Stage 04: Code Administrator Consultation Volume 2

Connection and Use of System Code (CUSC)

CMP207 Limit increases to TNUoS tariffs to 20% in any one year

This document contains the draft legal text for Section 14 and the Workgroup Consultation Responses.

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

Version	Published on	Author	Change Reference
1.0	3 October 2012	Code Administrator	Version to the Industry.

1 Proposed Legal Text

Original

~~CUSC v1.2~~

Deferred Zonal Demand Tariff (£/kW)

Deleted: Final £/kW Tariff

14.15.82 Where, in accordance with paragraph 14.15.88, there is a carry over of revenue from the previous charging year this will be known as **Deferred Zonal Revenue** and will be collected through the **Deferred Zonal Demand Tariff**. Deferred Zonal Revenue will be carried over to the following charging year on a zonal basis incorporating any adjustment as defined in National Grid's electricity transmission licence.

14.15.83 Deferred Zonal Demand Tariffs will be derived through the division of the Deferred Zonal Revenue for each demand zone by the current Total Forecast Metered Triad Demand for that zone:

$$DZDT_{Di} = \frac{DZR_{Di}}{D_{Di}}$$

Where
DZDT = Deferred Zonal Demand Tariff (£/kW)
DZR = Deferred Zonal Revenue (£m);

Final £/kW Tariff

14.15.84 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, the local tariff, and the deferred zonal demand tariff:

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

Where
ET = Effective TNUoS Tariff expressed in £/kW

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

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

14.15.86 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

14.15.87 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:

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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)

14.15.88 If the final demand TNUoS tariff is found, after accounting for the impact of the Retail Price Index (RPI), to be 20% higher or lower than the value of the previous year's final demand TNUoS tariff, then the final demand TNUoS tariff shall be capped, or collared as appropriate, to a 20% limit based on the previous year's tariff, $FT_{Di(Y-1)}$:

If $FT_{DiY} < 0.8 \times FT_{Di(Y-1)} \times (1 + RPI)$ then $FT_{DiY} = 0.8 \times FT_{Di(Y-1)} \times (1 + RPI)$

If $FT_{DiY} > 1.2 \times FT_{Di(Y-1)} \times (1 + RPI)$ then $FT_{DiY} = 1.2 \times FT_{Di(Y-1)} \times (1 + RPI)$

Any revenue excess or deficit arising as a result of this capping or collaring shall be recorded on a zonal basis and recovered in the following financial year accounting for any adjustments as defined in National Grid's electricity transmission licence.

14.15.89 In the event of a change to the TNUoS charging methodology that has the potential for significant change to the derivation of demand TNUoS tariffs, then the use of the process described in paragraph 14.15.88 for the following year's demand TNUoS tariffs will be reviewed by National Grid.

14.15.90 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**.**

14.15.91 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*.*

14.15.92 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.

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- 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.

14.15.93 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.

14.15.94 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**.

14.15.95 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.

14.15.96 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

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

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

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:

$$\frac{527.59\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£9.56/kW}}$$

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(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.

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 = **£22.54/kW**

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 following further adjustments:

- allowance for the minimum £0/kW demand charge;
- inclusion of the deferred zonal demand tariff to recover any deferred revenue from the prior charging year;
- a cap/collar arrangement of 20% for the final demand tariff against the prior year's final demand tariff, accounting for RPI.

(viii) The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

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14.28 Stability & Predictability of TNUoS tariffs

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.

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.

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.

- 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.

Finally, for final demand tariffs a 20% cap / collar arrangement exists to ensure that the year on year change to any final demand tariff cannot be greater than 20%. As a result, any significant step change in final demand tariffs is staggered across one or more years.

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.

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.

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.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- 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.

1 http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Deferred Zonal Demand Tariff (£/kW)

Deleted: Final £/kW Tariff

14.15.82 Where, in accordance with paragraph 14.15.88, there is a carry over of revenue from the previous charging year this will be known as **Deferred Zonal Revenue** and will be collected through the **Deferred Zonal Demand Tariff**. Deferred Zonal Revenue will be carried over to the following charging year on a zonal basis incorporating any adjustment as defined in National Grid's electricity transmission licence.

14.15.83 Deferred Zonal Demand Tariffs will be derived through the division of the Deferred Zonal Revenue for each demand zone by the current Total Forecast Metered Triad Demand for that zone:

$$DZDT_{Di} = \frac{DZR_{Di}}{D_{Di}}$$

Where
DZDT = Deferred Zonal Demand Tariff (£/kW)
DZR = Deferred Zonal Revenue (£m);

Final £/kW Tariff

14.15.84 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, the local tariff, and the deferred zonal demand tariff:

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

Where
ET = Effective TNUoS Tariff expressed in £/kW

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

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

14.15.86 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

14.15.87 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)

14.15.88 If the final demand TNUoS tariff is found, after accounting for the impact of changes in the Retail Price Index (RPI), to be 20% higher or lower than the value of the appropriate **Preliminary Forecast Demand TNUoS tariff** defined in paragraph 14.15.97, then the final demand TNUoS tariff shall be capped, or collared as defined in the formulae below:

If $FT_{DiY} < 0.8 \times PFDT_{Di(Y-1)} \times (1+RPI)$ then $FT_{DiY} = 0.8 \times PFDT_{Di(Y-1)} \times (1+RPI)$

If $FT_{DiY} > 1.2 \times PFDT_{Di(Y-1)} \times (1+RPI)$ then $FT_{DiY} = 1.2 \times PFDT_{Di(Y-1)} \times (1+RPI)$

Where
$PFDT_{Di(Y-1)}$ = Preliminary Forecast Demand TNUoS tariff published as defined in paragraph 14.15.97.

Any revenue excess or deficit arising as a result of this capping or collaring shall be recorded on a zonal basis and recovered in the following financial year accounting for any adjustments as defined in National Grid's electricity transmission licence.

14.15.89 In the event of a change to the TNUoS charging methodology that has the potential for significant change to the derivation of demand TNUoS tariffs, then the use of the process described in paragraph 14.15.88 for the following year's demand TNUoS tariffs will be reviewed by National Grid.

