Tariff Information Paper

April view of TNUoS tariffs for 2015/16

This information paper provides National Grid's April view of Transmission Network Use of System (TNUoS) tariffs for 2015/16, which apply to generators and suppliers. It is the second of a series of updates that National Grid will publish throughout the year.

April 2014

V1.1

Contents

Any Questions?

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1 Executive Summary

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. The resulting charges reflect the use and the impact that customers have on the transmission network. In order that customers can appropriately respond to transmission charges, National Grid produces a variety of tariff forecasts. This document forecasts tariffs for 2015/16.

Our TNUoS tariff forecast for 2015/16 is based on the current charging methodology and takes into account changes in generation and demand connected to the transmission system; changes in the transmission network due to investments undertaken by transmission owners (TOs); and changes in the revenues required to undertake this work.

However, we recognise that CUSC Modification Proposal CMP213 ('Project Transmit') proposes a number of changes to the TNUoS charging methodology which, if implemented for 2015/16, could cause significant changes to TNUoS tariffs. Whilst Ofgem's current minded to position is for implementation in April 2016, we have provided a forecast of 2015/16 tariffs based on the WACM2 methodology in Appendix B to aid understanding of the impact.

CUSC Modification Proposal CMP224 will enable the charging methodology to comply with the EU directive that limits average annual generation charges to €2.5/MWh. This update assumes that the proposal will be implemented and as a result there is an impact upon the residual element of tariffs. The proportion of TNUoS charges recovered from demand customers will increase from 73% to 76% and that recovered from generators will reduce from 27% to 24%.

The forecast total transmission allowed revenue has decreased slightly from £2,650m to £2,645m. There have been a few changes in generation since the initial forecast the most significant of these being closures at Keadbyand Fawley and TEC reductions at Cowes and Ironbridge. The GB demand profile remains unchanged for both the transport model and the charging base.

National Grid will update its forecast of 2015/16 tariffs on a quarterly basis taking new information into account as it becomes available. This includes changes in generation, forecast demand and the total revenue that TNUoS charges are set to recover. TNUoS tariffs for 2015/16 will be finalised at the end of January 2015.

2 Tariff Summary

This section shows the generation and demand tariffs forecast for 2015/16. Information on how these tariffs were calculated and why they have changed from the 2015/16 initial forecast can be found in later sections.

2.1 Generation Tariffs 2015/16

Wider Tariffs (£/kW)

Zone	Zone Name	Generation Tariff (£/kW)
1	North Scotland	**25.81**
2	East Aberdeenshire	**21.48**
3	Western Highlands	**23.97**
4	Skye and Lochalsh	**29.42**
5	Eastern Grampian and Tayside	**22.35**
6	Central Grampian	**21.35**
7	Argyll	**21.29**
8	The Trossachs	**18.04**
9	Stirlingshire and Fife	**17.20**
10	South West Scotland	**16.07**
11	Lothian and Borders	**13.28**
12	Solway and Cheviot	**11.74**
13	North East England	**8.51**
14	North Lancashire and The Lakes	**7.86**
15	South Lancs, Yorkshire and Humber	**6.17**
16	North Midlands and North Wales	**4.65**
17	South Lincs and North Norfolk	**2.88**
18	Mid Wales and The Midlands	**1.92**
19	Anglesey and Snowdon	**7.21**
20	Pembrokeshire	**5.08**
21	South Wales	**2.49**
22	Cotswold	**-0.75**
23	Central London	**-5.33**
24	Essex and Kent	**-0.89**
25	Oxfordshire, Surrey and Sussex	**-2.55**
26	Somerset and Wessex	**-4.58**
27	West Devon and Cornwall	**-6.58**

Small Generators Discount (£/kW) = 9.47

Local Substation Tariffs (£/kW)

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.180769	0.103411	0.074509
<1320 MW	Redundancy	0.398220	0.246380	0.179189
>=1320 MW	No redundancy	-	0.324240	0.234492
>=1320 MW	Redundancy	-	0.532319	0.388549

Local Circuit Tariffs (£/kW)

Substation Name	Local Circuit Tariff (£/kW)	Substation Name	Local Circuit Tariff (£/kW)
Aberdeen Bay	**0.82**	Foyers	**0.69**
Achruach	**2.43**	Glendoe	**1.66**
Aigas	**0.59**	Glenmoriston	**1.19**
An Suidhe	**-0.29**	Gordonbush	**2.19**
Arecleoch	**0.28**	Griffin Wind	**1.68**
Baglan Bay	**0.64**	Hadyard Hill	**2.48**
Afton	**3.66**	Harestanes	**4.80**
Blacklaw Extension	**2.16**	Hartlepool	**0.54**
Black Law	**0.90**	Hedon	**0.17**
Bodelwyddan	**-0.02**	Invergarry	**-0.62**
Carrington	**0.06**	Killgallioch	**-4.16**
Clyde (North)	**0.10**	Killingholme	**0.27**
Clyde (South)	**0.11**	Kilmorack	**0.18**
Corriegarth	**2.28**	Langage	**0.59**
Corriemoillie	**2.48**	Lochay	**0.33**
Coryton	**0.32**	Luichart	**1.02**
Cour	**0.41**	Mark Hill	**-0.79**
Cruachan	**1.72**	Marchwood	**0.34**
Crystal Rig	**-0.01**	Millennium Wind	**1.46**
Culligran	**1.56**	Mossford	**3.57**
Deanie	**2.56**	Nant	**-1.11**
Dersalloch	**1.65**	Neilston	**0.79**
Didcot	**0.22**	Rocksavage	**0.02**
Dinorwig	**2.16**	Saltend	**0.30**
Brochloch	**3.37**	South Humber Bank	**0.76**
Edinbane	**6.16**	Spalding	**0.27**
Ewe Hill	**2.33**	Kilbraur	**1.95**
Farr Windfarm	**2.00**	Strathy Wind	**3.87**
Fallago	**0.07**	Aikengall II	**1.10**
Carraig Gheal	**3.96**	Whitelee	**0.10**
Ffestiniogg	**0.23**	Whitelee Extension	**0.27**
Finlarig	**0.29**		

