Tariff Information Paper

Draft TNUoS tariffs for 2016/17

This information paper provides National Grid's forecast of Transmission Network Use of System (TNUoS) tariffs for 2016/17, which apply to Generators and Suppliers. Final Tariffs will be published by January 29th 2016.

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V1.0

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Any Questions?

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1 Executive Summary

This document contains our draft Transmission Network Use of System (TNUOs) tariffs for 2016/17. 2016/17 TNUoS tariffs will be finalised at the end of January 2016 and come into effect 1 April 2016.

This forecast incorporates the annual updates to price controlled revenue and Network Innovation Competition awards. Whilst individual elements of revenue have varied by up to £20m the net impact only increases revenue by £1.1m.

As required by the charging methodology, the generation background used to set the locational element of tariffs is based upon the TEC register of Friday 30 October 2015, a copy of which is in the tools and data section of our website[*]. The residual element of generator tariffs is determined by National Grid's view of potential closures and changes to new projects which is 2.5GW lower than the contracted background.

As indicated in the November forecast we continue to review our demand forecasts. Previous forecasts were based upon the Future Energy Scenarios but embedded generation has grown faster this year than anticipated in these scenarios. We have therefore decreased our forecasts for peak, HH and NHH demand in this forecast by around 4%. This increases HH demand tariffs by an average of £0.79/kW and NHH tariffs by an average of 0.34p/kWh. However, the growth of embedded generation across the country is uneven and therefore the tariff increase in each zone can vary significantly.

On 25 November 2015 Ofgem opened a consultation on retaining the discount provided to small generators. We have previously assumed this discount would lapse in April 2016 but this forecast shows the value of the discount and the impact on supplier tariffs if it is retained. The consultation is due to close on 23 December 2015 and a decision is expected in time for when final tariffs are set in January.

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

2 Tariff Summary

This section summarises the draft generation and demand tariff forecasts for 2016/17. Information can be found in later sections on how these tariffs were calculated and why they have changed from the previous forecast.

2.1 Generation Tariffs 2016/17

Table 1 - Wider Generation Tariffs

Under the Transmit methodology each generator has its own Annual Load Factor (ALF). Draft ALFs for 2016/17 are in the TNUoS forecast area of our website†. The 70% and 30% load factors used in this table are only for illustration.

		System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional 70%	Intermittent 30%
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	-1.99	10.51	7.77	0.49	13.63	11.42
2	East Aberdeenshire	-0.95	4.16	7.77	0.49	10.22	9.51
3	Western Highlands	-2.07	8.30	7.49	0.49	11.73	10.48
4	Skye and Lochalsh	-6.07	8.30	8.96	0.49	9.19	11.95
5	Eastern Grampian and Tayside	-2.11	7.47	7.20	0.49	10.81	9.94
6	Central Grampian	0.63	7.73	7.35	0.49	13.88	10.16
7	Argyll	-0.47	5.34	15.89	0.49	19.65	17.98
8	The Trossachs	0.11	5.34	5.86	0.49	10.19	7.95
9	Stirlingshire and Fife	-2.13	2.77	5.08	0.49	5.39	6.41
10	South West Scotlands	-0.30	4.22	5.41	0.49	8.56	7.17
11	Lothian and Borders	0.69	4.22	3.24	0.49	7.37	4.99
12	Solway and Cheviot	-0.74	2.74	2.97	0.49	4.65	4.29
13	North East England	0.91	2.10	-0.11	0.49	2.76	1.01
14	North Lancashire and The Lakes	1.10	2.10	1.85	0.49	4.91	2.97
15	South Lancashire, Yorkshire and Humber	4.01	1.44	0.10	0.49	5.61	1.02
16	North Midlands and North Wales	3.88	0.46		0.49	4.70	0.63
17	South Lincolnshire and North Norfolk	2.24	0.60		0.49	3.16	0.67
18	Mid Wales and The Midlands	1.61	0.33		0.49	2.33	0.59
19	Anglesey and Snowdon	4.96	1.03		0.49	6.18	0.80
20	Pembrokeshire	9.11	-2.68		0.49	7.73	-0.31
21	South Wales & Gloucester	6.25	-2.65		0.49	4.89	-0.30
22	Cotswold	3.19	3.11	-5.75	0.49	0.12	-4.32
23	Central London	-2.76	3.11	-6.32	0.49	-6.41	-4.89
24	Essex and Kent	-3.50	3.11		0.49	-0.83	1.43
25	Oxfordshire, Surrey and Sussex	-0.99	-1.52		0.49	-1.56	0.04
26	Somerset and Wessex	-1.01	-2.65		0.49	-2.37	-0.30
27	West Devon and Cornwall	0.25	-3.95		0.49	-2.02	-0.69
	Small Generation Discount				-11.36		

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

Table 2 - Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.18	0.10	0.07
<1320 MW	Redundancy	0.40	0.25	0.18
>=1320 MW	No redundancy		0.33	0.24
>=1320 MW	Redundancy		0.53	0.39

Table 3 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.88	Dinorwig	2.17	Luichart	0.52
Aigas	0.59	Dumnaglass	1.68	Marchwood	0.35
An Suidhe	0.85	Dunlaw Extension	5.37	Mark Hill	0.79
Arecleoch	1.88	Edinbane	6.19	Millennium	1.65
Baglan Bay	0.63	Ewe Hill	1.24	Moffat	0.17
Beinneun Wind Farm	1.36	Fallago	0.90	Mossford	2.60
Bhlaraidh Wind Farm	-0.58	Farr Windfarm	2.04	Nant	-1.11
Black Law	1.58	Ffestiniogg	0.23	Necton	-0.34
BlackLaw Extension	3.35	Finlarig	0.29	Rhigos	0.07
Bodelwyddan	0.10	Foyers	0.68	Rocksavage	0.02
Brochloch	1.94	Galawhistle	0.76	Saltend	0.31
Carraig Gheal	3.97	Glendoe	1.66	South Humber Bank	0.86
Carrington	-0.04	Gordonbush	1.17	Spalding	0.25
Clyde (North)	0.10	Griffin Wind	-0.85	Strathy Wind	2.44
Clyde (South)	0.11	Hadyard Hill	2.50	Western Dod	0.64
Corriegarth	3.41	Harestanes	2.28	Whitelee	0.10
Corriemoillie	1.50	Hartlepool	0.54	Whitelee Extension	0.27
Coryton	0.31	Hedon	0.16		
Cruachan	1.65	Invergarry	1.28		
Crystal Rig	0.33	Kilbraur	1.04		
Culligran	1.57	Kilgallioch	0.95		
Deanie	2.57	Kilmorack	0.18		
Dersalloch	2.18	Langage	0.59		
Didcot	0.47	Lochay	0.33		

Table 4 - Offshore Local Tariffs

Table 4 shows tariffs for generators connected to existing offshore transmission networks. We will discuss tariffs for new offshore networks with the affected generators prior to asset transfer.