14.15.90 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**.**

14.15.91 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.

14.15.92 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.

14.15.93 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.

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14.15.95 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.

14.15.96 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

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

14.15.98 National Grid will publish, by the end of January of each year, a forecast of £/kW Zonal Demand TNUoS tariffs for the charging year commencing at least fourteen months later. This forecast will be referred to as the **Preliminary Forecast Demand TNUoS tariffs** and will be used to limit changes to the final demand TNUoS tariffs as defined in paragraph 14.15.88. This forecast will be published using the same price base as was used to calculate charges for the year of publication.

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)
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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

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
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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:

$$\frac{527.59\text{km} * \pounds 10.07/\text{MWkm} * 1.8}{1000} = \mathbf{\pounds 9.56/kW}$$

(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.

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 the following further adjustments:
- allowance for the minimum £0/kW demand charge;
- inclusion of the deferred zonal demand tariff to recover any deferred revenue from the prior charging year;
- a cap/collar arrangement of 20% for the final demand tariff against the preliminary forecast demand TNUoS tariff and any associated RPI adjustment.

(viii) The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

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14.28 Stability & Predictability of TNUoS tariffs

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.

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.

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.

- 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.

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.

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.

Additionally, for demand users, the company publishes, by the end of January of each year, preliminary forecast demand TNUoS tariffs for the charging year commencing at least fourteen months later. A 20% cap / collar arrangement exists to ensure that the final demand tariffs cannot change from these preliminary forecast values by more than 20% (not accounting for RPI).

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.

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.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- 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.

[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Deferred Zonal Demand Tariff (£/kW)

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14.15.82 Where, in accordance with paragraph 14.15.88, there is a carry over of revenue from the previous charging year this will be known as **Deferred Zonal Revenue** and will be collected through the **Deferred Zonal Demand Tariff**. Deferred Zonal Revenue will be carried over to the following charging year on a zonal basis incorporating any adjustment as defined in National Grid's electricity transmission licence.

14.15.83 Deferred Zonal Demand Tariffs will be derived through the division of the Deferred Zonal Revenue for each demand zone by the current Total Forecast Metered Triad Demand for that zone:

$$DZDT_{Di} = \frac{DZR_{Di}}{D_{Di}}$$

Where
DZDT = Deferred Zonal Demand Tariff (£/kW)
DZR = Deferred Zonal Revenue (£m);

Final £/kW Tariff

14.15.84 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, the local tariff, and the deferred zonal demand tariff:

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

Where
ET = Effective TNUoS Tariff expressed in £/kW

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

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

14.15.86 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

14.15.87 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:

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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)

14.15.88 If the final demand TNUoS tariff is found, after accounting for the impact of changes in the Retail Price Index (RPI), to be 20% higher or lower than the value of the appropriate **Preliminary Forecast Demand TNUoS tariff** defined in paragraph 14.15.97, then the final demand TNUoS tariff shall be capped, or collared as defined in the formulae below:

If $FT_{DiY} < 0.8 \times PFDT_{Di(Y-1)} \times (1 + RPI)$ then $FT_{DiY} = 0.8 \times PFDT_{Di(Y-1)} \times (1 + RPI)$

If $FT_{DiY} > 1.2 \times PFDT_{Di(Y-1)} \times (1 + RPI)$ then $FT_{DiY} = 1.2 \times PFDT_{Di(Y-1)} \times (1 + RPI)$

Where
$PFDT_{Di(Y-1)}$ = Preliminary Forecast Demand TNUoS tariff published as defined in paragraph 14.15.97.

Any revenue excess or deficit arising as a result of this capping or collaring shall be recorded on a zonal basis and recovered in the following financial year accounting for any adjustments as defined in National Grid's electricity transmission licence.

14.15.89 In the event of a change to the TNUoS charging methodology that has the potential for significant change to the derivation of demand TNUoS tariffs, then the use of the process described in paragraph 14.15.88 for the following year's demand TNUoS tariffs will be reviewed by National Grid.

14.15.90 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**.**

14.15.91 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.

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14.15.92 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.

14.15.93 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.

14.15.94 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**.

14.15.95 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.

14.15.96 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

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

14.15.98 National Grid will publish, by the end of April of each year, a forecast of £/kW Zonal Demand TNUoS tariffs for the following charging year. This forecast will be referred to as the **Preliminary Forecast Demand TNUoS tariffs** and will be used to limit changes to the final demand TNUoS tariffs as defined in paragraph 14.15.88. This forecast will be published using the same price base as was used to calculate charges for the year of publication.

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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

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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:

$$\frac{527.59\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£9.56/kW}$$

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(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.

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 = **£22.54/kW**

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 the following further adjustments:

- allowance for the minimum £0/kW demand charge;
- inclusion of the deferred zonal demand tariff to recover any deferred revenue from the prior charging year;
- a cap/collar arrangement of 20% for the final demand tariff against the preliminary forecast demand TNUoS tariff and any associated RPI adjustment.

(viii) The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

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14.28 Stability & Predictability of TNUoS tariffs

Stability of tariffs

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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.

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.

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:

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- 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.

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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.

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.

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Additionally, for demand users, the company publishes, by the end of January of each year, preliminary forecast demand TNUoS tariffs for the charging year commencing at least fourteen months later. A 20% cap / collar arrangement exists to ensure that the final demand tariffs cannot change from these preliminary forecast values by more than 20% (not accounting for RPI).

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.

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- 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
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Deferred Zonal Demand Tariff (£/kW)

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14.15.82 Where, in accordance with paragraph 14.15.88, there is a carry over of revenue from the previous charging year this will be known as **Deferred Zonal Revenue** and will be collected through the **Deferred Zonal Demand Tariff**. Deferred Zonal Revenue will be carried over to the following charging year on a zonal basis incorporating any adjustment as defined in National Grid's electricity transmission licence.