Offshore Local Tariffs (£/kW)

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.42	27.59	8.55
Robin Rigg West	-0.42	27.59	8.55
Gunfleet Sands 1 & 2	15.76	14.47	2.70
Barrow	7.28	38.10	0.95
Ormonde	22.51	41.94	0.33
Walney 1	19.43	38.69	
Walney 2	19.29	39.03	
Sheringham Shoal	25.54	21.78	0.56
Greater Gabbard	31.41	13.67	
London Array	31.59	9.28	

2.2 Demand Tariffs 2015/16

Half Hour metered zonal tariffs (£/kW) and Non-Half Hour metered zonal tariffs (p/kWh)

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	**20.05**	**2.71**
2	Southern Scotland	**23.72**	**3.30**
3	Northern	**30.11**	**4.10**
4	North West	**33.06**	**4.73**
5	Yorkshire	**33.73**	**4.59**
6	N Wales & Mersey	**33.11**	**4.68**
7	East Midlands	**36.61**	**5.07**
8	Midlands	**37.34**	**5.24**
9	Eastern	**38.53**	**5.29**
10	South Wales	**35.80**	**4.73**
11	South East	**41.28**	**5.67**
12	London	**43.69**	**5.82**
13	Southern	**42.46**	**5.89**
14	South Western	**42.14**	**5.70**

3 Introduction

3.1 Background

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting in different parts of the country and to recover the total allowed revenues of the onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, National Grid determines a locational component of TNUoS tariffs using a model of power flows on the transmission system. This model considers the impact that increases in generation and demand have on power flows at times of peak demand. Where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced to reflect this. To calculate flows on the network information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on ‘standard’ conditions and are intended to be forward looking. This means that they reflect the cost of replacing assets at current rather than historical cost so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site. However, for offshore generators, project specific costs are taken into account since these costs vary significantly from one project to another.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct total revenue recovery, separate non-locational “residual” tariff elements are included in the generation and demand tariffs. The residuals are set to ensure that enough revenue is recovered to pay the Transmission Owners their allowed revenues.

The locational and residual tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate. For generation customers, local tariffs are also calculated. These reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the main interconnected transmission system (MITS), the cost of local circuits that the generator uses to export onto the MITS. This allows the charges to reflect where local connections are single circuit. These charges are therefore locational and specific to individual generators.

3.2 Generation:Demand split

EU Regulation ECR 838/2010 limits average annual generation use of system charges to €2.5/MWh. It is assumed that the proportions of revenue recovered from generation and demand will be adjusted in 2015/16 to comply with this regulation and CUSC Modification Proposals CMP224 and CMP227 are currently being considered to implement this. For this update it has been assumed that the proportion of TNUoS charges recovered from demand customers will increase from 73% to 76% and the proportion recovered from generation decrease from 27% to 24%.

3.3 Project TransmiT

CUSC Modification Proposal CMP213 proposes a new methodology for setting tariffs which introduces a year round locational price signal for generators that better reflects how Transmission Owners design the system. CMP213 is currently awaiting an Ofgem determination and the current ‘minded to’ position is to implement the WACM2 alternative from April 2016. In March 2014 Ofgem informed the industry that it was re-consulting on this change. A set of 2015/16 tariffs have been calculated using the WACM2 methodology and are included in Appendix B for information.

4 Updates to the Charging Model for 2015/16

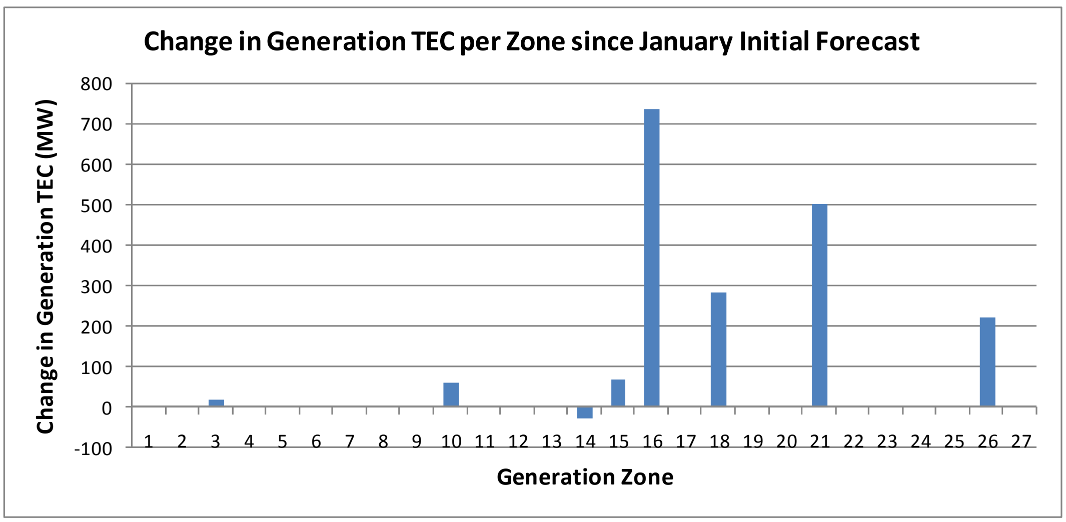
Since the initial forecast of tariffs for 2015/16 in February, updates have been made to contracted generation, chargeable generation, total revenue, local tariff charges and the generation:demand split. There have been no changes to transport model demand data, chargeable HH and NHH demand data or circuit data.

