Final TNUoS

Tariffs for 2018/19

January 2018

Final TNUoS tariffs for 2018/19

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

January 2018

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Executive Summary

This document contains the Transmission Network Use of System (TNUoS) Final 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 will be £2,670.3m in 2018/19, an increase of £0.1m from the forecast published in Draft tariffs. This is due to a small increase in revenues for TOs offset by a reduction in the value of the Network Innovation Competition fund as allowed by Ofgem.

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 Draft tariffs.

The chargeable TEC has increased by just 16MW. The average generation tariff is unchanged from the Draft tariffs at £5.98/kW.

Demand tariffs

Demand tariffs have been set to recover £2240.2m of revenue, an increase of £0.1m from the Draft tariffs. The Embedded Export tariff is forecast to pay £175.4m to eligible embedded export volumes and this is recovered from other demand tariffs.

The Demand Charging Base remains the same as the Draft tariffs. 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 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. Demand tariffs have changed only very slightly since Draft tariffs.

Changes to the Methodology affecting 2018/19 tariffs

There have been various CUSC changes implemented in the methodology used to calculate tariffs for 2018/19. These have all previously been reflected in our Draft tariffs, and there have been no further methodology changes. These Final tariffs include changes introduced[1] by

[1] *See: https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code?mods*

CMP264/265[2], CMP268[3], CMP282[4] and CMP283[5],

Drivers of changes to the Tariff forecast

There have only been minor changes between Draft tariffs and these Final tariffs. These have been driven by:

- A slight increase in chargeable generation.
- Local circuit corrections and HVDC changes in the transport model that affect system flows, particularly in Scotland.
- A very small increase in demand residual due to increased overall allowed revenue.

Potential Mid-Year Change to our charges

This is the final publication of 2018/19 tariffs on the usual timescales. However, there are current ongoing challenges to CMP261[6] through a CMA appeal and CMP264/265[7] through a judicial review. These processes may result in changes to the methodologies affecting 2018/19 tariffs within the charging year. This may require a change to our charges during the 2018/19 Charging Year.

If directed to do so, we will implement any required mid-year changes to charges as soon as practicable, in accordance with our licence, and in consultation with Ofgem.

[2] *Embedded generation Triad avoidance standstill and Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market*
[3] *Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits*
[4] *The effect negative demand has on zonal locational demand tariffs*
[5] *Consequential changes to enable the interconnector Cap and Floor regime*

[6] *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)*
[7] *introduction of gross HH demand charging, and changes to embedded benefits*

We intend to publish guidance on the potential impact of mid-year changes to charges during February.

2019/20 TNUoS Tariffs

Our next publication of TNUoS tariffs will be the forecast of 2019/20 tariffs in April 2018.

The latest tariff forecast timetable can be found on our website.[8]

Feedback

We welcome feedback on any aspect of this document and the tariff setting process. 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, whether you have any questions on this document or whether you still welcome webinar sessions following each forecast.

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

Demand Tariffs

Tables 1, 2 and 3 show Final Demand tariffs for 2018/19 for Half-Hourly, Embedded Export and Non-Half-Hour metered demand. The HH and NHH tariffs include the effect of the small generator discount.

Table 1: Summary of Demand tariffs

HH Tariffs	2018/19 Draft	2018/19 Final	Change
Average Tariff (£/kW)	46.167323	46.170244	0.002921
Residual (£/kW)	46.937840	46.933426	-0.004414
EET	**2018/19 Draft**	**2018/19 Final**	**Change**
Average Tariff (£/kW)	26.906579	26.914673	0.008094
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)	175.317954	175.370693	0.052739
NHH Tariffs	**2018/19 Draft**	**2018/19 Final**	**Change**
Average (p/kWh)	6.210566	6.210971	0.000405

Table 2: Demand tariffs by zone

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	26.304232	3.509185	11.357806
2	Southern Scotland	29.070427	3.918340	14.124001
3	Northern	37.816827	4.999041	22.870402
4	North West	43.806241	5.881985	28.859815
5	Yorkshire	44.073211	5.785198	29.126786
6	N Wales & Mersey	45.512765	5.928967	30.566339
7	East Midlands	47.501489	6.345087	32.555063
8	Midlands	48.796991	6.732502	33.850566
9	Eastern	49.428549	7.157677	34.482123
10	South Wales	45.804410	5.552697	30.857984
11	South East	52.110398	7.713198	37.163973
12	London	54.906683	6.106170	39.960257
13	Southern	53.419807	7.317489	38.473382
14	South Western	51.867520	7.560093	36.921094

Tariffs include small gen tariff of:	0.593000	0.080127
Residual charge for demand:	£ 46.933426	

Changes since the previous demand tariffs forecast

There has been very minimal change in all demand tariffs since our Draft tariffs. A slight change to the network model including parameters of the HVDC has caused some very minor changes to demand tariffs in Scotland. Changes in some of the local circuit tariffs as well as the increase in revenue to be recovered from demand have also contributed to these tariff variations.

Overall, the average demand tariff for HH has increased by less than £0.01/kW. The average NHH tariff has only changed in the fourth decimal place.

The average EET is £26.91/kW, also increasing by less than £0.01/kW since Draft tariffs. Our forecast predicts that this will result in £175.4m to be paid to embedded generators and suppliers, a very small increase of less than £0.1m since Draft tariffs.

Gross half hourly demand tariffs

Table 3 show the gross HH demand 2018/19 Final tariffs, compared to the Draft tariffs with the CMP264/265 methodology applied in both.

Table 3 – Gross HH demand tariffs

Zone	Zone Name	2018/19 Draft (£/kW)	2018/19 Final (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	26.298678	26.304232	0.005554	-0.004414
2	Southern Scotland	29.058761	29.070427	0.011666	-0.004414
3	Northern	37.816645	37.816827	0.000182	-0.004414
4	North West	43.804081	43.806241	0.002160	-0.004414
5	Yorkshire	44.071351	44.073211	0.001860	-0.004414
6	N Wales & Mersey	45.509619	45.512765	0.003146	-0.004414
7	East Midlands	47.499335	47.501489	0.002154	-0.004414
8	Midlands	48.794504	48.796991	0.002487	-0.004414
9	Eastern	49.426516	49.428549	0.002033	-0.004414
10	South Wales	45.802151	45.804410	0.002259	-0.004414
11	South East	52.108295	52.110398	0.002103	-0.004414
12	London	54.904610	54.906683	0.002073	-0.004414
13	Southern	53.417644	53.419807	0.002163	-0.004414
14	South Western	51.865303	51.867520	0.002217	-0.004414

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

The largest tariff change has been in Zone 2 (Southern Scotland) where the tariff has increased by £0.012/kW. This is a 0.04% change since Draft tariffs.

