day 365 ($MESP_{365}$) are assumed to be zero.

Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j

The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 of Settlement Day 365 can now be calculated using the following formula:

$$BSUoSEXT_{1365} = CSOBM_{1365} + BSCCV_{1365} + [\ (IncpayEXT_{365} + BSCCA_{365} + ET_{365} - OM_{365})$$
$$* \{ \left|\sum{}^{+}(QM_{i1365} * TLM_{i1365})\right| + \left|\sum{}^{-}(QM_{i1365} * TLM_{i1365})\right| \} / \sum_{j\in 365} \{ \left|\sum{}^{+}(QM_{ij365} * TLM_{ij365})\right| + \left|\sum{}^{-}(QM_{ij365} * TLM_{ij365})\right| \}\ ]$$

As with day one, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day (1/48).

The costs of the external SO Settlement Period variables are as follows:

CSOBM = £14,583
BSCCV = £3,125

The costs of the external SO Settlement Day variables are as follows:

IncpayEXT = £482,600
BSCCA = £200k
ET = £0k
OM = £0k

$$BSUoSEXT_{365} = £14{,}583 + £3{,}125 + [\ (£482{,}600 + £200k + £0k - £0k\ )/48\ ]$$
$$= £14{,}583 + £3{,}125 + £14{,}221$$
$$= £31{,}929$$

<u>Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The Internal Balancing Services Use of System (BSUoS) charge for Settlement Period 1 of Settlement Day 365 can now be calculated using the following formula:

$$BSUoSINT_{1,365} = (CSOC_{365} + IncpayINT_{365} + SOBR_{365} + NSOC_{365} + PSC_{365} + IAT_{365} + BI_{365} + TSPN_{365} + TSHN_{365} + ON_{365} + IONT_{365})$$
$$*\{\ \left|\sum^{+}(QM_{i1,365} * TLM_{i1,365})\right| + \left|\sum^{-}(QM_{i1,365} * TLM_{i1,365})\right|\ \} / \sum_{j\in 365}\{\ \left|\sum^{+}(QM_{i1,365} * TLM_{i1,365})\right| + \left|\sum^{-}(QM_{i1,365} * TLM_{i1,365})\right|\ \}$$

As with the external BSUoS charge, for simplicity, the BM Unit Metered Volume (QM_{ij}) is assumed to be the same in all half hour Settlement Periods in a Settlement Day (1/48).

The Settlement Day 365 costs of the internal SO cost variables assigned to Settlement Period 1 (based on values from Table BS3) are as follows:

$$BSUoSINT_{1,365} = (£129{,}032 + (-£8371) + £24657 + £13{,}699 + £82{,}192 + £2{,}740 + £0 + £32{,}876 + £0 +$$
$$= £5{,}938$$

<u>Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j</u>

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365

$$BSUoSTOT_{1,365} = BSUoSEXT_{1,365} + BSUoSINT_{1,365}$$
$$= £31{,}929 + £5{,}938$$
$$= £37{,}867$$

Deleted: 2

~~Glossary~~

Formatted: Strikethrough

~~The following definitions are intended to assist the reader's understanding of this document. In the event of conflict with definitions given elsewhere, those used in the Electricity Act 1989 (as amended by the Utilities Act 2000 and Energy Act 2004), Transmission Licence, Grid Code, Balancing and Settlement Code and Connection and Use of System Code take precedence.~~

~~For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.~~

~~10 Clear Days~~	~~Defined as 10 complete periods of 24 hours from 00:00hrs to 24:00hrs~~
~~Act~~	~~the Electricity Act 1989 as amended by the Utilities Act 2000 and the Energy Act 2004~~
~~Additional Load~~	~~Site Load other than Station Load and importing Generating Units for processes other than the production of electricity~~
~~Ancillary Services~~	~~Has the meaning given to that expression in the Transmission Licence~~
~~Applicable Value~~	~~The highest contractual Transmission Entry Capacity figure for year "t" provided to~~ The Company ~~in line with the process laid out in the CUSC up to and including 31 October in year "t-1" for publication in the October update of the Seven Year Statement~~
~~Authority~~	~~The Gas and Electricity Markets Authority (Ofgem)~~
~~Balancing and Settlement Code (BSC)~~	~~As defined in the Transmission Licence~~
~~Balancing Mechanism~~	~~As defined in the Transmission Licence~~
~~Bid~~	~~Defined in the BSC as:~~ ~~"The quantity (as provided in Section Q4.1.3(a)) in a Bid-Offer Pair if considered as a possible decrease in Export or increase in Import of the relevant BM Unit at given time"~~
~~Bilateral Agreement~~	~~Means, in relation to a User, a Bilateral Connection Agreement or a Bilateral Embedded Generation Agreement between~~ The Company ~~and the User, as defined in Standard Condition C1 of the Transmission Licence~~
~~Bilateral Connection Agreement~~	~~As defined in Standard Condition C1 of the Transmission Licence~~
~~Bilateral Embedded Generation Agreement~~	~~As defined in Standard Condition C1 of the Transmission Licence~~