4.1 Changes influencing the locational element of tariffs

4.1.1 Generation

Information about generation capacities for 2015/16 has been taken from the contracted generation background on 17 March 2014. Figure 1 shows there has been an increase in modelled generation of 1.9GW between the initial 2015/16 forecast and this forecast. Appendix A provides the same data in tabular form by station. Zones 1 to 12 represent Scotland and Zones 13 to 27 represent England & Wales.

Figure 1



The locational element of tariffs will be fixed using the contracted background on 31 October 2014. This may include TEC reductions of existing power stations for which notification has not yet been received and delays to planned future connections. These are published in the TEC Register and taken into account in future updates of forecast tariffs.

4.1.2 Demand

The locational element of tariffs is based upon week 24 demand forecast data provided by the Distribution Network Operators (DNO) under the Grid Code and forecasts of demand at directly connected demand sites such as steelworks and railways and some embedded generation. The DNO demand data used in this forecast is unchanged from that used in the initial forecast and this will not change before charges are finalised in January 2015. However, embedded generation and directly connected demand forecasts may be updated.

4.1.3 Transmission network

The circuit data has not changed since the initial forecast. It is envisaged that new data will be incorporated in the October update.

4.2 Changes influencing the residual element of tariffs

4.2.1 Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TO) in Great Britain. The revenues of onshore TOs are subject to RIIO price controls set by Ofgem at periodic price reviews. RIIO stands for Revenue = Incentives + Innovation + Outputs. This means that each TO's revenue is set at price review, but then adjusted during the price control period (2013/14 to 2020/21) depending on its performance against incentives, its innovation and the volume of connections and transmission capacity it delivers. Connections and capacity are driven by customer activity.

Onshore TOs may also receive revenue through Transmission Investment for Renewable Generation (TIRG) or Strategic Wider Works decisions. These are determined by Ofgem to fund specific infrastructure projects and are occasionally adjusted as projects incur unexpected costs or savings.

The RIIO price control generally lags adjustments by two years. Performance in 2013/14 will be reported during summer 2014/15 and the resulting adjustments to be incorporated into 2015/16 revenues are announced by Ofgem in late autumn 2014.

The revenues of offshore transmission owners (OFTOs) are determined by Ofgem in a competitive tender process. The revenue is confirmed when the network is transferred from the developer to the appointed OFTO. Prior to this there is uncertainty as to the value of the revenue and when it will start. Therefore, whilst the revenues for existing OFTOs are relatively predictable, the revenue for new OFTOs has to be forecast.

Table 1 shows the April forecast for 2015/16 revenue upon which tariffs for April 2015/16 have been calculated, and the Initial View for comparison.

Table 1

15/16 Revenue Forecast £m Nominal	Jan 2014 Initial View	April 2014 Update	Difference
National Grid	1,855.6	1,851.6	-4.1
Scottish Power	332.5	331.8	-0.7
Scottish Hydro Electricity	215.7	215.2	-0.5
Offshore	276.4	276.4	0.0
Network Innovation Competition	16.7	16.6	0.0
Maximum Revenue	2,696.9	2,691.6	-5.3
Pre-vesting connections	47.0	47.0	0.0
TNUoS	2,650.0	2,644.7	-5.3
Maximum Revenue	2,696.9	2,691.6	-5.3

Overall revenues are forecast to reduce by £5.3m. This is due to a change in the RPI forecast following HM Treasury's February forecast.

4.2.2 Charging bases for 2015/16

Generation

The generation base for 2015/16 uses the 17th March 2014 contracted background for 2015/16 excluding interconnectors which do not pay TNUoS charges (see below). However, market intelligence has been used to derive a view as to the likelihood of a number of new generation projects progressing as planned. Where progression looked likely to vary from plan, the relevant market intelligence was used to produce a revised view as to how the project was likely to progress. The contracted TEC held for those projects was then adjusted in line with this view. The overall result of these adjustments is that National Grid's best view is less than the contracted TEC shown in the TEC register. We are unable to breakdown the modelled TEC as some of the information used to derive the data could be commercially sensitive.

The generation charging base is subject to change as we approach 2015/16. Whilst the deadline date for non-chargeable TEC reductions has passed, there is still the potential for chargeable TEC reductions and delays to new projects.

Demand

The demand base and the split between Half-Hourly metered and Non-Half-Hourly demand are unchanged from the initial view of 2015/16 charges. This assumes a peak system demand of 55.3GW; HH demand at triad of 15.9GW; and chargeable NHH demand of 28.6TWh[*]. National Grid will continue to review the demand charging base and update as required.

It should be noted that actual peak demand (and the timing of the triads in any given year) depends on a number of factors including prevailing weather and the behaviour of commercial and industrial loads.

Adjustments for Interconnectors

When determining the flows on the transmission system at peak demand, the interconnectors are included within the transport model. However, since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases. Table 2 shows the difference in treatment between the transport model and charging base.

