nationalgrid

Tariff Information Paper

Quarterly update of forecast TNUoS tariffs for 2014/15

This information paper provides an update to the initial forecast of Transmission Network Use of System (TNUoS) tariffs for 2014/15. Forecast changes within this document affect both generation and demand TNUoS tariffs.
The forecasts tariffs for 2014/15 will be refined throughout the year and finalised in January 2014.

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Any Questions?

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1 Executive Summary

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. The resulting charges reflect the use 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 updates our view of 2014/15 tariffs. An initial view was published in February 2013 and subsequently updated in April 2013. This document refers to the February 2013 initial view. Changes from subsequent forecasts are highlighted but not analysed in terms of the effect on tariffs.

Tariff forecasts are based on the current charging methodology and take 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.

This updated view of tariffs reflects changes to contracted generation since October 2012, updated peak demand forecasts from Distribution Network Owners and updated revenue forecasts. Since October 2012, the contracted generation for 2014/15 has fallen by roughly 8.6GW, and peak demand by roughly 4GWh.

Generation tariffs in England & Wales are forecast to increase compared to 2013/14 mainly due to the increase in the residual with notable exceptions in areas Zones 23 and 24 which see reductions due to reductions in generation capacity in the locality. In Scotland Zones 3 and 4 see tariff increases over and above the average due to a combination of the changing generation and demand background which alter flows along circuits in the locality. Compared to the initial view of 2014/15 tariffs, tariffs have generally remained the same in Scotland and increased in England & Wales. Notable exceptions are in Zones 2 to 5 and Zones 23 and 24 where the changing generation and demand background have altered tariffs above or below average.

Forecast demand tariffs for 2014/15 are expected to increase by £3.63/kW on average compared to current tariffs mainly due to the increase in residual. Compared to the initial view tariffs generally decrease which mirrors the increase in the generation tariff. Exceptions to this are in Scotland where demand charges increase due to the overall reduction in generation in Scotland.

2 Introduction

National Grid sets Transmission Network Use of System (TNUoS) tariffs for onshore and offshore generators and suppliers across Great Britain. 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 locational component of TNUoS tariffs using a model of power flows on the transmission system. This model considers the impact that changes 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 reduce to reflect this. Information about generation and demand connected to the network and the electrical characteristics of the circuits that link these are used to calculate flows on the network.

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. Offshore, 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 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.

2.1 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), National Grid was directed to raise a CUSC modification proposal to enhance the current locational charges (CMP213). The proposal covers:

- 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. Final Working Group proposals and considerations were presented to the CUSC Panel in March 2013, and the Final CUSC Modification Report is now with Ofgem for consideration. A decision is expected in the autumn.

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. It is possible that implementation could be at the start of or during 2014/15. However, as it is uncertain at this stage which (if any) of the options developed would 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 Final CUSC Modification Report[1]

2.2 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.

2.3 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 further update the forecast of 2014/15 tariffs throughout 2013 according to the timetable below:

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 ahead of the publication of draft and final TNUoS tariffs.

1 http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/).

3 Updates to the Charging Model

In order to update the forecast generation and demand tariffs a number of changes must be made to the charging model. This update focuses on:

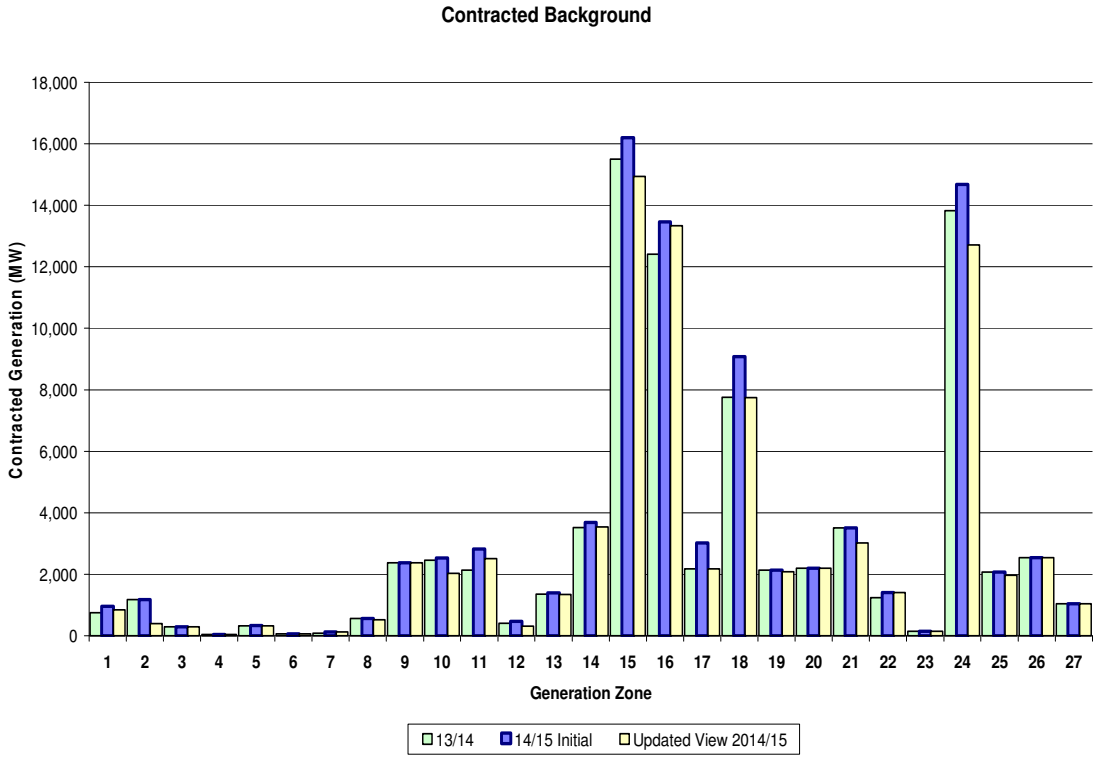
- changes to the generation and demand that affects the locational element of tariffs; and
- the resulting impact on the generation and demand charging bases
- updated revenues

