Tariff Information Paper

nationalgrid

Final TNUoS tariffs for 2015/16

This information paper provides Transmission Network Use of System (TNUoS) tariffs for 2015/16. These tariffs apply to generators and suppliers as of April 2015.

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V1.0

Contents

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1 Executive Summary

This document contains the Transmission Network Use of System (TNUoS) tariffs for implementation on 1 April 2015. TNUoS is paid by generators and suppliers for use of the GB Transmission network.

The total revenue recovered from TNUoS charges will be £2,637m, an increase of £159m on last year. Generation tariffs have been set to recover £612m to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010. This is a £57m reduction in revenue recovered from generation compared to last year and hence we see a reduction in the average generation tariff of £0.6/kW.

Demand tariffs have been set to recover £2,025m, an increase of £217m on last year. This is as a result of an increase in the total revenue to be recovered and the increase in the proportion of revenue to be recovered from demand to comply with the European Commission Regulation. System peak demand and daily peak energy consumption have reduced and as a result tariffs have been set based upon an average triad demand of 52.4GW; a reduction of 2.9GW from that used for 2014/15 tariffs. Similarly, as there is an underlying downward trend in energy consumption, NHH tariffs have been derived based upon 27.4TWh of energy; a fall of 1.2TWh on 2014/15 tariffs. Average Half-Hour demand tariffs have increased by £5.9/kW to £39.6/kW and average Non-Half-Hour demand tariffs have increased by 0.8p/kWh to 5.3p/kWh.

Throughout 2014 National Grid has provided updated forecasts of TNUoS tariffs. The final tariffs see no change in the locational element of the tariffs from the December forecast. There has been a £0.04/kW increase in generation tariffs (small change as a result of rounding in the calculations) since December. Half-Hour demand tariffs have all increased by £0.94/kW following a reduction in the demand charging base since December's forecast. Non-Half-Hour tariffs have similarly all increased by around 0.14p/kWh as energy consumption has been reduced.

2 Introduction

2.1 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 onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, we use a model of power flows on the transmission system to determine the locational component of TNUoS tariffs. This model considers the impact that increases in generation or demand have on power flows at times of peak demand. To calculate flows on the network, information about the generation and demand connected is used in conjunction with the electrical characteristics of the transmission system.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage, cable / overhead line, and 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 networks, 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 revenue that onshore and offshore transmission owners are allowed in their price controls or in the correct proportions between Generation and Demand. Therefore, separate, non-locational "residual" tariff elements are included in the generation and demand tariffs. The residuals are set to ensure that the correct amount of revenue is recovered and in the correct proportions.

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 and use of circuits between their connection and the MITS ('local charges'). These charges are therefore locational and specific to individual generators.

We produce an initial view of tariffs fourteen months before the charging year starts. Over time the data used in the model is updated until the tariffs are finalised two months ahead of the charging year. The degree of uncertainty in the forecasts reduces as we get closer to publishing final tariffs at the end of January.

3 Tariff Summary

This section shows generation and demand TNUoS tariffs for 2015/16. Information on how these tariffs were calculated and why they have changed from the forecast published in December or 2014/15 tariffs can be found in later sections.

Tariffs have been set to recover 23.2% of revenue from generation and 76.8% from demand.

3.1 Generation Tariffs 2015/16

Table 1 – Generation Wider Tariffs

2015/16 Wider Generation Tariffs		
Zone	**Zone Name**	**£/kW**
1	North Scotland	25.546023
2	East Aberdeenshire	21.084720
3	Western Highlands	23.455451
4	Skye and Lochalsh	28.869531
5	Eastern Grampian and Tayside	22.214915
6	Central Grampian	21.644276
7	Argyll	22.890024
8	The Trossachs	18.031264
9	Stirlingshire and Fife	17.153323
10	South West Scotland	15.825072
11	Lothian and Borders	13.372687
12	Solway and Cheviot	11.621553
13	North East England	8.600036
14	North Lancs and The Lakes	7.730613
15	South Lancs, Yorks and Humber	6.258567
16	North Midlands and North Wales	4.890027
17	South Lincs and North Norfolk	2.974367
18	Mid Wales and The Midlands	2.089218
19	Anglesey and Snowdon	7.684625
20	Pembrokeshire	5.933831
21	South Wales	3.308849
22	Cotswold	0.207391
23	Central London	-5.212171
24	Essex and Kent	-0.745812
25	Oxfordshire, Surrey and Sussex	-2.553608
26	Somerset and Wessex	-3.944445
27	West Devon and Cornwall	-5.804749
Small generators discount		10.110613

Table 2 – Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.179739	0.102822	0.074085
<1320 MW	Redundancy	0.395951	0.244977	0.178168
>=1320 MW	No redundancy	-	0.322393	0.233156
>=1320 MW	Redundancy	-	0.529287	0.386336

Table 3 – Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.839934	Dersalloch	1.590028	Killingholme	0.271148
Afton	2.080824	Didcot	0.225370	Kilmorack	0.176802
Aigas	0.585505	Dinorwig	2.152153	Langage	0.589396
An Suidhe	2.734127	Dumnaglass	3.240647	Lochay	0.327603
Arecleoch	0.292022	Dunlaw Extension	1.310271	Luichart	1.017407
Baglan Bay	0.664164	Edinbane	6.128902	Marchwood	0.341907
Black Law	0.895129	Fallago	0.970208	Mark Hill	-0.783834
Blacklaw Extension	1.965617	Farr Windfarm	2.143727	Millennium Wind	1.455406
Bodelwyddan	0.099481	Ffestiniogg	0.226870	Mossford	3.549527
Brochloch	1.919139	Finlarig	0.286652	Nant	-1.100208
Carraig Gheal	3.937977	Foyers	0.684073	Neilston	2.135568
Carrington	0.003283	Glendoe	1.646704	Rocksavage	0.015815
Clyde (North)	0.098177	Glenmoriston	1.182403	Saltend	0.298508
Clyde (South)	0.113537	Gordonbush	1.161867	South Humber Bank	0.754716
Corriegarth	2.269208	Griffin Wind	1.674516	Spalding	0.272102
Corriemoillie	2.461327	Hadyard Hill	2.477904	Strathy Wind	4.299193
Coryton	0.050241	Harestanes	4.781432	Whitelee	0.095010
Cruachan	1.591757	Hartlepool	0.530236	Whitelee Extension	0.264128
Crystal Rig	0.365898	Hedon	0.175418		
Culligran	1.551601	Invergarry	1.269646		
Deanie	2.549059	Kilbraur	1.034576		

Table 4 – Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.414208	27.437723	8.504214
Robin Rigg West	-0.414208	27.437723	8.504214
Gunfleet Sands 1 & 2	15.675263	14.391119	2.689783
Barrow	7.242928	37.894993	0.940985
Ormonde	22.391244	41.712790	0.332416
Walney 1	19.324705	38.485100	0.000000
Walney 2	19.184162	38.824156	0.000000
Sheringham Shoal	21.633823	25.371406	0.551499
Greater Gabbard	13.579639	31.204673	0.000000
London Array	9.214196	31.383039	0.000000
Lincs	13.535832	54.267778	0.000000