[*] TNUoS charges for NHH demand is based on the annual consumption between 4pm and 7pm

Table 2

Interconnector	Zone	Transport Model (Generation MW)	Charging Base (Generation MW)
French Interconnector	24	2000	0
Britned	24	1200	0
East-West	16	500	0
Moyle	10	295	0

4.2.3 Demand:Generation Split

Under current CUSC methodology, tariffs are set to recover 27% of TNUoS revenue from generation and 73% from demand. EU Regulation ECR 838/2010 limits the amount that can be recovered from generation to an average of €2.5/MWh per annum. As revenues are increasing this limit is being approached. CUSC modifications CMP224 and CMP227 are being considered which if implemented will adjust the balance of TNUoS charges between generation and demand to remain compliant with the regulation.

The proportion of TNUoS revenue to be recovered from generation (G) and from demand (D) is given by the formulas:

$$G \ <= \ \frac{EL}{RX}$$

$$D \ >= \ 1 - \frac{EL}{RX}$$

Where:

- G is the proportion of TNUoS revenue recovered from generation
- D is the proportion of TNUoS revenue recovered from demand
- E is the total energy consumed by demand over a year
- L is the average generator charge cap per kWh (Including any risk adjustment)
- R is the total TNUoS revenue to be recovered.
- X is the Euros/Sterling exchange rate

As the limit (L) is expected to be reached in 2015/16 an adjustment has been made to the proportions recovered from generation (G) and demand (D). In the absence of any increase in forecast energy (E) any increases in revenue (R) can only be recovered from demand decreasing the proportion recovered from generation and increasing the proportion from demand.

Table 3 shows the forecast generation and demand proportions for 2015/16 with 2014/15 also shown for comparison. A 7% risk margin has been applied to the €2.5/MWh limit reflecting year ahead revenue and charging base forecast accuracy and so generation tariffs have been limited to €2.34/MWh. The resulting 76:24 revenue split is not fixed and subject to change depending on exchange rates, revenues to be recovered and the energy forecast.

Table 3

	2014/15	2015/16
G	**0.27**	**0.24**
D	**0.73**	**0.76**
E (TWh)	**322**	**319**
L (€/MWh)	**2.5**	**2.34**
R (£m)	**2,477.3**	**2,644.7**
X (€/£)	**1.2**	**1.2**

4.2.4 Generation and Demand Residuals

The following formulas show how the residual element of generation and demand tariffs is calculated. This can be used to assess the sensitivity of the residual elements to assumptions.

$$R_G = \frac{GR - Z_G - O - L_G}{B_G}$$

$$R_D = \frac{DR - Z_D}{B_D}$$

Where:

- R_G is the generator residual tariff (£/kW)
- R_D is the demand residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from generation (see 3.3.5)
- D is the proportion of TNUoS revenue recovered from demand (see 3.3.5)
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from the locational element of generator tariffs (£m)
- Z_D is the TNUoS revenue recovered from the locational element of demand tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_G is the TNUoS revenue recovered from onshore local tariffs (£m)
- B_G is the generator charging base (GW)
- B_D is the demand charging base (Half-hour equivalent GW)

Approximately 75% of offshore revenues are collected from offshore local tariffs. Therefore if **R** is reduced/increased due to changes in offshore revenues, then **O** should be reduced/increased by 75%, i.e. if revenue reduces by £10m, reduce O by £7.5m.

Table 4 shows the residual calculation for 2015/16 with 2014/15 included for comparison under current methodology. $\mathbf{Z_G}$, $\mathbf{Z_D}$ and $\mathbf{L_G}$ are determined by locational tariffs and will have different values under CMP213 methodology.

Table 4 – Residual Calculation under Current Methodology

	2014/15	2015/16
R_G (£/kW)	5.81	4.32
R_D (£/kW)	30.05	33.55
G(%)	0.27	0.24
D(%)	0.73	0.76
R (£m)	2,477.3	2,644.7
Z_G (£m)	54	66
Z_D (£m)	147	154.7
O (£m)	160	207.3
L_G (£m)	31	35.3
B_G (GW)	73	75.5
B_D (GW)	55.3	55.3

4.3 Other changes

4.3.1 Expansion Constant

The expansion constant remains unchanged from the initial forecast of £13.288/MWkm.

5 Forecast generation tariffs for 2015/16 – Current Methodology

The following section provides details of the forecast wider and local generation tariffs for 2015/16 using the current methodology.