14.15.83 Deferred Zonal Demand Tariffs will be derived through the division of the Deferred Zonal Revenue for each demand zone by the current Total Forecast Metered Triad Demand for that zone:

$$DZDT_{Di} = \frac{DZR_{Di}}{D_{Di}}$$

Where
DZDT = Deferred Zonal Demand Tariff (£/kW)
DZR = Deferred Zonal Revenue (£m);

Final £/kW Tariff

14.15.84 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, the local tariff, and the deferred zonal demand tariff:

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

Where
ET = Effective TNUoS Tariff expressed in £/kW

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

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

14.15.86 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

14.15.87 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:

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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)

14.15.88 The final demand TNUoS tariffs will be compared with the respective **Preliminary Forecast Demand TNUoS tariffs** and **Preliminary Forecast Limits** published as defined in paragraphs 14.15.97 and 14.15.98. If any final demand TNUoS tariff is found, after accounting for the impact of the Retail Price Index (RPI), to be outside limits imposed by the formulae below, then that final demand TNUoS tariff shall be capped or collared, as appropriate, as shown below;

If $FT_{DiY} < PFDT_{Di(Y-1)} - PFL_{D(Y-1)} + RPI$ then $FT_{DiY} = PFDT_{Di(Y-1)} - PFL_{D(Y-1)} + RPI$
If $FT_{DiY} > PFDT_{Di(Y-1)} + PFL_{D(Y-1)} + RPI$ then $FT_{DiY} = PFDT_{Di(Y-1)} + PFL_{D(Y-1)} + RPI$

Where
$PFDT_{Di(Y-1)}$ = Preliminary Forecast Demand TNUoS tariff published as defined in paragraph 14.15.97.
$PFL_{D(Y-1)}$ = Preliminary Forecast Limit published as defined in paragraph 14.15.98..

Any revenue excess or deficit arising as a result of this capping or collaring shall be recorded on a zonal basis and recovered in the following financial year accounting for any adjustments as defined in National Grid's electricity transmission licence.

14.15.89 In the event of a change to the TNUoS charging methodology that has the potential for significant change to the derivation of demand TNUoS tariffs, then the use of the process described in paragraph 14.15.88 for the following year's demand TNUoS tariffs will be reviewed by National Grid.

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14.15.96 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

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

14.15.98 National Grid will publish, by the end of January of each year, a forecast of £/kW Zonal Demand TNUoS tariffs for the charging year commencing at least fourteen months later. This forecast will be referred to as the **Preliminary Forecast Demand TNUoS tariffs** and will be used to limit changes to the final demand TNUoS tariffs as defined in paragraph 14.15.88. These tariffs will be published alongside the £/kW cap/collar to be applied. Both tariffs and £/kW cap/collar will be published using the same price base as was used to calculate charges for the year of publication.

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14.15.99 The £/kW cap/collar, known as the **Preliminary Forecast Limit**, is defined by the following formula. Its application is defined in paragraph 14.15.88.

$$PFL_D = \frac{0.2 \times \sum_{i=z+1}^{14} \left(PFDT_{Di} \times D_{Di} \right)}{\sum_{i=z+1}^{14} D_{Di}}$$

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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

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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:

$$\frac{527.59\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£9.56/kW}$$

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(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.

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 = **£22.54/kW**

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 following further adjustments:

- allowance for the minimum £0/kW demand charge;
- inclusion of the deferred zonal demand tariff to recover any deferred revenue from the prior charging year;
- a cap/collar arrangement to limit changes to the final demand tariff from the preliminary forecast demand TNUoS tariff published at least fourteen months previously.

(viii) The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

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14.28 Stability & Predictability of TNUoS tariffs

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.

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.

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.

- 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.

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.

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.

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Additionally, for demand users, the company publishes, by the end of January of each year, preliminary forecast demand TNUoS tariffs for the charging year commencing at least fourteen months later. A cap / collar arrangement exists to ensure that the final demand tariffs cannot change from these preliminary forecast values by more than the £/kW Preliminary Forecast Limit that accompanies these forecasts (not accounting for RPI).

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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.

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.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- 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.

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[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Deferred Zonal Demand Tariff (£/kW)

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14.15.82 Where, in accordance with paragraph 14.15.88, there is a carry over of revenue from the previous charging year this will be known as **Deferred Zonal Revenue** and will be collected through the **Deferred Zonal Demand Tariff**. Deferred Zonal Revenue will be carried over to the following charging year on a zonal basis incorporating any adjustment as defined in National Grid's electricity transmission licence.

14.15.83 Deferred Zonal Demand Tariffs will be derived through the division of the Deferred Zonal Revenue for each demand zone by the current Total Forecast Metered Triad Demand for that zone:

$$DZDT_{Di} = \frac{DZR_{Di}}{D_{Di}}$$

Where
DZDT = Deferred Zonal Demand Tariff (£/kW)
DZR = Deferred Zonal Revenue (£m);

Final £/kW Tariff

14.15.84 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, the local tariff, and the deferred zonal demand tariff:

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

Where
ET = Effective TNUoS Tariff expressed in £/kW

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

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

14.15.86 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

14.15.87 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:

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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)

14.15.88 The final demand TNUoS tariffs will be compared with the respective **Preliminary Forecast Demand TNUoS tariffs** and **Preliminary Forecast Limits** published as defined in paragraphs 14.15.97 and 14.15.98. If any final demand TNUoS tariff is found, after accounting for the impact of the Retail Price Index (RPI), to be outside limits imposed by the formulae below, then that final demand TNUoS tariff shall be capped or collared, as appropriate, as shown below;

If $FT_{DiY} < PFDT_{Di(Y-1)} - PFL_{D(Y-1)} + RPI$ then $FT_{DiY} = PFDT_{Di(Y-1)} - PFL_{D(Y-1)} + RPI$
If $FT_{DiY} > PFDT_{Di(Y-1)} + PFL_{D(Y-1)} + RPI$ then $FT_{DiY} = PFDT_{Di(Y-1)} + PFL_{D(Y-1)} + RPI$

Where
PFDT$_{Di(Y-1)}$ = Preliminary Forecast Demand TNUoS tariff published as defined in paragraph 14.15.97.
PFL$_{D(Y-1)}$ = Preliminary Forecast Limit published as defined in paragraph 14.15.98..