3.2 Demand Tariffs 2015/16

Table 5 – Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	23.469195	3.388532
2	Southern Scotland	26.789320	3.559740
3	Northern	32.617844	4.283661
4	North West	35.683316	4.874799
5	Yorkshire	36.287690	5.185476
6	N Wales & Mersey	35.620770	5.679363
7	East Midlands	39.066214	5.234958
8	Midlands	39.629994	5.487374
9	Eastern	41.176427	5.539798
10	South Wales	37.608777	5.245539
11	South East	43.738784	5.808134
12	London	46.237472	6.011081
13	Southern	44.786928	6.088292
14	South Western	43.979049	5.807268

4 Updates to the 2015/16 Charging Model Since the December Forecast

Since the December forecast of tariffs, a small change has been made to the generation charging base, TNUoS revenue has been reduced by £24m to £2,637m and demand charging bases have been reduced.

4.1 The change in tariffs since the December forecast

4.1.1 Generation tariffs

Generation tariffs have increased by £0.05/kW. This small change is as a result of rounding when calculating the generation / demand split.

4.1.2 Demand tariffs

HH Demand tariffs have increased by £0.94/kW. The reduction in total revenue to be recovered would alone show a reduction in the demand tariff. However, the reduction in the expected 2015/16 triad demand has resulted in tariffs increasing.

A reduction in the expected daily energy consumption of the NHH metered customer between 4pm and 7pm has reduced the NHH customer charging base and has resulted in an increase in the NHH demand tariff of around 0.14p/kWh.

4.2 Changes to the model inputs

Table 6 shows contracted and modelled Generation (Transmission Entry Capacity or TEC). This remains unchanged since the December forecast.

Table 6 - Contracted and Modelled TEC

(GW)	2014/15	2015/16 May forecast	2015/16 July forecast	2015/16 October forecast	2015/16 Draft Tariffs	2015/16 Final Tariffs
Contracted TEC	78.2	80.3	78.8	78.7	78.7	78.7
Modelled TEC	78.2	79.5	77.9	78.4	78.7	78.7

4.2.1 Demand

Table 7 shows the transport model demand in the final tariffs is unchanged since the December forecast.

Table 7 - Transport Model Demand (GW)

(GW)	2014/15	2015/16 May forecast	2015/16 July forecast	2015/16 October forecast	2015/16 Draft Tariffs	2015/16 Final Tariffs
Transport Model Demand	56.6	55.6	55.7	55.7	55.7	55.7

4.2.2 Network Model Changes

There have been no changes to the network model since the December forecast.

4.3 Changes influencing the residual element of tariffs

4.3.1 Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs) in Great Britain. Table 8 shows the forecast 2015/16 revenues that have been used in these tariffs. Earlier forecasts and the final revenue upon which 2014/15 tariffs were set are also included for comparison.

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. Revenue is initially set at a price review and then adjusted during the price control period depending on performance against incentives, innovation and outputs delivered. Revenue adjustments are generally lagged by two years, so allowed revenues in 2015/16 have been adjusted to reflect outputs and performance in 2013/14.

2015/16 tariffs have been set to recover National Grid's own revenue, the revenues notified by the two Scottish Transmission Owners and twelve existing offshore Transmission Owners and Network Innovation Competition funding. We are expecting Humber Gateway, West of Duddon Sands and Westermost Rough to asset transfer during 2015/16 and have therefore included our forecast of their revenue requirements. Revenue to be recovered from TNUoS is £24m lower than forecast in the draft tariffs published before Christmas. Appendix B updates the revenue information provided in the forecast of 2016/17 to 2019/20 TNUoS tariffs with additional information on 2015/16.

Table 8 – Allowed Revenues

£m Nominal	2014/15 TNUoS Revenue	2015/16 TNUoS Revenue					
	Jan 2014 Final	Jan 2014 Initial View	April 2014 Update	July 2014 Update	Oct 2014 Update	Dec 2014 Draft	Jan 2015 Final
National Grid							
Price controlled revenue	*1,761.9*	*1,855.6*	*1,851.6*	*1,805.9*	*1,810.9*	*1,783.1*	*1,780.7*
Less income from connections	*47.0*	*47.0*	*47.0*	*47.0*	*47.0*	*48.3*	*45.0*
Income from TNUoS	**1,714.9**	**1,808.7**	**1,804.6**	**1,759.0**	**1,763.9**	**1,734.8**	**1,735.7**
Scottish Power Transmission							
Price controlled revenue	*323.0*	*342.3*	*341.6*	*344.7*	*322.8*	*310.5*	*306.4*
Less income from connections	*10.8*	*9.8*	*9.8*	*11.5*	*10.8*	*11.1*	*10.7*
Income from TNUoS	**312.2**	**332.5**	**331.8**	**333.2**	**312.0**	**299.4**	**295.7**
SHE Transmission							
Price controlled revenue	*217.4*	*219.3*	*218.7*	*229.7*	*270.3*	*355.4*	*341.7*
Less income from connections	*3.5*	*3.6*	*3.5*	*3.6*	*3.6*	*3.5*	*3.5*
Income from TNUoS	**214.0**	**215.7**	**215.2**	**226.2**	**266.8**	**351.9**	**338.2**
Offshore	**218.4**	**276.4**	**276.4**	**277.3**	**274.1**	**256.0**	**248.4**
Network Innovation Competition	**17.8**	**16.7**	**16.6**	**16.7**	**16.7**	**18.8**	**18.8**
Total to Collect from TNUoS	**2,477.3**	**2,650.0**	**2,644.7**	**2,612.3**	**2,633.4**	**2,660.9**	**2,636.7**

4.3.2 Generation: Demand Split

The annual average generator tariff is limited to €2.5/MWh. This limit has been reduced to €2.34/MWh to incorporate a risk margin for forecasting error. The amount of money to be recovered from generation is calculated as €2.34/MWh multiplied by 319.6TWh of forecast generation which gives €747.9m Dividing by an exchange rate of €1.22/£ results in £612m of revenue to be recovered from generation. This equates to 23.2% generation and 76.8% demand.

Table 9 shows the parameters used to calculate the G/D split.

Table 9 - G/D Split Calculation

		2014/15	2015/16
E (TWh)	Annual generation	322.0	319.6
L (€/MWh)	Limit on generation tariff	2.50	2.34
R (£m)	Total Revenue	2,477	2,637
X (€/£)	Exchange Rate	1.20	1.22
G	% revenue generation	27.0%	23.2%
D	% demand generation	73.0%	76.8%
G.R (£m)	Revenue recovered from generation	669	612
D.R (£m)	Revenue recovered from demand	1,808	2,025

4.3.3 Generator residual

The generator residual is set to recover the remainder of the generator revenue after onshore local, offshore local and locational generation charges have been subtracted.