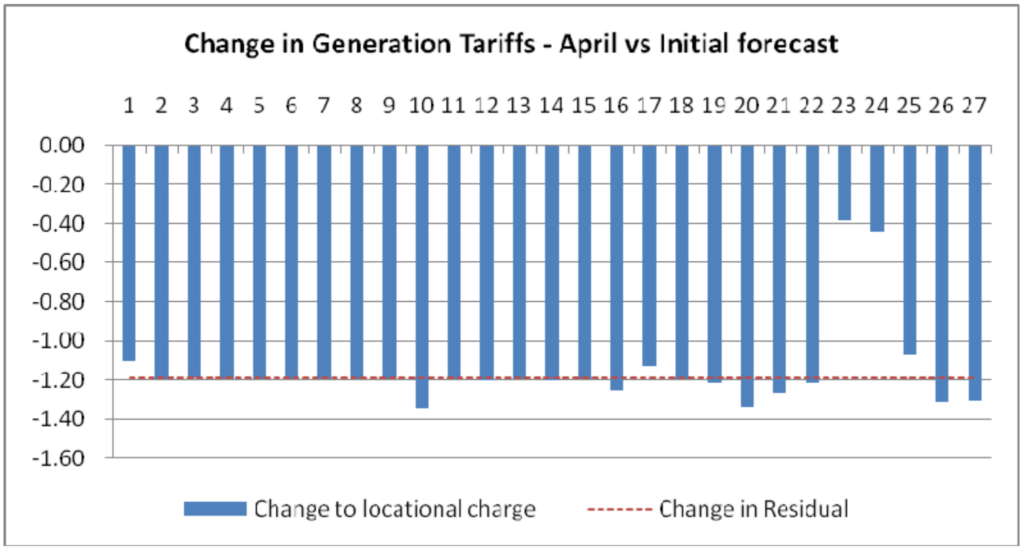
5.1 Wider zonal generation tariffs

Table 5 and Figure 2 show the differences between generation zonal TNUoS tariffs produced for the initial forecast and this April forecast.

Table 5

Zone	Zone Name	Initial Forecast 15/16 Tariff (£/kW)	April Forecast 15/16 Tariff (£/kW)	Difference due to revenue & 76:24 split change	Difference due to generation TEC changes
1	North Scotland	26.91	25.81	-1.19	0.09
2	East Aberdeenshire	22.67	21.48	-1.19	0.00
3	Western Highlands	25.15	23.97	-1.19	0.01
4	Skye and Lochalsh	30.61	29.42	-1.19	0.00
5	Eastern Grampian and Tayside	23.55	22.35	-1.19	0.00
6	Central Grampian	22.54	21.35	-1.19	0.00
7	Argyll	22.49	21.29	-1.19	0.00
8	The Trossachs	19.24	18.04	-1.19	0.00
9	Stirlingshire and Fife	18.40	17.20	-1.19	0.00
10	South West Scotland	17.41	16.07	-1.19	-0.15
11	Lothian and Borders	14.47	13.28	-1.19	0.00
12	Solway and Cheviot	12.94	11.74	-1.19	-0.01
13	North East England	9.71	8.51	-1.19	0.00
14	North Lancashire and The Lakes	9.06	7.86	-1.19	-0.01
15	South Lancs, Yorkshire and Humber	7.37	6.17	-1.19	0.00
16	North Midlands and North Wales	5.90	4.65	-1.19	-0.06
17	South Lincs and North Norfolk	4.00	2.88	-1.19	0.07
18	Mid Wales and The Midlands	3.12	1.92	-1.19	0.00
19	Anglesey and Snowdon	8.42	7.21	-1.19	-0.02
20	Pembrokeshire	6.42	5.08	-1.19	-0.15
21	South Wales	3.76	2.49	-1.19	-0.07
22	Cotswold	0.46	-0.75	-1.19	-0.02
23	Central London	-4.95	-5.33	-1.19	0.81
24	Essex and Kent	-0.46	-0.89	-1.19	0.76
25	Oxfordshire, Surrey and Sussex	-1.47	-2.55	-1.19	0.12
26	Somerset and Wessex	-3.27	-4.58	-1.19	-0.12
27	West Devon and Cornwall	-5.27	-6.58	-1.19	-0.11

Figure 2



Residual Tariff

The decrease in the proportion of revenue recovered through Generator TNUoS charges to 24%, described in section 4.2.3, reduces the residual element of the tariff by £1.09/kW. This is by far the most significant change to the residual. The total reduction in the residual tariff is £1.19/kW.

Locational Tariff

The further reduction in TNUoS tariffs in zones 26 and 27 are the result of generation TEC reductions at Fawley and Cowes.

TEC reduction in zone 21 further reduces tariffs in zone 20 and 21 but also affects the flows across London resulting in higher flows on expensive circuits. This increases the tariffs in Central London (Zone 23) and Essex and Kent (Zone 24).

The TEC reduction at Keady also impacts on flows in the South of the country, increasing charges in particular in Zone 24.

5.2 Onshore local generation tariffs

Onshore local generation tariffs remain unchanged from the initial view.

5.3 Onshore local substation tariffs

Local substation tariffs remain unchanged from the initial view. 2015/16 Local substation tariffs are subject to inflation. The forecast of 3% remains unchanged.

Table 6

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.180769	0.103411	0.074509
<1320 MW	Redundancy	0.398220	0.246380	0.179189
>=1320 MW	No redundancy	-	0.324240	0.234492
>=1320 MW	Redundancy	-	0.532319	0.388549

5.4 Offshore local generation tariffs

The local offshore tariffs (substation and circuit) have not changed from the initial view. Tariffs are subject to inflation and the forecast of 3% remains unchanged.

Table 7

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.42	27.59	8.55
Robin Rigg West	-0.42	27.59	8.55
Gunfleet Sands 1 & 2	15.76	14.47	2.70
Barrow	7.28	38.10	0.95
Ormonde	22.51	41.94	0.33
Walney 1	19.43	38.69	
Walney 2	19.29	39.03	
Sheringham Shoal	25.54	21.78	0.56
Greater Gabbard	31.41	13.67	
London Array	31.59	9.28	

5.5 Discount for Small Generation

The discount for small generation, which is equal to 25% of the combined generation and demand residuals, is forecast to increase from £9.40/kW to £9.50/kW.