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.31	38.25	0.95
Greater Gabbard	13.71	31.50	0.00
Gunfleet	15.82	14.53	2.71
Gwynt Y Mor	16.69	16.44	0.00
Lincs	13.66	53.49	0.00
London Array	9.30	31.68	0.00
Ormonde	22.60	42.10	0.34
Robin Rigg	-0.42	27.69	8.58
Robin Rigg West	-0.42	27.69	8.58
Sheringham Shoal	21.84	25.61	0.56
Thanet	16.63	30.99	0.75
Walney 1	19.51	38.84	0.00
Walney 2	19.36	39.19	0.00
West of Duddon Sands	7.53	37.14	0.00

2.2 Demand Tariffs 2016/17

Table 5 - Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	40.57	7.52
2	Southern Scotland	39.85	6.40
3	Northern	42.53	7.36
4	North West	42.43	6.50
5	Yorkshire	42.10	6.20
6	N Wales & Mersey	42.28	6.70
7	East Midlands	44.33	6.15
8	Midlands	45.34	6.49
9	Eastern	46.15	6.10
10	South Wales	41.91	6.61
11	South East	48.81	8.60
12	London	51.48	6.56
13	Southern	49.68	6.92
14	South Western	48.19	7.15

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 at different locations 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 two models of power flows on the transmission system: peak demand and year round. 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 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.

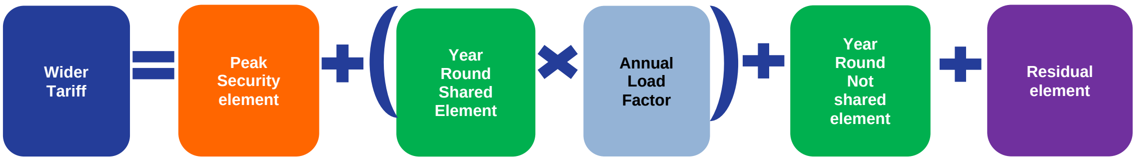
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and demand tariffs. The residual is also used to ensure the correct proportion of revenue is collected from Generation and Demand. 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 the cost and design of local connections and vary from project to project. For offshore Generators, these local charges reflect OFTO revenue allowances.

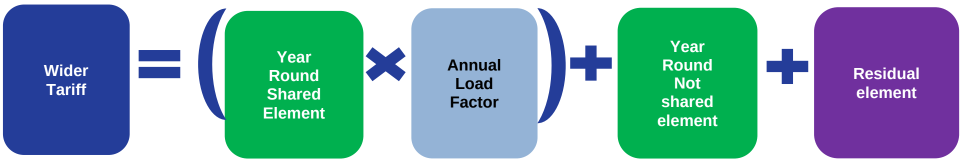
3.2 Project TransmiT

Under the TransmiT methodology there are still 27 generation zones but each zone now has four tariffs rather than just one. A Generator's liability is dependent upon its type of generation. Coal, Nuclear, Gas, Pumped Storage, Oil and Hydro are classed as conventional and wind is intermittent. Liability for each tariff component is shown below:

Conventional Generator



Intermittent Generator



Each generator has a specific annual load factor based on its performance over the last five years. Where new plant does not have at least three complete charging year's history then generic load factors specific to the technology are also used.

3.3 P272

Balancing and Settlement Code amendment P272 makes it mandatory that Non-Half-Hour (NHH) profile classes 5-8 move to metering classes E, F and G Half-Hour (HH) settlement. The subsequent amendment P322 revised the completion date for P272 to 1 April 2017 so the affected NHH demand will still be in transition during 2016/17.

Connection and Use of System Code Modification Proposals 241 and 247 have been approved by Ofgem. The combined effect of these is to treat meters that were profile classes 5 to 8 prior to 1 April 2015 as Non-half Hour metered until 31 March 2017. A small number of Metering Class E meters are also treated as Non-Half Hour metered under CMP241/247 but suppliers may opt for these to be treated as Half-Hour metered by providing additional data to National Grid. In summary there will be negligible change to the proportion of chargeable HH demand compared to NHH demand in 2016/17.

4 Updates to the Charging Model for 2016/17

Since our forecast in November we have updated: allowed revenue, contracted generation, chargeable generation and chargeable demand. We have also re-included the small generator discount.

We are expecting updated revenue forecasts for each Transmission Owner in January and will also continue to review our forecasts for chargeable generation, chargeable demand and forecast generator volumes.

4.1 Changes affecting the locational element of tariffs

4.1.1 Contracted Generation

We have updated generation for 2016/17 using the contracted generation background on 30 October 2015. This is the background we are required to use for calculating the locational element of charges when setting final tariffs for 2016/17 and therefore there is no difference between contracted and modelled TEC in Table 6. A copy of the TEC register for 30 October 2015 can be found in the Tools and Data section of our website[‡].

Changes in the contracted background since the November forecast are listed in Appendix B. The demand forecasts used for calculating the locational element of tariffs are net of licence exemptible distributed generation. Therefore licence exemptible distributed generation is excluded from the generation background to avoid double counting and is not included in Appendix B.

Table 6 - Contracted and Modelled TEC

(GW)	2015/16	2016/17 Initial forecast	2016/17 May Forecast	2016/17 July Forecast	2016/17 Oct Forecast	2016/17 Dec Draft
Contracted TEC	78.7	88.5	81.7	79.7	70.4	69.9
Modelled TEC	78.7	82.9	79.1	71.8	68.2	69.9

4.1.2 Locational 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, forecasts of demand at directly connected demand sites such as steelworks and railways and licence exemptable distributed embedded generation contracted at 30 October 2015. Subject to audit checks these will remain unchanged when tariffs are finalised in January 2016.

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

4.1.3 Transmission network

A few amendments to circuit data have been made since the November forecast based upon the 2015 Electricity Ten Year Statement (ETYS). These mainly affect local circuit charges.

4.2 Changes affecting the residual element of tariffs

4.2.1 Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Table 7 shows the forecast 2016/17 revenues that have been used in calculating tariffs. Previous forecasts and the final revenue upon which 2015/16 tariffs were set are also included for comparison.

Forecast revenues for onshore Transmission Owners have been updated to reflect price control adjustments by Ofgem in November. These reduced forecast revenue for National Grid and increased revenue for SHE Transmission. HM Treasury's November RPI forecast has also been used to update the inflation element of allowed revenue.

The Westermost Rough OFTO is forecast to asset transfer in February 2016 and Humber Gateway is expected to asset transfer at a later date, potentially during the 2016/17 charging year. As both asset transfers will occur after 2016/17 tariffs have been set, National Grid will forecast the 2016/17 revenue to be recovered through TNUoS tariffs for these two OFTOs.

