Forecast TNUoS

Draft Tariffs for 2018/19

December 2017

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This information paper provides National Grid's Draft Forecast Transmission Network Use of System (TNUoS) Tariffs for 2018/19, applicable to transmission connected Generators and Suppliers, effective from 1 April 2018.

December 2017

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If you have any comments or questions on the contents or format of this report, please don't hesitate to get in touch with us.

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Executive Summary

This document contains the latest draft of the Transmission Network Use of System (TNUoS) Tariffs for 2018/19, which will become effective on 1 April 2018. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.

Total Revenues to be recovered

Total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges is forecast to be £2,670.2m in 2018/19, an increase of £8.9m from the forecast published in October 2017.

Generation Tariffs

Generation tariffs have been set to recover £430.1m to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010. There is no change to total generation revenue compared to the October forecast. The chargeable TEC has decreased by 3.1GW, resulting in an overall increase of £0.24/kW to the average generation tariff of £5.98/kW. The Error Margin element of the tariff forecast which is used to calculate the split of revenue to be recovered from generation and demand (the G/D split) remains fixed at 21%.

Demand Tariffs

Demand tariffs have been set to recover £2,240.1m of revenue, an increase of £8.9m from the October forecast. This reflects the increase in overall revenue for GB TOs. The average gross demand Half Hourly (HH) tariff is £46.17/kW; the average Embedded Export Tariff (EET) is £26.91/kW; and the average Non Half Hourly (NHH) demand tariff is 6.21p/kWh.

Changes to the Methodology affecting 2018/19 tariffs

There are several CUSC modifications which affect the charging methodology for 2018/19. There are also a number of modifications pending an Ofgem decision which may change the methodology before final tariffs are set.

Approved Modifications: CMP282 & CMP283

CMP282 changes the way that demand at exporting network nodes is calculated, particularly reducing demand tariffs in zone 1 compared to the previous methodology. This modification was approved in November 2017.

Other Modifications

This tariff forecast has been undertaken in accordance with the CUSC charging methodology based only on modifications that have been approved.

Modification CMP251 is waiting for an Ofgem decision. This is discussed in Appendix A.

Modification CMP261 was rejected by Ofgem. It is subject to a review by the CMA and is also discussed in Appendix A. [1]

Demand Forecast

Following the methodology change CMP264/265, we have revised our demand forecasting “Monte Carlo” model. We now forecast separate gross demand and embedded exports for each zone.

Our modelling approach takes into account historical trends of metered triad demand and export volumes (2014/15 – 2016/17) provided by Elexon as part of the BSC P348/349 modifications. The model also includes other factors such as weather patterns, future demand shifts on the transmission system and expected levels of renewable generation.

For 2018/19 our demand charging base remains the same as the October forecast. We are forecasting average system gross triad demand of 52.5GW, average HH gross triad demand of 19.8GW, embedded export generation of 6.5GW and NHH demand of 24.2TWh. The values of gross demand, embedded exports and NHH demand are consistent with the declining trend over previous years.

Drivers of changes to the Tariff forecast

Changes to these Draft tariffs in relation to our October tariff forecast have predominantly been influenced by:

- A reduction in Conventional Carbon generation in Scotland in the transport model has reduced Peak tariffs in Scotland, and the extreme south west of the network. Generation tariffs in England remain relatively stable.
- A decrease in chargeable generation, and TEC reductions in the transport model that affect system flows, particularly in Scotland.
- The increase of 480MW in modelled demand through the Week 24 DNO update in our transport model. This will affect the locational tariffs across zones dependant on the change in nodal demand.

Next forecast

Our next publication of 2018/19 TNUoS tariffs will be our final tariffs in January 2018.

These tariffs will be set in accordance with the charging methodology to prevail from 1 April 2018 and will

[1] *https://www.gov.uk/cma-cases/edf-sse-code-modification-appeal*

include any changes which have been approved by Ofgem.

Significant updates expected in the Final tariffs will include our latest view of TEC volumes, which will affect the locational tariffs for generation and demand, and also the final TO revenues, which will mostly affect the demand residual.

You should also be aware that Ofgem has been served with a claim for judicial review concerning its decision to approve WACM4 of CUSC modifications CMP264 and CMP265. As stated on their website: "Ofgem's decision to approve WACM4 of CUSC modifications CMP264 and CMP265 stands unless quashed by the court".[2]

The latest tariff forecast timetable can be found on our website.[3]

Feedback

This tariff forecast is the fourth in our new report format, which has been redesigned in order 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.

[2] 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

[3] *Our revised forecast publication timetable is available on our website:* http://www.nationalgrid.com/tnuos

Demand Tariffs

Tables 1, 2 and 3 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.

PLEASE NOTE: these demand tariffs are compared to those published in Appendix A of the October Tariffs forecast document, not those in the main body of the report. The tariffs in Appendix A were calculated using the same inputs as the tariffs published in the main body of the report, but with the CMP282 methodology switched on.

The changes to the inputs made between October and now are better highlighted and their impact better understood by comparing these Draft tariffs with the version from October calculated under the CMP282 methodology.

The breakdown of the HH tariff into the peak and year round components can be found in Appendix B.

Table 1: Summary of Demand tariffs

HH Tariffs	2018/19 - October	2018/19 - Draft	Change
Average Tariff (£/kW)	45.814430	46.167323	0.352893
Residual (£/kW)	46.900294	46.937840	0.037546
EET	**2018/19 - October**	**2018/19 - Draft**	**Change**
Average Tariff (£/kW)	25.355203	26.906579	1.551375
Phased residual (£/kW)	29.360000	29.360000	0.000000
AGIC (£/kW)	3.220000	3.220000	0.000000
Embedded Export Volume (GW)	6.515803	6.515803	0.000000
Total Credit (£m)	165.209499	175.317954	10.108455
NHH Tariffs	**2018/19 - October**	**2018/19 - Draft**	**Change**
Average (p/kWh)	6.160776	6.210566	0.049790

Table 2: Demand tariffs

Zone	Zone Name	Gross HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	26.298678	3.508445	11.347693
2	Southern Scotland	29.058761	3.916767	14.107776
3	Northern	37.816645	4.999018	22.865659
4	North West	43.804081	5.881695	28.853095
5	Yorkshire	44.071351	5.784955	29.120365
6	N Wales & Mersey	45.509619	5.928558	30.558634
7	East Midlands	47.499335	6.344800	32.548350
8	Midlands	48.794504	6.732159	33.843518
9	Eastern	49.426516	7.157381	34.475531
10	South Wales	45.802151	5.552425	30.851165
11	South East	52.108295	7.712884	37.157310
12	London	54.904610	6.105943	39.953624
13	Southern	53.417644	7.317192	38.466659
14	South Western	51.865303	7.559768	36.914318

Tariffs include small gen tariff of:	0.593146	0.080147
Residual charge for gross demand:	£ 46.937840	

Changes since the previous demand tariffs forecast

Following the implementation of CMP264/265 into the TNUoS methodology, the way in which HH demand is charged has changed. HH tariffs are charged on a gross basis instead of net, and a separate Embedded Export Tariff payment is made to embedded generators which generate over triad periods.

A driver of change to this forecast compared to October includes the week 24 DNO demand update, a large generation TEC reduction in northern Scotland and changes to revenue.

Overall, average demand tariffs have increased, the average HH gross tariff is now £46.17/kW, and compared to the October forecast this has increased by £0.35/kW, the NHH average tariff is now 6.21p/kWh, a slight increase of 0.05p/kWh. This is offset marginally by the reduction in the small generator discount compared to October.

The average EET is £26.91/kW which has increased by £1.55/kW. Our forecast predicts that the increase in EET will result in an additional £10m to be paid to embedded generators/suppliers with the total payable now £175m. This is recovered through the demand tariffs. More information on the causes of specific zonal fluctuations is detailed in the HH and NHH sections below.