6 Forecast demand tariffs for 2015/16 – Current Methodology

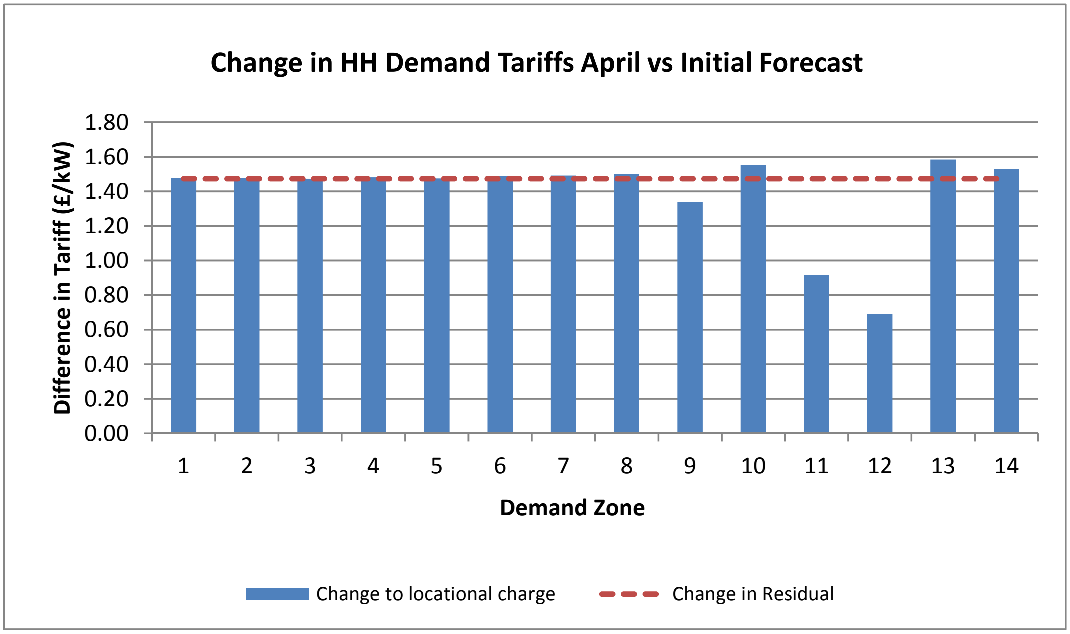
6.1.1 HH Demand Tariffs

Table 8 and Figure 3 show the difference in the Half-Hourly (HH) demand tariffs between the April and initial forecasts.

Table 8

Zone	Zone Name	Initial Forecast HH Demand Tariff (£/kW)	April Forecast HH Demand Tariff (£/kW)	Difference (£/kW)
1	Northern Scotland	18.57	20.05	1.48
2	Southern Scotland	22.24	23.72	1.48
3	Northern	28.64	30.11	1.47
4	North West	31.58	33.06	1.48
5	Yorkshire	32.25	33.73	1.47
6	N Wales & Mersey	31.63	33.11	1.49
7	East Midlands	35.11	36.61	1.49
8	Midlands	35.84	37.34	1.50
9	Eastern	37.19	38.53	1.34
10	South Wales	34.24	35.80	1.55
11	South East	40.36	41.28	0.91
12	London	43.00	43.69	0.69
13	Southern	40.88	42.46	1.59
14	South Western	40.61	42.14	1.53

Figure 3



Residual Tariff

The residual tariff element of HH demand tariffs, which is the same in each zone and ensures that the correct total revenue is recovered, has increased by £1.47/kW to £33.55/kW. The major driver is the increase in the proportion of revenue to be recovered from Demand TNUoS described in Section 4.2.3 which accounts for £1.40/kW of the increase.

Locational Tariff

The less pronounced increase in Zones 11 and 12 (London) reflects the generation tariff changes in generation zones 24 and 25 and is as a result of generation TEC reductions.

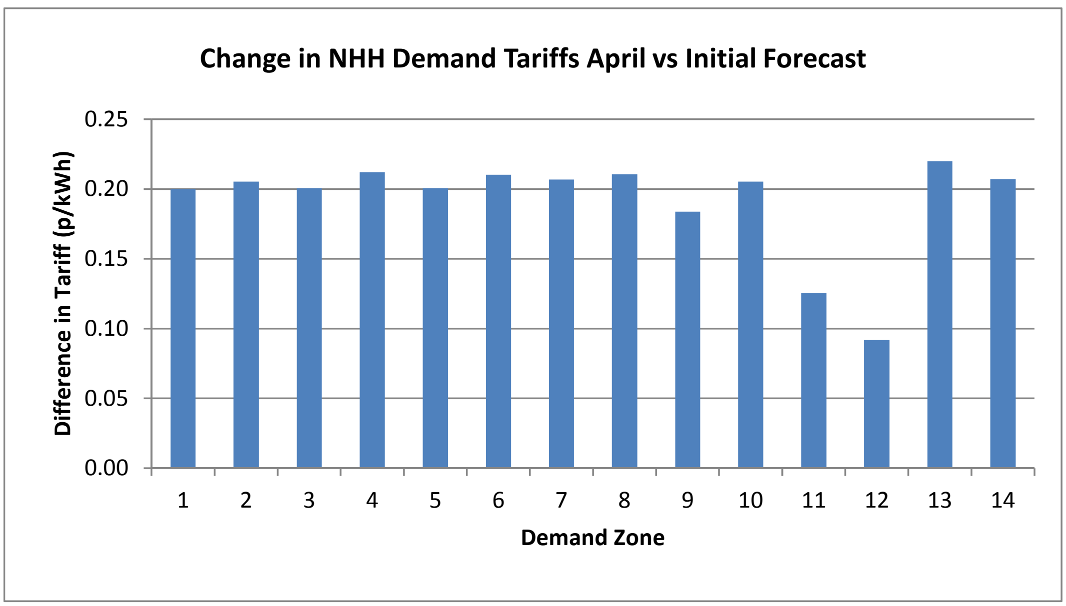
6.1.2 Non Half-hourly demand tariffs

Table 9 and Figure 4 show the difference in the Non-Half-Hourly (NHH) demand tariffs between the initial and the April forecasts. Similar changes to the HH demand tariffs are seen in NHH tariffs.