The Network Innovation Competition funding decided by Ofgem in November was higher than was previously forecast. However, the net effect of all changes in revenue is a modest £1.1m increase on the November forecast. Further detail on revenue can be found in Appendix A.

Table 7 – Allowed Revenues

£m Nominal	2015/16 TNUoS Revenue	2016/17 TNUoS Revenue				
	Jan 2015 Final	Jan 2015 Initial View	April 2015 Update	July 2015 Update	Oct 2015 Update	Dec 2015 Draft
National Grid						
Price controlled revenue	*1,780.7*	*1,953.8*	*1,937.0*	*1,938.8*	*1,848.9*	*1,827.5*
Less income from connections	*45.0*	*48.3*	*45.0*	*45.0*	*45.6*	*45.6*
Income from TNUoS	**1,735.7**	**1,905.5**	**1,892.0**	**1,893.9**	**1,803.3**	**1,781.9**
Scottish Power Transmission						
Price controlled revenue	*306.4*	*321.0*	*303.1*	*302.3*	*300.7*	*302.6*
Less income from connections	*10.7*	*10.5*	*8.9*	*8.9*	*12.4*	*12.4*
Income from TNUoS	**295.7**	**310.5**	**294.2**	**293.4**	**288.3**	**290.2**
SHE Transmission						
Price controlled revenue	*341.7*	*343.0*	*333.6*	*329.0*	*309.0*	*325.9*
Less income from connections	*3.5*	*3.6*	*3.5*	*3.5*	*3.5*	*3.5*
Income from TNUoS	**338.2**	**339.5**	**330.1**	**325.5**	**305.5**	**322.4**
Offshore	**248.4**	**269.1**	**265.6**	**259.3**	**262.5**	**261.8**
Network Innovation Competition	**18.8**	**48.4**	**40.5**	**40.5**	**40.5**	**44.9**
Total to Collect from TNUoS	**2,636.7**	**2,873.0**	**2,822.4**	**2,812.6**	**2,700.1**	**2,701.2**

4.2.2 Charging bases for 2016/17

Generation

Whilst the locational element of TNUoS tariffs is fixed using the contracted background on 30 October 2015, the generation charging base reflects the generation that is forecast to pay charges. The generation charging base excludes interconnectors, which are not chargeable, generation likely to close or reduce its capacity before the start of the charging year and new generation likely to delay its connection out of 2016/17. We currently forecast 62.8GW of generation will be chargeable in 2016/17.

Demand

Since the November forecast we have improved our modelling of demand in 2016/17. Improvements include updating the growth in embedded generation this year, updating the sensitivity of demand to weather as a result of more embedded generation and extending the range of weather scenarios considered.

Our forecast of system demand at Triad has reduced by 1.2% from 50.7GW to 50.0GW with a fairly even decrease across the country. Reducing system demand at Triad increases HH tariffs.

Our forecast of Half-Hour (HH) metered demand at Triad has decreased by 3.8% on average although the changes vary from zone to zone. Generally these reductions are due to the growth in licence exemptable distributed generation which is treated as negative HH demand.

Our forecast of Non-Half-Hour (NHH) metered demand has reduced by an average of 4.3%. Reducing NHH demand increases NHH tariffs. The capacity of solar generation installed this year is believed to have exceeded that forecast in the 2015 FES. This illustrates the speed with which solar projects have been constructed in response to incentives, or future reductions in incentives, contributing to a 10% year on year reduction in our NHH forecast.

Appendix C shows the changes in demand charging base between the November and this forecast.

Table 8 - Charging Base

Charging Base	2015/16	2016/17
Generation (GW)	71.5	62.8
Total Average Triad (GW)	52.4	50.0
HH Demand Average Triad (GW)	15.0	13.6
NHH Demand (4pm-7pm TWh)	27.4	24.6

4.2.3 Adjustments for Interconnectors

When modelling flows on the transmission system, interconnectors are not included in the peak model but are included in the year round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases, see Table 9.

Table 9 - Interconnectors

Interconnector	Site	Interconnected System	Generation Zone	Transport Model (Generation MW) Peak	Transport Model (Generation MW) Year Round	Charging Base (Generation MW)
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
Britned	Grain 400kV	Netherlands	24	0	1200	0
East - West	Deesside 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	295	0

4.2.4 Demand: Generation Split

EU Regulation ECR 838/2010 limits average annual generation use of system charges in Great Britain to €2.5/MWh. The net revenue that can be recovered from generation is therefore determined by: the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. As in the November forecast an 8.2% error margin has been applied to reflect revenue and output forecasting accuracy.

As prescribed by the Use of System charging methodology, the exchange rate for 2016/17 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2015. The value of €1.36/£ is unchanged and will be used in setting final tariffs.

The forecast output of generation subject to Generation TNUoS charges is unchanged in this forecast but will be kept under review in light of the changing generation background and demand forecast.

The parameters used to calculate the proportions of revenue collected from generation and demand are shown in Table 10.

Table 10 - Generation and Demand revenue proportions

		2015/16	2016/17
CAP_{EC}	Limit on generation tariff (€/MWh)	2.5	2.5
y	Error Margin	6.4%	8.2%
ER	Exchange Rate (€/£)	1.22	1.36
MAR	Total Revenue (£m)	2,637	2,701
GO	Gerneration Output (TWh)	319.6	268.7
G	% of revenue from generation	23.2%	16.8%
D	% of revenue from demand	76.8%	83.2%
G.R	Revenue recovered from generation (£m)	612	453
D.R	Revenue recovered from demand (£m)	2,025	2,248

4.2.5 Generation and Demand Residuals

The residual element of tariffs can be calculated using the formulas below. This can be used to assess the effect of changing the assumptions in our tariff forecasts without the need to run the transport and tariff model.

$$R_G = \frac{G.R - Z_G - O - L_c - L_S}{B_G}$$

$$R_D = \frac{D.R - Z_D}{B_D}$$

Where:

- R_G is the Generation residual tariff (£/kW)
- R_D is the Demand residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from Generation
- D is the proportion of TNUoS revenue recovered from Demand
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from Generation locational zonal tariffs (£m)
- Z_D is the TNUoS revenue recovered from Demand locational zonal tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_C is the TNUoS revenue recovered from onshore local circuit tariffs (£m)
- L_S is the TNUoS revenue recovered from onshore local substation tariffs (£m)
- B_G is the generator charging base (GW)

- B_D is the Demand charging base (Half-hour equivalent GW)

$\mathbf{Z_G}$, $\mathbf{Z_D}$ and $\mathbf{L_C}$ are determined by the locational elements of tariffs.

Typically 75% of offshore revenues are recovered from offshore local tariffs. In 2016/17 offshore local tariffs are forecast to be £201.6m which is included in the revenue recovered from generation.