Deleted: ~~National Grid~~

Deleted: ~~National Grid~~

~~**BM Unit**~~	~~Defined in the BSC as:~~ ~~"a unit established and registered (or to be established and registered) by a Party in accordance with section K3 [of the BSC]"~~
~~**BM Unit Metered Volume "QM_{ij}"**~~	~~Defined in the BSC as:~~ ~~"In respect of a Settlement Period:~~ ~~(i) in relation to a BM Unit (other than an Interconnector BM Unit) comprising CVA Metering Systems, the Metered Volume (as determined in accordance with Section R [of the BSC]);~~ ~~(ii) in relation to an Interconnector BM Unit, the quantity determined in accordance with Section R7.4.2 [of the BSC];~~ ~~(iii) in relation to an Interconnector Error Administrator BM Unit, the quantity determined in accordance with Section T4.1;and~~ ~~(iv) in relation to a Supplier BM Unit, the quantity determined in accordance with section T4.2.1 [of the BSC]."~~
~~**Central Volume Allocation**~~	~~Defined in the BSC as:~~ ~~"the determination of quantities of Active Energy to be taken into account for the purposes of Settlement in respect of Volume Allocation Units"~~
~~**Consumption**~~	~~Defined in the BSC in relation to a Consumption BM Unit as:~~ ~~"means a BM Unit which:~~ ~~i.) in the case of a BM Unit other than an Interconnector BM Unit, is classified as a Consumption BM Unit in accordance with the provisions of Section K 3.5.2 [of the BSC] or in the case of an Exempt Export BM Unit, the Lead Party has elected to treat as a Consumption BM Unit pursuant to Section K 3.5.5 [of the BSC]~~ ~~ii.) In the case of an Interconnector BM Unit, is designated by the CRA as a 'Consumption' BM Unit pursuant to Section K 5.5.5 [of the BSC]"~~
~~**DCLF**~~	~~Direct Current Loadflow~~
~~**Delivering**~~	~~As defined in the BSC~~
~~**Demand**~~	~~Electricity consumed at sites or by equipment not owned and operated by transmission licensees~~
~~**Designated sum**~~	~~As defined in Standard Condition C13 of the Transmission Licence.~~
~~**Directly-connected User**~~	~~A large, usually industrial, consumer of electricity who is directly connected to the GB transmission system~~

Formatted: Indent: Left: 0 cm, Hanging: 1.23 cm, Outline numbered + Level: 6 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 3.17 cm + Tab after: 3.81 cm + Indent at: 3.81 cm, Tabs: Not at 3.81 cm

Formatted: Indent: Left: 0 cm, Hanging: 1.27 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1.27 cm + Indent at: 0 cm

Deleted: 2

~~**Distribution Interconnector**~~	~~Defined in the BSC as:~~ ~~"An Interconnector whose connection to the Total System is only to a Distribution System"~~
~~**Distribution System**~~	~~As defined in the BSC:~~
~~**Eligible small generator**~~	~~Defined as eligible generator in Standard Condition C13 of the Transmission Licence.~~
~~**Embedded**~~	~~Direct connection to a distribution system or the system of any other User to which Users and /or Power Stations are connected~~
~~**Exempt Export BM Unit**~~	~~Defined in the BSC as:~~ ~~"A BM Unit which comprises Exemptible Generating Plant, for which the Lead Party is the Party responsible for Exports, subject to Section K3.3A;"~~
~~**Exemptible Generation**~~	~~Generating plant where the party generating electricity at that generating plant is, or would (if it generated electricity at no other generating plant and/or did not hold a generation licence) be, exempt from the requirement to hold a generation licence (including Scottish generation that export between 50 and 100MW that was connected on or before 30 September 2000).~~
~~**Export**~~	~~Defined in the BSC as:~~ ~~"in relation to a party, a flow of electricity from any Plant or apparatus (not comprising of the Total System) of that party to the Plant or apparatus (comprising part of the Total System) of a party."~~
~~**Final Reconciliation Settlement Run**~~	~~Defined in the BSC as:~~ ~~"the last required Timetabled Reconciliation Settlement Run"~~
~~**Final Reconciliation Volume Allocation Run**~~	~~Defined in the BSC as:~~ ~~"the last required Timetabled Reconciliation Volume Allocation Run"~~
~~**Financial Year**~~	~~The period of 12 months ending on 31st March in each calendar year~~
~~**Generating Unit**~~	~~As defined in the Grid Code~~
~~**Generation Capacity**~~	~~Defined in the BSC as:~~ ~~normal full load capacity of a Generating Unit as declared by the Generator, less the MW consumed by the Generating Unit through the Generating Unit's unit transformer when producing the same~~
~~**Generator**~~	~~A person who generates electricity under licence or exemption under the Act~~