The HH charging base remains unchanged since the Draft tariffs. The small change in the residual is due to slightly more revenue being recovered from locational tariffs and the marginal increase in credit from the embedded export tariff, as well as a £0.1m increase in overall revenue to be recovered from demand.

Embedded export tariff

Table 4 shows the embedded export 2018/19 Final tariffs compared to the Draft tariffs.

Table 4 – Embedded export tariffs

Zone	Zone Name	2018/19 Draft (£/kW)	2018/19 Final (£/kW)	Change (£/kW)
1	Northern Scotland	11.347693	11.357806	0.010113
2	Southern Scotland	14.107776	14.124001	0.016225
3	Northern	22.865659	22.870402	0.004743
4	North West	28.853095	28.859815	0.006720
5	Yorkshire	29.120365	29.126786	0.006421
6	N Wales & Mersey	30.558634	30.566339	0.007705
7	East Midlands	32.548350	32.555063	0.006713
8	Midlands	33.843518	33.850566	0.007048
9	Eastern	34.475531	34.482123	0.006592
10	South Wales	30.851165	30.857984	0.006819
11	South East	37.157310	37.163973	0.006663
12	London	39.953624	39.960257	0.006633
13	Southern	38.466659	38.473382	0.006723
14	South Western	36.914318	36.921094	0.006776

The largest value change has again been in Zone 2 (Southern Scotland) where the tariff has increased by £0.016/kW. This is a change of just over 0.1% since Draft tariffs. The variations in tariffs are driven by the locational tariff changes as previously described for the demand tariffs summary, as the EET uses the same locational elements of peak and year round within the HH tariffs.

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 £0.01/kW, which is almost unchanged from Draft tariffs. The total value of credit payable to embedded export volumes is £175m. The level of forecasted embedded export volumes over triads has remained the same at 6.52GW.

As the level of the EET is determined by the locational elements of the HH tariff, the EET is lowest in zone 1 (£11.35/kW; the zone 1 locational tariff is £-21.22/kW), but where the locational element is at its highest in zone 12, the EET is £39.96/kW.

NHH demand tariffs

Table 5 show the difference between the NHH demand Draft tariffs and these Final 2018/19 tariffs.

Table 5 - NHH demand tariff changes

Zone	Zone Name	2018/19 Draft (p/kWh)	2018/19 Final (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.508445	3.509185	0.000740
2	Southern Scotland	3.916767	3.918340	0.001573
3	Northern	4.999018	4.999041	0.000023
4	North West	5.881695	5.881985	0.000290
5	Yorkshire	5.784955	5.785198	0.000243
6	N Wales & Mersey	5.928558	5.928967	0.000409
7	East Midlands	6.344800	6.345087	0.000287
8	Midlands	6.732159	6.732502	0.000343
9	Eastern	7.157381	7.157677	0.000296
10	South Wales	5.552425	5.552697	0.000272
11	South East	7.712884	7.713198	0.000314
12	London	6.105943	6.106170	0.000227
13	Southern	7.317192	7.317489	0.000297
14	South Western	7.559768	7.560093	0.000325

The largest change has been in Zone 2 (Southern Scotland) where the tariff has increased by 0.0016p/kWh. This is a 0.04% change since Draft tariffs and is attributable to the higher amount of zonal revenue to be recovered from the NHH charging base following the slight increase in overall revenue to be recovered and the increase in the EET revenue. This is slightly offset by the very minor reduction in the small generator discount compared to Draft tariffs.

The NHH charging base remains the same as in the Draft tariffs at 24.2 TWh, which generally aligns with the declining trend in recent years.

Generation Tariffs

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

Table 6 – Summary of generation tariffs

Generation Tariffs	2018/19 Draft	2018/19 Final	Change since last forecast
Residual	-2.517938	-2.524518	-0.006580
Average Generation Tariff	5.980623	5.979268	-0.001355

On average, generation tariffs are only slightly changed since Draft tariffs, as there have only been HVDC and local circuit changes. An increase of 16MW of chargeable generation since Draft tariffs results in a small decrease in the residual.

Generation wider tariffs

The following section provides a summary of how the wider generation tariffs have changed between the Draft tariffs and this Final tariffs report, 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 C. These ALFs were published in December 2017 and are unchanged.

The classifications for different technology types are shown 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	-1.224803	7.087100	23.713708	-2.524518	20.891325	25.634067	24.024030
2	East Aberdeenshire	-1.564833	7.087100	16.322341	-2.524518	14.638202	17.902670	16.632663
3	Western Highlands	-1.151336	6.742400	23.080718	-2.524518	20.182640	24.798784	23.253160
4	Skye and Lochalsh	-7.080880	6.742400	22.985475	-2.524518	14.176902	18.773997	23.157917
5	Eastern Grampian and Tayside	0.223873	5.961071	20.926257	-2.524518	19.209217	23.394469	20.786167
6	Central Grampian	-0.540154	5.607589	19.625995	-2.524518	17.122195	21.047394	19.344513
7	Argyll	-4.281853	4.946349	19.310849	-2.524518	12.599387	16.461557	18.764871
8	The Trossachs	0.121027	4.946349	17.123688	-2.524518	15.252539	18.677276	16.577710
9	Stirlingshire and Fife	-0.695178	3.823151	15.547750	-2.524518	12.277025	15.386575	14.552492
10	South West Scotlands	2.759793	5.321630	17.252322	-2.524518	18.294437	21.744901	16.856456
11	Lothian and Borders	2.921369	5.321630	11.337033	-2.524518	13.723781	15.991188	10.941167
12	Solway and Cheviot	1.847792	3.299568	9.394343	-2.524518	9.478403	11.357271	8.189652
13	North East England	3.435017	2.166433	4.738297	-2.524518	6.434283	7.381942	3.080352
14	North Lancashire and The Lakes	1.753699	2.166433	3.628899	-2.524518	3.865447	4.591226	1.970954
15	South Lancashire, Yorkshire and Humber	4.369952	0.915048	0.108511	-2.524518	2.664281	2.685983	-2.049988
16	North Midlands and North Wales	3.793481	-0.903367		-2.524518	0.546269	0.546269	-2.885865
17	South Lincolnshire and North Norfolk	2.205750	-0.386413		-2.524518	-0.627898	-0.627898	-2.679083
18	Mid Wales and The Midlands	1.283844	-0.092373		-2.524518	-1.314572	-1.314572	-2.561467
19	Anglesey and Snowdon	4.578802	-0.988018		-2.524518	1.263870	1.263870	-2.919725
20	Pembrokeshire	9.102191	-4.448024		-2.524518	3.019254	3.019254	-4.303728
21	South Wales & Gloucester	6.189622	-4.419923		-2.524518	0.129166	0.129166	-4.292487
22	Cotswold	3.140018	2.190690	-6.586203	-2.524518	-2.900910	-4.218151	-8.234445
23	Central London	-5.396903	2.190690	-6.369195	-2.524518	-11.264225	-12.538064	-8.017437
24	Essex and Kent	-3.773103	2.190690		-2.524518	-4.545069	-4.545069	-1.648242
25	Oxfordshire, Surrey and Sussex	-1.273475	-2.863212		-2.524518	-6.088563	-6.088563	-3.669803
26	Somerset and Wessex	-1.323025	-4.266571		-2.524518	-7.260800	-7.260800	-4.231146
27	West Devon and Cornwall	0.166003	-5.663470		-2.524518	-6.889291	-6.889291	-4.789906

