Five-Year Forecast Of TNUoS Tariffs For 2018/19 to 2022/23

November 2017

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This information paper provides National Grid's Five-Year Forecast of Transmission Network Use of System (TNUoS) tariffs for 2018/19 to 2022/23.

November 2017

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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.

Executive Summary

This document contains our five-year forecast of the Transmission Network Use of System (TNUoS) tariffs for the years 2018/19 to 2022/23. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.

The publication of the forecast has been brought forward to provide insight in to the effect of the multiple modifications to the charging methodologies taking effect from 1 April 2018.

Methodology and approach

The charging methodology used in this report is defined in Section 14 of the CUSC as approved for 1 April 2018. Since our last five-year forecast modifications CMP264/265[1], CMP268, CMP282 and CMP283 have been approved and are implemented in this report.

Modification CMP261 was rejected by the Authority. No changes have been made to the existing methodology for calculating the G/D split in this report.

Modification CMP251 is awaiting an Authority decision, expected in December, and may impact tariffs for 2018/19. No changes have been made to the methodology arising from this modification proposal.

Further modifications may affect tariffs in future years and details of other modification can be found in Appendix A and on the National Grid website[2].

The general approach taken in this forecast is to use the latest view of all the data that is available, and where needed assume that users act in an economically rational way.

The last two years of this forecast, 2021/22 and 2022/23, will be in the new RIIO-T2 price control period for onshore transmission owners. There are various elements of the charging methodology that are due to be revised at the start of each price control, based on data from the new price control. Our assumptions in this forecast are listed in the report.

Demand tariffs

Demand tariffs increase each year over the five-year forecast period. This is due to a slightly declining charging base for HH and NHH tariffs, and increasing proportion of total revenue being recovered

[1] Ofgem has been served with a claim for judicial review concerning its decision to approve WACM4 of CUSC modifications CMP264/265. As stated on their website: "Ofgem's decision to approve WACM4 of CUSC modifications CMP264 and CMP265 stands unless quashed by the court". *https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators*

[2] *https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code*

through demand tariffs, due to the cap on generation tariffs. In 2018/19 the average gross HH demand tariff is £45.81/kW rising to £62.34/kW in 2022/23. The average NHH demand tariff increases from 6.16p/kWh to 8.63p/kWh.

We forecast that system gross peak will fall from 52.5GW in 2018/19 to 49.8GW in 2022/23. In the same period, we expect HH demand to fall from 19.8GW to 18.6GW, and NHH demand to fall from 24.2TWh to 22.2TWh.

We have also assumed that there is no significant shift in volumes between those demand customers charged on a half-hourly basis and those charged on a non-half-hourly basis.

The Embedded Export Tariff changes significantly in the next three years, as the value of the phased residual is reduced from £29.36/kW in 2018/19, to £14.65/kW in 2019/10 and zero in subsequent years. We forecast the volumes of generation receiving the Embedded Export Tariff to be broadly flat around 6GW from 2019/20 onward. Thus, the total value paid out through the Embedded Export Tariff reduces from £198m in 2018/19, to £16m in 2020/21 and is then broadly flat.

Generation tariffs

Generation tariffs have been set to recover a diminishing amount of revenue over the five-year period to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010 by following the current charging methodology. This is due both to the decreasing forecast of transmission connected generation output (in TWh), and an increase in the generation charging base from 73.1GW in 2018/19 to 94.1GW in 2022/23. The generation residual decreases from -£2.33 in 2018/19 to -£7.28 in 2022/23. The average generation tariff falls from £5.74/kW in 2018/19 to £4.34/kW in 2022/23.

Total revenues to be recovered

Total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges is forecast to be £2,968.4m in 2019/20, rising to £3,478.4m in 2022/23.

This covers allowed revenue for the onshore Transmission Owners (National Grid, Scottish Power Transmission, Scottish Hydro Electricity Transmission), the Offshore Transmission Owners, the Interconnector Cap & Floor regime, and some smaller schemes.

Our assumptions about revenue in the RIIO-T2 price control period are detailed in the report.

Drivers of changes to the five-year forecast

Changes to these forecast tariffs over the five-year period have predominantly been influenced by:

- CMP282 changes the way that demand at exporting network nodes is calculated, particularly reducing demand tariffs in zone 1.
- Revenue to be recovered increases by £800m over the five-years, which increases the amount to be collected from demand.
- A steady decrease in forecasted generation output reduces generation tariffs due to €2.50/MWh limit on generation tariffs.
- There are increases in generation volumes particularly in Scotland, including new circuits and generation on the Western Isles, Orkney and Shetland, which increase some generation tariffs.

Next forecast

Our next forecast of 2018/19 TNUoS tariffs will be our Draft tariffs in December 2017, followed by Final tariffs in January 2018. These tariffs will reflect the latest methodology of the CUSC at the time.

During 2018, we will produce quarterly updates of 2019/20 TNUoS tariffs. Our next five-year forecast is expected to be published in Summer 2018. The timetable for publications for 2019/20 tariffs will be published in early 2018.

Feedback

This is the first five-year forecast in our new report format, which has been redesigned to be easier to navigate and read for all interested parties. We welcome feedback on any aspect of this document and the tariff setting processes. Do let us know if you have any further suggestions as to how we can better work with you to improve the tariff forecasting process, if you have any questions on this document or whether you still welcome webinar sessions following each forecast.

Charging methodology and approach for the five-year forecast

Modelling approach

The report contains new forecasts for TNUoS tariffs for 2019/20 until 2022/23.

Tariffs for 2018/19 have not been updated since the October Forecast, but are included here for reference. 2018/19 tariffs will next be updated in our December Draft tariff publications.

The general approach taken in this forecast is to use the latest view of all the data that is available, and where needed assume that users act in an economically rational way.

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.

Changes to the methodology (modifications approved since the last five-year forecast)

The methodology used in the calculation of these charges is the methodology in Section 14 of the CUSC. The baseline methodology is taken to be that as of 29th November 2017, expected to be in place on 1 April 2018.

Since the last five-year forecast, there have been several modifications approved. These have been implemented in this report:

- **CMP264/265** which introduced gross charging for HH demand and an explicit Embedded Export Tariff for HH export volumes;
- **CMP268** which introduces a different category of charges for 'conventional carbon' generation;
- **CMP282** which changes the calculation of the demand locational tariff which results in the Northern Scotland tariff being lower than previously forecast; and
- **CMP283** which introduces revenues associated with interconnector cap and floors in to the maximum allowed revenue. Other modifications which are awaiting decision, or apply to future years have not been reflected in the tariffs.

Modification **CMP261** (Ensuring the TNUoS paid by generators in 2015/16 is in compliance with the €2.5/MWh annual limit) was rejected by Ofgem. This decision does not change the methodology. The existing methodology for the split of charges between generation and demand has been used in this forecast. Any changes to the allocation of TNUoS between generation and demand will need to be taken forward as a modification to the CUSC

There are various other modifications being considered by the CUSC Panel which may affect tariffs from 2018/19 onwards. Please refer to Appendix A or https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code for more information on these modifications.

Key changes to input data

All key inputs to the tariffs have been revised in this forecast for tariffs for 2019/20 until 2022/23.

Factors affecting all tariffs

- The changes in the methodology as described above.
- Latest view of RPI

Factors affecting locational elements of tariffs

- The circuits and lines have been updated based on the latest Electricity Ten Year Statement
- The contracted TEC of connected generation has been taken from the 31 October 2017 version of the TEC register.
- Demand data provided under the Grid Code, which includes week 24 demand forecast data provided by the Distribution Network Operators (DNO), forecasts of demand at directly connected demand sites such as steelworks and railways and the effect of some embedded generation; and
- Latest view on timing of asset transfer of offshore transmission assets to OFTOs, this impacts the date at which offshore local tariffs are expected to be triggered for offshore generators. It also revises the forecast of revenues to the paid to the OFTOs.

Factors affecting residual elements of tariffs

- Our best view of generation has been taken based on the 31 October 2017 version of the TEC register, and our latest intelligence.
- Latest calculated ALFs for the 2018/19 charging year, used throughout.
- Our view of chargeable demand has been created from our in-house Monte Carlo demand model.
- Latest view of forecast generation quantity, and the latest OBR forecast of exchange rates to form the total amount of revenue to be recovered from generation.
- A forecast of total revenue to be recovered.

The licence condition, C13, for the small generator discount expires on 31 March 2019. Therefore, we have not included any calculation of the small generator discount beyond 2018/19 tariffs.

RIIO-T2 impact on TNUoS tariffs and revenue assumptions

At the start of the next onshore price-control period in April 2021, the charging methodology requires various aspects of the TNUoS methodology to be revised and updated based on data from the new price-control period. The key components which need to be addressed at the price-control, and how they are being treated in this forecast are outlined in the following table.

Table 1 – RIIO-T2 revenue assumptions

Component	Description	Assumptions for 2021/22 and 2022/23
Maximum Allowed Revenue	The MAR for onshore TOs in the new price control period will be determined during the negotiations up to the start of the price control period.	**Our assumption in these tariffs is that MAR increases with RPI for each of the years in the new price control period.**
Generation zones	There are currently 27 generation zones. At the start of the next price control, there is a requirement to rezone to ensure the spread of nodal prices within a zone is +/- £1/kW. Preliminary analysis[3] in 2016 suggests that more than forty zones may be required to achieve this spread by the next price control.	**Our assumption in these tariffs is that the number of generation zones remains at 27.** We are also considering whether a change needs to be made to the charging methodology to provide greater stability in the number of charging zones.
Expansion Factor and Constants	The expansion factor and expansion constants need to be recalculated at the start of RIIO-T2 based on updated business plans and costs of investments. The expansion constant represents the cost of moving 1MW, 1km using 400kV OHL line. The expansion factors represent how many times more expensive moving 1MW, 1km is using different voltages and types of circuit.	**Our assumption in these tariffs is that the expansion constant continues to increase by RPI, and that the expansion factors are unchanged.**
Security Factor	The security factor is currently 1.8. This will be recalculated at start of the price-control period.	**Our assumption in these tariffs is the security factor remains as 1.8.**
Offshore tariffs	The elements for the Offshore tariffs will be recalculated at start of the price control, based on updated forecasts of OFTO revenue, and adjusting for differences in actual OFTO revenue to forecast revenue in RIIO-T1.	**Our assumption in these tariffs is that Offshore tariffs increase by RPI.**
Avoided GSP Infrastructure Credit	The AGIC is a component of the Embedded Export Tariff, paid to 'exporting demand' at the time of Triad. It will be recalculated based on up to 20 schemes from the RIIO-T2 price-control period.	**Our assumption in these tariffs is that the AGIC increases by RPI.**

[3] *May 2016 TCMF (page 16 of slide pack):* https://www.nationalgrid.com/sites/default/files/documents/8589935152-TCMF%20and%20CISG%20slidepack%2015th%20May%202016%20v1.0.pdf

Demand tariffs

Tables 3, 4 and 5 show demand tariffs for Half-Hourly, Embedded Export and Non-Half-Hour metered demand. The HH and NHH tariffs include the effect of the small generator discount for 2018/19 only.

Table 2 – Summary of average demand tariffs

HH Tariffs	2018/19	2019/20	2020/21	2021/22	2022/23
Average Tariff (£/kW)	45.81	51.16	54.45	59.12	62.34
Residual (£/kW)	46.90	52.13	55.54	60.36	63.65
EET	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
Average Tariff (£/kW)	25.36	13.28	2.69	3.11	2.98
Phased residual (£/kW)	29.36	14.65	-	-	-
AGIC (£/kW)	3.22	3.32	3.42	3.52	3.62
Total Credit (£m)	165.21	81.56	16.05	18.64	17.81
NHH Tariffs	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
Average (p/kWh)	6.16	6.95	7.38	8.06	8.63

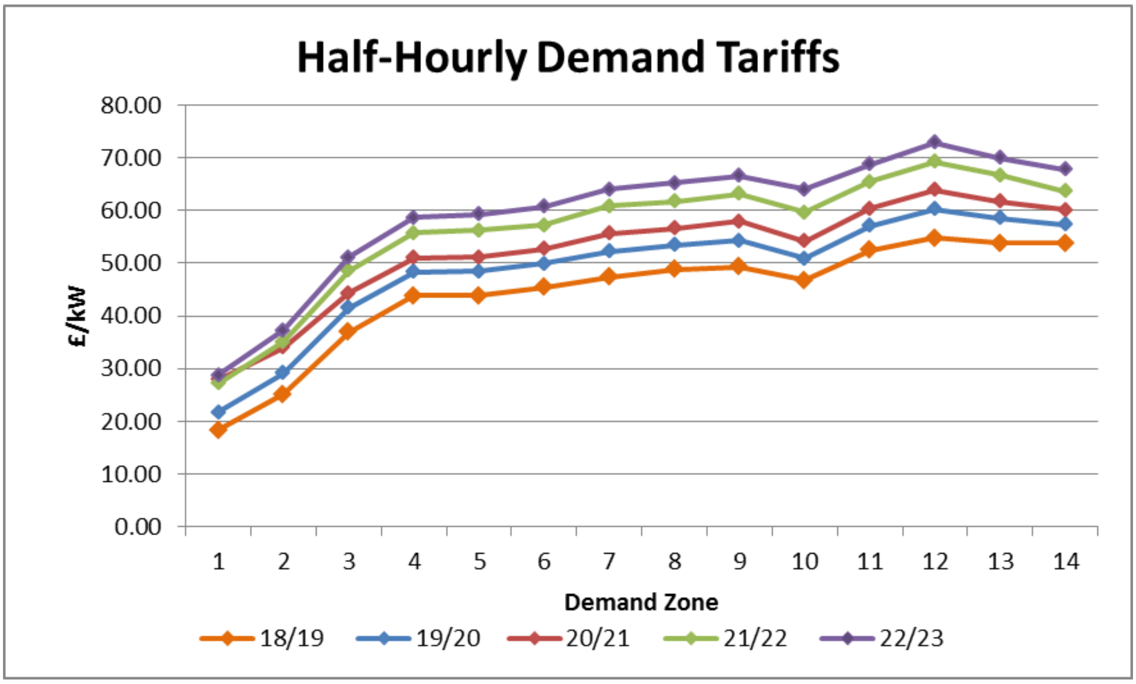
Gross Half-Hourly demand tariffs

Table 3 - Gross Half-Hourly demand tariffs by demand zone

Zone	Zone Name	18/19 (£/kW)	19/20 (£/kW)	20/21 (£/kW)	21/22 (£/kW)	22/23 (£/kW)
1	Northern Scotland	18.351267	21.687374	27.940282	27.187424	28.809173
2	Southern Scotland	25.131650	29.168681	33.986588	35.128061	37.323966
3	Northern	36.924540	41.500763	44.309281	48.634091	51.195440
4	North West	43.866489	48.398977	51.006613	55.789633	58.733362
5	Yorkshire	43.831984	48.473350	51.152962	56.246633	59.308627
6	N Wales & Mersey	45.433760	49.966859	52.659197	57.266236	60.703099
7	East Midlands	47.390135	52.258221	55.587333	60.830441	64.070284
8	Midlands	48.848501	53.495056	56.560706	61.714491	65.186039
9	Eastern	49.367285	54.333811	57.912627	63.165971	66.513740
10	South Wales	46.780645	50.889819	54.179047	59.636314	64.012906
11	South East	52.515613	57.105050	60.338076	65.506188	68.723159
12	London	54.838363	60.210439	63.920081	69.302364	72.887316
13	Southern	53.798692	58.553985	61.672206	66.744660	69.942437
14	South Western	53.859062	57.299753	60.084987	63.714857	67.731541
	Includes small generator tariff of:					
		0.595039	-	-	-	-

The breakdown of the locational and residual components of these tariffs is shown in Appendix B.

Figure 1 – Gross Half-Hourly demand tariffs by demand zone



From 2018/19 the HH demand tariff is now based on gross chargeable demand following the implementation of CMP264/265. Demand tariffs are also affected by the implementation of CMP282 reducing the demand locational tariff in Northern Scotland (zone 1).

Overall all zones follow the same pattern over the 5 year period, where the yearly increase in the tariffs and the residual can be attributed to an increase in revenue and offset by the reduction in credit for the Embedded Export Tariff. The increase in revenue recovered from demand is caused by two factors – the increasing total revenue, and an increase percentage of this to be recovered from demand due to the €2.50/MWh limit on average generation tariffs.

A steady decline in chargeable system peak and gross HH demand (full zonal forecasts are detailed in Appendix F) and changes in the expected location of generation (please see the generation tariffs section later in this document) have also contributed to this general increase in tariffs.

Zones 12 and 13 encompass London/Southern England and have a higher volume of HH demand in them than other zones. In year-on-year forecasts they see increases in HH demand and locational HH tariffs. This results in a greater volume of revenue for zone 12 and zone 13 being recovered from HH customers and less from NHH compared to other zones.

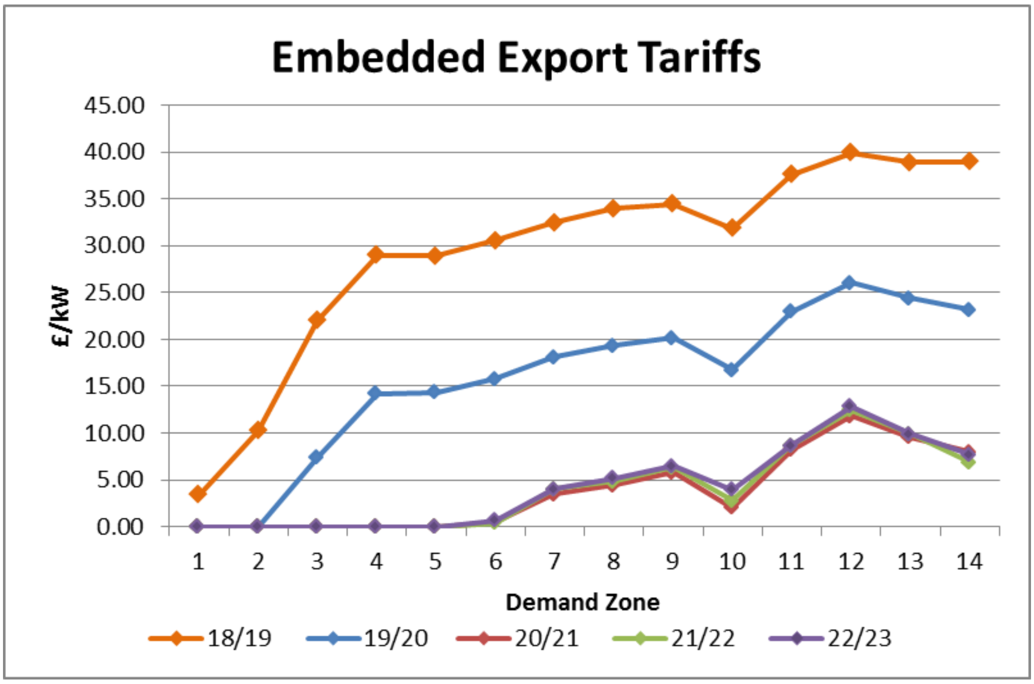
Embedded Export Tariff (EET)

Export volumes from embedded generation at Triad, are credited through the Embedded Export Tariff (EET). The value of the tariff will reduce in steps from 2018/19, through 2019/20 to 2020/21 as the phased residual is reduced.

Table 4 – Embedded Export Tariff

Zone	Zone Name	18/19 (£/kW)	19/20 (£/kW)	20/21 (£/kW)	21/22 (£/kW)	22/23 (£/kW)
1	Northern Scotland	3.435934	0.000000	0.000000	0.000000	0.000000
2	Southern Scotland	10.216317	0.000000	0.000000	0.000000	0.000000
3	Northern	22.009206	7.336788	0.000000	0.000000	0.000000
4	North West	28.951155	14.235002	0.000000	0.000000	0.000000
5	Yorkshire	28.916651	14.309375	0.000000	0.000000	0.000000
6	N Wales & Mersey	30.518427	15.802884	0.539883	0.422549	0.672014
7	East Midlands	32.474802	18.094246	3.468019	3.986754	4.039199
8	Midlands	33.933167	19.331081	4.441392	4.870804	5.154954
9	Eastern	34.451952	20.169836	5.793313	6.322284	6.482655
10	South Wales	31.865312	16.725844	2.059733	2.792627	3.981821
11	South East	37.600280	22.941075	8.218762	8.662501	8.692074
12	London	39.923029	26.046464	11.800767	12.458677	12.856231
13	Southern	38.883359	24.390010	9.552892	9.900973	9.911352
14	South Western	38.943729	23.135778	7.965673	6.871170	7.700456
	These tariffs include:					
	Phased residual (£/kW)	29.360000	14.650000	-	-	-
	AGIC (£/kW)	3.220000	3.320000	3.420000	3.520000	3.620000

Figure 2 – Embedded Export Tariff



The Embedded Export Tariff uses the locational demand elements with the addition of a phased residual (in 2018/19 and 2019/20), and the Avoided GSP Infrastructure Credit (AGIC). The locational elements of the EET are the same as the gross HH demand tariffs and are shown in Appendix B. The value of the EET is floored at zero to avoid negative tariffs.

As outlined in the EET summary above the phased residual will reduce to £0/kW from 2020/21 whereas the AGIC will increase each year in line with RPI until the next price control. This will result in a significant decrease in tariffs across all zones. From 2019/20 the EET will be £0/kW in zones 1 and 2, due to the negative local tariff which is not offset by the AGIC and the phased residual. From 2021/22 onwards the EET is expected to be zero in zones 1 to 5.

The volume metered embedded generation exports produced at triad by suppliers and embedded generators (<100MW) will determine the amount paid through the EET. The money to be paid out through the EET will be recovered through demand tariffs, which will affect the price of HH and NHH demand tariffs.