Gross half hourly demand tariffs

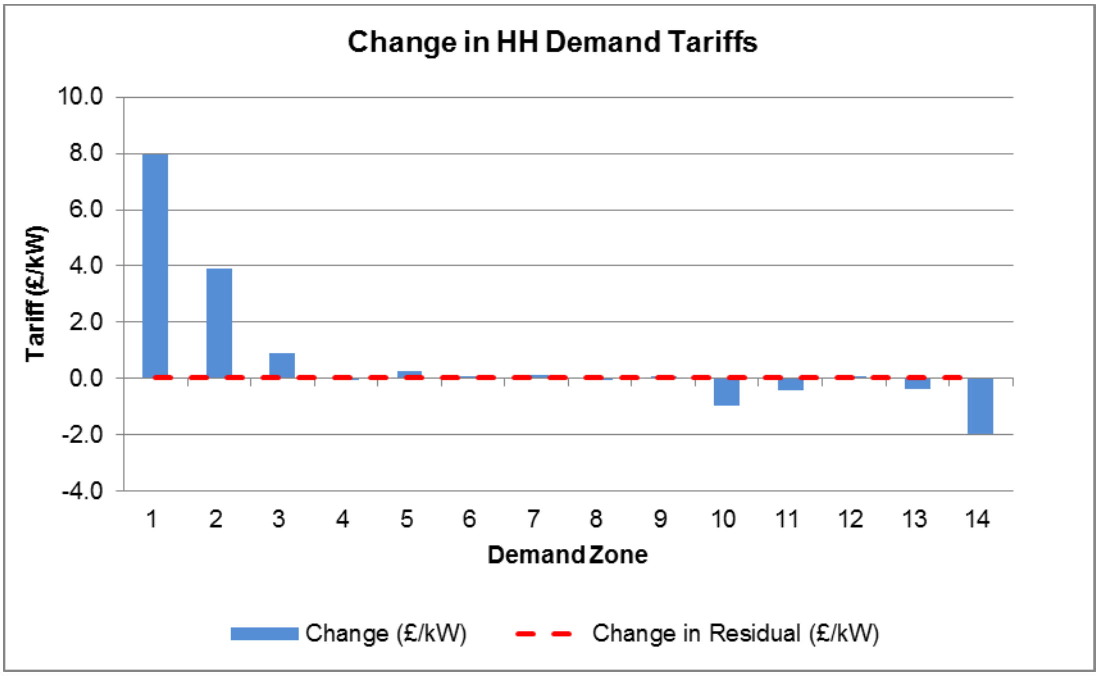
Table 3 and Figure 1 show the gross HH demand tariffs 2018/19 forecast with the CMP264/265 methodology.

Table 3 – Gross HH demand tariffs

Zone	Zone Name	2018/19 October (£/kW)	2018/19 Draft (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	18.351267	26.298678	7.947411	0.037546
2	Southern Scotland	25.131650	29.058761	3.927111	0.037546
3	Northern	36.924540	37.816645	0.892105	0.037546
4	North West	43.866489	43.804081	-0.062408	0.037546
5	Yorkshire	43.831984	44.071351	0.239367	0.037546
6	N Wales & Mersey	45.433760	45.509619	0.075859	0.037546
7	East Midlands	47.390135	47.499335	0.109200	0.037546
8	Midlands	48.848501	48.794504	-0.053997	0.037546
9	Eastern	49.367285	49.426516	0.059231	0.037546
10	South Wales	46.780645	45.802151	-0.978494	0.037546
11	South East	52.515613	52.108295	-0.407318	0.037546
12	London	54.838363	54.904610	0.066247	0.037546
13	Southern	53.798692	53.417644	-0.381048	0.037546
14	South Western	53.859062	51.865303	-1.993759	0.037546

The breakdown of the locational elements of these tariffs is shown in Appendix B.

Figure 1 - Gross HH demand tariffs



As outlined above the HH demand tariff is now based on gross chargeable demand, not net demand (gross – embedded export) as previously reflected in the June forecast.

The average HH gross demand tariff of £46.17/kW represents an increase of £0.35/kW, this is largely due to the locational effects of the generation TEC reduction of 1180MW in zone 2 and the zonal modelled demand changes through the Week 24 DNO forecast update. The rise in the average tariff can also be attributed to an increase in the total revenue to be recovered. This is slightly offset by the reduction in the small generator discount compared to October. The level of gross HH chargeable demand remains the same at 19.8GW.

Larger variations can be seen in zones 1 and 2 (Scotland) which have increased by £7.94/kW and £3.92/kW respectively. Elsewhere, decreases in zone 10 of £0.978/kW (South Wales) and in zone 14 of £1.99/kW (South Western) are also largely due to the effect of locational changes in both Peak and Year round tariffs. If we take zone 1 for example, the level of modelled demand (Week 24 DNO data) has increased by over 400MW yet generation in that zone and neighbouring zones has reduced. This has resulted in the Peak tariff increasing to £3.06/kW and the Year Round increasing to -£24.30/kW. Therefore the zone 1 locational element is now £-21.23/kW, which compared to -£29.14/kW in October is an increase of £7.90/kW.

The residual element of the tariff has increased slightly by £0.04/kW, this is primarily driven by an increase in both the total revenue forecast and the embedded export revenue as this is included within the HH demand residual as part of the total revenue to be recovered for demand. The level of embedded export revenue, which is calculated by multiplying the embedded export volume during triads with the associated zonal tariff, has a direct impact on HH demand tariffs.

Embedded export tariff

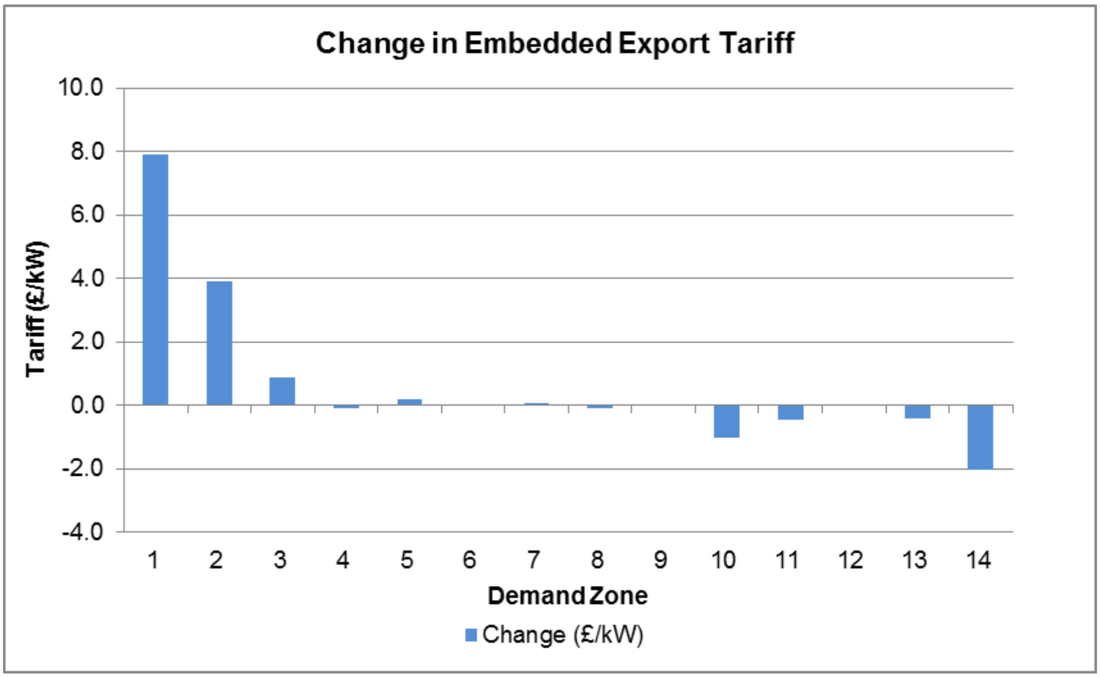
Table 4 and Figure 2 show the embedded export tariffs in the Draft 2018/19 forecast compared to the October forecast.

Table 4 – Embedded export tariffs

Zone	Zone Name	2018/19 October (£/kW)	2018/19 Draft (£/kW)	Change (£/kW)
1	Northern Scotland	3.435934	11.347693	7.911759
2	Southern Scotland	10.216317	14.107776	3.891459
3	Northern	22.009206	22.865659	0.856453
4	North West	28.951155	28.853095	-0.098060
5	Yorkshire	28.916651	29.120365	0.203714
6	N Wales & Mersey	30.518427	30.558634	0.040207
7	East Midlands	32.474802	32.548350	0.073548
8	Midlands	33.933167	33.843518	-0.089649
9	Eastern	34.451952	34.475531	0.023579
10	South Wales	31.865312	30.851165	-1.014147
11	South East	37.600280	37.157310	-0.442970
12	London	39.923029	39.953624	0.030595
13	Southern	38.883359	38.466659	-0.416700
14	South Western	38.943729	36.914318	-2.029411

The breakdown of the locational elements of these tariffs is shown in Appendix B.

Figure 2 – Embedded Export Tariff



Under CMP 264/265 the amount of 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 average EET has increased by £1.55/kW and is now £26.91/kW, which has resulted in the total value of credit payable to embedded export volumes rising by £10m to £175m. The level of forecasted embedded export volumes over triads has remained the same at 6.52GW.

The variations in tariffs are driven by the locational tariff changes as previously described for the HH tariffs as the EET uses the same locational elements of peak and year round. The largest variations occurred in zones 1 and 2 (Scotland) which have increased by £7.91/kW and £3.89/kW respectively, zone 10 (South Wales) and zone 14 (South Western) however have reduced by £1.01/kW and £2.03/kW.

As the level of the EET is determined by the locational elements of the HH tariff, the EET is lowest in zone 1 (£11.34/kW; the zone 1 locational tariff is £-21.23/kW), but where the locational element is at its highest in zone 12, the EET is £39.95/kW.

