**Tariff Information Paper**

# Forecast TNUoS tariffs from 2016/17 to 2019/20

This information paper provides a forecast of Transmission Network Use of System (TNUoS) tariffs from 2016/17 to 2019/20. These tariffs apply to generators and suppliers.

This annual publication is intended to show how tariffs may evolve over the next five years. The forecast tariffs for 2016/17 will be refined throughout the year.

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**Version 1.0**

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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

This document contains our forecast of how Transmission Network Use of System (TNUoS) tariffs will change between 2016/17 and 2019/20. TNUoS is paid by generators and suppliers for use of the GB electricity transmission networks. Tariffs for 2015/16 were discussed in more detail in December's Draft TNUoS tariffs for 2015/16 and will be finalised at the end of January 2015[1]. We will update the Tariffs for 2016/17 over the next year and finalise them in January 2016.

For charging years 2016/17 onwards, we are using the methodology associated with Working-group Alternative Code Modification 2 of CUSC Modification Proposal CMP213 (Project Transmit) which was approved by Ofgem in July 2014.

Forecasts take into account changes in: Generation and Demand connected to the transmission system; the transmission network due to investments undertaken by transmission owners (TOs); and TO revenues. TO revenues include a forecast of inflation, changes to onshore TO allowed revenue under RIIO price controls and a forecast of offshore transmission owners' revenue.

An EU regulation limits the average annual use of system charges that generators pay to €2.5/MWh for the foreseeable future. With rising revenues this limit is reached in 2015/16 and consequently the revenue recovered from generation is capped and variations in allowed revenue are only reflected in demand tariffs. The generation cap includes revenue from offshore generators which increases with more offshore transmission networks and this, combined with an increase in contracted generation, reduces the generation residual meaning that average Generation tariffs decrease year on year.

There are locational variances in Generation and Demand tariffs in 2017/18 due to the Western HVDC link which for the purposes of this report is assumed to commission in mid-2017. This link between Hunterston in Western Scotland and Deeside in North Wales is being built to facilitate the delivery of renewable energy between Scotland and England & Wales. The HVDC link generally increases Generation tariffs in the North and decreases Generation tariffs in the South, with the opposite effect on Demand tariffs.

In 2018/19, the Caithness-Moray HVDC link is planned to commission and new offshore wind farms in Scotland increase North to South flows. This generally increases Generation tariffs in the North and decreases Generation tariffs in the South, with the opposite effect on Demand tariffs. Certain zones do reverse this trend where large scale Generation projects connect.

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

# 2. Five Year Tariff Forecast Tables

This section contains the Generation and Demand Tariffs for 2016/17 to 2019/20 using the Diversity 1 methodology which forms part of CMP213 Working-group Alternative Code Modification proposal 2.

The proportion of revenue recovered from Generation and Demand is altered each year to limit the average generation charge to €2.5/MWh.

## 2.1 Generation Tariffs

Under the approved CMP213 Diversity 1 methodology the tariff paid by a generator depends on: the zone into which the generator connects, whether the generator is conventional or intermittent, and the generator's specific annual load factor. The tariff is built up from four elements as follows:

**System Peak:**Payable by conventional generators only

**Shared Year Round:** Payable by all generators, scaled by each generator's specific annual load factor

**Not Shared Year Round**: Payable by all generators. (Use £0/kW where no tariff is shown in the tables.)

**Residual:** Payable by all generators.

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

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

### Table 1 - 2016/17 Generation Tariffs

| Generation Tariffs | | System Peak Tariff | Shared Year Round Tariff | Not Shared Year Round Tariff | Residual Tariff | Conventional 70% Load Factor | Intermittent 30% Load Factor |
|---|---|---|---|---|---|---|---|
| **Zone** | **Zone Name** | **(£/kW)** | **(£/kW)** | **(£/kW)** | **(£/kW)** | **(£/kW)** | **(£/kW)** |
| 1 | North Scotland | 2.84 | 13.26 | 7.19 | 1.31 | 20.63 | 12.48 |
| 2 | East Aberdeenshire | 3.71 | 6.84 | 7.19 | 1.31 | 17.00 | 10.56 |
| 3 | Western Highlands | 2.60 | 11.21 | 6.90 | 1.31 | 18.66 | 11.57 |
| 4 | Skye and Lochalsh | -1.43 | 11.21 | 8.37 | 1.31 | 16.10 | 13.04 |
| 5 | Eastern Grampian and Tayside | 2.20 | 10.11 | 6.39 | 1.31 | 16.98 | 10.74 |
| 6 | Central Grampian | 4.05 | 10.03 | 6.33 | 1.31 | 18.71 | 10.65 |
| 7 | Argyll | 3.07 | 7.95 | 9.78 | 1.31 | 19.73 | 13.47 |
| 8 | The Trossachs | 3.19 | 7.95 | 4.77 | 1.31 | 14.84 | 8.47 |
| 9 | Stirlingshire and Fife | 3.65 | 7.03 | 4.43 | 1.31 | 14.31 | 7.85 |
| 10 | South West Scotland | 2.01 | 7.41 | 4.43 | 1.31 | 12.94 | 7.97 |
| 11 | Lothian and Borders | 4.00 | 7.41 | 2.01 | 1.31 | 12.51 | 5.54 |
| 12 | Solway and Cheviot | 1.76 | 4.58 | 3.03 | 1.31 | 9.31 | 5.71 |
| 13 | North East England | 3.79 | 2.38 | 1.83 | 1.31 | 8.60 | 3.86 |
| 14 | North Lancashire and The Lakes | 1.87 | 2.38 | 1.78 | 1.31 | 6.63 | 3.81 |
| 15 | South Lancashire, Yorkshire and Humber | 4.56 | 0.49 | | 1.31 | 6.22 | 1.46 |
| 16 | North Midlands and North Wales | 3.54 | 0.06 | | 1.31 | 4.90 | 1.33 |
| 17 | South Lincolnshire and North Norfolk | 1.61 | -0.07 | 0.00 | 1.31 | 2.87 | 1.29 |
| 18 | Mid Wales and The Midlands | 1.22 | -0.14 | | 1.31 | 2.44 | 1.27 |
| 19 | Anglesey and Snowdon | 4.78 | 1.58 | | 1.31 | 7.20 | 1.79 |
| 20 | Pembrokeshire | 8.07 | -3.44 | | 1.31 | 6.98 | 0.28 |
| 21 | South Wales & Gloucester | 5.40 | -3.53 | | 1.31 | 4.24 | 0.25 |
| 22 | Cotswold | 2.16 | 2.53 | -5.95 | 1.31 | -0.70 | -3.88 |
| 23 | Central London | -3.83 | 2.53 | -5.29 | 1.31 | -6.04 | -3.22 |
| 24 | Essex and Kent | -4.46 | 2.53 | | 1.31 | -1.38 | 2.07 |
| 25 | Oxfordshire, Surrey and Sussex | -1.80 | -2.08 | | 1.31 | -1.95 | 0.69 |
| 26 | Somerset and Wessex | -2.13 | -3.47 | | 1.31 | -3.25 | 0.27 |
| 27 | West Devon and Cornwall | -1.62 | -5.61 | | 1.31 | -4.24 | -0.37 |

## Table 2 - 2017/18 Generation Tariffs (With Western HVDC Link)

| Generation Tariffs | | System Peak Tariff | Shared Year Round Tariff | Not Shared Year Round Tariff | Residual Tariff | Conventional 70% Load Factor | Intermittent 30% Load Factor |
|---|---|---|---|---|---|---|---|
| Zone | Zone Name | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) |
| 1 | North Scotland | 2.77 | 19.05 | 12.55 | 0.45 | 29.11 | 18.72 |
| 2 | East Aberdeenshire | 3.76 | 11.94 | 12.55 | 0.45 | 25.12 | 16.58 |
| 3 | Western Highlands | 2.70 | 16.70 | 12.18 | 0.45 | 27.03 | 17.64 |
| 4 | Skye and Lochalsh | -3.20 | 16.70 | 12.11 | 0.45 | 21.06 | 17.57 |
| 5 | Eastern Grampian and Tayside | 2.32 | 15.73 | 11.64 | 0.45 | 25.43 | 16.81 |
| 6 | Central Grampian | 4.49 | 15.97 | 11.83 | 0.45 | 27.96 | 17.08 |
| 7 | Argyll | 3.62 | 13.94 | 16.68 | 0.45 | 30.51 | 21.31 |
| 8 | The Trossachs | 3.78 | 13.94 | 10.13 | 0.45 | 24.11 | 14.76 |
| 9 | Stirlingshire and Fife | 3.60 | 12.58 | 9.53 | 0.45 | 22.38 | 13.76 |
| 10 | South West Scotland | 2.44 | 14.82 | 9.53 | 0.45 | 22.79 | 14.43 |
| 11 | Lothian and Borders | 4.36 | 14.82 | 2.34 | 0.45 | 17.52 | 7.24 |
| 12 | Solway and Cheviot | 1.85 | 7.78 | 5.93 | 0.45 | 13.67 | 8.71 |
| 13 | North East England | 4.18 | 3.32 | 3.44 | 0.45 | 10.39 | 4.89 |
| 14 | North Lancashire and The Lakes | 1.77 | 3.32 | 1.70 | 0.45 | 6.25 | 3.15 |
| 15 | South Lancashire, Yorkshire and Humber | 4.85 | -0.08 | | 0.45 | 5.24 | 0.43 |
| 16 | North Midlands and North Wales | 3.67 | -1.57 | | 0.45 | 3.02 | -0.02 |
| 17 | South Lincolnshire and North Norfolk | 1.77 | -0.93 | | 0.45 | 1.57 | 0.17 |
| 18 | Mid Wales and The Midlands | 1.26 | -1.27 | | 0.45 | 0.83 | 0.07 |
| 19 | Anglesey and Snowdon | 4.01 | -1.51 | | 0.45 | 3.40 | 0.00 |
| 20 | Pembrokeshire | 8.22 | -4.80 | | 0.45 | 5.31 | -0.99 |
| 21 | South Wales & Gloucester | 5.48 | -4.88 | | 0.45 | 2.51 | -1.01 |
| 22 | Cotswold | 2.16 | 1.50 | -6.26 | 0.45 | -2.60 | -5.36 |
| 23 | Central London | -3.89 | 1.50 | -5.34 | 0.45 | -7.73 | -4.44 |
| 24 | Essex and Kent | -4.53 | 1.50 | | 0.45 | -3.02 | 0.90 |
| 25 | Oxfordshire, Surrey and Sussex | -1.84 | -3.28 | | 0.45 | -3.68 | -0.53 |
| 26 | Somerset and Wessex | -2.34 | -4.76 | | 0.45 | -5.22 | -0.98 |
| 27 | West Devon and Cornwall | -1.70 | -6.82 | | 0.45 | -6.02 | -1.59 |

## Table 3 - 2018/19 Generation Tariffs with Caithness-Moray

| Generation Tariffs | | System Peak Tariff | Shared Year Round Tariff | Not Shared Year Round Tariff | Residual Tariff | Conventional 70% Load Factor | Intermittent 30% Load Factor |
|---|---|---|---|---|---|---|---|
| Zone | Zone Name | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) |
| 1 | North Scotland | 1.92 | 17.00 | 21.01 | -1.34 | 33.49 | 24.77 |
| 2 | East Aberdeenshire | 1.65 | 8.13 | 19.85 | -1.34 | 25.85 | 20.95 |
| 3 | Western Highlands | 2.04 | 15.48 | 19.10 | -1.34 | 30.64 | 22.41 |
| 4 | Skye and Lochalsh | -8.05 | 15.48 | 19.04 | -1.34 | 20.49 | 22.35 |
| 5 | Eastern Grampian and Tayside | 3.61 | 13.89 | 16.17 | -1.34 | 28.16 | 19.00 |
| 6 | Central Grampian | 3.40 | 13.79 | 15.95 | -1.34 | 27.67 | 18.75 |
| 7 | Argyll | 2.39 | 12.75 | 19.81 | -1.34 | 29.79 | 22.30 |
| 8 | The Trossachs | 2.81 | 12.75 | 13.73 | -1.34 | 24.14 | 16.22 |
| 9 | Stirlingshire and Fife | 2.52 | 11.73 | 12.47 | -1.34 | 21.86 | 14.65 |
| 10 | South West Scotland | 2.94 | 13.39 | 12.59 | -1.34 | 23.56 | 15.27 |
| 11 | Lothian and Borders | 3.16 | 13.39 | 4.49 | -1.34 | 15.69 | 7.17 |
| 12 | Solway and Cheviot | 2.23 | 7.28 | 7.36 | -1.34 | 13.34 | 8.20 |
| 13 | North East England | 3.64 | 3.15 | 3.63 | -1.34 | 8.13 | 3.24 |
| 14 | North Lancashire and The Lakes | 1.83 | 3.15 | 2.43 | -1.34 | 5.12 | 2.03 |
| 15 | South Lancashire, Yorkshire and Humber | 4.60 | 0.23 | | -1.34 | 3.42 | -1.27 |
| 16 | North Midlands and North Wales | 3.53 | -1.46 | | -1.34 | 1.17 | -1.78 |
| 17 | South Lincolnshire and North Norfolk | 2.43 | -1.46 | | -1.34 | 0.07 | -1.78 |
| 18 | Mid Wales and The Midlands | 1.54 | -1.31 | | -1.34 | -0.72 | -1.73 |
| 19 | Anglesey and Snowdon | 3.04 | -0.11 | 0.00 | -1.34 | 1.62 | -1.37 |
| 20 | Pembrokeshire | 8.67 | -5.46 | | -1.34 | 3.51 | -2.98 |
| 21 | South Wales & Gloucester | 6.02 | -5.47 | | -1.34 | 0.85 | -2.98 |
| 22 | Cotswold | 2.36 | 1.62 | -7.12 | -1.34 | -4.96 | -7.97 |
| 23 | Central London | -6.07 | 1.62 | -6.10 | -1.34 | -12.37 | -6.95 |
| 24 | Essex and Kent | -3.55 | 1.62 | | -1.34 | -3.76 | -0.85 |
| 25 | Oxfordshire, Surrey and Sussex | -1.86 | -3.61 | | -1.34 | -5.72 | -2.42 |
| 26 | Somerset and Wessex | -2.39 | -5.58 | | -1.34 | -7.63 | -3.01 |
| 27 | West Devon and Cornwall | -1.83 | -7.90 | | -1.34 | -8.70 | -3.71 |