Table 9

Zone	Zone Name	Initial Forecast NHH Demand Tariff (p/kWh)	April Forecast NHH Demand Tariff (p/kWh)	Difference (£/kW)
1	Northern Scotland	2.51	2.71	0.20
2	Southern Scotland	3.09	3.30	0.21
3	Northern	3.90	4.10	0.20
4	North West	4.52	4.73	0.21
5	Yorkshire	4.38	4.59	0.20
6	N Wales & Mersey	4.47	4.68	0.21
7	East Midlands	4.86	5.07	0.21
8	Midlands	5.03	5.24	0.21
9	Eastern	5.10	5.29	0.18
10	South Wales	4.52	4.73	0.21
11	South East	5.54	5.67	0.13
12	London	5.73	5.82	0.09
13	Southern	5.67	5.89	0.22
14	South Western	5.50	5.70	0.21

Figure 4



7 Sensitivities & Uncertainties for 2015/16

7.1 Project Transmit

CUSC Modification Proposal 213 (CMP213) proposes a new methodology for setting wider tariffs that introduces year round locational price signals reflecting intermittency and load factor. In March 2014 Ofgem said they were minded to introduce the new methodology in April 2016.

An updated view of 2015/16 TNUOS tariffs under the CMP213 Working-group Alternative Code Modification 2 methodology (WACM2) is in Appendix B. All inputs to the WACM2 model are as above. Annual Load Factors are the same as for 2014-15 published on 13 December 2013[†].

7.2 Transmission revenue requirements

The scenarios set out below are intended to illustrate the sensitivity of the forecast tariffs to changes in the revenue collected TNUoS tariffs. These scenarios do not represent a minimum and maximum tariff range.

Table 10 shows the impact of a 1% change in onshore revenues upon generation and demand tariffs. Since this affects the residual tariff component the impact is the same in all zones.

Table 10

Average Tariff Change for 1% change in revenue (+/- 26.45m)	**15/16 Revenue**
Generation	+/- £0.08/kW
HH Demand	+/- £0.36/kW
NHH Demand	+/-0.04p/kWh

[†] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Tools-and-Data/

7.3 Demand charging base

An increase in the demand charging base decreases tariffs and vice versa. Table 11 shows the impact of a 500MW increase in the demand charging base. For simplicity this has been spread in proportion to the existing demand in each zone.

Table 11

Tariff change for 500MW increase in demand	Change to tariffs
HH Demand	-£0.30/kW
NHH Demand	-/+ <0.01 p/kWh

7.4 Generation charging base

The tariffs presented in this document are based upon the contracted generation background for 2015/16 as of 17 March 2014. The locational element of tariffs will be finalised using the contracted background as at 31 October 2014. However the residual element of generation tariffs may continue to be adjusted up to when tariffs are finalised in January 2015, to reflect changes in the charging base.

An increase in the generation charging base decreases tariffs and vice versa. Table 12 shows the impact of a 1GW increase / decrease in the generation charging base. For simplicity this has been spread in proportion to the existing generation in each zone. Note that an increase in the charging base decreases the tariff and vice versa.

Table 12

Tariff change for +/- 1GW generation change	Change to tariffs
Generation Tariff	-/+ £0.11/kW

7.5 Circuit parameters

The October forecast update on TNUoS tariffs will revise the circuit parameters.

8 Tools and Supporting Information

8.1 Feedback

National Grid is keen to ensure that customers understand the current charging arrangements and the reasons why tariffs change from year to year. We expect to attend future Transmission Charging Methodology Forums to discuss tariffs as they are updated through the year but we also welcome bilateral discussions should you have specific queries.

8.2 Publication of charging models

Customers can receive a copy of National Grid's charging model to conduct sensitivity analysis on alternative developments of generation and demand. This model will be based on the contracted TEC background which differs from National Grid's view that has been used to calculate the tariffs in this update. We are unable to provide a breakdown of National Grid's view as it may be based on commercially sensitive information.

If you would like a copy of the model to be emailed to you, together with a user guide, please contact National Grid. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

8.3 Tools and Useful Guides

National Grid has prepared a number of tools and guidance notes to help customers understand the charging arrangements. These include:

- Indicative 2015/16 CMP213 Diversity 1 Tariff Calculator
- Draft Annual Load Factors 2014-15
- Offshore Charging Guidance

http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Tools-and-Data/

9 Comments & Feedback

As part of our commitment to customers National Grid welcomes comments and feedback on the information contained in this statement. In particular, to ensure that information is provided and presented in a way that is of most use to customers, we would welcome specific feedback on:

- the level of numeric detail provided to explain tariff changes;
- the quality of the explanation given to describe and explain tariff changes;
- information that is not useful and could be omitted; and
- information that is missing that could be added.