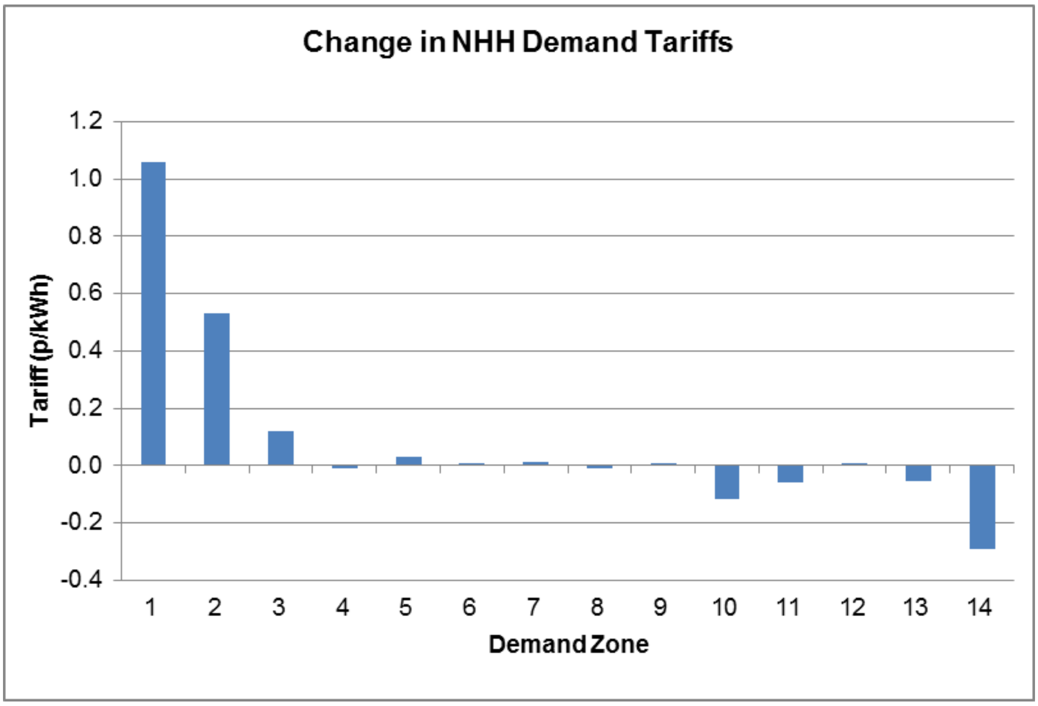
NHH demand tariffs

Table 5 and Figure 3 show the difference between the NHH demand tariffs forecast in October and this Draft 2018/19 forecast in December.

Table 5 - NHH demand tariff changes

Zone	Zone Name	2018/19 October Forecast (p/kWh)	2018/19 Draft (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.448517	3.508445	1.059928
2	Southern Scotland	3.387469	3.916767	0.529298
3	Northern	4.881137	4.999018	0.117881
4	North West	5.890076	5.881695	-0.008381
5	Yorkshire	5.753555	5.784955	0.031400
6	N Wales & Mersey	5.918690	5.928558	0.009868
7	East Midlands	6.330218	6.344800	0.014582
8	Midlands	6.739605	6.732159	-0.007446
9	Eastern	7.148778	7.157381	0.008603
10	South Wales	5.670893	5.552425	-0.118468
11	South East	7.773210	7.712884	-0.060326
12	London	6.098639	6.105943	0.007304
13	Southern	7.369393	7.317192	-0.052201
14	South Western	7.850599	7.559768	-0.290831

Figure 3 - NHH demand tariff changes



The weighted average NHH tariff is 0.05p/kWh higher than in the October forecast, this increase is attributable to the higher amount of zonal revenue to be recovered from the NHH charging base following the increase in overall revenue to be recovered and the increase in the EET revenue. This is slightly offset by the reduction in the small generator discount compared to October. The NHH charging base remains the same as in the October forecast at 24.2 TWh, this generally aligns with the declining trend in recent years.

The impact of the change to the amount of revenue to be recovered from NHH is seen mostly in zones 1 and 2 (Scotland) which increases their tariffs by 1.059p/kWh and 0.529p/kWh respectively. However where there is less zonal revenue to be recovered such as in zone 14 (South Western) then the tariff reduces, in this case very slightly in proportion to the small reduction in zonal revenue recovery.

Generally, the variations year on year across the zones are 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 as part of CMP264/265.

Generation tariffs

This section summarises the Draft generation tariffs for 2018/19, how these tariffs were calculated and how they have changed from the October forecast.

Table 6 – Summary of generation tariffs

Generation Tariffs	2018/19 October	2018/19 Draft	Change since last forecast
Residual	-2.337478	-2.517938	-0.180460
Average Generation Tariff	5.736512	5.980623	0.244112

On average, generation tariffs have increased by £0.24/kW due to a reduction in Chargeable TEC of 3.1GW; this is offset by a reduction to the already negative residual by £0.18 to -£2.52.

Generation wider tariffs

The following section provides a summary of how the wider generation tariffs have changed between the October forecast and this Draft forecast, 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%.

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

The classifications for different technology types are below:

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

The 80% and 40% load factors used in this table are for illustration only.

Table 7 - Generation wider tariffs

Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Example tariffs for a generator of each technology type: Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	-1.252280	7.269753	24.319562	-2.517938	21.501234	26.365146	24.709525
2	East Aberdeenshire	-1.577541	7.269753	15.555383	-2.517938	14.164630	17.275706	15.945346
3	Western Highlands	-1.133410	6.942392	23.718412	-2.517938	20.877295	25.620978	23.977431
4	Skye and Lochalsh	-7.063556	6.942392	23.613374	-2.517938	14.863119	19.585794	23.872393
5	Eastern Grampian and Tayside	0.225763	6.034415	21.214727	-2.517938	19.507139	23.750084	21.110555
6	Central Grampian	-0.538689	5.621005	19.694027	-2.517938	17.195399	21.134204	19.424491
7	Argyll	-4.280925	4.954749	19.349354	-2.517938	12.644419	16.514290	18.813316
8	The Trossachs	0.121983	4.954749	17.172736	-2.517938	15.306033	18.740580	16.636698
9	Stirlingshire and Fife	-0.695866	3.800182	15.552784	-2.517938	12.268569	15.379126	14.554919
10	South West Scotlands	2.759902	5.341869	17.306508	-2.517938	18.360666	21.821967	16.925318
11	Lothian and Borders	2.921055	5.341869	11.319983	-2.517938	13.732599	15.996595	10.938793
12	Solway and Cheviot	1.847489	3.305733	9.393832	-2.517938	9.489203	11.367969	8.198187
13	North East England	3.434630	2.172482	4.737309	-2.517938	6.444525	7.391987	3.088364
14	North Lancashire and The Lakes	1.753292	2.172482	3.629866	-2.517938	3.877232	4.603206	1.980921
15	South Lancashire, Yorkshire and Humber	4.369515	0.921466	0.108888	-2.517938	2.675860	2.697638	-2.040464
16	North Midlands and North Wales	3.793023	-0.903282		-2.517938	0.552459	0.552459	-2.879251
17	South Lincolnshire and North Norfolk	2.205308	-0.379467		-2.517938	-0.616204	-0.616204	-2.669725
18	Mid Wales and The Midlands	1.283397	-0.085223		-2.517938	-1.302719	-1.302719	-2.552027
19	Anglesey and Snowdon	4.578304	-0.979403		-2.517938	1.276844	1.276844	-2.909699
20	Pembrokeshire	9.101738	-4.440745		-2.517938	3.031204	3.031204	-4.294236
21	South Wales & Gloucester	6.189170	-4.412656		-2.517938	0.141107	0.141107	-4.283000
22	Cotswold	3.139566	2.197803	-6.586059	-2.517938	-2.888977	-4.206189	-8.224876
23	Central London	-5.397350	2.197803	-6.369213	-2.517938	-11.252416	-12.526259	-8.008030
24	Essex and Kent	-3.773550	2.197803		-2.517938	-4.533246	-4.533246	-1.638817
25	Oxfordshire, Surrey and Sussex	-1.273923	-2.856020		-2.517938	-6.076677	-6.076677	-3.660346
26	Somerset and Wessex	-1.323475	-4.259387		-2.517938	-7.248923	-7.248923	-4.221693
27	West Devon and Cornwall	0.165552	-5.656259		-2.517938	-6.877393	-6.877393	-4.780442

Small Generation Discount (£/kW)	11.104975

Changes since the last generation tariffs forecast

The following section provides details of the wider and local generation tariffs for 2018/19 and how these have changed compared with the October forecast.

