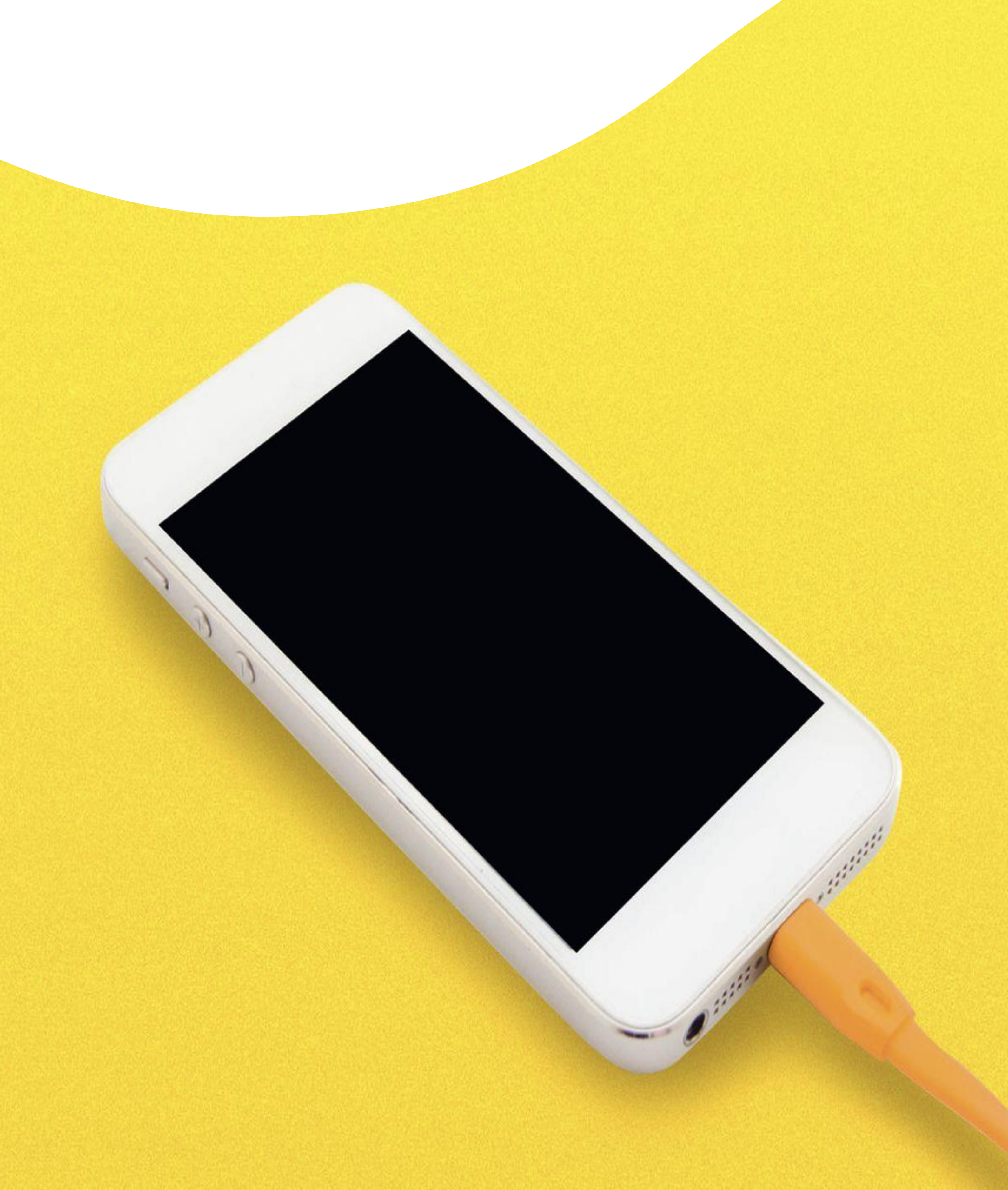
Final TNUoS Tariffs for 2020/21

National Grid Electricity System Operator

January 2020



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Executive summary

Transmission Network Use of System (TNUoS) charge is designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. It is applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the Final TNUoS Tariffs for 2020/21 which will be effective on 1st April 2020.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish the final Transmission Network Use of System (TNUoS) tariffs for year 2020/21 (Final Tariffs).