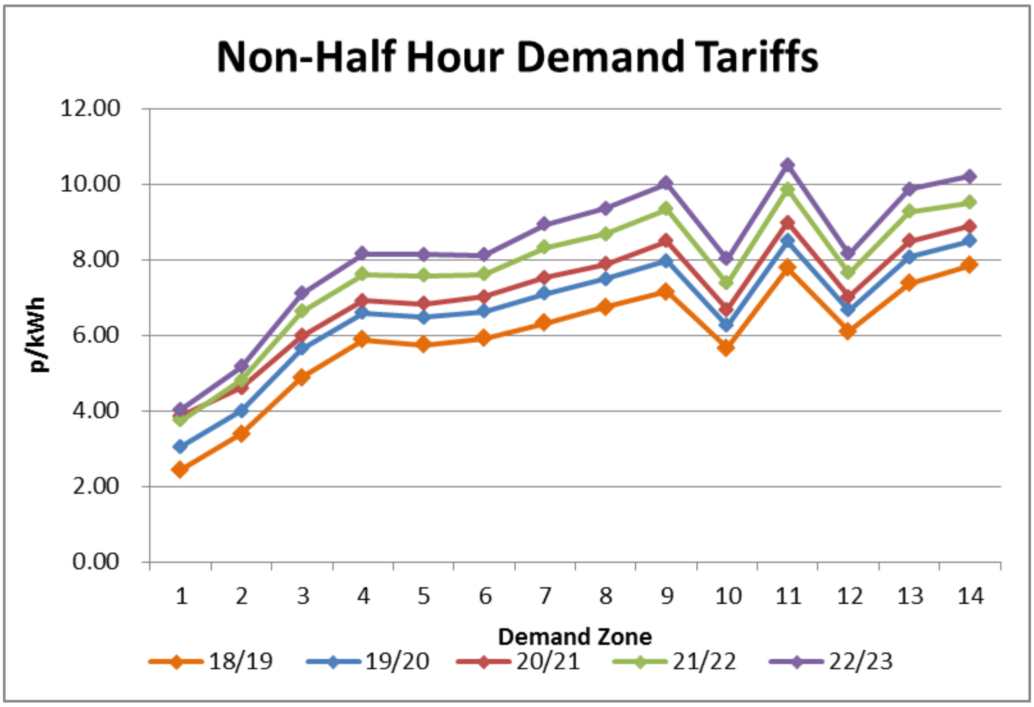
The total revenue credited for embedded exports is forecast to be £165m in 2018/19, falling to £82m in 2019/20 and £16m in 2020/21 (due to the reducing value of the phased residual). It then remains broadly flat.

NHH demand tariffs

Table 5 - NHH demand tariffs

Zone	Zone Name	18/19 (p/kWh)	19/20 (p/kWh)	20/21 (p/kWh)	21/22 (p/kWh)	22/23 (p/kWh)
1	Northern Scotland	2.448517	3.048118	3.867796	3.742820	4.037926
2	Southern Scotland	3.387469	4.006678	4.618586	4.823422	5.169576
3	Northern	4.881137	5.638348	5.987687	6.626749	7.101304
4	North West	5.890076	6.601478	6.913044	7.605573	8.154142
5	Yorkshire	5.753555	6.469700	6.836467	7.572633	8.140498
6	N Wales & Mersey	5.918690	6.622207	7.012542	7.604904	8.121867
7	East Midlands	6.330218	7.099223	7.533078	8.321400	8.926539
8	Midlands	6.739605	7.495568	7.888153	8.687026	9.350948
9	Eastern	7.148778	7.973654	8.490090	9.347633	10.014407
10	South Wales	5.670893	6.257491	6.675243	7.382311	8.012046
11	South East	7.773210	8.497337	8.986791	9.857695	10.509184
12	London	6.098639	6.669645	7.025759	7.638670	8.157699
13	Southern	7.369393	8.066432	8.493484	9.280549	9.868692
14	South Western	7.850599	8.498394	8.888054	9.513791	10.205668
	Includes small generator tariff of:					
		0.080403	-	-	-	-

Figure 3 - NHH demand tariffs



From 2018/19 the methodology for NHH demand tariffs remains the same following the demand TNUoS changes under CMP264/265, except the revenue to be recovered per Zone is calculated after calculating the amounts to be recovered from gross HH tariffs and paid out through the EET.

The NHH tariffs have gradually increased by between 0.3 - 0.8p/kWh for each Zone following the same pattern over the 5 year period, this trend aligns with the steady decline in chargeable zonal Non-Half-Hourly volumes where the smaller proportion of volume (overall reduction of 1.9TWh for the 5 year period) would result in lower tariffs.

Based on changing circuit flows on the network, the only NHH tariff reduction over the 5-year period is in zone 1 where the tariff reduces by 0.125p/kWh in 2021/22 compared to 2020/21.

The variations year on year across the zones are also attributable to changes in our demand forecast modelling approach which now more accurately captures variations in embedded renewable generation across GB. This has been further enhanced by using historical metered demand and embedded export data from Elexon through BSC modifications P348/349 following CMP264/265.

Generation tariffs

This section summarises forecasted generation tariffs for 2018/19 to 2022/23.

For details of the component of generation tariffs please refer to the Background to TNuoS Charging section later in this report.

The total revenue paid by generators results in average tariffs of £5.74/kW in 2018/19, then £6.01/kW in 2019/20, £5.47/kW on 2020/21, £4.96/kW in 2021/22, and £4.34/kW in 2022/23.

Generation wider tariffs

Below are the tariffs for each of the five years between 2018/19 and 2022/23 for the generation wider tariffs.

Under the current methodology each generator has its own load factor as listed in Appendix C, which has been updated and details the values that will be used for 2018/19 tariffs.

The Conventional Carbon 80%, Conventional Low Carbon 80%, and Intermittent 40% load factors used in these tables are for illustration and comparison only.

Table 6 – Generation wider tariffs 2018/19

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.241534	19.713585	15.377881	-2.337478	27.977229	31.052805	20.925837
2	East Aberdeenshire	4.493625	10.286068	15.377881	-2.337478	22.687306	25.762882	17.154830
3	Western Highlands	1.718980	18.661795	15.377881	-2.337478	26.613242	29.688818	20.505120
4	Skye and Lochalsh	1.734185	18.661795	21.196840	-2.337478	31.283614	35.522982	26.324080
5	Eastern Grampian and Tayside	2.733254	15.780106	14.954896	-2.337478	24.983777	27.974756	18.929460
6	Central Grampian	3.471545	14.914731	14.666316	-2.337478	24.798904	27.732168	18.294730
7	Argyll	3.139357	11.744597	24.331456	-2.337478	29.662722	34.529013	26.691817
8	The Trossachs	3.485394	11.744597	13.541154	-2.337478	21.376518	24.084748	15.901515
9	Stirlingshire and Fife	2.070737	8.812135	12.887017	-2.337478	17.092580	19.669983	14.074393
10	South West Scotland	2.393557	9.503815	13.011889	-2.337478	18.068642	20.671020	14.475937
11	Lothian and Borders	3.458965	9.503815	7.441956	-2.337478	14.678104	16.166495	8.906004
12	Solway and Cheviot	1.872723	5.515458	7.419831	-2.337478	9.883476	11.367442	7.288536
13	North East England	3.655606	3.273478	4.026336	-2.337478	7.157978	7.963245	2.998249
14	North Lancashire and The Lakes	1.456718	3.273478	2.570818	-2.337478	3.794677	4.308840	1.542731
15	South Lancashire, Yorkshire and Humber	4.255805	1.224412		-2.337478	2.897857	2.897857	-1.847713
16	North Midlands and North Wales	3.343571	-0.250677		-2.337478	0.805551	0.805551	-2.437749
17	South Lincolnshire and North Norfolk	2.090057	-0.187801		-2.337478	-0.397662	-0.397662	-2.412598
18	Mid Wales and The Midlands	1.213214	0.109926		-2.337478	-1.036324	-1.036324	-2.293508
19	Anglesey and Snowdon	3.582852	0.177756		-2.337478	1.387578	1.387578	-2.266376
20	Pembrokeshire	8.301451	-4.582854		-2.337478	2.297689	2.297689	-4.170620
21	South Wales & Gloucester	5.288730	-4.667698		-2.337478	-0.782906	-0.782906	-4.204557
22	Cotswold	2.164427	2.332048	-7.067750	-2.337478	-3.961612	-5.375162	-8.472408
23	Central London	-5.574745	2.332048	-6.261715	-2.337478	-11.055956	-12.308299	-7.666373
24	Essex and Kent	-3.954549	2.332048		-2.337478	-4.426389	-4.426389	-1.404659
25	Oxfordshire, Surrey and Sussex	-1.408390	-2.526834		-2.337478	-5.767335	-5.767335	-3.348212
26	Somerset and Wessex	-2.157555	-4.571951		-2.337478	-8.152594	-8.152594	-4.166259
27	West Devon and Cornwall	-1.564246	-6.853369		-2.337478	-9.384419	-9.384419	-5.078826

Table 7 – Generation wider tariffs 2019/20

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.568881	20.271427	14.677552	-3.846092	26.681972	29.617483	18.940031
2	East Aberdeenshire	4.717553	12.388241	14.677552	-3.846092	22.524095	25.459606	15.786756
3	Western Highlands	2.011498	18.903177	14.677552	-3.846092	25.029989	27.965500	18.392731
4	Skye and Lochalsh	-4.107693	18.903177	14.571078	-3.846092	18.825619	21.739835	18.286257
5	Eastern Grampian and Tayside	3.076564	16.569280	14.323154	-3.846092	23.944419	26.809050	17.104774
6	Central Grampian	4.086913	16.037324	14.143067	-3.846092	24.385134	27.213747	16.711905
7	Argyll	3.639863	12.904730	24.061851	-3.846092	29.367036	34.179406	25.377651
8	The Trossachs	4.051531	12.904730	13.015365	-3.846092	20.941515	23.544588	14.331165
9	Stirlingshire and Fife	2.221000	9.827513	12.316925	-3.846092	16.090458	18.553843	12.401838
10	South West Scotland	3.062281	10.638452	12.466307	-3.846092	17.699996	20.193258	12.875596
11	Lothian and Borders	3.544843	10.638452	6.737896	-3.846092	13.599829	14.947409	7.147185
12	Solway and Cheviot	1.851109	6.111135	7.137749	-3.846092	8.604124	10.031674	5.736111
13	North East England	3.949089	3.414337	3.702268	-3.846092	5.796281	6.536735	1.221911
14	North Lancashire and The Lakes	1.625569	3.414337	2.454512	-3.846092	2.474556	2.965459	-0.025845
15	South Lancashire, Yorkshire and Humber	4.472222	1.014435		-3.846092	1.437678	1.437678	-3.440318
16	North Midlands and North Wales	3.917429	-0.654214		-3.846092	-0.452034	-0.452034	-4.107778
17	South Lincolnshire and North Norfolk	2.178233	-0.511945		-3.846092	-2.077415	-2.077415	-4.050870
18	Mid Wales and The Midlands	1.280882	-0.336976		-3.846092	-2.834791	-2.834791	-3.980882
19	Anglesey and Snowdon	3.957857	-0.000569		-3.846092	0.111310	0.111310	-3.846320
20	Pembrokeshire	9.015669	-4.683069		-3.846092	1.423122	1.423122	-5.719320
21	South Wales & Gloucester	5.966658	-4.706772		-3.846092	-1.644852	-1.644852	-5.728801
22	Cotswold	2.786043	2.078439	-6.803028	-3.846092	-4.839720	-6.200326	-9.817744
23	Central London	-5.744459	2.078439	-6.473044	-3.846092	-13.106235	-14.400844	-9.487760
24	Essex and Kent	-4.061284	2.078439		-3.846092	-6.244625	-6.244625	-3.014716
25	Oxfordshire, Surrey and Sussex	-1.517060	-3.019666		-3.846092	-7.778885	-7.778885	-5.053958
26	Somerset and Wessex	-1.873110	-4.693029		-3.846092	-9.473625	-9.473625	-5.723304
27	West Devon and Cornwall	-0.305954	-6.107580		-3.846092	-9.038110	-9.038110	-6.289124

Table 8 – Generation wider tariffs 2020/21

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	1.657652	8.377912	25.860433	-5.081622	23.966706	29.138793	24.129976
2	East Aberdeenshire	0.653706	8.377912	19.712817	-5.081622	18.044667	21.987231	17.982360
3	Western Highlands	1.507953	7.891086	24.591553	-5.081622	22.412442	27.330753	22.666365
4	Skye and Lochalsh	-4.810078	7.891086	24.499779	-5.081622	16.020992	20.920948	22.574591
5	Eastern Grampian and Tayside	2.695284	7.262345	22.373661	-5.081622	21.322467	25.797199	20.196977
6	Central Grampian	2.834847	7.145540	21.854050	-5.081622	20.952897	25.323707	19.630644
7	Argyll	1.968702	6.402941	33.157558	-5.081622	28.535479	35.166991	30.637112
8	The Trossachs	2.789500	6.402941	18.471994	-5.081622	17.607826	21.302225	15.951548
9	Stirlingshire and Fife	1.253770	5.052376	16.109765	-5.081622	13.101861	16.323814	13.049093
10	South West Scotland	2.710447	5.929837	17.369136	-5.081622	16.268003	19.741831	14.659449
11	Lothian and Borders	4.268447	5.929837	11.267323	-5.081622	12.944553	15.198018	8.557636
12	Solway and Cheviot	2.970817	3.546167	9.687640	-5.081622	8.476241	10.413769	6.024485
13	North East England	5.028488	2.108579	4.774693	-5.081622	5.453484	6.408422	0.536503
14	North Lancashire and The Lakes	2.623221	2.108579	3.533122	-5.081622	2.054960	2.761584	-0.705068
15	South Lancashire, Yorkshire and Humber	5.476259	0.437564		-5.081622	0.744688	0.744688	-4.906596
16	North Midlands and North Wales	4.136991	-0.736273		-5.081622	-1.533649	-1.533649	-5.376131
17	South Lincolnshire and North Norfolk	2.087476	-0.436189		-5.081622	-3.343097	-3.343097	-5.256098
18	Mid Wales and The Midlands	1.370717	-0.259404		-5.081622	-3.918428	-3.918428	-5.185384
19	Anglesey and Snowdon	5.860673	-0.451700		-5.081622	0.417691	0.417691	-5.262302
20	Pembrokeshire	8.678361	-4.151134		-5.081622	0.275832	0.275832	-6.742076
21	South Wales & Gloucester	5.463698	-4.094581		-5.081622	-2.893589	-2.893589	-6.719454
22	Cotswold	2.151931	2.827082	-6.873936	-5.081622	-6.167174	-7.541961	-10.824725
23	Central London	-6.220811	2.827082	-7.097188	-5.081622	-14.718518	-16.137955	-11.047977
24	Essex and Kent	-4.705364	2.827082		-5.081622	-7.525320	-7.525320	-3.950789
25	Oxfordshire, Surrey and Sussex	-1.947140	-2.534591		-5.081622	-9.056435	-9.056435	-6.095458
26	Somerset and Wessex	-2.126256	-2.272979		-5.081622	-9.026261	-9.026261	-5.990814
27	West Devon and Cornwall	-0.689750	-4.760517		-5.081622	-9.579786	-9.579786	-6.985829

Table 9 – Generation wider tariffs 2021/22

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.702535	16.063087	22.897112	-6.971560	26.899134	31.478557	22.350787
2	East Aberdeenshire	3.639086	8.388712	22.897112	-6.971560	21.696185	26.275608	19.281037
3	Western Highlands	2.982087	14.722637	21.727198	-6.971560	25.170395	29.515835	20.644693
4	Skye and Lochalsh	-1.580419	14.722637	23.012263	-6.971560	21.635941	26.238394	21.929758
5	Eastern Grampian and Tayside	3.874338	12.684505	19.538913	-6.971560	22.681512	26.589295	17.641155
6	Central Grampian	4.587598	12.555103	19.369471	-6.971560	23.155697	27.029591	17.419952
7	Argyll	4.662823	10.560747	30.101326	-6.971560	30.220921	36.241187	27.354065
8	The Trossachs	4.543499	10.560747	16.715246	-6.971560	19.392733	22.735783	13.967985
9	Stirlingshire and Fife	3.080765	8.837944	15.012462	-6.971560	15.189530	18.192022	11.576080
10	South West Scotland	3.477087	9.062655	15.214889	-6.971560	15.927562	18.970540	11.868391
11	Lothian and Borders	3.550867	9.062655	8.723529	-6.971560	10.808254	12.552960	5.377031
12	Solway and Cheviot	2.910757	5.675678	8.117027	-6.971560	6.973361	8.596766	3.415738
13	North East England	4.543981	4.247626	4.959536	-6.971560	4.938151	5.930058	-0.312974
14	North Lancashire and The Lakes	2.665718	4.247626	1.727728	-6.971560	0.474441	0.819987	-3.544782
15	South Lancashire, Yorkshire and Humber	4.969943	0.687381		-6.971560	-1.451712	-1.451712	-6.696608
16	North Midlands and North Wales	4.050639	-0.864895		-6.971560	-3.612837	-3.612837	-7.317518
17	South Lincolnshire and North Norfolk	2.219743	-0.851624		-6.971560	-5.433116	-5.433116	-7.312210
18	Mid Wales and The Midlands	1.269052	-0.302736		-6.971560	-5.944697	-5.944697	-7.092654
19	Anglesey and Snowdon	4.533875	-0.144134		-6.971560	-2.552992	-2.552992	-7.029214
20	Pembrokeshire	8.690579	-4.666249		-6.971560	-2.013980	-2.013980	-8.838060
21	South Wales & Gloucester	5.340716	-4.625458		-6.971560	-5.331210	-5.331210	-8.821743
22	Cotswold	1.897778	2.585993	-7.175708	-6.971560	-8.745554	-10.180696	-13.112871
23	Central London	-6.382042	2.585993	-7.317701	-6.971560	-17.138968	-18.602509	-13.254864
24	Essex and Kent	-4.751707	2.585993		-6.971560	-9.654473	-9.654473	-5.937163
25	Oxfordshire, Surrey and Sussex	-1.945439	-2.742242		-6.971560	-11.110793	-11.110793	-8.068457
26	Somerset and Wessex	-1.533881	-1.975111		-6.971560	-10.085530	-10.085530	-7.761604
27	West Devon and Cornwall	0.170277	-3.377494		-6.971560	-9.503278	-9.503278	-8.322558

Table 10 – Generation wider tariffs 2022/23

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	4.979032	24.656424	16.563649	-7.275762	30.679328	33.992058	19.150457
2	East Aberdeenshire	2.952842	18.031942	16.563649	-7.275762	23.353553	26.666283	16.500664
3	Western Highlands	4.730641	19.716898	15.309438	-7.275762	25.475948	28.537835	15.920435
4	Skye and Lochalsh	-0.007930	19.716898	16.727305	-7.275762	21.871670	25.217131	17.338302
5	Eastern Grampian and Tayside	6.024060	16.383448	14.118893	-7.275762	23.150171	25.973949	13.396510
6	Central Grampian	4.909457	16.810935	14.323358	-7.275762	22.541129	25.405801	13.771970
7	Argyll	4.115796	14.469063	25.102486	-7.275762	28.497273	33.517770	23.614349
8	The Trossachs	3.864790	14.469063	13.177431	-7.275762	18.706223	21.341709	11.689294
9	Stirlingshire and Fife	3.846525	12.424957	12.354093	-7.275762	16.394003	18.864822	10.048314
10	South West Scotland	3.254826	12.454234	12.364964	-7.275762	15.834422	18.307415	10.070896
11	Lothian and Borders	4.361781	12.454234	6.169062	-7.275762	11.984656	13.218468	3.874994
12	Solway and Cheviot	3.589995	7.385361	6.858638	-7.275762	7.709432	9.081160	2.537020
13	North East England	5.090173	5.188999	4.325391	-7.275762	5.425923	6.291001	-0.874771
14	North Lancashire and The Lakes	3.013784	5.188999	0.855017	-7.275762	0.573235	0.744238	-4.345145
15	South Lancashire, Yorkshire and Humber	5.304899	0.621621		-7.275762	-1.473566	-1.473566	-7.027114
16	North Midlands and North Wales	4.324205	-0.793318		-7.275762	-3.586211	-3.586211	-7.593089
17	South Lincolnshire and North Norfolk	2.550757	-1.136528		-7.275762	-5.634227	-5.634227	-7.730373
18	Mid Wales and The Midlands	1.512238	-0.212223		-7.275762	-5.933302	-5.933302	-7.360651
19	Anglesey and Snowdon	4.571514	-0.308934		-7.275762	-2.951395	-2.951395	-7.399336
20	Pembrokeshire	7.607309	-4.608487		-7.275762	-3.355243	-3.355243	-9.119157
21	South Wales & Gloucester	4.360191	-4.265848		-7.275762	-6.328249	-6.328249	-8.982101
22	Cotswold	1.037538	2.755365	-6.697094	-7.275762	-9.391607	-10.731026	-12.870710
23	Central London	-6.271285	2.755365	-7.903462	-7.275762	-17.665525	-19.246217	-14.077078
24	Essex and Kent	-4.676313	2.755365		-7.275762	-9.747783	-9.747783	-6.173616
25	Oxfordshire, Surrey and Sussex	-2.808531	-1.654851		-7.275762	-11.408174	-11.408174	-7.937702
26	Somerset and Wessex	-1.843494	-1.319301		-7.275762	-10.174697	-10.174697	-7.803482
27	West Devon and Cornwall	-1.011278	-3.916724		-7.275762	-11.420419	-11.420419	-8.842452

Changes to tariffs over the five-year period

The following section provides a summary of how the wider generation tariffs change from 2018/19 to 2022/23, by comparing the example tariffs for Conventional Carbon generators with an ALF of 80%, Conventional Low Carbon generators with an ALF of 80%, and Intermittent generators with an ALF of 40%.