### Table 4 - 2019/20 Generation Tariffs

| Generation Tariffs | | System Peak Tariff | Shared Year Round Tariff | Not Shared Year Round Tariff | Residual Tariff | Conventional 70% Load Factor | Intermittent 30% Load Factor |
|---|---|---|---|---|---|---|---|
| **Zone** | **Zone Name** | **(£/kW)** | **(£/kW)** | **(£/kW)** | **(£/kW)** | **(£/kW)** | **(£/kW)** |
| 1 | North Scotland | 1.53 | 16.43 | 21.83 | -2.97 | 31.89 | 23.79 |
| 2 | East Aberdeenshire | 1.41 | 7.60 | 20.68 | -2.97 | 24.45 | 19.99 |
| 3 | Western Highlands | 1.59 | 15.15 | 19.83 | -2.97 | 29.05 | 21.40 |
| 4 | Skye and Lochalsh | -8.81 | 15.15 | 19.78 | -2.97 | 18.61 | 21.36 |
| 5 | Eastern Grampian and Tayside | 2.07 | 13.96 | 17.26 | -2.97 | 26.13 | 18.47 |
| 6 | Central Grampian | 2.03 | 13.86 | 17.00 | -2.97 | 25.76 | 18.19 |
| 7 | Argyll | 1.55 | 12.82 | 20.16 | -2.97 | 27.71 | 21.04 |
| 8 | The Trossachs | 1.65 | 12.82 | 14.38 | -2.97 | 22.03 | 15.26 |
| 9 | Stirlingshire and Fife | 2.24 | 11.58 | 12.57 | -2.97 | 19.95 | 13.07 |
| 10 | South West Scotland | 2.49 | 13.17 | 12.81 | -2.97 | 21.54 | 13.78 |
| 11 | Lothian and Borders | 4.19 | 13.17 | 5.80 | -2.97 | 16.23 | 6.78 |
| 12 | Solway and Cheviot | 1.83 | 7.53 | 7.04 | -2.97 | 11.16 | 6.33 |
| 13 | North East England | 4.20 | 5.09 | 4.43 | -2.97 | 9.23 | 2.99 |
| 14 | North Lancashire and The Lakes | 1.84 | 5.09 | 0.26 | -2.97 | 2.69 | -1.18 |
| 15 | South Lancashire, Yorkshire and Humber | 4.69 | 0.42 | | -2.97 | 2.01 | -2.84 |
| 16 | North Midlands and North Wales | 3.72 | -1.37 | | -2.97 | -0.21 | -3.38 |
| 17 | South Lincolnshire and North Norfolk | 2.69 | -1.42 | | -2.97 | -1.28 | -3.40 |
| 18 | Mid Wales and The Midlands | 0.88 | -0.80 | | -2.97 | -2.65 | -3.21 |
| 19 | Anglesey and Snowdon | 3.08 | -0.08 | | -2.97 | 0.05 | -3.00 |
| 20 | Pembrokeshire | 8.59 | -5.81 | | -2.97 | 1.56 | -4.71 |
| 21 | South Wales & Gloucester | 5.74 | -5.87 | | -2.97 | -1.34 | -4.73 |
| 22 | Cotswold | 1.95 | 1.59 | -7.55 | -2.97 | -7.46 | -10.05 |
| 23 | Central London | -6.06 | 1.59 | -6.06 | -2.97 | -13.97 | -8.55 |
| 24 | Essex and Kent | -2.55 | 1.59 | | -2.97 | -4.41 | -2.49 |
| 25 | Oxfordshire, Surrey and Sussex | -1.65 | -3.36 | | -2.97 | -6.97 | -3.98 |
| 26 | Somerset and Wessex | -2.77 | -4.38 | | -2.97 | -8.81 | -4.28 |
| 27 | West Devon and Cornwall | -2.76 | -8.35 | | -2.97 | -11.58 | -5.48 |

## 2.2 Onshore Local Circuit Tariffs

Onshore Local Circuit tariffs are applicable to generators not directly connected to the Main Interconnected Transmission System (MITS). Each generator paying this charge has a tariff specific to its location. Forecast onshore local Circuit Tariffs are listed in Table 5 and can change from year to year due to local circuit reconfiguration or variations in the flow on local circuits, particularly where flow reverses direction. Such variations in flow are usually influenced by changes in generation patterns or network developments.

**Table 5 - Onshore Local Circuit Tariffs**

| Connection Point | 2016/17 (£/kW) | 2017/18 (£/kW) | 2018/19 (£/kW) | 2019/20 (£/kW) |
|---|---|---|---|---|
| Achruach | 3.96 | 4.07 | 4.20 | 4.32 |
| Afton | 2.14 | 2.21 | 2.27 | 2.34 |
| Aigas | 0.60 | 0.62 | 0.64 | 0.66 |
| Aikengall II | 1.34 | 1.48 | 1.16 | 1.20 |
| Allt Duine | - | - | 3.60 | 3.71 |
| An Suidhe | 2.81 | 2.90 | 2.99 | 3.08 |
| Arecleoch | 3.27 | 1.97 | 2.03 | 2.09 |
| Aultmore | - | -3.20 | 3.30 | 3.40 |
| Baglan Bay | 0.67 | 0.69 | 0.46 | 0.48 |
| Beinneun Wind Farm | 4.52 | 4.66 | 4.80 | 4.94 |
| Black Craig | 1.13 | 3.14 | -2.62 | -0.35 |
| Black Law | 0.92 | 0.95 | 0.98 | 1.01 |
| Blacklaw Extension | 2.02 | 2.09 | 2.15 | 2.21 |
| Bodelwyddan | 0.10 | 0.11 | 0.11 | 0.11 |
| Brochloch | 1.10 | 1.13 | 1.17 | 1.20 |
| Carraig Gheal | 4.06 | 4.18 | 4.30 | 4.43 |
| Carrington | 0.00 | 0.00 | 0.00 | 0.00 |
| Clyde (North) | 0.10 | 0.10 | 0.11 | 0.11 |
| Clyde (South) | 0.12 | 0.12 | 0.12 | 0.13 |
| Coalburn | 0.06 | 0.02 | 0.02 | 0.03 |
| Corriemoillie | 2.54 | 2.61 | 2.69 | 2.77 |
| Coryton | 0.05 | 0.05 | 0.35 | 0.36 |
| Cruachan | 1.64 | 1.69 | 1.74 | 1.79 |
| Crystal Rig | 0.21 | 0.31 | -0.04 | -0.04 |
| Culligran | 1.60 | 1.65 | 1.70 | 1.75 |
| Deanie | 2.63 | 2.70 | 2.79 | 2.87 |
| Dell Wind Farm | - | - | 0.55 | 0.56 |
| Dersalloch | 3.93 | 1.69 | 1.74 | 1.79 |
| Didcot | 0.47 | 0.48 | 0.50 | 0.51 |
| Dinorwig | 2.22 | 2.28 | 2.35 | 2.42 |
| Dorenell | - | -2.98 | 1.54 | 1.58 |
| Dudgeon Offshore Wind Farm | -0.34 | -0.35 | -0.41 | 1.13 |
| Dumnaglass | 3.34 | 2.92 | 3.01 | 3.10 |
| Dunlaw Extension | 1.32 | 1.35 | 5.66 | 5.83 |
| Earlshaugh | - | 4.67 | 4.71 | 4.85 |
| Edinbane | 6.31 | 6.50 | 6.70 | 6.90 |

| Connection Point | 2016/17 (£/kW) | 2017/18 (£/kW) | 2018/19 (£/kW) | 2019/20 (£/kW) |
|---|---|---|---|---|
| Ewe Hill | 4.84 | 4.98 | 5.13 | 5.29 |
| Fallago | 0.60 | 0.16 | 0.02 | 0.02 |
| Farr Windfarm | 2.21 | 2.22 | 4.30 | 4.42 |
| Ffestiniogg | 0.23 | 0.24 | 0.25 | 0.26 |
| Finlarig | 0.30 | 0.30 | 0.31 | 0.32 |
| Foyers | 0.70 | 0.73 | 0.75 | 0.77 |
| Glendoe | 1.70 | 1.75 | 1.80 | 1.85 |
| Glenluce | - | 5.73 | 5.91 | 6.08 |
| Glenmoriston | 1.22 | 1.25 | 1.29 | 1.33 |
| Gordonbush | 1.20 | 0.36 | 0.10 | 0.11 |
| Griffin Wind | 1.75 | 1.78 | 10.16 | 6.06 |
| Hadyard Hill | 2.55 | 2.63 | 2.71 | 2.79 |
| Harestanes | 4.89 | 4.95 | 5.00 | 5.15 |
| Hartlepool | 0.55 | 0.57 | 0.59 | 0.07 |
| Hedon | 0.18 | 0.19 | 0.19 | 0.20 |
| Hornsea | 0.14 | 0.14 | 0.15 | 0.15 |
| Invergarry | -0.63 | -0.65 | -0.67 | -0.69 |
| Kendoon North | - | - | 1.38 | 6.15 |
| Kilbraur | 1.07 | 0.23 | -0.02 | -0.01 |
| Kilgallioch | 0.97 | 0.99 | 1.02 | 1.06 |
| Kilmorack | 0.18 | 0.19 | 0.19 | 0.20 |
| Langage | 0.61 | 0.47 | -0.33 | -0.34 |
| Lochay | 0.34 | 0.35 | 0.36 | 0.37 |
| Luichart | 1.05 | 1.08 | 1.11 | 1.15 |
| Marchwood | 0.07 | 0.36 | 0.37 | 0.39 |
| Margee | 0.88 | 2.88 | -2.89 | -0.63 |
| Mark Hill | 0.80 | 0.83 | 0.85 | 0.88 |
| Meygen | - | - | 2.35 | 2.42 |
| Millennium Wind | 0.00 | 1.54 | 1.59 | 1.64 |
| Mossford | 1.83 | 3.77 | 3.88 | 4.00 |
| Nant | -1.13 | -1.17 | -1.20 | -1.24 |
| Neilston | -2.20 | 1.34 | 1.38 | 1.06 |
| Newfield Wind | - | 6.27 | 6.45 | 6.65 |
| Rhigos | 0.12 | 0.12 | 0.12 | 0.12 |
| Rocksavage | 0.02 | 0.02 | 0.02 | 0.02 |
| Sallachy | - | - | 1.80 | 1.85 |
| Saltend | 0.31 | 0.32 | 0.33 | 0.34 |
| South Humber Bank | 0.38 | 0.39 | 0.40 | -0.19 |
| Spalding | 0.25 | 0.26 | 0.26 | 0.27 |
| Strathy Wind | 5.23 | 4.48 | 4.31 | 4.45 |
| Tomatin | - | - | 3.90 | 4.02 |
| Ulzieside | 9.67 | 9.96 | 10.25 | 10.56 |
| Whitelee | 0.10 | 0.10 | 0.10 | 0.11 |
| Whitelee Extension | 0.27 | 0.28 | 0.29 | 0.30 |

## 2.3 Onshore Local Substation Tariffs

Onshore Local substation tariffs for 2016/17 are shown in Table 6. These tariffs are inflated annually so for future year tariffs inflate the tariffs below by RPI (3% p.a.).

**Table 6 - 2016/17 Local Substation Tariffs**

| Substation Rating | Connection Type | Local Substation Tariff (£/kW) | | |
|---|---|---|---|---|
| | | 132kV | 275kV | 400kV |
| <1320 MW | No redundancy | 0.185859 | 0.106323 | 0.076608 |
| <1320 MW | Redundancy | 0.409433 | 0.253318 | 0.184235 |
| >=1320 MW | No redundancy | 0 | 0.33337 | 0.241095 |
| >=1320 MW | Redundancy | 0 | 0.547309 | 0.399491 |

## 2.4 Offshore Local Tariffs

Offshore Local tariffs for 2016/17 are shown in Table 7. For later years these are inflated by RPI (3% p.a.) Future offshore tariffs are dependent on asset costs and asset transfer date. If you would like to discuss these further please contact mary.owen@nationalgrid.com, 01926 653845.

**Table 7 - 2016/17 Offshore Local Tariffs**

| Offshore Generator | Tariff Component (£/kW) | | |
|---|---|---|---|
| | Substation | Circuit | ETUoS |
| Robin Rigg East | -0.43 | 28.37 | 8.79 |
| Robin Rigg West | -0.43 | 28.37 | 8.79 |
| Gunfleet Sands 1 & 2 | 16.21 | 14.88 | 2.78 |
| Barrow | 7.49 | 39.19 | 0.97 |
| Ormonde | 23.15 | 43.13 | 0.34 |
| Walney 1 | 19.98 | 39.80 | 0.00 |
| Walney 2 | 19.84 | 40.15 | 0.00 |
| Sheringham Shoal | 22.37 | 26.24 | 0.57 |
| Greater Gabbard | 14.04 | 32.27 | 0.00 |
| London Array | 9.53 | 32.45 | 0.00 |
| Lincs | 14.00 | 56.12 | 0.00 |

## 2.5 Demand Tariffs

The following tariffs are based on implementation of Connection and Use of System Code modification CMP213 WACM2 and Balancing and Settlement Code modification P272 by 1 April 2016. The effect of the Western HVDC Link is included from 2017/18 onwards and the Caithness Moray HVDC Link from 2018/19 onwards.

**Table 8 - Half Hour Demand Tariffs**

| Zone | Zone Name | 16/17 (£/kW) | 17/18 (£/kW) | 18/19 (£/kW) | 19/20 (£/kW) |
|---|---|---|---|---|---|
| 1 | Northern Scotland | 29.79 | 18.67 | 21.34 | 26.65 |
| 2 | Southern Scotland | 31.84 | 20.42 | 23.73 | 29.23 |
| 3 | Northern | 36.29 | 32.79 | 37.66 | 41.56 |
| 4 | North West | 40.09 | 39.68 | 44.02 | 49.35 |
| 5 | Yorkshire | 40.48 | 40.16 | 44.75 | 49.84 |
| 6 | N Wales & Mersey | 39.99 | 42.25 | 46.60 | 52.21 |
| 7 | East Midlands | 43.35 | 43.74 | 48.71 | 53.82 |
| 8 | Midlands | 43.96 | 45.07 | 49.86 | 55.37 |
| 9 | Eastern | 45.68 | 45.97 | 50.39 | 55.38 |
| 10 | South Wales | 41.82 | 42.41 | 47.47 | 53.33 |
| 11 | South East | 48.41 | 48.93 | 53.78 | 58.89 |
| 12 | London | 51.25 | 51.76 | 56.49 | 61.83 |
| 13 | Southern | 49.11 | 49.71 | 55.22 | 60.26 |
| 14 | South Western | 48.38 | 49.09 | 54.70 | 61.15 |

**Table 9 - Non Half Hour Demand Tariffs**

| Zone | Zone Name | 16/17 (p/kWh) | 17/18 (p/kWh) | 18/19 (p/kWh) | 19/20 (p/kWh) |
|---|---|---|---|---|---|
| 1 | Northern Scotland | 4.21 | 2.64 | 3.02 | 3.77 |
| 2 | Southern Scotland | 4.10 | 2.63 | 3.06 | 3.77 |
| 3 | Northern | 4.61 | 4.17 | 4.79 | 5.29 |
| 4 | North West | 5.32 | 5.28 | 5.85 | 6.57 |
| 5 | Yorkshire | 5.65 | 5.62 | 6.25 | 6.97 |
| 6 | N Wales & Mersey | 6.30 | 6.67 | 7.35 | 8.24 |
| 7 | East Midlands | 5.63 | 5.70 | 6.34 | 7.01 |
| 8 | Midlands | 5.92 | 6.09 | 6.73 | 7.48 |
| 9 | Eastern | 5.96 | 6.01 | 6.59 | 7.24 |
| 10 | South Wales | 5.68 | 5.77 | 6.46 | 7.26 |
| 11 | South East | 6.22 | 6.31 | 6.93 | 7.59 |
| 12 | London | 6.43 | 6.52 | 7.11 | 7.78 |
| 13 | Southern | 6.48 | 6.58 | 7.30 | 7.97 |
| 14 | South Western | 6.18 | 6.29 | 7.00 | 7.83 |

# 3. Key Drivers for Tariff Changes

Factors which affect tariffs include methodology, changes to the Transport model used to calculate the locational element and changes to the Tariff model used to calculate the residual element of tariffs. The main drivers behind tariff changes over the next five years are:

- CMP213 (Project TransmiT)
- HVDC Circuits
- Contracted Generation
- Generation/Demand Revenue proportions
- Transmission Owner Revenues
- Reducing Demand

## 3.1 CMP213 (Project TransmiT)

On conclusion of Ofgem's Significant Code Review of gas and electricity transmission charging arrangements known as Project TransmiT[2], National Grid were directed to raise a CUSC modification proposal (CMP213) to consider three potential improvements to the TNUoS charging methodology[3]. The first of these improvements was to better reflect the impact of a specific generator on transmission investment requirements, commonly referred to as the 'sharing' element of the proposal. A number of alternative proposals were raised by the CUSC working group and on 11 July 2014 Ofgem approved Working-group Alternative Code Modification 2 (WACM2) with an implementation date of April 2016.

In November 2014, RWE raised a judicial review of the decision to implement CMP213. This forecast is based on the approved methodology which National Grid has been directed to implement.

## 3.2 HVDC Circuits

The second improvement under CMP213 (Project TransmiT) was the treatment of parallel HVDC circuits as the existing charging methodology did not prescribe how parallel HVDC circuits should be included in the Transport model. CMP213 WACM2 modifies the TNUoS charging methodology to provide a methodology for the treatment of parallel HVDC circuits. The application of this methodology for parallel HVDC circuits is described in Appendix A.