Unless otherwise stated, all other model parameters remain unchanged from the Initial View prepared in February 2013.

3.1 Changes influencing the locational element of tariffs

3.1.1 Generation

For this quarterly update, the chargeable generation has been updated to reflect the changes made to contracted position for 2014/15 between 31 October 2012 and 08 July 2013. In this period, 42 power stations have decreased capacity for 2014/15 either by reducing their TEC; delaying commissioning; or terminating. The chart below shows the updated changes in generation that have been incorporated in the updated view for 2014/15. Appendix A and B provides the same data in tabular form on a station and zonal basis. For reference, Zones 1 to 12 represent Scotland and Zones 13 to 27 represent England & Wales.



3.1.2 Demand

Information for peak demand at each Grid Supply Point (GSP) is sourced from the 2013 Ten Year Statement (TYS) as required by the charging methodology. The TYS is based on information received in 2012 from DNOs and directly connected demand sites such as steelworks and other heavy industry. Forecast peak demand has dropped significantly across the majority of DNO's. This reflects work done by the DNO's over the past year to analyse outturn demand and the real effect of embedded generation at peak within their networks. Although there is a step change in demand forecasts, these forecasts are consistent with actual peak demands and forecasts being received this year.

3.1.3 Transmission network

No changes have been made to the transmission network since the Initial View

3.2 Changes to ensure the correct revenue recovery

3.2.1 Allowed Revenues

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

The revenues of the onshore TOs are based on the RIIO (Revenue = Incentives + Innovation Outputs) price control arrangements. One of the features of the RIIO framework is that network companies will only receive funding for the outputs delivered. This means that revenues may increase or decrease depending on the volume of new connections driving changes in network investment.

Revenue adjustments for pass-through costs, incentivised performance and under/over recovery are generally lagged by two years, e.g. performance in 2013/14 impacts revenues in 2015/16. Due to the transition from a one year lag in the previous price control arrangements to a two year lag in the current arrangements there are fewer adjustments in 2014/15.

Regulatory performance data is submitted by Transmission Owners to Ofgem by the end of July 2013. Ofgem is expected to notify any resulting revenue adjustments in November 2013 to allow these to be incorporated into 2014/15 tariffs. Where possible the data being submitted to Ofgem has been used in preparing these forecasts.

National Grid is working with SHETL and SPTL to prepare an initial forecast of revenues for 2014/15. The Scottish companies have provided indicative revenue forecasts for 2014/15 which have been incorporated into this forecast. Revenues are forecast to increase due to increased price control and transmission investment for renewable generation (TIRG) allowances and inflation. Revenues are inflated by a combination of actual RPI increases in 2012/13 and forecast RPI increases in 2013/14 and 2014/15. Actual RPI rose 3% in 2012/13 and recent Treasury forecasts for the subsequent years have also risen. Therefore an inflationary increase of 3.6% has been applied between 2013/14 and 2014/15 compared to 2.6% advised earlier in the year. The price control includes a true-up for actual RPI increases with a two year lag.

Revenue allowances collected for existing Offshore Transmission Owners (OFTO) are relatively predictable because the majority of each OFTO's revenue is fixed following the completion of the tender process. Existing OFTOs include Barrow, Gunfleet, Walney 1 & 2, Robin Rigg, Sheringham Shoal and Ormonde.

For the purpose of forecasting tariffs for 2014/15, we have assumed that OFTOs currently expected to be appointed during 2013/14 (Thanet, Greater Gabbard, London Array, and Lincs) will be in place in 2014/15. We have assumed that Gwynt y Môr will be appointed during 2014.

The revenue allowance for the Network Innovation Competition has been slightly increased from previous forecasts to £15.7m now that the bidders that have passed initial assessment are known. The successful bidders and associated revenue implications are due to be notified by Ofgem before final tariffs are published.

Revenue Element	2013/14 Revenue £m	2014/15 Revenue £m
National Grid	1,587.2	1,770.9
Scottish Power	271.3	313.5
Scottish Hydro Electricity	172.5	163.1
Offshore	165.5	211.0
Network Innovation Competition	-	15.7
Total	2,196.5	2,474.2

Charging Element	2013/14 Revenue £m	2014/15 Revenue £m
Pre-vesting connections	43.3	43.3
TNUoS	2,153.2	2,430.9
Total	2,196.5	2,474.2

3.2.2 Charging bases

Generation

The generation charging base has been updated to reflect the contracted position for 2014/15. This has reduced the charging base by approximately 7.3GW when compared to the Initial View and approximately 1.2GW compared to 2013/14.

