nationalgrid

Tariff Information Paper

TNUoS tariffs from 2013/14 to 2017/18

This information paper provides a forecast of Transmission Network Use of System (TNUoS) tariffs from 2013/14 to 2017/18. These tariffs apply to generators and suppliers.

This annual publication is intended to show how tariffs may evolve over the next 5 years. The forecasts tariffs for 2014/15 will be refined throughout the year.

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Any Questions?

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Disclaimer

This report is published without prejudice and whilst every effort has been made to ensure the accuracy of the information, it is subject to several estimations and forecasts and may not bear relation to either the indicative or actual tariffs National Grid will publish at later dates.

1 Executive Summary

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. The resulting charges reflect the use customers make of the network and the impact they have on it. In order that customers can appropriately respond to transmission charges, National Grid produces a variety of tariff forecasts. This document focuses on forecast tariffs from 2013/14 to 2017/18.

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

The forecast allowed revenue is expected to increase each year due to investment in the onshore and offshore transmission networks. This has tended to result in annual increases in average half-hourly demand tariffs of around £3/kW. Wider generation tariffs have tended to reduce on average by 38p/kW due to a large forecast increase in the generation charging base and additional forecast revenues collected from local generation tariffs. Over and above these trends, there are zonal variations. The most notable of these result from the completion of significant transmission reinforcements, particularly in Scotland, and areas where there are large changes in the contracted generation relative to the existing connections, for example, in the south-west of England.

The report also shows the impact of uncertainties in the forecast transmission revenue to be collected through TNUoS charges on behalf of all onshore and offshore transmission owners. The result of illustrative changes to the demand charging bases is also shown. Noting these uncertainties, updates to the forecasts for tariffs in 2014/15 will be prepared throughout 2013.

2 Introduction

2.1 Transmission Charges

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

To provide information about the cost of connecting in different parts of the network, National Grid determines a locationally varying component of TNUoS tariffs using a model of power flows on the transmission system. This model considers the impact that increases in generation and demand have on power flows at times of peak demand. Where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced to reflect this. In order 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 therefore do not necessarily reflect the actual cost of investment to connect a specific generator or demand site. However, for offshore generators, project specific costs are taken into account since these costs vary significantly from one project to another.

The locational components of TNUoS tariffs do not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct total revenue recovery, separate non-locational “residual” tariff elements are included in the locational generation and demand tariffs. The residuals are set to ensure that 27% of total transmission revenue is recovered from generation customers, and 73% from suppliers of both half hourly (HH) and non half-hourly (NHH) demand. This ratio is fixed in the charging methodology.

The main 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. These charges are therefore locational and specific to individual generators.

2.2 Project TransmiT / CMP213

Following Ofgem’s review of the charging arrangements to ensure these properly take into account the changing use of the transmission network and facilitate the move to a low carbon energy sector (Project TransmiT[1]), National Grid was directed to raise a CUSC modification proposal to enhance the current locational charges (CMP213)[2]. The proposal covers:

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[1] Project TransmiT is a Significant Code Review looking at the options for reforming the GB charging arrangements.

[2] CUSC Amendment CMP213

- sharing transmission network capacity by different type of generator;
- taking account of HVDC circuits that run parallel to the existing AC system; and
- island connections that use sub-sea cable technology.

Since July 2012, the CMP213 Working Group has been developing and assessing the proposal. In December 2012, the Working Group published a consultation on its findings and responses to this were received in mid-January. The Working Group has now considered these; developed alternatives to the original proposal; and undertaken detailed modelling of the impact of these proposals[3].

The Working Group has also considered and consulted upon possible implementation and transition arrangements, although it is for the Authority to determine the implementation date. Against this background, it is possible that if CMP213 were approved it could be implemented at the start or during 2014/15. However, as it is unclear which (if any) any of the options developed will be approved, **this forecast is based on the current charging methodology**. To understand the range of possible impacts of CMP213, please refer to the CMP213 Working Group Report.

2.3 Uncertainties

In addition to known possible changes to the charging methodology related to CMP213, other proposals to change the charging methodology could be raised by industry participants. Furthermore, changes to the generation (and demand) connected to the onshore and offshore transmission system and the consequential impact on network investment and revenue TO requirements, will also impact the level of transmission charges. Whilst this report does consider uncertainties, these are not exhaustive and seek to illustrate the sensitivity of tariffs.

2.4 Future Updates to tariff forecasts

Noting these uncertainties and our desire to provide timely and accurate information on the future path of tariffs, National Grid will update the forecast of 2014/15 tariffs throughout 2013 according to the timetable below:

26 April 2013	1st update of forecast tariffs for 2014/15
31 July 2013	2nd update of forecast tariffs for 2014/15
1 November 2013	3rd update of forecast tariffs for 2014/15
24 December 2013	Draft tariffs for 2014/15
31 January 2014	Final tariffs for 2014/15

This will allow customers to gauge the impact of changes to the key inputs into the charging model such as TEC reductions and allowed revenue ahead of the publication of draft and final TNUoS tariffs.

[3] The CMP213 Working Group has prepared illustrative tariffs under a number of scenarios and alternative charging methodologies. The status quo scenario in Working Group report is not directly comparable to the information included in this information paper, which has been prepared using the contracted generation background and the updated generation charging zone boundaries. Tariffs in this paper have also been presented in outturn prices, including the impact of inflationary changes to the expansion constant, whereas the CMP213 document is in constant prices.

3 Updates to the Charging Model

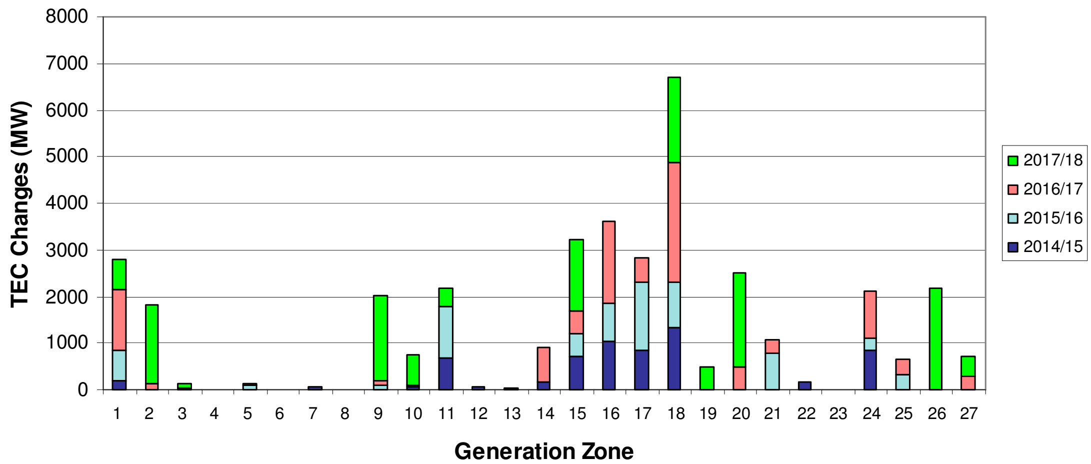
In order to forecast generation and demand tariffs a number of changes must be made to the charging model. These can be grouped into the following categories:

- generation, demand, and the transmission network, which affect the locational element of tariffs;
- the total revenue to collect and the charging bases, which affect the residual element of tariffs; and
- updates to model parameters, such as the unit cost of investment.

3.1 Changes influencing the locational element of tariffs

3.1.1 Generation

Information about generation capacities has been taken from the contracted background on 31 October 2012. The chart below shows the changes that have been incorporated in the charging model from 2014/15 to 2017/18. Appendix A and B provides the same data in tabular form on a station and zonal basis for 2014/15 out to 2017/18. For reference, Zones 1 to 12 represent Scotland and Zones 13 to 27 represent England & Wales.



Total annual increase in contracted generation (GW)			
2014/15	**2015/16**	**2016/17**	**2017/18**
6.2	7.2	10.0	13.7

3.1.2 Demand

Information for peak demand at each Grid Supply Point (GSP) has been sourced from the 2012 Ten Year Statement (TYS), which is based on information received from the DNOs and directly connected demand sites such as steelworks and other heavy industry. Appendix B provides the zonal information.

3.1.3 Transmission network

A number of provisional network changes have been made to connect new generation and reinforce the network. These have been based on the network information provided by the TOs together with any minimal changes needed to connect generation that is contracted to connect. Of particular note is the completion of the Beauly-Denny reinforcement, which has been modelled in 2015/16 and the North London Reinforcement Project which is modelled in 2016/17.

A number of new generation connections are dependent on HVDC connections. At present, there is no approved charging methodology for these connections. Against this background, these generators have been modelled at the nearest existing node. Please bear in mind therefore that local circuit charges have not been calculated for these generators.

3.2 Changes to ensure the correct revenue recovery

3.2.1 Allowed Revenues

TNUoS charges are set to recover the revenues for all onshore and offshore TOs. The revenues of the onshore TOs are subject to a price control set by Ofgem; whilst offshore TO revenues are determined following a competitive tender.

National Grid is working with SHETL and SPTL to prepare a forecast of future revenues and is in the process of amending the SO-TO Code to achieve this. In the meantime, as National Grid is not yet in receipt of a revenue forecast prepared by each TO, National Grid has sought to estimate the revenues for the **onshore TOs**. An inflation rate of 2.6% has been assumed between 2013/14 and 2014/15; and 2.5% thereafter. The “central case” revenue forecast has been prepared considering the base revenue requirements, as set out in each TOs’ licence, and allowances for transmission investment for renewable generation (TIRG) in line with each TO’s Final Proposals. An allowance of £14m has been included for the Network Innovation Competition, which is half the maximum that could be awarded across all of the TOs.

Under the RIIO price controls there is a “true-up” for inflation[4] and a revenue adjustment for a number of so-called uncertainty mechanisms. These cover financial uncertainties (e.g. tax, debt, and pension costs); legacy issues associated with performance under the pre-RIIO price control; and adjustments for changes to total expenditure that can vary according customers’ needs and the health of the network. Ofgem will determine a revenue adjustment to cover all these factors through a process that concludes in November following the end of each financial year. This means revenues in 2014/15 will include an adjustment for TPCR4, which will be determined in November 2013. The first adjustment related to RIIO-T1 will take place in 2015/16 and this will be determined in November 2014. It should be noted that the adjustments can substantially increase or decrease the total onshore allowed revenue and, as such, the use of the base revenue in the “central case” represents only one scenario, whereas a range of different outcomes are possible, particularly in the latter years of the RIIO period. Against this background, the sensitivity analysis in Section 6 illustrates how tariffs could evolve under alternative scenarios.