The classifications for different technology types are below:

Conventional Carbon	Conventional Low Carbon	Intermittent
Biomass CCGT/CHP Coal OCGT/Oil Pumped storage	Nuclear Hydro	Offshore wind Onshore wind Tidal

Table 11 – Comparison of Conventional Carbon (80%) tariffs

Wider Tariffs for a Conventional Carbon 80% Generator		2018/19	2019/20	2020/21	2021/22	2022/23
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	27.98	26.68	23.97	26.90	30.68
2	East Aberdeenshire	22.69	22.52	18.04	21.70	23.35
3	Western Highlands	26.61	25.03	22.41	25.17	25.48
4	Skye and Lochalsh	31.28	18.83	16.02	21.64	21.87
5	Eastern Grampian and Tayside	24.98	23.94	21.32	22.68	23.15
6	Central Grampian	24.80	24.39	20.95	23.16	22.54
7	Argyll	29.66	29.37	28.54	30.22	28.50
8	The Trossachs	21.38	20.94	17.61	19.39	18.71
9	Stirlingshire and Fife	17.09	16.09	13.10	15.19	16.39
10	South West Scotland	18.07	17.70	16.27	15.93	15.83
11	Lothian and Borders	14.68	13.60	12.94	10.81	11.98
12	Solway and Cheviot	9.88	8.60	8.48	6.97	7.71
13	North East England	7.16	5.80	5.45	4.94	5.43
14	North Lancashire and The Lakes	3.79	2.47	2.05	0.47	0.57
15	South Lancashire, Yorkshire and Humber	2.90	1.44	0.74	-1.45	-1.47
16	North Midlands and North Wales	0.81	-0.45	-1.53	-3.61	-3.59
17	South Lincolnshire and North Norfolk	-0.40	-2.08	-3.34	-5.43	-5.63
18	Mid Wales and The Midlands	-1.04	-2.83	-3.92	-5.94	-5.93
19	Anglesey and Snowdon	1.39	0.11	0.42	-2.55	-2.95
20	Pembrokeshire	2.30	1.42	0.28	-2.01	-3.36
21	South Wales & Gloucester	-0.78	-1.64	-2.89	-5.33	-6.33
22	Cotswold	-3.96	-4.84	-6.17	-8.75	-9.39
23	Central London	-11.06	-13.11	-14.72	-17.14	-17.67
24	Essex and Kent	-4.43	-6.24	-7.53	-9.65	-9.75
25	Oxfordshire, Surrey and Sussex	-5.77	-7.78	-9.06	-11.11	-11.41
26	Somerset and Wessex	-8.15	-9.47	-9.03	-10.09	-10.17
27	West Devon and Cornwall	-9.38	-9.04	-9.58	-9.50	-11.42

Figure 4 – Wider tariffs for a Conventional Carbon 90% generator

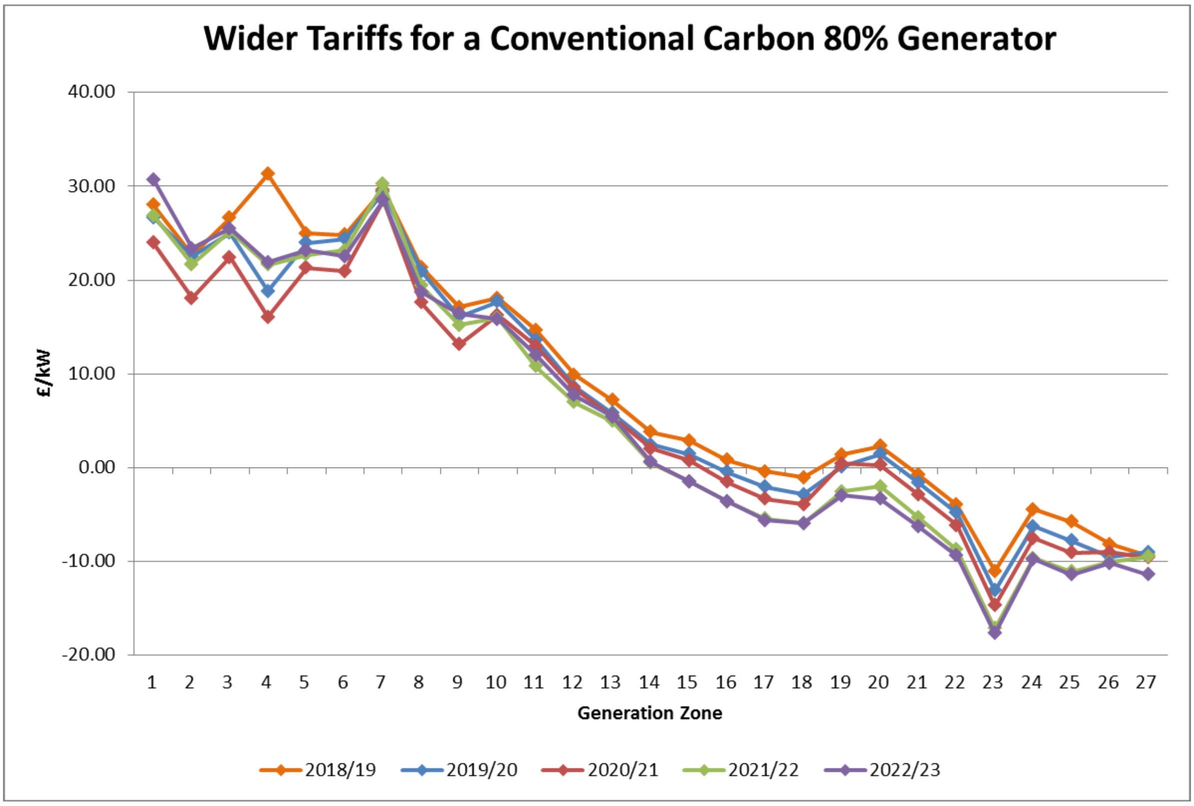


Table 12 – Comparison of Conventional Low Carbon (80%) tariffs

Wider Tariffs for a Conventional Low Carbon 80% Generator		2018/19	2019/20	2020/21	2021/22	2022/23
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	31.05	29.62	29.14	31.48	33.99
2	East Aberdeenshire	25.76	25.46	21.99	26.28	26.67
3	Western Highlands	29.69	27.97	27.33	29.52	28.54
4	Skye and Lochalsh	35.52	21.74	20.92	26.24	25.22
5	Eastern Grampian and Tayside	27.97	26.81	25.80	26.59	25.97
6	Central Grampian	27.73	27.21	25.32	27.03	25.41
7	Argyll	34.53	34.18	35.17	36.24	33.52
8	The Trossachs	24.08	23.54	21.30	22.74	21.34
9	Stirlingshire and Fife	19.67	18.55	16.32	18.19	18.86
10	South West Scotland	20.67	20.19	19.74	18.97	18.31
11	Lothian and Borders	16.17	14.95	15.20	12.55	13.22
12	Solway and Cheviot	11.37	10.03	10.41	8.60	9.08
13	North East England	7.96	6.54	6.41	5.93	6.29
14	North Lancashire and The Lakes	4.31	2.97	2.76	0.82	0.74
15	South Lancashire, Yorkshire and Humber	2.90	1.44	0.74	-1.45	-1.47
16	North Midlands and North Wales	0.81	-0.45	-1.53	-3.61	-3.59
17	South Lincolnshire and North Norfolk	-0.40	-2.08	-3.34	-5.43	-5.63
18	Mid Wales and The Midlands	-1.04	-2.83	-3.92	-5.94	-5.93
19	Anglesey and Snowdon	1.39	0.11	0.42	-2.55	-2.95
20	Pembrokeshire	2.30	1.42	0.28	-2.01	-3.36
21	South Wales & Gloucester	-0.78	-1.64	-2.89	-5.33	-6.33
22	Cotswold	-5.38	-6.20	-7.54	-10.18	-10.73
23	Central London	-12.31	-14.40	-16.14	-18.60	-19.25
24	Essex and Kent	-4.43	-6.24	-7.53	-9.65	-9.75
25	Oxfordshire, Surrey and Sussex	-5.77	-7.78	-9.06	-11.11	-11.41
26	Somerset and Wessex	-8.15	-9.47	-9.03	-10.09	-10.17
27	West Devon and Cornwall	-9.38	-9.04	-9.58	-9.50	-11.42

Figure 5 – Wider tariffs for a Conventional Low Carbon 80% generator

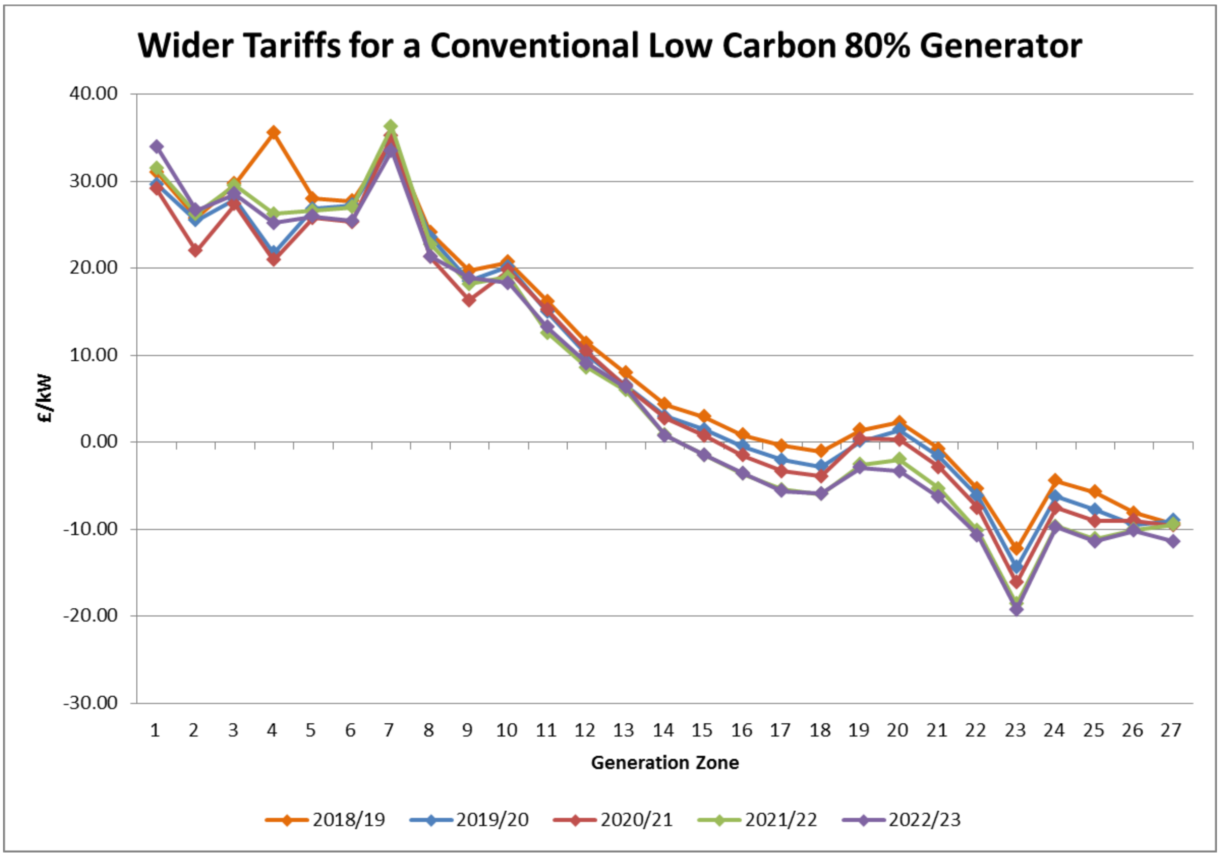
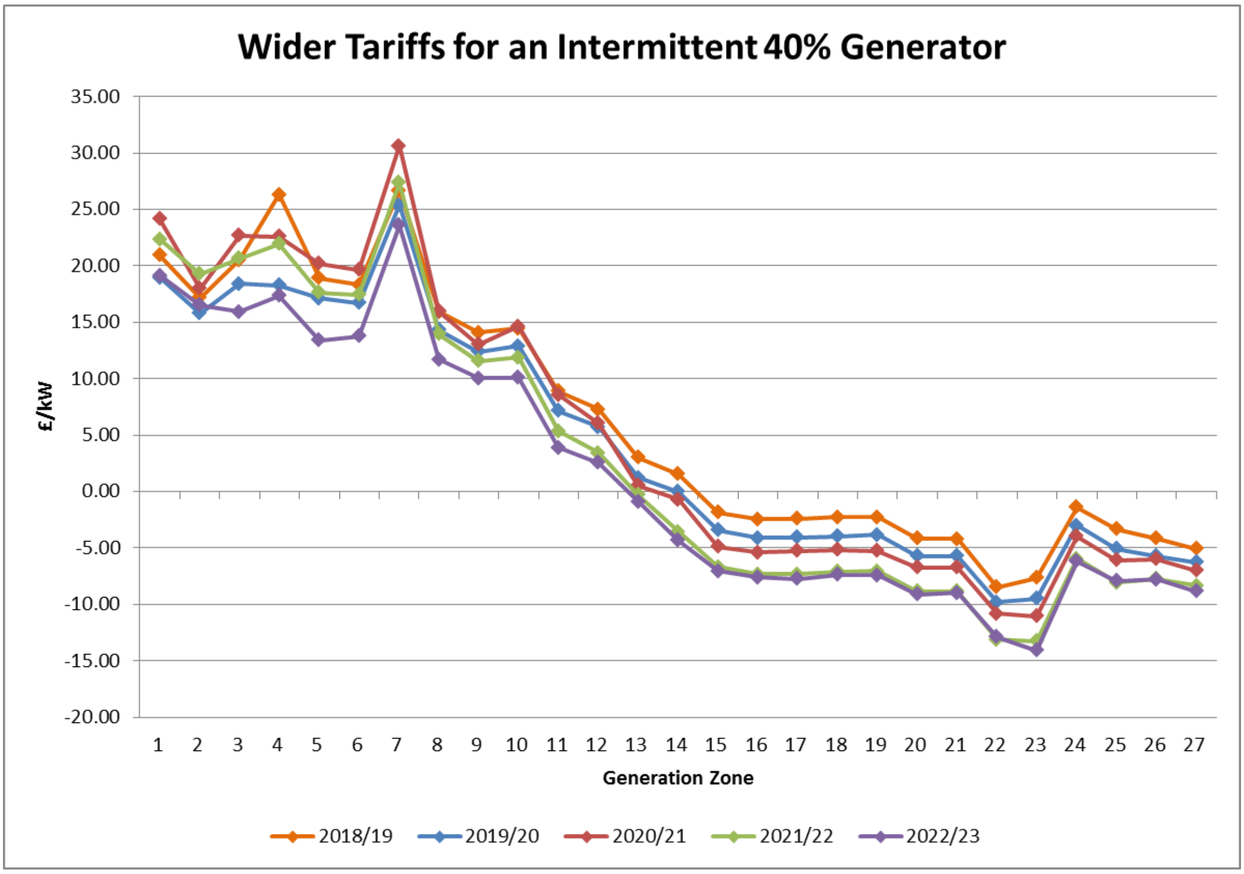


Table 13 – Comparison of Intermittent (40%) tariffs

Wider Tariffs for an Intermittent 40% Generator		2018/19	2019/20	2020/21	2021/22	2022/23
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	20.93	18.94	24.13	22.35	19.15
2	East Aberdeenshire	17.15	15.79	17.98	19.28	16.50
3	Western Highlands	20.51	18.39	22.67	20.64	15.92
4	Skye and Lochalsh	26.32	18.29	22.57	21.93	17.34
5	Eastern Grampian and Tayside	18.93	17.10	20.20	17.64	13.40
6	Central Grampian	18.29	16.71	19.63	17.42	13.77
7	Argyll	26.69	25.38	30.64	27.35	23.61
8	The Trossachs	15.90	14.33	15.95	13.97	11.69
9	Stirlingshire and Fife	14.07	12.40	13.05	11.58	10.05
10	South West Scotland	14.48	12.88	14.66	11.87	10.07
11	Lothian and Borders	8.91	7.15	8.56	5.38	3.87
12	Solway and Cheviot	7.29	5.74	6.02	3.42	2.54
13	North East England	3.00	1.22	0.54	-0.31	-0.87
14	North Lancashire and The Lakes	1.54	-0.03	-0.71	-3.54	-4.35
15	South Lancashire, Yorkshire and Humber	-1.85	-3.44	-4.91	-6.70	-7.03
16	North Midlands and North Wales	-2.44	-4.11	-5.38	-7.32	-7.59
17	South Lincolnshire and North Norfolk	-2.41	-4.05	-5.26	-7.31	-7.73
18	Mid Wales and The Midlands	-2.29	-3.98	-5.19	-7.09	-7.36
19	Anglesey and Snowdon	-2.27	-3.85	-5.26	-7.03	-7.40
20	Pembrokeshire	-4.17	-5.72	-6.74	-8.84	-9.12
21	South Wales & Gloucester	-4.20	-5.73	-6.72	-8.82	-8.98
22	Cotswold	-8.47	-9.82	-10.82	-13.11	-12.87
23	Central London	-7.67	-9.49	-11.05	-13.25	-14.08
24	Essex and Kent	-1.40	-3.01	-3.95	-5.94	-6.17
25	Oxfordshire, Surrey and Sussex	-3.35	-5.05	-6.10	-8.07	-7.94
26	Somerset and Wessex	-4.17	-5.72	-5.99	-7.76	-7.80
27	West Devon and Cornwall	-5.08	-6.29	-6.99	-8.32	-8.84

Figure 6 – Wider tariffs for an Intermittent 40% generator



Changes to generation tariffs from 2018/19 to 2022/23

Generation tariffs in Scotland appear to reduce until 2019/20 (Intermittent) or 2020/21 (Conventional), and then increase again until 2022/23. This is in part due to the gradual decrease of the residual element because of the steady reduction in generation revenue. As the forecasted generation output in TWh reduces steadily over the five years, the EU cap of €2.5/MWh limits the revenue to be collected from generation. The effect of this is to make the residual increasingly negative throughout the five-year period.

The small rebound in some generation tariffs in zones 1 – 14 that occurs in years 2021/22 or 2022/23 happens despite the more negative residual. This is a result of an increase of over 6GW of contracted TEC in these areas in 2021/22, and an additional 1GW in 2022/23, a mixture of onshore and offshore wind and interconnectors. As this generation is mostly intermittent, this causes system flows to become dominated by intermittent generation to an even greater extent, resulting in a large increase in the Year Round Shared element of all tariffs in these zones.

Tariffs in zones 15 downward follow the pattern reducing roughly in proportion to the rate at which the residual decreases. Contracted TEC volumes remain relatively stable, although there are some increases of 3-4GW per year in zones 15, 18, (generation increases) 24, 25 and 26 (interconnector increases) from 2021/22 onwards, which reduces the impact of the negative residual in reducing tariffs in those zones.

Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast we have used the final version of the 2018/19 ALFs, based upon data from 2012/13 - 2016/17, and were published on 19 October 2017 and are available from the National Grid website.§ The Final ALFs for 2018/19 can be found in Appendix C.

Small generators discount

2018/19

The small generators discount for 2018/19 with the methodology from CMP282 applied has been calculated as £ 11.140704/kW, paid to generators small than 100MW connected at 132kV Transmission.

This equates to a forecast cost of £31.2m which is recovered from suppliers through the gross HH and NHH tariffs. The recovery rate for HH is £0.595039/kW and for NHH 0.080403p/kWh. These rates are included in the demand tariffs for 2018/19.

For more details, please refer to the October 2017 forecast of TNUoS tariffs for 2018/19.

Table 14 – Small generators discount

	2018/19	2019/20	2020/21	2021/22	2022/23
Small Generator Discount (£/kW)	- 11.140704	Discontinued			
Included in HH Tariffs below (£/kW)	0.595039				
Included in NHH Tariffs below (p/kWh)	0.080403				

Future years

The licence condition, C13, for the small generator discount expires on 31 March 2019. Therefore, we have not included any calculation of the small generator discount beyond 2018/19 tariffs.

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

Onshore local tariffs for generation

Onshore local substation tariffs

Local substation tariffs reflect the cost of the first transmission substation to which transmission connected generators connect. They are increased each year by Average May – October RPI.

The following table shows the local substation tariffs for 2018/19. For subsequent years, these can be calculated by inflated annually using our internal RPI forecast, which is around 2-3% each year.

Table 15 – Local substation tariffs for 2018/19

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.191605	0.109610	0.078976
<1320 MW	Redundancy	0.422090	0.261150	0.189930
>=1320 MW	No redundancy	0	0.343677	0.248548
>=1320 MW	Redundancy	0	0.564230	0.411841

Onshore local circuit tariffs

A forecast of onshore local circuit tariffs from 2018/19 to 2022/23 is shown below. These have been calculated using contracted generation from 2018/19 onwards.

Where a transmission connected generator is not directly connected to the Main Interconnected Transmission System (MITS), the onshore local circuit tariffs reflect the cost and flows on circuits between its connection and the MITS. Local circuit tariffs are dependent on the length and type of circuit(s) connecting to it to the nearest MITS substation and can change as a result of system flows and RPI.

Local circuit tariffs are dependent on the particular flows modelled on a system in a given year, and can therefore change between years. If you require further insight in to any particular local circuit tariff, please contact us using the detail in the executive summary.

If you are unsure about your local circuit tariff or whether one will be applied, please contact your connection contract manager or alternatively use the contact details above the executive summary.