The forecast generation base for 2014/15 has been determined by taking the contracted background for each year, adjusting this for interconnectors (unchanged from the Initial View), then reducing the amended figure by this factor.

Demand

The demand charging base and the split between HH and NHH demand between the various demand zones has not changed from when setting charges for 2013/14 and the Initial view of tariffs for 2014/15. For the avoidance of doubt the demand charging base is different to the forecast peak demand submitted by DNO's used in the Transport model. The demand charging base, i.e. our forecasts of actual supplier demand, is not directly related to the change in DNO peak demand submissions.

National Grid will continue to review the demand charging bases as further actual metering data for 2013/14 comes in as well as future demand forecasts.

In the Initial View we noted that BSC amendment proposal P272[2], would, if approved, increase the HH demand chargeable over the triads (and reduce annual NHH consumption). Given no decision has been made yet, and the BSC Panel's recommended implementation data is 1 April 2015/16, this has not been included in our forecast. If approved the split between HH and NHH would be changed within the model and therefore the affect on tariffs would be largely neutral.

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.

[2] BSC Amendment Proposal P272

4 Forecast generation tariffs

Based on the changes outlined in this report, the following section provides details of the forecast tariffs for the year 2014/15. Please note generation background changes flow through to future years and affect future tariffs.

4.1 Wider zonal generation tariffs

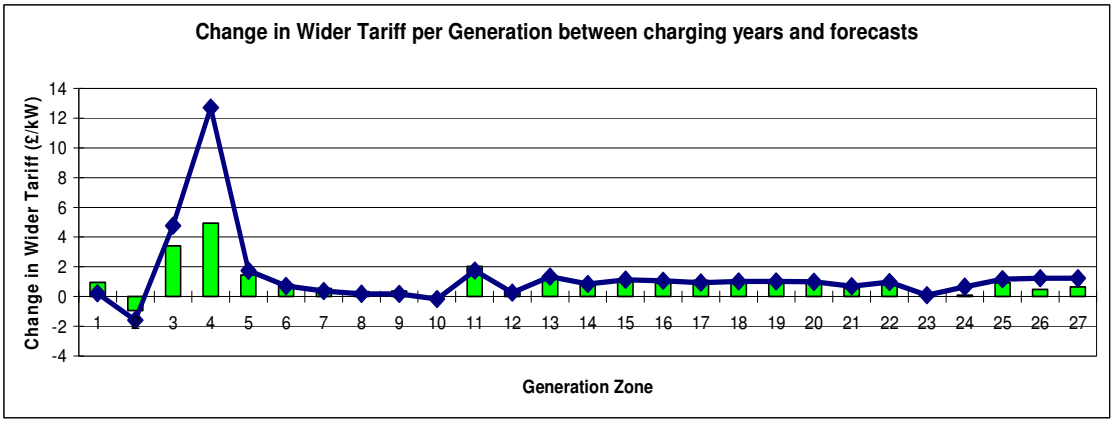
The following table shows the forecast wider generation TNUoS tariffs for 2014/15, expressed to 2 decimal places, and the differences between the initial (condition 5) and updated forecasts. Tariffs are presented in outturn prices based on the changes to allowed revenue and investment costs outlined in Section 3.

Generation Wider Tariff (£/kW)

Zone Name		2013/14	Updated 2014/15	Change compared to... 2013/14	Change compared to... Initial View
1	North Scotland	25.42	26.38	0.96	0.21
2	East Aberdeenshire	22.8	21.86	-0.94	-1.59
3	Western Highlands	26.15	29.56	3.41	4.77
4	Skye and Lochalsh	30.25	35.18	4.93	12.71
5	Eastern Grampian and Tayside	21.55	22.99	1.44	1.74
6	Central Grampian	19.75	20.55	0.80	0.70
7	Argyll	18.52	19.06	0.54	0.38
8	The Trossachs	16.49	16.81	0.32	0.18
9	Stirlingshire and Fife	16.4	16.76	0.36	0.17
10	South West Scotland	15.53	15.51	-0.02	-0.17
11	Lothian and Borders	12.84	14.87	2.03	1.75
12	Solway and Cheviot	11.07	11.48	0.41	0.26
13	North East England	8.64	9.98	1.34	1.34
14	North Lancashire and The Lakes	7.48	8.42	0.94	0.84
15	South Lancashire, Yorkshire and Humber	6.34	7.51	1.17	1.13
16	North Midlands and North Wales	5.18	6.09	0.91	1.06
17	South Lincolnshire and North Norfolk	3.49	4.57	1.08	0.93
18	Mid Wales and The Midlands	2.44	3.45	1.01	1.01
19	Anglesey and Snowdon	7.41	8.54	1.13	1.01
20	Pembrokeshire	5.57	6.53	0.96	0.99
21	South Wales	2.92	3.51	0.59	0.69
22	Cotswold	0.04	0.83	0.79	0.97
23	Central London	-4.44	-4.31	0.13	0.10
24	Essex and Kent	0.19	0.27	0.08	0.66
25	Oxfordshire, Surrey and Sussex	-1.69	-0.75	0.94	1.16
26	Somerset and Wessex	-3.05	-2.58	0.47	1.23
27	West Devon and Cornwall	-5.17	-4.52	0.65	1.22

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

The following chart shows the generation tariff changes between 2013/14 (chart bars) and the change between our initial and updated view of tariffs for 2014/15 (chart line).