Generation Revenue

The revenue to be collected from generators is £612m.

Onshore Local Charges

Onshore local substation and onshore local circuit charges are expected to recover £34m.

Offshore Local Charges

Offshore local charges are expected to recover £187m.

Locational Generation Wider Charges

The locational generation tariff is expected to recover £48m.

Calculating the Generation Residual

The revenue sought to be recovered through the generator residual tariff is:

£612m - £34m - £187m - £48m = £343m.

The generation residual tariff is calculated by sharing this revenue across the generation base:

£343m / 71.5GW = £4.81/kW

Table 10 shows a comparison of 2014/15 and 2015/16 generation residual parameters.

4.3.4 Demand Residual

The demand residual is set to recover the demand revenue that is left after subtracting the locational demand charge.

Revenue Recovered from Demand

Revenue collected from demand customers is calculated as total TNUoS revenue less revenue recovered from generation customers.

£2,637m - £612m = £2,025m

Locational Demand Charge

The locational demand tariff is expected to recover £158m.

Calculating the Demand Residual Charge

The revenue to be recovered through the demand residual tariff is the demand revenue less the locational demand charges:

£2,025m - £158m = £1,867m

Calculating the Demand Residual tariff

The demand residual tariff is calculated by sharing this revenue across the demand charging base:

£1,867m / 52.4GW = £35.63/kW.

Table 10 shows a comparison of 2014/15 and 2015/16 demand residual parameters.

Table 10 - Residual Calculation

		2014/15	2015/16
R_G (£/kW)	Generator residual tariff	5.81	4.81
R_D (£/kW)	Demand residual tariff	30.05	35.63
G (%)	Proportion of revenue recovered from generation	0.270	0.232
D (%)	Proportion of revenue recovered from demand	0.730	0.768
R (£m)	Total TNUoS revenue	2,477	2,637
Z_G (£m)	Revenue recovered from the locational element of generator tariffs	54.2	47.6
Z_D (£m)	Revenue recovered from the locational element of demand tariffs	146.5	157.7
O (£m)	Revenue recovered from offshore local tariffs	160.0	186.6
L_G (£m)	Revenue recovered from onshore local substation tariffs	18.5	20.1
S_G (£m)	Revenue recovered from onshore local circuit tariffs	12.2	13.8
B_G (GW)	Generator charging base	73.0	71.5
B_D (GW)	Demand charging base	55.3	52.4

4.4 Charging bases

4.4.1 Generation

A small change has been made to the charging base to reflect a delay to a new generation project.

The generation base for 2015/16 takes generation from the transport model (see Section 4.1.1) less;

- Interconnectors;
- An adjustment taking into account generators in negative zones who do not always generate up to TEC;
- Forecast changes to chargeable generation since the TEC register of 31 October, e.g. station closures, delayed works, advanced works

4.4.2 Demand

Last winter the peak demand for electricity was about 10% lower than anticipated which led to an under-recovery of 2013/14 revenues. This under-recovery will be recovered through £56.4m of additional revenue in 2015/16. Whilst the weather was exceptionally mild an underlying reduction in demand and increase in embedded generation offsetting demand was indicated. Therefore, in July, we reduced our demand forecasts for 2015/16 by around 2%. So far this year, demands have again been lower than anticipated despite more normal weather for the winter season. This indicates that demand is declining, or embedded generation is growing, faster than we first forecast. To ensure more accurate revenue recovery in 2015/16 we have reduced our demand forecast for the final tariffs by a further 3%.

These tariffs are based upon a peak demand forecast of 52.4GW with distribution between zones based on experience over the last three years; taking into account changes in embedded generation levels, Triad avoidance and closure of large demand sites. The forecasts for Half Hour metered demand at Triad and chargeable Non-Half Hourly metered energy between 4pm and 7pm have also been reduced to 15.0GW and 27.4TWh respectively.

Table 11 – Charging Bases

Charging Base	Charging Year	
	2014/15	2015/16
Generation (MW)	73.0	71.5
Total Average Triad (MW)	55.3	52.4
HH Demand Average Triad (MW)	15.9	15.0
NHH Demand (4pm-7pm TWh)	28.6	27.4

4.4.3 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 12 shows Interconnectors in the transport model and charging base.

Table 12 – Interconnectors

Interconnector	Zone	Transport Model (Generation MW)	Charging Base (Generation MW)
French - Sellindge 400kV	24	2000	0
Britned - Grain 400kV	24	1200	0
East West - Deesside 400kV	16	500	0
Moyle - Auchencrosh 275kV	10	295	0

4.5 Expansion Constant

The Expansion Constant is **£13.21255525/MWkm**. The expansion factor is calculated using a May-October average RPI. The average May – October index is 2.413%.

5 Comparison of 2014/15 and 2015/16 Generation Tariffs

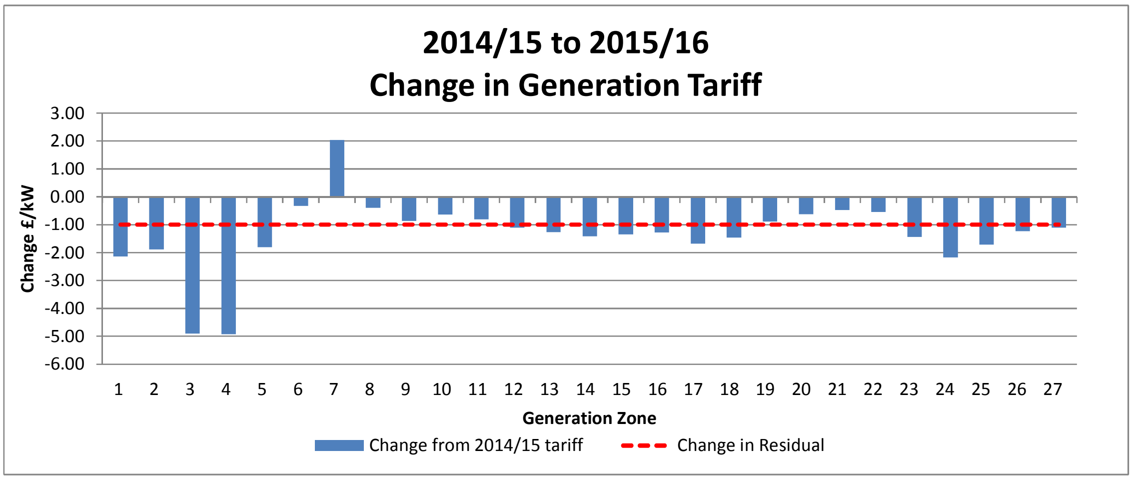
The following section provides details of the wider generation tariffs for 2015/16 and compares them to 2014/15 tariffs.