Table 16 - Onshore local circuit tariffs

Connection Point	2018/19 (£/kW)	2019/20 (£/kW)	2020/21 (£/kW)	2021/22 (£/kW)	2022/23 (£/kW)
Aberdeen Bay	2.488266	2.571147	2.648423	2.727819	2.809654
Achruach	4.096995	4.233300	4.360622	-2.670557	-2.750546
Aigas	0.624158	0.644948	0.664332	0.684248	0.704776
An Suidhe	-0.911354	-0.940908	3.094466	-0.999213	-1.029063
Arecleoch	1.982091	2.048112	2.109668	2.172913	1.294595
Aultmore				1.754738	1.807380
Baglan Bay	0.725636	0.750203	0.772751	0.795912	-0.157153
Bay of Skaill				65.359563	67.320350
Beinn an Tuirc WF				1.232860	1.269830
Beinneun Wind Farm	1.433097	1.481122	1.525634	1.571370	1.618509
Bhlaraidh Wind Farm	0.627980	0.648898	1.181017	0.675789	0.696061
Black Hill	0.823372	0.850797	1.311649	1.350971	1.391500
Black Law	1.667575	1.723120	1.774908	3.290611	3.389330
BlackCraig Wind Farm	6.007572	6.207678	6.394249	6.585941	6.783519
BlackLaw Extension	3.536308	3.654099	3.763922	3.876760	3.993063
Bodelwyddan	0.109805	0.113462	0.116872	0.653729	0.123987
Carrington	-0.030889	-0.032719	-0.033226	-0.185176	-0.190166
Clyde (North)	0.104659	0.108145	0.111395	0.114734	0.118176
Clyde (South)	0.121033	0.125064	0.128823	0.132685	0.136665
Corriegarth	3.008662	3.108877	3.202314	3.298316	3.397265
Corriemoillie	1.589153	1.640653	1.689963	1.740626	1.792845
Coryton	0.049583	0.051520	0.053287	0.055142	0.056894
Crossburns					0.323270
Cruachan	1.805974	1.865585	1.921698	1.979416	2.038790
Crystal Rig	0.031390	0.032728	0.034064	0.036892	0.037877
Culligran	1.654034	1.709128	1.760496	1.813274	1.867672
Dalquhandy				1.107279	1.140497
Deanie	2.717342	2.807854	2.892243	2.978949	3.068318
Dersalloch	2.298804	2.375375	2.446767	2.520118	2.595721
Didcot	0.497305	0.515328	0.532534	0.547720	0.564217
Dinorwig	2.289711	2.365979	2.063751	3.430986	3.533941
Dorenell	2.002796	2.069507	2.131706	2.195612	2.261480
Dumnaglass	1.771805	1.830822	1.885847	1.942382	2.000653
Dunhill	1.366908	1.412438	2.177515	2.242795	2.310079
Dunlaw Extension	1.433123	1.479481	1.524301	1.571616	1.618640
Edinbane	6.533826	6.748862	6.951655	7.158739	7.373428
Enoch Hill				1.743232	1.795529
Ewe Hill	1.311433	1.355115	1.395843	1.437689	1.480820
Fallago	0.191273	0.198181	0.204764	0.214283	0.220474
Farr	3.402585	3.515921	3.621592	3.730163	3.842068
Fernoch	4.198372	4.337616	4.467980	4.601922	4.739977

Connection Point	2018/19 (£/kW)	2019/20 (£/kW)	2020/21 (£/kW)	2021/22 (£/kW)	2022/23 (£/kW)
Ffestiniogg	0.241444	0.249487	0.256985	0.264689	0.272630
Finlarig	0.305576	0.315755	0.325245	0.334995	0.345045
Foyers	0.718600	0.742535	0.764852	0.787782	0.811415
Galawhistle	1.411472	1.458487	1.502322	1.547359	1.593780
Gills Bay	2.403355	2.483408	2.558047	2.634734	2.713776
Glen Ullinish					2.464609
Glendoe	1.755415	1.813886	1.868402	1.924414	1.982147
Glenglass	9.267413	9.576101	10.647415	10.966613	11.295611
Gordonbush	0.578820	0.159469	0.198430	0.182358	0.157669
Griffin Wind	4.079805	9.567793	9.865639	10.160664	10.465404
Hadyard Hill	2.641489	2.729474	2.811508	2.895794	2.982668
Harestanes	2.394748	2.473731	2.548396	2.626835	2.705419
Hartlepool	0.573697	0.592124	0.613383	0.350996	0.055126
Hedon	0.172684	0.178440	0.183805	0.189315	0.206486
Invergarry	1.354681	1.399172	-0.696083	-0.716919	-0.738398
Kendoon North			0.165850	-1.365971	-2.851505
Kergord			121.514355	125.373326	129.800200
Kilgallioch	1.004385	1.037840	1.924258	1.101081	1.134113
Killingholme	0.677069	0.700822	0.550448	0.711417	0.733088
Kilmorack	0.188474	0.194752	0.200605	0.206619	0.212817
Knottingley			0.152182	-0.119274	-0.122898
Kyllachy				0.478565	0.492922
Kype Muir	1.415515	1.462664	1.006639		1.067921
Langage	0.627477	0.648640	0.668166	-0.355480	-0.203564
Lochay	0.349230	0.360863	0.371708	0.382852	0.394337
Luichart	0.548697	0.565540	0.582538	0.600002	0.618002
Marchwood	0.364361	0.376359	0.387673	0.399295	0.411265
Margree	5.745649	5.937031	6.115467	0.000000	6.487766
Mark Hill	0.835581	0.863413	0.889363	0.916025	0.471753
Middle Muir	1.891664	1.954673	1.634746	1.683754	1.734267
Middleton	0.107505	0.109714	0.113592	0.151542	0.156220
Millennium South	0.899268	0.928601	0.536450	0.971540	1.000454
Millennium Wind	1.742662	1.800997	1.855124	1.910737	1.968057
Moffat	0.164040	0.168720	0.174108	0.181369	0.186589
Moray Firth				0.787782	0.811415
Mossford	2.749193	0.441973	0.455257	0.468906	0.482973
Nant	2.395571	-1.211431	-1.247835	-1.285235	-1.323785
Necton	-0.356936	-0.362202	-0.372277	-0.539737	-0.555276
Rhigos	0.096778	0.100382	0.103410	0.106498	0.109681
Rocksavage	0.016887	0.017458	-0.017983	-0.018522	-0.019077
Saltend	0.325403	0.336249	0.346358	0.356742	0.346538
South Humber Bank	0.903058	0.934339	0.845600	0.243930	0.251577
Spalding	0.266346	0.277678	0.286662	0.294223	0.303449

Connection Point	2018/19 (£/kW)	2019/20 (£/kW)	2020/21 (£/kW)	2021/22 (£/kW)	2022/23 (£/kW)
Stornoway				97.097353	100.010274
Strathbrora	0.427469	0.035247	0.068010	0.049648	0.023195
Strathy Wind	2.058713	2.007072	1.868576	2.137039	1.941492
Stronelairg	1.403544	1.414846	1.459237	1.784028	1.835674
Wester Dod	0.356126	0.368280	0.379701	0.392892	0.404556
Whitelee	0.101283	0.104656	0.107802	0.111033	0.114364
Whitelee Extension	0.281565	0.290944	0.539439	0.308673	0.317933
Willow				1.595216	1.643072

Table 17 – CMP203: Circuits subject to one-off charges

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way that they are modelled in the Transport and tariff model. This table shows the lines which have been amended in the model to account for the one-off charges that have already been made to the generators. For more information please see CUSC 2.14.4, 14.4, and 14.15.15 onwards.

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
Crystal Rig 132kV	Wester Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Elvanfoot 275kV	Clyde North 275kV	6.2km of Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km of Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Coalburn 132kV	Galawhistle 132kV	9.7km cable	9.7km OHL	Galawhistle II
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes
Coalburn 132kV	Kype Muir 132kV	17km cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km cable	13km OHL	Middle Muir
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
East Kilbride South 275kV	Whitelee 275kV	6km of Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km of Cable	16.68km of OHL	Whitelee Extension

Offshore local tariffs for generation

Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of price review or on transfer to the offshore transmission owner (OFTO) and indexed by average May to October RPI each year.

Offshore local generation tariffs associated with OFTOs yet to be appointed will be calculated following their appointment.

Offshore local tariffs for 2018/19 are shown in below. These tariffs are inflated annually so for later years please increase by RPI (assume 2-3% p.a.) We will discuss tariffs for new offshore networks with the individual affected generator prior to the Offshore Transmission Owner being appointed.

Table 18 – Offshore local tariffs for 2018/19

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.721088	40.396727	1.003106
Greater Gabbard	14.476133	33.264728	0.000000
Gunfleet	16.710105	15.341185	2.867356
Gwynt Y Mor	17.629613	17.367347	0.000000
Humber Gateway	14.029142	31.654419	0.000000
Lincs	14.429434	56.494534	0.000000
London Array	9.822495	33.454870	0.000000
Ormonde	23.869459	44.466566	0.354361
Robin Rigg East	-0.441553	29.249094	9.065641
Robin Rigg West	-0.441553	29.249094	9.065641
Sheringham Shoal	23.062034	27.046363	0.587908
Thanet	17.562577	32.725358	0.787815
Walney 1	20.600474	41.025791	0.000000
Walney 2	20.450653	41.387231	0.000000
West of Duddon Sands	7.949161	39.224181	0.000000
Westermost Rough	16.738261	28.313974	0.000000

Allowed revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Revenue for offshore networks is included with forecasts by National Grid where the Offshore Transmission Owner has yet to be appointed.

By October, most TOs have undertaken annual regulatory reporting, and thus have provided National Grid with their indicative revenue forecast. Table 12 shows the forecast 2018/19 revenues that have been used in calculating the October tariffs.

In addition, National Grid collects some pan-company funding items including the Network Innovation Competition (NIC) and the Environmental Discretionary Reward (EDR) allowances.

Following Ofgem's approval of CMP283, National Grid as the System Operator (SO) now has a mechanism to distribute or collect part of the revenues for interconnectors under the Cap and Floor regime. The principal of using TNUoS as the mechanism for interconnector cap and floor revenues was agreed under the licence changes last year.

For interconnectors under the Cap and Floor regime, the first scheduled Cap and Floor adjustment will be five years after commercial go-live, plus the period it takes for Ofgem to ratify the accounts. Therefore, for this five-year forecast, IFA is the only interconnector that is relevant to the TNUoS revenue forecast. IFA's forecasted income figure, which offsets the total TNUoS charge, has been aggregated with the total revenue forecast for future OFTOs.

Table 19 – Allowed revenues

£m Nominal	2018/19	2019/20	2020/21	2021/22	2022/23
National Grid					
Price controlled revenue	*1,647.1*	*1,768.5*	*1,936.0*	*1,998.4*	*2,048.3*
Less income from connections	*41.9*	*41.9*	*41.9*	*41.9*	*41.9*
Income from TNUoS	**1,605.2**	**1,726.6**	**1,894.1**	**1,956.5**	**2,006.4**
Scottish Power Transmission					
Price controlled revenue	*360.5*	*404.5*	*382.1*	*440.9*	*418.1*
Less income from connections	*14.2*	*14.5*	*14.9*	*15.3*	*15.8*
Income from TNUoS	**346.3**	**390.0**	**367.2**	**425.6**	**402.3**
SHE Transmission					
Price controlled revenue	*358.6*	*352.9*	*366.1*	*421.6*	*434.9*
Less income from connections	*3.5*	*3.5*	*2.9*	*3.0*	*3.1*
Income from TNUoS	**355.1**	**349.4**	**363.2**	**418.6**	**431.8**
Offshore (+ Interconnector from y2019/20)	**312.1**	**459.9**	**497.4**	**515.8**	**595.4**
Network Innovation Competition + EDR	**42.5**	**42.5**	**42.5**	**42.5**	**42.5**
Total to Collect from TNUoS	**2,661.3**	**2,968.4**	**3,164.5**	**3,359.0**	**3,478.4**

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.

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 2018/19 will be adjusted in November 2017 to reflect 2016/17 performance. The revenue forecasts in this document are provided by the TOs on a best endeavours basis and it should be noted that TO business plans and customer requirements which drive the need for investment, can alter over time.

The revenue forecasts for 2021/22 and 2022/23 are outside of the current price review period. The licence terms for calculating allowed revenue, in each onshore TO licence, are only relevant until March 2021. These licence terms will be renegotiated with Ofgem. With the future so uncertain, for the purposes of this forecast NGET assumed that the allowed revenue would roll over to 2021/22 and 2022/23 (with RPI inflation).

During the RIIO-T1 price control period, the onshore TOs may voluntarily have their allowed revenues reduced, and this will ultimately be reflected in the revenue forecast.

On 28 March 2017, National Grid announced that it would voluntarily return £480m of its RIIO-T1 allowances due to deferred investment. The effect of this will be a relative reduction in network charges from 2019/20 onwards. This has been reflected in the revenue forecast for 2019/20 and 2020/21. Reductions for years beyond RIIO-T1 cannot be quantified at this stage.

The recent £65.1m of voluntary reduction made by SHET, was not considered in the 5-year TNUoS forecast, as this had not been agreed at the time that SHET submit the revenue forecast to National Grid. SHET are currently in discussion with Ofgem as to how and when the voluntary reduction will be handed back, and will make sure that it communicated to stakeholders any further detail when available.

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. Future OFTO asset transfers are expected to occur within eighteen months of the offshore wind farm commissioning. Future OFTO commissioning has been forecast using similar assumptions as for Contracted generation and in line with FES methodology. Revenues have been extrapolated from previous offshore transmission network revenues and capacities.

Offshore revenue increases significantly over the period. However, this increase is dependent upon the progress of associated offshore generation. Where offshore revenues increase then income from local offshore tariffs will also increase, so only around 22% of the additional revenue will affect other TNUoS charges.

Pre-vesting and pre-BETTA connection revenues

Some 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 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.

Generation / Demand (G/D) Split

Section 14.14.5 (v) in the Connection and Use of System Code (CUSC) currently limits average annual generation use of system charges in Great Britain to €2.5/MWh. The net revenue that can be recovered from generation is therefore determined by: the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin is also applied to reflect revenue and output forecasting accuracy.

Exchange Rate

As prescribed by the Use of System charging methodology, the exchange rate for 2018/19 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility. The value for 2018/19 is €1.16/£, as published in the March 2017 report as require by the methodology.

For future years, the values used are from Autumn update to the Economic and Fiscal outlook published in November 2017. The £:€ rate reduces from 1.10 in 2019/20 to 1.08 by 2022/23.

Generation Output

The forecast output of generation is aligned with Future Energy Scenario generation output forecasts. Generation output reduces steadily from 253TWh in 2018/19 to 224.5TWh in 2022/23 reflecting our forecasted decrease in the total generation from generators that are liable for generation TNUoS charges over the five-year period. More information on generation forecast modelling is available in the FES publication from July 2017.[**]

Error Margin

The error margin remains unchanged at 21%.

[**] *http://fes.nationalgrid.com/*

Table 20 – Generation and demand revenue proportions

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

		2018/19	2019/20	2020/21	2021/22	2022/23
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50
y	Error Margin	21.0%	21.0%	21.0%	21.0%	21.0%
ER	Exchange Rate (€/£)	1.16	1.10	1.09	1.08	1.08
MAR	Total Revenue (£m)	2,661.3	2,968.4	3,164.5	3,359.0	3,478.4
GO	Generation Output (TWh)	252.6	247.0	243.1	234.2	224.5
G	% of revenue from generation	16.2%	14.9%	13.9%	12.7%	11.8%
D	% of revenue from demand	83.8%	85.1%	86.1%	87.3%	88.2%
G.MAR	Revenue recovered from generation (£m)	430.1	443.5	440.5	428.2	410.6
D.MAR	Revenue recovered from demand (£m)	2231.2	2524.8	2724.0	2930.8	3067.8

Further data used in the tariff forecasts

Generation Volumes

Contracted TEC is the full volume of chargeable TEC on the TEC register as of 31 October 2017.

Modelled TEC is the volume of chargeable generation that we expect to connect to the network each year plus interconnectors according to our Best View. This is the generation that will be used to calculate system flows in the Transport model.

Chargeable TEC is the volume of chargeable generation that we expect to connect to the network each year per our Best View (without interconnectors).

The Chargeable TEC is forecast to be less than Contracted TEC. It excludes interconnectors, which are not chargeable, and generation that we do not expect to be contracted during the charging year. This could be due to closure, termination or delay and also includes any generators that we believe may increase their TEC.

We are unable to provide a breakdown of our best view of generation as some of the information used to derive it could be commercially sensitive. The changes to Contracted TEC are shown in Appendix E.

Table 21 – Generation contracted, modelled and chargeable TEC

This was based on the TEC register from 31 October 2017, although the figures for 2018/19 are based on the TEC register used for the October 2018/19 tariffs forecast which was taken from the start of October. The Modelled and Chargeable TEC in 2018/19 are higher than in 2019/20 due to TEC reductions or deferments that entered the TEC register at the end of October 2017.

The TEC volumes for 2018/19 will be updated in the Draft tariffs which will be published in December 2017.

Best View	2018/19	2019/20	2020/21	2021/22	2022/23
Contracted TEC (GW)	82.4	85.5	104.7	121.7	130.7
Modelled TEC (GW)	79.7	77.7	86.8	96.2	108.1
Chargeable TEC (GW)	75.0	73.8	80.9	86.4	94.6

Demand volumes

Transport Model demand (Week 24 data)

The contracted demand at Grid Supply Points (GSPs) is used in the transport model to provide locational signals for future energy consumption. This data is based on demand forecasts from DNOs and directly connected users (the week 24 data).

Demand levels at individual GSPs are made specifically for the purposes of the week 24 “snapshot” of national peak demand.

Several DNOs have indicated that they expect that there will be increased volatility on the week 24 demand forecast in the future, due mainly to the increasing levels of embedded and micro generation at GSP level, and the unpredictability of when system peak demand occurs. Participation in demand side response services by embedded parties will add to the uncertainty.

Table 22 – Week 24 DNO zonal demand forecast

Demand Zone	2018/19 MW	2019/20 MW	2020/21 MW	2021/22 MW	2022/23 MW
1	227.0	499.4	443.1	417.9	432.3
2	2820.4	2695.3	2670.1	2670.7	2667.6
3	2508.0	2702.3	2715.2	2728.1	2739.6
4	3234.0	3067.5	2940.0	2852.4	2767.9
5	4347.0	4384.1	4421.0	4425.8	4423.2
6	2831.0	2557.7	2641.9	2690.5	2743.5
7	5333.0	5375.8	5428.3	5506.1	5593.0
8	4594.0	4424.7	4446.3	4487.4	4536.0
9	5843.0	6238.2	6407.5	6529.7	6648.1
10	1969.0	1673.9	1685.5	1702.3	1711.0
11	3355.0	3870.8	3861.5	3765.0	3800.7
12	5271.0	5599.2	5736.3	5823.6	5956.7
13	5668.0	6565.9	6833.2	6942.2	7023.0
14	2609.0	2210.1	2178.2	2156.1	2136.6
Total	**50609.4**	**51865.0**	**52407.9**	**52697.8**	**53179.2**

Chargeable demand

We forecast that system gross peak will fall from 52.5GW in 2018/19 to 49.8GW in 2022/23. In the same period, we expect HH demand to fall from 19.8GW to 18.6GW, and NHH demand to fall from 24.2TWh to 22.2TWh.

This forecast has been prepared using a Monte Carlo modelling approach described in the recently published October 2018/19 TNUoS tariff report. This approach incorporates historical gross metered demand and Embedded Export data from 2014-2017 under BSC P348/349 to better understand zonal demand behaviours. The full set of data by year and zone can be found in Appendix F.

Demand quantities used in charges are forecast to decline due to several factors including the growth in distributed generation and ‘behind the meter’ microgeneration. Further out, population growth and technology (likely switching from gas to electric heating and increasing use of electric vehicles) is not expected to increase consumption at the level previously assumed, therefore the effects are unlikely to have a significant influence on our forecast.

We have assumed that recent historical trends in declining volumes will continue, and that there will be no significant shift of volumes from HH to NHH (or vice versa).

Table 23 – Demand charging base

	2018/19	2019/20	2020/21	2021/22	2022/23
Average System Demand at Triad (GW)	45.95	51.25	50.58	50.18	49.82
Average HH Metered Demand at Triad (GW)	19.80	19.03	18.86	18.87	18.66
NHH Annual Energy between 4pm and 7pm (TWh)	24.17	23.50	23.20	22.74	22.28

Adjustments for interconnectors

When modelling flows on the transmission system, interconnector flows are not included in the Peak model but are included in the Year Round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases.

Table 24 – Interconnectors

The table below reflects the contracted position in the TEC register of interconnectors on 31 October 2017.

Interconnector	Node	Zone	Capacity (MW)	Effective From
Aquind Interconnector	LOVE40	26	2000	2021/22
Auchencrosh (Moyle interconnector CCT)	AUCH20	10	80	Built
Belgium Interconnector (Nemo)	CANT40	24	1000	2018/19
Britned	GRAI40	24	1200	Built
East West Interconnector	CONQ40	16	505	Built
ElecLink	SELL40	24	1000	Built
FAB Link Interconnector	EXET40	26	1400	2020/21
Greenage Power Interconnector	GRAI40	24	1400	2022/23
Greenlink	PEMB40	20	500	2022/23
Gridlink Interconnector	KINO40	24	1500	2022/23
IFA Interconnector	SELL40	24	2000	Built
IFA2 Interconnector	FAWL40	26	1100	2019/20
Norway Interconnector	PEHE40	2	1400	2021/22
NS Link	BLYT4A	13	1400	2020/21
Viking Link Denmark Interconnector	BICF4A	17	1500	2022/23

Note: we are aware that ElecLink is not currently connected and their website suggests it will be operational in Q1 2020.

Circuits

Following the 2017 ETYS (Electricity Ten Year Statement) study, the circuit data in the transport model for the next five years were updated with the latest ETYS circuits information.

Some of the main changes include the Western bootstrap HVDC (built in 2017) and Caithness-Moray HVDC (from 2018/19).

From 2020/21 the HVDC link to Shetland (Kergord substation) is included as a local circuit in the local tariffs. From 2021/22 the link to Orkney (Bay of Skaill) and HVDC link to the Western Isles (Stornoway) are included as local circuits. These are included to connect the generators at these substations as detailed in the TEC register.

RPI

The RPI index for the components detailed below is derived as the percentage increase of the average May – October RPI for 2017/18 compared to 2016/17.