These should be sent to:

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CV34 6DA

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01926 653845

Our commitment to UK Transmission Customers

► We will work closely with you to build a foundation for trust through open and honest relationships
► We will listen, understand your needs and expectations, and seek solutions that work for you
► We will help you understand our business so that we can work better together
► We will be accountable for delivering a clear and timely service
► We will seek and act upon your feedback

10 Appendices

Appendix A Generation changes for 2015/16

Appendix B Tariffs for 2015/16 using the CMP213 WACM2 model

Appendix C Generation Zones

Appendix A: Generation changes for 2015/16

Table 13 provides details of TEC changes notified between 20th December 2013 (used for the 2015/16 initial view) and 17th March 2014 (used for this update.)

Table 13

Station	Zone	New TEC (MW)	Change (MW)
Auchencross Interconnector	10	295	215
Cowes[‡]	26	99	145
Fawley	26	0	75
Fiddlers Ferry	15	1953	-34
Ferrybridge	15	980	-34
Heysham	14	2433	27
Ironbridge	18	680	-284
Keadby	16	0	-735
Quioch[§]	3	0	-18

[‡] Not chargeable

[§] Change from Bilateral Connection Agreement to a Bilateral Embedded Generation Agreement

Appendix B: 2015/16 TNUoS Tariffs calculated using the CMP213 WACM2 model ('Project TransmiT')

Residual calculation under CMP213 WACM2 methodology

Please refer to section 4.2.4 for an explanation of the following terms:

	2015/16
R_G (£/kW)	2.16
R_D (£/kW)	36.52
G(%)	0.24
D(%)	0.76
R (£m)	2,644.7
Z_G (£m)	191.55
Z_D (£m)	-9.41
O (£m)	207.3
L_G (£m)	20.8
B_G (GW)	75.5
B_D (GW)	55.3

CMP213 WACM2 Generation Tariffs

The tariff paid by a generator depends on the zone that the generator connects in, whether or not the generator is conventional or intermittent and the generators specific load factor. It is built up from four tariff elements as follows:

System Peak: Payable by conventional generators only

Shared Year Round: Payable by all but reduced by the generator's specific load factor

Not Shared Year Round: Payable by all

Residual: Payable by all

To illustrate the combined effect of these elements we have included examples of the tariff that would be paid by:

- A conventional generator with a load factor of 70%
- An intermittent generator with a load factor of 30%.

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	2.91	13.71	6.21	2.16	20.87	12.48
2	East Aberdeenshire	3.88	8.07	6.21	2.16	17.89	10.79
3	Western Highlands	2.95	11.99	6.01	2.16	19.51	11.76
4	Skye and Lochalsh	-2.64	11.99	5.88	2.16	13.79	11.63
5	Eastern Grampian and Tayside	2.56	10.92	5.66	2.16	18.01	11.09
6	Central Grampian	4.44	10.46	5.40	2.16	19.31	10.69
7	Argyll	3.59	8.44	7.59	2.16	19.24	12.28
8	The Trossachs	3.66	8.44	4.16	2.16	15.88	8.85
9	Stirlingshire and Fife	3.86	7.88	4.00	2.16	15.53	8.52
10	South West Scotlands	2.89	9.32	4.00	2.16	15.57	8.95
11	Lothian and Borders	3.00	9.32	0.06	2.16	11.73	5.01
12	Solway and Cheviot	1.60	5.63	2.77	2.16	10.47	6.61
13	North East England	3.23	3.11	1.09	2.16	8.66	4.18
14	North Lancashire and The Lakes	1.70	3.11	1.81	2.16	7.84	4.90
15	South Lancashire, Yorkshire and Humber	3.97	0.93		2.16	6.77	2.43
16	North Midlands and North Wales	3.54	-0.09		2.16	5.64	2.13
17	South Lincolnshire and North Norfolk	1.92	-0.44		2.16	3.77	2.02
18	Mid Wales and The Midlands	1.32	-0.35		2.16	3.23	2.05
19	Anglesey and Snowdon	4.95	1.18		2.16	7.93	2.51
20	Pembrokeshire	7.84	-3.49		2.16	7.56	1.11
21	South Wales & Gloucester	5.38	-3.51		2.16	5.08	1.10
22	Cotswold	2.13	2.17	-5.57	2.16	0.24	-2.76
23	Central London	-3.99	2.17	-4.86	2.16	-5.19	-2.06
24	Essex and Kent	-4.62	2.17		2.16	-0.95	2.81
25	Oxfordshire, Surrey and Sussex	-1.83	-2.08		2.16	-1.13	1.53
26	Somerset and Wessex	-2.01	-3.29		2.16	-2.16	1.17
27	West Devon and Cornwall	-0.04	-3.92		2.16	-0.63	0.98

CMP213 WACM2 Demand Tariffs

Demand Tariffs		HH Tariff	NHH Tariff
Zone	**Zone Name**	**(£/kW)**	**(p/kWh)**
1	Northern Scotland	22.32	3.02
2	Southern Scotland	23.59	3.28
3	Northern	29.62	4.03
4	North West	32.69	4.68
5	Yorkshire	33.39	4.54
6	N Wales & Mersey	32.69	4.62
7	East Midlands	36.27	5.02
8	Midlands	36.82	5.17
9	Eastern	38.47	5.28
10	South Wales	34.84	4.60
11	South East	41.54	5.70
12	London	44.25	5.90
13	Southern	41.89	5.81
14	South Western	40.31	5.45

Tariffs include small gen tariff of £0.26/kW or 0.04p/kWh

Appendix C: Generation Zones