Small Generation Discount (£/kW)	11.102227

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 Draft tariffs.

Generation wider zonal tariffs

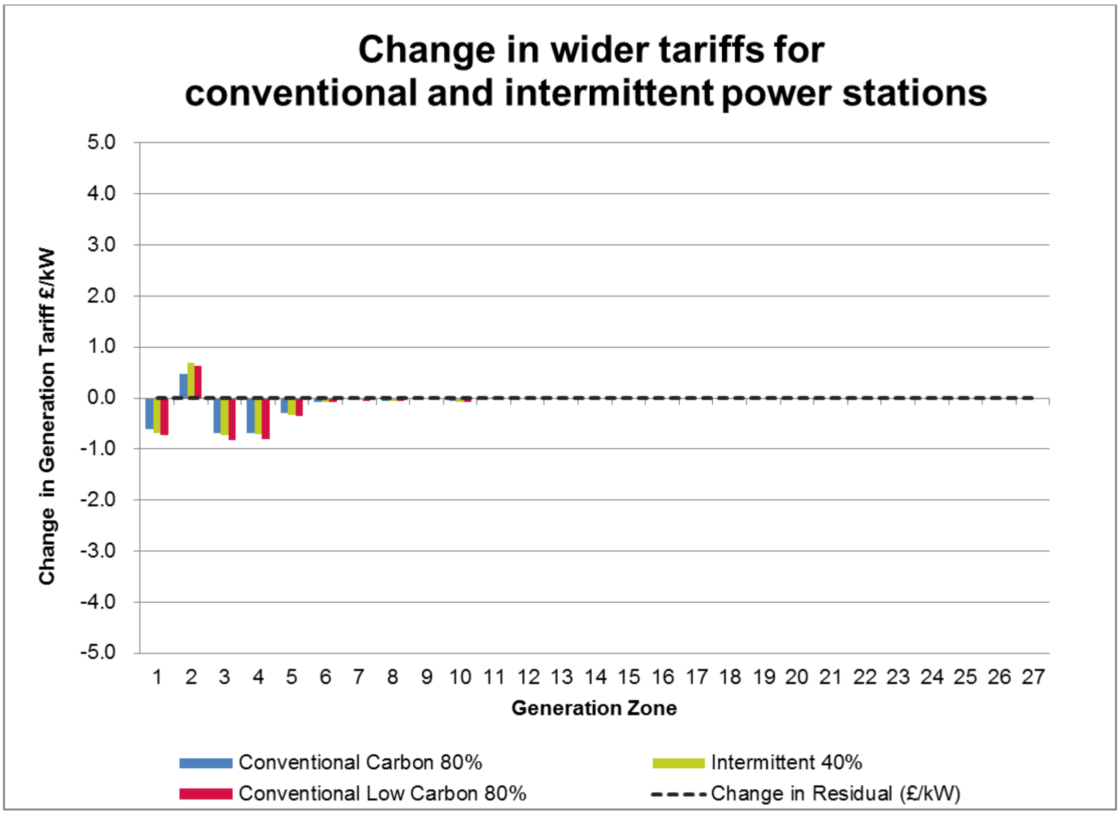
Table 8 and Figure 4 show the changes in generation wider TNUoS tariffs between the Draft tariffs and these Final 2018/19 tariffs.