Table 25 – Inflation Indices

2009/10		2018/19	2019/20	2020/21	2021/22	2022/23
1.0000		1.3140	1.3570	1.3960	1.4390	1.4810

Table 26 – Expansion constant

The expansion constant is assumed to increase with RPI during the five-year period.

£/MWkm	18/19	19/20	20/21	21/22	22/23
Expansion Constant	14.084815	14.553966	14.991383	15.440807	15.904031

Generation and demand residuals

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

generation Residual = (Total Money collected from generators as determined by G/D split less money recovered through location tariffs, onshore local substation & circuit tariffs and offshore local circuit & substation tariffs) divided by the total chargeable TEC

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

Where

- R_G is the generation residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from generation
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from generation 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)

The **demand Residual** = (Total demand revenue less revenue recovered from locational demand tariffs, plus revenue paid to embedded exports) divided by total system gross triad demand

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

Where:

- R_D is the gross demand residual tariff (£/kW)
- D is the proportion of TNUoS revenue recovered from demand
- R is the total TNUoS revenue to be recovered (£m)
- Z_D is the TNUoS revenue recovered from demand locational zonal tariffs (£m)
- EE is the amount to be paid to Embedded Export Volumes through the Embedded Export Tariff (£m)

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

Z_G, Z_D, L_C, and EE are determined by the locational elements of tariffs, and for EE the value of the AGIC and Phased Residual.

Table 27 – Residual Calculation

	Component	2018/19	2019/20	2020/21	2021/22	2022/23
G	Proportion of revenue recovered from generation (%)	16.2%	14.9%	13.9%	12.7%	11.8%
D	Proportion of revenue recovered from demand (%)	83.8%	85.1%	86.1%	87.3%	88.2%
R	Total TNUoS revenue (£m)	2,661.3	2968.4	3164.5	3359.0	3478.4
Generation Residual						
R_G	Generator residual tariff (£/kW)	-2.34	-3.85	-5.08	-6.97	-7.28
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	322.2	331.4	419.8	490.6	484.0
O	Revenue recovered from offshore local tariffs (£m)	244.0	356.0	385.2	399.7	461.8
L_G	Revenue recovered from onshore local substation tariffs (£m)	20.7	20.1	23.6	26.4	30.1
S_G	Revenue recovered from onshore local circuit tariffs (£m)	18.5	20.0	21.1	113.7	123.0
B_G	Generator charging base (GW)	75.0	73.8	80.5	86.4	94.6
Gross Demand Residual						
R_D	Demand residual tariff (£/kW)	46.66	52.13	55.54	60.36	63.65
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-26.6	-65.3	-68.9	-79.9	-85.3
EE	Amount to be paid to Embedded Export Tariffs (£m)	189.9	81.6	16.0	18.6	17.8
B_D	Demand Gross charging base (GW)	52.5	51.2	50.6	50.2	49.8

Guide to TNUoS charging

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, National Grid determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: peak demand and year round. Where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced. To calculate flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on 'standard' conditions, which means that they reflect the cost of replacing assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and demand tariffs. The residual is also used to ensure the correct proportion of revenue is collected from generation and demand. The locational and residual tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate.

For generation customers, local tariffs are also calculated. These reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the main interconnected transmission system (MITS), the cost of local circuits that the generator uses to export onto the MITS. This allows the charges to reflect the cost and design of local connections and vary from project to project. For offshore generators, these local charges reflect OFTO revenue allowances.

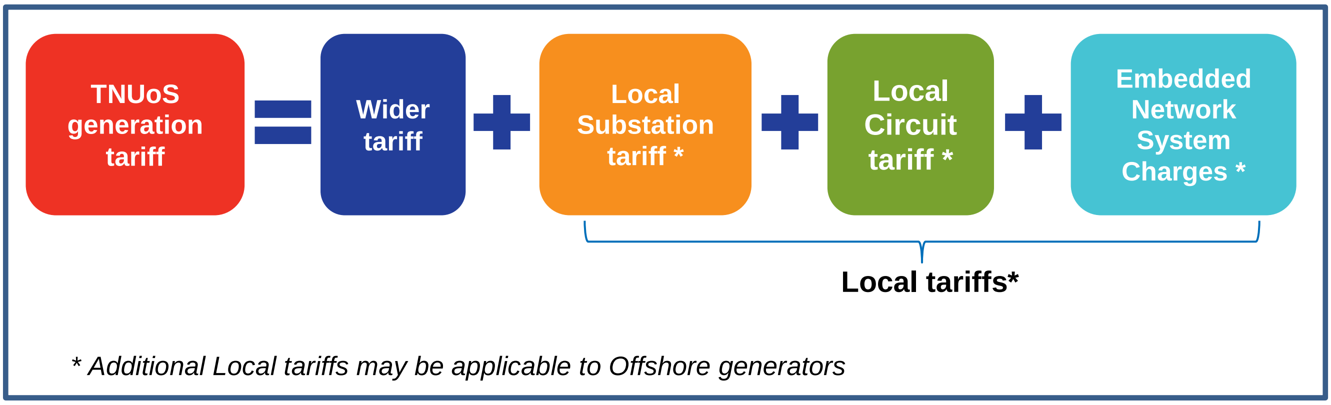
Generation charging principles

Generators pay TNUoS (Transmission Network Use of System) tariffs to allow National Grid as System Operator to recover the capital costs of building and maintaining the transmission network on behalf of the transmission asset owners (TOs).

The TNUoS tariff specific to each generator depends on many factors, including the location, type of connection, connection voltage, plant type and volume of TEC (Transmission Entry Capacity) held by the generator. The TEC figure is equal to the maximum volume of MW the generator is allowed to output onto the transmission network.

Under the current methodology there are 27 generation zones, and each Zone has four tariffs. Liability for each tariff component is shown below:

TNUoS tariffs are made up of two general components, the **Wider tariff**, and **Local tariffs**.



The wider tariff is set to recover the costs incurred by the generator for the use of the whole system, whereas the local tariffs are for the use of assets in the immediate vicinity of the connection site.

*Embedded Network system charges are only payable by generators that are not directly connected to the transmission network and are not applicable to all generators.

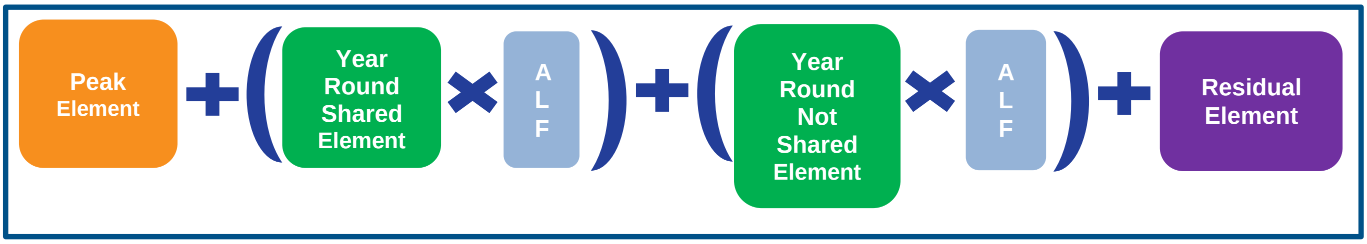
The Wider tariff

The wider tariff is made up of four components, two of which may be multiplied by the generator's specific Annual Load Factor (ALF), depending on the generator type.

As CUSC Modification CMP268 has added an extra variation to the calculation formula, generators classed as Conventional Carbon now pay the Year Round Not Shared element in proportion to their ALF.

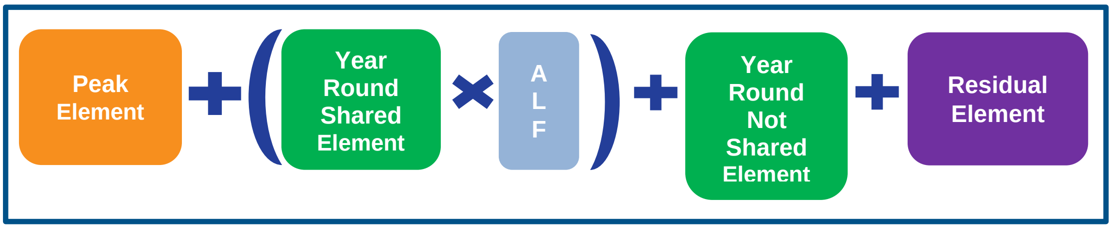
Conventional Carbon generators

(Biomass, CHP, Coal, Gas, Pump Storage)



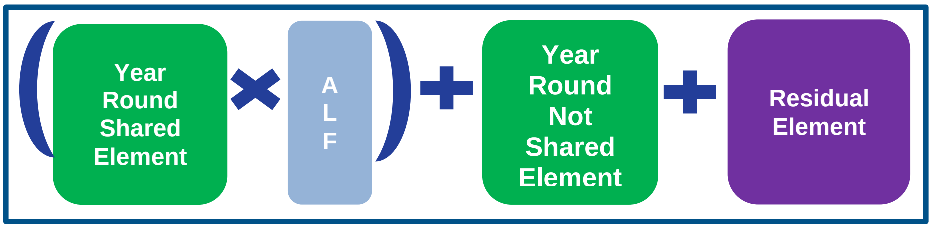
Conventional Low Carbon generators

(Hydro, Nuclear)



Intermittent generators

(Wind, Wave, Tidal)



The **Peak** element reflects the cost of using the system at peak times. This is only paid by conventional and peaking generators; intermittent generators do not pay this element.

The **Year Round Shared** and **Year Round Not Shared** elements represent the proportion of transmission network costs shared with other zones, and those specific to each particular Zone respectively.

ALFs are calculated annually using data available from the most recent charging year. Any generator with fewer than three years of historical generation data will have any gaps derived from the generic ALF calculated for that generator type.

The **Residual** element is a flat rate for all generation zones which adds a non-locational charge (which may be positive or negative) to the Wider TNUoS tariff, to ensure that the correct amount of aggregate revenue is collected from generators as a whole.

The Annual Load Factors used in this report are listed in Appendix C.

Local substation tariffs

A generator will have a charge depending on the first onshore substation on the transmission system to which it connects. The cost is based on the voltage of the substation, whether there is a single or double ('redundancy') busbar, and the volume of generation TEC connected at that substation.

Local onshore substation tariffs are set at the start of each TO price-control period, and are increased by RPI each year.

Local circuit tariffs

If the first onshore substation which the generator connects to is categorised as a MITS (Main Interconnected Transmission System) in accordance with CUSC 14.15.33, then there is no local circuit charge. Where the first onshore substation is not classified as MITS, there will be a specific circuit charge for generators connected at that location.

Embedded network system charges

If a generator is not connected directly to the transmission network, they will have a BEGA connection agreement allowing them to export power onto the transmission system from the distribution network. Generators will incur local DUoS charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

Embedded-connected offshore generators will need to pay an estimated DUoS charge to NGET through TNUoS tariffs to cover DNO charges, called ETUoS (Embedded Transportation Use of System).

Click here to find a map of the DNO regions.

Offshore Local tariffs

Where an offshore generator's connection assets have been transferred to the ownership of an OFTO (Offshore Transmission Owner), there will be additional **Offshore Substation** and **Offshore Circuit** tariffs specific to that OFTO.

Billing

TNUoS is charged annually and costs are calculated on the highest level of TEC held by the generator during the year. (A TNUoS charging year runs from 1 April to 31 March). This means that if a generator holds 100MW in TEC from 1 April to 31 January, then 350MW from 1 February to 31 March, the generator will be charged for 350MW of TEC for that charging year.

The calculation for TNUoS generator liability is as follows:

$$\frac{(\text{(TEC * TNUoS tariff)} - \text{TNUoS charges already paid})}{\text{Number of months remaining in the charging year}}$$

All tariffs are in £/kW of TEC held by the generator.

TNUoS charges are billed each month, for the month ahead.

Generators with negative TNUoS tariffs

Where a generator's specific tariff is negative, the generator will be paid during the year based on their highest TEC for that year. After the end of the year, there is reconciliation, when the true amount to be paid to the generator is recalculated.

The value used for this reconciliation is the average output of the generator over the three settlement periods of highest output between 1 November and the end of February of the relevant charging year. Each settlement period must be separated by at least ten clear days. Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

For more details, please see CUSC 14.18.13–17.

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers now have two specific tariffs following the implementation of CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff.

HH gross demand tariffs

HH gross demand tariffs are charged to customers on their metered imports during the triads. Triads are the three Half-Hourly settlement periods of highest net system demand between November and February inclusive each year. They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is available, via the NGET website.[††] The tariff is charged on a £/kW basis. On triads, HH customers are charged the HH gross demand tariff against their gross demand volumes.

HH metered customers tend to be large industrial users, however as the rollout of smart meters progresses more domestic demand will become HH metered.

Embedded Export Tariffs

The EET is a new tariff under CMP 264/265 and is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

This tariff contains the locational demand elements, a phased residual over 3 years (reaching £0/kW in 2020/21) and an Avoided GSP Infrastructure Credit. The final zonal EET is floored at £0/kW for the avoidance of negative tariffs and is applied to the metered triad volumes of embedded exports for each demand Zone. The money to be paid out through the EET will be recovered through demand tariffs.

Suppliers must now submit forecasts for both HH gross demand and embedded export volumes as to what their expected demand volumes will be. Suppliers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon up to 16 months after the financial year in question.

For suppliers any embedded export payment will be fed into a net demand charge (gross demand – payment for embedded export) which will be capped at the level of the total demand charge so not to exceed the demand charge. Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads.

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

Note: HH demand and embedded export is charged at the GSP, where the transmission network connects to the distribution network, or directly to the customer in question.

NHH demand tariffs

NHH metered customers are charged based on their average demand usage between 16:00 – 19:00 on every day of the year. Suppliers must submit forecasts throughout the year as to what their expected demand volumes will be in each demand Zone. The tariff is charged on a p/kWh basis. The NHH methodology remains the same under CMP264/265.

Suppliers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon up to 16 months after the financial year in question.

Tools and Supporting Information

Further information

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

Charging forums

We will hold a webinar for the October tariffs on Friday 8 December from 10:30 to 11:30. If you wish to join the webinar, please contact us using the details below.

We always welcome questions and are happy to discuss specific aspects of the material contained in this tariffs report should you wish to do so.

Charging models

We can provide a copy of our charging model. If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

Numerical data

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

http://www.nationalgrid.com/TNUoS

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Appendices

Appendix A: Changes and possible changes to the charging methodology affecting future TNUoS forecasts

Appendix B: Demand locational tariffs

Appendix C: Annual Load Factors

Appendix D: National Grid Revenue Forecast

Appendix E: Contracted generation TEC

Appendix F: Historic & future chargeable demand data

Appendix G: Generation zones map

Appendix H: Demand zones map

Appendix A: Changes and possible changes to the charging methodology affecting future TNUoS forecasts

This section focuses on CUSC modifications which may impact on the TNUoS tariff calculation methodology.

Many modifications have been approved since the last five-year forecast, and all of these modifications have been reflected in the tariffs in this report (CMP264/265, CMP268, CMP282 and CMP283).

There are several other modifications which may affect future tariffs. For tariffs from 2019/20 onwards several other CUSC modifications are being considered (CMP271, CMP274, CMP276, CMP280, CMP 284, CMP286 and CMP287). Further modifications may be proposed which affect future years' tariffs. These modifications are not reflected in this report.

More information about current modifications can be found at the following location: https://www.nationalgrid.com/uk/electricity/codes/connection-use-system-code-cusc/modifications

A summary of the mods which could affect the future tariffs and their status are in the following table:

Table 28 – Summary of CUSC modifications affecting or potentially affecting TNUoS tariffs

Mod Number	Description	Status	Status in the Five-Year Forecast
Approved Modification affecting Methodology from 1 April 2018			
264	Embedded generation Triad avoidance standstill	Approved – WACM 4 was approved by Ofgem	**Implemented.** See below for information about Judicial Review.
265	Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market		
268	Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits	Approved – the original proposal was approved	**Implemented**
282	The effect negative demand has on zonal locational demand tariffs	Approved – the original proposal was approved	**Implemented**
283	Consequential changes to enable the interconnector Cap and Floor regime	Approved – the original proposal was approved	**Implemented**

Mod Number	Description	Status	Status in the Five-Year Forecast
Modification which may affect tariffs from 1 April 2018 if approved			
251	Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010	Pending Ofgem decision – the final modification report was submitted to Ofgem in October 2016.	**Not implemented.** See note below
Modifications proposing changes to methodology from or after 1 April 2019			
271	Improving the cost reflectivity of demand transmission charges	**Workgroup** Workgroup has recommended suspending work on these modifications, whilst the Ofgem TCR is ongoing.	Future modifications are not reflected in this report. Impacts of modifications on future tariffs will be considered during the development of the modifications.
274	Winter TNUoS Time of Use tariff TToUT for demand TNUoS		
276	Socialising TO costs associated with green policies		
280	Creation of a new generator TNUoS demand tariff which removes liability for TNUoS demand residual charges from generation and storage users	**Workgroup**	
284	Improving TNUoS cost reflectivity (reference node)	The modification has been **withdrawn** by the proposer, and no Relevant Party has taken over as official owner of this modification.	
286	Improving TNUoS predictability through increased notice of the target revenue used in the TNUoS tariff setting process	**Workgroup** shortly to commence.	
287	Improving TNUoS predictability through increased notice of inputs used in the TNUoS tariff setting process.	**Workgroup** shortly to commence.	
Modifications rejected by Ofgem.			
261	Ensuring the TNUoS paid by generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3)	Rejected	See note below.

Notes on specific methodology changes

CMP264 and CMP265 – Potential for a Judicial Review

Embedded generation Triad Avoidance Standstill and gross charging of TNUoS for HH demand where embedded generation is in Capacity Market

The following update has been posted to Ofgem's website following the approval of the two modifications:

"UPDATE AS OF 23 OCTOBER 2017:

Ofgem has been served with a claim for judicial review concerning its decision to approve WACM4 of CUSC modifications CMP264 and CMP265.
The case number is: CO/4397/2017.

National Grid Electricity Transmission plc has been named by the claimants as an interested party to the proceedings.

Ofgem has filed its Acknowledgement of Service and Summary Grounds of Resistance for contesting the claim.

Any bodies that consider themselves interested parties should take their own legal advice in relation to this matter.

Ofgem's decision to approve WACM4 of CUSC modifications CMP264 and CMP265 stands unless quashed by the court." [‡‡]

In line with our licence and code obligations, National Grid's implementation activities in readiness for April 2018 will continue.

CMP251 – Pending Ofgem decision, may impact 2018/19 tariffs

Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010

This modification seeks to remove the error margin from the G:D Split calculation. The post-charging year billing reconciliation process would recalculate the tariffs according to the €2.50/MWh limit imposed on generators by EU Regulation 838/2010, so that generator tariffs will charge exactly €2.50/MWh on average.

In setting tariffs for 2018/19, removing the error margin would transfer £114m of revenue from demand TNUoS to generation TNUoS. This would increase the generation residual from -£2.34/kW to -£0.81/kW. The gross HH residual would fall from £46.90/kW to £44.72/kW. The average NHH tariffs would decrease from 6.16p/kWh to 5.87p/kWh.

[‡‡] https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators

CMP261 – Rejected by Ofgem

Ensuring the TNUoS paid by generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3)

CMP261 contested that the TNUoS paid by generators in GB in Charging Year 2015/16 was not in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3). Ofgem rejected this modification in November 2017.

No changes to the methodology follow as a result of Ofgem's decision. Any changes to the allocation of revenue between generation and demand will require a CUSC modification. National Grid will not be proposing any changes to the methodology for 2018/19.

This report therefore assumes the *status quo* methodology for the split of generation and demand revenues.

Appendix B: Demand locational tariffs

The following tables show the components of the Gross HH Demand charge. The locational elements (peak security and year round) and residual.

For the Embedded Export Tariffs, the demand locational elements (peak security and year round) is added to the phased residual (in 2018/19 and 2019/20) and the AGIC, and the resulting tariff floored at zero to avoid negative tariffs.