The Western HVDC link is assumed to commission mid-2017 in this forecast[4]. The Caithness - Moray HVDC link is scheduled to commission in 2018/19. As HVDC schemes near completion, we will work with the Transmission Owners to gather further cost information on the HVDC circuits to be used within the Transport Model. Alternative tariffs have been provided in Appendix B, which for 2017/18 show tariffs without the Western HVDC link and for 2018/19 show tariffs without the Caithness-Moray link. These are provided to show the effect of the HVDC links in those years.

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[2] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

[3] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

[4] https://www.gov.uk/government/groups/electricity-networks-strategy-group#minutes

## 3.3 Contracted Generation

In previous five year forecasts the Generation data used to create the transport model has been based upon contracted TEC. Generation significantly affects tariff forecasts but contracted TEC has not always been a good basis for forecasting tariffs due to station closures, project delays and cancellations. Therefore, similar to the five year forecast published in May 2014, we no longer simply use contracted TEC. Instead, market intelligence has been used to derive a 'best view' as to the likelihood of new Generation projects progressing as planned. Where progression looked likely to vary from plan, the contracted TEC for those projects has been adjusted. The overall result of these adjustments is that the modelled TEC is less than the contracted position shown in the TEC register. Please note that we have not taken a view on the closure of current generation.

To enable the report to be written and analysis undertaken a freeze on generation data was taken in mid-December.

We are looking to further enhance this process going forward. For example, future models might include a view on current generation closures, or how much generation is likely to be required to match forecast demand.

We are unable to breakdown the modelled TEC as some of the information used to derive our view could be commercially sensitive. Table 10 shows the TEC that has been included in our models compared to the contracted TEC for that year. It also shows chargeable TEC after deduction of interconnectors who do not pay TNUoS charges.

**Table 10 – Contracted and Modelled TEC**

| | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|
| Contracted TEC (GW) | 88.5 | 95.4 | 111.7 | 125.8 |
| Modelled TEC (GW) | 82.9 | 85.4 | 98.4 | 112.3 |
| Chargeable TEC (GW) | 77.9 | 80.3 | 92.3 | 103.8 |

## 3.4 Generation/Demand Revenue Proportions

Until recently the charging methodology prescribed that 27% of TNUoS revenue should be recovered from Generation and 73% from Demand (the G:D Split). EU Regulation ECR 838/2010 has been in effect since 2011 and limits average annual Generation charges to €2.5/MWh. With increasing revenues, declining demand and a weakening Euro, this limit is expected to be breached in 2015/16. CUSC modification CMP224 was approved 8 October 2014 to adjust the balance of revenue between Generation and Demand to remain compliant with the regulation.

The Agency for the Cooperation of Energy Regulators (ACER) published an opinion in April 2014 that the €2.5/MWh limit should be removed[5]. However, the EU regulation does not provide for this recommendation to be adopted and we are not aware of any EU initiatives to amend the regulation. Therefore our forecasts are based on the premise that the limit will remain in place for the foreseeable future.

Section 6 illustrates how the G:D split is calculated and provides formulae which allow customers to change the proportions and gauge the resulting effect on the Generation and Demand residuals.

[5] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf

## 3.5 Transmission Owners' Revenue

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs) in Great Britain. The tariffs in this forecast have been calculated to recover the revenues shown in Table 11.

**Table 11 – Transmission Owner Revenues**

| £m Nominal | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|
| **National Grid** | | | | |
| *Price controlled revenue* | *1,953.8* | *1,818.0* | *1,923.8* | *1,958.3* |
| *Less income from connections* | *48.3* | *48.3* | *48.3* | *48.3* |
| **Income from TNUoS** | **1,905.5** | **1,769.7** | **1,875.6** | **1,910.0** |
| **Scottish Power Transmission** | | | | |
| *Price controlled revenue* | *321.0* | *368.5* | *415.9* | *433.4* |
| *Less income from connections* | *10.5* | *10.9* | *11.6* | *12.2* |
| **Income from TNUoS** | **310.5** | **357.6** | **404.3** | **421.2** |
| **SHE Transmission** | | | | |
| *Price controlled revenue* | *343.0* | *347.6* | *335.7* | * |
| *Less income from connections* | *3.6* | *3.7* | *3.8* | * |
| **Income from TNUoS** | **339.5** | **344.0** | **331.9** | **338.5** |
| **Offshore** | **269.1** | **284.8** | **349.7** | **522.2** |
| **Network Innovation Competition** | **48.4** | **49.7** | **51.7** | **52.7** |
| **Total to Collect from TNUoS** | **2,873.0** | **2,805.8** | **3,013.2** | **3,244.6** |

** No data provided.*

All figures are in millions of pounds and nominal 'money of the day'. Assumptions have been made on future inflation, consistent with H M Treasury forecasts. Inflation forecasts are shown in Table 12 and are relative to 2009/10. Further information on revenues can be found in Appendix C.

**Table 12 – Inflation Indices**

| 2009/10 | | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|
| 1.0000 | | 1.2763 | 1.3083 | 1.3616 | 1.3887 |

### 3.5.1 Onshore Transmission Owners

The revenues of the Onshore Transmission Owners (TOs) are subject to RIIO price controls set by Ofgem in 2012. RIIO stands for Revenue = Incentives + Innovation + Outputs. This means that TO revenues are set at price review, but then adjusted during the price control period depending on performance against incentives, innovation and delivered output. Revenue adjustments are generally lagged by two years, e.g. revenues in 2016/17 will be adjusted in November 2015 to reflect 2014/15 performance.

The five year forecast in May 2014 was largely based upon Ofgem's Final Proposals 'best view' published in December 2012. The forecasts in this document are the TOs latest view of revenues over the next five years which contain significantly different profiles of investment in some cases. These forecasts are provided on a best endeavours basis and it should be noted that TO business plans as well customer requirements, which drive the need for investment, can alter over time.

Subject to consultation on need case and cost, Ofgem may award additional funding for Strategic Wider Works projects. Where determinations have been made by Ofgem then the effect of these have been included in the revenue forecasts. Where determinations have yet to be made, the TOs may take a view on whether to include additional funding in their forecasts. The following Strategic Wider works have been included in this forecast:

- Kintyre – Hunterston
- Beauly – Mossford
- Caithness – Moray
- Hinckley - Seabank

An estimate has been included in 2016/17 revenues for retrospective recovery of under-recovered 2014/15 revenue. This reflects the lower than anticipated demand seen so far during 2014/15 but the size of the under-recovery will not be known until after the end of the financial year. There are no adjustments for revenue recovery or variations in inflation in later years.

### 3.5.2 Offshore Transmission Owners

The revenues of offshore transmission owners (OFTOs) are determined by Ofgem in a competitive tender process. The revenue is confirmed when the network is transferred from the developer to the appointed OFTO. Prior to this there is uncertainty as to the value of the revenue stream and when it will start. Therefore, whilst the revenues for existing OFTOs are relatively predictable, the revenue for future OFTOs is a forecast. OFTO asset transfers have tended to occur within two years of the associated wind farm commissioning although this will be reduced to eighteen months or less for tender round 3 OFTOs. Transfer values have been extrapolated from previous values and sizes of wind farm.

### 3.5.3 Pan-Company Funding

National Grid also collects revenue to fund pan-company incentives awarded by Ofgem in the November prior to the charging year. The Network Innovation Competition Fund provides up to £27m (2009/10 prices) each year for electricity transmission owners. From 2016/17 onwards a further £60m will be available for the electricity distribution Network Innovation completion Fund. Ofgem may also make Environmental Discretionary awards of up to £4m each year to electricity transmission owners with 50% of un-awarded funding carried over to later years. We have assumed 50% of pan-company funding will be awarded each year.

### 3.5.4 Connection Revenues

Part of the onshore transmission owner revenues are recovered from pre-vesting connection assets in the case of National Grid, and pre-BETTA connection assets in the case of the Scottish TOs. These revenues are therefore deducted from allowed revenue to calculate the revenue to be recovered from TNUoS charges. Whilst this revenue is diminishing due to depreciation and replacement, it may remain broadly flat in nominal terms due to inflation and the operating cost element.

## 3.6 Demand Forecasts

Two types of Demand forecast are used to determine the location element and the residual element of the tariffs.

### 3.6.1 Locational Element

The locational model uses peak demands at each Grid Supply Point (GSP). The July 2013 Week 24 demand submissions provided by Distribution Network Operators and forecasts of directly connected demand sites such as steelworks and other heavy industry have been used. Zonal demand information is summarised in Table 13 and detailed in Appendix E.

### 3.6.2 Residual Element

National Grid's forecasts of demand are used to determine the charging bases that will actually pay demand tariffs. The residual is used to recover the correct proportion of revenue from demand with the overall aim of recovering allowed revenue. Changes to the demand charging base therefore impact the residual element of Half-Hourly (HH) demand tariffs and subsequently Non Half Hourly (NHH) tariffs. National Grid's forecasts cover average system demand over the Triads[6], average Half-Hour metered demand over the Triads and Non-Half-Hourly metered energy between 4pm and 7pm over the year. Section 7 shows how the residuals are calculated to allow customers to model the impact on demand tariffs of their own forecasts of future demand.

The demand charging bases have all decreased from the May 2014 five year forecast. The decrease in total peak demands and Non-Half-Hourly energy are due to a number of different factors including; Triad avoidance, energy efficiency, embedded generation, price elasticity and Balancing & Settlement Code (BSC) changes.

### 3.6.3 P272

BSC amendment 272 will make it mandatory that customer classes 5-8 move from Non-Half-Hour settlement to Half-Hour settlement by April 2016. This change alters our demand charging bases from 2016/17 onwards. Using profiling data for each half hour period we estimate that classes 5-8 make up approximately 9.4% of NHH demand between the hours of 4-7pm. Therefore we have reduced the NHH demand base by this amount from 2016/17 onwards with the decrease spread across each zone on a pro rata basis.

As these classes become half hourly metered the proportion of HH demand at Triad will increase. The proportion of NHH demand at Peak for classes 5-8 is similar to the proportion of NHH energy use between 4-7pm for classes 5-8. Therefore the effect on HH and NHH tariffs is currently forecasted to be minimal as the extra revenue we receive from HH offsets the decrease in revenue from NHH.

National Grid only receives aggregated data on a BMU basis. We have assumed that the proportion of demand Classes 5-8 compared to Classes 1-4 is the same across all zones. We are working with Elexon to break this data set down further. We actively encourage feedback on forecasting demand post P272 to avoid future tariff forecast volatility.

The demand bases used to forecast tariffs are shown in Table 13. Due to lower than expected levels of demand in recent years we have initiated an internal review of how demands are forecast and will update the demand bases as required in future reports.

**Table 13 – Demand Base Forecasts**

| | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|
| Average System Demand at Triad (GW) | 52.3 | 51.5 | 50.7 | 50.1 |
| Average HH Metered Demand at Triad (GW) | 18.7 | 18.2 | 17.9 | 17.6 |
| NHH Annual Energy between 4pm and 7pm (TWh) | 25.4 | 25.0 | 24.7 | 24.4 |

## 3.7 Other model inputs

### 3.7.1 Transmission Network Changes

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. The following projects are of particular note:

[6] The three half-hour settlement periods of highest demand between November and February, separated from each other by at least ten clear days.

- North London Reinforcement Project – This is included from 2016/17 and alters flows on the system and therefore tariffs. Flows on these new circuits are heavily determined by Generation, so if Generation changes from that forecast then the tariff can change.
- Western HVDC link - This is included from 2017/18 and increases generation tariffs in Scotland and reduces generation tariffs in Wales and England.
- Caithness Moray HVDC link - This is included from 2018/19.

### 3.7.2 Expansion Constant

The charging methodology requires the expansion constant to be updated each year in line with RPI inflation. Table 14 shows the expansion constants used in the forecasts.

**Table 14 – Expansion Constant**

| £/MWkm | 16/17 | 17/18 | 18/19 | 19/20 |
|---|---|---|---|---|
| Expansion Constant | 13.608932 | 14.017200 | 14.437716 | 14.870847 |

### 3.7.3 Generation Charging Base

The generator charging base for each year is based on the generator data used for the transport model. Interconnectors are included in the transport model for determining Year Round tariffs but not for System Peak tariffs. Interconnectors are not liable for Generation or Demand TNUoS charges so when calculating the Generation charging base the reductions in Table 15 are made.

**Table 15 – Interconnector Adjustments**

| Interconnector | Zone | Adjustment (MW) |
|---|---|---|
| Britned | 24 | 1200 |
| East-West | 16 | 500 |
| IFA Interconnector | 24 | 2000 |
| France Interconnector | 24 | 1000 |
| Moyle | 10 | 295 (from 2014/15),375 (from 2017/18) |
| Belgian Interconnector | 24 | 1000 (from 2018/19) |
| IFA 2 Interconnector | 26 | 1000 (from 19/20) |
| Norwegian Interconnector | 13 | 1400 (from 19/20) |

### 3.7.4 Annual Load Factors (ALFs)

Under the new methodology the final tariff payable by a Generator is dependent on its specific annual load factor for that year. For the purposes of forecasting tariffs it is necessary to assign an annual load factor to each Generator as the DCLF model calculates the amount of revenue collected from the Year Round Shared tariff. Any changes in the annual load factors from those used within this forecast will alter the Generation residual. However the effect is likely to be minimal due to the proportion of revenue collected from the Year Round Shared element of the tariff and the process used to calculate Load Factors which prevents volatility when compared to the previous year.

The ALFs used within this forecast can be found in the Tools and Data section of the link below.

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

The ALFs will be updated in 2015. Further updates/information will be provided in our Quarterly updates of 2016/17 tariffs.

# 4. Commentary on Forecast Generation Tariffs

## 4.1 Wider Zonal Generation Tariffs

### 4.1.1 Key Assumptions

- CMP213 implemented April 2016
- Western HVDC link completed in 2017/18
- Caithness Moray completed in 2018/19
- EU Regulation ECR 838/2010 limits generation to €2.5/MWh

Figure 1 illustrates forecast Generation TNUoS tariffs from April 2016 onwards using the tariffs in Section 2. The tariff payable by each Generator is unique to that generator due to differences in load factor and whether the generator is convention or intermittent. Therefore we show two example Generators, a Conventional Generator with an annual load factor of 70% and an Intermittent Generator with an annual load factor of 30%.

From Figure 1 we can see that northern generation has a higher tariff than southern generation but the differential is greater for a conventional generator with a higher load factor because it makes use of the network for longer periods.