~~**Genset**~~	~~Is used to have the same meaning as Generating Unit as defined by the Grid Code~~
~~**Good industry practice**~~	~~In relation to any undertaking and any circumstances, the exercise of that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced operator in the same type of undertaking under the same or similar circumstances~~
~~**Grid Code**~~	~~A document prepared by the licensee in accordance with Standard Condition C14 of the Transmission Licence setting out the technical parameters for the operation and use of the transmission system and of plant and apparatus connected to the transmission system~~
~~**Grid Supply Point (GSP)**~~	~~A point of delivery from the GB Transmission System to a distribution system or Non-Embedded User~~
~~**GSP Group**~~	~~Is used to have the same meaning as in the BSC~~
~~**Import**~~	~~Defined in the BSC as:~~ ~~"in relation to a party, a flow of electricity to any Plant or Apparatus (not comprising part of the Total System) of that Party from the Plant or Apparatus (comprising part of the Total System) of a Party."~~
~~**Income Adjusting Event**~~	~~Has the meaning given to that expression in the Transmission Licence~~
~~**Initial Settlement Run**~~	~~Is used to have the same meaning as in the BSC~~
~~**Initial Volume Allocation Run**~~	~~As defined in the BSC~~
~~**Interconnector**~~	~~As defined in the BSC~~
~~**Interconnector Asset Owner**~~	~~The owner of the Interconnector~~
~~**ICRP**~~	~~Investment Cost Related Pricing~~
~~**Less than 100MW**~~	~~Is defined as not having the capability to export 100MW to the Total System~~
~~**Licensable Generation**~~	~~Generating plant that is not Exemptible Generation.~~
~~**Natural Demand**~~	~~The Demand (active power) which is necessary to meet the needs of customers excluding that Demand (active power) met by embedded generating units whose generation is not traded by trading parties through energy metering systems registered under the BSC~~

Deleted: 2

~~**Net Demand**~~	~~Sum of the BM Unit Metered Volumes (QM_{ij}) of the Trading Unit during the three Settlement Periods of the Triad expressed as a positive number (i.e. $\sum QM_{ij}$.)~~
~~**GB Transmission System**~~	~~The system consisting (wholly or mainly) of high voltage electric lines owned by the transmission licensees and operated by The Company and used for the transmission of electricity from one Power Station to a substation or to another Power Station or between substations or to or from any External Interconnection and includes any Plant and Apparatus and meters owned by the transmission licensees and operated by The Company in connection with the transmission of electricity but does not include any Remote Transmission Assets~~
~~**Non-embedded User**~~	~~A User, except an Electricity Distributor, receiving electricity direct from the GB Transmission System irrespective of from whom it is supplied~~
~~**Offer**~~	~~Defined in the BSC as:~~ ~~"The quantity (as provided in Section Q4.1.3 (a)) in a Bid-Offer pair if considered as a possible increase in Export or decrease in Import of the relevant BM Unit at a given time"~~
~~**Offtaking**~~	~~As defined in the BSC~~
~~**Ownership boundary**~~	~~Shall be the boundary defined by Clause 2.12 of the Connection and Use of System Code~~
~~**Power Station**~~	~~Defined in the Grid Code as:~~ ~~"an installation comprising one or more Generating Units (even where sited separately) owned and/or controlled by the same Generator, which may be reasonably considered as being managed as one Power Station."~~
~~**Production**~~	~~Defined in the BSC in relation to a Production BM Unit as:~~ ~~"means a BM Unit which:~~ i.) ~~In the case of a BM Unit other than an interconnector BM Unit, is classified as a Production BM Unit in accordance with the provisions of Section K 3.5.2 [of the BSC] or in the case of an Exempt Export BM Unit, the Lead Party has elected to treat as a Production BM Unit pursuant to Section K 3.5.5 [of the BSC]~~ ii.) ~~In the case of an Interconnector BM Unit, is designated by the CRA as a 'Production' BM Unit pursuant to Section K 5.5.5 [of the BSC]"~~
~~**Reconciliation Settlement Run**~~	~~Defined in the BSC as:~~ ~~"A Timetabled Reconciliation Settlement Run or an Ad Hoc Settlement Run"~~
~~**Registered Capacity**~~	~~As defined in the Grid Code~~