Table 13 shows the generation wider TNUoS tariffs for 2015/16, changes from the 2014/15 tariffs and changes from the December forecast. Figure 1 shows the change from the 2014/15 tariffs graphically.

Table 13 - Wider Generation Tariffs

Wider Generation Tariffs (£/kW)					
Zone	**Zone Name**	**2014/15**	**2015/16**	**Change from 2014/15 tariff**	**Change from Dec forecast**
1	North Scotland	27.68	25.55	-2.13	0.05
2	East Aberdeenshire	22.97	21.08	-1.88	0.05
3	Western Highlands	28.35	23.46	-4.90	0.05
4	Skye and Lochalsh	33.79	28.87	-4.92	0.05
5	Eastern Grampian and Tayside	24.02	22.21	-1.81	0.05
6	Central Grampian	21.97	21.64	-0.33	0.05
7	Argyll	20.85	22.89	2.04	0.05
8	The Trossachs	18.42	18.03	-0.39	0.05
9	Stirlingshire and Fife	18.02	17.15	-0.86	0.05
10	South West Scotland	16.46	15.83	-0.63	0.05
11	Lothian and Borders	14.18	13.37	-0.81	0.05
12	Solway and Cheviot	12.73	11.62	-1.10	0.05
13	North East England	9.87	8.60	-1.27	0.05
14	North Lancs and The Lakes	9.15	7.73	-1.42	0.05
15	South Lancs, Yorks and Humber	7.61	6.26	-1.35	0.05
16	North Midlands and North Wales	6.17	4.89	-1.28	0.05
17	South Lincs and North Norfolk	4.65	2.97	-1.67	0.05
18	Mid Wales and The Midlands	3.55	2.09	-1.46	0.05
19	Anglesey and Snowdon	8.57	7.68	-0.89	0.05
20	Pembrokeshire	6.55	5.93	-0.62	0.05
21	South Wales	3.78	3.31	-0.47	0.05
22	Cotswold	0.75	0.21	-0.54	0.05
23	Central London	-3.78	-5.21	-1.43	0.05
24	Essex and Kent	1.43	-0.75	-2.18	0.05
25	Oxfordshire, Surrey and Sussex	-0.83	-2.55	-1.72	0.05
26	Somerset and Wessex	-2.71	-3.94	-1.24	0.05
27	West Devon and Cornwall	-4.70	-5.80	-1.10	0.05

Figure 1 - Generation Tariff Changes



Generator Residual Tariff

The generator residual has reduced by £1/kW and is represented on the graph as the dotted red line as it impacts on all zonal tariffs. There are two reasons for this reduction. The first is due to the European Commission Regulation (EU) No 838/2010 that limits the annual average generation tariffs to €2.5/MWh. The impact of this is to limit the revenue recovered from generators to £612m. Hence, the revenue recovered from generation has reduced from £669m in 2014/15 to £612m in 2015/16. Secondly, the revenue recovered by the generator locational and local charges has increased significantly with the increase in offshore transmission assets so the remainder that is recovered by the wider tariff reduces. Therefore the generator residual tariff has reduced from £5.81/kW in 2014/15 to £4.81/kW in 2015/16. A breakdown of the figures can be found in Table 10 with a description of the calculation in 4.3.3 Generator residual.

Generator Locational Tariff

Circuit changes have reduced the tariffs in the north of Scotland (Zones 1 - 5). This is particularly apparent in zones 3 and 4 in the North West.

The circuit changes cause an increase in the tariffs in zones 6 - 8 with the largest increase in tariffs to zone 7. The increase in tariffs in zone 7 is exacerbated by the generation changes in Scotland.

In the south of England changes in locational tariffs highlight the impact of changes in east west flows. Zones 23 – 25 on the west, see a greater reduction in tariffs as a result of generation and demand changes than those on the east of England in Zones 18 - 22 and 26 - 27.

5.1 Onshore local substation tariffs

Local substation tariffs (Table 2 in Section 3) are calculated by inflating 2014/15 tariffs using a May-October average RPI. The average May – October index is 2.413%.

5.2 Offshore local generation tariffs

The local offshore tariffs (Table 4, Section 3) are calculated by inflating 2014/15 tariffs using a May-October average RPI. The average May – October index is 2.413%.

5.3 Discount for Small Generation

The discount for small generation, which is equal to 25% of the combined generation and demand residuals, has increased from £8.964509/kW to £10.110613/kW, due to the significant increase in demand residuals.

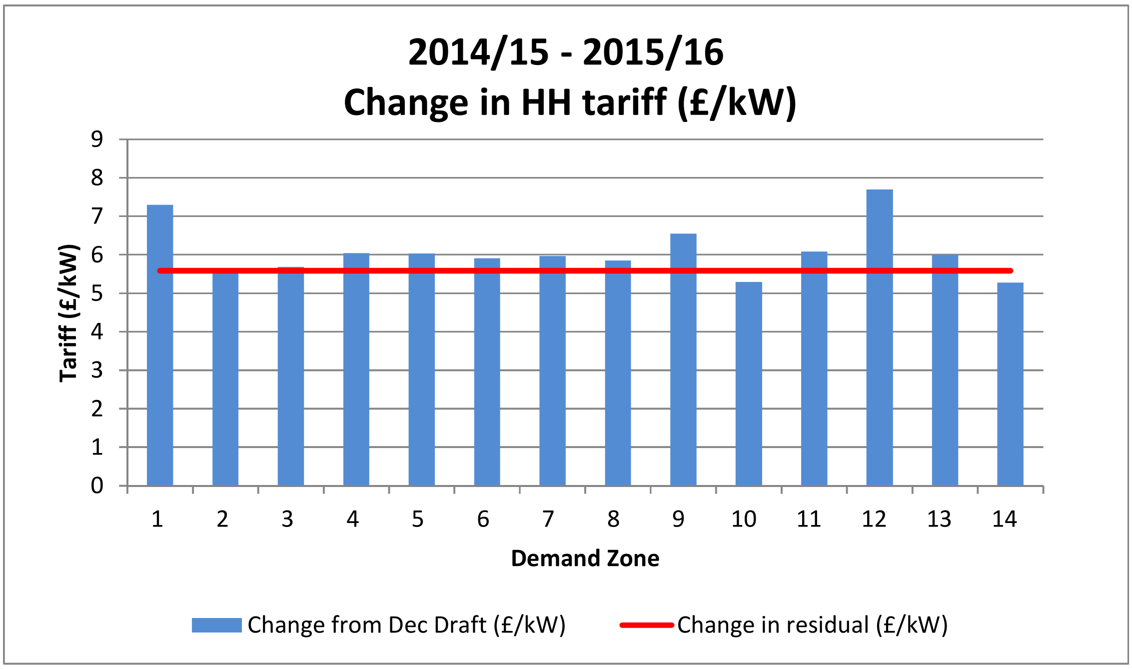
6 Comparison of 2014/15 and 2015/16 Demand Tariffs

Table 14 shows the 2015/16 Half-Hour (HH) demand tariffs. Changes from 2014/15 and the December forecast are shown for comparison. Figure 2 shows the change from the 2014/15 tariffs graphically. As the demand and generation tariffs are derived from the same model, whilst they are grouped in zones differently, the overall changes mirror each other i.e. if the generation tariff in the north increases more than the average, then the demand tariff in the north will decrease more than the average change.