The tariffs for 2020/21 were last forecast in November 2019 (Draft Tariffs). The Final Tariffs will be effective on 1 April 2020.

Total revenues to be recovered

Total revenue to be collected is finalised at £2,843m, a reduction of £42.8m from draft forecast of £2,885.8m. Of the £42.8m of reduction, £11m is attributed to TOs' allowed revenue reduction, and the rest are due to pass-through items adjustment particularly the Network Innovation Competition (NIC) fund, which reduced from the forecast of £31.6m to Ofgem's final decision of £13.9m.

Generation tariffs

The total revenue to be recovered from generation tariffs is £374.9m, and this value has been locked down since the July forecast.

The generation charging base has been updated to 70.7GW based on our best view on generation projects for 2020/21. This is a significant decrease since the draft forecast. As a result, the average generation tariff is increased by £0.37/kW to £5.30/kW and the generator residual has decreased by £0.07/kW to £-4.85/kW.

Small Generator Discount

The Small Generator Discount is defined in National Grid ESO's Electricity Transmission licence condition C13.

The Small Generator Discount runs until 31 March 2021, and will expire when the Targeted Charging Review (TCR) is implemented by April 2021.

The Small Generator Discount reduces the tariff for transmission connected generation connected at 132kV and with Transmission Export Capacity (TEC) <100MW. The discount is £11.55/kW, £0.23/kW less than the draft forecast.

Demand tariffs

The revenue to be recovered from demand tariffs is £2,468.1m in 2020/21. This value has decreased by £42.8m since the November draft tariffs.

The gross half-hourly (HH) demand charging base has increased by 1.5GW to 19.6GW due to review of historical trends and outturn data for the current winter period so far. This has increased the expected revenue to be collected from HH demand and decreased the amount to be collected through non-half-hourly (NHH) demand and NHH tariffs.

NHH and embedded export volumes have remained the same and are forecast to be 25.1TWh and 7.2GW respectively.

£17.1m will be payable through the Embedded Export Tariff (EET). This is a slight decrease since the draft tariffs due to a PRI update in the AGIC (Avoided Grid Supply Point Infrastructure Credit). The average EET is £2.37/kW.

Not including the effect of the Small Generator Discount, the average gross HH demand tariff is £49.56/kW, a decrease of £0.85kW. The average NHH demand tariff is 6.02p/kWh, a decrease of 0.40p/kWh. The demand tariffs have decreased since the draft tariffs, due to the decrease in revenue to be collected from demand users and updates to the demand charging base.

Demand tariffs (except average tariffs) in this report are inclusive of the effect of the Small Generator Discount.

TCR Impact

Ofgem's decision on the Targeted Charging Review (TCR) has no impact on 2020-21 tariffs. It is due to be implemented from April 2021. Currently we are working closely with Ofgem and the industry to design the charging methodology in CUSC, and will provide clarity and early visibility on its potential implications soon.

Next TNUoS tariff publications

Our next TNUoS tariff publication will be the forecast of 2021/22 tariffs in March 2020. We have published our TNUoS tariff forecast for 2021/22 on our website[1].

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Contact us

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.

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1 https://www.nationalgrideso.com/charging/trasmission-network-use-system-tnuos-charges

Demand tariffs

Half-Hourly (HH), Non-Half-Hourly (NHH) tariffs and the Embedded Export Tariff (EET)

1. Demand tariffs summary

The tables in this section show final demand tariffs for Half-Hourly (HH), Embedded Export (EET) and Non-Half-Hourly (NHH) metered demand.

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

Table 1 Summary of demand tariffs

HH Tariffs	2020/21 Draft	2020/21 Final	Change
Average Tariff (£/kW)	50.413547	49.565062	- 0.848485
Residual (£/kW)	51.881473	51.032314	- 0.849159
EET	**2020/21 Draft**	**2020/21 Final**	**Change**
Average Tariff (£/kW)	2.372907	2.371818	- 0.001089
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	3.416495	3.414926	- 0.001569
Embedded Export Volume (GW)	7.230000	7.230000	-
Total Credit (£m)	17.156120	17.148241	- 0.007879
NHH Tariffs	**2020/21 Draft**	**2020/21 Final**	**Change**
Average (p/kWh)	6.425854	6.023290	- 0.402564

Please note that these average tariffs **DO NOT** include the additional levy for the Small Generator Discount scheme.