Table 11 - Residual Calculation

		2015/16	2016/17
R_G	Generator residual tariff (£/kW)	4.81	0.49
R_D	Demand residual tariff (£/kW)	35.63	44.96
G	Proportion of revenue recovered from generation (%)	23.2%	16.8%
D	Proportion of revenue recovered from demand (%)	76.8%	83.2%
R	Total TNUoS revenue (£m)	2,637	2,701
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	47.6	191.7
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	157.7	-2.0
O	Revenue recovered from offshore local tariffs (£m)	186.6	201.6
L_G	Revenue recovered from onshore local substation tariffs (£m)	20.1	15.9
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.8	13.2
B_G	Generator charging base (GW)	71.5	62.8
B_D	Demand charging base (GW)	52.4	50.0

4.3 Other changes

4.3.1 Expansion Constant

The expansion constant has decreased to £13.336061/MWkm from the November forecast to reflect lower actual and forecast RPI.

5 Forecast generation tariffs for 2016/17

The following section provides details of the forecast wider and local generation tariffs for 2016/17.

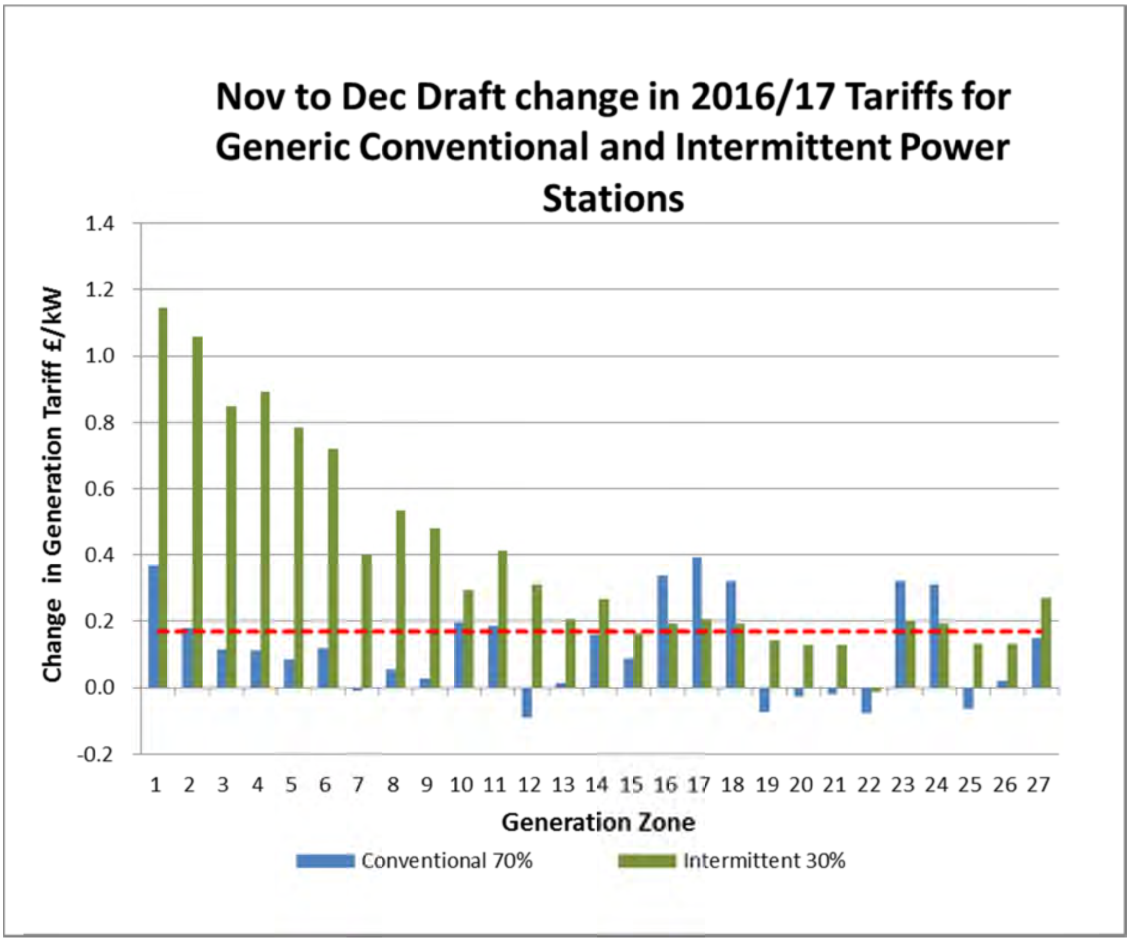
5.1 Wider zonal generation tariffs

Table 12 and Figure 1 show the changes in generation wider TNUoS tariffs between the November and this forecast for a conventional generator with 70% load factor and an intermittent generator with 30% load factor. Under the Transmit methodology each generator has its own load factor and the 70% and 30% load factors used here are only for illustration.

Table 12 – Generation tariff changes

Wider Generation Tariffs (£/kW)									
		Conventional 70%			Intermittent 30%			
Zone	Zone Name	2016/17 Nov Forecast (£/kW)	2016/17 Draft Tariffs (£/kW)	Change (£/kW)	2016/17 Nov Forecast (£/kW)	2016/17 Draft Tariffs (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	13.26	13.63	0.37	10.27	11.42	1.14	0.17
2	East Aberdeenshire	10.04	10.22	0.18	8.45	9.51	1.06	0.17
3	Western Highlands	11.61	11.73	0.12	9.63	10.48	0.85	0.17
4	Skye and Lochalsh	9.08	9.19	0.11	11.05	11.95	0.89	0.17
5	Eastern Grampian and Tayside	10.73	10.81	0.08	9.16	9.94	0.78	0.17
6	Central Grampian	13.76	13.88	0.12	9.44	10.16	0.72	0.17
7	Argyll	19.66	19.65	-0.01	17.58	17.98	0.40	0.17
8	The Trossachs	10.14	10.19	0.06	7.42	7.95	0.53	0.17
9	Stirlingshire and Fife	5.36	5.39	0.03	5.93	6.41	0.48	0.17
10	South West Scotland	8.36	8.56	0.20	6.87	7.17	0.30	0.17
11	Lothian and Borders	7.18	7.37	0.19	4.58	4.99	0.41	0.17
12	Solway and Cheviot	4.74	4.65	-0.09	3.97	4.29	0.31	0.17
13	North East England	2.75	2.76	0.01	0.81	1.01	0.21	0.17
14	North Lancs and The Lakes	4.76	4.91	0.16	2.71	2.97	0.27	0.17
15	South Lancs, Yorks and Humber	5.52	5.61	0.09	0.86	1.02	0.16	0.17
16	North Midlands and North Wales	4.36	4.70	0.34	0.44	0.63	0.19	0.17
17	South Lincs and North Norfolk	2.76	3.16	0.39	0.47	0.67	0.21	0.17
18	Mid Wales and The Midlands	2.01	2.33	0.32	0.40	0.59	0.19	0.17
19	Anglesey and Snowdon	6.25	6.18	-0.07	0.66	0.80	0.14	0.17
20	Pembrokeshire	7.76	7.73	-0.03	-0.44	-0.31	0.13	0.17
21	South Wales	4.91	4.89	-0.02	-0.43	-0.30	0.13	0.17
22	Cotswold	0.20	0.12	-0.08	-4.30	-4.32	-0.01	0.17
23	Central London	-6.73	-6.41	0.32	-5.09	-4.89	0.20	0.17
24	Essex and Kent	-1.13	-0.83	0.31	1.24	1.43	0.19	0.17
25	Oxfordshire, Surrey and Sussex	-1.49	-1.56	-0.06	-0.09	0.04	0.13	0.17
26	Somerset and Wessex	-2.39	-2.37	0.02	-0.43	-0.30	0.13	0.17
27	West Devon and Cornwall	-2.17	-2.02	0.15	-0.96	-0.69	0.27	0.17