Generation wider zonal tariffs

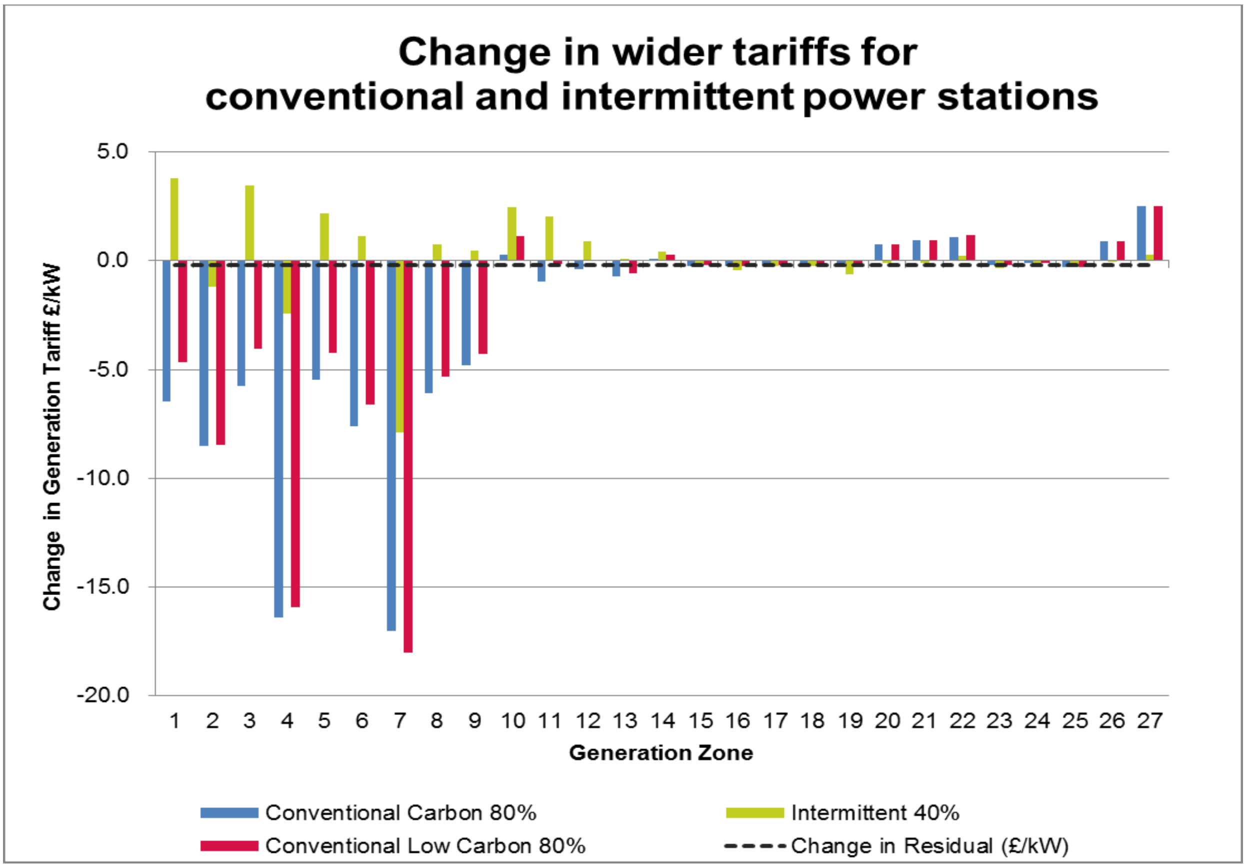
Table 8 and Figure 4 show the changes in generation wider TNUoS tariffs between October and this Draft 2018/19 forecast.

Table 8 – Generation tariff changes

The table and graph below show the change in the example Conventional Carbon, Conventional Low Carbon and Intermittent tariffs. The Conventional tariffs use a load factor of 80%, and the Intermittent tariff uses a 40% load factor as an example.

Wider Generation Tariffs (£/kW)											
		Conventional Carbon 80%			Conventional Low Carbon 80%			Intermittent 40%			
Zone	Zone Name	2018/19 October tariffs (£/kW)	2018/19 Draft tariffs (£/kW)	Change (£/kW)	2018/19 October tariffs (£/kW)	2018/19 Draft tariffs (£/kW)	Change (£/kW)	2018/19 October tariffs (£/kW)	2018/19 Draft tariffs (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	27.977229	21.501234	-6.475995	31.052805	26.365146	-4.687659	20.925837	24.709525	3.783688	-0.180460
2	East Aberdeenshire	22.687306	14.164630	-8.522676	25.762882	17.275706	-8.487176	17.154830	15.945346	-1.209484	-0.180460
3	Western Highlands	26.613242	20.877295	-5.735947	29.688818	25.620978	-4.067841	20.505120	23.977431	3.472310	-0.180460
4	Skye and Lochalsh	31.283614	14.863119	-16.420496	35.522982	19.585794	-15.937189	26.324080	23.872393	-2.451687	-0.180460
5	Eastern Grampian and Tayside	24.983777	19.507139	-5.476639	27.974756	23.750084	-4.224672	18.929460	21.110555	2.181095	-0.180460
6	Central Grampian	24.798904	17.195399	-7.603506	27.732168	21.134204	-6.597964	18.294730	19.424491	1.129761	-0.180460
7	Argyll	29.662722	12.644419	-17.018303	34.529013	16.514290	-18.014723	26.691817	18.813316	-7.878502	-0.180460
8	The Trossacks	21.376518	15.306033	-6.070485	24.084748	18.740580	-5.344168	15.901515	16.636698	0.735182	-0.180460
9	Stirlingshire and Fife	17.092580	12.268569	-4.824011	19.669983	15.379126	-4.290858	14.074393	14.554919	0.480526	-0.180460
10	South West Scotlands	18.068642	18.360666	0.292024	20.671020	21.821967	1.150947	14.475937	16.925318	2.449381	-0.180460
11	Lothian and Borders	14.678104	13.732599	-0.945505	16.166495	15.996595	-0.169900	8.906004	10.938793	2.032789	-0.180460
12	Solway and Cheviot	9.883476	9.489203	-0.394273	11.367442	11.367969	0.000527	7.288536	8.198187	0.909651	-0.180460
13	North East England	7.157978	6.444525	-0.713453	7.963245	7.391987	-0.571259	2.998249	3.088364	0.090115	-0.180460
14	North Lancashire and The Lakes	3.794677	3.877232	0.082556	4.308840	4.603206	0.294365	1.542731	1.980921	0.438190	-0.180460
15	South Lancashire, Yorkshire and Humber	2.897857	2.675860	-0.221996	2.897857	2.697638	-0.200219	-1.847713	-2.040464	-0.192750	-0.180460
16	North Midlands and North Wales	0.805551	0.552459	-0.253092	0.805551	0.552459	-0.253092	-2.437749	-2.879251	-0.441502	-0.180460
17	South Lincolnshire and North Norfolk	-0.397662	-0.616204	-0.218542	-0.397662	-0.616204	-0.218542	-2.412598	-2.669725	-0.257126	-0.180460
18	Mid Wales and The Midlands	-1.036324	-1.302719	-0.266396	-1.036324	-1.302719	-0.266396	-2.293508	-2.552027	-0.258519	-0.180460
19	Anglesey and Snowdon	1.387578	1.276844	-0.110735	1.387578	1.276844	-0.110735	-2.266376	-2.909699	-0.643324	-0.180460
20	Pembrokeshire	2.297689	3.031204	0.733515	2.297689	3.031204	0.733515	-4.170620	-4.294236	-0.123616	-0.180460
21	South Wales & Gloucester	-0.782906	0.141107	0.924013	-0.782906	0.141107	0.924013	-4.204557	-4.283000	-0.078443	-0.180460
22	Cotswold	-3.961612	-2.888977	1.072636	-5.375162	-4.206189	1.168974	-8.472408	-8.224876	0.247533	-0.180460
23	Central London	-11.055956	-11.252416	-0.196460	-12.308299	-12.526259	-0.217960	-7.666373	-8.008030	-0.341656	-0.180460
24	Essex and Kent	-4.426389	-4.533246	-0.106857	-4.426389	-4.533246	-0.106857	-1.404659	-1.638817	-0.234158	-0.180460
25	Oxfordshire, Surrey and Sussex	-5.767335	-6.076677	-0.309342	-5.767335	-6.076677	-0.309342	-3.348212	-3.660346	-0.312134	-0.180460
26	Somerset and Wessex	-8.152594	-7.248923	0.903672	-8.152594	-7.248923	0.903672	-4.166259	-4.221693	-0.055434	-0.180460
27	West Devon and Cornwall	-9.384419	-6.877393	2.507026	-9.384419	-6.877393	2.507026	-5.078826	-4.780442	0.298384	-0.180460

Figure 4 - Variation in generation zonal tariffs



There have been some large reductions in Conventional Carbon generation in the contracted TEC (the version of the TEC register published by 31 October 2017 and the last version to be used before tariffs are set in January 2018) compared to the version used to calculate October 2017 tariffs. One of these reduces the Conventional carbon generation in Scotland significantly, which has a knock-on effect on all zones down to zone 10 in significantly reducing the Peak element of the tariffs (see Appendix E for more information).

Conventional Carbon and Conventional Low Carbon tariffs in Scotland reduce by £4-£9/kW in most zones, with two exceptional decreases in zone 4 of £16/kW and over £17/kW in zone 7, which are dominated by Low Carbon generation. The reduction is driven by reductions to the Peak and Year Round Shared element of the tariffs, and the increase in Year Round Not Shared tariffs is offset for Conventional Carbon generators as after CMP268 was approved, they will only pay a share of this in proportion to their ALF.