Deleted: National Grid

Deleted: National Grid

Formatted: Indent: Left: 0 cm, Hanging: 1.27 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 0 cm + Tab after: 1.27 cm + Indent at: 0 cm

~~**Security Standard**~~	~~GB Transmission System Security and Quality of Supply Standard~~
~~**Settlement Administration Agent (SAA)**~~	~~Defined in the BSC as:~~ ~~"the BSC Agent for Settlement Administration in accordance with Section E [of the BSC]."~~
~~**Settlement Day**~~	~~has the meaning given to that expression in the BSC~~
~~**Settlement Period**~~	~~Defined in the BSC as:~~ ~~"Settlement Period j starts at the spot time occurring at the beginning of the half hour and ends at the spot time occurring exactly 30 minutes later. The spot time at the beginning of one period therefore coincides with the spot time at the end of the previous period."~~
~~**Settlement Run**~~	~~Defined in the BSC as:~~ ~~"a determination (in accordance with Section T), in relation to a Settlement Day, of amounts giving rise, on the part of Trading Parties and the Transmission Company, to a liability to pay or a right to be paid by the BSC Clearer amounts in respect of Trading Charges in each Settlement Period in that Settlement Day, and of the net credit or debit in respect of such amounts; and where the context requires a reference to a Settlement Run includes the data and information produced by the SAA following such a determination and delivered to the FAA in accordance with Section N"~~
~~**Site Load**~~	~~May comprise Station Load and Additional Load.~~ ~~The sum of the BM Unit Metered Volumes~~ (QM_{ij})~~, expressed as a positive number, of BM Units within the Trading Unit with~~ QM_{ij} ~~less than zero during the three Settlement Periods of the Triad (i.e.~~ $\sum QM_{ij}$ ~~where~~ $QM_{ij}<0$)
~~**Small Power Station**~~	~~As defined in the Grid Code~~
~~**Sole Trading Unit**~~	~~Defined in the BSC as:~~ ~~"a Trading Unit comprising a single BM Unit as described in Section K4.1.3 [of the BSC]."~~
~~**Station Load**~~	~~The Station Load is equal to the sum of the demand of BM Units solely comprising the Station Transformers within the Power Station. For the avoidance of doubt, Station Load excludes BM Units comprising Additional Load~~
~~**Station Transformer**~~	~~Defined in the Grid Code "as a transformer supplying electrical power to the auxiliaries of a power station which is not directly connected to the generating unit terminals."~~
~~**Supplier**~~	~~A holder of an electricity supply licence~~

Deleted: 2

~~**Supplier Half Hourly Demand**~~	~~Means BM Unit Metered Volumes (QM_{ij}) expressed as a positive number (i.e. $\sum QM_{ij}$) of the Trading Unit during the three Settlement Periods of the Triad due to half-hourly metered imports~~
~~**Supplier Non Half-Hourly Demand**~~	~~Means BM Unit Metered Volumes (QM_{ij}) expressed as a positive number (i.e. $\sum QM_{ij}$) of the Trading Unit over the charging year between Settlement Periods 33 to 38 due to Non-half-hourly metered imports~~
~~**Supplier Volume Allocation**~~	~~Defined in the BSC as:~~ ~~"the determination of quantities of Active Energy to be taken into account for the purposes of Settlement in respect of Supplier BM Units"~~
~~**Total System**~~	~~Has the meaning given to that expression in Standard Condition C1 of the Transmission Licence.~~
~~**Trading Party**~~	~~As defined in the BSC~~
~~**Trading Unit**~~	~~Defined in the BSC as:~~ ~~"a BM Unit or a combination of BM Units established in accordance with and satisfying the requirements of Section K4 [of the BSC]"~~
~~**Transmission Entry Capacity (TEC)**~~	~~As defined in the Connection and Use of System Code~~
~~**Transmission Licence**~~	~~The licence granted to National Grid Company plc, Scottish Power Transmission ltd and Scottish-Hydro Transmission ltd under the Act~~
~~**Transmission Network Use of System Demand Reconciliation Charges**~~	~~Has the meaning given in the Connection and Use of System Code~~
~~**Transmission Owner Activity**~~	~~The function of Transmission Licensees Transmission Business covered under the Transmission Owner Activity Price Control~~
~~**Transmission voltage**~~	~~In Scotland voltages of 132kV and above; in England and Wales voltages above 132kV - usually 275kV and 400kV~~
~~**Triad**~~	~~Is used as a short hand way to describe the three settlement periods of highest transmission system demand, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 Clear Days, between November to February inclusive~~