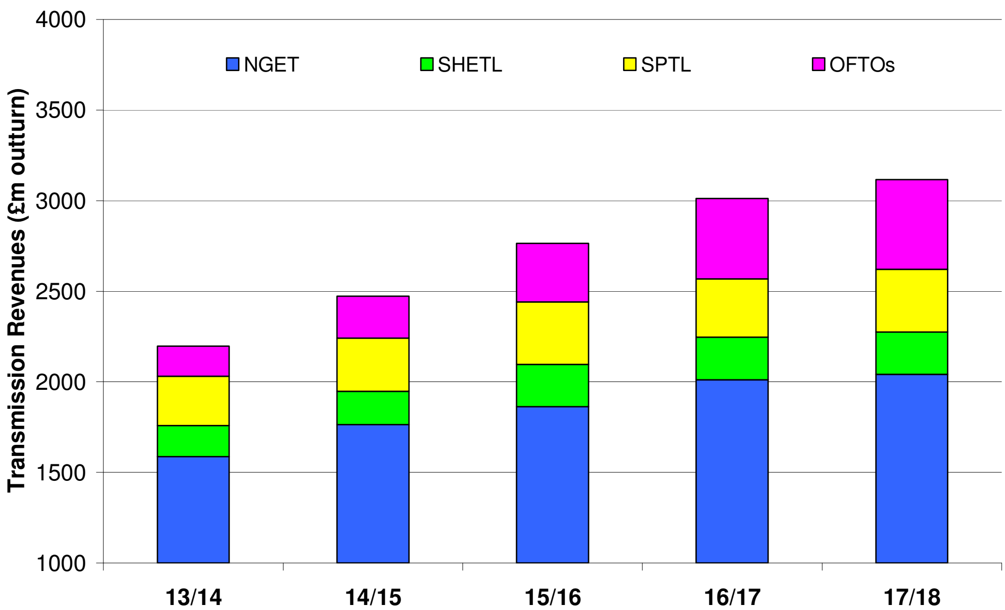
In the case of the **offshore TOs** National Grid has assumed that all OFTOs that are currently expected to be appointed during 2013/14 (Greater Gabbard, Sheringham Shoal, Thanet, Lincs, London Array, and Gwynt y Môr) are appointed and that each of the OFTOs is in place as from April 2014. Thereafter, it has been assumed that offshore TOs are appointed 12 months after the contracted generation completion date. Revenues for offshore TOs that have not been appointed have been estimated using the estimated capital value of the project or an historic

[4] The allowed revenue of each onshore TO is calculated using a forecast of inflation, which is prepared using a methodology described in the transmission licence. To the extent actual inflation is different to the forecast, an adjustment is made to take this into account. Based on the allowed revenues in 2012/13 (the first year to be trued-up), a ±0.1% forecast error would result in a revenue adjustment in 2013/14 of around ±£2m.

average, as set out in Appendix D. In addition to the uncertainty in the cost of offshore networks, the timing of completion of offshore transmission works and the subsequent appointment of offshore TOs to own and operate these is not fixed. Against this background, the revenue uncertainties presented in Section 6 include consideration of advancements and delays of OFTO appointments for contracted offshore generation.

The following table and chart illustrates forecast transmission allowed revenue from 2013/14 to 2017/18 (in outturn prices). The revenue recovered through TNUoS charges is the total transmission allowed revenue less the revenue collected from pre-vesting connection charges[5]. Equivalent data in 2013/14 prices has been included in Appendix E.

£m outturn	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**
NGET	1,587	1,763	1,862	2,012	2,041
SHETL	172	185	234	235	233
SPTL	271	293	346	322	346
Offshore TOs	167	232	322	443	496
Total Transmission Revenue	2,198	2,473	2,763	3,012	3,116
Pre-Vesting Connection	43	40	39	37	36
TNUoS Charges	**2,155**	**2,433**	**2,724**	**2,975**	**3,081**



3.2.2 Charging bases

Generation

When setting tariffs for 2013/14 an assessment was made on possible delays in the completion of new power stations. Following this assessment the contracted generation (after adjustments for interconnectors) was adjusted by 96.1%[6] to ensure the correct revenue recovery from connected generators. If all contracted generation was expected, this figure would have been 100% after making interconnector adjustments. The forecast generation base for future years has been determined by taking the contracted background for each year, adjusting this for interconnectors, then reducing the amended figure by this factor. Note, this is not a reflection

[5] Connection charges are separated into "pre-vesting" and "post-vesting" charges, which relate to whether the relevant connection assets existed when National Grid was privatised in 1990.

[6] This factor is based on the difference between generation in the contracted background and the chargeable generation as applied when tariffs for 2013/14 were calculated.

of the likelihood of generation for that year connecting but an assessment of the adjustment to be made to the charging base at the time of setting tariffs for 2013/14.

Demand

The demand base and the split between HH and NHH demand have remained unchanged from when setting charges for 2013/14. This assumes a peak system demand of 56GW; half-hourly demand at triad will be 16.1GW; and chargeable NHH demand of 28.6TWh[7]. We have fixed these demand bases when calculating future tariffs, as future forecasts of demand currently indicates minimal growth, and by fixing the charging base, the affect of locational changes to tariffs is more transparent.

National Grid will continue to review the demand charging bases and, in particular, will take into account any changes that may result from BSC amendment proposal P272[8], which, if approved, would increase the HH demand chargeable over the triads (and reduce annual NHH consumption).

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

Adjustments for Interconnectors

When determining the flows on the transmission system at peak demand, the interconnectors are included within the charging model. However, since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases. Therefore, when calculating the generation charging base from the contracted TEC background, the following reductions are made to reflect the charging treatment.

Interconnector	Zone	Adjustment (MW)
French Interconnector	24	1988
Britned	24	1200
Norwegian Interconnector	2	1400 (2017/18)
East-West	16	500
Moyle	10	80 +360 (2017/18)

3.3 Other changes

The charging methodology requires the **expansion constant** to be updated each year for inflation. For the purpose of preparing the forecast of tariffs, the expansion constant in 2013/14 has been increased by 2.6% in 2014/15 and, thereafter, by 2.5% each year. The following table shows the expansion constants used.

£/MWkm	13/14	14/15	15/16	16/17	17/18
Expansion Constant	12.514404	12.883779	13.160733	13.489792	13.827037

The **G / D split**, which ensures 73% of revenues is collected through demand charges and 27% through generation charges, has not been changed throughout the forecast period.

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

[8] BSC Amendment Proposal P272

4 Forecast generation tariffs

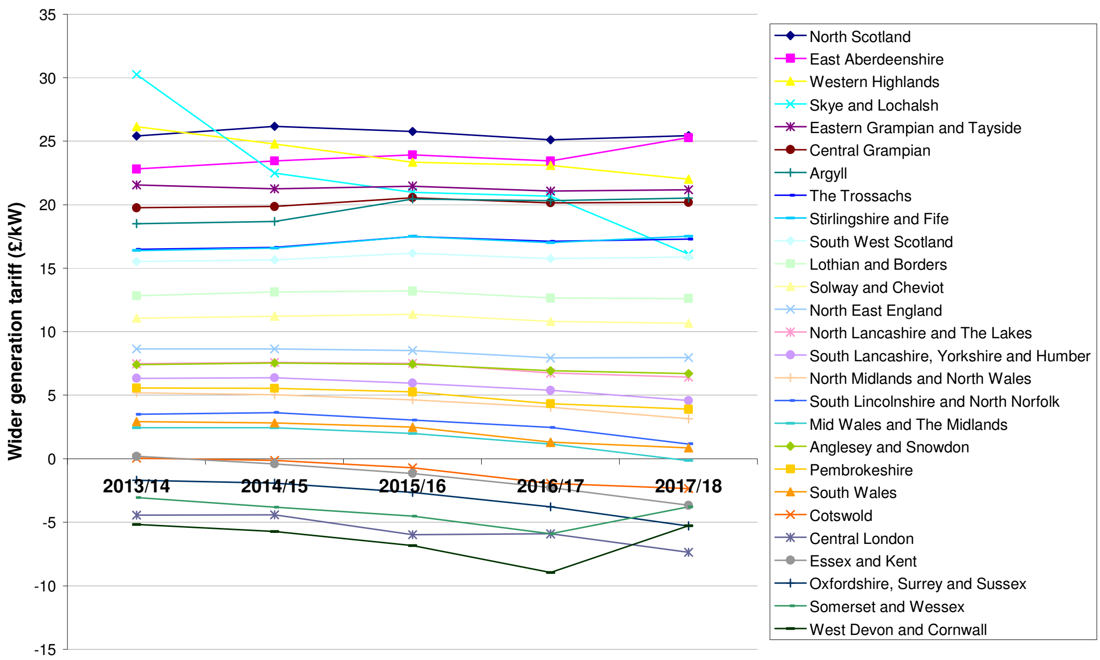
Based on the changes outlined in this report, the following section provides details of the forecast wider tariffs from 2013/14 to 2017/18.

4.1 Wider zonal generation tariffs

The following table and chart shows the forecast wider generation TNUoS tariffs, expressed to 2 decimal places. Tariffs are presented in outturn prices based on the changes to allowed revenue and investment costs outlined in Section 3.

Zone Name		2013/14	2014/15	2015/16	2016/17	2017/18
1	North Scotland	25.42	26.17	25.77	25.12	25.43
2	East Aberdeenshire	22.80	23.45	23.93	23.44	25.27
3	Western Highlands	26.15	24.79	23.35	23.10	22.01
4	Skye and Lochalsh	30.25	22.48	20.97	20.67	16.11
5	Eastern Grampian and Tayside	21.55	21.25	21.46	21.08	21.17
6	Central Grampian	19.75	19.85	20.56	20.15	20.20
7	Argyll	18.52	18.68	20.45	20.31	20.53
8	The Trossachs	16.49	16.63	17.51	17.11	17.29
9	Stirlingshire and Fife	16.40	16.59	17.51	17.01	17.52
10	South West Scotland	15.53	15.67	16.17	15.76	15.89
11	Lothian and Borders	12.84	13.12	13.20	12.64	12.62
12	Solway and Cheviot	11.07	11.22	11.37	10.82	10.66
13	North East England	8.64	8.64	8.53	7.92	7.97
14	North Lancashire and The Lakes	7.48	7.58	7.50	6.75	6.43
15	South Lancashire, Yorkshire and Humber	6.34	6.38	5.96	5.39	4.58
16	North Midlands and North Wales	5.18	5.03	4.63	4.04	3.13
17	South Lincolnshire and North Norfolk	3.49	3.64	3.05	2.46	1.17
18	Mid Wales and The Midlands	2.44	2.44	1.99	1.15	-0.15
19	Anglesey and Snowdon	7.41	7.53	7.45	6.92	6.70
20	Pembrokeshire	5.57	5.54	5.25	4.33	3.89
21	South Wales	2.92	2.82	2.48	1.30	0.84
22	Cotswold	0.04	-0.14	-0.71	-1.95	-2.36
23	Central London	-4.44	-4.41	-5.98	-5.91	-7.38
24	Essex and Kent	0.19	-0.39	-1.15	-2.28	-3.67
25	Oxfordshire, Surrey and Sussex	-1.69	-1.91	-2.65	-3.78	-5.29
26	Somerset and Wessex	-3.05	-3.81	-4.52	-5.92	-3.80
27	West Devon and Cornwall	-5.17	-5.73	-6.84	-8.97	-5.28

Appendix E contains a geographic map of the generation zone boundaries that have been assumed to apply throughout the forecast period.