Table 2 Demand tariffs

Demand Zone		HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	21.126849	2.742642	-
2	Southern Scotland	28.760295	3.528995	-
3	Northern	40.022002	4.768367	-
4	North West	46.674676	5.735191	-
5	Yorkshire	47.834680	5.645414	-
6	N Wales & Mersey	48.904955	5.811644	0.587601
7	East Midlands	51.387929	6.281123	3.070575
8	Midlands	52.648445	6.525494	4.331091
9	Eastern	53.488450	6.994220	5.171096
10	South Wales	50.613794	5.594905	2.296440
11	South East	56.501849	7.511337	8.184495
12	London	59.267002	5.828242	10.949648
13	Southern	57.772417	7.136303	9.455063
14	South Western	57.020402	7.608806	8.703048

Residual charge for demand:	51.031645	
Tariffs include small gen tariff of:	0.700635	0.085865

Please note the tariffs in Table 2 above **include** the effect of the Small Generator Discount. Please see page 25 for the detailed calculation of the Small Generator Discount.

2. Changes since the previous demand tariffs forecast

Demand tariffs have decreased, mainly due to the reduction in overall revenue to be collected through TNUoS tariffs. The HH demand charging base has increased, taking into account the year on year trend and outturn data so far for the current winter period. More revenue is expected to be collected from HH demand, thus decreasing the revenue to be collected via NHH demand and decreasing NHH tariffs.

The average HH gross tariff is now £49.56/kW, this has decreased by £0.85/kW. The average NHH tariff is now 6.02p/kWh, a decrease of 0.40p/kWh. Please note this does not include the effect of the Small Generator Discount.

There has been a slight increase of the Avoided Grid Supply Point Infrastructure Credit (AGIC) due to a RPI update, but this change was minimal and the average EET remains at £2.37/kW.

3. Half-Hourly demand tariffs

This table and chart show the final gross HH demand tariffs for 2020/21 compared to the November Draft Tariffs.