**Figure 1**

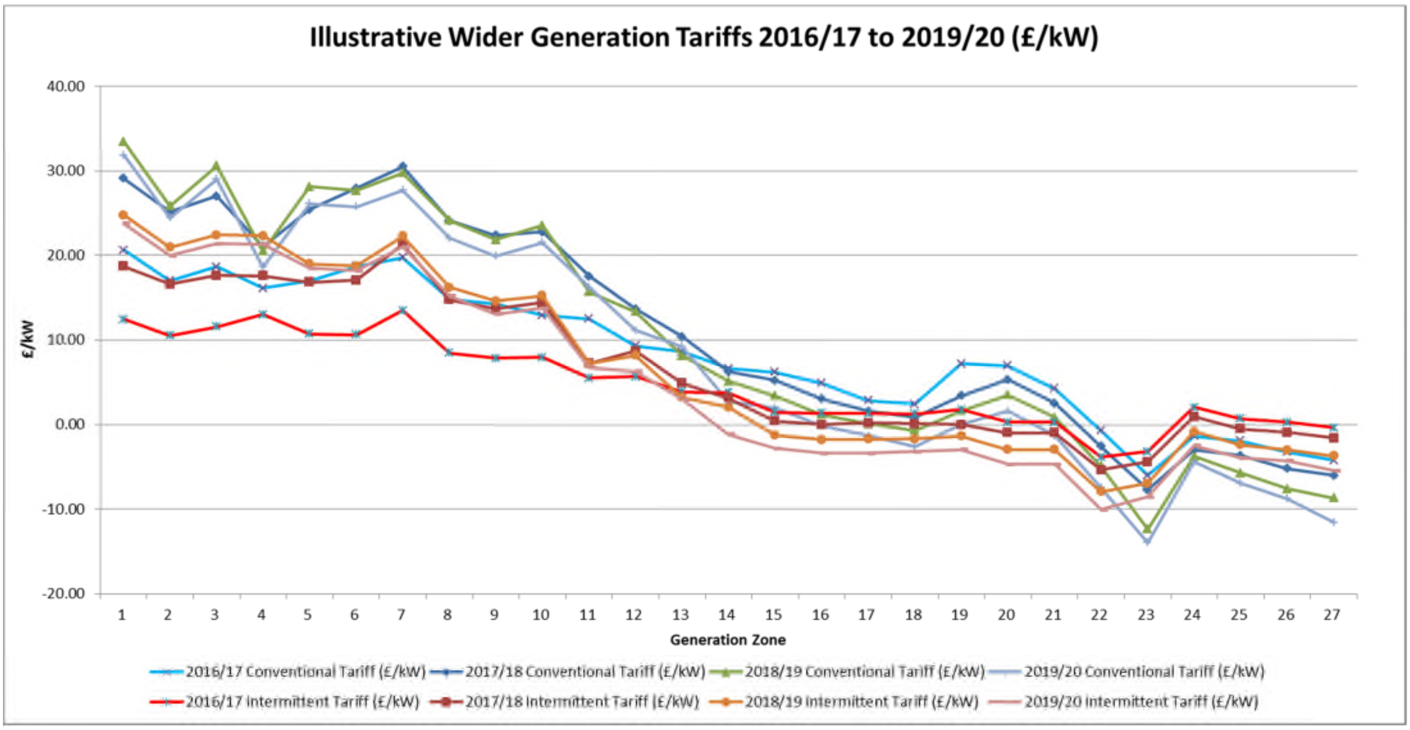

Table 16 shows the year on year change in tariffs for a conventional (70%) and intermittent (30%) generator.

**Table 16**

| Generation Tariffs | | 17/18 Tariffs Compared to 16/17 | | 18/19 Tariffs Compared to 17/18 | | 19/20 Tariffs Compared to 18/19 | |
|---|---|---|---|---|---|---|---|
| | | Conv | Int | Conv | Int | Conv | Int |
| Zone | Zone Name | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) |
| 1 | North Scotland | 0.60 | 0.25 | 12.26 | 12.04 | -1.59 | -0.98 |
| 2 | East Aberdeenshire | 0.32 | 0.10 | 8.54 | 10.30 | -1.40 | -0.96 |
| 3 | Western Highlands | 0.45 | 0.05 | 11.54 | 10.79 | -1.59 | -1.00 |
| 4 | Skye and Lochalsh | -2.96 | -1.50 | 7.35 | 10.81 | -1.88 | -0.99 |
| 5 | Eastern Grampian and Tayside | 0.40 | 0.08 | 10.79 | 8.19 | -2.03 | -0.53 |
| 6 | Central Grampian | 0.44 | 0.22 | 8.52 | 7.88 | -1.90 | -0.56 |
| 7 | Argyll | 1.28 | 0.90 | 8.79 | 7.93 | -2.08 | -1.26 |
| 8 | The Trossachs | 0.31 | 0.16 | 8.99 | 7.60 | -2.10 | -0.96 |
| 9 | Stirlingshire and Fife | 0.28 | -0.03 | 7.27 | 6.83 | -1.91 | -1.58 |
| 10 | South West Scotland | 0.46 | 0.07 | 10.17 | 7.23 | -2.02 | -1.49 |
| 11 | Lothian and Borders | -0.16 | -0.29 | 3.35 | 1.92 | 0.55 | -0.40 |
| 12 | Solway and Cheviot | 0.22 | -0.01 | 3.82 | 2.50 | -2.18 | -1.87 |
| 13 | North East England | -0.23 | -0.38 | -0.23 | -0.24 | 1.09 | -0.25 |
| 14 | North Lancashire and The Lakes | -0.08 | -0.04 | -1.42 | -1.74 | -2.43 | -3.21 |
| 15 | South Lancashire, Yorkshire and Humber | -0.19 | -0.32 | -2.61 | -2.41 | -1.41 | -1.57 |
| 16 | North Midlands and North Wales | -0.14 | -0.32 | -3.59 | -2.78 | -1.38 | -1.60 |
| 17 | South Lincolnshire and North Norfolk | -0.31 | -0.34 | -2.49 | -2.73 | -1.34 | -1.62 |
| 18 | Mid Wales and The Midlands | -0.24 | -0.30 | -2.91 | -2.70 | -1.93 | -1.48 |
| 19 | Anglesey and Snowdon | -0.15 | -0.27 | -5.42 | -2.88 | -1.57 | -1.62 |
| 20 | Pembrokeshire | -0.15 | -0.36 | -3.32 | -2.89 | -1.95 | -1.74 |
| 21 | South Wales & Gloucester | -0.23 | -0.36 | -3.15 | -2.87 | -2.19 | -1.75 |
| 22 | Cotswold | -0.36 | -0.44 | -3.89 | -3.65 | -2.50 | -2.08 |
| 23 | Central London | -0.48 | -0.37 | -5.85 | -3.36 | -1.60 | -1.60 |
| 24 | Essex and Kent | -0.45 | -0.33 | -1.92 | -2.59 | -0.65 | -1.64 |
| 25 | Oxfordshire, Surrey and Sussex | -0.42 | -0.35 | -3.36 | -2.76 | -1.25 | -1.56 |
| 26 | Somerset and Wessex | -0.59 | -0.36 | -3.79 | -2.92 | -1.17 | -1.27 |
| 27 | West Devon and Cornwall | -0.38 | -0.34 | -4.07 | -3.00 | -2.88 | -1.77 |

### 4.1.2 2016/17

This is the first year of the CMP213 methodology so it is impractical to compare the four element tariff structure to the single tariff structure in 2015/16. However due to the limit on Generation tariffs of €2.5MWh, the increase in Generation connecting to the system requires the Generation residual to be lowered thus the overall average tariff will be lower regardless of the methodology.

### 4.1.3 2017/18

The Generation residual decreases by £0.86kW from £1.31kW to £0.45kW. Other changes are caused by locational inputs. The main change in 2017/18 is the commissioning of the Western HVDC link. This increases Generation tariffs in zones whose incremental flows utilise the link i.e. the majority of Scotland or where flows now increase, with a corresponding decrease in tariffs elsewhere. Appendix B shows 2017/18 tariffs without the HVDC link to allow users to gauge its effect. The increase in the expansion constant effectively stretches the network widening the spread of tariffs.

#### 4.1.4 2018/19

The Generation residual decreases by £1.79kW from £0.45kW to -£1.34kW due to the increase in offshore revenue and increase in generation connecting to the system. The residual turns negative as the sum of the revenue recovered from Local Tariffs (onshore and offshore) and the locational elements of the Wider tariff is greater than what is required to be recovered from Generation. Other changes are caused by locational inputs.

Tariffs in Scotland generally have higher increases due to the increase in North to South flows. North of Scotland (Zones 1, 2 and 3) see a higher increase than the rest of Scotland due to the completion of the Caithness Moray HVDC link.

The increase in low carbon generation results in flows along circuits driving year round tariffs to change direction. This increases the distance of year round generation flows, in terms of km. Also the increasing proportion of low carbon in Scotland switches costs from Year Round Shared to Year Round Not-Shared. The latter is not reduced by annual load factors, increasing the effective tariff. The switch occurs when Non-Carbon based generation becomes the dominant form of generation within a zone.

Tariffs paid by conventional Generation in certain zones in Scotland don't increase as much as intermittent Generation because it benefits from a decrease in the Peak tariff. Intermittent does not pay the Peak Tariff and so the increase in Year Round Shared has a greater effect on its tariffs.

Zone 23 (Central London) sees larger decreases due to the uprating of circuits.

The increase in the expansion constant effectively stretches the network widening the spread of tariffs.

#### 4.1.5 2019/20

The Generation residual decreases by -£1.63kW from -£1.34kW to -£2.97kW due to the increase in offshore revenue and the increase in Generation connecting to the system. Other changes are caused by locational inputs i.e. large increases in Generation in the East/South East of the country and Yorkshire/North East

The increase in the expansion constant effectively stretches the network widening the spread of tariffs.

### 4.2 Changes in the Generator Residual

The Residual element of the Generation charge is affected by the following variables:

- Generation and Demand split – Discussed in Section 6.
- Revenue assumptions – Discussed in Section 3.5.
- Generation charging base - As the Generation charging base increases from year to year the Generation residual decreases. The increase in the generator charging base is described in Section 3.3. The calculation of generator residuals is described in Section 7.

### 4.3 Onshore Local Circuit Tariffs

A forecast of onshore local circuit tariffs from 2016/17 to 2019/20 is shown in Table 5 - Onshore Local Circuit Tariffs. These have been calculated using contracted generation from 2016/17 onwards. The Onshore Local Circuit charge for a Generation Spur is dependent on the length of the circuit (s), type of circuit (s) connecting to the nearest MITS substation. For those local circuits which tee into a line the impedance and flows along the circuits also affect the tariff.

For later years where there is limited information on how or where the generator intends to connect to the Transmission system, Generation has been mapped to the nearest existing node. This will alter the forecast Local Circuit Tariff. If you are unsure about your local circuit tariff or whether one will be applied please contact your Connection Account Manager or alternatively use the contact details in Section 9.

## 4.4 Onshore Local Substation Tariffs

Table 6 shows the onshore local substation tariffs that are forecasted to apply during 2016/17. These tariffs only apply to transmission connected generators. The tariffs will be indexed by RPI for each year of the price control. For future year we assume tariffs inflate by 3% each year.

If no significant work is planned at a substation that changes whether or not there is redundancy, the tariff will only alter by RPI. 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. If you are unsure about what tariff may apply please contact National Grid for further information.

## 4.5 Small Generators Discount

Under Condition C13 of National Grid's electricity transmission licence a discount is applied to small generators connected to 132kV transmission systems who, but for the fact they are connected to a transmission system, would not otherwise be liable for TNUoS charges. The discount lapses on 1 April 2016.

## 5. Commentary on Forecast Demand Tariffs

### 5.1.1 Key Assumptions

- New methodology implemented April 2016
- Western HVDC link completed in 2017/18
- Caithness Moray completed in 2018/19
- EU Regulation ECR 838/2010 limits generation to €2.5/MWh
- P272 Implemented 2016/17

The above assumptions are the major drivers of demand tariff changes over the next 5 years other than specific Generation connecting.

## 5.2 Half-Hourly Demand Tariffs (£/kW)

Figure 2 illustrates the forecast TNUoS tariffs set out in Section 3 for Half-Hour (HH) metered demand from 2016/17 to 2019/20.

**Figure 2**

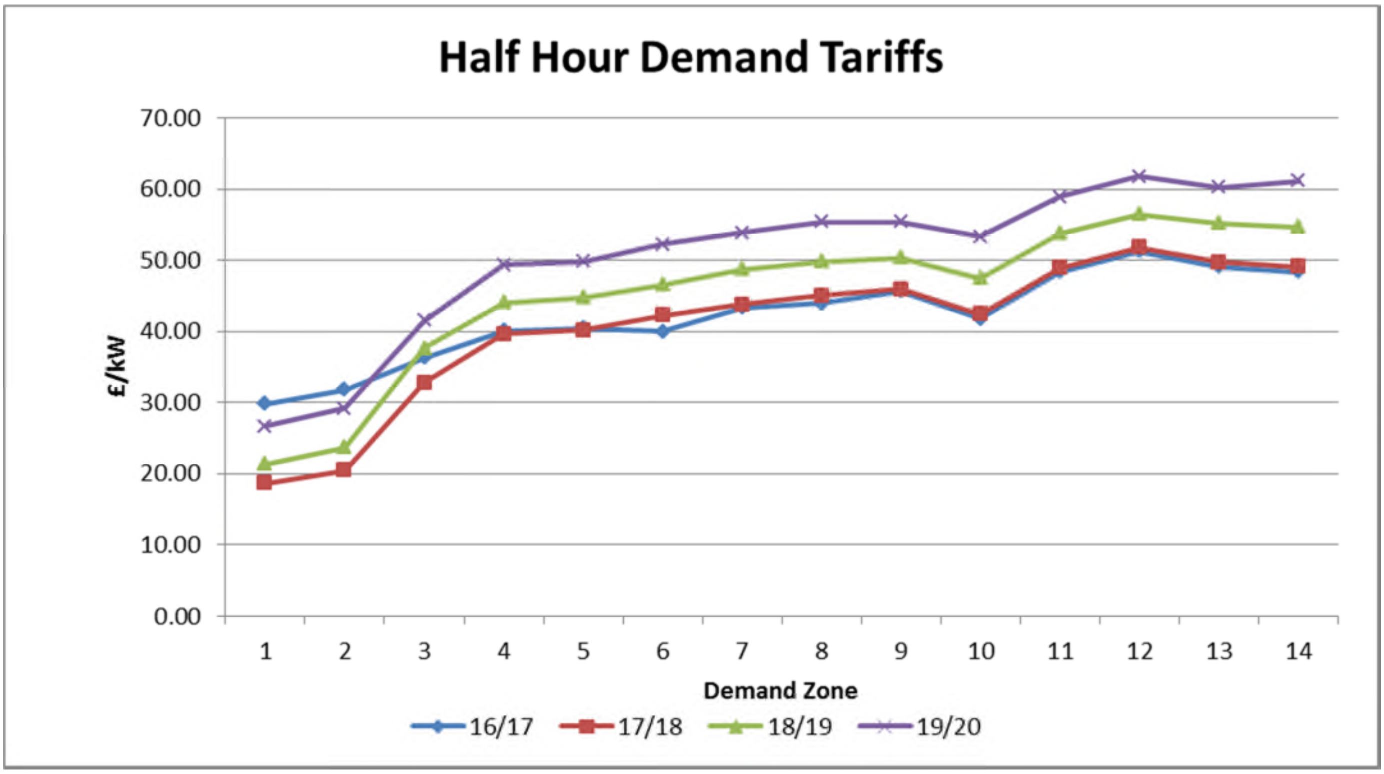

**Table 17 – Changes in Half-Hourly Metered Tariffs**

| Zone | Zone Name | Difference 16/17 to 17/18 (£/kW) | Difference 17/18 to 18/19 (£/kW) | Difference 18/19 to 19/20 (£/kW) |
|---|---|---|---|---|
| 1 | Northern Scotland | -11.12 | 2.67 | 5.30 |
| 2 | Southern Scotland | -11.42 | 3.31 | 5.50 |
| 3 | Northern | -3.49 | 4.87 | 3.90 |
| 4 | North West | -0.42 | 4.34 | 5.34 |
| 5 | Yorkshire | -0.32 | 4.60 | 5.09 |
| 6 | N Wales & Mersey | 2.26 | 4.36 | 5.61 |
| 7 | East Midlands | 0.39 | 4.96 | 5.12 |
| 8 | Midlands | 1.11 | 4.79 | 5.51 |
| 9 | Eastern | 0.30 | 4.42 | 4.99 |
| 10 | South Wales | 0.59 | 5.06 | 5.86 |
| 11 | South East | 0.52 | 4.84 | 5.11 |
| 12 | London | 0.51 | 4.73 | 5.34 |
| 13 | Southern | 0.60 | 5.51 | 5.04 |
| 14 | South Western | 0.71 | 5.61 | 6.45 |

## 5.3 Non Half-Hourly Demand Tariffs (p/kWh)

Figure 3 illustrates the forecast TNUoS tariffs set out in Section 3 for Non Half-Hour (NHH) metered demand Table 18 shows the year on year change in NHH TNUoS tariffs.