Intermittent tariffs increase generally in zones where the Peak tariff has decreased, however they reduce as well in zones 4 and 7. The increases of up to £4/kW per zone are driven mostly by the increase in the Not Shared element, although they are somewhat offset by the reduction in Shared tariffs in all but four generation zones.

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, so have been updated from the October forecast to reflect actual RPI for the period May 2017 to October 2017.

Table 9 - Local substation tariffs

2018/19		Local Substation Tariff (£/kW)		
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.191582	0.109597	0.078967
<1320 MW	Redundancy	0.422039	0.261118	0.189906
>=1320 MW	No redundancy	0	0.343635	0.248518
>=1320 MW	Redundancy	0	0.564161	0.411791

Onshore local circuit tariffs

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 can change as a result of system flows and RPI. If you require further information around a particular local circuit tariff please feel free to contact us.

Some local circuits have been charged through a one off charge, these are listed in Table 11.

Table 10 - Onshore local circuit tariffs

The largest changes to local circuit tariffs are to An Suidhe (£3.82), Mossford (-£2.32) and Nant (-£3.57).

All other local circuit tariffs remain relatively stable.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	4.096253	Dinorwig	2.289432	Langage	0.627620	Dorenell	2.002552
Aigas	0.624082	Dunlaw Extension	1.430019	Lochay	0.349188	Millennium South	0.898567
An Suidhe	2.907312	Dunhill	1.366742	Luichart	0.547243	Aberdeen Bay	2.487963
Arecleoch	1.981850	Dumnaglass	1.771589	Mark Hill	0.835479	Killingholme	0.676668
Baglan Bay	0.725926	Edinbane	6.530545	Marchwood	0.364258	Middleton	0.104624
Beinneun Wind Farm	1.433206	Ewe Hill	1.311273	Millennium Wind	1.742733		
Bhlaraidh Wind Farm	0.627905	Fallago	0.572433	Moffat	0.160091		
Black Hill	0.823271	Farr	3.402170	Mossford	0.427674		
BlackCraig Wind Farm	6.006840	Fernoch	4.197281	Nant	-1.172241		
Black Law	1.667371	Ffestiniogg	0.241415	Necton	-0.351536		
BlackLaw Extension	3.535877	Finlarig	0.305539	Rhigos	0.097111		
Bodelwyddan	0.109791	Foyers	0.718512	Rocksavage	0.016893		
Carrington	-0.032264	Galawhistle	1.411300	Saltend	0.325367		
Clyde (North)	0.104646	Glendoe	1.755201	South Humber Bank	0.902631		
Clyde (South)	0.121018	Glenglass	9.266284	Spalding	0.267922		
Corriegarth	3.008295	Gordonbush	0.520569	Strathbrora	0.373504		
Corriemoillie	1.587573	Griffin Wind	4.076407	Stronelairg	1.396652		
Coryton	0.049502	Hadyard Hill	2.641167	Strathy Wind	2.013532		
Cruachan	1.805089	Harestanes	2.390528	Wester Dod	0.814284		
Crystal Rig	0.489587	Hartlepool	0.573287	Whitelee	0.101270		
Culligran	1.653833	Hedon	0.172665	Whitelee Extension	0.281531		
Deanie	2.717011	Invergarry	1.353893	Gills Bay	2.403062		
Dersalloch	2.298524	Kilgallioch	1.004263	Kype Muir	1.415343		
Didcot	0.496119	Kilmorack	0.188451	Middle Muir	1.891434		

Table 11 - 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, so have been updated from the October forecast to reflect actual RPI for the period May 2017 to October 2017. Offshore local generation tariffs associated with OFTOs yet to be appointed will be calculated following their appointment.

Table 12 - Offshore Local Tariffs 2018/19

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.720148	40.391807	1.002984
Greater Gabbard	14.474370	33.260677	0.000000
Gunfleet	16.708070	15.339316	2.867007
Gwynt Y Mor	17.627466	17.365232	0.000000
Lincs	14.427677	56.487653	0.000000
London Array	9.821298	33.450796	0.000000
Ormonde	23.866552	44.461150	0.354318
Robin Rigg East	-0.441499	29.245531	9.064537
Robin Rigg West	-0.441499	29.245531	9.064537
Sheringham Shoal	23.059225	27.043069	0.587837
Thanet	17.560438	32.721373	0.787719
Walney 1	20.597966	41.020795	0.000000
Walney 2	20.448162	41.382190	0.000000
West of Duddon Sands	7.948192	39.219404	0.000000
Westermost Rough	16.736222	28.310526	0.000000
Humber Gateway	14.027433	31.650564	0.000000

Background 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.

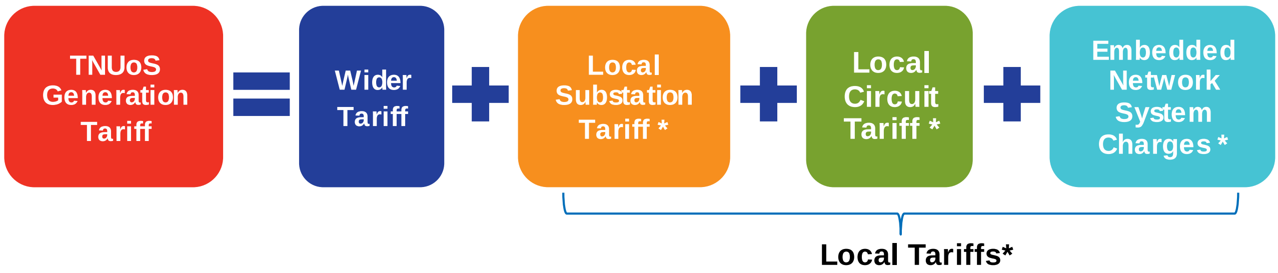
Generation charging principles

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**.



** Additional Local Tariffs may be applicable to Offshore generators*

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.

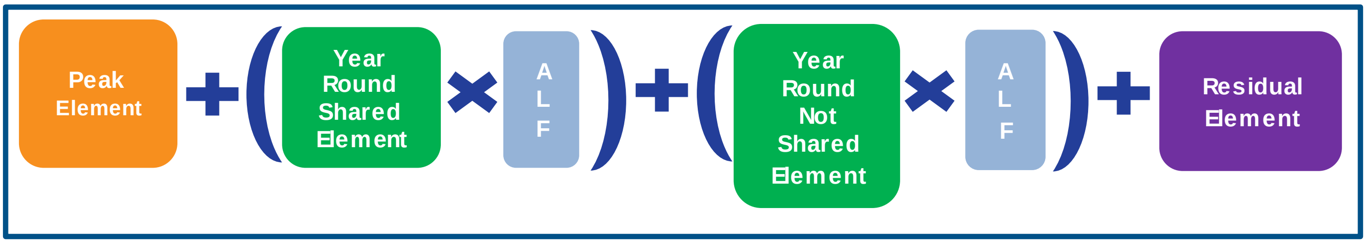
The Wider tariff

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.

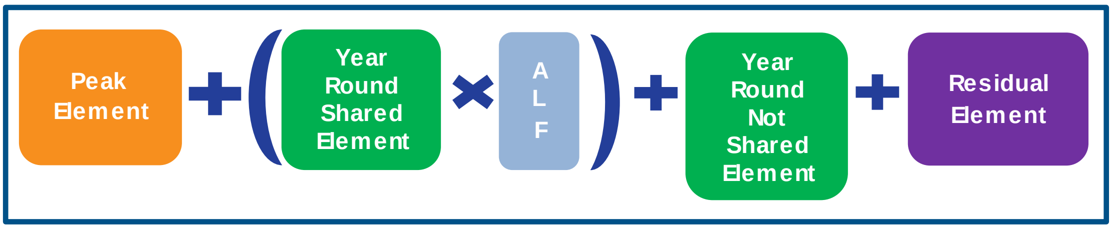
Conventional Carbon Generators

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



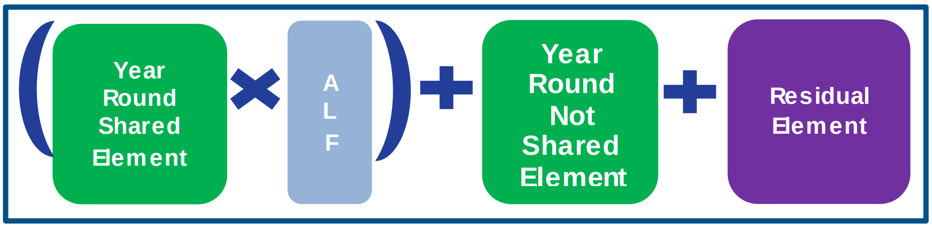
Conventional Low Carbon Generators

(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 the Draft tariffs are listed in Appendix D.

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 financial regulatory 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[§] 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).

<u>Click here to find out more about DNO regions.</u>

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:

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

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.