Table 14 – HH Demand Tariffs

Zone	Zone Name	2014/15 (£/kW)	2015/16 Final (£/kW)	Change from 2014/15 (£/kW)	Change from Dec Draft (£/kW)
1	Northern Scotland	16.17	23.47	7.30	0.94
2	Southern Scotland	21.24	26.79	5.55	0.94
3	Northern	26.94	32.62	5.68	0.94
4	North West	29.64	35.68	6.04	0.94
5	Yorkshire	30.25	36.29	6.04	0.94
6	N Wales & Mersey	29.72	35.62	5.90	0.94
7	East Midlands	33.10	39.07	5.97	0.94
8	Midlands	33.78	39.63	5.85	0.94
9	Eastern	34.63	41.18	6.55	0.94
10	South Wales	32.32	37.61	5.29	0.94
11	South East	37.66	43.74	6.08	0.94
12	London	38.55	46.24	7.69	0.94
13	Southern	38.79	44.79	6.00	0.94
14	South Western	38.70	43.98	5.28	0.94

Figure 2 – HH Demand Tariff Changes



Demand Residual Tariff

The residual element of HH demand tariffs has increased by £5.58/kW from £30.05/kW to £35.63/kW. This is due to increase in the total amount of revenue to be recovered; an increase in the proportion of the revenue to be recovered from demand customers; and a decrease in the demand charging base (making the cost per unit higher). A breakdown of the figures can be found in Table 10 with the calculation described in 4.3.4 Demand Residual. The lower charges to generators are expected to feed through to energy prices which will partially offset the increase in supplier tariffs.

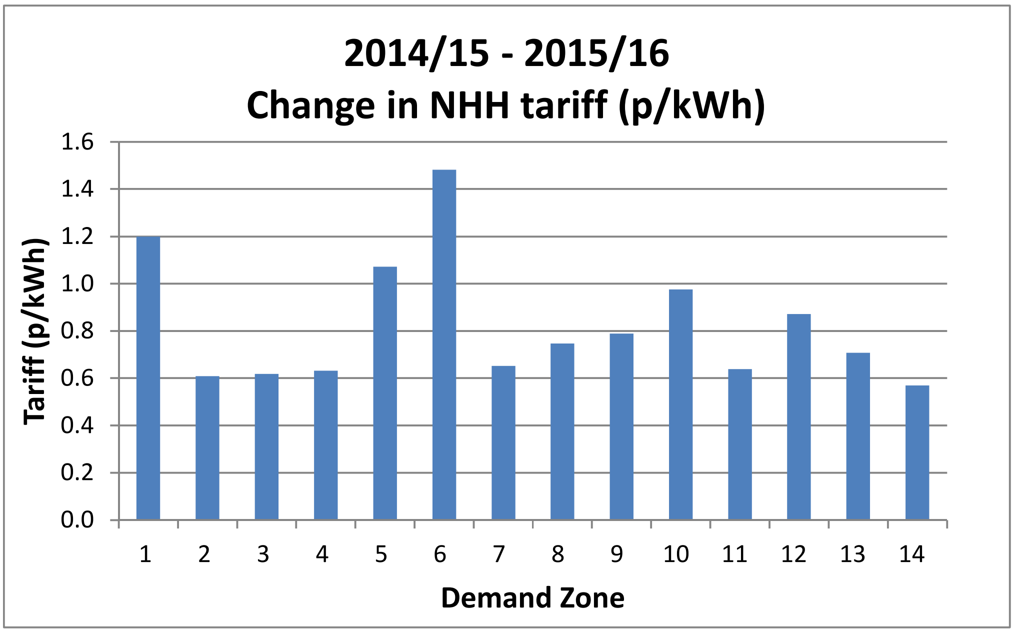
Demand Locational Tariff

The zone 1 tariff increases as a result of demand and circuit changes. Demand changes mostly increase the tariffs in the north and reduce tariffs in the south. However, this trend is not followed in London (Zone 12) where tariffs are seen to increase as a result of both demand and circuit changes.

Table 15 – NHH Demand Tariffs

Zone	Zone Name	Tariffs 14/15 (p/kWh)	Tariffs 15/16 (p/kWh)	Change from 2014/15 (p/kWh)	Change from Dec forecast (p/kWh)
1	Northern Scotland	2.19	3.39	1.20	0.14
2	Southern Scotland	2.95	3.56	0.61	0.13
3	Northern	3.67	4.28	0.62	0.13
4	North West	4.24	4.87	0.63	0.13
5	Yorkshire	4.11	5.19	1.07	0.14
6	N Wales & Mersey	4.20	5.68	1.48	0.15
7	East Midlands	4.58	5.23	0.65	0.13
8	Midlands	4.74	5.49	0.75	0.13
9	Eastern	4.75	5.54	0.79	0.13
10	South Wales	4.27	5.25	0.98	0.13
11	South East	5.17	5.81	0.64	0.13
12	London	5.14	6.01	0.87	0.13
13	Southern	5.38	6.09	0.71	0.13
14	South Western	5.24	5.81	0.57	0.13

Figure 3 – Change in NHH Tariff



7 Tools and Supporting Information

7.1 Further Information

We are keen to ensure that customers understand the current charging arrangements and the reasons why tariffs change from year to year. If you have specific queries on this forecast please contact Mary or Stuart using the details below. Feedback on the content and format of this forecast is also welcome. We are particularly interested to hear how accessible you find the report and if it provides the right level of detail.

7.2 Charging forums

We will be hosting a webinar on February 6th 2015 to present the material in this forecast and answer questions in an open forum. Please contact us if you wish to participate so that we may send you details. In addition we will be discussing this report at the Transmission Charging Methodology Forum on 14 March.

7.3 Charging models

We can provide a copy of our charging model. If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. 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.

7.4 Numerical data

All tables in this document can also be downloaded as an Excel spreadsheet from our website:

http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

7.5 Contact Details

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Appendices

Appendix A : Contracted Generation Changes

Appendix B : Transmission Owner Revenues

Appendix C : Generation Zones

Appendix D : Demand Zones

Appendix A : Contracted Generation Changes

Table 16 provides details of contracted TEC changes between 2014/15 tariff setting and 2015/16 tariff setting.