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 an illustrative 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%			Change in Residual (£/kW)
Zone	Zone Name	2018/19 Draft (£/kW)	2018/19 Final (£/kW)	Change (£/kW)	2018/19 Draft (£/kW)	2018/19 Final (£/kW)	Change (£/kW)	2018/19 Draft (£/kW)	2018/19 Final (£/kW)	Change (£/kW)	
1	North Scotland	21.501234	20.891325	-0.609909	26.365146	25.634067	-0.731079	24.709525	24.024030	-0.685495	-0.006580
2	East Aberdeenshire	14.164630	14.638202	0.473572	17.275706	17.902670	0.626964	15.945346	16.632663	0.687317	-0.006580
3	Western Highlands	20.877295	20.182640	-0.694655	25.620978	24.798784	-0.822194	23.977431	23.253160	-0.724271	-0.006580
4	Skye and Lochalsh	14.863119	14.176902	-0.686217	19.585794	18.773997	-0.811797	23.872393	23.157917	-0.714476	-0.006580
5	Eastern Grampian and Tayside	19.507139	19.209217	-0.297921	23.750084	23.394469	-0.355615	21.110555	20.786167	-0.324388	-0.006580
6	Central Grampian	17.195399	17.122195	-0.073203	21.134204	21.047394	-0.086810	19.424491	19.344513	-0.079978	-0.006580
7	Argyll	12.644419	12.599387	-0.045032	16.514290	16.461557	-0.052733	18.813316	18.764871	-0.048445	-0.006580
8	The Trossachs	15.306033	15.252539	-0.053494	18.740580	18.677276	-0.063304	16.636698	16.577710	-0.058988	-0.006580
9	Stirlingshire and Fife	12.268569	12.277025	0.008456	15.379126	15.386575	0.007449	14.554919	14.552492	-0.002426	-0.006580
10	South West Scotlands	18.360666	18.294437	-0.066229	21.821967	21.744901	-0.077066	16.925318	16.856456	-0.068862	-0.006580
11	Lothian and Borders	13.732599	13.723781	-0.008817	15.996595	15.991188	-0.005407	10.938793	10.941167	0.002374	-0.006580
12	Solway and Cheviot	9.489203	9.478403	-0.010800	11.367969	11.357271	-0.010698	8.198187	8.189652	-0.008535	-0.006580
13	North East England	6.444525	6.434283	-0.010242	7.391987	7.381942	-0.010044	3.088364	3.080352	-0.008012	-0.006580
14	North Lancashire and The Lakes	3.877232	3.865447	-0.011786	4.603206	4.591226	-0.011979	1.980921	1.970954	-0.009967	-0.006580
15	South Lancashire, Yorkshire and Humber	2.675860	2.664281	-0.011579	2.697638	2.685983	-0.011654	-2.040464	-2.049988	-0.009524	-0.006580
16	North Midlands and North Wales	0.552459	0.546269	-0.006190	0.552459	0.546269	-0.006190	-2.879251	-2.885865	-0.006614	-0.006580
17	South Lincolnshire and North Norfolk	-0.616204	-0.627898	-0.011695	-0.616204	-0.627898	-0.011695	-2.669725	-2.679083	-0.009358	-0.006580
18	Mid Wales and The Midlands	-1.302719	-1.314572	-0.011853	-1.302719	-1.314572	-0.011853	-2.552027	-2.561467	-0.009440	-0.006580
19	Anglesey and Snowdon	1.276844	1.263870	-0.012974	1.276844	1.263870	-0.012974	-2.909699	-2.919725	-0.010026	-0.006580
20	Pembrokeshire	3.031204	3.019254	-0.011950	3.031204	3.019254	-0.011950	-4.294236	-4.303728	-0.009492	-0.006580
21	South Wales & Gloucester	0.141107	0.129166	-0.011942	0.141107	0.129166	-0.011942	-4.283000	-4.292487	-0.009487	-0.006580
22	Cotswold	-2.888977	-2.900910	-0.011934	-4.206189	-4.218151	-0.011962	-8.224876	-8.234445	-0.009569	-0.006580
23	Central London	-11.252416	-11.264225	-0.011809	-12.526259	-12.538064	-0.011805	-8.008030	-8.017437	-0.009407	-0.006580
24	Essex and Kent	-4.533246	-4.545069	-0.011823	-4.533246	-4.545069	-0.011823	-1.638817	-1.648242	-0.009425	-0.006580
25	Oxfordshire, Surrey and Sussex	-6.076677	-6.088563	-0.011886	-6.076677	-6.088563	-0.011886	-3.660346	-3.669803	-0.009457	-0.006580
26	Somerset and Wessex	-7.248923	-7.260800	-0.011877	-7.248923	-7.260800	-0.011877	-4.221693	-4.231146	-0.009454	-0.006580
27	West Devon and Cornwall	-6.877393	-6.889291	-0.011898	-6.877393	-6.889291	-0.011898	-4.780442	-4.789906	-0.009464	-0.006580

Figure 1 - Variation in generation zonal tariffs



The locational element of generation tariffs has remained relatively stable. Due to the updates to the parameter of the Caithness – Moray HVDC link (CM HVDC), and the minor corrections to local circuits at Blackcraig and Bodelwyddan, these transport model updates have caused the locational parts of all tariffs to vary slightly when compared to Draft tariffs.

Caithness-Moray HVDC has had the greatest impact in zones 1-5 in northern Scotland. The most significant reduction has been to the Year Round Shared tariff in zones 1-4 (-18p to -20p per kW) and to the Year Round Not Shared tariff (zones 1, 3 and 4 reduce by 60p-64p; zone 2 increases by 77p, zone 5 reduces by 29p per kW).

Elsewhere, the Peak tariff has increased in zone 12 onwards by 0.03p to 0.05p per kW, this is offset by the Year Round Shared tariff which has reduced by 0.01p to 0.7p per kW.

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. These have not changed since the Draft tariffs.

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 only changes from Draft tariffs are small reductions at Gordonbush (£0.27/kW) and Strathbrora (£0.25/kW). This is due to a small correction to the local circuit configuration of Blackcraig, whose tariff has increased.

All other local circuits are as published in the Draft tariffs. Bodelwyddan no longer has a local circuit tariff as the node is modelled as a MITS circuit from 2018/19 due to changes in the network.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberdeen Bay	2.487963	Dumnaglass	1.771589	Langage	0.627620
Achruach	4.096258	Dunhill	1.366742	Lochay	0.349188
Aigas	0.624082	Dunlaw Extension	1.430014	Luichart	0.547243
An Suidhe	2.907302	Edinbane	6.530545	Marchwood	0.364258
Arecleoch	1.981850	Ewe Hill	1.311273	Mark Hill	0.835479
Baglan Bay	0.725926	Fallago	0.572436	Middle Muir	1.891434
Beinneun Wind Farm	1.433206	Farr	3.402170	Middleton	0.104624
Bhlaraidh Wind Farm	0.627905	Fernoch	4.197281	Millennium South	0.898567
Black Hill	0.823271	Ffestiniogg	0.241415	Millennium Wind	1.742733
Black Law	1.667371	Finlarig	0.305539	Moffat	0.160084
BlackCraig Wind Farm	6.006840	Foyers	0.718512	Mossford	0.427674
BlackLaw Extension	3.535877	Galawhistle	1.411300	Nant	-1.172241
Carrington	-0.032263	Gills Bay	2.403062	Necton	-0.351536
Clyde (North)	0.104646	Glendoe	1.755201	Rhigos	0.097111
Clyde (South)	0.121018	Glenglass	9.266284	Rocksavage	0.016893
Corriegarth	3.008295	Gordonbush	0.248568	Saltend	0.325367
Corriemoillie	1.587573	Griffin Wind	4.075370	South Humber Bank	0.902631
Coryton	0.049502	Hadyard Hill	2.641167	Spalding	0.267922
Cruachan	1.805084	Harestanes	2.390520	Strathbrora	0.121450
Crystal Rig	0.489589	Hartlepool	0.573288	Strathy Wind	1.997707
Culligran	1.653833	Hedon	0.172665	Stronelairg	1.375663
Deanie	2.717011	Invergarry	1.353893	Wester Dod	0.814285
Dersalloch	2.298524	Kilgallioch	1.004263	Whitelee	0.101270
Didcot	0.496119	Killingholme	0.676669	Whitelee Extension	0.281531
Dinorwig	2.289432	Kilmorack	0.188451		
Dorenell	2.002552	Kype Muir	1.415343		

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.

These tariffs have not changed since the Draft tariffs in December.