Table 29 – Elements of the demand locational tariff for 2018/19

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	-1.993368	-27.150698	46.900294
2	Southern Scotland	-1.961762	-20.401921	46.900294
3	Northern	-3.480363	-7.090431	46.900294
4	North West	-1.173400	-2.455444	46.900294
5	Yorkshire	-2.933824	-0.729525	46.900294
6	N Wales & Mersey	-1.657943	-0.403630	46.900294
7	East Midlands	-2.083848	1.978650	46.900294
8	Midlands	-1.179327	2.532494	46.900294
9	Eastern	1.267987	0.603964	46.900294
10	South Wales	-5.354272	4.639584	46.900294
11	South East	3.987643	1.032637	46.900294
12	London	5.385967	1.957062	46.900294
13	Southern	2.162847	4.140511	46.900294
14	South Western	0.296077	6.067652	46.900294

Table 30 – Elements of the demand locational tariff for 2019/20

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	-1.982874	-28.463727	52.133975
2	Southern Scotland	-2.201787	-20.763507	52.133975
3	Northern	-3.642435	-6.990777	52.133975
4	North West	-1.328706	-2.406292	52.133975
5	Yorkshire	-3.153040	-0.507585	52.133975
6	N Wales & Mersey	-1.863272	-0.303844	52.133975
7	East Midlands	-2.216382	2.340628	52.133975
8	Midlands	-1.468306	2.829388	52.133975
9	Eastern	1.319040	0.880796	52.133975
10	South Wales	-5.942829	4.698673	52.133975
11	South East	4.196723	0.774353	52.133975
12	London	5.630045	2.446419	52.133975
13	Southern	1.943261	4.476748	52.133975
14	South Western	-0.601753	5.767531	52.133975

Table 31 – Elements of the demand locational tariff for 2020/21

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	0.287839	-27.886871	55.539314
2	Southern Scotland	-1.580464	-19.972262	55.539314
3	Northern	-4.546286	-6.683748	55.539314
4	North West	-2.442171	-2.090531	55.539314
5	Yorkshire	-4.288515	-0.097837	55.539314
6	N Wales & Mersey	-2.783109	-0.097008	55.539314
7	East Midlands	-2.323732	2.371750	55.539314
8	Midlands	-1.803350	2.824742	55.539314
9	Eastern	1.624088	0.749225	55.539314
10	South Wales	-5.474963	4.114696	55.539314
11	South East	4.474398	0.324364	55.539314
12	London	6.119987	2.260780	55.539314
13	Southern	2.375063	3.757830	55.539314
14	South Western	-0.120841	4.666514	55.539314

Table 32 – Elements of the demand locational tariff for 2021/22

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	-2.001475	-31.174789	60.363687
2	Southern Scotland	-3.097808	-22.137818	60.363687
3	Northern	-4.285563	-7.444033	60.363687
4	North West	-2.186488	-2.387566	60.363687
5	Yorkshire	-3.909567	-0.207487	60.363687
6	N Wales & Mersey	-2.640245	-0.457207	60.363687
7	East Midlands	-2.275911	2.742665	60.363687
8	Midlands	-1.690206	3.041010	60.363687
9	Eastern	1.673280	1.129005	60.363687
10	South Wales	-5.367179	4.639806	60.363687
11	South East	4.463366	0.679135	60.363687
12	London	6.272285	2.666392	60.363687
13	Southern	2.435442	3.945530	60.363687
14	South Western	-0.612602	3.963773	60.363687

Table 33 – Elements of the demand locational tariff for 2022/23

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	-2.153753	-32.688159	63.651085
2	Southern Scotland	-3.723720	-22.603398	63.651085
3	Northern	-4.816472	-7.639173	63.651085
4	North West	-2.535260	-2.382463	63.651085
5	Yorkshire	-4.306671	-0.035787	63.651085
6	N Wales & Mersey	-2.690293	-0.257693	63.651085
7	East Midlands	-2.506314	2.925513	63.651085
8	Midlands	-1.550686	3.085640	63.651085
9	Eastern	1.418501	1.444155	63.651085
10	South Wales	-4.178061	4.539883	63.651085
11	South East	4.523468	0.548606	63.651085
12	London	6.272280	2.963951	63.651085
13	Southern	2.789384	3.501968	63.651085
14	South Western	0.261262	3.819194	63.651085

Appendix C: Annual Load Factors

ALFs

Table 19 lists the Annual Load Factors (ALFs) of generators expected to be liable for generator charges during 2018/19. ALFs are used to scale the Shared Year Round element of tariffs for each generator, and the Year Round Not shared for Conventional Carbon generators, so that each has a tariff appropriate to its historical load factor.

ALFs have been calculated using Transmission Entry Capacity, Metered Output and Final Physical Notifications from charging years 2012/13 to 2016/17. Generators which commissioned after 1 April 2014 will have fewer than three complete years of data so the Generic ALFs listed below are added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2018/19 also use the Generic ALF.

These ALFs have been updated since the February five year forecast.[§§]

Table 34: Specific Annual Load Factors

[§§] *The Final ALFs report for 2018-19 can be found here:*
http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
ABERTHAW	Coal	Actual	Actual	Actual	Actual	Actual	74.0137%	65.5413%	59.0043%	54.2611%	50.8335%	59.6022%
ACHRUACH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.6464%	36.7140%	34.8994%
AN SUIDHE WIND FARM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.6380%	41.5843%	36.9422%	35.4900%	34.0938%	35.5087%
ARECLEOCH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.4826%	33.8296%	29.7298%	36.8612%	19.7246%	32.0140%
BAGLAN BAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.5756%	16.4106%	37.9194%	29.1228%	55.2030%	31.5393%
BARKING	CCGT_CHP	Actual	Actual	Partial	Generic	Generic	2.3383%	1.8802%	14.1930%	0.0000%	0.0000%	6.1371%
BARROW OFFSHORE WIND LTD	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	42.8840%	54.1080%	47.0231%	47.1791%	44.2584%	46.1536%
BARRY	CCGT_CHP	Actual	Actual	Actual	Actual	Partial	0.6999%	1.2989%	0.4003%	2.1727%	25.4300%	1.3905%
BEAULY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	25.4532%	35.6683%	37.1167%	35.0094%	30.4872%	33.7216%
BEINNEUN	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	30.9622%	33.2125%
BHLARAIDH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.4338%	34.0364%
BLACK LAW	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	22.0683%	31.9648%	26.7881%	26.9035%	23.4623%	25.7180%
BLACKLAW EXTENSION	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.4635%	13.1095%	26.9702%
BRIMSDOWN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	21.8759%	18.7645%	11.1229%	16.4463%	45.0615%	19.0289%
BURBO BANK	Offshore_Wind	Generic	Generic	Generic	Actual	Actual	0.0000%	0.0000%	0.0000%	16.7781%	25.0233%	30.4355%
CARRAIG GHEAL	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	29.8118%	45.2760%	48.9277%	45.6254%	40.4211%	46.6097%
CARRINGTON	CCGT_CHP	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.7318%	58.0115%	46.6520%
CLUNIE SCHEME	Hydro	Actual	Actual	Actual	Actual	Actual	33.4563%	45.3256%	43.2488%	47.9711%	32.8297%	40.6769%
CLYDE (NORTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.5345%	42.6598%	36.8882%	41.4120%	26.8858%	35.6116%
CLYDE (SOUTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.6084%	39.8941%	29.4115%	39.9615%	34.8751%	35.4592%
CONNAHS QUAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.5104%	12.8233%	18.3739%	28.2713%	37.4588%	21.7185%
CONON CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	47.5286%	54.2820%	55.5287%	58.9860%	48.6782%	52.8296%
CORRIEGARTH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	22.5644%	30.4133%
CORRIEMOILLIE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.2315%	33.6356%
CORYTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.6869%	9.7852%	17.5123%	26.4000%	63.0383%	19.8664%
COTTAM	Coal	Actual	Actual	Actual	Actual	Actual	65.0700%	67.3951%	51.4426%	34.4157%	14.9387%	50.3095%
COTTAM DEVELOPMENT CENTRE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	13.7361%	16.0249%	31.3132%	28.2382%	67.2482%	25.1921%
COUR	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.3246%	35.6667%
COWES	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.1743%	0.0956%	0.3135%	0.4912%	0.5319%	0.3264%
CRUACHAN	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	8.4281%	9.6969%	9.0516%	8.8673%	7.1914%	8.7823%
CRYSTAL RIG II	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	40.6845%	50.2549%	47.5958%	48.3836%	40.2679%	45.5546%
CRYSTAL RIG III	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	39.9503%	36.2086%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
DAMHEAD CREEK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	45.0617%	77.1783%	67.4641%	64.8983%	68.1119%	66.8248%
DEESIDE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	19.7551%	17.3035%	13.9018%	17.4579%	27.1090%	18.1722%
DERSALLOCH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.7728%	34.1494%
DIDCOT B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	49.0134%	18.6624%	25.5345%	41.1389%	50.1358%	38.5623%
DIDCOT GTS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0720%	0.0902%	0.2843%	0.4861%	0.0452%	0.1488%
DINORWIG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	15.0990%	15.0898%	15.0650%	14.6353%	15.9596%	15.0846%
DRAX	Coal	Actual	Actual	Actual	Actual	Actual	82.4774%	80.5151%	82.2149%	76.2030%	62.2705%	79.6443%
DUDGEON	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	42.4791%	47.1631%
DUNGENESS B	Nuclear	Actual	Actual	Actual	Actual	Actual	59.8295%	61.0068%	54.6917%	70.7617%	79.3403%	63.8660%
DUNLAW EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.3771%	34.8226%	30.0797%	29.1203%	26.5549%	30.5257%
DUNMAGLASS	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.9713%	35.8822%
EDINBANE WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	29.3933%	39.4785%	31.2458%	35.5937%	32.5009%	33.1135%
EGGBOROUGH	Coal	Actual	Actual	Actual	Actual	Partial	72.6884%	72.1843%	45.7421%	27.0157%	39.7693%	63.5383%
ERROCHTY	Hydro	Actual	Actual	Actual	Actual	Actual	14.5869%	28.2628%	25.3585%	28.1507%	16.1775%	23.2289%
EWE HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.3314%	34.0023%
FALLAGO	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	32.9869%	54.8683%	44.7267%	55.7992%	43.2176%	51.7981%
FARR WINDFARM TOMATIN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	34.0149%	44.7212%	38.5712%	40.9963%	34.1766%	37.9147%
FASNAKYLE G1 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	22.1176%	35.3695%	57.4834%	53.1573%	30.9768%	39.8345%
FAWLEY CHP	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.1362%	63.3619%	72.8484%	57.6978%	63.2006%	62.5662%
FFESTINIOGG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	2.9286%	5.4631%	4.3251%	3.4113%	5.6749%	4.3999%
FIDDLERS FERRY	Coal	Actual	Actual	Actual	Actual	Actual	61.6386%	49.0374%	45.2435%	27.4591%	8.2478%	40.5800%
FINLARIG	Hydro	Actual	Actual	Actual	Actual	Actual	40.2952%	59.9142%	59.4092%	65.1349%	49.6402%	56.3212%
FOYERS	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	13.4800%	14.7097%	12.3048%	15.4323%	11.3046%	13.4982%
FREASDAIL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.5600%	33.7451%
GALAWHISTLE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	34.9764%	34.5506%
GARRY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	48.5993%	55.9308%	64.3828%	60.2772%	61.0498%	59.0859%
GLANDFORD BRIGG	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.3336%	1.5673%	0.5401%	1.8191%	2.7682%	1.3088%
GLEN APP	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	25.1373%	31.2709%
GLENDOE	Hydro	Actual	Actual	Actual	Actual	Actual	17.3350%	36.3802%	32.3494%	34.8532%	23.8605%	30.3544%
GLENMORISTON	Hydro	Actual	Actual	Actual	Actual	Actual	36.3045%	44.4594%	48.7487%	50.6921%	34.6709%	43.1709%
GORDONBUSH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	37.8930%	46.5594%	47.7981%	47.7161%	50.4126%	47.3579%
GRAIN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	25.4580%	41.3833%	44.0031%	39.7895%	53.8227%	41.7253%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
GRANGEMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	52.8594%	55.9047%	62.6168%	59.8274%	51.4558%	56.1972%
GREAT YARMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	19.0270%	20.7409%	18.6633%	59.8957%	63.5120%	33.2212%
GREATER GABBARD OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	40.1778%	48.3038%	42.1327%	50.2468%	43.1132%	44.5166%
GRIFFIN WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	17.9885%	31.9566%	31.3152%	31.0284%	25.8228%	29.3888%
GUNFLEET SANDS I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	50.1496%	56.6472%	47.0132%	50.4650%	45.7940%	49.2093%
GUNFLEET SANDS II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	45.0132%	52.2361%	44.7211%	49.0521%	43.9893%	46.2622%
GWYNT Y MOR	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	18.8535%	8.0036%	61.6185%	63.1276%	44.8323%	56.5262%
HADYARD HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	27.6927%	31.9488%	27.7635%	36.6527%	31.4364%	30.3829%
HARESTANES	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	22.2448%	28.6355%	27.8093%	22.5464%	26.3304%
HARTLEPOOL	Nuclear	Actual	Actual	Actual	Actual	Actual	80.2632%	73.7557%	56.2803%	53.8666%	78.0390%	69.3583%
HEYSHAM	Nuclear	Actual	Actual	Actual	Actual	Actual	83.3828%	73.3628%	68.8252%	72.7344%	79.6169%	75.2380%
HINKLEY POINT B	Nuclear	Actual	Actual	Actual	Actual	Actual	61.7582%	68.8664%	70.1411%	67.6412%	71.2265%	68.8829%
HUMBER GATEWAY OFFSHORE WIND FARM	Offshore_Wind	Generic	Generic	Generic	Actual	Actual	0.0000%	0.0000%	0.0000%	62.9631%	59.7195%	57.3959%
HUNTERSTON	Nuclear	Actual	Actual	Actual	Actual	Actual	73.5984%	84.7953%	79.1368%	82.1786%	83.2939%	81.5365%
IMMINGHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	50.1793%	37.8219%	56.8316%	69.4686%	71.9550%	58.8265%
INDIAN QUEENS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.3423%	0.2321%	0.0876%	0.0723%	0.0847%	0.1348%
KEADBY	CCGT_CHP	Actual	Actual	Generic	Partial	Actual	4.6125%	0.0001%	0.0000%	35.1858%	28.6076%	11.0734%
KILBRAUR	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	45.2306%	51.3777%	54.3550%	50.3807%	46.5342%	49.4309%
KILGALLIOCH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	25.2739%	31.3164%
KILLIN CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	32.3429%	45.5356%	44.8205%	53.2348%	27.4962%	40.8997%
KINGS LYNN A	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	0.0003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0001%
LANGAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.9115%	40.8749%	34.8629%	16.5310%	44.5413%	39.2164%
LINCS WIND FARM	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	20.3244%	46.5987%	43.8178%	49.1306%	44.5192%	46.7495%
LITTLE BARFORD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.3807%	33.6286%	49.6644%	39.9829%	64.8597%	41.0920%
LOCHLUICHART	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	24.9397%	20.2103%	29.2663%	31.6897%	27.0554%
LONDON ARRAY	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	38.9520%	51.2703%	64.0880%	66.8682%	53.6245%	61.5269%
LYNEMOUTH	Coal	Generic	Generic	Generic	Partial	Generic	0.0000%	0.0000%	0.0000%	68.0196%	0.0000%	58.6875%
MARCHWOOD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	43.3537%	48.6845%	66.4021%	55.0879%	75.4248%	56.7248%
MARK HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	30.1675%	30.2863%	26.7942%	34.0227%	21.9653%	29.0827%
MEDWAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	1.0718%	14.5545%	28.0962%	34.1799%	35.1505%	25.6102%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
MILLENNIUM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	42.1318%	52.6618%	53.2636%	48.4038%	44.9764%	48.6806%
NANT	Hydro	Actual	Actual	Actual	Actual	Actual	20.8965%	35.5883%	36.4040%	37.3788%	30.6350%	34.2091%
ORMONDE	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	48.8406%	49.6561%	42.8711%	47.1986%	41.2188%	46.5753%
PEMBROKE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.5434%	60.3928%	67.5346%	64.5596%	77.6478%	64.5459%
PEN Y CYMOEDD	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	26.9446%	31.8733%
PETERBOROUGH	CCGT_CHP	Actual	Actual	Actual	Partial	Actual	0.9506%	1.8311%	1.0929%	4.1032%	1.7914%	1.5718%
PETERHEAD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	31.3766%	41.8811%	0.4858%	23.3813%	42.2292%	32.2130%
RACE BANK	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	45.3062%	48.1055%
RATCLIFFE-ON-SOAR	Coal	Actual	Actual	Actual	Actual	Actual	66.7461%	71.7403%	56.1767%	19.6814%	15.4657%	47.5347%
ROBIN RIGG EAST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	37.4157%	46.7562%	55.3209%	51.9700%	50.5096%	49.7453%
ROBIN RIGG WEST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	38.2254%	48.0629%	53.4150%	56.0881%	51.5383%	51.0054%
ROCKSAVAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.4820%	2.6155%	4.4252%	19.8061%	58.6806%	21.9044%
ROOSECOTE	-	Actual	Actual	Actual	Actual	Actual	0.0121%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
RUGELEY B	-	Actual	Actual	Actual	Actual	Actual	68.6109%	82.6505%	59.4472%	44.5189%	12.3429%	57.5257%
RYE HOUSE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	10.7188%	7.4695%	5.3701%	7.7906%	15.6538%	8.6596%
SALTEND	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	81.5834%	69.0062%	67.9518%	55.6228%	77.4019%	71.4533%
SEABANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.2311%	18.2781%	25.6956%	27.2136%	41.6815%	23.7291%
SELLAFIELD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	14.0549%	25.0221%	18.9719%	28.6790%	19.8588%	21.2842%
SEVERN POWER	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.7976%	32.4163%	24.6354%	18.3226%	64.4246%	28.2831%
SHERINGHAM SHOAL	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	36.6431%	49.3517%	46.2286%	53.6184%	46.9715%	47.5173%
SHOREHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.0000%	20.7501%	10.2239%	48.9514%	68.9863%	26.6418%
SIZEWELL B	Nuclear	Actual	Actual	Actual	Actual	Actual	96.7260%	82.5051%	84.7924%	98.7826%	81.6359%	88.0078%
SLOY G2 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	9.1252%	14.3471%	15.5941%	13.9439%	8.1782%	12.4721%
SOUTH HUMBER BANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.9763%	24.3373%	34.4673%	48.6753%	55.3419%	37.0396%
SPALDING	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	34.6976%	33.4800%	39.3092%	47.9407%	60.9748%	40.6492%
STAYTHORPE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	54.4117%	37.6216%	56.6148%	69.4422%	65.7791%	58.9352%
STRATHY NORTH & SOUTH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	49.6340%	36.1987%	40.0568%
SUTTON BRIDGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.1652%	9.4124%	17.2025%	13.1999%	38.0184%	16.8559%
TAYLORS LANE	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.2037%	0.0483%	0.0640%	0.1708%	0.8047%	0.1462%
THANET OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	41.1093%	39.7489%	35.5935%	41.3434%	33.7132%	38.8172%
TODDLEBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.7175%	39.5374%	33.7211%	35.0823%	31.3435%	33.8403%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	84.8669%	86.4669%	91.4945%	85.7725%	97.9942%	87.9113%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
USKMOUTH	Coal	Actual	Actual	Partial	Actual	Actual	45.1938%	38.9899%	46.9428%	25.5184%	24.3304%	36.5674%
WALNEY I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	44.2799%	57.7046%	52.0555%	50.7535%	47.4617%	50.0902%
WALNEY II	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	54.7907%	61.9219%	58.2355%	35.7988%	54.9727%	58.3767%
WEST BURTON	Coal	Actual	Actual	Actual	Actual	Actual	70.5868%	68.9176%	61.5364%	32.7325%	10.1071%	54.3955%
WEST BURTON B	CCGT_CHP	Partial	Actual	Actual	Actual	Actual	21.3299%	30.3021%	46.8421%	59.3477%	54.2878%	53.4925%
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	40.4447%	40.0506%	48.7540%	48.7691%	45.8579%
WESTERMOST ROUGH	Offshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	26.2900%	54.8014%	58.1061%	46.3992%
WHITELEE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.2265%	35.1074%	29.8105%	31.8773%	27.2893%	29.9714%
WHITELEE EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	12.4146%	27.0102%	27.7787%	26.7655%	23.5253%	25.7670%
WILTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	3.4258%	4.4941%	21.5867%	16.1379%	14.4130%	11.6817%

Table 35: Generic Annual Load Factors

Technology	Generic ALF
Gas_Oil	0.1890%
Pumped_Storage	10.4412%
Tidal	18.9000%
Biomass	26.8847%
Wave	31.0000%
Onshore_Wind	34.3377%
CCGT_CHP	43.2127%
Hydro	41.3656%
Offshore_Wind	49.5051%
Coal	54.0215%
Nuclear	76.4001%

*Note: ALF figures for Wave and Tidal technology are generic figures provided by BEIS due to no metered data being available.

The Biomass ALF for 2016/17 has been copied from the 2015/16 year due to there not being any single majority biomass-fired stations operating over that period.