Table 16 – Generation TEC Changes

Power Station	Zone	2014/15	2015/16	Change
Abernedd	21	0	500	500
Achruach Wind Farm	7	49.9	43	-7
Afton	10	0	68	68
Arecleoch	10	120	114	-6
Barry	21	142	235	93
Blacklaw Extension	11	0	69	69
Brockloch Rig Wind Farm	10	0	75	75
Clyde North	11	221	331.8	111
Clyde South	11	129.0	179.8	51
Corriegarth	1	0	69	69
Cour	7	0	23	23
Cowes	26	145	0	-145
Dumnaglass Wind Farm	1	0	94	94
Ewe Hill	12	12	0	-12
Fawley	26	75	0	-75
Ferrybridge C	15	1014	980	-34
Fiddlers Ferry	15	1987	1953	-34
Grain	24	1524	1517	-7
Harelaw	10	0	80	80
Harestanes	12	126	146	20
Heysham	14	2406	2433	27
Ironbridge	18	964	680	-284
Keadby	16	735	0	-735
Mark Hill Wind Farm	10	56	53	-3
Pogbie Wind Farm	11	0	11.8	12
Quioch	3	18	0	-18
Rampion	25	0	332	332
Strathy N & S Wind	1	0	76	76
West Burton B	16	1305	1332	27
Wilton	13	183	141	-42

Appendix B : Transmission Owner Revenues

These pages update the revenue information in the 2016/17 to 2019/20 TNUoS forecast by including information for 2015/16. Forecasts have been provided by National Grid, Scottish Power Transmission, SHE Transmission and existing Offshore Transmission Owners. National Grid has also produced forecasts for offshore networks that are still be to be transferred or still to be constructed.

The Scottish Power Transmission and SHE Transmission data is based on submissions received by National Grid in December 2014 under STCP24-1. Updates on 2015/16 revenue were received in January 2015 under STCP14-1. Therefore the licence terms for 2015/16 have been adjusted to align with the newer submissions. This assumes any difference in 2015/16 revenue is only due to these terms.

Notes:

All monies are quoted in millions of pounds, accurate to one decimal place and are in nominal ‘money of the day’ prices unless stated otherwise.

Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders.

Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formula are constructed.

Network Innovation Competition Funding is included in the National Grid price control but is additional to the price controls of other Transmission Owners who receive funding. NIC funding is therefore only shown in the National Grid table.

All reasonable care has been taken in the preparation of these illustrative tables and the data therein. National Grid and other TOs offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither National Grid nor other TOs accept or assume responsibility for the use of this information by any person or any person to whom this information is shown or any person to whom this information otherwise becomes available.

The base revenues forecasts reflect the figures authorised by Ofgem in the RIIO-T1 or offshore price controls.

Within the bounds of commercial confidentiality these forecasts provide as much information as possible. Generally allowances determined by Ofgem are shown, whilst those for which Ofgem determinations are expected are not. This respects commercial confidentiality and disclosure considerations and actual revenues may vary for these forecasts.

It is assumed that there is only one set of price changes each year on 1 April.

Table 17 – Summary of Revenue Forecasts

£m Nominal	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
National Grid						
Price controlled revenue	*1,761.9*	*1,780.7*	*1,953.8*	*1,818.0*	*1,923.8*	*1,958.3*
Less income from connections	*47.0*	*45.0*	*45.0*	*45.0*	*45.0*	*45.0*
Income from TNUoS	**1,714.9**	**1,735.7**	**1,908.8**	**1,773.0**	**1,878.9**	**1,913.3**
Scottish Power Transmission						
Price controlled revenue	*323.0*	*306.4*	*321.0*	*368.5*	*415.9*	*433.4*
Less income from connections	*10.8*	*10.7*	*10.5*	*10.9*	*11.6*	*12.2*
Income from TNUoS	**312.2**	**295.7**	**310.5**	**357.6**	**404.3**	**421.2**
SHE Transmission						
Price controlled revenue	*217.4*	*341.7*	*343.0*	*347.6*	*335.7*	*
Less income from connections	*3.5*	*3.5*	*3.6*	*3.7*	*3.8*	*
Income from TNUoS	**214.0**	**338.2**	**339.5**	**344.0**	**331.9**	**338.5**
Offshore	**218.4**	**248.4**	**272.0**	**288.2**	**352.4**	**522.4**
Network Innovation Competition	**17.8**	**18.8**	**48.4**	**49.7**	**51.7**	**52.7**
Total to Collect from TNUoS	**2,477.3**	**2,636.7**	**2,879.2**	**2,812.5**	**3,019.2**	**3,248.0**

** No data provided*

Table 18

National Grid Revenue Forecast				Updated:	26/01/2015							
Description		Licence	Special	Applicable	Yr t-1	Yr t	Yr t+1	Yr t+2	Yr t+3	Yr t+4	Yr t+5	
Regulatory Year					2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Notes
Actual RPI					251.73							April to March average
RPI Actual		RPIAt	3A		1.1667							Office of National Statistics
Assumed Interest Rate		It	3A		0.50%	0.50%	0.70%	1.50%	2.20%	2.60%	2.60%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	1,342.3	1,443.8	1,475.6	1,571.4	1,554.9	1,587.6	1,585.2	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		-5.5	-114.4	-100.0	-190.0	-200.0	-200.0	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		-0.5	4.7	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3A	ALL	3.1%	3.1%	2.5%	2.4%	3.2%	3.3%	3.4%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3A	ALL	2.7%	3.1%	2.4%	3.2%	3.3%	3.4%	2.8%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3A	ALL	2.5%	3.0%	3.2%	3.3%	3.4%	2.8%	2.8%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2267	1.2763	1.3083	1.3616	1.3887	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**1561.1**	**1732.7**	**1675.5**	**1877.9**	**1785.8**	**1889.4**	**1923.6**	
Pass-Through Business Rates	B1	RBt	3B	ALL			1.2	1.4	1.4	1.5	1.5	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.1	0.0	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Licence Fee	B3	LFt	3B	NG			2.0	2.3	2.3	2.3	2.3	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt	3B	NG			3.8	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	3B	NG	2.6	0.0	0.0	0.0	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	3B	NG	271.3	312.2	295.7	310.5	357.6	404.3	421.2	13/14 & 14/15 Charge setting. Later from TSP Tab
SHE Transmission Pass-Through	B7	TSHt	3B	NG	172.5	214.0	338.2	339.5	344.0	331.9	338.5	13/14 & 14/15 Charge setting. Later from TSH Tab
Offshore Transmission Pass-Through	B8	TOFTOt	3B	NG	105.4	218.4	248.4	272.0	288.2	352.4	522.4	13/14 & 14/15 Charge setting. Later from OFTO Tab
Embedded Offshore Pass-Through	B9	OFETt	3B	NG	0.6	0.4	0.6	0.7	0.7	0.7	0.7	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**3B**	**ALL**	**552.3**	**745.1**	**890.0**	**926.3**	**994.2**	**1093.2**	**1286.6**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL	12.4		2.4	2.4	2.5	2.6	2.6	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			8.7	9.3	9.1	10.3	10.0	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			2.8	2.9	3.1	3.2	3.4	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	0.0	0.0	0.0	0.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**3A**	**ALL**	**12.4**	**0.0**	**13.9**	**14.6**	**14.6**	**16.1**	**16.0**	
Network Innovation Allowance	D	NIAt	3H	ALL	6.1	10.9	10.6	11.8	11.3	11.9	12.1	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	3I	NG	0.0	17.8	18.8	48.4	49.7	51.7	52.7	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt	3F	ALL				3.0	2.0	2.0	2.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	16.0	16.0	15.7	-0.1	-0.1	-0.0	-0.0	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	3A	NG	-1.6	2.0	0.8	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	3A	NG	-0.4	-0.3	0.1	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL	-2.7		56.4	42.1	0.0	0.0	0.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**		**ALL**	**2143.3**	**2524.2**	**2681.6**	**2924.2**	**2857.4**	**3064.2**	**3293.0**	
Termination Charges	B5			NG	2.6	0.0	0.0	0.0	0.0	0.0	0.0	
Pre-vesting connection charges	P			ALL	43.3	47.0	45.0	45.0	45.0	45.0	45.0	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**			**NG**	**2097.4**	**2477.3**	**2636.7**	**2879.2**	**2812.5**	**3019.2**	**3248.0**	
Final Collected Revenue	U	TNRt		ALL	2089.6							Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	-53.7							
Forecast percentage change to Maximum Revenue M				**NG**		**17.8%**	**6.2%**	**9.0%**	**-2.3%**	**7.2%**	**7.5%**	
Forecast percentage change to TNUoS Collected Revenue T				**NG**		**18.1%**	**6.4%**	**9.2%**	**-2.3%**	**7.4%**	**7.6%**	