Any revenue excess or deficit arising as a result of this capping or collaring shall be recorded on a zonal basis and recovered in the following financial year accounting for any adjustments as defined in National Grid's electricity transmission licence.

14.15.89 In the event of a change to the TNUoS charging methodology that has the potential for significant change to the derivation of demand TNUoS tariffs, then the use of the process described in paragraph 14.15.88 for the following year's demand TNUoS tariffs will be reviewed by National Grid.

14.15.90 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**.**

14.15.91 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information

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for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.92 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.

14.15.93 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.

14.15.94 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**.

14.15.95 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.

14.15.96 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

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

14.15.98 National Grid will publish, by the end of April of each year, a forecast of £/kW Zonal Demand TNUoS tariffs for the following charging year. This forecast will be referred to as the **Preliminary Forecast Demand TNUoS tariffs** and will be used to limit changes to the final demand TNUoS tariffs as defined in paragraph 14.15.88. These tariffs will be published alongside the £/kW cap/collar to be applied. Both tariffs and £/kW cap/collar will be published using the same price base as was used to calculate charges for the year of publication.

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14.15.99 The £/kW cap/collar, known as the **Preliminary Forecast Limit**, is defined by the following formula. Its application is defined in paragraph 14.15.88.

$$PFL_D = \frac{0.2 \times \sum_{i=z+1}^{14} \left(PFDT_{Di} \times D_{Di} \right)}{\sum_{i=z+1}^{14} D_{Di}}$$

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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)
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14	LAND40	-438.65	297
14	MELK40_SWEB	-162.96	102
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14	TAUN4A	-273.79	0
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		Totals	3078

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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:

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		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:

$$\frac{527.59\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£9.56/kW}$$

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(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.

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$$\frac{£779m - £130m}{50000MW} = \underline{£12.98/kW}$$

(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 = **£22.54/kW**

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 following further adjustments:
- allowance for the minimum £0/kW demand charge;
- inclusion of the deferred zonal demand tariff to recover any deferred revenue from the prior charging year;
- a cap/collar arrangement to limit changes to the final demand tariff from the preliminary forecast demand TNUoS tariff published in the previous charging year.

(viii) The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

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14.28 Stability & Predictability of TNUoS tariffs

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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:

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- 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.

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.

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.

Additionally, for demand users, the company publishes, by the end of April of each year, preliminary forecast demand TNUoS tariffs for the following charging year. A cap / collar arrangement exists to ensure that the final demand tariffs cannot change from these preliminary forecast values by more than the £/kW Preliminary Forecast Limit that accompanies these forecasts (not accounting for RPI).

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[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Paul Mott
Company Name:	EDF Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The consultation report is of good quality and does identify all the issues and considerations as we see them.
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	No. This proposal would reduce the extent to which the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs. This would have a negative impact on CUSC Charging Objective (b). This change proposal would also reduce the extent to which the use of system charging methodology facilitates effective competition in the generation and supply of electricity and so would not facilitate competition in the sale, distribution and purchase of electricity. This is because it impedes cost-reflectivity, and is unworkable, for reasons we elaborate on further on in this response. We do not believe that there have been any relevant developments in transmission licensees' transmission businesses, so Charging CAO (c) is not relevant
Do you agree with the	We agree that CMP207 could be implemented in time for April

proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other comments?**	2013/14. However, the workgroup Report does not document by when NG needs this change to be passed for this to be feasible. We note that the principle in CUSC is that charging method changes should be implemented on the 1st April. For alternatives considering limits to TNUoS tariffs against year ahead forecast tariffs, we agree with the Report / WG, that nominal implementation on the 1st April 2013 would mean that the first applicable year ahead forecast tariffs would be produced during the 2013/14 charging year as a forecast for the 2015/16 charging year. Hence there would be no impact (in terms of limits on changes) on final TNUoS tariffs until the start of the 2015/16 charging year.
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	No

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	We note that the Proposer felt the best way to manage changes caused through variables altered at the start of a Price Control Period was by amending the original proposal to incorporate a 'force majeure' clause to cover such eventualities. We believe that this would add unnecessary complexity to the mod – we would not support such a clause.
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	No, this proposal does not work as written, and would, in any event, take volatility from one party and place it onto others.
3	**What is the best time of year for the forecast upon which a cap could be based?**	We agree with the Workgroup that if a TNUoS limit was linked to a forecast of tariff charges, the date of such a forecast would need to be defined at a suitable time in advance of the charging year. We agree with the Workgroup suggestion that publishing the forecast at the same time as confirming the final tariffs for the following charging year would be the most valuable.

Q	Question	Response
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	We do not agree with a limit at all. However, we agree that a percentage limit has some clear drawbacks as it could prevent a small increase in a small tariff. An absolute limit would seem to more closely implement the intended effect of this mod. The cap £/kW limit could be annually incremented by RPI. We note that the Workgroup suggested that an absolute limit could be developed from an averaged annual 20% change for average zonal demand TNUoS tariffs representative in £/kW, weighted by the zonal demand.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	No. Limits damage cost-reflectivity, and may not even work. The potential increase in MAR from this year (£1.8b) to next (£2.2b) exceeds 20%, so if there were no zonal differential changes, the annual allowed MAR next year couldn't be recovered with this change in place. This is clearly untenable for the TOs.
6	**Do you believe that such a limit is suitable for a(charging) year on year change, or a forecast change? Please provide justification.**	We are opposed to the application of this limit on either basis as it damages cost-reflectivity. The proposers' intent does seem better given effect by capping actual charges, than forecast charges.
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	Yes. Recovering any shortfall in transmission revenue due to the operation of the cap is a difficult aspect. If recovered from new Users who had not had the chance to potentially benefit from the lower capped TNUoS tariff, it would arguably be discriminatory. User specific targeting to recover the capped revenue the next year, from the specific beneficiaries, seems fair, yet would be a little more complex than a generalised recovery from all Users in the relevant year. .
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	We agree with the Workgroup that the CMP207 proposal would be more difficult to implement for generation Users and generation TNUoS tariffs because of possible complications around the treatment of local generator charges which are User specific, and the treatment of generation wider tariff re-zoning. In consequence we do agree with the majority view that there could be benefit in limiting this mod. It is then at least a little more workable. For clarity we do not support implementation of this proposal as it has a detrimental impact on the relevant objectives.