[§] *For more information about connections, please visit our website:* <u>https://www.nationalgrid.com/uk/electricity/connections/applying-connection</u>
[**] *These specific charges include any onshore local circuit and substation charges.*

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 output during the triads. Triads are the three half hour 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.

Customers must now submit forecasts for both HH gross demand and embedded export volumes as to what their expected demand volumes will be. Customers 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

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

(<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads.

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 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.

Updates to revenue & the charging model since the last forecast

Since the October forecast tariffs were published, we have updated allowed revenue for onshore and offshore Transmission Owners, the local circuits model, the generation charging bases, transport model demand (the week 24 demand) and RPI.

There have been no changes to the transport model circuits, or the error margin that is used to calculate the proportion of revenue to be recovered from generation and demand (G/D split).

Changes affecting the locational element of tariffs

The locational element of generation and demand tariffs is based upon:

- Contracted generation as of 31 October 2017;
- The network model;
- 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
- RPI (which increases the expansion constant).

Table 13 – Contracted and modelled TEC

This was fixed based on the TEC register from 31 October 2017. This will not change in the Final Tariffs which will be published in January.

(GW)	2017/18	2018/19 Initial Forecast	2018/19 June Forecast	2018/19 Oct Forecast	2018/19 Draft Tariffs
Contracted TEC	72.2	79.6	78.8	82.4	79.0
Modelled Best View TEC	72.2	72.6	75.5	79.7	79.0

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 calculations of chargeable TEC for either the generation or demand charging bases.

Table 14 – Interconnectors

The table below reflects the contracted position of interconnectors in the interconnector register as of 31 October 2017; there has been no change since the June forecast.

Interconnector	Site	Interconnected System	Generation Zone	Transport Model (Generation MW) Peak	Transport Model (Generation MW) Year Round	Charging Base (Generation MW)
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
Britned	Grain 400kV	Netherlands	24	0	1200	0
East - West	Deesside 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	80	0

RPI

The RPI index for the components detailed below is calculated based on the average May – October RPI for 2017/18.

Expansion Constant

The expansion constant has reduced marginally from £14.08481547 to £14.08310011 in the Draft tariffs, to reflect lower actual RPI than the level that was forecast. This has had a very small impact on tariffs in all zones, decreasing the 'stretch' of the system circuit lengths and so decreasing the magnitude of locational tariffs, i.e. positive tariffs become less positive and negative tariffs become less negative.

Local substation and offshore substation tariffs

Local onshore substation tariffs are indexed by May - October RPI as are offshore local circuit tariffs, so have been updated from the October forecast to reflect actual RPI for the period May 2017 – October 2017.

Allowed revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Compared to the October forecast, tariffs have now been calculated to recover £2,670.2m of revenue. This is an increase of £8.9m from the October forecast of £2661.3m.

Onshore TOs have collectively increased their revenue forecasts by £12m, following Ofgem's confirmation of the allowed revenue, and the revised RPI forecast. OFTO revenue is offset by that of interconnectors, and the combined effect is -£3m.

CMP283 (Consequential Changes to enable the Interconnector Cap and Floor regime) was approved in November 2017 to allow the provision of revenue data between interconnectors and NGET SO. This will allow the recovery and/or redistribution of revenue in accordance with the Cap and Floor regime. CMP283 has been implemented in this latest revenue forecast.

Table 15 – Allowed revenues

£m Nominal Value	2017/18 TNUoS Revenue	2018/19 TNUoS Revenue				
	Jan 2017 Final	Feb 2017 Initial View	June 2017 Update	Oct 2017 Update	Dec 2017 Draft	Jan 2018 Final
National Grid						
Price controlled revenue	*1,748.8*	*1,727.8*	*1,719.0*	*1,647.1*	*1,652.5*	
Less income from connections	*41.9*	*41.9*	*41.9*	*41.9*	*41.9*	
Income from TNUoS	**1,706.9**	**1,685.9**	**1,677.2**	**1,605.2**	**1,610.7**	**-**
Scottish Power Transmission						
Price controlled revenue	*333.7*	*390.5*	*377.7*	*360.5*	*361.2*	-
Less income from connections	*12.8*	*26.8*	*14.0*	*14.2*	*14.2*	
Income from TNUoS	**321.0**	**363.8**	**363.8**	**346.3**	**347.0**	
SHE Transmission						
Price controlled revenue	*304.7*	*366.5*	*366.7*	*358.6*	*366.4*	-
Less income from connections	*3.4*	*3.2*	*3.6*	*3.5*	*3.4*	
Income from TNUoS	**301.4**	**363.2**	**363.1**	**355.1**	**363.0**	
Offshore	**270.2**	**380.2**	**373.2**	**312.1**	**309.0**	
Network Innovation Competition	**32.1**	**40.5**	**40.5**	**40.5**	**40.5**	
Transmission EDR			**2.0**	**2.0**		
Total to Collect from TNUoS	**2,631.5**	**2,833.6**	**2,819.8**	**2,661.3**	**2,670.2**	**-**

Generation / Demand (G/D) Split

Apart from the revenue to be collected, the G/D split has not changed since the October tariff forecast.

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 in March 2017. The value published is €1.16/£, which has remained the same since the June tariffs.

Generation Output

The forecast output of generation is aligned with Future Energy Scenario generation output forecasts. Our forecast of 253TWh reflects our view of the total generation of generators that are liable for generation TNUoS charges during 2018/19, and has remained the same since the June tariffs. More information on generation forecast modelling is available in the FES publication from July 2017.‡‡

Error Margin

The error margin remains unchanged from the June forecast at 21%. The parameters used to calculate the proportions of revenue collected from generation and demand are shown below.

Table 16 – Generation and demand revenue proportions

		2018/19
CAPEC	Limit on generation tariff (€/MWh)	2.50
y	Error Margin	21.0%
ER	Exchange Rate (€/£)	1.16
MAR	Total Revenue (£m)	2,670.2
GO	Generation Output (TWh)	252.6
G	% of revenue from generation	16.1%
D	% of revenue from demand	83.9%
G.MAR	Revenue recovered from generation (£m)	430.1
D.MAR	Revenue recovered from demand (£m)	2240.1

Charging bases for 2018/19

Generation

The generation charging base we are forecasting is 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 either due to closure, termination or delay and includes any generators that we believe may increase their TEC.

We are unable to breakdown our best view of generation as some of the information used to derive it could be commercially sensitive. The change in contracted TEC, as per the TEC register is shown in the appendices.

Demand

Our forecasts of demand and embedded generation have remained the same as the October tariff forecast using the revised demand forecasting methodology which has been developed under CMP264/265 and was implemented in October for 2018/19 tariffs.

‡‡ *http://fes.nationalgrid.com/*

Table 17 – Charging base

Charging Bases	2017/18	2018/19 Initial	2018/19 June	2018/19 October	2018/19 Draft
Generation (GW)	67.6	66.8	69.7	75.0	71.9
NHH Demand (4pm-7pm TWh)	25.3	23.7	24.2	24.2	24.2
Net Charging					
Total Average Net Triad (GW)	47.7	46.4	46.0	*45.9*	45.9
HH Demand Average Net Triad (GW)	13.2	14.3	13.2	*13.3*	13.3
Gross charging					
Total Average Gross Triad (GW)	*Introduced by CMP264/265*			52.5	52.5
HH Demand Average Gross Triad (GW)				19.8	19.8
Embedded Generation Export (GW)				6.5	6.5

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 available from the National Grid website.[§§] The Final ALFs for 2018/19 can be found in Appendix D.

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)

[§§] *https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.pdf*

- 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 18 - Residual calculation

	Component	2017/18	2018/19 Initial	2018/19 June	2018/19 October	2018/19 Draft
G	Proportion of revenue recovered from generation (%)	14.8%	15.1%	15.3%	16.2%	16.1%
D	Proportion of revenue recovered from demand (%)	85.2%	84.9%	84.7%	83.8%	83.9%
R	Total TNUoS revenue (£m)	2,631	2,833	2,820	2,661	2,670
Generation Residual						
R_G	Generator residual tariff (£/kW)	-1.85	-3.20	-3.28	-2.34	-2.52
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	275.0	313.2	334.0	322.2	330.8
O	Revenue recovered from offshore local tariffs (£m)	208.5	293.9	288.4	244.0	243.6
L_G	Revenue recovered from onshore local substation tariffs (£m)	17.5	17.0	17.8	20.7	19.2
S_G	Revenue recovered from onshore local circuit tariffs (£m)	14.6	16.9	18.5	18.5	17.6
B_G	Generator charging base (GW)	67.6	66.8	69.7	75.0	71.9
Net Demand Residual						
R_D	Demand residual tariff (£/kW)	47.26	52.24	52.20	*no longer calculated*	*no longer calculated*
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-12.4	-19.0	-12.0	*no longer calculated*	*no longer calculated*
B_D	Demand Net charging base (GW)	47.7	46.4	46.0	*no longer calculated*	*no longer calculated*
Gross Demand Residual						
R_D	Demand residual tariff (£/kW)	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	46.90	46.94
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	-64.2	-47.1
EE	Amount to be paid to Embedded Export Tariffs (£m)	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	165.2	175.3
B_D	Demand Gross charging base (GW)	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	*Introduced by CMP264/265 to replace 'net residual'*	52.5	52.5

Small generators' discount

The small generators' discount has been calculated as £11.104975/kW. This equates to a forecast of £30.6m which is recovered from suppliers through the HH and NHH tariffs.