4.1.1 Changes between 2013/14 and Updated views for 2014/15

Summary explanation

Generation tariffs have risen due to an increase in the revenue to be collected from generators due to an increase in revenues and a reduction in the charging base. Tariff rises are lower in those zones where generation capacity has reduced, i.e. the majority of Scotland (Zones 1 to 12).

The Tariff increases in Zones 3, 4 and partially 5 are due to the reduction in demand, caused by a combination of more embedded generation thus lowering demand forecasts in these zones. The reduction in demand without a concurrent reduction in generation, changes flows in these zones from import to export.

- 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 £0.67/kW to £5.48/kW. This has mainly been caused by the increase in revenue, as shown in the table below. For those zones with no specific changes due to circuits, demand or generation updates, this will cause tariffs to increase.

Item (£m, unless stated)		**13/14**	**14/15**	**Δ**
Revenue recoverable through TNUoS	*A*	2,153	2,431	278
Revenue to collect from generation	*B = 0.27 x A*	581	656	76
Revenue from zonal tariffs	*C*	55	55	0
Revenue from onshore local tariffs	*D*	34	33	-1
Revenue from offshore local tariffs	*E*	131	162	31
Revenue to recover from residual	*F = B-C-D-E*	361	405	44
Generation charging base (GW)	*G*	75.1	73.9	-1.2
Residual (£/kW)	*F / G*	**4.81**	**5.48**	**0.67**

- In **Zone 4** (in which there is one generator) and, to a lesser extent in **Zone 3**, the increase in the tariff has been caused by power flows reversing direction on a long radial spur. The increase in the current embedded generation forecast in this area has resulted in more circuits exporting thus increasing the tariff.

- A TEC reduction at Peterhead of 780MW reduces tariffs in most zones in Scotland, particularly **Zone 2.**

- The generation scheme at Neart Na Gaoithe Offshore Wind Farm (450MW) increases tariffs in **Zone 11** within which it connects. This more than offsets any decreases due to Peterhead and other TEC reductions in Scotland.

- The reduction in generation capacity at Grain offsets the increase in **Zones 23 and 24** that would otherwise have been seen due to the increase in the residual.

- Historically the extremities of the network, i.e. **Zones 1 and 2** and **Zones 24 to 27**, have seen changes in tariffs due to the inflationary increase in the expansion constant. However reductions in contracted generation and reductions in demand, counter the tariff changes historically witnessed.

4.1.2 Changes between initial and updated views for 2014/15

Summary explanation

Generation tariffs have risen due to an increase in the revenue to be collected from generators due to an increase in revenues and a reduction in the charging base. The exceptions to this rule are where generation reductions have affected tariffs, for example, at Peterhead (Zone 2) and in the south and south-west of Scotland (Zones 6 to 10) and in and around London (Zones 23 to 24).

Detailed explanation

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the tariff changes between the initial and updated view of tariffs:

- The generation **residual element**, which ensures the correct total revenue is recovered from generation, has increased by £0.79/kW to £5.48/kW. This is due to the reduction in the generation charging base and an updated assessment of revenue from offshore local tariffs.

Item (£m, unless stated)		**Initial View**	**Update View**	**Δ**
Revenue recoverable through TNUoS	*A*	2,433	2,431	-2
Revenue to collect from generation	*B = 0.27 x A*	657	656	-1
Revenue from zonal tariffs	*C*	57	55	-2
Revenue from onshore local tariffs	*D*	35	33	-2
Revenue from offshore local tariffs	*E*	184	162	-22
Revenue to recover from residual	*F = B-C-D-E*	381	405	24
Generation charging base (GW)	*G*	81.3	73.9	-7.4
Residual (£/kW)	*F / G*	**4.69**	**5.48**	**0.79**

- TEC reductions at Peterhead of 780MW and in **Zone 1** (not included in the Initial view), reduce tariffs in the majority of zones in Scotland, particularly **Zone 2.**

- The demand and generation background used in the Initial view resulted in generators in **Zones 3, 4 & partially 5** backing off flows along long circuits thus resulting in tariff decreases. Subsequent demand reductions due to increased embedded generation and changes in DNO forecasts without a concurrent drop in generation have reversed the decreases shown in the Initial view thus exaggerating the overall change in tariffs in these zones. In the Initial view this export did not occur due to a higher overall generation forecast and lower forecasted embedded generation.

- **Zone 10** sees a significant reduction in generation capacity (485MW in total) compared to the initial view, which results in a decrease in the forecast tariff for this zone.

- **Zones 23 and 24** see minimal change compared to the neighbouring zones following a decrease in TEC at Grain and Thames Haven.

4.2 Onshore Local Circuit Tariffs

Appendix C shows an updated forecast of onshore local circuit tariffs from 2013/14 to 2014/15. Where tariffs have changed these are due to local generation and demand changes which alter flows along the local circuits which comprise the tariffs.

4.3 Onshore Local Substation Tariffs

The table below shows the forecast onshore local substation tariffs that will apply during 2014/15. These tariffs only apply to transmission connected generators. The tariffs are indexed by historical RPI for each year of the price control. For the purposes of the forecast the inflation rate of 3.6%[3] was used to inflate 2013/14 tariffs.