Q	Question	Response
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	The application of a limit to TNUoS tariff changes on a company basis rather than a zonal or User-specific basis could be a barrier to expansion for small Suppliers across different zonal areas. This is because Suppliers with customers in multiple zones would have some element of smearing of overall TNUoS charge increase(s), thus reducing the efficacy of a cap. On this basis, such a company based targeting approach, which could also be considered discriminatory, has been correctly discounted by the Workgroup. It is not clear why the impact of CMP207 would differ between small and large Suppliers. We note that although small Suppliers might sometimes have a stronger geographical focus, the same is true of larger Suppliers, with roots in an original PES ("Area Board") franchise area.

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 14th August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Colin-Prestwich@smartestenergy.com 020 7448 0964
Company Name:	SmartestEnergy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We do not think it is practical to implement CMP207 as originally proposed given the difficulties of moving costs elsewhere, especially in view of Ofgem's desire for charges to be cost reflective and as far as possible in the periods in which the costs are incurred. However, if the proposal is to include caps on increases and decreases on a zonal basis (and this is deemed to significantly reduce any shortfalls) the proposal may have some merits.
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	We believe that CMP207 does meet the first objective to a certain extent: "*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 is because there are detrimental impacts on competition from sharp increases as it increases risk to suppliers, especially small suppliers. We do not believe that CMP207 meets the second objective "*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); We have no comment to make on the third objective: *"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."*
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other comments?**	No comment.
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	No

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	Yes
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	Yes
3	**What is the best time of year for the forecast upon which a cap could be based?**	We agree that publishing the forecast at the same time as confirming the final tariffs for the following charging year would be the most valuable.

Q	Question	Response
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	We acknowledge the fact that allowing a percentage cap means that in some transmission charging zones a 20% cap could be reached even for cases where the absolute value of the increase in the TNUoS tariff is relatively low. A solution could be to use a cap of 20% or 20p whichever is the higher.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	If the proposal is to go forward 20% seems intuitively reasonable.
6	**Do you believe that such a limit is suitable for a(charging) year on year change, or a forecast change? Please provide justification.**	A limit is possibly a better idea for deviations from forecast. Variations could be funded from NGT's incentive or by delaying investment. This would provide NGT with an incentive to forecast accurately and would provide at least some protection for suppliers, especially since two year fixed deals are so prevalent in the commercial retail market.
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	Yes
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	Yes
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	Yes. Smaller suppliers are less likely to have a portfolio which has a typical national spread and could therefore be exposed to greater average increases.

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Antony Badger*
Company Name:	*Haven Power Limited*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	*Haven is the proposer of CMP207 and participated in each of the Workgroup meetings and the Workgroup Consultation is a fair representation of the discussions.*
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(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;* *In our view, CMP207 would enable suppliers to improve the accuracy of their forecasts and assessments of future costs. This should lead to more informed business plans and pricing strategies. Suppliers would also face less uncertainty with respect to future changes in use of system charges and so be exposed to less risk. This means that in general prices to end customers can be lower.* *(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.* *CMP207 would enable more orderly phasing of significant changes to NGET's (and other TO's) charging. Capping changes in this way may also enable NGET to better meet the "reasonably practical" test in this objective.*
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other comments?**	*We are supportive of the proposed approach such that CMP207 would be implemented from April 2013 if approved.* *Both WACMs refer to forecasts published in January. If either of these are approved for implementation from April 2013, then we propose that for the first year of their implementation, the next forecast published under CMP206 after April 2013 for the 2014/15 Charging Year is used as the CMP207 reference forecast.* *In the event that CMP206 is not approved and either CMP207 WACM is, then we propose that NGET publish a reference forecast before the end of April 2013.*
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	*No.*

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	*We understand the reasoning behind the suggestion to include a force majeure clause to manage unforeseen circumstances. However, we believe that these should be very limited – e.g. to a price control re-opener.* *Where factors may give rise to step changes (e.g. from price control settlements or other CUSC modifications) then decisions on their implementation approach should take into account CMP207. Early visibility of factors which will affect TNUoS tariffs (e.g. price control settlements) is important to allow any changes to be factored into the regular cycle to avoid a force majeure clause being used as a way of adjusting TNUoS charges because future changes were not communicated in the right time horizon.* *Circumstances arising from "business as usual" during the year which could result in the principles of CMP207 being broken (i.e. limiting increases to 20%) should not trigger a re-opener and any under recovery should be dealt with in the following charging year.*
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	*Suppliers require the ability to take TNUoS charges into account when pricing retail contracts. Charge volatility can mean suppliers price in an additional risk premium, particularly for longer-term customer offers. As the generation mix changes (to accommodate low carbon technologies) it is recognised that charges will change—predictability is preferred as stability is unlikely to be more easily achieved.*
3	**What is the best time of year for the forecast upon which a cap could be based?**	*If a cap on the change of TNUoS forecasts was to be implemented, we agree that January would be the most appropriate time for forecasts to be published, i.e. at the same time as final tariffs for the next year. This would provide suppliers with a higher degree of certainty regarding how charges may change in the year following the next charging year. If CMP206 were implemented then we would expect the forecast to be one of those set out in the Forecast Timetable which would be produced by NGET.*
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	*As the proposer of CMP207, our preference is for a percentage limit as set out in the original proposal.* *However, we note the points and arguments raised by other Workgroup members in favour of an absolute limit during the Workgroup Meetings.*
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	*Yes.*