~~Index to the Statement of the Use of System Charging Methodology (Issue 6) Revisions~~

~~Issue 6~~	~~Modifications~~	~~Changes to Pages~~
~~Revision 1~~	~~Revisions to incorporate mid-year charge changes~~	
~~Revision 2~~	~~Revisions to update offshore charging~~	
~~Revision 3~~	~~Revised Interconnector Charging Arrangements~~	~~Sections 4 & 5, TN5 & 6~~
~~Revision 4~~	~~Revision to remove end of Scheme Year Reconciliation Process~~	~~Chapter 10~~

Deleted: 2

Page 46: [1] Deleted **andy.wainwright** **31/01/2011 18:19:00**

~~National Grid~~

Page 46: [1] Deleted **andy.wainwright** **30/03/2011 11:59:00**

~~6~~

Page 47: [2] Deleted **andy.wainwright** **31/01/2011 18:19:00**

~~**NATIONAL GRID**~~

Page 47: [2] Deleted **andy.wainwright** **17/03/2011 13:34:00**

~~**66**~~

Page 53: [3] Formatted **andy.wainwright** **16/03/2011 20:52:00**

Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 5 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm

Page 54: [4] Formatted **andy.wainwright** **17/03/2011 13:24:00**

Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Page 54: [5] Formatted **andy.wainwright** **17/03/2011 13:24:00**

Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Page 54: [6] Formatted **andy.wainwright** **17/03/2011 13:24:00**

Indent: Left: 2.54 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 1 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 2.54 cm + Indent at: 2.54 cm, Tabs: Not at 2.54 cm

Page 54: [7] Formatted **andy.wainwright** **16/03/2011 20:54:00**

Normal, Left, Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 5 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm, Tabs: Not at 2.54 cm

Page 54: [8] Formatted **andy.wainwright** **16/03/2011 20:55:00**

Font: (Default) Arial, 11 pt

Page 54: [9] Formatted **andy.wainwright** **16/03/2011 20:55:00**

Font: (Default) Arial, 11 pt

Page 54: [10] Formatted **andy.wainwright** **16/03/2011 20:56:00**

Normal, Left, Indent: Left: 2.54 cm, No bullets or numbering, Tabs: Not at 2.54 cm

Page 54: [11] Formatted **andy.wainwright** **16/03/2011 20:55:00**

Font: (Default) Arial, 11 pt

Page 54: [12] Formatted **andy.wainwright** **16/03/2011 20:55:00**

Font: (Default) Arial, 11 pt

Page 54: [13] Formatted **andy.wainwright** **16/03/2011 20:55:00**

Font: (Default) Arial, 11 pt

Page 54: [14] Formatted **andy.wainwright** **16/03/2011 20:55:00**

Font: (Default) Arial, 11 pt

Page 54: [15] Formatted **andy.wainwright** **16/03/2011 20:56:00**

Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 5 + Alignment: Left + Aligned at: 1.27 cm + Tab after: 1.27 cm + Indent at: 2.87 cm

Page 76: [16] Formatted **andy.wainwright** **17/03/2011 13:24:00**

Indent: Left: 2.54 cm, Bulleted + Level: 1 + Aligned at: 0 cm + Tab after: 0.63 cm + Indent at: 0.63 cm, Tabs: 2.54 cm, List tab + 2.63 cm, List tab + Not at 0.63 cm + 2 cm

Page 80: [17] Formatted **andy.wainwright** **17/03/2011 13:24:00**

Indent: Left: 2.87 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 3 + Alignment: Left + Aligned at: 0 cm + Tab after: 1 cm + Indent at: 1 cm, Tabs: 2.62 cm, List tab + Not at 1 cm + 2.25 cm

Page 80: [18] Formatted **andy.wainwright** **17/03/2011 13:24:00**

Indent: Left: 2.87 cm, Numbered + Level: 1 + Numbering Style: i, ii, iii, … + Start at: 3 + Alignment: Left + Aligned at: 0 cm + Tab after: 1 cm + Indent at: 1 cm, Tabs: 2.62 cm, List tab + Not at 1 cm + 2.25 cm