**Figure 3**

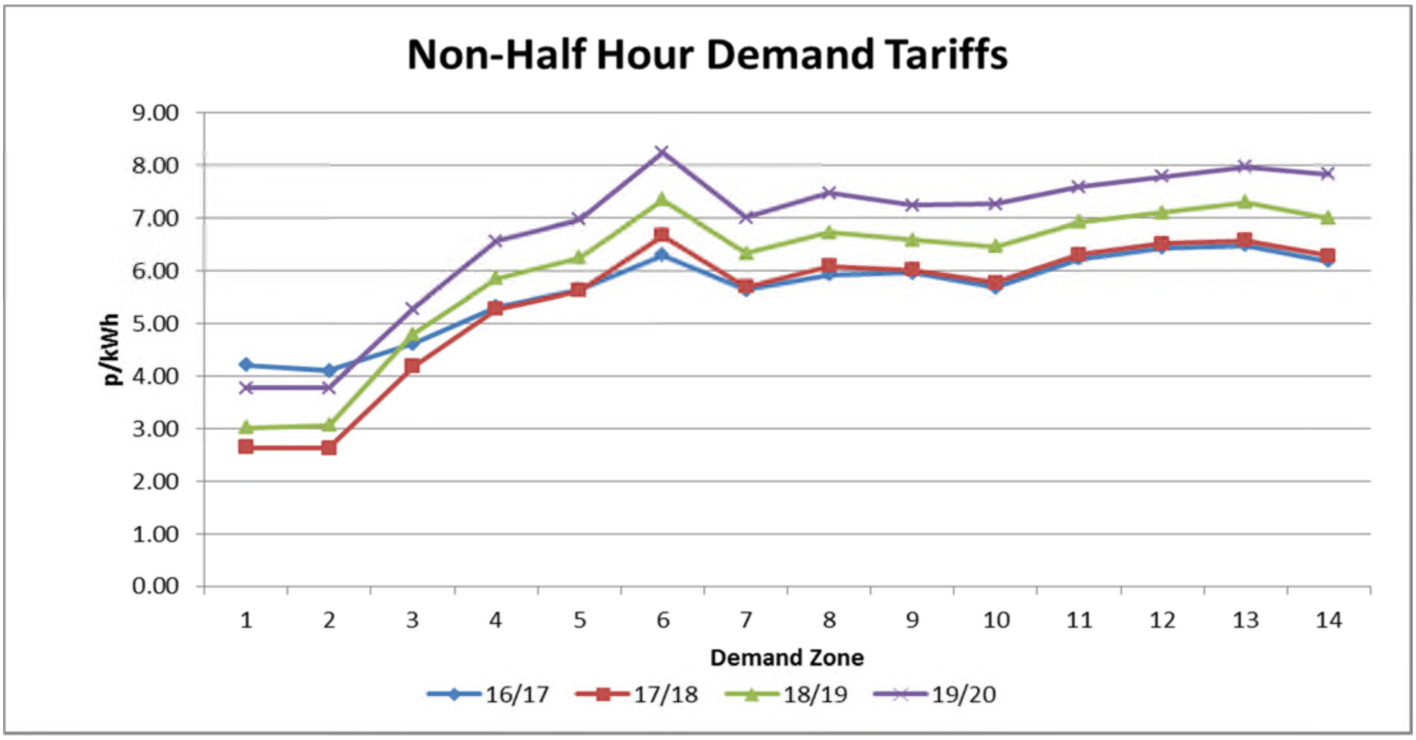

**Table 18 – Changes in Non-Half-Hour Metered Tariffs**

| Zone | Zone Name | Difference 16/17 to 17/18 (p/kWh) | Difference 17/18 to 18/19 (p/kWh) | Difference 18/19 to 19/20 (p/kWh) |
|---|---|---|---|---|
| 1 | Northern Scotland | -1.56 | 0.38 | 0.75 |
| 2 | Southern Scotland | -1.46 | 0.42 | 0.71 |
| 3 | Northern | -0.43 | 0.62 | 0.50 |
| 4 | North West | -0.04 | 0.57 | 0.71 |
| 5 | Yorkshire | -0.03 | 0.64 | 0.72 |
| 6 | N Wales & Mersey | 0.37 | 0.68 | 0.89 |
| 7 | East Midlands | 0.07 | 0.64 | 0.67 |
| 8 | Midlands | 0.16 | 0.64 | 0.75 |
| 9 | Eastern | 0.05 | 0.57 | 0.66 |
| 10 | South Wales | 0.09 | 0.68 | 0.80 |
| 11 | South East | 0.08 | 0.62 | 0.66 |
| 12 | London | 0.08 | 0.59 | 0.68 |
| 13 | Southern | 0.10 | 0.72 | 0.67 |
| 14 | South Western | 0.11 | 0.71 | 0.83 |

## 5.4 Residual Demand Changes

The Residual element of the demand charge is affected by the following variables:

- Generation and Demand split – discussed in Section 6.
- Revenue assumptions - Discussed in Section 3.5.
- Demand charging base – Discussed in Section 3.6

Reductions in the demand charging base, coupled with the cap on average annual generation charges with increasing revenue, generally increases the demand residual over the forecast period.

The information in Sections 6 and 7 can be used to alter the demand charging bases to see the effect on the residual.

## 5.5 Locational Demand Changes

### 5.5.1 2016/17 to 2017/18

The major driver for change in tariffs in from 2016/17 to 2017/18 is the commissioning of the Western HVDC link. This increases demand tariffs in zones at the receiving end of the link, i.e. Zones 6 and 8, whilst reducing demand tariffs in zones who export through the link, i.e. Zones 1 and 2. Appendix B shows 2017/18 tariffs without the HVDC link to allow users to gauge its effect.

### 5.5.2 2017/18 to 2018/19

Demand tariffs in Scotland and the North increase less than the increase in the residual due to the connection of new generation. This may be reversed if there are any large closures of generation not yet announced.

### 5.5.3 2018/19 to 2019/20

Increases in Generation in the East and South East alter flows in the South of England particularly west to East flows, resulting in an increase in tariffs in the South West and South Wales. Zone 3 has a lower increase due to the planned connection of the Norwegian Interconnector in that zone.

## 6. Generation and Demand Revenue Proportions

Until recently the charging methodology fixed the proportion of revenue collected from Generation (G) at 27% and the proportion from Demand (D) at 73%. CMP224 modifies the charging methodology such that the proportions alter to comply with EU Regulation ECR 838/2010 which limits the revenue that can be recovered from Generation to an average of €2.5/MWh per annum.

The proportions will change due to forecast increases in revenue and the Euro and lower demand. The proportions of TNUoS revenue to be recovered from Generation (G) and from Demand (D) are given by the formulas:

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

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

Where:

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

Table 19 shows how the G and D proportions vary over time based on forecast revenues. As average annual generator charges are limited, any changes in revenue only affect demand resulting in changes to the G and D proportions.

**Table 19 – Calculation of Generator and Demand Revenue Proportions**

| G/D split | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|
| E (TWh) | 318.68 | 317.92 | 314.58 | 309.89 |
| L (€/MWh) | 2.34 | 2.34 | 2.34 | 2.34 |
| R (£m) | 2,873.0 | 2,805.8 | 3,013.2 | 3,244.6 |
| X (€/£) | 1.25 | 1.23 | 1.21 | 1.19 |
| G | 0.208 | 0.216 | 0.202 | 0.188 |
| D | 0.792 | 0.784 | 0.798 | 0.812 |
| G.R (£m) | 596.6 | 604.8 | 608.4 | 609.4 |
| D.R (£m) | 2276.4 | 2201.0 | 2404.9 | 2635.2 |

## 7. Generation and Demand Residuals

This section shows how to calculate the residual element of tariffs. This can be used to assess the effect of changing the assumptions in our tariff forecasts without the need to run the DCLF model.

The residual elements of the Generator and Demand TNUoS tariffs are given by the formulas:

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

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

Where:

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

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

Typically 75% of offshore revenues are recovered from offshore local tariffs. Therefore if revenue (R) is reduced / increased due to offshore revenue changes then **O** must also be adjusted by 75%. E.g., if offshore revenues reduce by £10m, reduce R by £10m and O by £7.5m.

Table 20 shows the residuals for each charging year.

**Table 20 – Calculation of Residuals**

| | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|
| $R_G$ (£/kW) | 1.31 | 0.45 | -1.34 | -2.97 |
| $R_D$ (£/kW) | 43.61 | 42.92 | 47.66 | 52.91 |
| G | 0.208 | 0.216 | 0.202 | 0.188 |
| D | 0.792 | 0.784 | 0.798 | 0.812 |
| R (£m) | 2,872.98 | 2,805.78 | 3,013.22 | 3,244.55 |
| $Z_G$ (£m) | 254.27 | 314.43 | 419.71 | 470.89 |
| $Z_D$ (£m) | -6.40 | -10.17 | -13.57 | -13.50 |
| O (£m) | 201.81 | 213.63 | 262.31 | 391.66 |
| $L_C$ (£m) | 16.90 | 17.67 | 22.17 | 22.65 |
| $L_S$ (£m) | 21.62 | 22.77 | 27.67 | 32.75 |
| $B_G$ (£m) | 77.92 | 80.28 | 92.28 | 103.84 |
| $B_D$ (£m) | 52.34 | 51.51 | 50.75 | 50.06 |

## 7.1 Effect of Changing Demand Charging Bases

This section shows how the residual is calculated allowing the user to model the impact of different charging bases. These formulas are also contained within the spreadsheet published alongside this document on our website.

Table 20 only shows the effect on the HH residual. Within the spreadsheet accompanying the report is a worksheet titled Worksheet A. This worksheet shows the effect changing both HH and NHH demand charging bases has on both HH and NHH tariffs. The worksheet replicates the tariff part of the DCLF model with the assumption that locational factors/tariffs do not change.

# 8. Tools and Supporting Information

## 8.1 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 these forecasts

## 8.2 Future Updates to Tariff Forecasts

Final tariffs for 2015/16 will be published 30 January 2015.

National Grid will update the forecast of 2016/17 tariffs throughout 2015. The timetable for this is yet to be confirmed but will be at least done on a quarterly basis. 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.

## 8.3 Charging Models

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

If you would like a copy of any of the models please contact us. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

## 8.4 Tools and Useful Guides

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

- Annual Load Factors 2014-15
- Offshore Charging Guidance

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

## 9. Comments & Feedback

As part of our commitment to customers, National Grid welcomes comments and feedback on the information contained in this document. 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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# Appendices

## Appendix A : Treatment of HVDC Links

### Link Flows

Due to the nature of this technology, the flow on an HVDC link, such as the Western HVDC, will be selectively controlled by the System Operator rather than determined by the impedance of the circuit. The flow determined by the System Operator will depend upon operational conditions at the time, and the resulting decision will take a range of factors into account.

As TNUoS tariffs vary depending on the flow assumed in the transport model, an algorithm in the transport model will objectively determine the desired flow on the HVDC link. This is then used to set the impedance of each HVDC link within the transport model. The following example explains how this algorithm is applied.

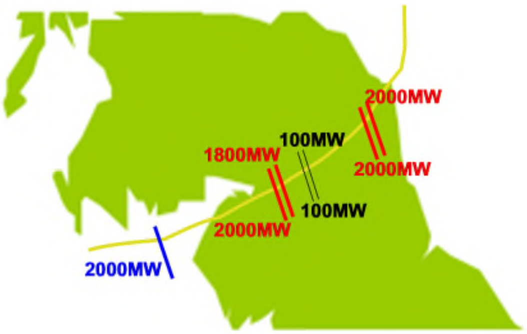

The adjacent diagram depicts the Western HVDC link connecting the transmission network in Southwest Scotland to that in North Wales. In doing so the link crosses multiple transmission constraint boundaries (B6, B7, B11, and B16).

The first step is to determine the flows across each boundary with no flow present on the HVDC link (the base boundary flow).

The desired flow on the link for each boundary in turn is then determined as the same proportion of the base boundary flow as the proportion of additional boundary capacity added by the link.

The final desired flow for the link is then determined as the average of the desired flows on the link for each boundary.

For the purposes of the example, running the transport model without flows on the HVDC element of the network results in boundary flows of: 6,000MW over the B6; 7,000MW over the B7; 10,000 over the B11; and 15,000MW over the B16.




The adjacent diagram shows the circuits on the B6 constraint boundary and their capacities. The total capacity of the B6 is 10,000MW, 2,000MW of which relates to the HVDC link (shown in blue). As the HVDC link makes up 20% of the B6 boundary capacity, the desired B6 boundary flow on the HVDC link will be 1,200MW (20% of the B6 base boundary flow (6000MW)).

Similarly, the following table provides the desired boundary flows on the HVDC link on each boundary, based on an example set of boundary assumptions:

| Boundary | Total Capacity (MW) | HVDC Capacity (MW) | HVDC Capacity Proportion | Base Boundary Flow (MW) | Desired Boundary flow on HVDC link (MW) |
|---|---|---|---|---|---|
| B6 | 10,000 | 2,000 | 20% | 6,000 | 1,200 |
| B7 | 14,000 | 2,000 | 14.3% | 7,000 | 1,000 |
| B11 | 25,000 | 2,000 | 8.0% | 10,000 | 800 |
| B16 | 30,000 | 2,000 | 6.7% | 15,000 | 1,000 |

The overall desired flow on the link is determined by taking the average of each of the desired boundary flow on the HVDC link. In this case the desired flow on the link is 1,000MW. Following this calculation, an iterative process is undertaken in the transport model to determine the impedance required to result in the desired flow on the HVDC link.

### Link Costs

Each HVDC link will have its own individual Expansion Factor so that the costs of the circuit are accurately reflected in tariffs. Within the transport model this is achieved by expanding the length of the circuit within the transport model rather than having an actual definitive Expansion Factor.

Actual cost information relating to the project cannot be gathered early on in the project's lifetime as tenders and negotiations are still ongoing and this information is commercially sensitive.

For both the Caithness Moray and Western HVDC links we followed the approach taken in the CMP213 workgroup and based figures on previously published cost information for HVDC subsea cable and converter costs[7]. We will look to update information as and when we receive it.

[7] http://www.nationalgrid.com/NR/rdonlyres/26AE1FA4-2C3B-4895-BC0B-7B2EF0229BFE/49226/Part5AppendixD.pdf

## Appendix B : TNUoS Tariffs without HVDC Links

This section shows the impact on tariffs of HVDC links by showing the tariffs without these links. Table 21 and Table 22 show 2017/18 tariffs omitting the Western HVDC link from the locational model.