Q	Question	Response
6	**Do you believe that such a limit is suitable for a (charging) year on year change, or a forecast change? Please provide justification.**	*As the proposer of CMP207, we believe that limit is suitable for a cap on year on year charge changes.* *However, we would support a modification proposal which limited changes to a band around a published forecast as set out in the Workgroup Consultation. In our view such a limit would be suitable in this type of arrangement too.*
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	*Yes. Key issues would be around the complexities that are introduced if the changes were applied to individual users or groups of users (e.g. generators) rather than zones.*
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	*Taking into account the increased response to cost reflective signals of generation users, complexities surrounding price control generation re-zoning, we agree that the proposal could be targeted on demand users only via demand tariffs and energy consumption tariffs.*
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	*The significant variations in regulated charges such as TNUoS that we have seen recently can dwarf margins in some customer sectors. Smaller suppliers are often niche players and don't have large diverse portfolios over which unexpected increases can be recovered.*

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Melissa McKerrow mmckerrow@intergen.com 0131 624 7500
Company Name:	InterGen
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	InterGen is one of the UK's largest independent generators and owns and operates Coryton Power Station in Essex, Rocksavage Power Station in Runcorn and Spalding Power Station in Lincolnshire. As over two-thirds of InterGen's portfolio is merchant generation, InterGen supports a cap on TNUoS tariff increase as currently it is extremely difficult to accurately forecast this volatile cost element. InterGen's Coryton plant this year (2012/13) was subject to a tariff increase of up to 134%. At current low spark spreads, rises in fixed operating costs of this magnitude are unsustainable.
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* • *that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity* • *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); • *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.* InterGen believes that the original proposal CMP 207 does better facilitate the CUSC Objectives as the current volatility of TNUoS charges from year to year makes it difficult for generators and suppliers to plan effectively and therefore manage risk. However, InterGen is disappointed that the Workgroup discussions proposed that CMP 207 be applied to demand users only, due to the perceived complexity of applying this to the generation tariff (local and wider tariff changes) and due to the upcoming Transmission Price Control Review. There are significant changes expected in the coming years regarding how traditional flexible gas plant will achieve returns from the market, with EMR, Project TransmiT and the Carbon Floor to name but a few. Each of these proposals will result in significant changes to codes and associated charges, arguably more complex than the application of this modification to generation users. In this period of regulatory instability, better foresight of transmission charging will provide at least some predictability to assist business planning for independent merchant generators, who will be the most affected by current regulatory change proposals. InterGen has always located its plant in the UK near to centres of demand. The consultation rightly states that generators, more than demand users, are able to be most reactive to changes in locational signal (and therefore any dampening of the locational signal would result in inefficient citing of plant). InterGen does not believe that capping the TNUoS charging changes year on year will dampen that locational signal, particularly when considered alongside the more material changes in the charging regime likely to be implemented under Project TransmiT.
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other**	InterGen agrees with the proposed implementation approach in terms of timescale for delivery of the changes, i.e. implementation on 1st April 2013.

comments?	
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website, and return to the above email address with your completed Workgroup Consultation response proforma.*

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	Yes, InterGen agrees that a force majeure cap would be of use for the reasons set out in the consultation, particularly regarding the upcoming Transmission Price Control Review.
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	Yes, although it should be applied to generation as well as demand user to be complaint with the CUSC objectives in facilitating and promoting competition.
3	**What is the best time of year for the forecast upon which a cap could be based?**	InterGen agrees that publishing the forecast for the following charging year at the same time and publishing the current year final tariffs is most valuable.
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	Yes, it may be useful to apply an absolute limit as opposed to a percentage limit, in terms of a £/kW cap.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	Yes, 20% is manageable in terms of business planning cycles and risk.
6	**Do you believe that such a limit is suitable for a(charging) year on year change, or a forecast change? Please provide justification.**	Blank
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	Blank

Q	Question	Response
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	No, InterGen does not agree as explained above.
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	No

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*James Anderson (tel 0141 614 3006; mob 07753 621684)*
Company Name:	*ScottishPower Energy Management Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* • *that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity* • *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);* • *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. ScottishPower believes that the proposal better meets the applicable Charging Objectives as it facilitates competition in the sale of electricity through improving the stability of TNUoS tariffs. Although the proposal will not improve the cost-reflectivity of charging, the proposal has safeguards to ensure that cost-reflectivity between users is maintained between charging years.
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other comments?**	ScottishPower agrees with the proposed implementation date of 1 April 2013.
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	No.

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	We do not agree that there should be a force majeure clause. The aim of the proposal is to provide increased certainty over the movement of TNUoS tariffs. Introduction of a force majeure clause would introduce uncertainty as to when such a clause may be invoked and add additional complexity to the proposal as a definition of what constituted force majeure in a charging context would be required. Changes arising from a Price Control would not constitute force majeure in the normal usage of the term.
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	ScottishPower believes that this proposal would improve stability of TNUoS charges through the imposition of a cap on changes. However, we believe that the changes proposed under CMP 206 will better meet the requirements for improved predictability.

Q	Question	Response
3	**What is the best time of year for the forecast upon which a cap could be based?**	The notified TEC changes potentially represent one of the largest influences on the locational differentials in TNUoS tariffs and therefore it would seem appropriate to set the cap on a forecast prepared once those changes were known (i.e. an end of April forecast for the subsequent charging year).
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	In order to account for the large differences in tariffs between transmission charging zones, ScottishPower believes that an absolute limit on tariff movements would be more suitable than a percentage limit. This would deal with the possibility of tariffs becoming "trapped" at low values as outlined in para 4.37.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	As outlined in our response to Q.4, we would prefer to see an absolute limit applied.
6	**Do you believe that such a limit is suitable for a (charging) year on year change, or a forecast change? Please provide justification.**	There may be occasions, such as the first year of a new price control period, when there is a major step change in the amount of allowed revenue to be recovered through TNUoS charges. This change may lead to breaches of any cap (% or absolute) and subsequent under-recovery of revenue. Provided Suppliers have sufficient warning of tariff changes through accurate forecasting by National Grid, such changes can be factored into tariffs, For this reason, we believe that it would be more appropriate to apply any cap to the difference between forecast and actual tariffs. This would have the added benefit of incentivising National Grid to provide accurate forecasts.
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	We agree with the Workgroup's conclusion that the proposal would have a greater impact on generators (who compete on a single market price regardless of their locational TNUoS tariff) than suppliers who all face the same tariffs in the same TNUoS charging zones and are therefore better able to pass through TNUoS changes. We do not believe that the marginally improved cost reflectivity involved in introducing a user-specific recovery of under-recovered revenues merits the additional complexity involved.