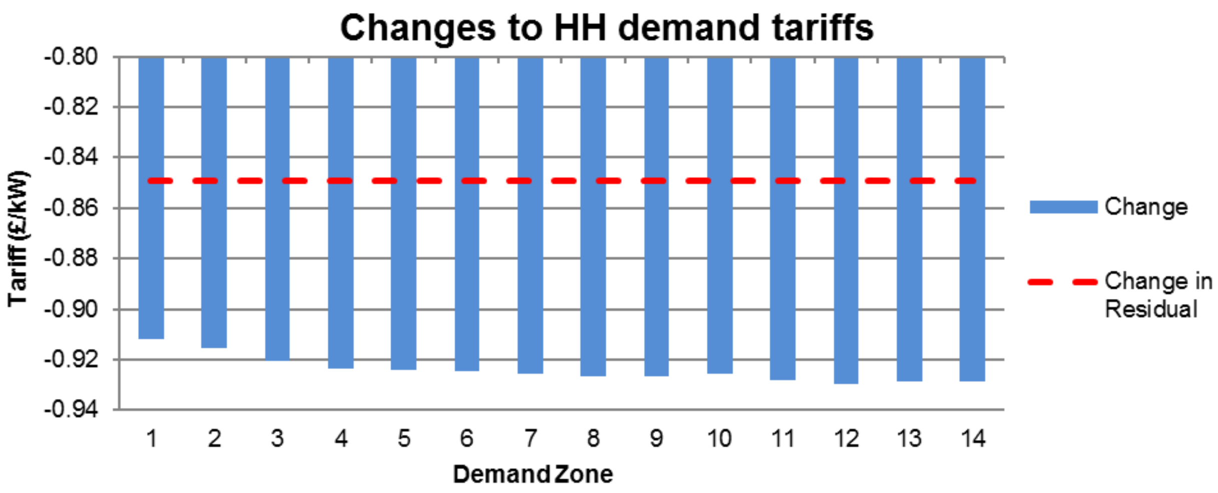
Table 3 Half-Hourly demand tariffs

Demand Zone (£/kW)		2020/21 Draft	2020/21 Final	Change	Change in Residual
1	Northern Scotland	22.039463	21.127528	- 0.911935	- 0.849159
2	Southern Scotland	29.676415	28.760974	- 0.915441	- 0.849159
3	Northern	40.943296	40.022680	- 0.920616	- 0.849159
4	North West	47.599027	46.675355	- 0.923672	- 0.849159
5	Yorkshire	48.759563	47.835359	- 0.924204	- 0.849159
6	N Wales & Mersey	49.830330	48.905633	- 0.924697	- 0.849159
7	East Midlands	52.314445	51.388608	- 0.925837	- 0.849159
8	Midlands	53.575540	52.649124	- 0.926416	- 0.849159
9	Eastern	54.415931	53.489129	- 0.926802	- 0.849159
10	South Wales	51.539954	50.614473	- 0.925481	- 0.849159
11	South East	57.430714	56.502528	- 0.928186	- 0.849159
12	London	60.197138	59.267681	- 0.929457	- 0.849159
13	Southern	58.701866	57.773096	- 0.928770	- 0.849159
14	South Western	57.949506	57.021081	- 0.928425	- 0.849159

The breakdown of the locational elements of these tariffs is shown on page 38.

Please note these tariffs **include** the effect of the Small Generator Discount.

Figure 1 Changes to gross Half-Hourly demand tariffs



As you can see from the figure above, the HH demand tariff have decreased in all zones. The decrease is spread relatively equal across the 14 zones with a slightly lower reduction seen in zones 1–3.

Please note that the average HH gross demand tariff **does not** include the additional levy for the Small Generator Discount scheme. The forecasted level of gross HH chargeable demand has been increased by 1.5GW since the November Draft Tariffs and is now set at 19.6GW.

The additional levy for the Small Generator Discount scheme increases the HH demand tariffs by £0.70/kW (reduced by £0.08p/kW since the Draft Tariffs).

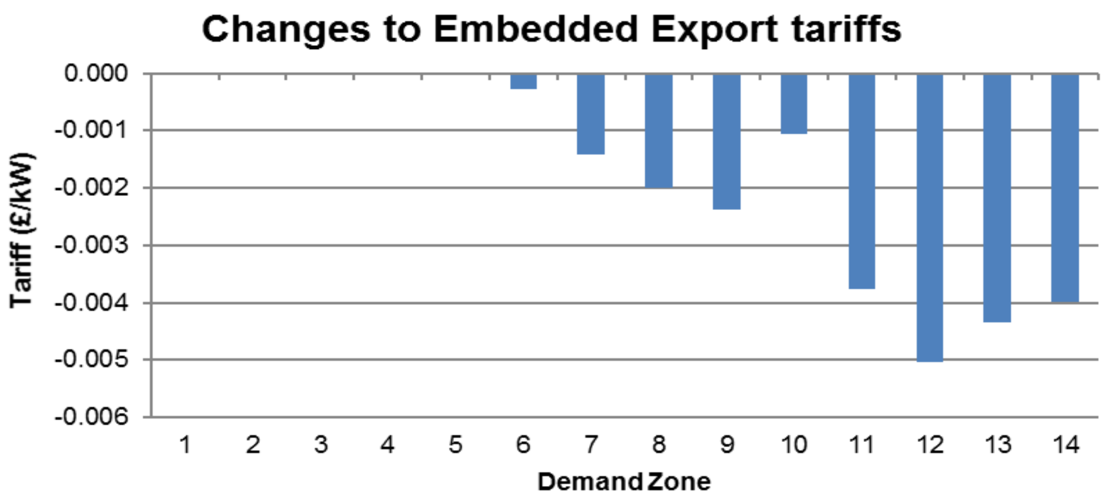
4. Embedded Export Tariffs (EET)

The next table and figure show the 2020/21 EET compared to the Draft Tariffs.