4.2 Year-on-Year Changes

The following sections describe the year-on-year tariff changes and the main drivers for these.

4.2.1 2013/14 Changes

Summary explanation

As of a result of the re-zoning exercise that occurred in 2013/14 it is not possible to describe zonal tariff changes on a consistent zonal basis. However, in general, generation tariffs have increased most in Scotland (Zones 1 to 12); have moderately increased in northern and central England and Wales (Zones 13 to 21); and have reduced in southern England (Zones 24 to 27). The tariff for Central London (Zone 23) has increased and is discussed in more detail below.

This broad pattern of changes has occurred because generation capacity in England & Wales has decreased, whilst in Scotland there have been comparatively few changes. This means generators in the northern parts of Great Britain "use" more of the network to transfer their energy to where it is consumed and tariffs increase to reflect this.

Detailed explanation

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the tariff changes:

- ❑ the generation **residual element**, which ensures the correct total revenue is recovered from generation, has increased by £0.57/kW to £4.81/kW. The increase is mainly due to a reduction in the charging base, as shown in the following table.

Item (£m, unless stated)		**12/13**	**13/14**	**Δ**
Revenue recoverable through TNUoS	*A*	1,949	2,153	205
Revenue to collect from generation	*B = 0.27 x A*	526	581	55
Revenue from zonal tariffs	*C*	53	55	2
Revenue from onshore local tariffs	*D*	42	34	-7
Revenue from offshore local tariffs	*E*	78	131	53
Revenue to recover from residual	*F = B-C-D-E*	353	361	8.0
Generation charging base (GW)	*G*	83.3	75	-8.2
Residual (£/kW)	*F / G*	**4.24**	**4.81**	**0.57**

- the increase in tariffs throughout Scotland (**Zones 1 to 12**) is due to a combination of changes to the location of contracted generation in Scotland and the significant reduction of generation capacity in England & Wales.

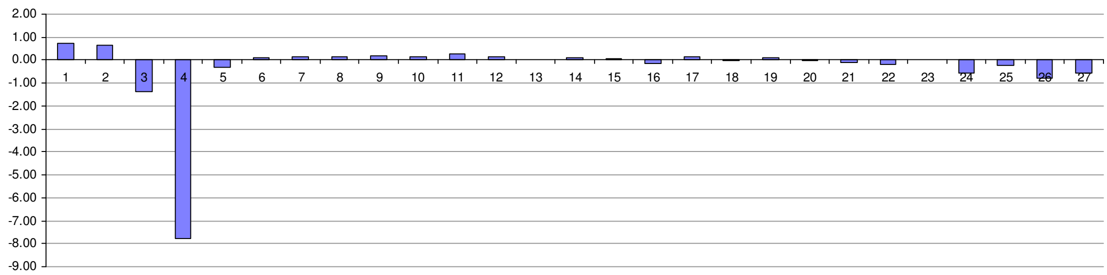
- tariffs in western parts of northern England & Scotland (for example, **Zones 4, 7, 10, and 14**) have increased more than eastern areas due to changes in contracted generation in the region in recent years. These changes have been reflected in the revised tariff zone boundaries for these regions.

- the generation tariff in Central London (**Zone 23**) has, as predicted in previous forecasts, increased to a level similar to that seen in 2011/12 (and years previous to this) and reverses the decrease that took place in 2012/13. This change has occurred because changes in the network and generation background have altered power flows on expensive cable circuits in London.

- the decreases in southern areas of England (**Zones 24 – 26**) are due to reduced generation capacity in this area, which include Kingsnorth (1966MW) and Didcot A (1558MW), and increased demand in England & Wales.

4.2.2 2014/15 Changes

The following chart shows the generation tariff changes between 2013/14 and 2014/15.



Summary explanation

In general, generation tariffs throughout most areas of the network have remained largely unchanged. The exceptions to this are in the most northern and southern parts of Great Britain, where the impact of an inflationary increase in investment costs is greatest: increasing tariffs in northern areas and reducing them in southern regions.

The tariff reduction in Zone 4 has occurred because the generator in this zone reduces modelled power flows on a long circuit spur, which results in a lower tariff, whereas previously it added to the flows.

Detailed explanation

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the tariff changes:

- the generation **residual element**, which ensures the correct total revenue is recovered from generation, has decreased by £0.12/kW to £4.69/kW. The increase in revenue that TNUoS seeks to recover from generators has been offset by additional revenues from offshore generators and the increase in the forecast generation charging base, as shown in the table below.

Item (£m, unless stated)		**13/14**	**14/15**	**Δ**
Revenue recoverable through TNUoS	*A*	2,153	2,433	280
Revenue to collect from generation	*B = 0.27 x A*	581	657	76
Revenue from zonal tariffs	*C*	55	57	2
Revenue from onshore local tariffs	*D*	34	35	1
Revenue from offshore local tariffs	*E*	131	184	53
Revenue to recover from residual	*F = B-C-D-E*	361	381	20
Generation charging base (GW)	*G*	75.1	81.3	6.1
Residual (£/kW)	*F / G*	**4.81**	**4.69**	**-0.12**

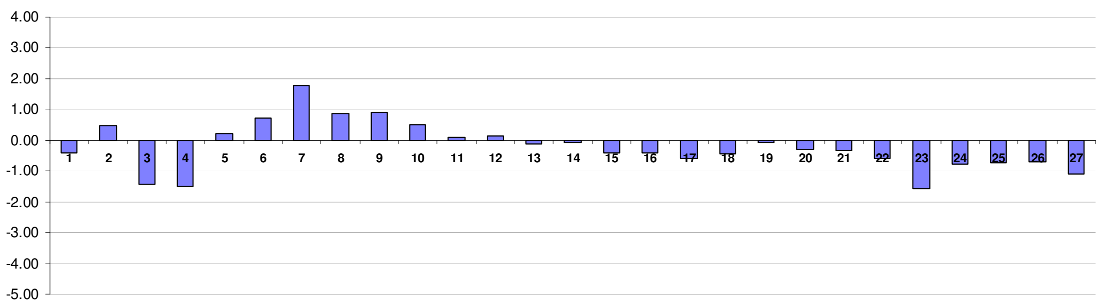
- in **Zone 4** (in which there is one generator) and, to a lesser extent in **Zone 3**, the decrease in the tariff has been caused by power flows reversing direction on a long radial spur. The power exported by this generator now reduces flows along this circuit, resulting in a lower tariff, whereas previously it added to them. The change in power flows arises from a combination of factors including local demand changes and generation increases throughout GB.

- the reductions in **Zones 26 & 27** have been caused mainly by the combined effect of increased generation in central regions of England and within Scotland, which increase the benefit these power stations provide to the wider transmission system when they generate.

- the changes at the extremities of the network, in particular the increases in **Zones 1 & 2** and decreases in **Zones 24 – 27**, have been amplified by the inflationary increase in the expansion constant.

4.2.3 2015/16 Changes

The following chart shows the generation tariff changes between 2014/15 and 2015/16.



Summary explanation

In the northern and western parts of Scotland, tariffs are expected to decrease following the completion of the Beauly-Denny reinforcements. These reductions would have been greater in the absence of additional contracted generation connecting in the north of Scotland and the inflationary increase to investment costs. Reductions in the South can be attributed to the change in investment costs usually seen year on year.

Detailed explanation

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the tariff changes:

- the generation **residual element**, which ensures the correct total revenue is recovered from generation, has decreased by £0.19 to £4.50/kW. The increase in revenue that TNUoS seeks to recover from generators has been offset by additional revenues from offshore generators and the increase in the forecast generation charging base so that the residual decreases, as shown in the following table.

Item (£m, unless stated)		**14/15**	**15/16**	**Δ**
Revenue recoverable through TNUoS	*A*	2,433	2,724	291
Revenue to collect from generation	*B = 0.27 x A*	657	735	89
Revenue from zonal tariffs	*C*	57	64	7
Revenue from onshore local tariffs	*D*	35	36	1
Revenue from offshore local tariffs	*E*	184	239	55
Revenue to recover from residual	*F = B-C-D-E*	381	396	15
Generation charging base (GW)	*G*	81.3	88.1	6.8
Residual (£/kW)	*F / G*	**4.69**	**4.50**	**-0.19**

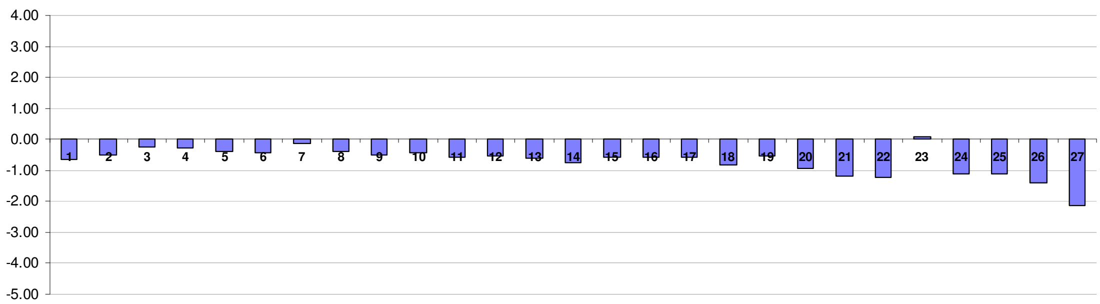
- in **Zone 7** the increase is caused by a generator connecting at Cour.

- the decreases in **Zones 24 – 27**, have been amplified by the inflationary increase in the expansion constant. An increase in **Zones 1 – 4** would have been seen but this has been offset by decreases due to the completion of the Beauly-Denny reinforcements.

- the reduction in **Zone 1** due to circuit changes would have been greater but has been offset by new generation connections in this zone totalling 624MW.

4.2.4 2016/17 Changes

The following chart shows the generation tariff changes between 2015/16 and 2016/17.