		Local Substation Tariff (£/kW)		
Sum of TEC at Substation	**Connection Type**	**132kV**	**275kV**	**400kV**
<1320 MW	No redundancy	0.18	0.10	0.07
<1320 MW	Redundancy	0.39	0.24	0.17
>=1320 MW	No redundancy	-	0.32	0.23
>=1320 MW	Redundancy	-	0.52	0.38

4.4 Discount for Small Generation

The discount for small generation, which is equal to 25% of the combined generation and demand residuals, is forecast to increase from £7.55/kW to **£8.62/kW**. The increase is due to the change in revenue expected to be collected from generation and demand tariffs and reduction in the charging bases which combine to increase the residuals.

[3] Inflation using historical RPI uses the May to October average RPI of the previous year divided by the May to October average RPI of the year before that. This differs from the inflation used for Revenues which uses RPI two years previous plus Treasury forecasts for inflation since. Hence the inflation factor for Onshore Local Substation Tariffs differs to that for revenues.

5 Forecast demand tariffs

Based on the changes outlined in this report, the following section provides details of the forecast demand tariffs for the year 2014/15. Please note that generation background changes flow through to future years and affect subsequent future tariffs.

5.1 Wider demand tariffs

The following tables and charts show the forecast half-hourly and non half-hourly demand TNUoS tariffs for 2014/15 as well as the differences between 2013/14 and the Initial View 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)

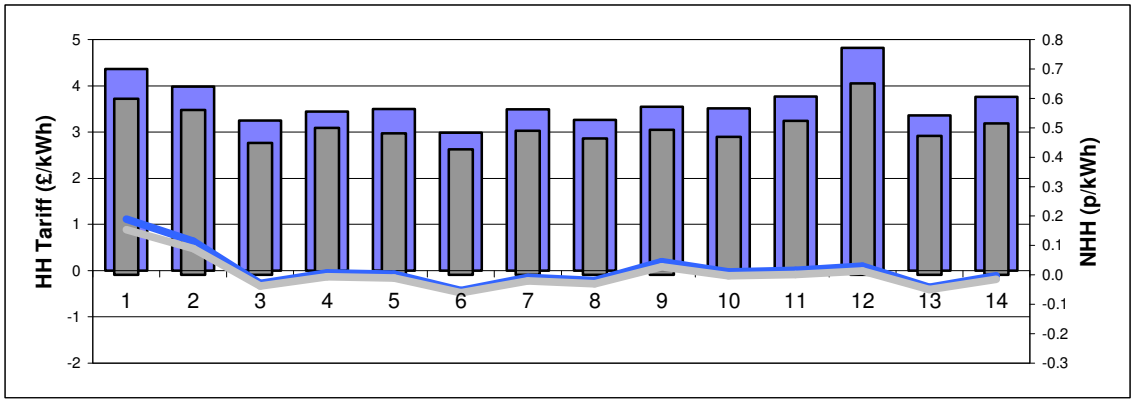
Zone Name		2013/14	Updated 2014/15	Change compared to…	
				2013/14	Initial View
1	Northern Scotland	11.05	15.42	4.37	1.12
2	Southern Scotland	16.79	20.78	3.99	0.64
3	Northern	22.35	25.60	3.25	-0.27
4	North West	25.18	28.63	3.45	-0.05
5	Yorkshire	25.49	28.99	3.50	-0.07
6	N Wales & Mersey	25.63	28.62	2.99	-0.43
7	East Midlands	28.21	31.71	3.50	-0.14
8	Midlands	29.20	32.47	3.27	-0.21
9	Eastern	29.89	33.44	3.55	0.20
10	South Wales	27.54	31.06	3.52	-0.03
11	South East	32.83	36.60	3.77	0.01
12	London	34.08	38.90	4.82	0.10
13	Southern	33.75	37.12	3.37	-0.35
14	South Western	33.55	37.32	3.77	-0.11

Non half-hourly demand tariffs (p/kWh)

Zone Name		2013/14	Updated 2014/15	Change compared to…	
				2013/14	Initial View
1	Northern Scotland	1.52	2.11	0.59	0.15
2	Southern Scotland	2.36	2.92	0.56	0.09
3	Northern	3.08	3.53	0.45	-0.04
4	North West	3.65	4.15	0.50	-0.01
5	Yorkshire	3.51	3.99	0.48	-0.01
6	N Wales & Mersey	3.67	4.09	0.42	-0.06
7	East Midlands	3.96	4.45	0.49	-0.02
8	Midlands	4.15	4.61	0.46	-0.03
9	Eastern	4.15	4.65	0.50	0.03
10	South Wales	3.69	4.16	0.47	0.00
11	South East	4.56	5.09	0.53	0.00
12	London	4.60	5.25	0.65	0.01
13	Southern	4.74	5.21	0.47	-0.05
14	South Western	4.60	5.11	0.51	-0.01

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

tariffs for 2014/15 and this updated view of tariffs is shown on the (blue line) for HH and (grey line) for NHH. 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.



5.1.1 Changes between 2013/14 and Updated view for 2014/15

Summary explanation

Demand tariffs are expected to increase in all zones and on average by £3.63/kW. This is because National Grid expects to recover around £277m more revenue through charges during 2014/15 compared to the prior year. Scotland sees an increase in forecast demand tariffs because there is less contracted generation in Scotland compared to 2013/14.