Table 4 Embedded Export Tariffs

Demand Zone (£/kW)		2020/21 Draft	2020/21 Final	Change
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.587871	0.587601	- 0.000270
7	East Midlands	3.071986	3.070575	- 0.001411
8	Midlands	4.333081	4.331091	- 0.001990
9	Eastern	5.173472	5.171096	- 0.002376
10	South Wales	2.297495	2.296440	- 0.001055
11	South East	8.188255	8.184495	- 0.003760
12	London	10.954679	10.949648	- 0.005031
13	Southern	9.459407	9.455063	- 0.004344
14	South Western	8.707047	8.703048	- 0.003999

Figure 2 Embedded export tariff changes



Since the November Draft Tariffs, there has been minimal impact to the average EET which remains at £2.37/kW (rounded value). There has been a slight decrease in the AGIC (Avoided Grid Supply Point Infrastructure Credit) due to an RPI update, but this has had no noticeable impact as seen in the above figure (largest reduction shows a .5p reduction). The EET charging base remains at 7.2GW. Due to the slight decreases in the EET tariff, the forecasted EET revenue has decreased to £17.16m from £17.15m.

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

In accordance with the methodology of the phased reduction to the residual element of the EET, from 2020/21, the EET will be £0/kW in demand zones 1 to 5.

5. Non-Half-Hourly demand tariffs

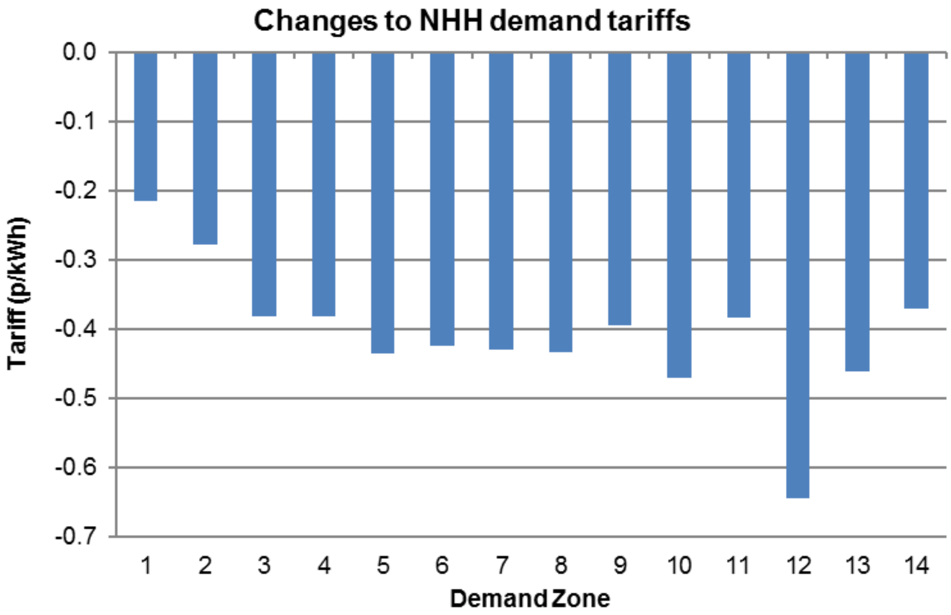
This table and chart show the difference between this forecast and the Draft Tariffs.

Table 5 Changes to Non-Half-Hourly demand tariffs

Demand Zone (p/kWh)		2020/21 Draft	2020/21 Final	Change
1	Northern Scotland	2.958074	2.742730	- 0.215344
2	Southern Scotland	3.806319	3.529078	- 0.277241
3	Northern	5.149410	4.768447	- 0.380963
4	North West	6.117466	5.735275	- 0.382191
5	Yorkshire	6.080959	5.645494	- 0.435465
6	N Wales & Mersey	6.234944	5.811724	- 0.423220
7	East Midlands	6.711382	6.281206	- 0.430176
8	Midlands	6.959651	6.525578	- 0.434073
9	Eastern	7.389274	6.994309	- 0.394965
10	South Wales	6.065145	5.594980	- 0.470165
11	South East	7.895471	7.511427	- 0.384044
12	London	6.472525	5.828309	- 0.644216
13	Southern	7.598027	7.136386	- 0.461641
14	South Western	7.979705	7.608896	- 0.370809

Please note these tariffs DO include the effect of the Small Generator Discount, see page 25.