Summary explanation

In 2016/17 approximately 9.6GW of new generation is contracted to connect, most of which is in central regions of the transmission system. This causes flows from north to south to decrease, resulting in a gradual decrease in tariffs from North to South. North London reinforcements alter flows to the South West, which increases the tariff reduction in Zone 27 and reverses the tariff reduction in Zone 23 that occurred in 2015/16.

Detailed explanation

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the tariff changes:

- the generation **residual element**, which ensures the correct total revenue is recovered from generation, has decreased by £0.64 to £3.86/kW. The increase in revenue that TNUoS seeks to recover from generators is more than offset by additional revenues from offshore generators and the large increase in the forecast generation charging base, as shown in the table below.

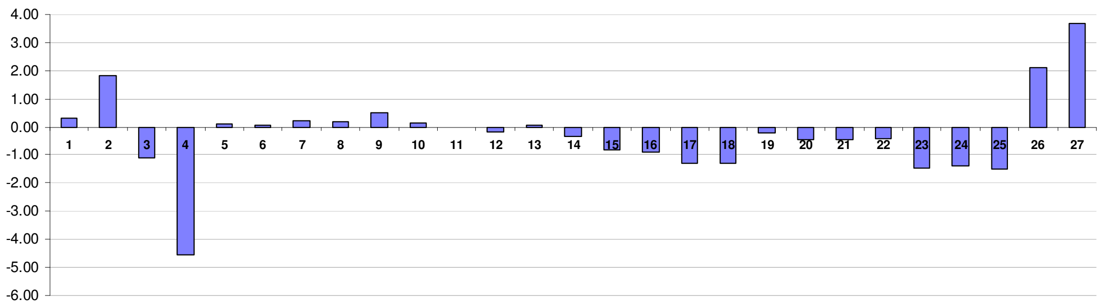
Item (£m, unless stated)		**15/16**	**16/17**	**Δ**
Revenue recoverable through TNUoS	*A*	2,724	2,975	251
Revenue to collect from generation	*B = 0.27 x A*	735	803	68
Revenue from zonal tariffs	*C*	64	67	3
Revenue from onshore local tariffs	*D*	36	38	2
Revenue from offshore local tariffs	*E*	239	321	82
Revenue to recover from residual	*F = B-C-D-E*	396	377	19
Generation charging base (GW)	*G*	88.1	97.8	9.6
Residual (£/kW)	*F / G*	**4.50**	**3.86**	**-0.64**

- circuit changes in and around the London area reduce flows in the South and South West. This causes slight reductions in tariffs in these zones but most notably in **Zone 27**. Central London (**Zone 23**) sees an increase due to these circuit changes.

- the changes at the extremities of the network, in particular the decreases in **Zones 24 – 27**, have been amplified by the inflationary increase in the expansion constant. An increase in **Zones 1 – 4** would have been seen but this has been offset by reduced flows from north to south, caused by the extensive new generation connecting in central regions.

4.2.5 2017/18 Changes

The following chart shows the generation tariff changes between 2016/17 and 2017/18.



Summary explanation

For 2017/18 tariffs in northern areas do not increase as would normally be expected due to large amounts of generation contracted to connect in the South, which tends to reduce north to south flows. Apart from those zones which have specific generation connecting, most zones see a minimal change or a reduction due to the larger generation charging base.

Detailed explanation

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the tariff changes:

- the generation **residual element**, which ensures the correct total revenue is recovered from generation, has decreased by £0.44 to £3.42/kW. The increase in revenue that TNUoS seeks to recover from generators has been more than offset by additional revenues from offshore generators and the large increase in the forecast generation charging base, as shown below.

Item (£m, unless stated)		**16/17**	**17/18**	**Δ**
Revenue recoverable through TNUoS	*A*	2,975	3,081	106
Revenue to collect from generation	*B = 0.27 x A*	803	832	29
Revenue from zonal tariffs	*C*	67	72	5
Revenue from onshore local tariffs	*D*	38	36	-2
Revenue from offshore local tariffs	*E*	321	350	29
Revenue to recover from residual	*F = B-C-D-E*	377	374	-3
Generation charging base (GW)	*G*	97.8	109.2	9.6
Residual (£/kW)	*F / G*	**3.86**	**3.42**	**-0.44**

- **Zones 26 and 27** are affected by the connection of Atlantic Array (404MW), Navitus Bay Offshore (400MW), Alderney Renewable Energy (100MW), and Hinkley Point C (1670MW).

- **Zones 20, 21** and **22** are also affected by the new generation listed above as well as the new wind generation at Pembroke (2000MW). Without this generation tariffs would have seen a drop similar in size to the other zones in their locality.

- **Zone 2** sees an increase due the large amounts of new generation in this zone e.g. Beatrice Wind Farm (300MW) and Firth of Forth (1825MW), and the Norwegian Interconnector (1400MW).

- In **Zone 4** (in which there is one generator) the decrease in the tariff has been caused by power flows reversing direction on a long radial spur. The power exported by this generator now reduces flows along this circuit, resulting in a lower tariff, whereas previously it added to them. The change in power flows arises from a combination of factors including local demand changes and generation increases throughout GB.

4.3 Onshore Local Circuit Tariffs

Appendix C shows a forecast of onshore local circuit tariffs from 2013/14 to 2017/18. Since, the changes to these tariffs are generator specific, please contact National Grid using the detailed provided in Section 8 to obtain detailed explanations.

4.4 Onshore Local Substation Tariffs

The table below shows the onshore local substation tariffs that apply during 2013/14. These tariffs only apply to transmission connected generators. The tariffs will be indexed by RPI for each year of the price control.

If no significant work is planned at the substation that changes whether or not there is redundancy, the tariff will only alter by RPI. Similarly, if the sum of the TEC of the generators at a substation changes such that the 1320MW threshold is crossed, this will change the tariff applied to all generators at that location beyond the normal RPI increase. If you are unsure about what tariff may apply please contact National Grid directly for further information.

		Local Substation Tariff (£/kW)		
Sum of TEC at connecting Substation	**Connection Type**	**132kV**	**275kV**	**400kV**
<1320 MW	No redundancy	0.17	0.10	0.07
<1320 MW	Redundancy	0.38	0.23	0.17
>=1320 MW	No redundancy	-	0.31	0.22
>=1320 MW	Redundancy	-	0.50	0.37

5 Forecast demand tariffs

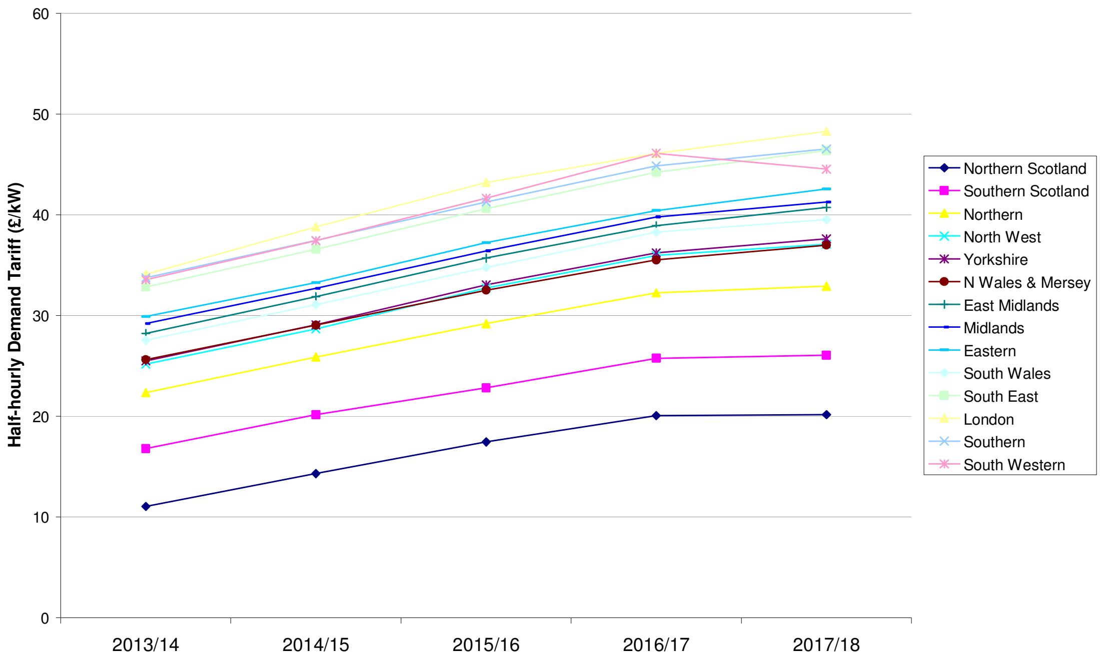
Based on the changes outlined in this report, the following section provides details of the forecast demand tariffs from 2013/14 to 2017/18.

5.1 Wider demand tariffs

The following tables and charts show the forecast half-hourly and non half-hourly demand TNUoS tariffs, expressed to 2 decimal places. Tariffs are presented in outturn prices based on the changes to allowed revenue and investment costs outlined in Section 3.

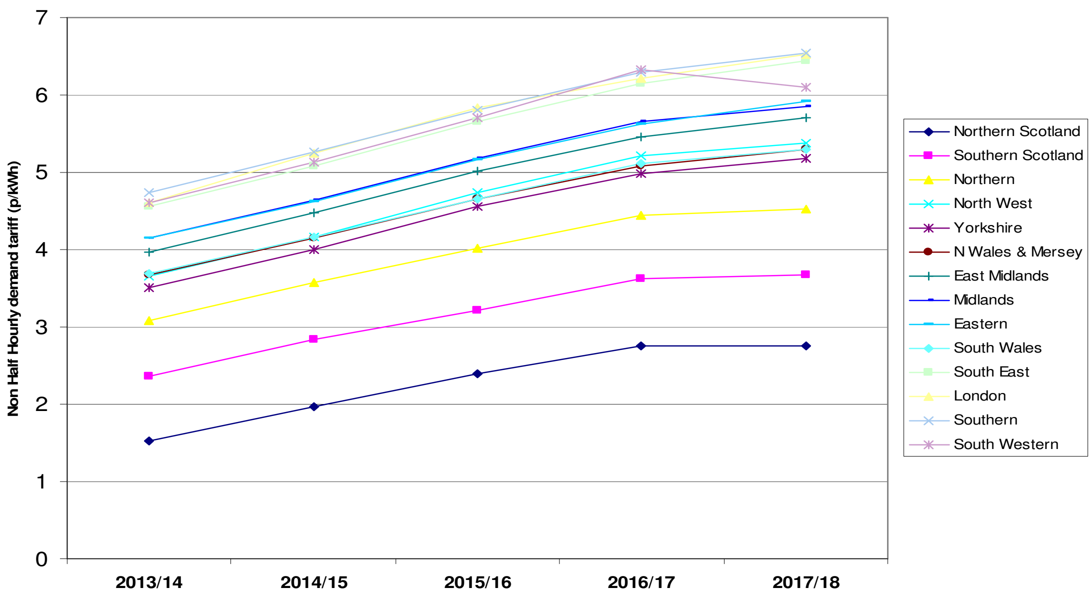
Half-hourly demand tariffs (£/kW)