Appendix D: National Grid Revenue Forecast

Table 36 – Indicative National Grid Revenue Forecast

National Grid Revenue Forecast			Feb-17							
Regulatory Year			2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	Notes
Actual RPI			264.99							
RPI Actual		RPIAt	1.228			-	-	-	-	
Assumed Interest Rate		It	0.336%	0.292%	0.375%	0.563%	0.821%	0.821%	0.821%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1,571.4	1,554.9	1,587.6	1,585.2	1,571.6	1,571.6	1,571.6	From Licence; assumed similar in 2021/22
Price Control Financial Model Iteration Adjustment	A2	MODt	-185.4	-253.3	-311.0	-334.0	-234.0	-234.0	-234.0	Determined by Ofgem; NGET forecast
RPI True Up	A3	TRUt	-19.9	-31.4	-6.1	3.3	2.1	-1.0	0.0	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	1.0%	1.8%	3.5%	3.5%	3.0%	3.0%	3.0%	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	2.1%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.1%	3.0%	3.0%	3.0%	3.0%	3.0%	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.2330	1.2710	1.3140	1.3570	1.3960	1.4390	1.4810	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1684.4**	**1614.5**	**1669.5**	**1702.3**	**1870.2**	**1923.4**	**1981.0**	
Pass-Through Business Rates	B1	RBt	1.5	2.7	1.6	35.1	35.6	36.5	37.5	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.0	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Licence Fee	B3	LFt	2.7	3.2	-0.4	4.5	2.6	10.4	1.0	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt	2.7	0.5	1.3	0.8	0.7	0.8	0.8	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.1	0.0	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	294.6	321.0	346.3	390.0	367.2	425.6	402.3	14/15 - 17/18 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	322.8	301.4	355.1	349.4	363.2	418.6	431.8	14/15 - 17/18 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	260.8	270.2	312.1	459.9	497.4	515.8	595.4	14/15 - 17/18 Charge setting. Later from OFTO Calculation.
Embedded Offshore Pass-Through	B9	OFETt	0.7	0.5	0.6	0.6	0.6	0.6	0.6	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**885.9**	**899.4**	**1016.8**	**1240.2**	**1267.4**	**1408.2**	**1469.4**	
Reliability Incentive Adjustment	C1	RIt	3.9	4.0	4.1	4.2	4.3	4.5	4.5	Licensee Actual/Forecast
Stakeholder Satisfaction Adjustment	C2	SSOt	10.1	8.6	7.6	8.6	8.5	8.5	8.7	Licensee Actual/Forecast
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	2.7	2.6	1.4	1.6	1.7	1.7	1.7	Licensee Actual/Forecast
Awarded Environmental Discretionary Rewards	C4	EDRt	2.0	0.0	0.0	0.0	0.0	0.0	0.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**18.7**	**15.3**	**13.1**	**14.4**	**14.5**	**14.7**	**14.9**	
Network Innovation Allowance	D	NIAt	10.6	10.2	10.5	10.7	11.8	12.1	12.5	Licensee Actual/Forecast
Network Innovation Competition	E	NICFt	44.9	32.1	40.5	40.5	40.5	40.5	40.5	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt		0.0	2.0	2.0	2.0	2.0	2.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	2.9	6.1	6.3	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	0.1	-1.1	-0.0	0.0	0.0	0.0	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt	104.0	97.0	-55.4	0.0	0.0	0.0	0.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2751.3**	**2673.4**	**2703.3**	**3010.2**	**3206.4**	**3400.9**	**3520.3**	
Termination Charges	B5		0.0	0.0	0.1	0.0	0.0	0.0	0.0	
Pre-vesting connection charges	P		42.7	41.9	41.9	41.9	41.9	41.9	41.9	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2708.7**	**2631.5**	**2661.3**	**2968.4**	**3164.5**	**3359.0**	**3478.4**	
Final Collected Revenue	U	TNRt	2592.7	0.0						
Forecast percentage change to Maximum Revenue M				**-2.8%**	**1.1%**	**11.4%**	**6.5%**	**6.1%**	**3.5%**	
Forecast percentage change to TNUoS Collected Revenue T				**-2.8%**	**1.1%**	**11.5%**	**6.6%**	**6.1%**	**3.6%**	

Notes:
All monies are 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
NIC payments to all Transmission Owners are inlcuded in National Grid Maximum Revenue and are included here

Appendix E: Contracted generation TEC

Table 37 – Contracted generation TEC at peak

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Aquind Interconnector	Interconnectors	LOVE40	26	0	0	0	2000	2000
Auchencrosh (interconnector CCT)	Interconnectors	AUCH20	10	80	80	80	80	80
Belgium Interconnector (Nemo)	Interconnectors	CANT40	24	1000	1000	1000	1000	1000
Britned	Interconnectors	GRAI40	24	1200	1200	1200	1200	1200
East West Interconnector	Interconnectors	CONQ40	16	505	505	505	505	505
ElecLink	Interconnectors	SELL40	24	1000	1000	1000	1000	1000
FAB Link Interconnector	Interconnectors	EXET40	26	0	0	1400	1400	1400
Greenage Power Interconnector	Interconnectors	GRAI40	24	0	0	0	0	1400
Greenlink	Interconnectors	PEMB40	20	0	0	0	0	500
Gridlink Interconnector	Interconnectors	KINO40	24	0	0	0	0	1500
IFA Interconnector	Interconnectors	SELL40	24	2000	2000	2000	2000	2000
IFA2 Interconnector	Interconnectors	FAWL40	26	0	1100	1100	1100	1100
Norway Interconnector	Interconnectors	PEHE40	2	0	0	0	1400	1400
NS Link	Interconnectors	BLYT4A	13	0	0	1400	1400	1400
Viking Link Denmark Interconnector	Interconnectors	BICF4A	17	0	0	0	0	1500
Aberarder Wind Farm	Wind Onshore	ABED10	1	0	0	0	41.8	41.8
Aberdeen Offshore Wind Farm	Wind Offshore	ABBA10	10	99	99	99	99	99
Aberthaw	Coal	ABTH20	21	1610	1610	1610	1610	1610
A'Chruach Wind Farm	Wind Onshore	ACHR1R	7	43	43	43	43	43
Afton	Wind Onshore	BLAC10	10	50	50	50	50	50
Aigas	Hydro	AIGA1Q	1	20	20	20	20	20
Aikengall II Windfarm	Wind Onshore	WDOD10	11	140	140	140	140	140
An Suidhe Wind Farm, Argyll (SRO)	Wind Onshore	ANSU10	7	19.3	19.3	19.3	19.3	19.3
Arecleoch	Wind Onshore	AREC10	10	114	114	114	114	114
Aultmore Wind Farm	Wind Onshore	AULW10	1	0	0	29.5	29.5	29.5

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Bad a Cheo Wind Farm	Wind Onshore	MYBS11	1	29.9	29.9	29.9	29.9	29.9
Baglan Bay	CCGT	BAGB20	21	552	552	552	552	552
Barrow Offshore Wind Farm	Wind Offshore	HEYS40	14	90	90	90	90	90
Barry Power Station	CCGT	ABTH20	21	142	142	142	142	142
Beatrice Wind Farm	Wind Offshore	BLHI40	1	294	588	588	588	588
Beaw Field Wind Farm	Wind Onshore	KERG20	1	0	0	72	72	72
Beinn an Tuirc 3	Wind Onshore	CAAD1Q	7	0	0	50	50	50
Beinneun Wind Farm	Wind Onshore	BEIN10	3	109	109	109	109	109
Benbrack Wind Farm	Wind Onshore	KEON10	1	0	72	72	72	72
Bhlaraidh Wind Farm	Wind Onshore	BHLA10	3	108	108	108	108	108
Blackcraig Wind Farm	Wind Onshore	BLCW10	10	57.5	52.9	52.9	52.9	52.9
Blacklaw	Wind Onshore	BLKL10	11	118	118	118	118	118
Blacklaw Extension	Wind Onshore	BLKX10	11	60	60	60	60	60
BP Grangemouth	CHP	GRMO20	9	120	120	120	120	120
Bradwell B	Nuclear	GRAI40	24	0	0	0	1670	1670
Burbo Bank Extension Offshore Wind Farm	Wind Offshore	BODE40	16	254	254	254	254	254
C.Gen Killingholme North Power Station	CCGT	KILL40	15	0	0	0	490	490
Cantick Head	Tidal	BASK20	1	0	0	0	30	95
Carnedd Wen Wind Farm	Wind Onshore	TRAW40	18	0	150	150	150	150
Carraig Gheal Wind Farm	Wind Onshore	FERO10	7	46	46	46	46	46
Carrington Power Station	CCGT	CARR40	16	910	910	910	910	910
CDCL	CCGT	COTT40	16	445	445	445	445	445
Chirmorie Wind Farm	Wind Onshore	MAHI10	10	0	0	0	0	80
Clunie	Hydro	CLUN1S	5	61.2	61.2	61.2	61.2	61.2
Clyde North	Wind Onshore	CLYN2Q	11	374.5	374.5	374.5	374.5	374.5
Clyde South	Wind Onshore	CLYS2R	11	128.8	128.8	128.8	128.8	128.8
Codling Park Wind Farm	Wind Offshore	PENT40	19	0	0	0	1000	1000
Connahs Quay	CCGT	CONQ40	16	1380	1380	1380	1380	1380
Corby	CCGT	GREN40_EME	18	401	401	401	401	401
Corriegarth	Wind Onshore	COGA10	1	69	69	69	69	69
Corriemoillie Wind Farm	Wind Onshore	CORI10	1	47.5	47.5	47.5	47.5	47.5
Coryton	CCGT	COSO40	24	704	704	704	704	704
Costa Head Wind Farm	Wind Onshore	BASK20	1	0	0	0	0	20.4

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Cottam	Coal	COTT40	16	2000	2000	2000	2000	2000
Cour Wind Farm	Wind Onshore	CRSS10	7	20.5	20.5	20.5	20.5	20.5
Creag Riabhach Wind Farm	Wind Onshore	CASS1Q	1	0	0	0	72.6	72.6
Crookedstane Windfarm	Wind Onshore	CLYS2R	11	0	26.8	26.8	26.8	26.8
Crossburns Wind Farm	Wind Onshore	CROB20	5	0	0	0	99	99
Crossdykes	Wind Onshore	EWEH1Q	12	46	46	46	46	46
Cruachan	Pump Storage	CRUA20	8	440	440	440	440	440
Crystal Rig 2 Wind Farm	Wind Onshore	CRYR40	11	138	138	138	138	138
Crystal Rig 3 Wind Farm	Wind Onshore	CRYR40	11	13.8	13.8	62	62	62
Culligran	Hydro	CULL1Q	1	19.1	19.1	19.1	19.1	19.1
Cumberhead	Wind Onshore	GAWH10	11	0	0	50	50	50
Dalquhandy Wind Farm	Wind Onshore	DALQ10	11	0	0	0	45	45
Damhead Creek	CCGT	KINO40	24	805	805	805	805	805
Damhead Creek II	CCGT	KINO40	24	0	0	1800	1800	1800
Deanie	Hydro	DEAN1Q	1	38	38	38	38	38
Deeside	CCGT	CONQ40	16	1	1	1	1	1
Dersalloch Wind Farm	Wind Onshore	DERS1Q	10	69	69	69	69	69
Didcot B	CCGT	DIDC40	25	1550	1550	1550	1550	1550
Dinorwig	Pump Storage	DINO40	19	1644	1644	1644	1644	1644
Dogger Bank Platform 1	Wind Offshore	CREB40	15	0	0	0	500	1000
Dogger Bank Platform 4	Wind Offshore	CREB40	15	0	0	0	500	1000
Dorenell Wind Farm	Wind Onshore	DORE11	1	220	220	220	220	220
Douglas West	Wind Onshore	COAL10	11	0	0	0	45	45
Drax (Biomass)	Biomass	DRAX40	15	1905	1905	1905	1905	1905
Drax (Coal)	Coal	DRAX40	15	2001	2001	2001	2001	2001
Druim Leathann	Wind Onshore	COUA1Q	5	0	0	0	46.2	46.2
Dudgeon Offshore Wind Farm	Wind Offshore	NECT40	17	400	400	400	400	400
Dungeness B	Nuclear	DUNG40	24	1091	1091	1091	1091	1091
Dunlaw Extension	Wind Onshore	DUNE10	11	29.75	29.75	29.75	29.75	29.75
Dunmaglass Wind Farm	Wind Onshore	DUNM10	1	94	94	94	94	94
East Anglia 2	Wind Offshore	BRFO40	18	0	0	0	0	1200
East Anglia 3	Wind Offshore	BRFO40	18	0	0	0	1200	1200
East Anglia One	Wind Offshore	BRFO40	18	129	680	680	680	680

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
East Anglia One North	Wind Offshore	BRFO40	18	0	0	520	520	520
Edinbane Wind, Skye	Wind Onshore	EDIN10	4	42.75	42.75	42.75	42.75	42.75
Eggborough	Coal	EGGB40	15	1870	1870	1870	1870	1870
Enfield	CCGT	BRIM2A_LPN	24	408	408	408	408	408
Enoch Hill	Wind Onshore	ENHI10	10	0	0	69	69	69
Errochty	Hydro	ERRO10	5	75	75	75	75	75
Ewe Hill	Wind Onshore	EWEH1Q	12	39	39	39	39	39
Fallago Rig Wind Farm	Wind Onshore	FALL40	11	144	144	144	144	144
Farr Wind Farm, Tomatin	Wind Onshore	FAAR1Q	1	92	92	92	92	92
Fasnakyle G1 & G2	Hydro	FASN20	3	46	46	46	46	46
Fawley CHP	CHP	FAWL40	26	158	158	158	158	158
Ffestiniog	Pump Storage	FFES20	16	360	360	360	360	360
Fiddlers Ferry	Coal	FIDF20_ENW	15	1455	1455	1987	1987	1987
Finlarig	Hydro	FINL1Q	6	16.5	16.5	16.5	16.5	16.5
Firth of Forth Offshore Wind Farm 1A	Wind Offshore	TEAL20	9	0	0	0	545	545
Firth of Forth Offshore Wind Farm 1B	Wind Offshore	TEAL20	9	0	0	0	530	530
Foyers	Pump Storage	FOYE20	1	300	300	300	300	300
Freasdail	Wind Onshore	CRSS10	7	22.2	22.2	22.2	22.2	22.2
Galawhistle Wind Farm	Wind Onshore	GAWH10	11	55.2	55.2	55.2	55.2	55.2
Galloper Wind Farm	Wind Offshore	LEIS10	18	184	184	184	184	184
Gateway Energy Centre Power Station	CCGT	COSO40	24	0	0	1096	1096	1096
Gilston Hill Wind Farm	Wind Onshore	DUNE10	11	0	0	21	21	21
Glen App Windfarm	Wind Onshore	AREC10	10	32.2	32.2	32.2	32.2	32.2
Glen Kyllachy Wind Farm	Wind Onshore	GLKY10	1	0	0	48.5	48.5	48.5
Glen Ullinish Wind Farm	Wind Onshore	GLNU10	4	0	0	0	42	42
Glendoe	Hydro	GLDO1G	3	99.9	99.9	99.9	99.9	99.9
Glenmoriston	Hydro	GLEN1Q	3	37	37	37	37	37
Glenmuckloch Pumped Storage	Pump Storage	NECU10	10	0	0	0	0	99.9
Glenmuckloch Wind Farm	Wind Onshore	GLGL1Q	10	0	0	0	25.6	25.6
Glenouther Wind Farm (Harelaw)	Wind Onshore	NEIL10	11	0	0	24	24	24
Golticlay Wind Farm	Wind Onshore	SPIT10	1	0	0	0	0	64.6
Gordonbush Wind	Wind Onshore	GORW20	1	70	70	70	70	108
Grain	CCGT	GRAI40	24	1517	1517	1517	1517	1517

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Great Yarmouth	CCGT	NORM40	18	405	405	405	405	405
Greater Gabbard Offshore Wind Farm	Wind Offshore	LEIS10	18	500	500	500	500	500
Greenwire Wind Farm - Pentir	Wind Offshore	PENT40	19	0	0	1000	1000	1000
Griffin Wind Farm	Wind Onshore	GRIF1S	5	188.6	188.6	188.6	188.6	188.6
Gunfleet Sands II Offshore Wind Farm	Wind Offshore	BRFO40	18	64	64	64	64	64
Gunfleet Sands Offshore Wind Farm	Wind Offshore	BRFO40	18	99.9	99.9	99.9	99.9	99.9
Gwynt Y Mor Offshore Wind Farm	Wind Offshore	BODE40	16	574	574	574	574	574
Hadyard Hill	Wind Onshore	HADH10	10	99.9	99.9	99.9	99.9	99.9
Halsary Wind Farm	Wind Onshore	SPIT10	1	0	0	0	0	28.5
Harestanes	Wind Onshore	HARE10	12	125	125	125	125	125
Harting Rig Wind Farm	Wind Onshore	KYPE10	11	0	0	61.2	61.2	61.2
Hartlepool	Nuclear	HATL20	13	1207	1207	1207	1207	1207
Hatfield Power Station	CCGT	THOM41	16	0	0	0	0	800
Hesta Head Wind Farm	Wind Onshore	BASK20	1	0	0	0	0	20.4
Heysham Power Station	Nuclear	HEYS40	14	2400	2400	2400	2400	2400
Hinkley Point B	Nuclear	HINP40	26	1061	1061	1061	1061	1061
Hirwaun Power Station	OCGT	RHIG40	21	0	0	299	299	299
Holyhead	Biomass	WYLF40	19	0	210	210	210	210
Hopsrig Wind Farm	Wind Onshore	EWEH1Q	12	0	0	0	73.6	73.6
Hornsea Power Station 1A	Wind Offshore	KILL40	15	0	400	400	400	400
Hornsea Power Station 1B	Wind Offshore	KILL40	15	400	400	400	400	400
Hornsea Power Station 1C	Wind Offshore	KILL40	15	0	400	400	400	400
Hornsea Power Station 2A	Wind Offshore	KILL40	15	0	0	440	440	440
Hornsea Power Station 2B	Wind Offshore	KILL40	15	0	0	0	440	440
Hornsea Power Station 2C	Wind Offshore	KILL40	15	0	0	0	440	440
Humber Gateway Offshore Wind Farm	Wind Offshore	HEDO20	15	220	220	220	220	220
Hunterston	Nuclear	HUER40	10	1020	1020	1020	1020	1020
Immingham	CHP	HUMR40	15	1218	1218	1218	1218	1218
Inch Cape Offshore Wind Farm Platform 1	Wind Offshore	COCK20	11	0	0	0	330	330
Inch Cape Offshore Wind Farm Platform 2	Wind Offshore	COCK20	11	0	0	0	270	270
Indian Queens	OCGT	INDQ40	27	140	140	140	140	140
Invergarry	Hydro	INGA1Q	3	20	20	20	20	20
J G Pears	CHP	HIGM20	16	13	30	30	30	30

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Keadby	CCGT	KEAD40	16	755	755	755	755	755
Keadby II	CCGT	KEAD40	16	0	0	852	852	852
Kilbraur Wind Farm	Wind Onshore	STRB20	1	67	67	67	67	67
Kilgallioch	Wind Onshore	KILG20	10	228	228	228	228	502
Killingholme	CCGT	KILL40	15	1200	1200	1200	1200	1200
Kilmorack	Hydro	KIOR1Q	1	20	20	20	20	20
Kings Lynn A	CCGT	WALP40_EME	17	281	281	281	281	281
Knottingley Power Station	CCGT	KNOT40	15	0	0	1658	1658	1658
Kype Muir	Wind Onshore	KYPE10	11	88.4	88.4	88.4	88.4	88.4
Langage	CCGT	LAGA40	27	905	905	905	905	905
Limekilns	Wind Onshore	DOUN10	1	0	0	90	90	90
Lincs Offshore Wind Farm	Wind Offshore	WALP40_EME	17	256	256	256	256	256
Little Barford	CCGT	EASO40	18	740	740	740	740	740
Lochay	Hydro	LOCH10	6	47	47	47	47	47
Lochluichart	Wind Onshore	CORI10	1	69	69	69	69	69
Loganhead Windfarm	Wind Onshore	EWEH1Q	12	36	36	36	36	36
London Array Offshore Wind Farm	Wind Offshore	CLEH40	24	630	630	630	630	630
Long Burn Wind Farm	Wind Onshore	NECU10	10	0	0	0	0	60
Luichart	Hydro	LUIC1Q	1	34	34	34	34	34
Lynemouth Power Station	Coal	BLYT20	13	396	396	396	396	396
Marchwood	CCGT	MAWO40	26	920	920	920	920	920
Marex	Pump Storage	CONQ40	16	1500	1500	1500	1500	1500
Margree	Wind Onshore	MARG10	10	0	0	43	43	43
Mark Hill Wind Farm	Wind Onshore	MAHI20	10	53	53	53	53	53
Medway Power Station	CCGT	GRAI40	24	735	735	735	735	735
MeyGen Tidal	Tidal	GILB10	1	15	71	154	237	237
Middle Muir Wind Farm	Wind Onshore	MIDM10	11	51	51	51	51	51
Millennium South	Wind Onshore	MILS1Q	3	25	25	25	25	25
Millennium Wind (Stage 3), Ceannacroc	Wind Onshore	MILW1Q	3	65	65	65	65	65
Minnygap	Wind Onshore	MOFF10	11	25	25	25	25	25
Moray Firth Offshore Wind Farm	Wind Offshore	NEDE20	2	0	0	20	1000	1000
Mossford	Hydro	MOSS1S	1	18.66	18.66	18.66	18.66	18.66
Muaitheabhal Wind Farm	Wind Onshore	STWN20	4	0	0	0	150	150

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Nant	Hydro	NANT1Q	7	15	15	15	15	15
Neart Na Gaoithe Offshore Wind Farm	Wind Offshore	CRYR40	11	450	450	450	450	450
Ormonde Offshore Wind Farm	Wind Offshore	HEYS40	14	150	150	150	150	150
Orrin	Hydro	ORRI10	1	18	18	18	18	18
Pembroke Power Station	CCGT	PEMB40	20	2199	2199	2199	2199	2199
Pen Y Cymoedd Wind Farm	Wind Onshore	RHIG40	21	228	228	228	228	228
Pencloe Windfarm	Wind Onshore	BLAC10	10	0	0	63	63	96
Peterborough	CCGT	WALP40_EME	17	245	245	245	245	245
Peterhead	CCGT	PEHE20	2	1180	0	0	1180	1180
Pogbie Wind Farm	Wind Onshore	DUNE10	11	0	11.8	11.8	11.8	11.8
Powersite @ Drakelow	CCGT	DRAK40	18	380	380	760	760	760
Progress Power Station	OCGT	BRFO40	18	0	0	299	299	299
Race Bank Wind Farm	Wind Offshore	WALP40_EME	17	565	565	565	565	565
Rampion Offshore Wind Farm	Wind Offshore	BOLN40	25	0	400	400	400	400
Ratcliffe on Soar	Coal	RATS40	18	2021	2021	2021	2021	2021
Robin Rigg East Offshore Wind Farm	Wind Offshore	HARK40	12	92	92	92	92	92
Robin Rigg West Offshore Wind Farm	Wind Offshore	HARK40	12	92	92	92	92	92
Rocksavage	CCGT	ROCK40	16	810	810	810	810	810
Rye House	CCGT	RYEH40	24	715	715	715	715	715
Sallachy Wind Farm	Wind Onshore	CASS1Q	1	0	0	66	66	66
Saltend	CCGT	SAES20	15	1100	1100	1100	1100	1100
Sandy Knowe Wind Farm	Wind Onshore	GLGL1Q	10	0	0	0	51	90
Sanquhar II Wind Farm	Wind Onshore	GLGL1Q	10	0	0	0	0	99
Sanquhar Wind Farm	Wind Onshore	GLGL1Q	10	30	30	30	30	30
Seabank	CCGT	SEAB40	22	1234	1234	1234	1234	1234
Sellafield	CHP	HUTT40	14	155	155	155	155	155
Severn Power	CCGT	USKM20	21	850	850	850	850	850
Sheringham Shoal Offshore Wind Farm	Wind Offshore	NORM40	18	315	315	315	315	315
Shoreham	CCGT	BOLN40	25	420	420	420	420	420
Sizewell B	Nuclear	SIZE40	18	1216	1216	1216	1216	1216
Sizewell C	Nuclear	SIZE40	18	0	1670	1670	3340	3340
Sloy G2 and G3	Hydro	SLOY10	8	80	80	80	80	80
South Humber Bank	CCGT	SHBA40	15	1365	1365	1365	1365	1365