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 £3.60/kW to £29.01kW. 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	2,431	278
Revenue to collect from demand	*B = 0.73 x A*	1,572	1,774	202
Revenue from zonal charges	*C*	149	150	1
Revenue from residual	*D = B - C*	1,423	1,625	202
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**25.41**	**29.01**	**3.60**

- The increase in **Zone 12** (London) is greater than other parts of the country because of re-wiring works in the London area, particularly on cable circuits.
- Reductions in generation in Scotland cause increased tariffs in **Zones 1 and 2**
- A drop in forecasted demand in **Zone 6** over and above the average drop across all zones sees a decrease in tariffs

5.1.2 Changes between initial and updated views for 2014/15

Summary explanation

Demand tariffs have generally remained the same as those presented in the initial forecast because the amount of revenue to collect has remained the same as well as the charging bases. The exception to this is where there have been changes in the generation background, which is most notable in Scotland where demand tariffs have increased more than previously expected and an opposite effect in southerly zones albeit to a lesser extent.

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 that the correct total revenue recovery, has increased by £0.05/kW to £29.01kW between forecasts.

Item (£m, unless stated)		**Initial View**	**Update View**	**Δ**
Revenue recoverable through TNUoS	*A*	2,433	2,431	-2
Revenue to collect from demand	*B = 0.73 x A*	1,776	1,774	-2
Revenue from zonal charges	*C*	155	150	-5
Revenue from residual	*D = B - C*	1,621	1,625	4
Charging Base (GW)	*E*	56	56	0
Residual (£/kW)	*D / E*	**28.96**	**29.01**	**0.05**

- A reduction in the generation in Scotland has caused demand tariffs in **Zones 1 and 2** to increase more than previously expected

6 Sensitivities & Uncertainties

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 table provides details of wider 2014/15 TNUoS tariffs in a high and low revenue scenario. These scenarios show an example of how different assumptions about the onshore TO allowed revenues; the allowed revenues of OFTOs yet to be appointed; and the impact of inflation affect tariffs. For more details of how these scenarios have been prepared, see Appendix D.

Change to…	**Scenario**	
	Low Case	**High Case**
Allowed Revenue	-£30m	+£10m
Generation tariffs	-0.08 (£/kW)	+0.03 (£/kW)
HH Demand tariffs	-0.39 (£/kW)	+0.13 (£/kW)
NHH Demand tariffs	-0.05 (p/kWh)	+0.02 (p/kWh)

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.

Tariff	**Change to tariffs**
HH Demand	± £0.28/kW
NHH Demand	± 0.02 p/kWh

The charging bases will be reviewed before finalising tariffs for 2014/15. This review will examine Peak conditions and outturn HH demand at Peak by looking at historic outturn demand and future forecasts. This is necessary to ensure correct revenue recovery.

The following tables show tariffs if 2012/13 outturn demands were to be used. This reduces Peak demand down to 55.3GWh and alters the chargeable HH Zonal Triad demand.

		Existing Charge Base		2012/13 Outturn Charge Base			
Zone No.	Zone Name.	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)	Change HH	Change NHH
1	Northern Scotland	15.41	2.11	15.90	2.35	0.48	0.24
2	Southern Scotland	20.78	2.92	21.26	2.75	0.48	-0.17
3	Northern	25.60	3.53	26.08	3.35	0.48	-0.18
4	North West	28.63	4.15	29.11	3.96	0.48	-0.19
5	Yorkshire	28.98	3.99	29.47	4.14	0.48	0.15
6	N Wales & Mersey	28.62	4.09	29.10	4.57	0.48	0.48
7	East Midlands	31.71	4.45	32.19	4.31	0.48	-0.14
8	Midlands	32.47	4.61	32.95	4.58	0.48	-0.04
9	Eastern	33.44	4.65	33.92	4.62	0.48	-0.02
10	South Wales	31.05	4.16	31.54	4.36	0.48	0.21
11	South East	36.60	5.09	37.08	5.14	0.48	0.05
12	London	38.90	5.25	39.38	5.16	0.48	-0.09
13	Southern	37.12	5.21	37.60	5.30	0.48	0.08
14	South Western	37.31	5.11	37.80	4.98	0.48	-0.13

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 change 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 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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9 Appendices