Zone	2013/14	2014/15	2015/16	2016/17	2017/18
Northern Scotland	11.05	14.30	17.44	20.06	20.14
Southern Scotland	16.79	20.14	22.82	25.76	26.05
Northern	22.35	25.88	29.20	32.24	32.90
North West	25.18	28.68	32.72	35.96	37.08
Yorkshire	25.49	29.06	33.03	36.22	37.61
N Wales & Mersey	25.63	29.05	32.51	35.52	36.99
East Midlands	28.21	31.85	35.70	38.91	40.74
Midlands	29.20	32.68	36.42	39.78	41.25
Eastern	29.89	33.25	37.23	40.43	42.56
South Wales	27.54	31.08	34.76	38.29	39.50
South East	32.83	36.59	40.60	44.22	46.36
London	34.08	38.80	43.21	46.09	48.29
Southern	33.75	37.47	41.26	44.85	46.52
South Western	33.55	37.42	41.63	46.10	44.53



Non half-hourly demand tariffs (p/kWh)

Zone	2013/14	2014/15	2015/16	2016/17	2017/18
Northern Scotland	1.52	1.96	2.39	2.75	2.76
Southern Scotland	2.36	2.83	3.21	3.63	3.67
Northern	3.08	3.57	4.02	4.44	4.53
North West	3.65	4.16	4.74	5.21	5.38
Yorkshire	3.51	4.00	4.55	4.99	5.18
N Wales & Mersey	3.67	4.15	4.65	5.08	5.29
East Midlands	3.96	4.47	5.01	5.46	5.71
Midlands	4.15	4.64	5.18	5.65	5.86
Eastern	4.15	4.62	5.17	5.62	5.91
South Wales	3.69	4.16	4.65	5.12	5.29
South East	4.56	5.09	5.65	6.15	6.45
London	4.60	5.24	5.83	6.22	6.52
Southern	4.74	5.26	5.80	6.30	6.54
South Western	4.60	5.13	5.71	6.32	6.10

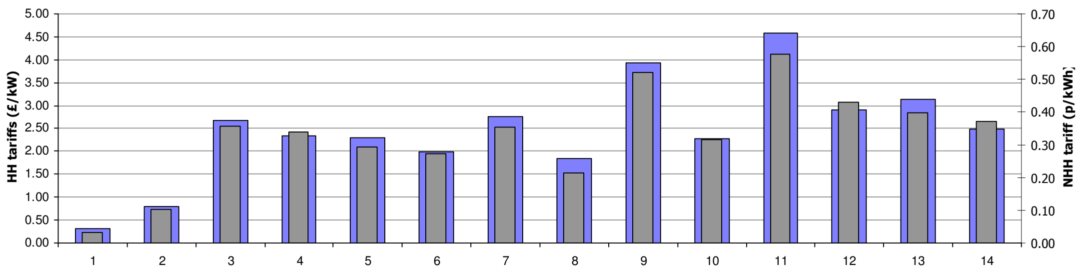


5.2 Year-on-Year changes

The following sections describe the year-on-year tariff changes and the main drivers for these. Since it has been assumed that the proportion of HH and NHH demand in each zone has remained constant across the forecast period, the trend in NHH tariffs mirrors that of HH tariffs.

5.2.1 2013/14 Changes

The following chart shows the change in HH (blue bars) and NHH (grey bars) demand tariffs between 2012/13 and 2013/14.



Summary explanation

Demand tariffs increase in all zones and on average[9] by £2.69/kW. This is because National Grid expects to recover around £205m more revenue through TNUoS during 2013/14 compared to the prior year to fund the investment in transmission both onshore and offshore. The increases are lowest in Scotland (Zones 1 and 2) and gradually increase towards southern England & Wales (Zones 13 and 14).

This national trend is caused mainly by the large reductions in generation in England & Wales, which means consumers in southern areas "use" more of the network (to transfer energy from where it is produced to where it is consumed). This is reflected in the charge for using the network.

The final demand tariffs are lower than draft tariffs because tariffs have been calculated to recover a lower allowed revenue than previously assumed and takes account of lower revenues National Grid expects to recover for onshore and offshore TOs.

Detailed explanation

A more detailed explanation of the main changes in demand tariffs follows:

- the **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures correct revenue recovery, has increased by £2.58/kW to £25.41/kW. This reflects the increase in the total allowed revenue, as shown in the following table.

Item (£m, unless stated)		**12/13**	**13/14**	**Δ**
Revenue recoverable through TNUoS	*A*	1,949	2,153	205
Revenue to collect from demand	*B = 0.73 x A*	1,422	1,572	149
Revenue from zonal charges	*C*	144	149	5
Revenue from residual	*D = B - C*	1,278	1,423	144
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**22.83**	**25.41**	**2.58**

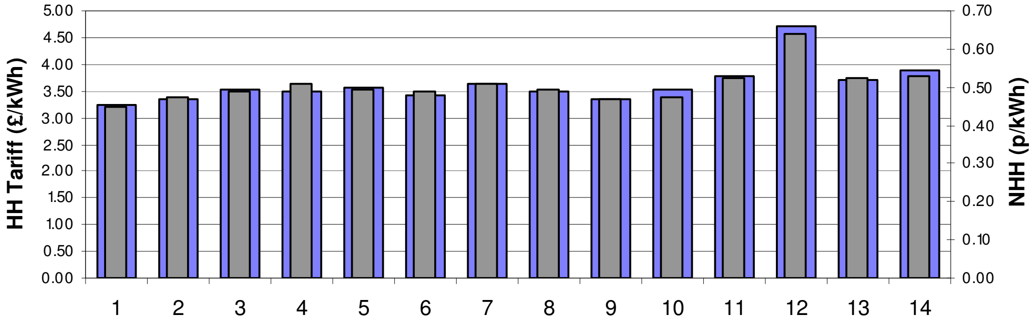
- the increases in **Zones 1 and 2** (Scotland) are lower than other parts of the country because of the generation reductions that have occurred in England & Wales.

- the higher than average increases in **Zones 11 – 14** (the southern part of England) are due to the large reduction in generation in this area, including Kingsnorth, Fawley, Didcot A, and Littlebrook.

5.2.2 2014/15 Changes

The following chart shows the change in HH (blue bars) and NHH (grey bars) demand tariffs between 2013/14 and 2014/15.

[9] Weighted average based on peak demand in each zone.



Summary explanation

Demand tariffs are expected to increase in all zones and on average by £3.66/kW. This is because National Grid expects to recover around £280m more revenue through charges during 2014/15 compared to the prior year. There are relatively small variations throughout the country, with increases in Scotland being slightly lower than most areas of England & Wales.

Detail explanation

A more detailed explanation of the main changes in demand tariffs follows:

- the **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures that the correct total revenue recovery, has increased by £3.55/kW to £28.96/kW. This reflects the expected increase in the total allowed revenue, as shown in the following table.

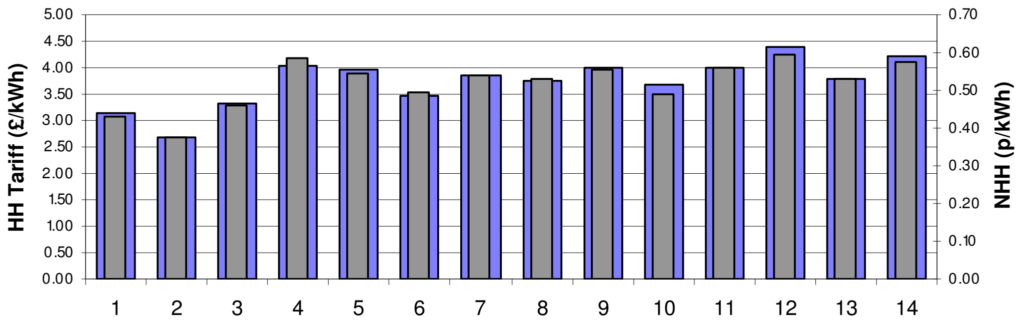
Item (£m, unless stated)		**13/14**	**14/15**	**Δ**
Revenue recoverable through TNUoS	*A*	2,153	2,433	280
Revenue to collect from demand	*B = 0.73 x A*	1,572	1,776	204
Revenue from zonal charges	*C*	149	155	6
Revenue from residual	*D = B - C*	1,423	1,621	199
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**25.41**	**28.96**	**3.55**

- the increase in **Zones 12** (London) is greater than other parts of the country because of re-wiring works in the London area, particularly on cable circuits.

- the increase in the expansion constant has resulted in a lower tariff increase in Scotland (**Zones 1 and 2**) compared to southern England (**Zones 11, 13, 14**).

5.2.3 2015/16 Changes

The following chart shows the change in HH (blue bars) and NHH (grey bars) demand tariffs between 2014/15 and 2015/16.



Summary explanation

Demand tariffs are expected to increase in all zones and on average by £3.81/kW. This is because National Grid expects to recover around £291m more revenue through TNUoS charges during 2015/16 compared to the prior year. Demand charges in the North have risen less than southern regions due to the increase in generation in these demand zones and the affect of inflationary increases in investment costs.

Detail explanation

A more detailed explanation of the main changes in demand tariffs follows:

- the **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures that the correct total revenue recovery, has increased by £3.45/kW to £32.41/kW. This reflects the expected increase in the total allowed revenue, as shown in the following table.