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
South Kyle	Wind Onshore	NECU10	10	0	0	165	165	165
Spalding	CCGT	SPLN40	17	880	880	880	880	880
Spalding Energy Expansion	CCGT	SPLN40	17	300	300	300	920	920
Staythorpe C	CCGT	STAY40	16	1752	1752	1752	1752	1752
Stella North EFR Submission	Pump Storage	STEW40	13	25	25	25	25	25
Stornoway Wind Farm	Wind Onshore	STWN20	1	0	0	0	129.6	129.6
Stranoch Wind Farm	Wind Onshore	MAHI10	10	0	0	0	0	72
Strathy North and South Wind	Wind Onshore	STRW10	1	67.65	67.65	67.65	225.25	225.25
Strathy Wood	Wind Onshore	GORW20	1	0	0	54.4	54.4	54.4
Stronelairg	Wind Onshore	STRL10	3	227.8	227.8	227.8	227.8	227.8
Sutton Bridge	CCGT	WALP40_EME	17	850	850	850	850	850
Swansea Bay	Tidal	BAGB20	21	0	0	320	320	320
Taylors Lane	CCGT	WISD20_LPN	23	0	144	144	144	144
Tees Renewable Energy Plant	Biomass	GRSA20	13	0	285	285	285	285
Thanet Offshore Wind Farm	Wind Offshore	CANT40	24	300	300	300	300	300
Thorpe Marsh	CCGT	THOM41	16	0	0	1600	1600	1600
Toddleburn Wind Farm	Wind Onshore	DUNE10	11	27.6	27.6	27.6	27.6	27.6
Torness	Nuclear	TORN40	11	1250	1250	1250	1250	1250
Trafford Power	CCGT	CARR40	16	1944	0	2050	2050	2050
Tralorg Wind Farm	Wind Onshore	MAHI20	10	20	20	20	20	20
Triton Knoll Offshore Wind Farm	Wind Offshore	BICF4A	17	0	360	900	900	900
Upper Sonachan	Wind Onshore	MYBS11	1	0	0	0	58	58
Uskmouth	Coal	USKM20	21	230	230	230	230	230
Viking Wind Farm	Wind Onshore	KERG20	1	0	0	412	412	412
Walney 3 Offshore Wind Farm	Wind Offshore	MIDL40	14	330	330	330	330	330
Walney 4 Offshore Wind Farm	Wind Offshore	MIDL40	14	330	330	330	330	330
Walney I Offshore Wind Farm	Wind Offshore	HEYS40	14	182	182	182	182	182
Walney II Offshore Wind Farm	Wind Offshore	STAH4A	14	182	182	182	182	182
West Burton A	Coal	WBUR40	16	1987	1987	1987	1987	1987
West Burton B	CCGT	WBUR40	16	1295	1295	1295	1295	1295
West Burton Energy Storage	CCGT	WBUR40	16	38	38	38	38	38
West of Duddon Sands Offshore Wind Farm	Wind Offshore	HEYS40	14	382	382	382	382	382

Generator	Technology	Nodes	Zone	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
Westermost Rough Offshore Wind Farm	Wind Offshore	HEDO20	15	205	205	205	205	205
Westray South	Tidal	DOUN20	1	0	0	0	60	60
Whitelaw Brae Windfarm	Wind Onshore	CLYS2R	11	0	0	54.4	54.4	54.4
Whitelee	Wind Onshore	WLEE20	10	305	305	305	305	305
Whitelee Extension	Wind Onshore	WLEX20	10	206	206	206	206	206
Whiteside Hill Wind Farm	Wind Onshore	GLGL1Q	10	27	27	27	27	27
Willington	CCGT	WILE40	18	0	0	1530	1530	1530
Willow Wind Farm	Wind Onshore	WILW10	10	0	0	45	45	45
Wilton	CCGT	GRSA20	13	141	141	141	141	141
Windy Standard II (Brockloch Rig 1) Wind Farm	Wind Onshore	DUNH1R	10	61.5	61.5	61.5	61.5	75
Windy Standard III Wind Farm	Wind Onshore	DUNH1Q	10	0	0	0	0	43.5

Table 38 – Contracted TEC at peak by zone

Zone	Zone Name	2018/19 (MW)	2019/20 (MW)	2020/21 (MW)	2021/22 (MW)	2022/23 (MW)
1	North Scotland	1,602.8	2,024.8	2,880.2	3,512.8	3,749.7
2	East Aberdeenshire	1,180.0	-	20.0	3,580.0	3,580.0
3	Western Highlands	737.7	737.7	737.7	737.7	737.7
4	Skye and Lochalsh	42.8	42.8	42.8	234.8	234.8
5	Eastern Grampian and Tayside	324.8	324.8	324.8	470.0	470.0
6	Central Grampian	63.5	63.5	63.5	63.5	63.5
7	Argyll	166.0	166.0	216.0	216.0	216.0
8	The Trossachs	520.0	520.0	520.0	520.0	520.0
9	Stirlingshire and Fife	120.0	120.0	120.0	1,195.0	1,195.0
10	South West Scotland	2,552.1	2,547.5	2,932.5	3,009.1	3,823.0
11	Lothian and Borders	3,094.1	3,132.7	3,391.5	4,081.5	4,081.5
12	Solway and Cheviot	430.0	430.0	430.0	503.6	503.6
13	North East England	1,769.0	2,054.0	3,454.0	3,454.0	3,454.0
14	North Lancashire and The Lakes	4,201.0	4,201.0	4,201.0	4,201.0	4,201.0
15	South Lancashire, Yorkshire and Humber	12,939.0	13,739.0	16,369.0	18,739.0	19,739.0
16	North Midlands and North Wales	16,523.0	14,596.0	19,098.0	19,098.0	19,898.0
17	South Lincolnshire and North Norfolk	3,777.0	4,137.0	4,677.0	5,297.0	6,797.0
18	Mid Wales and The Midlands	6,454.9	8,825.9	11,554.9	14,424.9	15,624.9
19	Anglesey and Snowdon	1,644.0	1,854.0	2,854.0	3,854.0	3,854.0
20	Pembrokeshire	2,199.0	2,199.0	2,199.0	2,199.0	2,699.0
21	South Wales & Gloucester	3,612.0	3,612.0	4,231.0	4,231.0	4,231.0
22	Cotswold	1,234.0	1,234.0	1,234.0	1,234.0	1,234.0
23	Central London	-	144.0	144.0	144.0	144.0
24	Essex and Kent	12,105.0	12,105.0	15,001.0	16,671.0	19,571.0
25	Oxfordshire, Surrey and Sussex	1,970.0	2,370.0	2,370.0	2,370.0	2,370.0
26	Somerset and Wessex	2,139.0	3,239.0	4,639.0	6,639.0	6,639.0
27	West Devon and Cornwall	1,045.0	1,045.0	1,045.0	1,045.0	1,045.0

Appendix F: Historic & future chargeable demand data

In the tables below we have published the historic demand volumes, per demand zone, used for TNUoS for 2014/15, 2015/16 and 2016/17. We have also published the (net) demand data used in tariff setting for 2017/18 tariffs, and the forecast (gross) demand data used in the forecasts on 2018/19 to 2022/23 tariffs.

The historic data was provided to National Grid under BSC modifications P348/P349 which were consequential modifications following CMP264/265 to provide National Grid with gross demand data.

The tables are structured as follows:

- The first three tables (40, 41, 22), are gross demand data (GW) for system peak, gross HH demand and embedded export volumes.
- The fourth table (43) is the NHH demand data (TWh) for consumption between 4pm and 7pm. The way this data is used in tariff setting is unchanged between historic and future methodologies.
- The final three tables (44, 45) show, for information, the net demand data for system peak and net HH demand, the basis of charging before 2018/19. These values are not used in the calculation of tariffs in this report, but are included for information.

Table 39 - Gross system peak demand (GW)

		Actual Demand			Tariff Setting Forecast	October Forecast	Five Year Forecast			
Zone	Zone Name	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1	Northern Scotland	1.594	1.675	1.423	*Gross data was not forecast for 2017/18 tariffs*	1.477	1.457	1.446	1.419	1.432
2	Southern Scotland	4.042	4.078	3.749		3.500	3.425	3.397	3.363	3.353
3	Northern	3.401	2.751	2.475		2.664	2.606	2.560	2.542	2.522
4	North West	4.682	4.503	3.997		4.117	4.027	3.966	3.932	3.908
5	Yorkshire	4.707	4.689	4.539		3.920	3.820	3.770	3.745	3.715
6	N Wales & Mersey	3.001	3.328	3.413		2.678	2.623	2.592	2.564	2.543
7	East Midlands	5.547	5.213	5.210		4.763	4.638	4.588	4.555	4.521
8	Midlands	4.867	4.661	4.536		4.371	4.251	4.195	4.163	4.127
9	Eastern	7.266	6.818	6.605		6.605	6.413	6.339	6.296	6.237
10	South Wales	2.169	2.223	2.633		1.843	1.817	1.792	1.781	1.779
11	South East	4.323	4.054	3.919		3.999	3.898	3.849	3.820	3.786
12	London	5.332	5.009	4.692		4.323	4.227	4.132	4.111	4.056
13	Southern	6.479	6.193	6.232		5.584	5.459	5.395	5.359	5.321
14	South Western	2.919	2.711	2.629		2.621	2.584	2.554	2.534	2.517
	TOTAL	**60.330**	**57.906**	**56.053**		**52.463**	**51.247**	**50.576**	**50.185**	**49.816**

Table 40 – Gross HH demand (GW)

		Actual Demand			Tariff Setting Forecast	October Forecast	Five Year Forecast			
Zone	Zone Name	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1	Northern Scotland	0.443	0.437	0.483	*Gross data was not forecast for 2017/18 tariffs*	0.489	0.435	0.436	0.434	0.429
2	Southern Scotland	1.217	1.215	1.297		1.259	1.195	1.204	1.188	1.185
3	Northern	1.052	1.029	1.120		1.078	1.026	1.012	1.014	1.002
4	North West	1.486	1.431	1.558		1.523	1.464	1.444	1.445	1.416
5	Yorkshire	1.512	1.496	1.588		1.610	1.541	1.519	1.525	1.501
6	N Wales & Mersey	1.045	1.027	1.095		1.085	1.048	1.026	1.033	1.026
7	East Midlands	1.872	1.806	1.902		1.878	1.784	1.773	1.771	1.742
8	Midlands	1.579	1.555	1.714		1.617	1.542	1.539	1.541	1.516
9	Eastern	2.051	2.030	2.267		2.133	2.021	2.021	2.027	2.001
10	South Wales	0.743	0.797	0.765		0.839	0.820	0.797	0.801	0.798
11	South East	1.136	1.128	1.250		1.169	1.140	1.130	1.129	1.118
12	London	2.269	2.236	2.332		2.286	2.259	2.223	2.227	2.205
13	Southern	2.012	2.013	2.189		2.072	2.025	2.007	2.008	1.994
14	South Western	0.738	0.705	0.793		0.764	0.736	0.729	0.730	0.725
	TOTAL	**19.156**	**18.904**	**20.354**		**19.801**	**19.034**	**18.861**	**18.873**	**18.657**

Table 41 – Embedded export volumes (GW)

		Actual Demand			Tariff Setting Forecast	October Forecast	Five Year Forecast			
Zone	Zone Name	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1	Northern Scotland	0.541	0.550	0.849	*Export data was not forecast for 2017/18 tariffs*	1.001	0.899	0.926	0.785	0.884
2	Southern Scotland	0.300	0.395	0.563		0.670	0.580	0.623	0.467	0.614
3	Northern	0.716	0.396	0.259		0.581	0.512	0.465	0.487	0.465
4	North West	0.202	0.281	0.315		0.343	0.330	0.312	0.328	0.324
5	Yorkshire	0.452	0.627	0.642		0.635	0.605	0.587	0.626	0.611
6	N Wales & Mersey	0.343	0.473	0.432		0.538	0.504	0.502	0.509	0.508
7	East Midlands	0.335	0.373	0.413		0.477	0.470	0.446	0.480	0.470
8	Midlands	0.213	0.237	0.311		0.211	0.198	0.187	0.214	0.181
9	Eastern	0.562	0.553	0.560		0.624	0.660	0.591	0.633	0.606
10	South Wales	0.243	0.352	0.381		0.331	0.322	0.306	0.328	0.315
11	South East	0.299	0.304	0.287		0.318	0.302	0.286	0.312	0.286
12	London	0.121	0.138	0.257		0.149	0.139	0.132	0.149	0.127
13	Southern	0.463	0.584	0.637		0.437	0.402	0.398	0.453	0.386
14	South Western	0.239	0.244	0.347		0.200	0.219	0.205	0.221	0.197
	TOTAL	**5.030**	**5.506**	**6.253**		**6.516**	**6.143**	**5.966**	**5.989**	**5.974**

Table 42 – NHH demand (TWh)

		Actual Demand			Tariff Setting Forecast	October Forecast	Five Year Forecast			
Zone	Zone Name	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1	Northern Scotland	0.876	0.811	0.819	0.752	0.741	0.727	0.729	0.716	0.715
2	Southern Scotland	1.988	1.838	1.845	1.763	1.663	1.623	1.613	1.584	1.565
3	Northern	1.468	1.355	1.362	1.287	1.200	1.163	1.146	1.121	1.096
4	North West	2.243	2.150	2.160	2.064	1.932	1.879	1.861	1.825	1.795
5	Yorkshire	2.094	1.961	1.973	1.850	1.761	1.708	1.685	1.649	1.613
6	N Wales & Mersey	1.475	1.363	1.368	1.296	1.223	1.189	1.177	1.153	1.133
7	East Midlands	2.508	2.388	2.403	2.227	2.160	2.101	2.077	2.034	1.995
8	Midlands	2.374	2.232	2.245	2.098	1.995	1.934	1.904	1.863	1.820
9	Eastern	3.617	3.427	3.444	3.189	3.086	2.993	2.945	2.885	2.814
10	South Wales	0.983	0.913	0.917	0.870	0.829	0.811	0.808	0.792	0.784
11	South East	2.250	2.132	2.141	1.996	1.910	1.854	1.825	1.789	1.745
12	London	2.180	2.038	2.046	1.928	1.836	1.776	1.738	1.709	1.654
13	Southern	3.014	2.856	2.870	2.676	2.563	2.493	2.460	2.411	2.358
14	South Western	1.530	1.426	1.434	1.319	1.273	1.246	1.234	1.208	1.190
	TOTAL	**28.600**	**26.890**	**27.025**	**25.313**	**24.172**	**23.498**	**23.201**	**22.738**	**22.277**

Table 43 – Net system peak demand (GW)

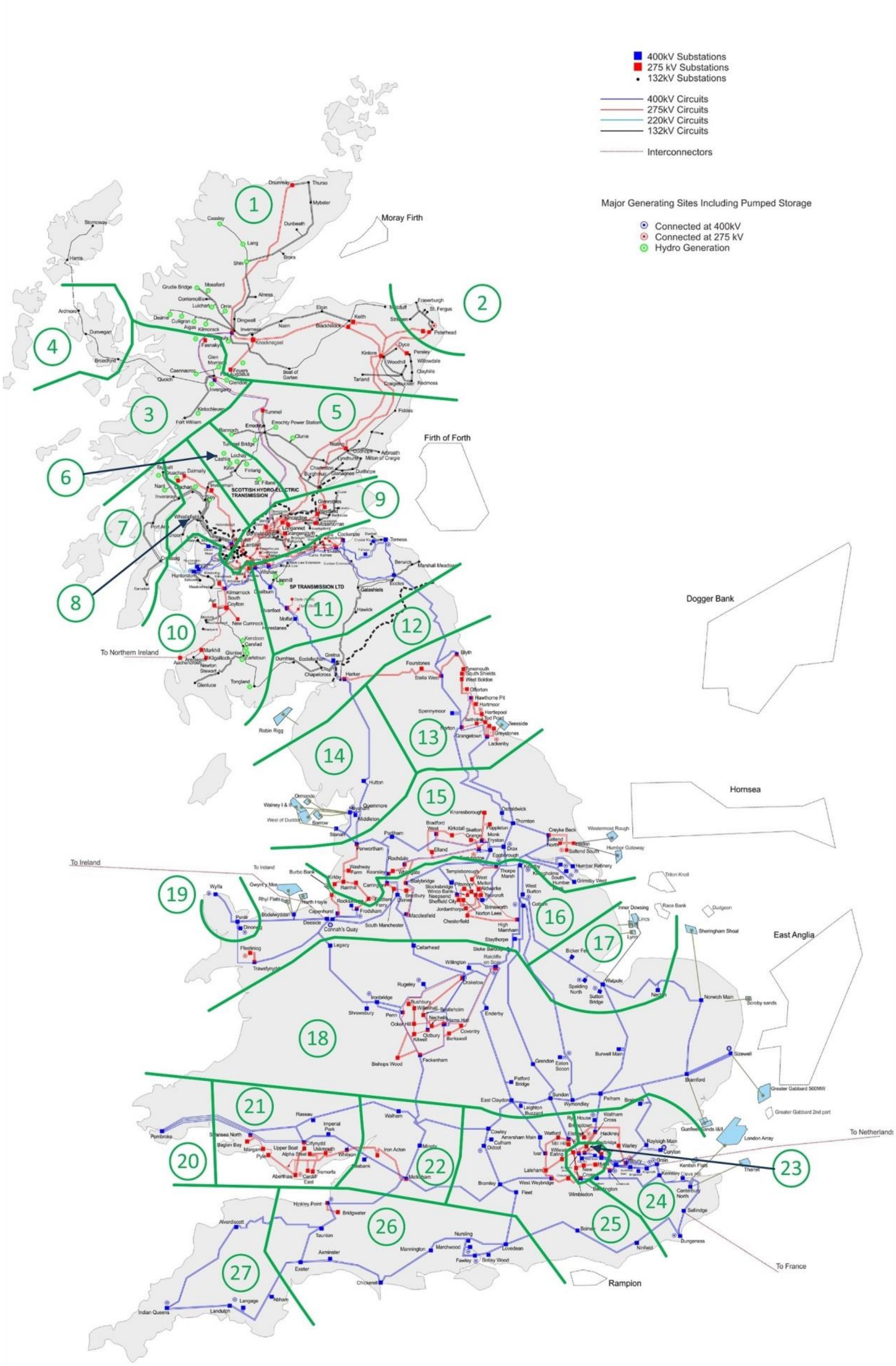
						Not required for tariffs, but included for reference				
		Actual Demand			Tariff Setting Forecast	October Forecast	Five Year Forecast			
Zone	Zone Name	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1	Northern Scotland	1.053	1.125	0.574	0.923	0.476	0.558	0.520	0.634	0.548
2	Southern Scotland	3.743	3.683	3.187	3.109	2.831	2.845	2.773	2.896	2.739
3	Northern	2.684	2.355	2.216	2.267	2.083	2.094	2.095	2.055	2.057
4	North West	4.480	4.222	3.682	3.854	3.773	3.697	3.654	3.604	3.584
5	Yorkshire	4.255	4.061	3.897	3.566	3.284	3.215	3.183	3.119	3.103
6	N Wales & Mersey	2.658	2.855	2.981	2.350	2.140	2.119	2.090	2.056	2.034
7	East Midlands	5.212	4.840	4.797	4.360	4.286	4.169	4.142	4.075	4.051
8	Midlands	4.655	4.424	4.225	4.125	4.159	4.054	4.008	3.950	3.946
9	Eastern	6.704	6.265	6.046	6.036	5.980	5.753	5.748	5.664	5.630
10	South Wales	1.926	1.871	2.252	1.657	1.511	1.495	1.487	1.453	1.464
11	South East	4.023	3.750	3.631	3.711	3.681	3.596	3.563	3.508	3.499
12	London	5.211	4.872	4.436	4.112	4.174	4.087	4.000	3.962	3.930
13	Southern	6.016	5.610	5.595	5.179	5.147	5.058	4.997	4.907	4.935
14	South Western	2.680	2.467	2.282	2.436	2.420	2.364	2.349	2.313	2.321
	TOTAL	**55.300**	**52.400**	**49.800**	**47.684**	**45.947**	**45.103**	**44.610**	**44.196**	**43.842**

Table 44 – Net HH demand (GW)

						Not required for tariffs, but included for reference				
		Actual Demand			Tariff Setting Forecast	October Forecast	Five Year Forecast			
Zone	Zone Name	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1	Northern Scotland	-0.098	-0.113	-0.366	-0.668	-0.512	-0.464	-0.489	-0.351	-0.454
2	Southern Scotland	0.918	0.821	0.735	0.642	0.589	0.615	0.581	0.721	0.571
3	Northern	0.336	0.633	0.860	0.314	0.498	0.514	0.547	0.528	0.537
4	North West	1.284	1.150	1.242	1.175	1.179	1.134	1.132	1.117	1.091
5	Yorkshire	1.060	0.869	0.946	1.107	0.974	0.935	0.932	0.899	0.889
6	N Wales & Mersey	0.701	0.555	0.663	0.520	0.547	0.544	0.523	0.525	0.518
7	East Midlands	1.536	1.433	1.488	1.456	1.401	1.314	1.327	1.292	1.272
8	Midlands	1.367	1.318	1.403	1.400	1.406	1.344	1.352	1.327	1.335
9	Eastern	1.489	1.477	1.708	1.473	1.508	1.360	1.430	1.394	1.394
10	South Wales	0.500	0.445	0.384	0.554	0.507	0.498	0.491	0.473	0.483
11	South East	0.836	0.823	0.963	0.870	0.851	0.837	0.844	0.817	0.831
12	London	2.148	2.098	2.076	2.194	2.137	2.120	2.090	2.078	2.078
13	Southern	1.548	1.429	1.552	1.650	1.636	1.624	1.609	1.555	1.608
14	South Western	0.499	0.461	0.447	0.540	0.564	0.517	0.524	0.509	0.528
	TOTAL	**14.126**	**13.398**	**14.101**	**13.227**	**13.285**	**12.891**	**12.895**	**12.883**	**12.683**

Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



Appendix H: Demand zones map