**Table 21 - 2017/18 Generation Tariffs without the Western HVDC Link**

| Generation Tariffs | | System Peak Tariff | Shared Year Round Tariff | Not Shared Year Round Tariff | Residual Tariff | Conventional 70% Load Factor | Intermittent 30% Load Factor |
|---|---|---|---|---|---|---|---|
| Zone | Zone Name | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) |
| 1 | North Scotland | 3.17 | 13.33 | 7.76 | 0.98 | 21.23 | 12.73 |
| 2 | East Aberdeenshire | 4.11 | 6.40 | 7.76 | 0.98 | 17.32 | 10.65 |
| 3 | Western Highlands | 3.13 | 10.90 | 7.37 | 0.98 | 19.10 | 11.62 |
| 4 | Skye and Lochalsh | -2.77 | 10.90 | 7.30 | 0.98 | 13.14 | 11.54 |
| 5 | Eastern Grampian and Tayside | 2.58 | 9.96 | 6.85 | 0.98 | 17.38 | 10.81 |
| 6 | Central Grampian | 4.27 | 10.02 | 6.89 | 0.98 | 19.15 | 10.87 |
| 7 | Argyll | 3.42 | 8.04 | 10.98 | 0.98 | 21.00 | 14.37 |
| 8 | The Trossachs | 3.30 | 8.04 | 5.24 | 0.98 | 15.15 | 8.62 |
| 9 | Stirlingshire and Fife | 3.99 | 6.95 | 4.76 | 0.98 | 14.59 | 7.82 |
| 10 | South West Scotland | 2.29 | 7.67 | 4.76 | 0.98 | 13.40 | 8.04 |
| 11 | Lothian and Borders | 4.02 | 7.67 | 1.97 | 0.98 | 12.34 | 5.25 |
| 12 | Solway and Cheviot | 1.90 | 4.80 | 3.29 | 0.98 | 9.53 | 5.70 |
| 13 | North East England | 3.88 | 2.54 | 1.73 | 0.98 | 8.37 | 3.47 |
| 14 | North Lancashire and The Lakes | 1.76 | 2.54 | 2.03 | 0.98 | 6.54 | 3.77 |
| 15 | South Lancashire, Yorkshire and Humber | 4.68 | 0.53 | | 0.98 | 6.03 | 1.14 |
| 16 | North Midlands and North Wales | 3.71 | 0.10 | | 0.98 | 4.76 | 1.01 |
| 17 | South Lincolnshire and North Norfolk | 1.64 | -0.09 | | 0.98 | 2.55 | 0.95 |
| 18 | Mid Wales and The Midlands | 1.23 | -0.02 | 0.00 | 0.98 | 2.20 | 0.97 |
| 19 | Anglesey and Snowdon | 4.83 | 1.77 | | 0.98 | 7.05 | 1.51 |
| 20 | Pembrokeshire | 8.31 | -3.53 | | 0.98 | 6.82 | -0.08 |
| 21 | South Wales & Gloucester | 5.56 | -3.62 | | 0.98 | 4.00 | -0.11 |
| 22 | Cotswold | 2.23 | 2.55 | -6.06 | 0.98 | -1.07 | -4.32 |
| 23 | Central London | -3.95 | 2.55 | -5.33 | 0.98 | -6.52 | -3.59 |
| 24 | Essex and Kent | -4.59 | 2.55 | | 0.98 | -1.83 | 1.74 |
| 25 | Oxfordshire, Surrey and Sussex | -1.85 | -2.13 | | 0.98 | -2.37 | 0.34 |
| 26 | Somerset and Wessex | -2.32 | -3.57 | | 0.98 | -3.84 | -0.10 |
| 27 | West Devon and Cornwall | -1.67 | -5.62 | | 0.98 | -4.62 | -0.71 |

**Table 22 - 2017/18 Demand Tariffs without Western HVDC Link**

| Zone | Zone Name | Half Hourly (£/kW) | Non Half Hourly (p/kWh) |
|---|---|---|---|
| 1 | Northern Scotland | 28.60 | 4.05 |
| 2 | Southern Scotland | 30.56 | 3.94 |
| 3 | Northern | 35.40 | 4.51 |
| 4 | North West | 39.19 | 5.21 |
| 5 | Yorkshire | 39.64 | 5.54 |
| 6 | N Wales & Mersey | 39.08 | 6.17 |
| 7 | East Midlands | 42.58 | 5.54 |
| 8 | Midlands | 43.21 | 5.84 |
| 9 | Eastern | 45.03 | 5.89 |
| 10 | South Wales | 41.01 | 5.58 |
| 11 | South East | 47.85 | 6.17 |
| 12 | London | 50.74 | 6.39 |
| 13 | Southern | 48.51 | 6.42 |
| 14 | South Western | 47.77 | 6.12 |

Table 23 and Table 24 show tariffs for 2018/19 without the Caithness Moray HVDC link.

**Table 23 - 2018/19 Generation Tariffs without the Caithness-Moray HVDC Link**

| Generation Tariffs | | System Peak Tariff | Shared Year Round Tariff | Not Shared Year Round Tariff | Residual Tariff | Conventional 70% Load Factor | Intermittent 30% Load Factor |
|---|---|---|---|---|---|---|---|
| Zone | Zone Name | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) | (£/kW) |
| 1 | North Scotland | 1.86 | 15.58 | 18.59 | -1.23 | 30.13 | 22.04 |
| 2 | East Aberdeenshire | 1.68 | 12.19 | 18.15 | -1.23 | 27.14 | 20.58 |
| 3 | Western Highlands | 1.99 | 14.35 | 17.05 | -1.23 | 27.86 | 20.13 |
| 4 | Skye and Lochalsh | -8.10 | 14.35 | 17.01 | -1.23 | 17.73 | 20.09 |
| 5 | Eastern Grampian and Tayside | 3.60 | 13.81 | 16.05 | -1.23 | 28.09 | 18.97 |
| 6 | Central Grampian | 3.39 | 13.66 | 15.75 | -1.23 | 27.48 | 18.62 |
| 7 | Argyll | 2.39 | 12.65 | 19.70 | -1.23 | 29.71 | 22.26 |
| 8 | The Trossachs | 2.81 | 12.65 | 13.57 | -1.23 | 24.01 | 16.14 |
| 9 | Stirlingshire and Fife | 2.52 | 11.72 | 12.43 | -1.23 | 21.92 | 14.72 |
| 10 | South West Scotland | 2.93 | 13.33 | 12.55 | -1.23 | 23.58 | 15.32 |
| 11 | Lothian and Borders | 3.16 | 13.33 | 4.56 | -1.23 | 15.82 | 7.33 |
| 12 | Solway and Cheviot | 2.23 | 7.26 | 7.35 | -1.23 | 13.43 | 8.30 |
| 13 | North East England | 3.64 | 3.14 | 3.64 | -1.23 | 8.24 | 3.35 |
| 14 | North Lancashire and The Lakes | 1.83 | 3.14 | 2.42 | -1.23 | 5.21 | 2.13 |
| 15 | South Lancashire, Yorkshire and Humber | 4.60 | 0.21 | 0.00 | -1.23 | 3.52 | -1.17 |
| 16 | North Midlands and North Wales | 3.53 | -1.48 | | -1.23 | 1.27 | -1.67 |
| 17 | South Lincolnshire and North Norfolk | 2.43 | -1.47 | | -1.23 | 0.16 | -1.67 |
| 18 | Mid Wales and The Midlands | 1.54 | -1.32 | | -1.23 | -0.62 | -1.63 |
| 19 | Anglesey and Snowdon | 3.04 | -0.13 | | -1.23 | 1.72 | -1.27 |
| 20 | Pembrokeshire | 8.67 | -5.47 | | -1.23 | 3.60 | -2.87 |
| 21 | South Wales & Gloucester | 6.02 | -5.49 | | -1.23 | 0.95 | -2.88 |
| 22 | Cotswold | 2.36 | 1.61 | -7.12 | -1.23 | -4.86 | -7.86 |
| 23 | Central London | -6.07 | 1.61 | -6.10 | -1.23 | -12.27 | -6.84 |
| 24 | Essex and Kent | -3.55 | 1.61 | | -1.23 | -3.66 | -0.75 |
| 25 | Oxfordshire, Surrey and Sussex | -1.86 | -3.62 | | -1.23 | -5.62 | -2.32 |
| 26 | Somerset and Wessex | -2.39 | -5.59 | | -1.23 | -7.54 | -2.91 |
| 27 | West Devon and Cornwall | -1.83 | -7.92 | | -1.23 | -8.60 | -3.60 |

**Table 24 - 2018/19 Demand Tariffs without the Caithness-Moray HVDC Link**

| Zone | Zone Name | Half Hourly (£/kW) | Non Half Hourly (p/kWh) |
|---|---|---|---|
| 1 | Northern Scotland | 20.20 | 2.86 |
| 2 | Southern Scotland | 23.80 | 3.07 |
| 3 | Northern | 37.67 | 4.79 |
| 4 | North West | 44.04 | 5.85 |
| 5 | Yorkshire | 44.78 | 6.26 |
| 6 | N Wales & Mersey | 46.63 | 7.35 |
| 7 | East Midlands | 48.73 | 6.34 |
| 8 | Midlands | 49.88 | 6.73 |
| 9 | Eastern | 50.41 | 6.59 |
| 10 | South Wales | 47.49 | 6.46 |
| 11 | South East | 53.80 | 6.93 |
| 12 | London | 56.52 | 7.11 |
| 13 | Southern | 55.24 | 7.30 |
| 14 | South Western | 54.72 | 7.00 |

## Appendix C : Revenue Analysis

These pages provide more detail on the price control forecasts for National Grid, Scottish Power Transmission and SHE Transmission.  Forecasts are also provided for offshore networks with forecasts by National Grid where these have yet to be transferred to the Offshore Transmission Owner or are still to be constructed.

***Notes:***

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

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

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

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

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

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

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

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

## Table 25

| National Grid Revenue Forecast | | | | Updated: | 21/01/2015 | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | | Licence Term | Special Condition | Applicable to | Yr t-1 | Yr t | Yr t+1 | Yr t+2 | Yr t+3 | Yr t+4 | Yr t+5 | |
| Regulatory Year | | | | | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Notes |
| Actual RPI | | | | | 251.73 | | | | | | | April to March average |
| RPI Actual | | RPIAt | 3A | | 1.1667 | | | | | | | Office of National Statistics |
| Assumed Interest Rate | | It | 3A | | 0.50% | 0.50% | | 1.50% | 2.20% | 2.60% | 2.60% | Bank of England Base Rate |
| Opening Base Revenue Allowance (2009/10 prices) | A1 | PUt | 3A | ALL | 1,342.3 | 1,443.8 | | 1,571.4 | 1,554.9 | 1,587.6 | 1,585.2 | From Licence |
| Price Control Financial Model Iteration Adjustment | A2 | MODt | 3A | ALL | | -5.5 | | -100.0 | -190.0 | -200.0 | -200.0 | Determined by Ofgem/Licensee forecast |
| RPI True Up | A3 | TRUt | 3A | ALL | | -0.5 | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| Prior Calendar Year RPI Forecast | | GRPIFc-1 | 3A | ALL | 3.1% | 3.1% | | 2.4% | 3.2% | 3.3% | 3.4% | HM Treasury Forecast then 2.8% |
| Current Calendar Year RPI Forecast | | GRPIFc | 3A | ALL | 2.7% | 3.1% | | 3.2% | 3.3% | 3.4% | 2.8% | HM Treasury Forecast then 2.8% |
| Next Calendar Year RPI forecast | | GRPIFc+1 | 3A | ALL | 2.5% | 3.0% | | 3.3% | 3.4% | 2.8% | 2.8% | HM Treasury Forecast then 2.8% |
| RPI Forecast | A4 | RPIFt | 3A | ALL | 1.1630 | 1.2051 | | 1.2763 | 1.3083 | 1.3616 | 1.3887 | Using HM Treasury Forecast |
| **Base Revenue [A=(A1+A2+A3)*A4]** | **A** | **BRt** | **3A** | **ALL** | **1561.1** | **1732.7** | | **1877.9** | **1785.8** | **1889.4** | **1923.6** | |
| Pass-Through Business Rates | B1 | RBt | 3B | ALL | | | | 1.4 | 1.4 | 1.5 | 1.5 | Licensee Actual/Forecast |
| Temporary Physical Disconnection | B2 | TPDt | 3B | ALL | | 0.1 | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| Licence Fee | B3 | LFt | 3B | NG | | | | 2.3 | 2.3 | 2.3 | 2.3 | Licensee Actual/Forecast |
| Inter TSO Compensation | B4 | ITCt | 3B | NG | | | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| Termination of Bilateral Connection Agreements | B5 | TERMt | 3B | NG | 2.6 | 0.0 | | 0.0 | 0.0 | 0.0 | 0.0 | Does not affect TNUoS |
| SP Transmission Pass-Through | B6 | TSPt | 3B | NG | 271.3 | 312.2 | | 310.5 | 357.6 | 404.3 | 421.2 | 13/14 & 14/15 Charge setting. Later from TSP Tab |
| SHE Transmission Pass-Through | B7 | TSHt | 3B | NG | 172.5 | 214.0 | | 339.5 | 344.0 | 331.9 | 338.5 | 13/14 & 14/15 Charge setting. Later from TSH Tab |
| Offshore Transmission Pass-Through | B8 | TOFTOt | 3B | NG | 105.4 | 218.4 | To be updated in 2015/16 Final Tariffs | 269.1 | 284.8 | 349.7 | 522.2 | 13/14 & 14/15 Charge setting. Later from OFTO Tab |
| Embedded Offshore Pass-Through | B9 | OFETt | 3B | NG | 0.6 | 0.4 | | 0.7 | 0.7 | 0.7 | 0.7 | Licensee Actual/Forecast |
| **Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]** | **B** | **PTt** | **3B** | **ALL** | **552.3** | **745.1** | | **923.4** | **990.9** | **1090.5** | **1286.4** | |
| Reliability Incentive Adjustment | C1 | RIt | 3C | ALL | 12.4 | | | 2.4 | 2.5 | 2.6 | 2.6 | Licensee Actual/Forecast/Budget |
| Stakeholder Satisfaction Adjustment | C2 | SSOt | 3D | ALL | | | | 9.3 | 9.1 | 10.3 | 10.0 | Licensee Actual/Forecast/Budget |
| Sulphur Hexafluoride (SF6) Gas Emissions Adjustment | C3 | SFIt | 3E | ALL | | | | 2.9 | 3.1 | 3.2 | 3.4 | Licensee Actual/Forecast/Budget |
| Awarded Environmental Discretionary Rewards | C4 | EDRt | 3F | ALL | | | | 0.0 | 0.0 | 0.0 | 0.0 | Only includes EDR awarded to licensee to date |
| **Outputs Incentive Revenue [C=C1+C2+C3+C4]** | **C** | **OIPt** | **3A** | **ALL** | **12.4** | **0.0** | | **14.6** | **14.6** | **16.1** | **16.0** | |
| Network Innovation Allowance | D | NIAt | 3H | ALL | 6.1 | 10.9 | | 11.8 | 11.3 | 11.9 | 12.1 | Licensee Actual/Forecast/Budget |
| Network Innovation Competition | E | NICFt | 3I | NG | 0.0 | 17.8 | | 48.4 | 49.7 | 51.7 | 52.7 | Sum of NICF awards determined by Ofgem/Forecast by National Grid |
| Future Environmental Discretionary Rewards | F | EDRt | 3F | ALL | | | | 3.0 | 2.0 | 2.0 | 2.0 | Sum of future EDR awards forecast by National Grid |
| Transmission Investment for Renewable Generation | G | TIRGt | 3J | ALL | 16.0 | 16.0 | | -0.1 | -0.1 | -0.0 | -0.0 | Licensee Actual/Forecast |
| Scottish Site Specific Adjustment | H | DISt | 3A | NG | -1.6 | 2.0 | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| Scottish Terminations Adjustment | I | TSt | 3A | NG | -0.4 | -0.3 | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| Correction Factor | K | -Kt | 3A | ALL | -2.7 | | | 42.1 | 0.0 | 0.0 | 0.0 | Calculated by Licensee |
| **Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]** | **M** | **TOt** | | **ALL** | **2143.3** | **2524.2** | | **2921.3** | **2854.1** | **3061.5** | **3292.8** | |
| Termination Charges | B5 | | | NG | 2.6 | 0.0 | | 0.0 | 0.0 | 0.0 | 0.0 | |
| Pre-vesting connection charges | P | | | ALL | 43.3 | 47.0 | | 48.3 | 48.3 | 48.3 | 48.3 | Licensee Actual/Forecast |
| **TNUoS Collected Revenue [T=M-B5-P]** | **T** | | | **NG** | **2097.4** | **2477.3** | | **2873.0** | **2805.8** | **3013.2** | **3244.6** | |
| Final Collected Revenue | U | TNRt | | ALL | 2089.6 | | | | | | | Licensee Actual/Forecast |
| Over / (Under) Recovery [V=U-M] | V | | | ALL | -53.7 | | | | | | | |
| **Forecast percentage change to Maximum Revenue M** | | | | **NG** | | **17.8%** | | | **-2.3%** | **7.3%** | **7.6%** | |
| **Forecast percentage change to TNUoS Collected Revenue T** | | | | **NG** | | **18.1%** | | | **-2.3%** | **7.4%** | **7.7%** | |