Figure 1 - Variation in Generation Zonal Tariffs



Locational Tariff

The increase in Scottish tariffs, and particularly the tariffs paid by intermittent generation, is due to additional Scottish renewable generation. This generation was expected to defer connection and was therefore removed from earlier forecasts. However, it is now included because it was contracted in the 30 October TEC register upon which the locational element of tariffs is based.

This additional generation causes a modest increase in the year round north to south flow in key circuits. Previously the peak south to north flow in these key circuits was slightly higher than the year round north to south flow so these circuits were included in the peak tariff cost base. The modest increase in year round flow means these circuits now have higher flows in the year round scenario. Therefore peak tariffs in Scotland have reduced as these circuits are no longer contributing to the peak scenario and year round tariffs have increased as these circuits are now contributing to year round costs. Conventional generation is exposed to both the peak reduction and the year round increase and sees a small net increase due to the modest increase in flow. Intermittent generation is only exposed to the year round increase so sees a larger increase.

The higher tariffs around zones 16 to 18 are due to generators in this area being contracted in the 30 October TEC register which we had expected to reduce or defer and therefore removed from earlier forecasts.

The higher tariffs in zones 23 and 24 and corresponding reductions in zones 19 to 22 and 25 to 27 are caused by changes in Welsh and East Anglian contracted generation which modify East-West flows in England.

Residual Tariff

The forecast residual element of the tariff has increased by £0.17/kW since our November forecast whilst average generation charges have increased by £0.13/kW. This increase in tariffs is mainly caused by the 1.2GW reduction in forecast chargeable generation since the last forecast.

5.2 Onshore local circuit tariffs

Onshore local circuit tariffs have been updated from the November forecast. Variations from that forecast are generally caused by changes in flows on surrounding circuits. If you require further information around a particular local circuit tariff please feel free to contact us.

Charging modification CMP203 requires circuits in the transport model to be modelled differently from the actual circuit parameters if they have been subject to a one off charge[§]. Table 13 lists those circuits which we will amend for 2016/17 to reflect the fact that the customer has already paid/or will pay for the non-standard incremental cost.

Table 13 - Circuits subject to one off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
East Kilbride South 275kV	Whitelee 275kV	6km of Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km of Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km of Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km of Cable	7.17km of OHL	Clyde South
Crystal Rig 132kV	Western Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Coalburn 132kV	Galawhistle 132kV	9.7km cable	9.7km OHL	Galawhistle II
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes

5.3 Onshore local substation tariffs

Local substation tariffs have been updated from the November forecast to reflect actual and forecast RPI but have changed little.

5.4 Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) have been updated from the November forecast to reflect lower actual and forecast RPI. Offshore local generation tariffs associated with Offshore Transmission Owners yet to be appointed will be calculated following their appointment.

[§] CUSC section 14.15.12 to 14.15.20

6 Forecast demand tariffs for 2016/17

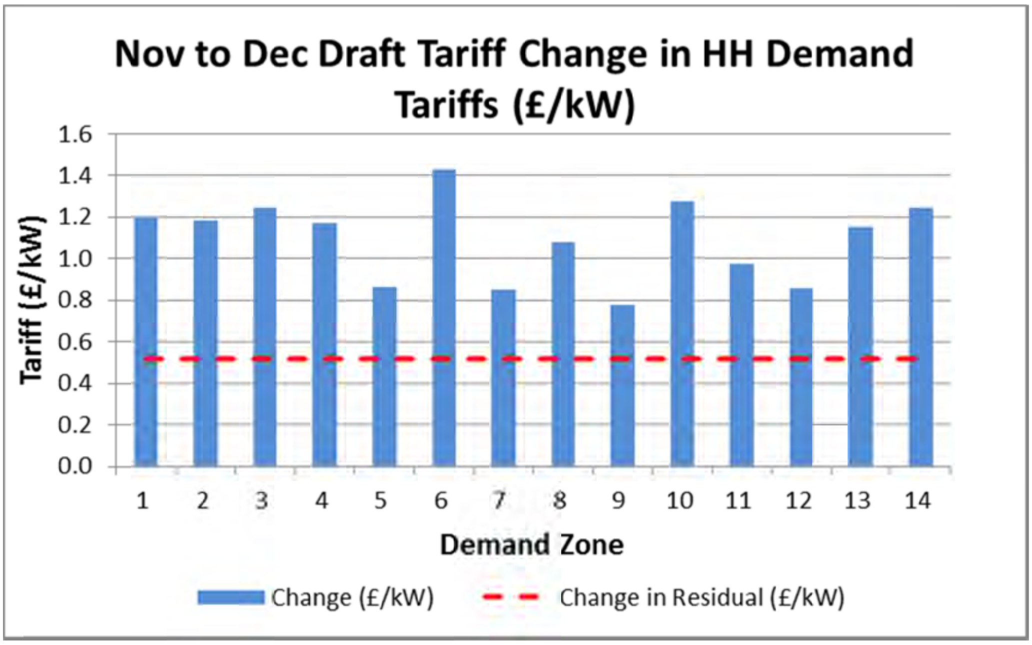
6.1 Half Hour demand tariffs

Table 14 and Figure 2 show the difference between the Half-Hourly (HH) demand tariffs forecast in November and this forecast.