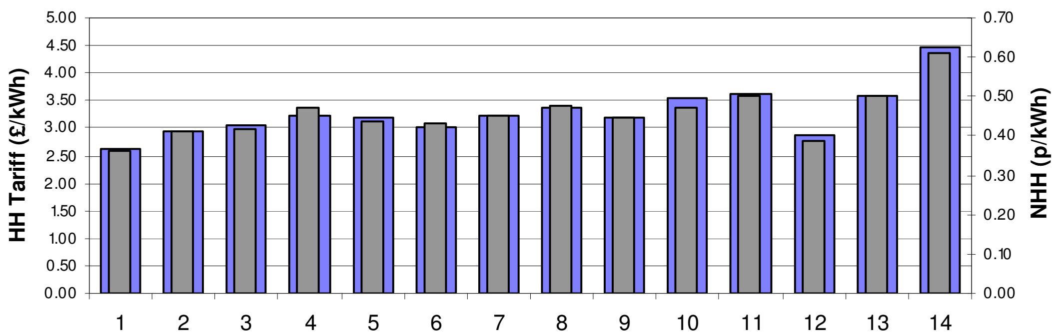
Item (£m, unless stated)		**14/15**	**15/16**	**Δ**
Revenue recoverable through TNUoS	*A*	2,433	2,724	291
Revenue to collect from demand	*B = 0.73 x A*	1,776	1,989	213
Revenue from zonal charges	*C*	155	174	19
Revenue from residual	*D = B - C*	1,621	1,815	255
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**28.96**	**32.41**	**3.45**

- tariff increase in **Zones 1 and 2** are less than other regions in GB because of the new generation connecting in this part of the network. The affect in **Zone 1** is partially offset by the completion of the Beauly-Denny reinforcements.

- **Zone 10** sees a decrease due to new generation at Abernedd (470MW) and Port Talbot (320MW).

5.2.4 2016/17 Changes

The following chart shows the change in HH (blue bars) and NHH (grey bars) demand tariffs between 2015/16 and 2016/17.



Summary explanation

Demand tariffs are expected to increase in all zones and on average by £3.29/kW. This is because National Grid expects to recover around £251m more revenue through TNUoS charges during 2016/17 compared to the prior year. There are relatively small variations throughout the country, with the vast majority altering due to the change in investment costs. The above average increases in Zones 13 and 14 are caused by changes in flows in the South and South West; and the below average increases in **Zone 12** are caused by network changes in and around the London area.

Detail explanation

A more detailed explanation of the main changes in demand tariffs follows:

- the **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures that the correct total revenue recovery, has increased by £3.11/kW to £35.52/kW. This reflects the expected increase in the total allowed revenue, as shown in the table below. If the charging base was to increase then the residual would decrease

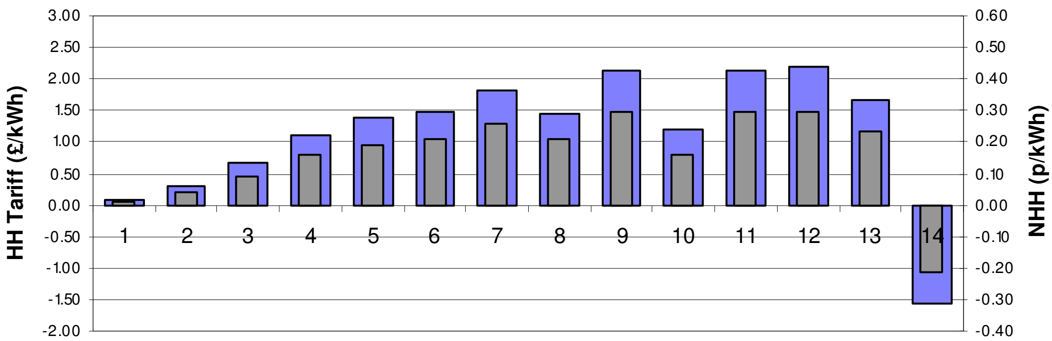
Item (£m, unless stated)		**15/16**	**16/17**	**Δ**
Revenue recoverable through TNUoS	*A*	2,724	2,975	251
Revenue to collect from demand	*B = 0.73 x A*	1,989	2,172	183
Revenue from zonal charges	*C*	174	183	9
Revenue from residual	*D = B - C*	1,815	1,989	174
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**32.41**	**35.52**	**3.11**

- the decrease in **Zones 12** (London) is due to circuit changes in and around the London area.

- the increase in investment costs has resulted in a lower tariff increase in Scotland (**Zones 1 and 2**) compared to southern regions of England (**Zones 11, 13, and 14**).

5.2.5 2017/18 Changes

The following chart shows the change in HH (blue bars) and NHH (grey bars) demand tariffs between 2016/17 and 2017/18. Please note the change in vertical scale on the graph when comparing to previous years.



Summary explanation

Demand tariffs are expected to increase in all zones, except the South West, and on average by £1.39/kW. The general increase is because National Grid expects to recover around £106m more revenue through TNUoS charges during 2017/18 compared to the prior year. Increased investment costs mean that without specific new generation there is a gradual increase in tariffs from North to South. However, new generation in Scotland, Wales, and the South West causes tariffs to rise less than average or decrease, as is the case in Zone 14.

Detail explanation

A more detailed explanation of the main changes in demand tariffs follows:

- the **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures that the correct total revenue recovery, has increased by £1.13kW to £36.65/kW. This reflects the expected increase in the total allowed revenue, as shown in the table below.

Item (£m, unless stated)		**16/17**	**17/18**	**Δ**
Revenue recoverable through TNUoS	*A*	2,975	3,081	106
Revenue to collect from demand	*B = 0.73 x A*	2,172	2,249	77
Revenue from zonal charges	*C*	183	197	14
Revenue from residual	*D = B - C*	1,989	2,052	63
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**35.52**	**36.65**	**1.13**

- the decrease in **Zone 14** is caused by the connection of Atlantic Array (404MW), Navitus Bay Offshore (400MW), Alderney Renewable Energy (100MW), and Hinkley Point C (1670MW).

- **Zone 10** is also affected by the new generation listed above as well as the new wind generation at Pembroke (2000MW).

- The tariffs in Scotland and northern England do not increase as much as in more central regions because of the connection of new generation at Beatrice Wind Farm (300MW) and Firth of Forth (1825MW), and the Norwegian Interconnector (1400MW).

6 Sensitivities & Uncertainties

National Grid has not modelled any sensitivities due to changes in generation and demand capacities. Where a new generator causes a change in tariffs this has been noted in Sections 4 & 5. However, more often than not, it is a combination of various schemes that is the cause of the tariff changes. The charging model used to calculate TNUoS tariffs is publically available, which allows customers to consider the scenarios that they consider most likely. Please see Section 7 to obtain more information on how to obtain the model and the support available for its use.

The scenarios set out below are intended to illustrate the sensitivity of the forecast tariffs to various factors that affect revenue collected through the residual element of tariffs. There are other factors that affect tariffs and these scenarios do not represent a minimum and maximum tariff range.

6.1 Changes to transmission revenue requirements

The following section considers different assumptions about the onshore TOs' allowed revenues and the offshore TO allowed revenues of OFTOs yet to be appointed.

National Grid has prepared an initial estimate of the uncertainty in the central revenue forecast. To illustrate that the allowed revenue can increase or decrease, a symmetrical range has been applied. Whilst the resulting range between the high and low cases is large, as shown in the table below, there are scenarios that could result in this level of revenue change when taking into account the uncertainties associated with onshore and offshore TOs. The range seeks to take into account different level of onshore and offshore investments, which result from different generation connections and corresponding network investment options. Against this background, customers should note the uncertainty particularly in outer years. Over the coming months, as more information becomes available and as RIIO beds in, National Grid intends update the long-term revenue forecast.

Scenario	Transmission Revenues (£m outturn)				
	13/14	2014/15	2015/16	2016/17	2017/18
Low	2,155	2,393	2,604	2,775	2,871
Central / Base	2,155	2,433	2,724	2,975	3,081
High	2,155	2,458	2,844	3,175	3,291

Since revenue changes affect only the residual tariff component, the impact is the same in all zones. The table below shows the impact on generation and demand TNUoS tariffs (presented in outturn prices).

	Change to tariffs – Low Case			
	2014/15	2015/16	2016/17	2017/18
Generation (£/kW)	+ 0.09	+ 0.01	- 0.20	- 0.38
HH Demand (£/kW)	- 0.53	- 1.56	- 2.61	- 2.74
NHH Demand (p/kWh)	- 0.07	- 0.22	- 0.36	- 0.38

	Change to tariffs – High Case			
	2014/15	2015/16	2016/17	2017/18
Generation (£/kW)	+ 0.02	- 0.02	+ 0.40	+ 0.52
HH Demand (£/kW)	+ 0.33	+ 1.56	+ 2.61	+ 2.74
NHH Demand (p/kWh)	+ 0.05	+ 0.22	+ 0.36	+ 0.38

Impact of ±£50m in transmission allowed revenues

To further illustrate the impact of a change to transmission allowed revenue would have on wider zonal tariffs, the following table shows the impact that a ± £50m change has on generation and demand tariffs. As the generation base increases in future years, revenue changes have less of an impact.

	Change to tariffs due to ±£50m change in allowed revenue			
	2014/15	2015/16	2016/17	2017/18
Generation (£/kW)	± 0.17	± 0.15	± 0.14	± 0.12
HH Demand (£/kW)	± 0.65	± 0.65	± 0.65	± 0.65
NHH Demand (p/kWh)	± 0.09	± 0.09	± 0.09	± 0.09

6.2 Changes to the charging base

The following table shows the impact of an increase / decrease of 500MW on the demand charging base. For simplicity this has been spread in proportion to the existing demand in each zone.

	Change to tariffs			
	2014/15	2015/16	2016/17	2017/18
HH Demand (£/kW)	± £0.28	± 0.32	± 0.36	± 0.39
NHH Demand (p/kWh)	± <0.02	± <0.02	± <0.02	± <0.02

7 Tools and Supporting Information

7.1 Discussing tariff changes

National Grid is keen to ensure that customers understand the current charging arrangements and the reasons why charges have changed from year to year. Therefore, we expect to attend a future charging methodology forum to discuss this forecast.

7.2 Publication of charging models

Customers can receive a copy of National Grid's charging model, which will allow them to better understand how their tariffs have been calculated and conduct sensitivity analysis concerning alternative developments of generation and demand to be undertaken.

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

7.3 Tools and Useful Guides

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

- ❑ a guide to offshore local TNUoS charges.
- ❑ a tool to calculate generation TNUoS charges.
- ❑ a guide to assist new suppliers understand monthly TNUoS charges and the annual reconciliations.