Changes to the small generators' discount recovery following CMP264 and CMP265

The small generators' discount calculation has changed following the move to gross charging for TNUoS demand under CMP264/265. Following the introduction of the EET and HH demand being charged on a gross basis, the calculation of the small generators' discount will change.

The small generators' discount recovery is now taken from gross HH demand, and the residual used in the calculation of the discount is now the gross demand residual.

The rate charged to HH demand tariffs is now charged at a gross demand level instead of net.

Table 19 – Small generators' discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-2.52
Demand Residual (£/kW)	D	46.94
Small Generator Discount (£/kW)	T = (G + D)/4	11.10
Forecast Small Generator Volume (kW)	V	2,780,910
2017/18 SGD cost (£)	V x T	30,881,936
Prior year reconcilation (£)	R	- 236,300
Total SGD Cost (£)	C = (V x T) + R	30,645,636
Total Gross System Triad Demand (kW)	TD	52,463,074
Total HH Gross Triad Demand (kW)	HHD	19,801,167
Total NHH Consumption (kWh)	NHHD	24,172,250,677
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.58
Total Cost to HH Customers (£)	HHC = HHT * HHD	11,566,599
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.08
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	19,079,036

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 Draft tariffs on Friday 5 January 2018 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 the Draft 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://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

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Appendices

Appendix A: Changes and possible changes to the charging methodology affecting 2018/19 TNUoS Tariffs

Appendix B: Locational demand tariff charges

Appendix C: Locational demand profiles

Appendix D: Annual Load Factors

Appendix E: Contracted generation changes since the June forecast

Appendix F: Transmission company revenues

Appendix G: Generation zones map

Appendix H: Demand zones map

Appendix A: Changes and possible changes to the charging methodology affecting 2018/19 TNUoS Tariffs

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2018/19 onwards. All these modifications are subject to whether or not they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

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

A summary of the mods which could affect the 2018/19 tariffs and their status are listed below. More detail follows this table.

Table 20: Summary of CUSC modifications affecting 2018/19 TNUoS Tariffs

Mod Number	Description	Status	Status in the Draft 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**
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 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 – 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 Draft tariffs for 2018/19, removing the error margin would transfer £114.3m of revenue from demand TNUoS to generation TNUoS. This would increase the generation residual from -£2.52/kW to -£0.93/kW. The gross HH residual would fall from £46.94/kW to £44.76/kW. The average NHH tariffs would decrease from 6.21p/kWh to 5.92p/kWh.

We understand that any decision on CMP251 by Ofgem will be delayed pending the outcome of the review of CMP261.

[***] 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.

EDF Energy and SSE have requested that the decision to reject CMP261 should be reviewed by the Competition and Markets Authority.[†††] The CMA has granted the request.

No changes to the methodology follow as a result of Ofgem's decision, unless the CMA direct otherwise. 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.

[†††] *https://www.gov.uk/cma-cases/edf-sse-code-modification-appeal*

Appendix B: Locational demand tariff charges

The table below shows the locational demand tariff elements used in the gross HH demand tariff and the EET and the associated changes from the October forecast to the Draft forecast.

The zonal variations for both the peak security and year round tariffs have been driven by the changes to modelled demand (please see Appendix C) and generation TEC reductions in northern Scotland. This can be seen largely in zones 1, 2 (Scotland) and 14 (South Western) which has resulted in increased tariffs for Scotland and a reduction for South Western.

Table 21 – Locational tariffs

	October Forecast		Draft		Changes	
Zone	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	-1.993368	-27.150698	3.065285	-24.297592	5.058653	2.853106
2	-1.961762	-20.401921	0.134686	-18.606910	2.096448	1.795011
3	-3.480363	-7.090431	-3.097681	-6.616660	0.382682	0.473771
4	-1.173400	-2.455444	-1.214669	-2.512235	-0.041269	-0.056791
5	-2.933824	-0.729525	-2.902127	-0.557508	0.031697	0.172017
6	-1.657943	-0.403630	-2.334653	0.313286	-0.676710	0.716916
7	-2.083848	1.978650	-2.257707	2.226057	-0.173859	0.247407
8	-1.179327	2.532494	-1.800712	3.064231	-0.621386	0.531737
9	1.267987	0.603964	1.140503	0.755028	-0.127485	0.151064
10	-5.354272	4.639584	-6.151443	4.422608	-0.797171	-0.216976
11	3.987643	1.032637	3.869828	0.707482	-0.117816	-0.325154
12	5.385967	1.957062	5.119155	2.254470	-0.266812	0.297408
13	2.162847	4.140511	1.637860	4.248799	-0.524987	0.108287
14	0.296077	6.067652	-1.028052	5.362369	-1.324128	-0.705283

Appendix C: Locational demand profiles

The table below shows the latest demand forecast used in the Draft tariff forecast.

The locational model demand profiles have been updated following the submission of week 24 data from the DNOs and directly connected demand (DCC).

Locational model demand is now 51.09GW, this is an increase of 480MW since the October forecast. Significant variations can be seen in zones 1, 6, 11 and 13 compared to the data used in October. Overall net peak demand has not changed since the October forecast from 45.95GW.

HH demand is now calculated on a gross basis rather than net, which removes the negative demand caused by embedded generation.

Table 22 – Demand profiles

Zone	Zone Name	2018/19 October					2018/19 Draft				
		Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)	Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	227	1,477	489	0.74	1,001	640	1,477	489	0.74	1,001
2	Southern Scotland	2,820	3,500	1,259	1.66	670	2,724	3,500	1,259	1.66	670
3	Northern	2,508	2,664	1,078	1.20	581	2,649	2,664	1,078	1.20	581
4	North West	3,234	4,117	1,523	1.93	343	3,169	4,117	1,523	1.93	343
5	Yorkshire	4,347	3,920	1,610	1.76	635	4,388	3,920	1,610	1.76	635
6	N Wales & Mersey	2,831	2,678	1,085	1.22	538	2,394	2,678	1,085	1.22	538
7	East Midlands	5,333	4,763	1,878	2.16	477	5,296	4,763	1,878	2.16	477
8	Midlands	4,594	4,371	1,617	2.00	211	4,410	4,371	1,617	2.00	211
9	Eastern	5,843	6,605	2,133	3.09	624	6,097	6,605	2,133	3.09	624
10	South Wales	1,969	1,843	839	0.83	331	1,666	1,843	839	0.83	331
11	South East	3,355	3,999	1,169	1.91	318	3,813	3,999	1,169	1.91	318
12	London	5,271	4,323	2,286	1.84	149	5,380	4,323	2,286	1.84	149
13	Southern	5,668	5,584	2,072	2.56	437	6,220	5,584	2,072	2.56	437
14	South Western	2,609	2,621	764	1.27	200	2,244	2,621	764	1.27	200
Total		**50,609**	**52,463**	**19,801**	**24.17**	**6,516**	**51,090**	**52,463**	**19,801**	**24.17**	**6,516**

Appendix D: Annual Load Factors

ALFs

Table 23 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 ALF 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 were finalised for the Five-year forecast tariffs published on 1 December 2017.[‡‡‡]

[‡‡‡] *https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.pdf*

Table 23: Specific Annual Load Factors

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 DEVELOPMENTCENTRE	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%
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%

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	
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%
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%

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	
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%
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%

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	
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%
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 24: 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 E: Contracted generation changes since the October forecast

Table 25 shows the TEC changes notified between October 2017 (used as the basis for the initial forecast) and December 2017 for these Draft tariffs. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table. The tariffs in this forecast are based on National Grid's best view and therefore may include different generation to that shown below.

Table 25: Generation Contracted TEC Changes

Power Station	Node	MW Change	Generation Zone
Barry Power Station	ABTH20	93.00	21
Blackcraig Wind Farm	BLCW10	-4.60	10
Killingholme	KILL40	-600.00	15
Kings Lynn A	WALP40_EME	99.00	17
Loganhead Windfarm	EWEH1Q	-36.00	12
Peterhead	PEHE20	-1180.00	2
Pogbie Wind Farm	DUNE10	11.80	11
Powersite @ Drakelow	DRAK40	-380.00	18
Rampion Offshore Wind Farm	BOLN40	400.00	25
Taylors Lane	WISD20_LPN	144.00	23
Trafford Power	CARR40	-1944.00	16
Tralorg Wind Farm	MAHI20	-20.00	10

Appendix F: Transmission company revenues

National Grid revenue forecast

We seek to provide the detail behind price control revenue forecasts for National Grid, Scottish Power Transmission and SHE Transmission, however, the contractual position between NGSO and TOs does not presently require a breakdown to the TO final position.