Appendix A Generation changes for 2014/15

Appendix B Zonal generation and demand changes from 2014/15

Appendix C Onshore local circuit tariff changes from 2014/15

Appendix D Revenue scenarios

Appendix E Generation Zone Map

Appendix A: Generation changes for 2014/15

Power Station	Zone	13_14 Final Chargeable Generation	Difference between July 14_15 and Final 13_14	Reason for change	Feb 14_15 Chargeable Generation	Difference between July 14_15 and Feb 14_15	Reason for change
Afton	10	68	-68	Revised TEC date	68	-68	Revised TEC date
Aikengall II Windfarm	11	0	0		108	-108	
Aultmore Wind Farm	1	0	0		60	-60	
Barry Power Station	21	142	-142		142	-142	
Blackcraig Wind Farm	10	71	-71		71	-71.3	
Blacklaw Extension	11	69	-69		69	-69	
Brockloch Rig Wind Farm	10	0	0		75	-75	
Corriegarth	1	0	0		50	-49.9	
Crystal Rig 2	11	138	0		200	-62	
Drakelow D	18	0	0		1,320	-1320	
Ewe Hill	12	18	-18		66	-66	
Learney Wind Generating Station	5	0	0		9	-9.2	
Margree	10	43	-43		43	-42.5	
Neilston	10	80	-80		80	-80	
Newfield Wind Farm	12	60	-60		60	-60	
Pencloe	10	63	-63		63	-63	
Rowantree Wind Farm	11	0	0		67	-67	
Spalding Energy Expansion	17	0	0		840	-840	
Teesside	13	45	-45		45	-45	
Thames Haven Power Station	24	0	0		840	-840	
Ulzieside	10	30	-30		30	-30	
Whitelee	10	322	-17		322	-17	
Whitelee Extension	10	238	-32		238	-32	
Whiteside Hill	10	27	-27		27	-27	
Andershaw	11	45	-45	TEC Decrease	45	-45	TEC Decrease
Black Law	11	121	-3		121	-3	
Brigg	16	260	-105		260	-105	
Didcot A GTs	25	100	-100		100	-100	
Ferrybridge	15	1,986	-972		1,986	-972	
Glendoe	3	100	0		100	-0.1	
Great Yarmouth	18	420	-15		420	-15	
Grain	24	2,645	-1121		2,645	-1121	
Gwynt Y Mor Offshore Wind Farm	16	432	133		574	-9	
Harestanes	12	142	-16		163	-37.3	
Peterhead	2	1,180	-780		1,180	-780	
Roosecote	14	152	-152		152	-152	
Stacain Wind Farm	8	43	-43		43	-42.5	
Uskmouth	21	345	-345		345	-345	
Wheedlemont	1	0	0		2	-1.5	
Wylfa	19	490	-50		490	-50	
Erica Wind Farm	1	0	0	TEC Cancelled	22	-21.6	TEC Cancelled
Immingham Renewable Power Station	15	290	-290		290	-290	
Lochluichart	1	51	18	Tec Increase	51	18	Tec Increase
Torness	11	1,215	35		1,215	35	
AChruach Wind Farm	7	0	50		50	0	
Bristol	22	0	165		165	0	
Carrington Power Station	16	0	910		910	0	
Hornsea Offshore Wind Farm - Platform 1A	15	0	500		500	0	
Neart Na Gaoithe Offshore Wind Farm	11	0	450		450	0	
Wilton	13	99	42		141	0	
Westermost Rough	15	0	205		205	0	
Strathy North & South Wind	1	0	76		76	0	
West of Duddon Sands Offshore Wind Farm	14	204	178		374	8	
Total			-2,039.50			-8,272.90	

Appendix B: Zonal generation and demand information

Generation changes (MW)

Gen Zone	Generation Zone Name	Updated View 2014/15	Difference between Updated View 2014/15 and Final 2013/14	Diff between Updated View 2014/15 and Initial View 2014/15
1	North Scotland	**842**	94	-115
2	East Aberdeenshire	**400**	-780	-780
3	Western Highlands	**286**	0	0
4	Skye and Lochalsh	**41**	0	0
5	Eastern Grampian and Tayside	**325**	0	-9
6	Central Grampian	**64**	0	0
7	Argyll	**132**	50	0
8	The Trossachs	**520**	-43	-43
9	Stirlingshire and Fife	**2380**	0	0
10	South West Scotland	**2027**	-431	-506
11	Lothian and Borders	**2507**	368	-319
12	Solway and Cheviot	**310**	-94	-163
13	North East England	**1348**	-3	-45
14	North Lancashire and The Lakes	**3547**	26	-144
15	South Lancashire Yorkshire and Humber	**14940**	-557	-1262
16	North Midlands and North Wales	**13345**	938	-114
17	South Lincolnshire and North Norfolk	**2179**	0	-840
18	Mid Wales and The Midlands	**7740**	-15	-1335
19	Anglesey and Snowdon	**2084**	-50	-50
20	Pembrokeshire	**2199**	0	0
21	South Wales	**3022**	-487	-487
22	Cotswold	**1399**	165	0
23	Central London	**144**	0	0
24	Essex and Kent	**12711**	-1121	-1961
25	Oxfordshire Surrey and Sussex	**1970**	-100	-100
26	Somerset and Wessex	**2539**	0	0
27	West Devon and Cornwall	**1045**	0	0
Total		**80045**	**-2040**	**-8273**

Demand changes (MW)

Zone	Zone Name	13/14	14/15	Diff	%
1	Northern Scotland	1,247	875	-372	-30%
2	Southern Scotland	3,921	3,760	-161	-4%
3	Northern	2,676	2,939	263	10%
4	North West	4,242	4,011	-231	-5%
5	Yorkshire	5,213	4,787	-426	-8%
6	N Wales & Mersey	3,553	2,546	-1,007	-28%
7	East Midlands	5,699	5,188	-511	-9%
8	Midlands	5,144	4,808	-336	-7%
9	Eastern	6,925	6,679	-246	-4%
10	South Wales	2,169	2,110	-59	-3%
11	South East	4,188	3,883	-305	-7%
12	London	6,053	5,944	-109	-2%
13	Southern	6,387	6,236	-151	-2%
14	South Western	2,801	2,810	9	0%