8 Comments & Feedback

Comments & Feedback

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

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

These should be sent to:

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Warwick
CV34 6DA

01926 656416

Our commitment to UK Transmission Customers

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

9 Appendices

There are 4 appendices to this information paper:

Appendix A	Generation changes for 2014/15, 2015/16, 2016/17 and 2017/18
Appendix B	Zonal generation and demand changes from 2014/15
Appendix C	Onshore local circuit tariff changes from 2014/15
Appendix D	Offshore revenue forecast methodology
Appendix E	Transmission revenues in outturn and 2013/14 prices
Appendix F	Generation Zone Map

Appendix A: Generation changes for 2014/15 to 2017/18

2014/15 TEC Changes

Power Station	Zone	TEC Change (MW)
Aultmore Wind Farm	1	60
Corriegarth	1	49.9
Erica Wind Farm	1	21.6
Strathy North & South Wind	1	76
Wheedlemont	1	1.5
Learney Wind Generating Station	5	9
AChruach Wind Farm	7	49.9
Brockloch Rig Wind Farm	10	75
Aikengall II Windfarm	11	108
Crystal Rig 2	11	62
Neart Na Gaoithe Offshore Wind Farm	11	450
Rowantree Wind Farm	11	67
Ewe Hill	12	48
Harestanes	12	21.3
Wilton	13	42
West of Duddon Sands Offshore Wind Farm	14	170
Hornsea Offshore Wind Farm - Platform 1A	15	500
Westermost Rough Offshore Wind Farm	15	205
Carrington Power Station	16	910
Gwynt Y Mor Offshore Wind Farm	16	142
Spalding Energy Expansion	17	840
Drakelow D	18	1320
Bristol Biomass	22	165
Thames Haven Power Station	24	840
	Total	**6,233.2**

2015/16 TEC Changes

Power Station	Zone	TEC Change (MW)
Corriemoillie Wind Farm, Dingwall	1	69.5
Druim Ba Wind Farm	1	69
Dunmaglass	1	98.5
Eishken Estate, Isle of Lewis	1	150
Lairg Phase 2	1	2.5
Lewis Wave Generating Station	1	3
Marwick Head Wave Farm	1	9
Pairc Wind Farm	1	43.2
SSE Orkney Wave	1	29
Strathy North & South Wind	1	150
Aberdeen Bay Wind Farm	5	77
Ardtalnaig Hydro Generating Station	5	1.5
Tibberchindy Wind Farm	5	20
Cour	7	23
Earlshaugh Wind Farm	9	108
Firth of Forth Offshore Wind	9	1075
Loch Hill Wind Farm	10	27.5
Glentaggart Wind Farm	11	20.7
Hornsea Offshore Wind Farm - Platform 1B	15	500
Burbo Bank Extension Offshore Wind Farm	16	234
Trafford Power Station	16	570
Kings Lynn B	17	981
Race Bank Wind Farm	17	500
Dudgeon Offshore Wind Farm	18	500
Galloper Wind Farm	18	500
Abernedd Power Station	21	470
Port Talbot Woodchip Power Station	21	320
London Array	24	277
Rampion	25	332
	Total	**7,160.4**

2016/17 TEC Changes

Power Station	Zone	TEC Change (MW)
Allt Duine Wind Farm	1	87
Beatrice Wind Farm	1	400
Duncansby Tidal Array	1	30
Halsary Wind Farm	1	41.4
Marwick Head Wave Farm	1	13.5
MeyGen Tidal	1	66
North Nesting Wind Farm	1	250
Sallachy Wind Farm	1	66
Spittal Hill Wind Farm	1	75
Viking Wind Farm	1	300
Moray Firth Offshore Windfarm	2	120
Millennium South	3	25
Griffin Wind Farm	5	15.4
Hearthstanes B Wind Farm	9	81
Walney Extension Power Station A	14	360
Walney Extension Power Station B	14	392
Dogger Bank Platform 1	15	500
Hatfield Power Station	16	800
Thorpe Marsh	16	960
Docking Shoal Wind Farm	17	500
Carnedd Wen Wind Farm	18	150
East Anglia Offshore Wind Farm	18	2400
Pembroke 400kV substation	20	490
Pen-y-Cymoedd	21	299
Damhead Creek II	24	986
Rampion	25	332
Atlantic Array	27	302
	Total	**10,041.3**

2017/18 TEC Changes

Power Station	Zone	TEC Change (MW)
Beatrice Wind Farm	1	300
Duncansby Tidal Array	1	30
Lag Na Greine	1	10
Marwick Head Wave Farm	1	26.5
MeyGen Tidal	1	78
South Muaitheabhal Wind Farm	1	150
SSE Orkney Wave	1	38
Moray Firth Offshore Windfarm	2	300
Norway Interconnector	2	1400
Glenmorie Windfarm	3	114
Kilgallioch	10	274
Moyle Interconnector	10	360
Firth of Forth Offshore Wind	11	1825
Galawhistle Wind Farm	11	55.2
Inch Cape Offshore Wind Farm	11	330
Dogger Bank Platform 1	15	500
Dogger Bank Platform 2	15	500
Hornsea Offshore Wind Farm - Platform 2A	15	500
Barking Power Station C	18	470
East Anglia Offshore Wind Farm	18	1200
Nant-Y-Moch Wind Farm	18	160
Celtic Array	19	500
Greenwire Wind Farm - Pembroke	20	2000
Alderney Renewable Energy	26	100
Hinkley Point C	26	1670
Navitus Bay Offshore	26	400
Atlantic Array	27	404
	Total	**13,694.7**

Appendix B: Zonal generation and demand information

Generation changes (MW)

Generation Zone		13/14	14/15	Difference to 13/14	15/16	Difference to 14/15	16/17	Difference to 15/16	17/18	Difference to 16/17
1	North Scotland	748	957	209	1580	624	2909	1329	3542	633
2	East Aberdeenshire	1180	1180	0	1180	0	1300	120	3000	1700
3	Western Highlands	286	286	0	286	0	311	25	425	114
4	Skye and Lochalsh	41	41	0	41	0	41	0	41	0
5	Eastern Grampian and Tayside	325	334	9	433	99	448	15	448	0
6	Central Grampian	64	64	0	64	0	64	0	64	0
7	Argyll	82	132	50	155	23	155	0	155	0
8	The Trossachs	563	563	0	563	0	563	0	563	0
9	Stirlingshire and Fife	2380	2380	0	2488	108	2569	81	4394	1825
10	South West Scotland	2458	2533	75	2560	28	2560	0	3194	634
11	Lothian and Borders	2139	2826	687	3922	1096	3922	0	4307	385
12	Solway and Cheviot	404	473	69	473	0	473	0	473	0
13	North East England	1351	1393	42	1393	0	1393	0	1393	0
14	North Lancashire and The Lakes	3521	3691	170	3691	0	4443	752	4443	0
15	South Lancashire, Yorkshire and Humber	15497	16202	705	16702	500	17202	500	18702	1500
16	North Midlands and North Wales	12407	13459	1052	14263	804	16023	1760	16023	0
17	South Lincolnshire and North Norfolk	2179	3019	840	4500	1481	5000	500	5000	0
18	Mid Wales and The Midlands	7755	9075	1320	10075	1000	12625	2550	14455	1830
19	Anglesey and Snowdon	2134	2134	0	2134	0	2134	0	2634	500
20	Pembrokeshire	2199	2199	0	2199	0	2689	490	4689	2000
21	South Wales	3509	3509	0	4299	790	4598	299	4598	0
22	Cotswold	1234	1399	165	1399	0	1399	0	1399	0
23	Central London	144	144	0	144	0	144	0	144	0
24	Essex and Kent	13832	14672	840	14949	277	15935	986	15935	0
25	Oxfordshire, Surrey and Sussex	2070	2070	0	2402	332	2734	332	2734	0
26	Somerset and Wessex	2539	2539	0	2539	0	2539	0	4709	2170
27	West Devon and Cornwall	1045	1045	0	1045	0	1347	302	1751	404
Total contracted TEC as of 31/10/2013		**82084**	**88318**	**6233**	**95478**	**7160**	**105519**	**10041**	**119214**	**13695**

Demand changes (MW)

Zone Name		13/14	14/15	Difference to 13/14	15/16	Difference to 14/15	16/17	Difference to 15/16	17/18	Difference to 16/17
1	Northern Scotland	1,247	1,259	12	1,271	12	1,304	33	1,317	13
2	Southern Scotland	3,921	3,907	-14	3,907	0	3,907	0	3,907	0
3	Northern	2,676	2,863	187	2,890	27	2,916	26	2,942	26
4	North West	4,242	4,417	176	4,476	59	4,534	58	4,560	26
5	Yorkshire	5,213	5,248	35	5,283	35	5,317	35	5,353	36
6	N Wales & Mersey	3,553	3,503	-50	3,525	22	3,541	17	3,560	19
7	East Midlands	5,699	5,755	56	5,809	54	5,859	49	5,904	45
8	Midlands	5,144	5,194	51	5,235	41	5,258	23	5,281	23
9	Eastern	6,925	7,137	213	7,323	186	7,486	163	7,624	137
10	South Wales	2,169	2,188	19	2,207	19	2,227	20	2,247	20
11	South East	4,188	4,293	105	4,393	100	4,482	90	4,552	70
12	London	6,053	6,259	206	6,445	186	6,562	118	6,701	139
13	Southern	6,387	6,447	60	6,493	46	6,540	47	6,571	31
14	South Western	2,801	2,829	28	2,858	29	2,886	29	2,915	29
Total Demand (MW)		**60,218**	**61,299**	**1,084**	**62,114**	**815**	**62,821**	**707**	**63,435**	**614**

Appendix C: Onshore local circuit tariff changes for 2014/15 to 2017/18

Substation	13/14	14/15	Change	15/16	Change	16/17	Change	17/18	Change
Aberdeen Wind Farm	-	-	-	-	-	1.68	-	1.72	0.04
Achruach	-	4.66	-	4.19	-0.47	3.17	-1.03	3.24	0.08
Aigas	0.53	0.55	0.01	0.56	0.01	0.57	0.01	0.59	0.01
Aikengall II	-	0.41	-	-0.01	-0.42	1.48	1.49	1.51	0.04
Allt Duine Wind Farm	-	-	-	-	-	7.18	-	6.95	-0.22
An Suidhe	1.17	1.20	0.03	1.23	0.03	0.00	-1.23	0.00	0.00
Andershaw	2.42	2.48	0.06	2.54	0.06	2.61	0.06	2.67	0.07
Arecleoch	0.07	0.07	0.00	0.07	0.00	0.08	0.00	0.08	0.00
Aultmore	-	3.15	-	3.23	0.08	3.31	0.08	3.39	0.08
Baglan Bay	0.55	0.57	0.01	0.59	0.02	0.60	0.01	0.62	0.02
Black Hill	1.36	1.39	0.04	1.43	0.04	1.46	0.04	1.50	0.04
Black Law	0.85	0.87	0.02	0.89	0.02	0.91	0.02	0.94	0.02
BlackCraig	1.04	1.06	0.03	1.09	0.03	1.12	0.03	1.14	0.03
Blacklaw Extension	2.48	2.55	0.06	2.61	0.06	2.67	0.07	2.74	0.07
Bodelwyddan	-0.02	-0.02	0.00	-	-	-	-	-	-
Brockloch	-	0.72	-	0.74	0.02	0.76	0.02	0.78	0.02
Carraig Gheal	3.73	3.83	0.10	3.92	0.09	4.02	0.10	4.12	0.10
Carrington	-	0.01	-	0.01	0.00	0.01	0.00	0.01	0.00
Cleve Hill	0.32	0.33	0.01	0.33	0.00	0.34	0.01	0.35	0.01
Clyde (North)	0.09	0.10	0.00	0.10	0.00	0.10	0.00	0.10	0.00
Clyde (South)	0.11	0.11	0.00	0.11	0.00	0.12	0.00	0.12	0.00