## Table 26

| Scottish Power Transmission Revenue Forecast | | | | Updated: | 22/12/2014 | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | | Licence Term | Special Condition | Applicable to | Yr t-1 | Yr t | Yr t+1 | Yr t+2 | Yr t+3 | Yr t+4 | Yr t+5 | |
| Regulatory Year | | | | | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Notes |
| Actual RPI | | | | | 251.73 | | | | | | | April to March average |
| RPI Actual | | RPIAt | | | 1.1667 | | | | | | | Office of National Statistics |
| Assumed Interest Rate | | It | | | 0.50% | 0.50% | | 1.50% | 2.20% | 2.60% | 2.60% | As forecast by National Grid |
| Opening Base Revenue Allowance (2009/10 prices) | A1 | PUt | 3A | ALL | 225.1 | 237.0 | | 244.7 | 249.4 | 253.1 | 256.4 | From Licence |
| Price Control Financial Model Iteration Adjustment | A2 | MODt | 3A | ALL | | 6.2 | | -16.7 | 8.9 | 30.1 | 34.0 | Determined by Ofgem/Licensee forecast |
| RPI True Up | A3 | TRUt | 3A | ALL | | -0.1 | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| RPI Forecast | A4 | RPIFt | 3A | ALL | 1.1630 | 1.2051 | | 1.2763 | 1.3083 | 1.3616 | 1.3887 | National Grid forecast |
| **Base Revenue [A=(A1+A2+A3)*A4]** | **A** | **BRt** | **3A** | **ALL** | **261.8** | **292.9** | | **291.0** | **337.9** | **385.6** | **403.3** | |
| Pass-Through Business Rates | B1 | RBt | 3B | ALL | | | | -4.7 | -5.1 | -5.6 | -5.3 | Licensee Actual/Forecast |
| Temporary Physical Disconnection | B2 | TPDt | 3B | ALL | | 0.0 | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast |
| **Pass-Through Items [B=B1+B2]** | **B** | **PTt** | **3B** | **ALL** | **0.0** | **0.0** | | **-4.7** | **-5.1** | **-5.6** | **-5.3** | |
| Reliability Incentive Adjustment | C1 | RIt | 3C | ALL | 0.5 | | **To be updated in 2015/16 Final tariffs** | 1.2 | 1.2 | 1.2 | 1.2 | Licensee Actual/Forecast/Budget |
| Stakeholder Satisfaction Adjustment | C2 | SSOt | 3D | ALL | | | | 0.6 | 0.6 | 0.6 | 0.6 | Licensee Actual/Forecast/Budget |
| Sulphur Hexafluoride (SF6) Gas Emissions Adjustment | C3 | SFIt | 3E | ALL | | | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast/Budget |
| Awarded Environmental Discretionary Rewards | C4 | EDRt | 3F | ALL | | | | 0.0 | 0.0 | 0.0 | 0.0 | Only includes EDR awarded to licensee to date |
| Financial Incentive for Timely Connections Output | C5 | -CONADJt | 3G | SP, SHE | | | | 0.0 | 0.0 | 0.0 | 0.0 | Licensee Actual/Forecast/Budget |
| **Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]** | **C** | **OIPt** | **3A** | **ALL** | **0.5** | **0.0** | | **1.8** | **1.8** | **1.8** | **1.8** | |
| Network Innovation Allowance | D | NIAt | 3H | ALL | 0.6 | 1.0 | | 0.8 | 0.8 | 0.8 | 0.8 | Licensee Actual/Forecast/Budget |
| Transmission Investment for Renewable Generation | G | TIRGt | 3J | ALL | 25.5 | 29.2 | | 31.9 | 33.1 | 33.3 | 32.8 | Licensee Actual/Forecast |
| Correction Factor | K | -Kt | 3A | ALL | -0.8 | | | 0.2 | 0.0 | 0.0 | 0.0 | Calculated by Licensee |
| **Maximum Revenue (M= A+B+C+D+G+J+K]** | **M** | **TOt** | | **ALL** | **287.6** | **323.1** | | **321.0** | **368.5** | **415.9** | **433.4** | |
| Excluded Services | P | EXCt | | SP, SHE | 7.0 | 7.7 | | 8.7 | 9.9 | 10.5 | 11.3 | Post BETTA Connection Charges |
| Site Specifc Charges | S | EXSt | | SP, SHE | 15.0 | 18.5 | | 19.2 | 20.8 | 22.0 | 23.5 | Pre & Post BETTA Connection Charges |
| **TNUoS Collected Revenue (T=M+P-S)** | **T** | **TSPt** | | **NG** | **279.6** | **312.3** | | **310.5** | **357.6** | **404.3** | **421.2** | General System Charge |
| Final Collected Revenue | U | TNRt | | ALL | 271.3 | | | | | | | Licensee Actual/Forecast |
| Over / (Under) Recovery [V=U-M] | V | | | ALL | -8.3 | | | | | | | |
| **Forecast percentage change to TNUoS Collected Revenue T** | | | | **ALL** | | **11.7%** | | | **15.2%** | **13.1%** | **4.2%** | |

## Table 27

| SHE Transmission Revenue Forecast | | | | Updated: | 16/12/2014 | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Description** | | **Licence Term** | **Special Condition** | **Applicable to** | **Yr t-1** | **Yr t** | **Yr t+1** | **Yr t+2** | **Yr t+3** | **Yr t+4** | **Yr t+5** | |
| **Regulatory Year** | | | | | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** | **2018/19** | **2019/20** | **Notes** |
| Actual RPI | | | | | 251.73 | | **To be updated in 2015/16 Final tariffs** | | | | | April to March average |
| RPI Actual | | RPIAt | | | 1.1667 | | | | | | | Office of National Statistics |
| Assumed Interest Rate | | It | | | 0.50% | 0.50% | | 1.50% | 2.20% | 2.60% | 2.60% | As forecast by National Grid |
| Opening Base Revenue Allowance (2009/10 prices) | A1 | PUt | 3A | ALL | 104.5 | 111.5 | | 123.6 | 119.6 | 120.0 | **No forecast available for 2019/20 so indicative numbers based upon inflated 2018/19 forecast.** | From Licence |
| Price Control Financial Model Iteration Adjustment | A2 | MODt | 3A | ALL | | 8.7 | | 89.0 | 87.2 | 71.9 | | Forecast of cummulativce MOD impacts, excl non approved |
| RPI True Up | A3 | TRUt | 3A | ALL | | 0.0 | | -0.3 | 2.0 | 0.0 | | Licensee Actual/Forecast |
| RPI Forecast | A4 | RPIFt | 3A | ALL | 1.1630 | 1.2051 | | 1.2763 | 1.3083 | 1.3616 | | Using HM Treasury Forecast |
| **Base Revenue [A=(A1+A2+A3)*A4]** | **A** | **BRt** | **3A** | **ALL** | **121.6** | **144.9** | | **270.9** | **273.1** | **261.3** | | |
| Pass-Through Business Rates | B1 | RBt | 3B | ALL | | 0.0 | | -16.1 | -9.1 | -9.4 | | RBt rebate received in 2014/15, pass through in 2016/17 |
| Temporary Physical Disconnection | B2 | TPDt | 3B | ALL | | 0.0 | | 0.0 | 0.0 | 0.0 | | Licensee Actual/Forecast |
| **Pass-Through Items [B=B1+B2]** | **B** | **PTt** | **3B** | **ALL** | **0.0** | **0.0** | | **-16.1** | **-9.1** | **-9.4** | | |
| Reliability Incentive Adjustment | C1 | RIt | 3C | ALL | 0.0 | | | 0.0 | 0.0 | 0.0 | | Licensee Actual/Forecast/Budget |
| Stakeholder Satisfaction Adjustment | C2 | SSOt | 3D | ALL | | | | 0.0 | 0.0 | 0.0 | | Licensee Actual/Forecast/Budget |
| Sulphur Hexafluoride (SF6) Gas Emissions Adjustment | C3 | SFIt | 3E | ALL | | | | 0.0 | 0.0 | 0.0 | | Licensee Actual/Forecast/Budget |
| Awarded Environmental Discretionary Rewards | C4 | EDRt | 3F | ALL | | | | 0.0 | 0.0 | 0.0 | | Only includes EDR awarded to licensee to date |
| Financial Incentive for Timely Connections Output | C5 | -CONADJt | 3G | SP, SHE | | | | 0.0 | 0.0 | 0.0 | | Licensee Actual/Forecast/Budget |
| **Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]** | **C** | **OIPt** | **3A** | **ALL** | **0.0** | **0.0** | | **0.0** | **0.0** | **0.0** | | |
| Network Innovation Allowance | D | NIAt | 3H | ALL | 1.2 | 1.8 | | 1.8 | 1.8 | 1.8 | | Licensee Actual/Forecast |
| Transmission Investment for Renewable Generation | G | TIRGt | 3J | ALL | 54.5 | 72.2 | | 84.9 | 81.8 | 82.0 | | Excludes Asset Adjusting Events impacts |
| Compensatory Payments Adjustment | J | SHCPt | 3C | SHE | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | Licensee Actual/Forecast/Budget |
| Correction Factor | K | -Kt | 3A | ALL | -2.8 | | | 1.5 | 0.0 | 0.0 | | Latest Forecast |
| **Maximum Revenue (M= A+B+C+D+G+J+K]** | **M** | **TOt** | | **ALL** | **174.5** | **218.9** | | **343.0** | **347.6** | **335.7** | | |
| Excluded Services | P | EXCt | | SP, SHE | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | Post BETTA Connection Charges |
| Site Specifc Charges | S | EXSt | | SP, SHE | 3.5 | 3.5 | | 3.6 | 3.7 | 3.8 | | Post-Vesting, Pre-BETTA Connection Charges |
| **TNUoS Collected Revenue (T=M+P-S)** | **T** | **TSHt** | | **NG** | **171.0** | **215.4** | | **339.5** | **344.0** | **331.9** | **338.5** | General System Charge |
| Final Collected Revenue | U | TNRt | | ALL | 175.9 | | | | | | | Licensee Actual/Forecast |
| Over / (Under) Recovery [V=U-M] | V | | | ALL | 1.5 | | | | | | | |
| **Forecast percentage change to TNUoS Collected Revenue T** | | | | **ALL** | | **26.0%** | | | **1.3%** | **-3.5%** | **2.0%** | |

## Table 28

| Offshore Transmission Revenue Forecast | 21/01/2015 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Yr t-1** | **Yr t** | **Yr t+1** | **Yr t+2** | **Yr t+3** | **Yr t+4** | **Yr t+5** | |
| **Regulatory Year** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** | **2018/19** | **2019/20** | **Notes** |
| Barrow | 5.3 | 5.5 | **To be updated in 2015/16 Final Tariffs** | 5.8 | 6.0 | 6.2 | 6.3 | Current revenues plus indexation |
| Gunfleet | 6.6 | 6.9 | | 7.3 | 7.5 | 7.7 | 7.9 | Current revenues plus indexation |
| Walney 1 | 12.1 | 12.5 | | 13.2 | 13.6 | 14.0 | 14.5 | Current revenues plus indexation |
| Robin Rigg | 7.5 | 7.7 | | 8.2 | 8.4 | 8.7 | 8.9 | Current revenues plus indexation |
| Walney 2 | 12.6 | 12.9 | | 13.7 | 14.1 | 14.5 | 15.0 | Current revenues plus indexation |
| Sheringham Shoal | 15.6 | 18.9 | | 20.2 | 20.8 | 21.4 | 22.0 | Current revenues plus indexation |
| Ormonde | 11.2 | 11.6 | | 12.3 | 12.6 | 13.0 | 13.4 | Current revenues plus indexation |
| Greater Gabbard | 11.4 | 26.0 | | 27.5 | 28.4 | 29.2 | 30.1 | Current revenues plus indexation |
| London Array | 23.0 | 37.6 | | 37.6 | 38.8 | 39.9 | 41.1 | Current revenues plus indexation |
| Thanet | | 78.9 | | 17.7 | 18.2 | 18.8 | 19.3 | Current revenues plus indexation |
| Lincs | | | | 25.5 | 26.2 | 27.0 | 27.8 | Current revenues plus indexation |
| Gwynt y mor | | | | 26.2 | 26.9 | 27.7 | 28.6 | Current revenues plus indexation |
| West of Duddon Sands | | | | 54.1 | 55.3 | 57.0 | 58.7 | National Grid Forecast |
| Humber Gateway | | | | | | | | National Grid Forecast |
| Westermost Rough | | | | | | | | National Grid Forecast |
| Galloper | | | | | 8.0 | 24.6 | 24.3 | National Grid Forecast |
| Race Bank | | | | | | 40.0 | 116.4 | National Grid Forecast |
| Burbo Bank | | | | | | | | National Grid Forecast |
| Dudgeon | | | | | | | | National Grid Forecast |
| Rampion | | | | | | | | National Grid Forecast |
| Beatrice | | | | | | | 87.8 | National Grid Forecast |
| East Anglia 1 | | | | | | | | National Grid Forecast |
| Inch Cape 1 | | | | | | | | National Grid Forecast |
| Moray Firth | | | | | | | | National Grid Forecast |
| Navitus Bay 1 | | | | | | | | National Grid Forecast |
| Neart Na Goaith | | | | | | | | National Grid Forecast |
| Triton Knoll 1 | | | | | | | | National Grid Forecast |
| Walney Extension | | | | | | | | National Grid Forecast |
| **Offshore Transmission Pass-Through (B7)** | **105.4** | **218.4** | | **269.1** | **284.8** | **349.7** | **522.2** | |

## Appendix D : Contracted Generation Changes from 16/17 to 19/20

The tables below lists the contracted Generation changes for the years modelled. Actual contracted Generation may differ from the year in question due to TEC reductions of current Generation and delays/terminations of new connections.