Table 14 - Change in HH Demand Tariffs

Zone	Zone Name	2016/17 Nov Forecast (£/kW)	2016/17 Dec Draft (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	39.37	40.57	1.20	0.52
2	Southern Scotland	38.67	39.85	1.18	0.52
3	Northern	41.29	42.53	1.25	0.52
4	North West	41.26	42.43	1.17	0.52
5	Yorkshire	41.24	42.10	0.86	0.52
6	N Wales & Mersey	40.86	42.28	1.43	0.52
7	East Midlands	43.48	44.33	0.85	0.52
8	Midlands	44.26	45.34	1.08	0.52
9	Eastern	45.37	46.15	0.77	0.52
10	South Wales	40.64	41.91	1.27	0.52
11	South East	47.84	48.81	0.97	0.52
12	London	50.62	51.48	0.86	0.52
13	Southern	48.53	49.68	1.15	0.52
14	South Western	46.94	48.19	1.24	0.52

Figure 2 - Change in HH Demand Tariffs



Locational Tariff

The changes in HH tariffs relative to other zones are generally the inverse of the corresponding change in generation tariffs in the same area. For example, the welsh zones 6 and 10 are forecast to have higher increases in HH tariffs and conventional generation in the equivalent generation zones 19 and 20 are forecast to have lower tariffs.

Residual Tariff

The residual tariff element of HH demand tariffs has increased by £0.58/kW and the average HH demand tariff by £0.79/kW since the November forecast. This is largely due to the re-inclusion of the small generator discount and the reduction in system demand.

On 25 November Ofgem opened a consultation on whether to extend National Grid's licence condition to apply this discount by three years. Ofgem is minded to make the extension so we have re-included it in this forecast which results in an increase in HH and NHH tariffs. If Ofgem decide not to extend the condition then HH tariffs would decrease by £0.52/kW.

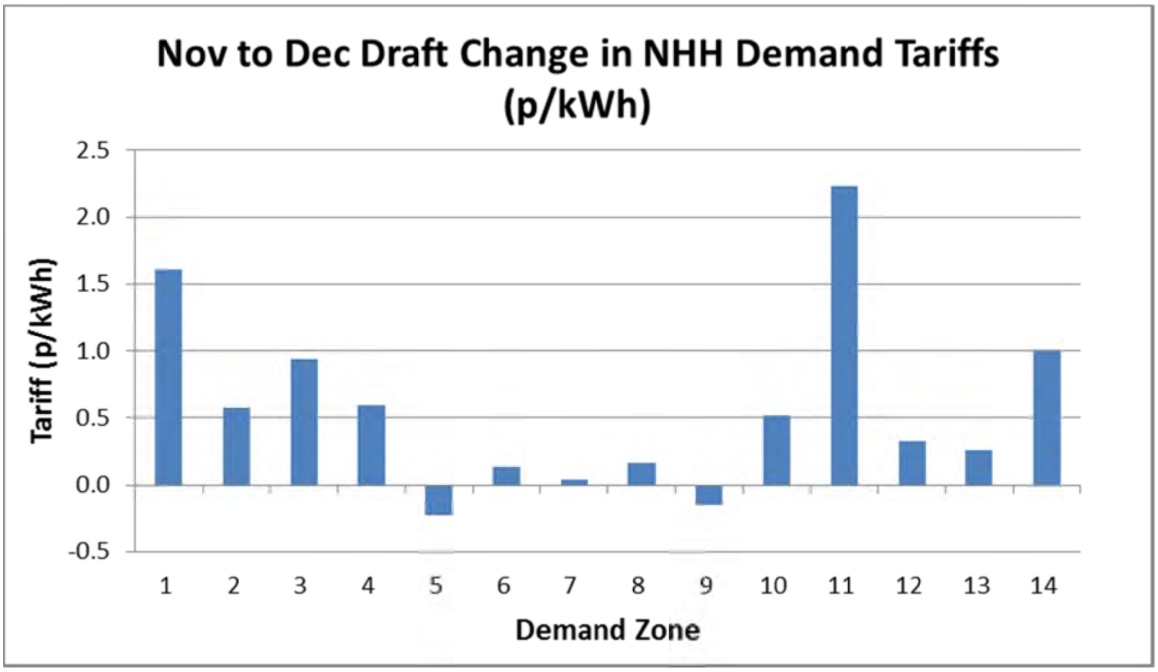
6.2 Non Half-hourly demand tariffs

Table 15 and Figure 3 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in November and this forecast.

Table 15 - NHH Demand Tariff Changes

Zone	Zone Name	2016/17 Nov Forecast (p/kWh)	2016/17 Dec Draft (p/kWh)	Change (p/kWh)
1	Northern Scotland	5.91	7.52	1.61
2	Southern Scotland	5.82	6.40	0.58
3	Northern	6.42	7.36	0.94
4	North West	5.91	6.50	0.59
5	Yorkshire	6.44	6.20	-0.23
6	N Wales & Mersey	6.56	6.70	0.14
7	East Midlands	6.11	6.15	0.04
8	Midlands	6.32	6.49	0.17
9	Eastern	6.25	6.10	-0.15
10	South Wales	6.09	6.61	0.52
11	South East	6.37	8.60	2.23
12	London	6.23	6.56	0.33
13	Southern	6.65	6.92	0.26
14	South Western	6.15	7.15	1.00

Figure 3 - NHH Tariff Demand Changes



The forecast weighted average Non Half Hour tariff is 0.34p/kWh higher than the previous forecast. Individual NHH tariffs have varied more widely due to changes in forecast HH and NHH demand.

Our modelling of HH demand forecasts has been improved to model the expected output of distributed licence exemptable generation over different Triad weather scenarios. Distributed licence exemptable generation receives demand TNUoS payments for output over the winter Triads so is treated as negative demand. An increase in this generation reduces forecast HH demand and therefore increases the proportion of revenue recovered from NHH demand. Where NHH demand is also reducing then this will magnify the increase in NHH tariffs. This is particularly noticeable in northern Scotland where the volume of distributed generation gives rise to negative HH demand forecasts. A comparison of modelled demands to the November forecast can be found in Appendix C.

7 Sensitivities & Uncertainties

7.1 Transmission revenue requirements

Table 16 illustrates the sensitivity of the forecast tariffs to a £10m increase in the revenue collected from TNUoS tariffs. This scenario does not represent a minimum or maximum tariff range.

Table 16 – Impact of change in TNUoS Revenue

£10m increase in revenue recovered from TNUoS	
Change in Generation Tariffs (£/kW)	0.0
Change in HH Demand Tariffs (£/kW)	0.20
Change in NHH Demand Tariffs (p/kWh)	0.03

7.2 Demand charging base

An increase in the demand charging base decreases tariffs. Table 17 shows the impacts of a 1% increase in system and HH chargeable demand.

Table 17 - Impact of 1% increase in system and HH in demand

Change in Demand		Change in Tariff	
Peak Demand (MW)	500		
HH Demand (MW)	136	HH Tariff (£/kW)	-0.44
NHH Demand (TWh)	0.25	NHH Tariff (p/kWh)	-0.07

7.3 Generation charging base

The locational element of tariffs is fixed using the contracted background as at 30 October 2015. However the residual element of generation tariffs may continue to be adjusted up to when tariffs are finalised in January 2016 to reflect forecast changes in the charging base.