Substation	13/14	14/15	Change	15/16	Change	16/17	Change	17/18	Change
Corriegarth	-	2.31	-	2.18	-0.13	2.24	0.05	2.29	0.06
Corriemoillie	2.83	2.91	0.07	2.98	0.07	3.06	0.07	3.13	0.08
Coryton	0.29	0.31	0.02	0.32	0.01	0.33	0.01	-0.19	-0.52
Cruachan	1.52	1.56	0.04	1.60	0.04	1.64	0.04	1.68	0.04
Crystal Rig	0.35	0.41	0.06	-0.01	-0.42	-0.01	0.00	-0.01	0.00
Culligran	1.47	1.51	0.04	1.55	0.04	1.58	0.04	1.62	0.04
Deanie	2.41	2.48	0.06	2.54	0.06	2.60	0.06	2.67	0.07
Dersalloch	1.55	1.59	0.04	1.63	0.04	1.67	0.04	1.71	0.04
Didcot	0.22	0.22	0.00	0.22	0.00	0.17	-0.05	0.18	0.00
Dinorwig	2.04	2.09	0.05	2.14	0.05	2.20	0.05	2.25	0.05
Druim Ba	-	-	-	1.90	-	1.95	0.05	2.00	0.05
Dunmaglass	-	-	-	1.56	-	1.60	0.04	1.64	0.04
Earlshaugh	-	-	-	2.09	-	2.14	0.05	2.19	0.05
Edinbane	5.81	5.96	0.15	6.10	0.14	6.26	0.15	-6.41	-12.67
Ewe Hill	2.35	2.41	0.06	2.47	0.06	2.53	0.06	2.60	0.06
Fallago	0.92	0.43	-0.49	0.06	-0.37	0.07	0.00	0.07	0.00
Farr Windfarm	1.90	1.95	0.05	2.00	0.05	6.13	4.13	6.28	0.15
Ffestiniogg	0.21	0.22	0.01	0.23	0.01	0.23	0.01	0.24	0.01
Finlarig	0.27	0.28	0.01	0.29	0.01	0.29	0.01	0.30	0.01
Foyers	0.65	0.66	0.02	0.34	-0.32	0.35	0.01	0.36	0.01
Glendoe	1.56	1.60	0.04	1.64	0.04	1.68	0.04	1.72	0.04

Substation	13/14	14/15	Change	15/16	Change	16/17	Change	17/18	Change
Glenmoriston	1.12	1.15	0.03	1.18	0.03	1.21	0.03	1.24	0.03
Gordonbush	3.47	3.56	0.09	0.66	-2.90	0.79	0.12	0.81	0.02
Griffin Wind	2.72	0.54	-2.18	2.77	2.23	4.51	1.74	7.17	2.67
Hadyard Hill	2.46	2.52	0.06	2.58	0.06	2.65	0.06	2.71	0.07
Harestanes	4.30	4.41	0.11	4.50	0.09	4.61	0.11	4.73	0.12
Hartlepool	0.50	0.51	0.01	0.53	0.02	0.54	0.01	0.07	-0.47
Hearthstanes	-	-	-	-	-	2.42	-	2.48	0.06
Hedon	0.15	0.16	0.01	0.16	0.00	0.17	0.00	0.17	0.00
Hornsea	-	0.01	-	0.01	0.00	0.01	0.00	0.01	0.00
Invergarry	-0.58	-0.60	-0.02	-0.61	-0.01	-0.63	-0.02	-0.64	-0.02
Kilbraur	1.72	1.76	0.04	0.24	-1.52	0.28	0.04	0.29	0.01
Killgallioch	-	-	-	-	-	-	-	-0.65	-
Kilmorack	0.15	0.15	0.00	0.15	0.00	0.16	0.00	0.16	0.00
Langage	0.56	0.57	0.01	0.59	0.02	0.60	0.01	0.62	0.02
Little Dunham	-	-	-	-	-	-0.31	-	-0.32	-0.01
Lochay	0.31	0.32	0.01	0.33	0.01	0.33	0.01	0.34	0.01
Luichart	0.96	0.99	0.03	1.01	0.02	1.04	0.03	1.06	0.03
Marchwood	0.32	0.33	0.01	0.34	0.01	0.35	0.01	0.36	0.01
Margee	0.89	0.91	0.02	0.93	0.02	0.96	0.02	0.98	0.02
Mark Hill	-0.74	-0.76	-0.02	-0.78	-0.02	-0.80	-0.02	-0.82	-0.02
Millennium Wind	1.38	1.41	0.03	1.45	0.04	1.49	0.04	1.52	0.04

Substation	13/14	14/15	Change	15/16	Change	16/17	Change	17/18	Change
Mossford	3.17	3.26	0.09	3.34	0.08	3.42	0.08	3.51	0.09
Nant	-1.04	-1.07	-0.03	-1.10	-0.03	-1.12	-0.03	-1.15	-0.03
Neilston	1.05	1.08	0.03	1.11	0.03	1.13	0.03	1.16	0.03
Newfield	3.71	3.81	0.10	3.90	0.09	4.00	0.10	4.10	0.10
Quoich	1.68	3.77	2.09	3.86	0.09	3.96	0.10	-3.60	-7.56
Rhigos	-	-	-	-	-	0.91	-	0.93	0.02
Rocksavage	0.01	0.02	0.01	0.02	0.00	0.02	0.00	0.02	0.00
Rowantree	-	1.74	-	1.78	0.04	1.83	0.04	1.87	0.05
Sallachy Wind	-	-	-	-	-	0.84	-	0.86	0.02
Saltend South	0.29	0.30	0.01	0.30	0.00	0.31	0.01	0.32	0.01
Sth Humber Bank	0.71	0.51	-0.20	-	-	-	-	-	-
Spalding	0.26	0.26	0.00	0.27	0.01	0.29	0.02	0.30	0.01
Staycain Windfarm	1.29	1.33	0.04	1.36	0.03	1.39	0.03	1.43	0.03
Strathy Wind	-	4.52	-	4.54	0.02	4.51	-0.03	4.62	0.11
Teesside	0.06	0.06	0.00	0.06	0.00	0.07	0.00	0.07	0.00
Thames Haven	-	0.24	-	0.25	0.01	0.26	0.01	-0.16	-0.42
Tibberchindy	-	-	-	-0.19	-	-0.16	0.03	-0.17	0.00
Ulzieside	3.83	3.93	0.10	4.03	0.10	4.13	0.10	4.23	0.10
Whitelee	0.09	0.09	0.00	0.09	0.00	0.10	0.00	0.10	0.00
Whitelee Extension	0.25	0.26	0.01	0.26	0.00	0.27	0.01	0.28	0.01

Appendix D: Offshore revenue assumptions

The revenue that National Grid expects to collect for each offshore network has been prepared using a range of approaches, depending on what information is publically available. These are:

- where an OFTO has been appointed, the actual revenues derived from the relevant OFTO's licence have been used.

- where an OFTO has not been appointed and the tender process has commenced, revenues have been based on the following relationship between estimated project values (ETV) and revenue information National Grid has received through the tender process:

  Forecast OFTO Revenue (£m) = £4.1m + 0.0716 x ETV (in £m)

- project-specific unit costs used by Redpoint when assessing the impact of TransmiT.

- where none of the above methods apply, the revenue has been calculated using the following relationship between TEC and OFTO revenues:

  Forecast OFTO Revenue (£m) = £0.0639m x TEC (in MW)

The following table shows the assumed project unit costs (in £m 13/14) that have been used to prepare the revenue forecasts in this report. It should be noted that the unit cost of projects will only be known once the appointment of the OFTO is completed.

Project	Basis of cost	Cost (£/kW)
Barrow	Actual	59
Gunfleet	Actual	41
Ormonde	Actual	75
Robin Rigg	Actual	42
Walney 1	Actual	67
Walney 2	Actual	69
Greater Gabbard	ETV	64
Lincs	ETV	105
London Array	ETV	61
Sheringham Shoal	ETV	56
Thanet	ETV	59
Atlantic Array	Average	64
Irish Sea	Average	64
West of Isle of Wight	Average	64
Neart Na Gaoithe	Average	64
Firth of Forth SPT	Average	64
Firth of Forth SHETL	Average	64
East Anglia	Average	64
Moray Firth	Average	64
Inch Cape	Average	64
Docking Shoal	Redpoint	43
Gwynt Y Mor	Redpoint	64
Humber Gateway	Redpoint	88
Race Bank	Redpoint	101

Project	Basis of cost	Cost (£/kW)
Triton Knoll	Redpoint	54
West of Duddon Sands	Redpoint	80
Westernmost Rough	Redpoint	33
Greater Gabbard Extension	Redpoint	57
Dogger Bank	Redpoint	166
Rampion (Hastings)	Redpoint	37
Hornsea	Redpoint	95
Argyll Array	Redpoint	30
Beatrice	Redpoint	39

Appendix E: Transmission Revenues

	Transmission Revenues (£m Outturn)				
Transmission Owner	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**
NGET	1,587	1,763	1,862	2,012	2,041
SHETL	172	185	234	235	233
SPTL	271	293	346	322	346
OFTOs	167	232	322	443	496
Total	2,198	2,473	2,763	3,012	3,116
Pre-Vesting Connections	43	40	39	37	36
TNUoS	**2,155**	**2,433**	**2,724**	**2,975**	**3,081**
High TNUoS	2,155	2,458	2,844	3,175	3,291
Low TNUoS	2,155	2,393	2,604	2,775	2,871

	Transmission Revenues (£m 13/14)				
Transmission Owner	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**
NGET	1,587	1,718	1,771	1,866	1,847
SHETL	172	181	222	218	211
SPTL	271	285	329	298	313
OFTOs	167	226	306	411	449
Total	2,198	2,411	2,627	2,794	2,820
Pre-Vesting Connections	43	39	37	34	32
TNUoS	**2,155**	**2,372**	**2,591**	**2,760**	**2,788**
High TNUoS	2,198	2,435	2,741	2,979	3,010
Low TNUoS	2,198	2,372	2,513	2,608	2,630

Appendix F: Generation Zone Map