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

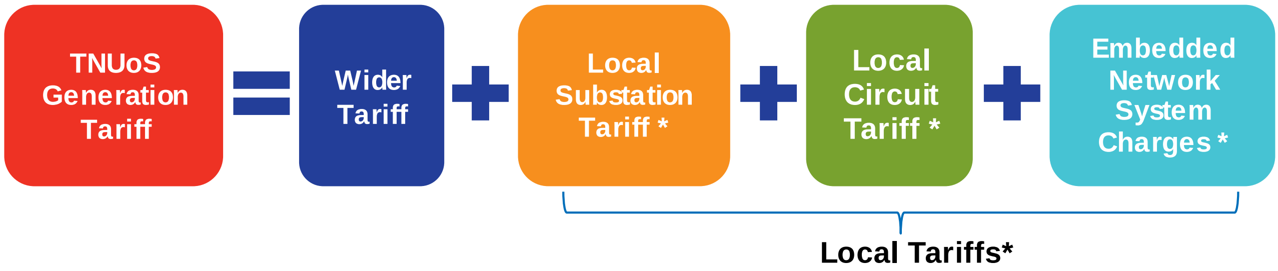
Generators pay TNUoS (Transmission Network Use of System) tariffs to allow National Grid as System Operator to recover the capital costs of building and maintaining the transmission network on behalf of the transmission asset owners (TOs).

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.

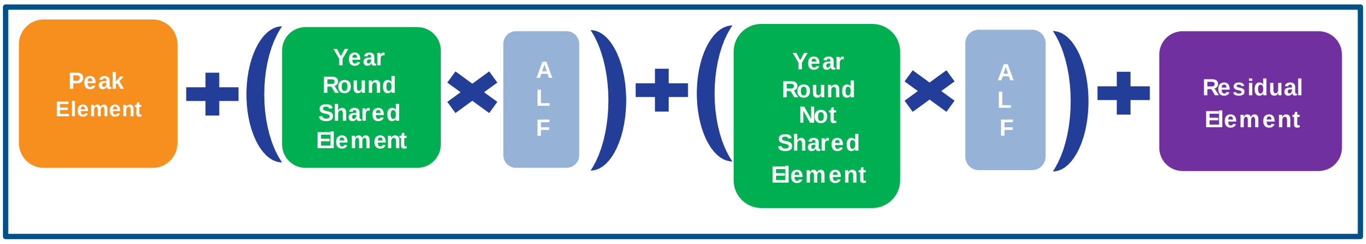
The Wider tariff

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.

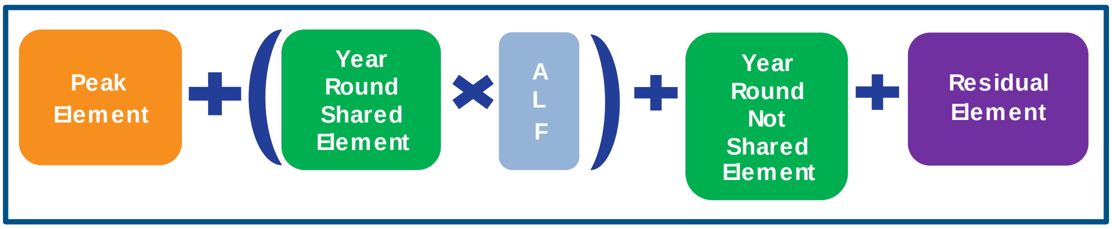
Conventional Carbon Generators

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



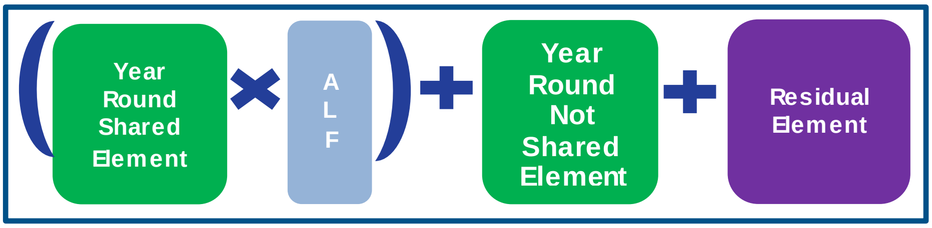
Conventional Low Carbon Generators

(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 Final tariffs are listed in Appendix C.

Local substation tariffs

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

Local onshore substation tariffs are set at the start of each TO 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).

Click here to find out more about DNO regions.

Offshore local tariffs

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

Billing

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

The calculation for TNUoS generator liability is as follows:

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

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.

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

[***] *For more information about connections, please visit our website:* https://www.nationalgrid.com/uk/electricity/connections/applying-connection

[†††] *These specific charges include any onshore local circuit and substation charges.*

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

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

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

NHH demand tariffs

NHH metered customers are charged based on their 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 Draft tariffs were published, we have updated the allowed revenue for onshore and offshore Transmission Owners, the transport model circuits, the local circuits model and the generation charging bases.

There have been no changes to the, transport model demand (the week 24 demand), RPI 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:

- The network model;
- Contracted generation as of 31 October 2017;
- 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).

Of the above elements, only the network model has changed since Draft tariffs.

Changes to the Network Model

The Caithness-Moray HVDC link is expected to be commissioned by the end of 2018, and has therefore been included in the TNUoS transport model for Final tariffs. This link allows the transmission of large volumes of electricity between Spittal in Caithness and Blackhillock in Moray.

The HVDC converter station at Spittal is rated at 800MW, while the HVDC converter station at Blackhillock is rated at 1200MW. For the TNUoS charging year of 2018/19, only 800MW of the capacity can be fully utilised, therefore we have revised the capacity of the HVDC link from 1200MW (in the draft tariff calculation) to 800MW (in the final tariff calculation).

The capacity of the Caithness-Moray link has an impact on wider tariffs, particularly around North Scotland. No further changes have been made to the network model.

Contracted and modelled TEC

This was fixed based on the TEC register from 31 October 2017. This has not changed in the Final tariffs compared to the December Draft tariffs. Chargeable TEC has increased by 16MW.

Table 13 – Contracted and modelled TEC

(GW)	2017/18	2018/19 Initial Forecast	2018/19 June Forecast	2018/19 Oct Forecast	2018/19 Draft Tariffs	2018/19 Final Tariffs
Contracted TEC	72.2	79.6	78.8	82.4	79.0	79.0
Modelled Best View TEC	72.2	72.6	75.5	79.7	79.0	79.0
Chargeable TEC	67.6	66.8	69.7	75.0	71.9	71.9

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

Transport Model Demand Data

The transport model uses demand data provided under the Grid Code, which includes week 24 demand forecast data provided by the Distribution Network Operators (DNO), and forecasts of demand at directly connected demand sites (such as steelworks and railways and the effect of some embedded generation). There have been no changes to these forecasts since Draft tariffs.