**Table 29 - 2016/17 Contracted TEC Changes**

| Project Name | TEC Change (MW) | Node 1 | Node 2 | Gen Zone |
|---|---|---|---|---|
| Achruach Wind Farm | 7 | ACHR1R | | 7 |
| Aikengall II Windfarm | 108 | WDOD10 | | 11 |
| Beinneun Wind Farm | 109 | BEIN10 | | 3 |
| Blackcraig Wind Farm | 58 | BLCW10 | | 11 |
| Burbo Bank Extension Offshore Wind Farm | 254 | BODE40 | | 16 |
| C.Gen Killingholme North Power Station | 490 | KILL40 | | 15 |
| Corriemoillie Wind Farm | 48 | CORI10 | | 1 |
| Crystal Rig 2 | 62 | CRYR40 | | 11 |
| Damhead Creek II | 1200 | KINO40 | | 24 |
| Dudgeon Offshore Wind Farm | 400 | NECT40 | | 17 |
| Ewe Hill | 18 | EWEH1Q | | 11 |
| Galawhistle Wind Farm | 55 | COAL10 | | 11 |
| Galloper | 184 | LEIS1B | | 18 |
| Galloper | 156 | LEIS1B | | 18 |
| Glen App Windfarm | 32 | AREC10 | | 10 |
| Griffin Wind Farm | 15 | GRIF1S | GRIF1T | 5 |
| Harestanes Extension | 17 | HARE10 | | 12 |
| Hinkley Point B | -200 | HINP40 | | 26 |
| Hornsea Offshore Wind Farm - Platform 1A | 500 | HORN40 | | 15 |
| Hornsea Offshore Wind Farm - Platform 1B | 500 | HORN40 | | 15 |
| Keadby II | 710 | KEAD40 | | 16 |
| Keiths Hill Wind Farm | 4 | DUNE10 | | 11 |
| Kilgallioch | 274 | KILG20 | | 10 |
| Kings Lynn A | 365 | WALP40_EME | | 17 |
| Lynemouth Power Station | 376 | BLYT20 | | 13 |
| Margree | 43 | MARG10 | | 11 |
| Millennium South | 25 | FAUG10 | | 3 |
| Neart Na Goaithe Offshore Wind Farm | 450 | CRYR40 | | 11 |
| Newfield Wind Farm | 53 | NEWF1Q | | 11 |
| Pencloe Windfarm | 63 | BLAC10 | | 10 |
| Race Bank Wind Farm | 160 | WALP40_EME | | 17 |
| Rampion | 332 | BOLN40 | | 25 |
| Rhigos | 228 | RHIG40 | | 21 |
| South Hook CHP Plant | 490 | PEMB40 | | 20 |
| Strathy North and South Wind | 150 | STRW12 | | 1 |
| Tees Renewable Energy Plant | 280 | GRST20 | | 13 |

| Project Name | TEC Change (MW) | Node 1 | Node 2 | Gen Zone |
|---|---|---|---|---|
| Ulzieside | 30 | GLGL1Q | GLGL1R | 10 |
| Walney Extension Power Station A Offshore Wind Farm | 330 | HEYS40 | | 14 |
| Walney Extension Power Station B Offshore Wind Farm | 330 | HEYS40 | | 14 |
| Whiteside Hill Wind Farm | 27 | GLGL1Q | GLGL1R | 10 |
| Wilton | 42 | GRST20 | | 13 |
| France Interconnector | 1000 | SELL40 | | 24 |
| **Total** | **9774** | | | |

**Table 30 - 2017/18 Contracted TEC Changes**

| Project Name | TEC Change (MW) | Node 1 | Node 2 | Gen Zone |
|---|---|---|---|---|
| Airies Wind Farm | 35 | GLLU1Q | GLLU1R | 11 |
| Allt Duine Wind Farm | 10 | ALLT10 | | 1 |
| Aultmore Wind Farm | 30 | AULW1S | | 1 |
| Barking Power Station C | 470 | BARK40 | | 18 |
| Beatrice Wind Farm | 20 | BLHI40 | | 1 |
| Brigg | 110 | KEAD40 | | 16 |
| Dorenell Wind Farm | 220 | DORE10 | | 1 |
| Earlshaugh Wind Farm | 55 | EHAU10 | | 9 |
| Ewe Hill | 48 | EWEH1Q | | 11 |
| Greenwire Wind Farm - Pembroke | 2000 | PEMB40 | | 20 |
| Inch Cape Offshore Wind Farm Platform 1 | 18 | COCK20 | | 11 |
| Keadby | 735 | KEAD40 | | 16 |
| Navitus Bay Offshore Wind Project Platform 1 | 368 | MANN40 | | 26 |
| Peterborough | 130 | WALP40_EME | | 17 |
| Race Bank Wind Farm | 405 | WALP40_EME | | 17 |
| South Humber Bank | 80 | SHBA40 | | 15 |
| Spalding Energy Expansion | 920 | SPLN40 | | 17 |
| Thorpe Marsh | 1200 | THOM40 | | 16 |
| Auchencrosh (Interconnector CCT) | -215 | AUCH20 | | 10 |
| **Total** | **6639** | | | |

**Table 31 - 2018/19 Contracted TEC Changes**

| Project Name | TEC Change (MW) | Node 1 | Node 2 | Gen Zone |
|---|---|---|---|---|
| Abernedd Power Station | 414 | BAGB20 | | 21 |
| Allt Duine Wind Farm | 77 | ALLT10 | | 1 |
| Bad a Cheo Wind Farm | 30 | MYBS1Q | MYBS1R | 1 |
| Beatrice Wind Farm | 380 | BLHI40 | | 1 |
| Benbrack & Quantans Hill | 72 | KEON1Q | KEON1R | 11 |
| Codling Park Wind Farm | 1000 | PENT40 | | 19 |
| Coryton | -96 | COSO40 | | 24 |
| Costa Head and Brough Head | 8 | THSO20 | | 1 |
| Crossburns Wind Farm | 99 | ERRO10 | | 5 |
| Dell Wind Farm | 42 | LAGG1Q | | 3 |
| Dogger Bank Platform 3 | 500 | CREB40 | | 15 |
| Duncansby Tidal Array | 30 | DOUN20 | | 1 |
| East Anglia 1 | 600 | BRFO40 | | 18 |
| East Anglia 1 | 600 | BRFO40 | | 18 |
| Firth of Forth Offshore Wind Farm 1A | 545 | TEAL20 | | 9 |
| Firth of Forth Offshore Wind Farm 1B | 530 | TEAL20 | | 9 |
| Gateway Energy Centre Power Station | 1096 | COSO40 | | 24 |
| Glen App Windfarm | 51 | AREC10 | | 10 |
| Glen Kyllachy Wind Farm | 49 | FAAR1Q | FAAR1R | 1 |
| Glenmorie Windfarm | 114 | FYRI10 | | 1 |
| Greenwire Wind Farm - Pentir | 1000 | PENT40 | | 19 |
| Halsary Wind Farm | 29 | MYBS1Q | MYBS1R | 1 |
| Inch Cape Offshore Wind Farm Platform 1 | 312 | COCK20 | | 11 |
| Inch Cape Offshore Wind Farm Platform 2 | 360 | COCK20 | | 11 |
| Knottingley Power Station | 1500 | EGGB40 | | 15 |
| Kype Muir | 100 | COAL10 | | 11 |
| Loch Hill Wind Farm | 27 | MARG10 | | 11 |
| Loch Urr | 84 | KEON1Q | KEON1R | 11 |
| Marex | 1500 | CONQ40 | | 16 |
| Marwick Head Wave Farm | 9 | DOUN20 | | 1 |
| MeyGen Tidal | 15 | MEYG10 | | 1 |
| Middle Muir Wind Farm | 51 | COAL10 | | 11 |
| Millenderdale Wind Farm | 21 | MAHI20 | | 10 |
| Minnygap | 25 | MOFF10 | | 9 |
| Moray Firth Offshore Wind Farm | 504 | PEHE20 | | 2 |
| Navitus Bay Offshore Wind Project Platform 2 | 368 | MANN40 | | 26 |
| Sallachy Wind Farm | 66 | SALA10 | | 1 |
| South Kyle | 165 | NECU10 | | 10 |
| Spalding | -255 | SPLN40 | | 17 |
| Spittal Hill Wind Farm | 21 | BLHI20 | | 1 |
| Stronelairg | 241 | GLDO1G | | 3 |
| Tidal Lagoon | 320 | BAGB20 | | 21 |
| Tom Na Clach | 75 | TOMN10 | | 1 |
| Trafford Power - Stage 1 | 1882 | CARR40 | | 16 |

| Project Name | TEC Change (MW) | Node 1 | Node 2 | Gen Zone |
|---|---|---|---|---|
| Tralorg Wind Farm | 20 | MAHI20 | | 10 |
| Triton Knoll Offshore Wind Farm 1 | 200 | BICF4A | BICF4B | 16 |
| Viking Wind Farm | 412 | BLHI20 | | 1 |
| Windy Standard III Wind Farm | 44 | DUNH1Q | | 10 |
| Belgium Interconnector | 1000 | CANT40 | | 24 |
| **Total** | **16236** | | | |

**Table 32 - 2019/20 Contracted TEC Changes**

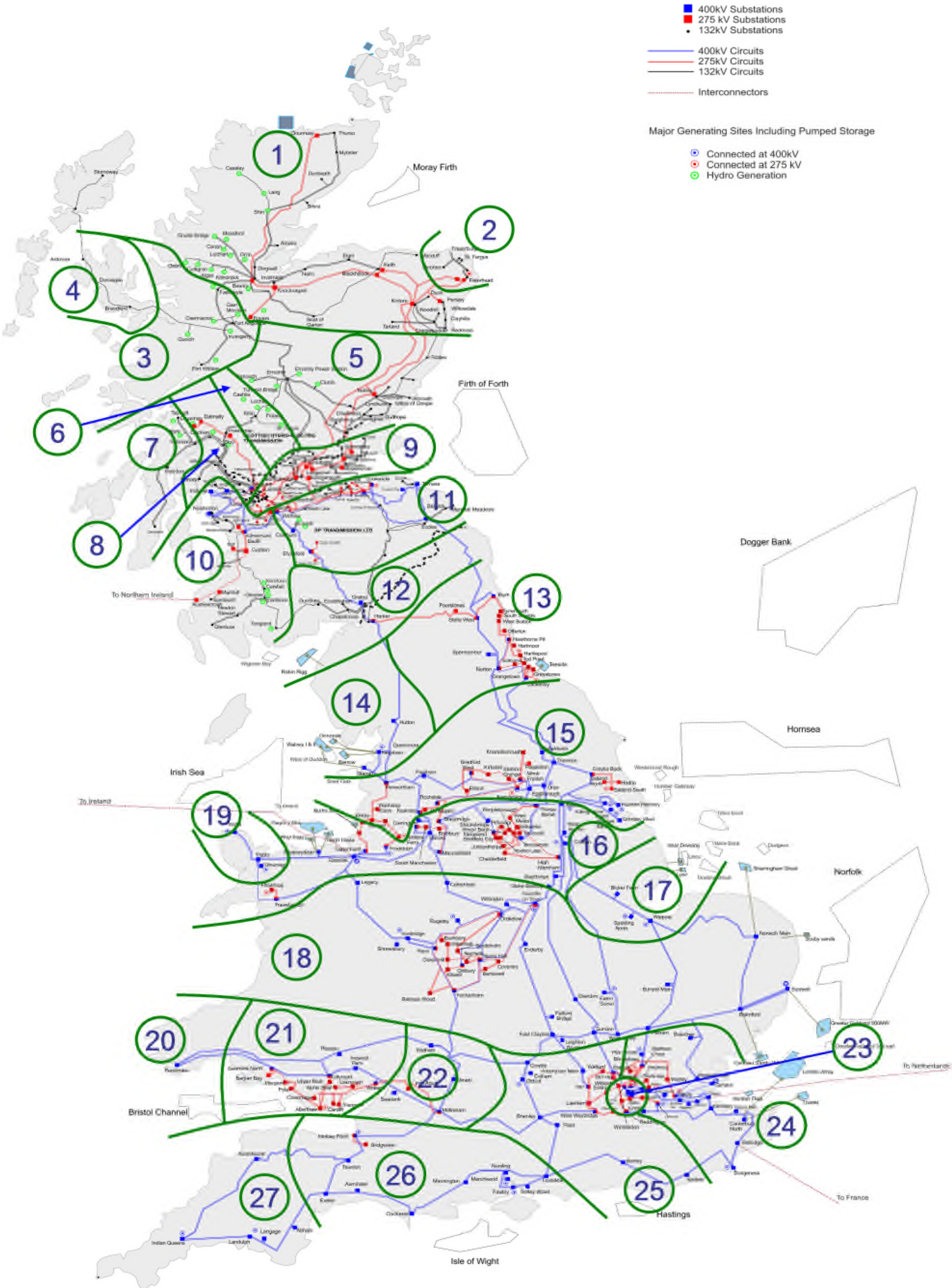
| Project Name | TEC Change (MW) | Node 1 | Node 2 | Gen Zone |
|---|---|---|---|---|
| Beatrice Wind Farm | 264 | BLHI40 | | 1 |
| Cantick Head | 30 | DOUN20 | | 1 |
| Carnedd Wen Wind Farm | 150 | CANW40 | | 18 |
| Costa Head and Brough Head | 10 | THSO20 | | 1 |
| Cumberhead | 99 | COAL10 | | 11 |
| Dogger Bank Platform 1 | 500 | CREB40 | | 15 |
| Dogger Bank Platform 2 | 500 | CREB40 | | 15 |
| Dogger Bank Platform 3 | 500 | CREB40 | | 15 |
| Dogger Bank Platform 4 | 500 | CREB40 | | 15 |
| Dogger Bank Platform 5 | 500 | CREB40 | | 15 |
| Druim Leathann | 39 | COUA10 | | 5 |
| Duncansby Tidal Array | 30 | DOUN20 | | 1 |
| Eishken Estate, Isle of Lewis | 133 | BEAU40 | | 1 |
| Glenmount Wind Farm | 73 | NECU10 | | 10 |
| Hatfield Power Station | 800 | THOM40 | | 16 |
| Hinkley Point C | 1670 | HINP40 | | 26 |
| Hirwaun Power Station | 299 | UPPB20 | | 21 |
| Hornsea Offshore Wind Farm - Platform 2A | 500 | HORN40 | | 15 |
| Inch Cape Offshore Wind Farm Platform 3 | 360 | COCK20 | | 11 |
| Kennoxhead Wind Farm | 60 | COAL10 | | 11 |
| Lag Na Greine Phase 1 | 10 | BEAU40 | | 1 |
| Marwick Head Wave Farm | 14 | DOUN20 | | 1 |
| MeyGen Tidal | 56 | MEYG10 | | 1 |
| Navitus Bay Offshore Wind Project Platform 3 | 368 | MANN40 | | 26 |
| Progress Power Station | 299 | BRFO40 | | 18 |
| Sizewell C | 1670 | SIZE40 | | 18 |
| South Muaitheabhal Wind Farm | 150 | BEAU40 | | 1 |
| Stornoway Wind Farm | 39 | BEAU40 | | 1 |
| Tilbury C | 1800 | TILB20 | | 24 |
| Triton Knoll Offshore Wind Farm 1 | 200 | BICF4A | BICF4B | 16 |
| Westray South | 60 | DOUN20 | | 1 |
| IFA2 Interconnector | 1000 | FAWL40 | | 26 |
| NSN Link | 1400 | BLYT4A | BLYT4B | 13 |
| **Total** | **14082** | | | |

## Appendix E : Zonal Summaries of Modelled Demand

**Table 33 - Zonal Summaries of Modelled Demand (MW)**

| Demand Zone | 2016/17 | Change from previous Year | 2017/18 | Change from previous Year | 2018/19 | Change from previous Year | 2019/20 | Change from previous Year |
|---|---|---|---|---|---|---|---|---|
| 1 | 896.39 | 30.96 | 906.55 | 10.16 | 893.93 | -12.61 | 915.84 | 21.91 |
| 2 | 3842.36 | -23.61 | 3820.11 | -22.25 | 3801.07 | -19.04 | 3802.18 | 1.11 |
| 3 | 2936.97 | 16.32 | 2952.17 | 15.20 | 2965.49 | 13.32 | 2992.34 | 26.84 |
| 4 | 4151.53 | 60.32 | 4194.16 | 42.63 | 4229.44 | 35.28 | 4273.60 | 44.16 |
| 5 | 4889.18 | 25.16 | 4915.82 | 26.64 | 4941.98 | 26.15 | 4996.08 | 54.10 |
| 6 | 2698.88 | 10.69 | 2709.30 | 10.42 | 2720.67 | 11.38 | 2826.19 | 105.51 |
| 7 | 5300.70 | 31.70 | 5349.40 | 48.70 | 5379.00 | 29.60 | 5490.80 | 111.80 |
| 8 | 4527.54 | 15.70 | 4535.74 | 8.20 | 4551.24 | 15.50 | 4619.54 | 68.30 |
| 9 | 6268.01 | 62.60 | 6334.93 | 66.92 | 6389.77 | 54.84 | 6436.22 | 46.45 |
| 10 | 1994.58 | 1.23 | 1995.48 | 0.91 | 1996.27 | 0.78 | 2004.61 | 8.35 |
| 11 | 3882.19 | 31.28 | 3893.16 | 10.97 | 3905.41 | 12.25 | 3917.70 | 12.29 |
| 12 | 5514.63 | 25.89 | 5632.41 | 117.78 | 5729.64 | 97.23 | 5820.09 | 90.46 |
| 13 | 6279.21 | 83.85 | 6342.22 | 63.01 | 6407.99 | 65.76 | 6466.73 | 58.75 |
| 14 | 2934.69 | 12.82 | 2947.66 | 12.97 | 2969.48 | 21.82 | 3001.36 | 31.88 |
| **Total** | **56116.86** | **384.92** | **56529.12** | **412.26** | **56881.37** | **352.26** | **57563.28** | **681.91** |

# Appendix F : Generation Zone Map



# Appendix G : Demand Zone Map