Table 19

Scottish Power Transmission Revenue Forecast				Updated:	23/01/2015							
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	Yr t+2	Yr t+3	Yr t+4	Yr t+5	
Regulatory Year					2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Notes
Actual RPI					251.73							April to March average
RPI Actual		RPIAt			1.1667							Office of National Statistics
Assumed Interest Rate		It			0.50%	0.50%	0.70%	1.50%	2.20%	2.60%	2.60%	As forecast by National Grid
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	225.1	237.0	258.6	244.7	249.4	253.1	256.4	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		6.2	-20.3	-16.7	8.9	30.1	34.0	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		-0.1	0.8	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2267	1.2763	1.3083	1.3616	1.3887	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**261.8**	**292.9**	**293.4**	**291.0**	**337.9**	**385.6**	**403.3**	
Pass-Through Business Rates	B1	RBt	3B	ALL			-19.1	-4.7	-5.1	-5.6	-5.3	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.0	0.0	0.0	0.0	0.0	0.0	
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**0.0**	**-19.1**	**-4.7**	**-5.1**	**-5.6**	**-5.3**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL	0.5		2.6	1.2	1.2	1.2	1.2	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			1.9	0.6	0.6	0.6	0.6	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			-0.2	0.0	0.0	0.0	0.0	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	0.0	0.0	0.0	0.0	Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE			0.0	0.0	0.0	0.0	0.0	Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.5**	**0.0**	**4.3**	**1.8**	**1.8**	**1.8**	**1.8**	
Network Innovation Allowance	D	NIAt	3H	ALL	0.6	1.0	1.2	0.8	0.8	0.8	0.8	Licensee Actual/Forecast/Budget
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	25.5	29.2	18.0	31.9	33.1	33.3	32.8	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL	-0.8		8.6	0.2	0.0	0.0	0.0	Calculated by Licensee
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**287.6**	**323.1**	**306.4**	**321.0**	**368.5**	**415.9**	**433.4**	
Excluded Services	P	EXCt		SP, SHE	7.0	7.7	8.0	8.7	9.9	10.5	11.3	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	15.0	18.5	18.8	19.2	20.8	22.0	23.5	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**		**NG**	**279.6**	**312.3**	**295.7**	**310.5**	**357.6**	**404.3**	**421.2**	General System Charge
Final Collected Revenue	U	TNRt		ALL	271.3							
Over / (Under) Recovery [V=U-M]	V			ALL	-8.3							
Forecast percentage change to TNUoS Collected Revenue T				**ALL**		**11.7%**	**-5.3%**	**5.0%**	**15.2%**	**13.1%**	**4.2%**	