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 was calculated for the Draft tariffs as £14.08310011. This has not been recalculated in this Final tariffs report.

Local substation and offshore substation tariffs

Local onshore substation tariffs are indexed by May - October RPI as are offshore local circuit tariffs. These have not changed since the Draft tariffs.

Allowed revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Compared to the Draft tariffs, tariffs have now been calculated to recover £2,670.3m of revenue. This is an increase of £0.1m from the Draft tariffs of £2670.2m.

Revenue has increased by £0.1m since we calculated the Draft tariffs in December. This is a net effect of an increase of TO Revenues of £8.7m, a reduction of Ofgem's Network Innovation Competition funding of £7.8m and other pass-through items such as termination adjustments totalling -£0.8m.

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*	*1,653.9*
Less income from connections	*41.9*	*41.9*	*41.9*	*41.9*	*41.9*	*44.0*
Income from TNUoS	**1,706.9**	**1,685.9**	**1,677.2**	**1,605.2**	**1,610.7**	**1,609.9**
Scottish Power Transmission						
Price controlled revenue	*333.7*	*390.5*	*377.7*	*360.5*	*361.2*	*364.8*
Less income from connections	*12.8*	*26.8*	*14.0*	*14.2*	*14.2*	*14.9*
Income from TNUoS	**321.0**	**363.8**	**363.8**	**346.3**	**347.0**	**350.0**
SHE Transmission						
Price controlled revenue	*304.7*	*366.5*	*366.7*	*358.6*	*366.4*	*369.8*
Less income from connections	*3.4*	*3.2*	*3.6*	*3.5*	*3.4*	*3.4*
Income from TNUoS	**301.4**	**363.2**	**363.1**	**355.1**	**363.0**	**366.4**
Offshore	**270.2**	**380.2**	**373.2**	**312.1**	**315.8**	**318.1**
Network Innovation Competition	**32.1**	**40.5**	**40.5**	**40.5**	**40.5**	**32.7**
EDR			**2.0**	**2.0**		
Interconnectors (Cap & Floor)					**(6.8)**	**(6.8)**
Total to Collect from TNUoS	**2,631.5**	**2,833.6**	**2,819.8**	**2,661.3**	**2,670.2**	**2,670.3**

Generation / Demand (G/D) Split

Apart from the revenue to be collected, the G/D split has not changed since the June 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 Final
CAPEC	Limit on generation tariff (€/MWh)	2.50
y	Error Margin	21.0%
ER	Exchange Rate (€/£)	1.16
MAR	Total Revenue (£m)	2,670.3
GO	Generation Output (TWh)	252.6
G	% of revenue from generation	16.1%
D	% of revenue from demand	83.9%
G.R	Revenue recovered from generation (£m)	430.1
D.R	Revenue recovered from demand (£m)	2240.2

[§§§] *http://fes.nationalgrid.com/*

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 since 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.

Table 17 – Charging base

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

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.

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

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

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

Where

- R_G is the generation residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from generation
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from generation locational zonal tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_C is the TNUoS revenue recovered from onshore local circuit tariffs (£m)
- L_S is the TNUoS revenue recovered from onshore local substation tariffs (£m)
- B_G is the generator charging base (GW)

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

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

Where:

- R_D is the gross demand residual tariff (£/kW)
- D is the proportion of TNUoS revenue recovered from demand
- R is the total TNUoS revenue to be recovered (£m)
- Z_D is the TNUoS revenue recovered from demand locational zonal tariffs (£m)
- EE is the amount to be paid to embedded export volumes through the embedded export tariff (£m)
- B_D is the demand charging base (Gross 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	2018/19 Final
G	Proportion of revenue recovered from generation (%)	14.8%	15.1%	15.3%	16.2%	16.1%	16.1%
D	Proportion of revenue recovered from demand (%)	85.2%	84.9%	84.7%	83.8%	83.9%	83.9%
R	Total TNUoS revenue (£m)	2,631	2,833	2,820	2,661	2,670	2,670
Generation Residual							
R_G	Generator residual tariff (£/kW)	-1.85	-3.20	-3.28	-2.34	-2.52	-2.52
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	275.0	313.2	334.0	322.2	330.8	329.4
O	Revenue recovered from offshore local tariffs (£m)	208.5	293.9	288.4	244.0	243.6	245.3
L_G	Revenue recovered from onshore local substation tariffs (£m)	17.5	17.0	17.8	20.7	19.2	19.2
S_G	Revenue recovered from onshore local circuit tariffs (£m)	14.6	16.9	18.5	18.5	17.6	17.8
B_G	Generator charging base (GW)	67.6	66.8	69.7	75.0	71.9	71.9
Net Demand Residual							
R_D	Demand residual tariff (£/kW)	47.26	52.24	52.20	*no longer calculated*		
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-12.4	-19.0	-12.0			
B_D	Demand Net charging base (GW)	47.7	46.4	46.0			
Gross Demand Residual							
R_D	Demand residual tariff (£/kW)	*Introduced by CMP264/265 to replace 'net residual'*			46.90	46.94	46.93
Z_D	Revenue recovered from the locational element of demand tariffs (£m)				-64.2	-47.1	-46.7
EE	Amount to be paid to Embedded Export Tariffs (£m)				165.2	175.3	175.4
B_D	Demand Gross charging base (GW)				52.5	52.5	52.5

Small generators' discount

The small generators' discount has been calculated as £11.102227/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	46.93
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	30,874,294
Prior year reconcilation (£)	R	-236,300
Total SGD Cost (£)	C = (V x T) + R	30,637,994
Total System Triad Demand (kW)	TD	45,947,272
Total HH 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	0.67
Total Cost to HH Customers (£)	HHC = HHT * HHD	13,203,570
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.07
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	17,434,423

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.

Webinar on These tariffs

We will hold a webinar for the Final tariffs on Friday 2 February 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 Final 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:

https://www.nationalgrid.com/tnuos/

Team Email & Phone Charging.enquiries@nationalgrid.com 01926 654633

Appendices

Appendix A: Locational demand tariff charges

Appendix B: Locational demand profiles

Appendix C: Annual Load Factors

Appendix D: Transmission company revenues

Appendix E: Generation zones map

Appendix F: Demand zones map

Appendix A: 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 tariffs.

The zonal variations for both the peak security and year round tariffs have been driven by the changes to the HVDC parameters and local circuits. This can be seen largely in zones 1, 2 (Scotland) which along with the slight increase in overall revenue has resulted in the average demand tariff increase.