Q	Question	Response
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	ScottishPower believes that there would be merit in extending the proposal to generation users. The proposal could be applied to the wider locational element of the TNUoS tariff only as the local circuit and substation charges are unique to the generation tariff. Generation re-zoning only takes place at the beginning of a new price control period (or under exceptional circumstances) and therefore should not trigger the application of a cap on a frequent basis. Indeed, smoothing of the transition of a generator's tariff from one zone to another may be advantageous. There are two aspects to the tariff changes arising from TEC changes; changes where the users tariffs are affected by a change in its own TEC which are partially predictable by that users and tariff changes driven by other users' TEC changes which can be unforeseen and would merit the application of a cap.
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	ScottishPower does not believe that there would be any materially different impact from this proposal on small Suppliers.

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Gemma Trembecki, Regulations Manager. Gemma.trembecki@opusenergy.com or 01604 673179
Company Name:	Opus Energy Ltd
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are supportive of the modification overall, believing it will reduce the risk that users are exposed to from unexpected TNUoS charge increases.
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *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. We agree with the proposer that it would better facilitate objective a). It would increase predictability of future TNUoS charges, reducing supplier uncertainty and the resultant risk they are exposed to, thereby benefitting competition. We also agree with the proposer that it would better facilitate object c) by meeting the 'reasonably practical' test for phasing in significant charging changes
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other comments?**	*Yes*
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	*No*

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	We agree that a force majeure clause would be beneficial to deal with circumstances such as new modification proposals and new price control periods.
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	See 6)
3	**What is the best time of year for the forecast upon which a cap could be based?**	We agree with the workgroup suggestion that January would be the most appropriate time.

Q	Question	Response
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	Users in high charging zones could be disadvantaged by a % cap and vice versa. Therefore an absolute cap seems more sensible.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	Any % is initially going to be an arbitrary figure, 20% seems reasonable. If we're working based on an absolute cap then calculating a figure based on previous year's tariff changes seems a sensible approach.
6	**Do you believe that such a limit is suitable for a(charging) year on year change, or a forecast change? Please provide justification.**	Both of these are preferable to the status quo. A charging limit would be ideal as it would improve both stability and predictability of charges. A forecast limit would still be beneficial as it would increase the predictability of charges.
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	As far as possible this modification should not dilute the cost reflective signals in the charging methodology. Areas that are capped should be targeted to recover the revenue in the following charging year. Targeting this further to particular users that have benefited from capped charges would give still less potential for discrimination. The main issue with this user targeted approach is the much greater complexity that it introduces, which raises questions about how workable it is.
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	Agree that due to the extra complexities surrounding generation users that this should only be targeted on demand users.
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	No

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Paul Jones paul.jones@eon-uk.com
Company Name:	E.ON
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We have no other comments other than those provided to the questions below.
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	If the correct combination of elements are put together then the first objective would be better met by promoting competition in supply of electricity. This combination in our opinion would be: • An absolute limit. • Applied against a forecast provided in January 15 months prior to the beginning of the year concerned. • Applied to demand charges only. • With surpluses and deficits rolled over into the charges for the same zone in the following year.
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other**	Yes, although an implementation date of 1 April is less of an objective if the limit is to be applied against a forecast. Therefore, the change could be implemented in December 2012 with a forecast for 2014/15 provided in January 2013. The actual effect of the proposal would not be seen on actual charges until the 1 April 2014. However, this approach would not leave much time for National Grid to make the necessary process and/or

comments?	systems changes needed so on balance the proposed implementation approach would seem appropriate.
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	No thank you.

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	A force majeure clause maybe needed to cover rezoning if a solution is implemented for generation too. However, if it is solely aimed at demand charges then rezoning is an unlikely prospect, as demand zones are based on GSP Groups which would be very difficult to change.
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	It should be aimed at improving predictability of charges. Cost reflective charges are important and should be allowed to move in response to changes in generation and demand on the network. However, given the amount of new investment that is being undertaken at present, anything that helps parties with predicting future charges will be helpful.
3	**What is the best time of year for the forecast upon which a cap could be based?**	Clearly suppliers will want as much notice as possible but this has to be set against the ability of National Grid to forecast charges to a reasonable degree of accuracy. Therefore, on balance it would seem appropriate to provide the forecast in the January 15 months prior to the start of the relevant year that it being forecast, at the same time that the final tariffs are published for the previous year. Therefore, the forecast for the charging year 2014/15 would be produced in January 2013.
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	Absolute. Absolute changes are more important. A 100% increase in a £0.5/kW charge has less of an impact than a 10% change in a £10/kW charge.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	We do not support a percentage limit.

Q	Question	Response
6	**Do you believe that such a limit is suitable for a (charging) year on year change, or a forecast change? Please provide justification.**	The limit should be against the forecast rather than the year on year change, as the modification should assist with predictability as in our answer to 2 above. This would also remove a significant potential issue with a year on year limit which is that, if under-recovered money is carried over into the charges for same zone in the following year, then there is a risk that the limit could be triggered again simply because of effect of the amount of money carried over. Against a background of increasing network costs, this could result in the limit being reached for several consecutive years with the associated revenue remaining unrecovered over a significant period. However, the forecast can take into account expected over-recoveries (or under-recoveries) from the previous year.
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	Seeking to recover under-recoveries solely from the particular user/s who benefitted from the capping would be most cost reflective and non discriminatory. However, it would also introduce a significant amount of complexity into the solution. A reasonable compromise may be to recover any under recovery from the same zone (for demand charges) as customers within that zone would not be expected to change much from year to year.
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	Yes, simply because applying the solution to generation zones would be unduly complex if issues of discrimination are to be avoided.
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	No.