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

Substation	13/14	14/15 Upd	Change	14/15 Initial	Change
Achruach	-	4.09	-	4.66	-0.57
Aigas	0.53	0.55	0.02	0.55	0.00
Aikengall II	-	-	-	0.41	-
An Suidhe	1.17	1.20	0.03	1.2	0.00
Andershaw	2.42	-	-	2.48	-
Arecleoch	0.07	0.07	0.00	0.07	0.00
Aultmore	-	-	-	3.15	-
Baglan Bay	0.55	0.57	0.02	0.57	0.00
Black Hill	1.36	-	-	1.39	-
Black Law	0.85	0.87	0.02	0.87	0.00
BlackCraig	1.04	-	-	1.06	-
Blacklaw Extension	2.48	-	-	2.55	-
Bodelwyddan	-0.02	-0.02	0.00	-0.02	0.00
Brockloch	-	-	-	0.72	-
Carraig Gheal	3.73	3.83	0.10	3.83	0.00
Carrington	-	0.01	-	0.01	0.00
Cleve Hill	0.32	0.33	0.01	0.33	0.00
Clyde (North)	0.09	0.10	0.01	0.1	0.00
Clyde (South)	0.11	0.11	0.00	0.11	0.00
Corriegarth	-	-	-	2.31	-
Corriemoillie	2.83	2.91	0.08	2.91	0.00
Coryton	0.29	0.31	0.02	0.31	0.00
Cruachan	1.52	1.56	0.04	1.56	0.00
Crystal Rig	0.35	0.41	0.06	0.41	0.00
Culligran	1.47	1.51	0.04	1.51	0.00
Deanie	2.41	2.48	0.07	2.48	0.00
Dersalloch	1.55	1.59	0.04	1.59	0.00
Didcot	0.22	0.22	0.00	0.22	0.00
Dinorwig	2.04	2.09	0.05	2.09	0.00
Edinbane	5.81	5.96	0.15	5.96	0.00
Ewe Hill	2.35	-	-	2.41	-
Fallago	0.92	0.43	-0.49	0.43	0.00
Farr Windfarm	1.9	1.95	0.05	1.95	0.00
Ffestiniogg	0.21	0.22	0.01	0.22	0.00
Finlarig	0.27	0.28	0.01	0.28	0.00
Foyers	0.65	0.66	0.01	0.66	0.00
Glendoe	1.56	1.60	0.04	1.6	0.00
Glenmoriston	1.12	1.15	0.03	1.15	0.00
Gordonbush	3.47	3.56	0.09	3.56	0.00
Griffin Wind	2.72	0.54	-2.18	0.54	0.00
Hadyard Hill	2.46	2.52	0.06	2.52	0.00
Harestanes	4.3	4.41	0.11	4.41	0.00
Hartlepool	0.5	0.01	-0.49	0.51	-0.50
Hedon	0.15	0.16	0.01	0.16	0.00
Hornsea	-	0.01	-	0.01	0.00
Invergarry	-0.58	1.23	1.81	-0.6	1.83
Kilbraur	1.72	1.76	0.04	1.76	0.00
Kilmorack	0.15	0.15	0.00	0.15	0.00
Langage	0.56	0.57	0.01	0.57	0.00

Substation	13/14	14/15 Upd	Change	14/15 Initial	Change
Lochay	0.31	0.32	0.01	0.32	0.00
Luichart	0.96	0.99	0.03	0.99	0.00
Marchwood	0.32	0.33	0.01	0.33	0.00
Margee	0.89	-	-	0.91	-
Mark Hill	-0.74	-0.76	-0.02	-0.76	0.00
Millennium Wind	1.38	1.41	0.03	1.41	0.00
Mossford	3.17	3.26	0.09	3.26	0.00
Nant	-1.04	2.18	3.22	-1.07	3.25
Neilston	1.05	-	-	1.08	-
Newfield	3.71	-	-	3.81	-
Quoich	1.68	3.77	2.09	3.77	0.00
Rocksavage	0.01	0.02	0.01	0.02	0.00
Rowantree	-	-	-	1.74	-
Saltend South	0.29	0.30	0.01	0.3	0.00
Spalding	0.26	0.26	0.00	0.26	0.00
Staycain Windfarm	1.29	-	-	1.33	-
Sth Humber Bank	0.71	1.15	0.44	0.51	0.64
Strathy Wind	-	4.52	-	4.52	0.00
Teesside	0.06	-	-	0.06	-
Thames Haven	-	-	-	0.24	-
Ulzieside	3.83	-	-	3.93	-
Whitelee	0.09	0.09	0.00	0.09	0.00
Whitelee Extension	0.25	0.26	0.01	0.26	0.00

Appendix D: Revenue Scenarios

Low Scenario

In the low scenario we have reduced the total transmission allowed revenue by ~£30m, which is based on:

- Ofgem awards no additional revenues under the Network Innovation Competition; (-~£15m)
- Delay in asset transfer of Gwynt y Môr by 6 months (-~£10m)
- A reduction in annual inflation from 3.6% to 3.4%. (-~£5m)
- No change in Scottish TO revenues

High Scenario

In the high scenario we have increased the total transmission allowed revenue by £10m, which is based on:

- Earlier asset transfer for Gwynt y Môr with Lincs Wind Farm one offs occurring in 2014/15 (+~£5m)
- An increase in annual inflation from 3.6% to 3.8%. (+~£5m)
- No change in Scottish TO revenues

Appendix E: Generation Zone Map