Table 20 – Locational tariffs

	2018/19 Draft		2018/19 Final		Changes	
Zone	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	3.065285	-24.297592	3.074137	-24.296330	0.008851	0.001262
2	0.134686	-18.606910	0.134735	-18.590734	0.000049	0.016176
3	-3.097681	-6.616660	-3.098072	-6.611526	-0.000391	0.005133
4	-1.214669	-2.512235	-1.215101	-2.505084	-0.000431	0.007152
5	-2.902127	-0.557508	-2.902564	-0.550650	-0.000437	0.006858
6	-2.334653	0.313286	-2.335129	0.321468	-0.000476	0.008182
7	-2.257707	2.226057	-2.258156	2.233219	-0.000449	0.007162
8	-1.800712	3.064231	-1.801172	3.071737	-0.000459	0.007507
9	1.140503	0.755028	1.140058	0.762065	-0.000445	0.007038
10	-6.151443	4.422608	-6.151896	4.429880	-0.000452	0.007271
11	3.869828	0.707482	3.869380	0.714592	-0.000447	0.007110
12	5.119155	2.254470	5.118708	2.261549	-0.000446	0.007079
13	1.637860	4.248799	1.637411	4.255971	-0.000449	0.007172
14	-1.028052	5.362369	-1.028503	5.369597	-0.000451	0.007227

Appendix B: Locational demand profiles

The table below shows the latest demand forecast used in the Final tariffs. All values are unchanged from the Draft tariffs.

The locational model demand profiles were updated for the Draft tariffs following the submission of week 24 data from the DNOs and directly connected demand (DCC).

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

Table 21 – Demand profiles

Zone	Zone Name	2018/19 Draft					2018/19 Final				
		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	640	1,477	489	0.74	1,001	640	1,477	489	0.74	1,001
2	Southern Scotland	2,724	3,500	1,259	1.66	670	2,724	3,500	1,259	1.66	670
3	Northern	2,649	2,664	1,078	1.20	581	2,649	2,664	1,078	1.20	581
4	North West	3,169	4,117	1,523	1.93	343	3,169	4,117	1,523	1.93	343
5	Yorkshire	4,388	3,920	1,610	1.76	635	4,388	3,920	1,610	1.76	635
6	N Wales & Mersey	2,394	2,678	1,085	1.22	538	2,394	2,678	1,085	1.22	538
7	East Midlands	5,296	4,763	1,878	2.16	477	5,296	4,763	1,878	2.16	477
8	Midlands	4,410	4,371	1,617	2.00	211	4,410	4,371	1,617	2.00	211
9	Eastern	6,097	6,605	2,133	3.09	624	6,097	6,605	2,133	3.09	624
10	South Wales	1,666	1,843	839	0.83	331	1,666	1,843	839	0.83	331
11	South East	3,813	3,999	1,169	1.91	318	3,813	3,999	1,169	1.91	318
12	London	5,380	4,323	2,286	1.84	149	5,380	4,323	2,286	1.84	149
13	Southern	6,220	5,584	2,072	2.56	437	6,220	5,584	2,072	2.56	437
14	South Western	2,244	2,621	764	1.27	200	2,244	2,621	764	1.27	200
Total		**51,090**	**52,463**	**19,801**	**24.17**	**6,516**	**51,090**	**52,463**	**19,801**	**24.17**	**6,516**

Appendix C: 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 22: 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%
KILLINGHOLME (NP)	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	10.6552%	7.4217%	11.6191%	0.0000%	0.0000%	9.8987%
KILLINGHOLME (POWERGEN)	Gas_Oil	Generic	Generic	Generic	Generic	Generic	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
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%

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	
RATCLIFFE-ON-SOAR	Coal	Actual	Actual	Actual	Actual	Actual	66.7461%	71.7403%	56.1767%	19.6814%	15.4657%	47.5347%
ROBIN RIGG EAST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	37.4157%	46.7562%	55.3209%	51.9700%	50.5096%	49.7453%
ROBIN RIGG WEST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	38.2254%	48.0629%	53.4150%	56.0881%	51.5383%	51.0054%
ROCKSAVAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.4820%	2.6155%	4.4252%	19.8061%	58.6806%	21.9044%
ROOSECOTE	-	Actual	Actual	Actual	Actual	Actual	0.0121%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
RUGELEY B	-	Actual	Actual	Actual	Actual	Actual	68.6109%	82.6505%	59.4472%	44.5189%	12.3429%	57.5257%
RYE HOUSE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	10.7188%	7.4695%	5.3701%	7.7906%	15.6538%	8.6596%
SALTEND	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	81.5834%	69.0062%	67.9518%	55.6228%	77.4019%	71.4533%
SEABANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.2311%	18.2781%	25.6956%	27.2136%	41.6815%	23.7291%
SELLAFIELD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	14.0549%	25.0221%	18.9719%	28.6790%	19.8588%	21.2842%
SEVERN POWER	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.7976%	32.4163%	24.6354%	18.3226%	64.4246%	28.2831%
SHERINGHAM SHOAL	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	36.6431%	49.3517%	46.2286%	53.6184%	46.9715%	47.5173%
SHOREHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.0000%	20.7501%	10.2239%	48.9514%	68.9863%	26.6418%
SIZEWELL B	Nuclear	Actual	Actual	Actual	Actual	Actual	96.7260%	82.5051%	84.7924%	98.7826%	81.6359%	88.0078%
SLOY G2 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	9.1252%	14.3471%	15.5941%	13.9439%	8.1782%	12.4721%
SOUTH HUMBER BANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.9763%	24.3373%	34.4673%	48.6753%	55.3419%	37.0396%
SPALDING	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	34.6976%	33.4800%	39.3092%	47.9407%	60.9748%	40.6492%
STAYTHORPE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	54.4117%	37.6216%	56.6148%	69.4422%	65.7791%	58.9352%
STRATHY NORTH & SOUTH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	49.6340%	36.1987%	40.0568%
SUTTON BRIDGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.1652%	9.4124%	17.2025%	13.1999%	38.0184%	16.8559%
TAYLORS LANE	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.2037%	0.0483%	0.0640%	0.1708%	0.8047%	0.1462%
THANET OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	41.1093%	39.7489%	35.5935%	41.3434%	33.7132%	38.8172%
TODDLEBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.7175%	39.5374%	33.7211%	35.0823%	31.3435%	33.8403%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	84.8669%	86.4669%	91.4945%	85.7725%	97.9942%	87.9113%
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 23: 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.