CUSC Workgroup Consultation Response Proforma

CMP207 – Limit increases to TNUoS tariffs to 20% in any one year.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 21st August 2012** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Robyn Jenkins at cusc.team@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Garth Graham (garth.graham@sse.com*
Company Name:	*SSE*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Overall, for the reasons we detail below, we believe that CMP207 (as proposed) would undermine the cost reflectivity of TNUoS and could introduce unintended (and detrimental) consequences, including discrimination against Users in high charging zones. Furthermore (for the reasons noted below) we believe there is a strong case, if CMP 207 is to be introduced, that it only apply to demand and not generation due to the complexity and impacts that would arise otherwise.
Do you believe that CMP207 better facilitates the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* • *(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.* We concur with the Workgroup's initial view that CMP207 does not better facilitate Applicable CUSC Objective (b) on the ground of reducing cost reflectivity. Given the impact, with respect to undermining cost reflectivity, it is our initial view that CMP207 would not better facilitate Applicable CUSC Objective (a) as there would be a detrimental effect; on effective competition in the generation and supply of electricity; if costs were not reflected on those that gave rise to them. At this stage we, like the Workgroup, have not reached an initial view on Applicable Objective (c).
Do you agree with the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible. **Do you have any other comments?**	We note the proposed implementation approach set out in section 6 of the consultation document. We agree with this approach as it conforms with the 1st April charging change philosophy. In terms of the possible alternatives, we concur with the possible implementation approach outlined in paragraph 6.2. We note the comments from National Grid in paragraph 6.3 regarding changes to the Transport and Tariff model. It should be recognised that Users would wish to see any changes to the Transport and Tariff model published by National Grid at the earliest opportunity so that Users can use this to (a) check the National Grid calculated TNUoS tariffs and (b) undertake their own forecast(s) of tariffs etc., in the future.
Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?	No.

Specific questions for CMP207

Q	Question	Response
1	**Do you agree that there should be a force majeure clause (as outlined in paragraph 4.16) or do you have any different views?**	We note the discussion in paragraph 4.16 and agree that a force majeure clause should be included to deal with Price Control period variables.

Q	Question	Response
2	**Do you believe this CMP207 proposal should improve predictability or stability of TNUoS charges?**	Whilst we can see a case for CMP207 leading to an improvement in the stability of TNUoS charges, we do not necessarily see this equating to stability in the predictability of TNUoS as the TNUoS charge (in terms of the amount of money (£) to be recovered from demand and generation) will remain.
3	**What is the best time of year for the forecast upon which a cap could be based?**	Given that the main variables for setting TNUoS are (a) the amount of money to be recovered and (b) the volume of (i) demand and (ii) generation from which (a) is to be recovered it would seem sensible to go with the forecast after (i) and (ii) are better known; namely after the week 24 (demand) submission as this comes after the (generation) TEC changes in March.
4	**Do you believe an absolute or percentage limit (as outlined in paragraphs 4.27-4.30) would be a more suitable use of a limit?**	Notwithstanding our general concerns over the detrimental impact on cost reflectivity associated with a limit, if CMP207 were to be implemented then; in our view; the limit should be an absolute cap to reflect, in particular, the issue (as noted in paragraph 4.28) of low £ charging zones where relatively small £ changes could 'max out' if based on the percentage limit. This could, in extremis, lead to such low £ charging zones hitting the percentage limit over repeated years when the previous year(s) under recovery (plus National Grid financing costs) are factored in. This 'racking up' of old under recovered amounts over many years could result in the amounts involved, effectively, never being recovered in those zones. We agree with those that argue (in paragraph 4.28) that a percentage limit would, in these circumstances, discriminate disproportionally against those users in high charging zones.
5	**Do you agree with the 20% limit suggested by the proposer? If not, why not?**	For the reasons outlined elsewhere in this response, we do not believe a limit is appropriate, due to the impact on cost reflectivity associated with such a limit. Notwithstanding this, if a limit is to be imposed then 20% might be considered suitable – although we note that TNUoS / transmission costs make up a small part of end consumers overall electricity bills (circa 4%) so even a 25% increase in those charges, year on year, should equate (in this simple example) to a circa 1% increase in end consumers overall charges. Given the other variable elements in electricity bills, such as fuel costs, and that the under recovered amount (plus National Grid financing costs) will have to be recovered from end consumers at a later date a question arises as to whether there should be a limit at all.

Q	Question	Response
6	**Do you believe that such a limit is suitable for a(charging) year on year change, or a forecast change? Please provide justification.**	Notwithstanding our general concerns over the detrimental impact on cost reflectivity associated with a limit, if CMP207 were to be implemented then; in our view; given the defect identified, it would be more appropriate to apply the limit based on the forecast change. We believe a limit should not be based on the (charging) year on year change.
7	**Do you agree with the Workgroup's views on cost reflectivity and the potential for discrimination?**	Yes. As noted elsewhere in this response, we have concerns that CMP207 would substantially impact on cost reflectivity and could, as a result, discriminate against Users. Notwithstanding our comments under Q8 below, the effect on cost reflectivity and discrimination would be especially acute if CMP207 were to apply to generation (as well as demand).
8	**Do you agree with the Workgroup's consensus that the proposal could be targeted on demand users only?**	Yes. We believe there would be substantially detrimental effects on generation if CMP207 were to apply to generation and demand. In particular, there would be the effect on competition in generation if, say, those in zone A (who were due for a 25% increase) were able to offer lower prices (in the wholesale market) than those in zone B (who were due for a 15% increase) as zone A costs were less than what the costs should be in that year. A further, compounding, problem is the re-zoning of generation charging zones (which does not, practically, happen with demand) and the effect of generation plant closing / opening in zones where charges in previous year(s) have been reduced due to the limit.
9	**Do you believe there is any impact on small Suppliers over and above those already identified by the Workgroup?**	Our initial view is that there are no significant additional impacts over and above those already identified by the Workgroup – although we appreciate small Suppliers may, via this consultation, provide additional items that we are not as familiar with as them.