8 Tools and Supporting Information

8.1 Further information

We are keen to ensure that customers understand the current charging arrangements and the reason why tariffs change. If you have specific queries on this forecast please contact us 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.

8.2 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.

We also provide a tariff calculator on the tools and data section of our website to calculate generator tariffs under the CMP213 ('Transmit') methodology.

8.3 Numerical data

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

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

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Appendices

Appendix A: Revenue Tables

Appendix B: Generation changes

Appendix C: Demand changes

Appendix D: Generation Zones

Appendix E: Demand Zones

Appendix A : Revenue Tables

These pages provide more detail on the price control forecasts for National Grid, Scottish Power Transmission and SHE Transmission. Revenue for offshore networks is also included with forecasts by National Grid where the Offshore Transmission Owner has yet to be appointed.

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 onshore and offshore 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 Transmission Owners 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 Transmission Owners 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 revenue 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 18 - National Grid Revenue Forecast

National Grid Revenue Forecast			04/12/2015			
Description		**Licence**	**Yr t-1**	**Yr t**	**Yr t+1**	
Regulatory Year			**2014/15**	**2015/16**	**2016/17**	**Notes**
Actual RPI			256.67			April to March average
RPI Actual		RPIAt	1.190			Office of National Statistics
Assumed Interest Rate		It	0.50%	0.70%	0.95%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1,443.8	1,475.6	1,571.4	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.5	-114.4	-185.4	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	-0.5	4.7	-19.9	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.1%	2.5%	1.0%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1732.7**	**1675.5**	**1684.4**	
Pass-Through Business Rates	B1	RBt		1.2	1.5	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	Licensee Actual/Forecast
Licence Fee	B3	LFt		2.0	2.7	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt		3.8	2.7	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	290.2	14/15 & 15/16 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.4	14/15 & 15/16 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	261.8	14/15 & 15/16 Charge setting. Later from OFTO Calculation.
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**745.1**	**890.0**	**882.0**	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0.0**	**13.9**	**18.7**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt			0.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.2	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt		56.4	104.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2524.3**	**2681.6**	**2746.9**	
Termination Charges	B5		0.0	0.0	0.0	
Pre-vesting connection charges	P		47.0	45.0	45.6	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2701.2**	
Final Collected Revenue	U	TNRt	2375.9			Licensee Actual/Forecast
Forecast percentage change to Maximum Revenue M			**0.0%**	**6.2%**	**2.4%**	
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**6.4%**	**2.4%**	

Table 19 - Scottish Power Revenue Forecast

Scottish Power Transmission Revenue Forecast			Updated:	02/12/2015		
Description		Licence Term	Yr t-1 2014/15	Yr t 2015/16	Yr t+1 2016/17	Notes
Actual RPI			256.67			April to March average
RPI Actual		RPIAt	1.1900			Office of National Statistics
Assumed Interest Rate		It	0.50%	0.63%	1.13%	National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	237.0	258.6	244.7	
Price Control Financial Model Iteration Adjustment	A2	MODt	6.2	-20.3	-21.8	16/17 MOD Direction
RPI True Up	A3	TRUt	-0.1	0.9	-3.8	0.0
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2350	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**292.9**	**293.4**	**270.6**	
Pass-Through Business Rates	B1	RBt	0.0	-20.2	-4.5	
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	0.0	
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**0.0**	**-20.2**	**-4.5**	
Reliability Incentive Adjustment	C1	RIt	0.0	2.6	3.0	
Stakeholder Satisfaction Adjustment	C2	SSOt	0.0	1.7	2.1	
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	0.0	-0.2	0.1	
Awarded Environmental Discretionary Rewards	C4	EDRt	0.0	0.0	0.0	
Financial Incentive for Timely Connections Output	C5	-CONADJt	0.0	0.0	0.0	
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**0.0**	**4.1**	**5.2**	
Network Innovation Allowance	D	NIAt	0.7	1.3	1.0	
Transmission Investment for Renewable Generation	G	TIRGt	29.3	29.6	30.9	
Correction Factor	K	-Kt	0.0	8.7	-0.1	
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**	**322.9**	**316.8**	**303.1**	
Excluded Services	P	EXCt	7.7	8.0	9.4	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt	18.5	18.8	21.8	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**	**312.1**	**306.0**	**290.7**	General System Charge
Final Collected Revenue	U	TNRt	312.2	0.0	0.0	
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**-1.9%**	**-5.0%**	

Table 20 - SHE Transmission Revenue Forecast

SHE Transmission Revenue Forecast			Updated:	02/12/2015		
Description		Licence Term	Yr t-1 2014/15	Yr t 2015/16	Yr t+1 2016/17	Notes
Actual RPI			256.67			April to March average
RPI Actual		RPIAt	1.1900			Office of National Statistics
Assumed Interest Rate		It	0.50%	0.63%	1.13%	National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	111.5	124.1	123.6	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	8.7	85.2	87.6	16/17 MOD direction
RPI True Up	A3	TRUt	-0.0	0.5	-2.6	Based on NG forecast RPIA. RPIF based on assumed Treasury Forecast of 3%
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2350	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**144.9**	**257.4**	**257.7**	
Pass-Through Business Rates	B1	RBt	0.0	-0.7	-16.1	RBt rebate received in 2014/15, pass through in 2016/17
Temporary Physical Disconnection	B2	TPDt	0.0	0.6	0.1	
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**0.0**	**-0.1**	**-15.9**	
Reliability Incentive Adjustment	C1	RIt		1.2	0.2	Forecast values based on average of previous energy not supplied actuals
Stakeholder Satisfaction Adjustment	C2	SSOt		1.6	2.3	Forecast values based on average of previous actuals; also reflects step-change to Base Revenue
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		-0.1	-0.0	Forecast based on latest actual SF6 emissions and baseline targets
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	0.0	
Financial Incentive for Timely Connections Output	C5	-CONADJt		0.0	0.0	
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**0.0**	**2.7**	**2.5**	
Network Innovation Allowance	D	NIAt	1.3	1.3	1.3	Forecast assumes same level of allowance in nominal values
Transmission Investment for Renewable Generation	G	TIRGt	72.2	81.2	80.0	Based on adjusted licence condition values
Compensatory Payments Adjustment	J	SHCPt	0.0	0.4	0.0	
Correction Factor	K	-Kt		-1.7	0.9	
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**	**218.3**	**341.1**	**326.5**	
Excluded Services	P	EXCt	0.0	0.0	0.0	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt	3.5	3.5	3.5	Post-Vesting, Pre-BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**	**214.8**	**337.6**	**323.0**	General System Charge
Final Collected Revenue	U	TNRt				
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**57.2%**	**-9.5%**	