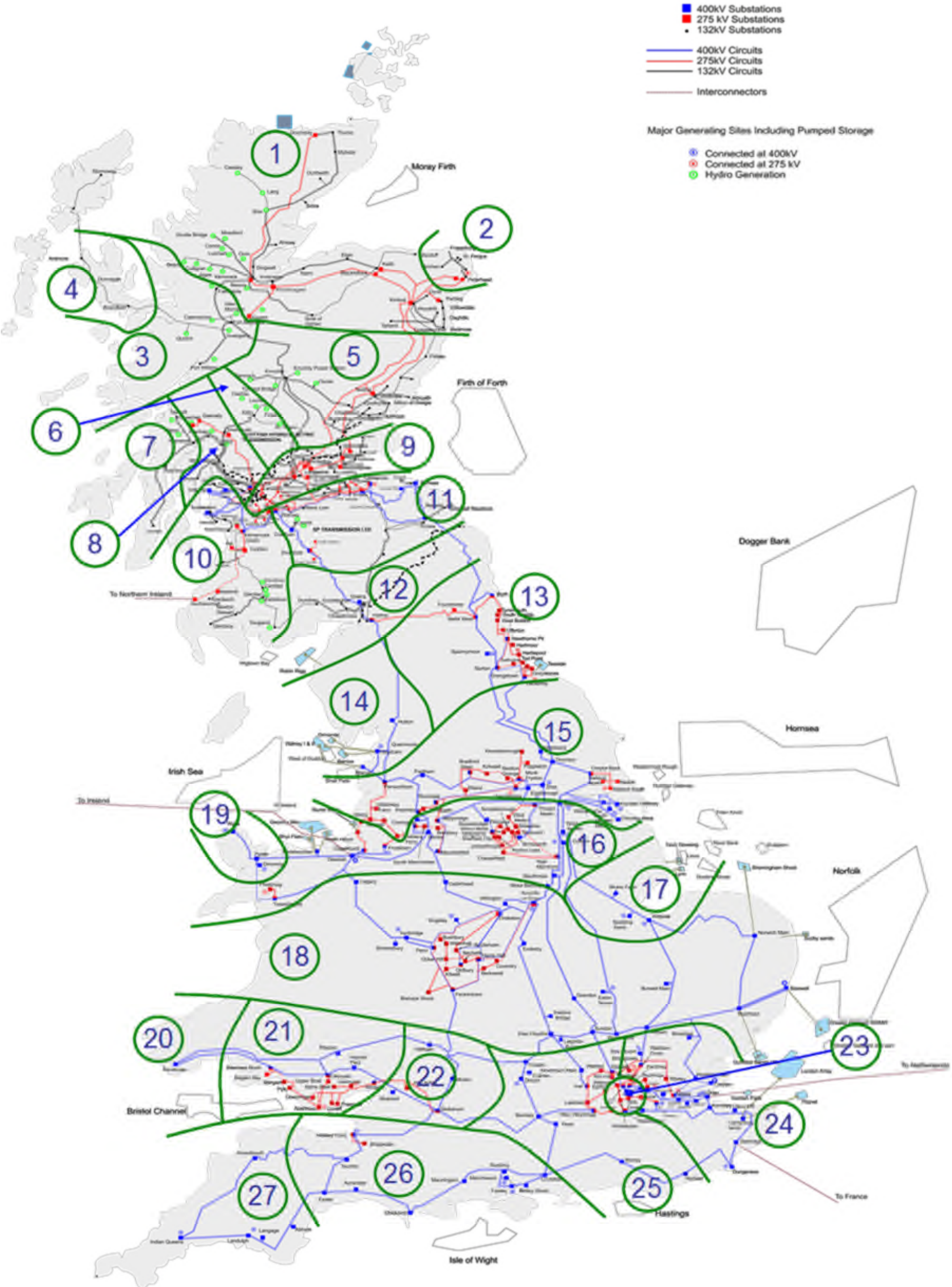
Table 20

SHE Transmission Revenue Forecast				Updated:	23/01/2015							
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	Yr t+2	Yr t+3	Yr t+4	Yr t+5	
Regulatory Year					2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Notes
Actual RPI					251.73							April to March average
RPI Actual		RPIAt			1.1667							Office of National Statistics
Assumed Interest Rate		It			0.50%	0.50%	0.70%	1.50%	2.20%	2.60%	2.60%	As forecast by National Grid
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	104.5	111.5	124.1	123.6	119.6	120.0	**No forecast available for 2019/20 so indicative numbers based upon inflated 2018/19 forecast.**	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		8.7	85.0	89.0	87.2	71.9		Forecast of cummulativce MOD impacts, excl non approved
RPI True Up	A3	TRUt	3A	ALL		0.0	0.5	-0.3	2.0	0.0		Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2267	1.2763	1.3083	1.3616		Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**121.6**	**144.9**	**257.1**	**270.9**	**273.1**	**261.3**		
Pass-Through Business Rates	B1	RBt	3B	ALL		0.0	-0.7	-16.1	-9.1	-9.4		RBt rebate received in 2014/15, pass through in 2016/17
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.0	0.6	0.0	0.0	0.0		Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**0.0**	**-0.1**	**-16.1**	**-9.1**	**-9.4**		
Reliability Incentive Adjustment	C1	RIt	3C	ALL	0.0		1.2	0.0	0.0	0.0		Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			1.6	0.0	0.0	0.0		Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			-0.1	0.0	0.0	0.0		Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	0.0	0.0	0.0		Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE			0.0	0.0	0.0	0.0		Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.0**	**0.0**	**2.7**	**0.0**	**0.0**	**0.0**		
Network Innovation Allowance	D	NIAt	3H	ALL	1.2	1.8	1.8	1.8	1.8	1.8		Licensee Actual/Forecast
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	54.5	72.2	81.3	84.9	81.8	82.0		Excludes Asset Adjusting Events impacts
Compensatory Payments Adjustment	J	SHCPt	3C	SHE	0.0	0.0	0.4	0.0	0.0	0.0		Licensee Actual/Forecast/Budget
Correction Factor	K	-Kt	3A	ALL	-2.8		-1.5	1.5	0.0	0.0		Latest Forecast
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**174.5**	**218.9**	**341.7**	**343.0**	**347.6**	**335.7**		
Excluded Services	P	EXCt		SP, SHE	0.0	0.0	0.0	0.0	0.0	0.0		Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	3.5	3.5	3.5	3.6	3.7	3.8		Post-Vesting, Pre-BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**		**NG**	**171.0**	**215.4**	**338.2**	**339.5**	**344.0**	**331.9**	**338.5**	General System Charge
Final Collected Revenue	U	TNRt		ALL	175.9							Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	1.5							
Forecast percentage change to TNUoS Collected Revenue T				**ALL**		**26.0%**	**57.0%**	**0.4%**	**1.3%**	**-3.5%**	**2.0%**	

Table 21

Offshore Transmission Revenue Forecast	21/01/2015							
Description	**Yr t-1**	**Yr t**	**Yr t+1**	**Yr t+2**	**Yr t+3**	**Yr t+4**	**Yr t+5**	
Regulatory Year	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**Notes**
Barrow	5.3	5.5	5.6	5.8	6.0	6.2	6.3	Current revenues plus indexation
Gunfleet	6.6	6.9	7.0	7.3	7.5	7.7	7.9	Current revenues plus indexation
Walney 1	12.1	12.5	12.8	13.2	13.6	14.0	14.4	Current revenues plus indexation
Robin Rigg	7.5	7.7	7.9	8.2	8.4	8.7	8.9	Current revenues plus indexation
Walney 2	12.6	12.9	13.2	13.7	14.1	14.5	15.0	Current revenues plus indexation
Sheringham Shoal	15.6	18.9	19.5	20.2	20.8	21.4	22.0	Current revenues plus indexation
Ormonde	11.2	11.6	11.8	12.2	12.6	13.0	13.4	Current revenues plus indexation
Greater Gabbard	11.4	26.0	26.6	27.5	28.3	29.2	30.1	Current revenues plus indexation
London Array	23.0	37.6	39.2	38.8	40.0	41.2	42.4	Current revenues plus indexation
Thanet			17.5	18.1	18.7	19.2	19.8	Current revenues plus indexation
Lincs		78.9	25.6	26.0	26.8	27.6	28.4	Current revenues plus indexation
Gwynt y mor			26.3	27.2	28.0	28.9	29.7	Current revenues plus indexation
West of Duddon Sands								National Grid Forecast
Humber Gateway			35.3	53.8	55.4	57.1	58.8	National Grid Forecast
Westermost Rough								National Grid Forecast
Galloper					8.0	23.7	24.4	National Grid Forecast
Race Bank								National Grid Forecast
Burbo Bank						40.2	112.4	National Grid Forecast
Dudgeon								National Grid Forecast
Rampion								National Grid Forecast
Beatrice								National Grid Forecast
East Anglia 1								National Grid Forecast
Inch Cape 1								National Grid Forecast
Moray Firth							88.4	National Grid Forecast
Navitus Bay 1								National Grid Forecast
Neart Na Goaith								National Grid Forecast
Triton Knoll 1								National Grid Forecast
Walney Extension								National Grid Forecast
Offshore Transmission Pass-Through (B7)	**105.4**	**218.4**	**248.4**	**272.0**	**288.2**	**352.4**	**522.4**	

Appendix C : Generation Zones



Appendix D : Demand Zones