Appendix D: 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.

Under the relevant STC (System Operator Transmission Owner Code) procedures, the Transmission Owners' revenue forecast was finalised by 25 January 2018. In addition, the interconnector cap & floor revenue adjustment term was also finalised by 25 January 2018, under the relevant CUSC clauses.

Table 24 – Indicative National Grid revenue forecast

Description			26/01/2018					Notes
			Licence Term		Yr t+1			
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%	0.71%	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	0.04	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	0.03	0.02	0.02	0.04	0.03	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	0.03	0.03	0.03	0.03	0.03	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	0.00	Forecast
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	294.6	321.0	350.0	Forecast
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	301.4	366.4	Forecast
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	270.2	318.1	Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	0.5	0.5	Forecast
Interconnectors Cap&Floor Revenue Adjustment	B10	TICFt					-6.8	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**745.10**	**889.97**	**885.86**	**899.43**	**1031.51**	
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	0.0	Forecast
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0.00**	**13.86**	**18.73**	**15.26**	**14.85**	
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	32.7	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	6.6	Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	-1.1	3.1	Forecast
Correction Factor	K	-Kt	0.0	56.4	104.0	97.0	-55.5	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**	**2714.3**	
Pre-vesting connection charges	P		47.0	45.0	42.7	41.9	44.0	Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2631.5**	**2670.3**	

Scottish Power Transmission revenue forecast

The indicative SPT revenue to be collected via TNUoS for 2018/19 is £350m.

SHE Transmission revenue forecast

The indicative SHET Transmission revenue to be collected via TNUoS for 2018/19 is £366.4m.

Offshore Transmission Owner revenues

Collectively, the indicative OFTOs' Transmission revenue to be collected via TNUoS for 2018/19 is £318.1m.

Interconnectors under Cap and Floor Revenue Adjustment

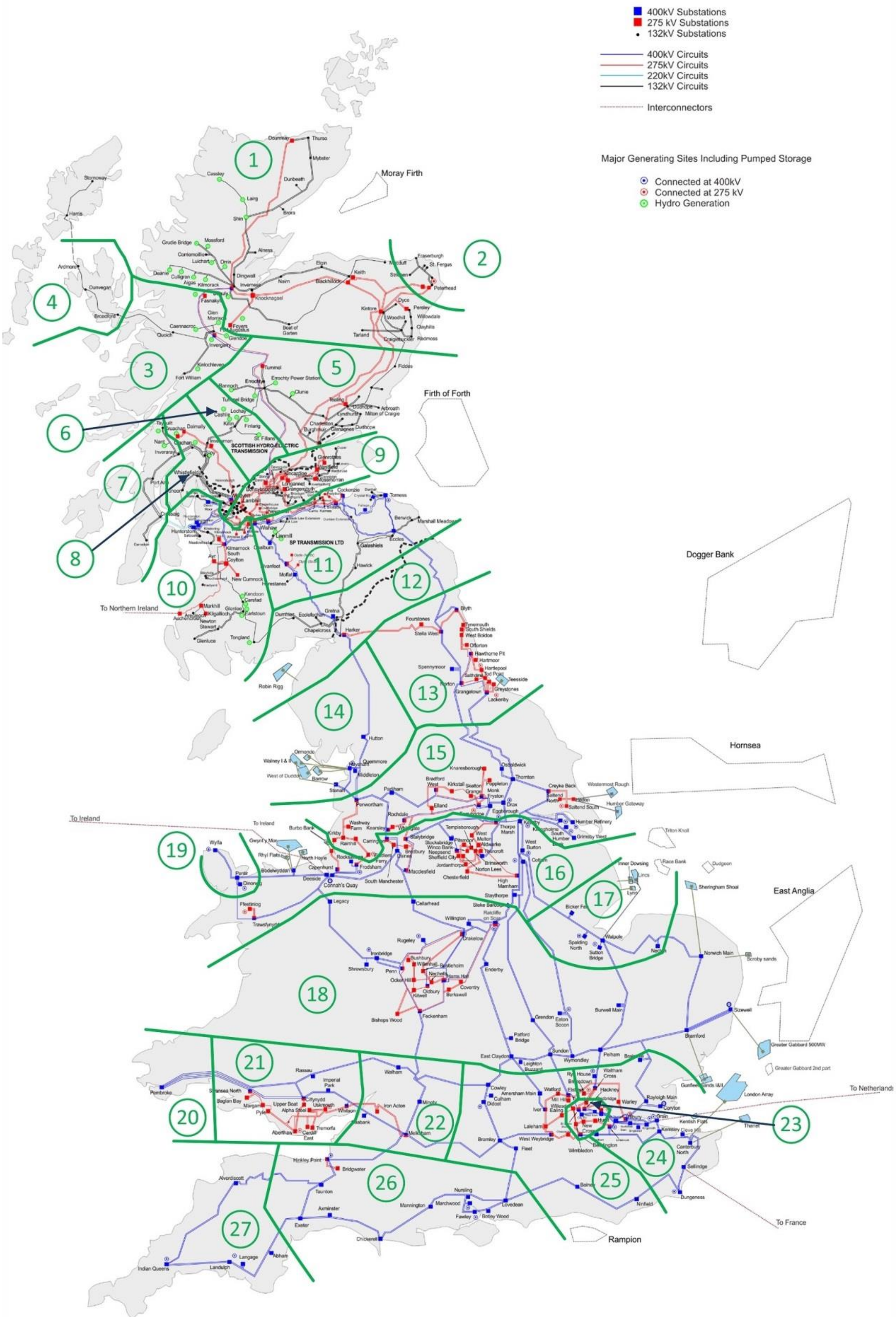
Under CMP283, TNUoS charges can be adjusted by an amount determined by Ofgem to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime. The indicative total Interconnector revenue adjustment is -6.8m. This means 6.8m is to be reduced from TNUoS charge for 2018/19.

Table 25 - Offshore Transmission Owner revenues (indicative)

<table>
<tr><th>Offshore Transmission Revenue Forecast</th><th colspan="5">26/01/2018</th><th></th></tr>
<tr><th></th><th></th><th></th><th></th><th></th><th></th><th rowspan="2">Notes</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></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</td><td>6.3</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>8.7</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>12.6</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>28.4</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>41.8</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>18.6</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>22.6</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</td><td></td><td></td><td></td><td>4.7</td><td>34.5</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>270.2</td><td>318.1</td><td></td></tr>
</table>

Appendix E: Generation zones map

Figure A2: GB Existing Transmission System



Appendix F: Demand zones map