Table 21 - Offshore Transmission Owner Revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast</th><th colspan="3">04/12/2015</th><th></th></tr>
<tr><th>Description</th><th>Yr t-1</th><th>Yr t</th><th>Yr t+1</th><th rowspan="2">Notes</th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>13.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>11.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>39.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>15.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>25.6</td><td>26.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>0.0</td><td rowspan="2">30.6</td><td rowspan="2">National Grid Forecast</td></tr>
<tr><td>Westermost Rough</td><td>0.0</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>261.8</td><td></td></tr>
</table>

Appendix B : Generation changes

Table 22 shows TEC changes notified between 23 September 2015 (used for the November forecast) and 30 October 2015 (used for this forecast.) Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

Table 22 - Generation TEC Changes

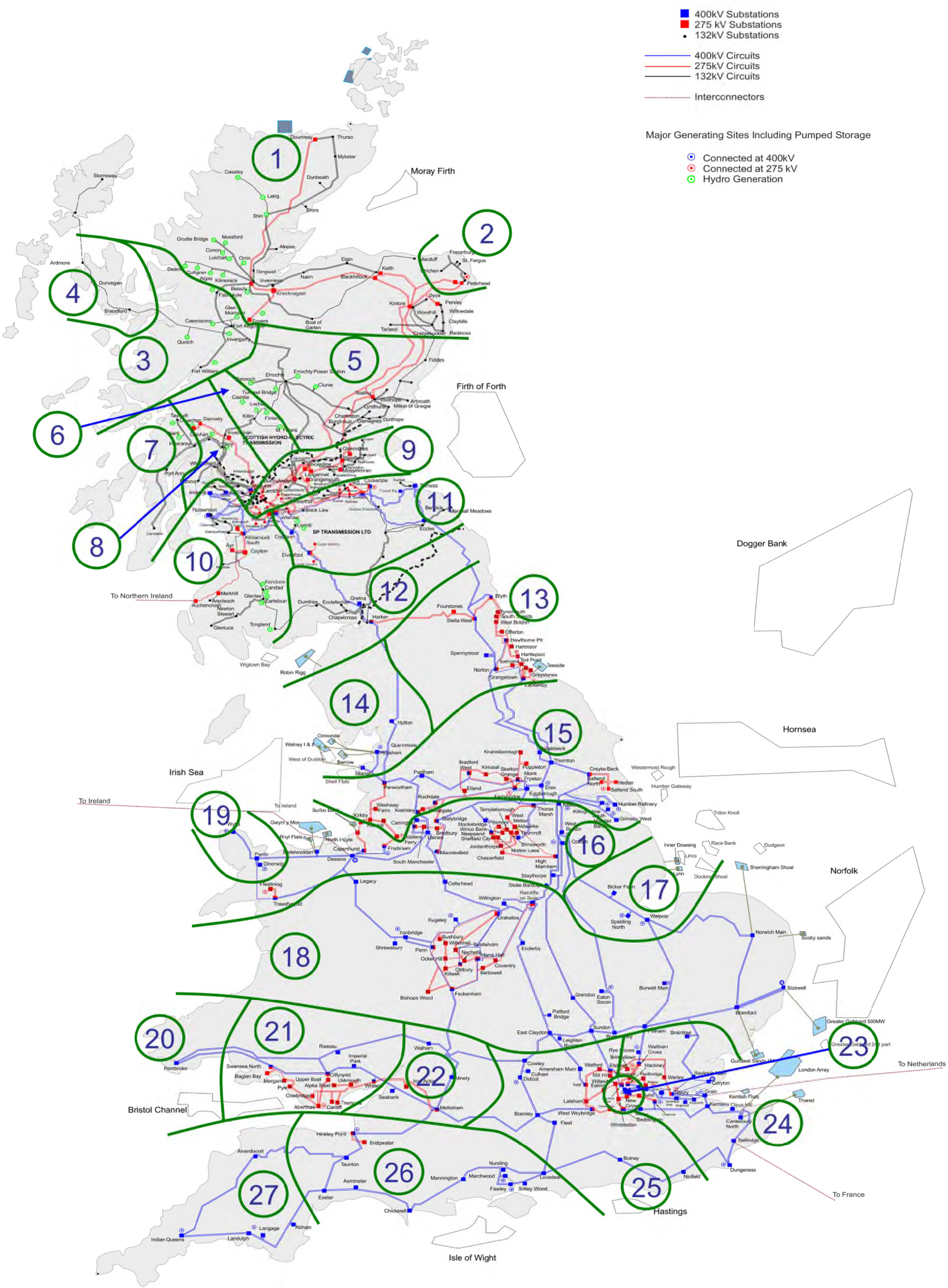
Station	Agreement Type	Node	Zone	23/09/2015	30/10/2015	MW Change
Kings Lynn A	BEGA	WALP40_EME	17	365	0	-365
Stronelairg	BCA	GLDO1G	3	227.8	0	-227.8
Tees Renewable Energy Plant	BCA	GRST20	13	280	0	-280
Whiteside Hill Wind Farm	BCA	GLGL1Q	10	27	0	-27
Total				899.8	0	-899.8

Appendix C : Demand changes

Table 23 - Demand Profiles

		Nov Forecast				Dec Draft Tariffs			
Zone	Zone Name	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)
1	Northern Scotland	629	1,061	- 162	0.81	623	727	- 488	0.65
2	Southern Scotland	3,237	3,538	962	1.71	3,226	3,062	493	1.60
3	Northern	2,609	2,295	296	1.29	2,609	2,134	143	1.15
4	North West	4,005	4,096	1,261	1.98	4,005	3,778	946	1.85
5	Yorkshire	4,559	3,908	1,104	1.80	4,559	3,806	1,012	1.90
6	N Wales & Mersey	2,092	2,707	696	1.25	2,092	3,031	1,031	1.26
7	East Midlands	4,967	4,713	1,535	2.26	4,967	4,769	1,600	2.29
8	Midlands	4,414	4,321	1,279	2.13	4,414	4,314	1,276	2.12
9	Eastern	5,581	6,103	1,617	3.25	5,581	5,997	1,515	3.39
10	South Wales	1,920	1,808	503	0.87	1,920	2,265	963	0.82
11	South East	3,609	3,590	854	2.05	3,609	3,579	852	1.55
12	London	4,730	4,737	2,137	2.11	4,730	4,434	1,835	2.04
13	Southern	5,814	5,404	1,576	2.79	5,814	5,879	2,058	2.75
14	South Western	2,699	2,391	514	1.43	2,699	2,267	393	1.26
Total		50,865	50,672	14,172	25.75	50,848	50,042	13,629	24.63

Appendix D : Generation Zones



Appendix E : Demand Zones