Revenue for offshore networks is included with forecasts by National Grid where the Offshore Transmission Owner has yet to be appointed.

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

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

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

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

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

Table 26 – Indicative National Grid revenue forecast

Description			18/12/2017 Licence Term		Yr t+1			Notes
Regulatory Year			2014/15	2015/16	2016/17	2017/18	2018/19	
Actual RPI					264.99			April to March average
RPI Actual		RPIAt			1.228			Office of National Statistics
Assumed Interest Rate		It	0.50%	0.70%	0.34%	0.29%	0.38%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1443.83	1475.59	1571.39	1554.94	1587.63	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.50	-114.40	-185.40	-253.30	-310.24	Forecast
RPI True Up	A3	TRUt	-0.53	4.70	-19.92	-31.40	-6.08	Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	0.03	0.03	0.01	0.02	3.50%	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	0.03	0.02	0.02	0.04	3.50%	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	0.03	0.03	0.03	0.03	3.00%	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.21	1.23	1.23	1.27	1.31	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1732.69**	**1675.48**	**1684.36**	**1614.48**	**1670.49**	
Pass-Through Business Rates	B1	RBt		1.2	1.5	2.7	1.6	Forecast
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	0.0	0.7	Forecast
Licence Fee	B3	LFt		2.0	2.7	3.2	-0.4	Forecast
Inter TSO Compensation	B4	ITCt		3.8	2.7	0.5	1.3	Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.00	0.00	0.00	0.00	0.0	Forecast
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	294.6	321.0	347.0	Forecast
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	301.4	363.0	Forecast
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	270.2	309.0	Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	0.5	0.6	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**745.10**	**889.97**	**885.86**	**899.43**	**1022.83**	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	4.0	4.1	Forecast
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	8.6	9.3	Forecast
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	2.6	1.4	Forecast
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	0.0	2.0	Forecast
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0.00**	**13.86**	**18.73**	**15.26**	**16.83**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.2	10.5	Forecast
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	32.1	40.5	Forecast
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0	0.0	0.0	0.0	Forecast
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	0.0	0.0	Forecast
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.9	6.1	6.3	Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	-1.1	0.0	Forecast
Correction Factor	K	-Kt	0.0	56.4	104.0	97.0	-55.4	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2524.3**	**2681.6**	**2751.3**	**2673.4**	**2712.1**	
Termination Charges	B5		0	0	0	0	0	
Pre-vesting connection charges	P		47.0	45.0	42.7	41.9	41.9	Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2631.5**	**2670.2**	
Final Collected Revenue	U	TNRt						Forecast
Forecast percentage change to Maximum Revenue M				6.2%	2.6%	-2.8%	1.1%	
Forecast percentage change to TNUoS Collected Revenue T				6.4%	2.7%	-2.8%	1.1%	

Scottish Power Transmission revenue forecast

Under the relevant STC (System Operator Transmission Owner Code) procedures, the Scottish Power Transmission revenue forecast was updated in early December and will be finalised by 25 January 2018. The indicative SPT revenue to be collected via TNUoS for 2018/19 is £347m.

SHE Transmission revenue forecast

Under the relevant STC (System Operator Transmission Owner Code) procedures, the Scottish Hydro Electric Transmission (SHE Transmission) revenue forecast was updated in early December and will be finalised by 25 January 2018. The indicative SHET Transmission revenue to be collected via TNUoS for 2018/19 is £363m.

Offshore Transmission Owner revenues

Under the relevant STC (System Operator Transmission Owner Code) procedures, OFTO revenue was updated in early December and will be finalised by 25 January 2018.

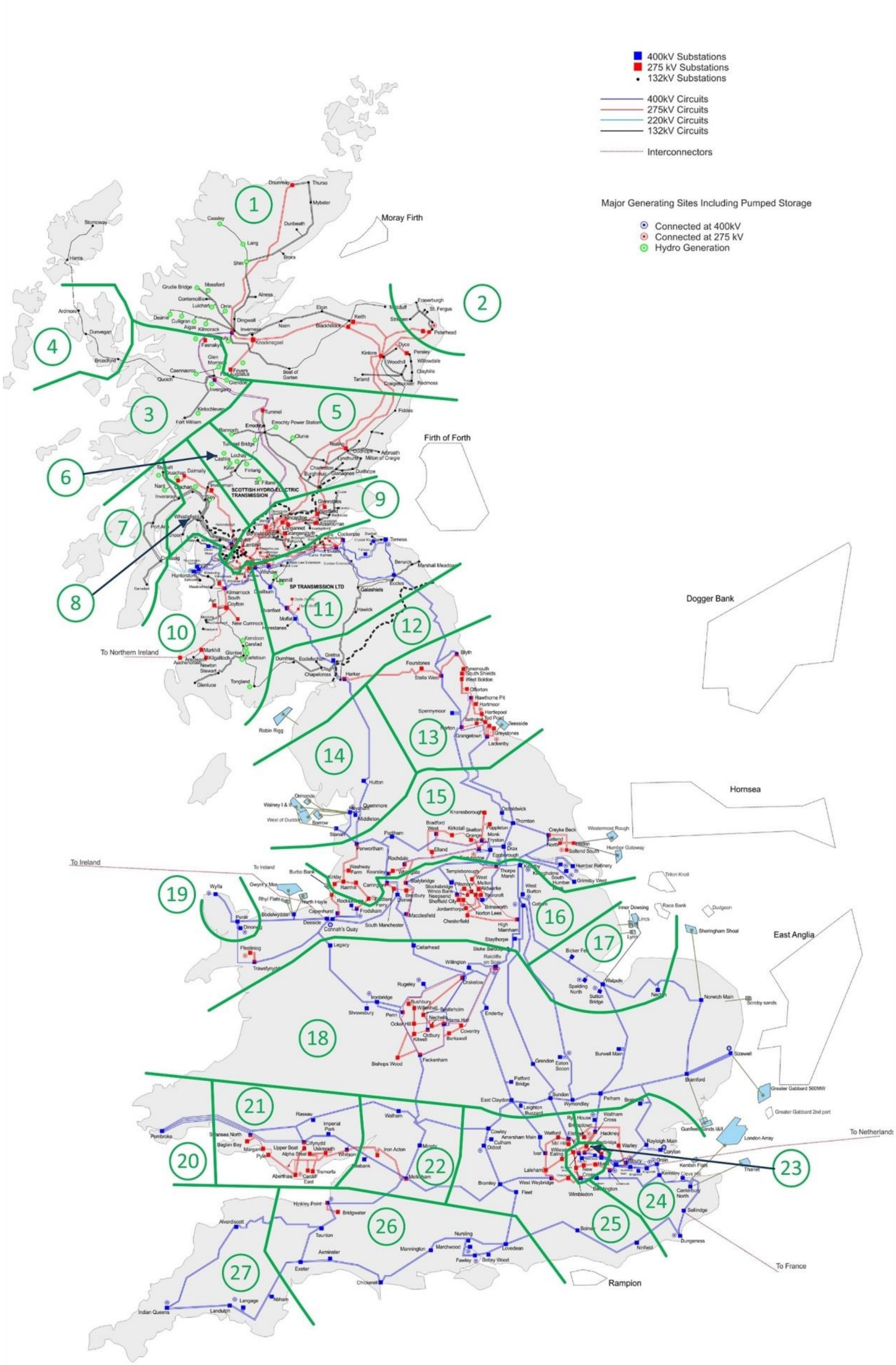
Under CMP283, TNUoS charges can be adjusted by an amount determined by Ofgem to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime. We have aggregated this adjustment with future OFTO revenue. The indicative total OFTO + Interconnector revenue to be collected via TNUoS for 2018/19 is £ 309m.

Table 27 - Offshore Transmission Owner revenues (indicative)

<table>
<tr><th>Offshore Transmission Revenue Forecast</th><th colspan="5">14/12/2017</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th><th>2017/18</th><th>2018/19</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</td><td>6.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>7.4</td><td>7.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>13.1</td><td>13.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>8.4</td><td>8.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>12.5</td><td>12.3</td><td>16.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.0</td><td>20.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>12.2</td><td>13.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>27.3</td><td>28.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>39.5</td><td>39.5</td><td>40.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>15.7</td><td>19.5</td><td>18.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>25.6</td><td>26.7</td><td>27.2</td><td>28.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.6</td><td>29.3</td><td>32.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.3</td><td>22.0</td><td>22.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td></td><td rowspan="2">29.3</td><td>9.7</td><td>12.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td></td><td>11.6</td><td>13.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO + Interconnector revenue in 2018/19</td><td></td><td></td><td></td><td></td><td>26.6</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2019/20</td><td></td><td></td><td></td><td></td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2020/21</td><td></td><td></td><td></td><td></td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2021/22</td><td></td><td></td><td></td><td></td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>260.8</td><td>265.5</td><td>309.0</td><td></td></tr>
</table>

Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



Appendix H: Demand zones map