Figure 3 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff is now set at 6.02p/kWh, 0.40p/kWh lower than in the Draft Tariffs. This is due to the impact of the HH demand charging base increasing, which will increase the expected revenue to be collected from HH. Subsequently the NHH tariffs have decreased in all zones (see figure 3), zones 1 & 2 have reduced the least (0.20p - 0.30p/kWh) whilst zone 12 has decreased the most (0.64p/kWh). The remaining zones have adjusted around the 0.40p/kWh.

Generation tariffs

Wider tariffs, onshore local circuit and substation tariffs, and offshore local circuit tariffs

6. Generation tariffs summary

This section summarises the forecasted generation tariffs for 2020/21, how these tariffs were calculated and how they have changed since the Draft Tariffs.

Table 6 Summary of generation tariffs

Generation Tariffs (£/kW)	2020/21 Draft	2020/21 Final	Change since last forecast
Residual	- 4.776901	- 4.849145	- 0.072245
Avg. Generation Tariff*	4.928537	5.299849	0.371311

The average generation tariff is calculated by dividing the total revenue payable by generation over the generation charging base in GW.

Average generation tariffs have increased by £0.37/kW due the decrease in the generation charging base.

Please note these average generation tariffs DO NOT include the effect of the Small Generator Discount, but include revenues from local tariffs.

7. Generation wider tariffs

The following section summarises the wider generation tariffs for 2020/21. A brief description of generation wider tariff structure can be found in Appendix A.

The wider tariffs are calculated depending on the generator type and made of four components, two of the components (Year Round Shared Element and Year Round Not Shared Element) are multiplied by the generator's specific Annual Load Factor (ALF). The ALF is explained in Appendix E.

The classifications of generator type are listed below.

Conventional Carbon	Conventional Low Carbon	Intermittent
Biomass CCGT/CHP Coal OCGT/Oil Pumped storage (including battery storage)	Nuclear Hydro	Offshore wind Onshore wind Solar PV Tidal

Table 7 Generation wider tariffs

		Tariff(£/kW)						
						Example tariffs for a generator of each technology type		
Generation Zone		System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80%	Conventional Low Carbon 80%	Intermittent 40%
1	North Scotland	2.756293	20.876589	15.013811	- 4.849145	26.619468	29.622230	18.515302
2	East Aberdeenshire	4.932772	13.269866	15.013811	- 4.849145	22.710569	25.713331	15.472612
3	Western Highlands	2.154270	19.428157	14.818277	- 4.849145	24.702272	27.665928	17.740395
4	Skye and Lochalsh	- 4.187934	19.428157	14.734427	- 4.849145	18.292988	21.239874	17.656545
5	Eastern Grampian and Tayside	3.076871	17.722549	14.283033	- 4.849145	23.832192	26.688798	16.522908
6	Central Grampian	3.775150	16.967576	13.905167	- 4.849145	23.624199	26.405233	15.843052
7	Argyll	3.600719	13.842955	23.996813	- 4.849145	29.023388	33.822751	24.684850
8	The Trossachs	3.680023	13.842955	12.274252	- 4.849145	19.724644	22.179494	12.962289
9	Stirlingshire and Fife	2.448114	11.515492	11.455403	- 4.849145	15.975685	18.266766	11.212455
10	South West Scotlands	2.863723	12.079258	11.625499	- 4.849145	16.978384	19.303483	11.608057
11	Lothian and Borders	3.992083	12.079258	6.031905	- 4.849145	13.631868	14.838249	6.014463
12	Solway and Cheviot	1.798534	7.644909	6.430470	- 4.849145	8.209692	9.495786	4.639289
13	North East England	3.909481	5.860353	4.259232	- 4.849145	7.156004	8.007850	1.754228
14	North Lancashire and The Lakes	1.911978	5.860353	0.871121	- 4.849145	2.448012	2.622236	- 1.633883
15	South Lancashire, Yorkshire and Humber	4.632105	1.427044	0.133525	- 4.849145	1.031415	1.058120	- 4.144802
16	North Midlands and North Wales	3.364918	0.356055	-	- 4.849145	- 1.199383	- 1.199383	- 4.706723
17	South Lincolnshire and North Norfolk	1.772926	0.372940	-	- 4.849145	- 2.777867	- 2.777867	- 4.699969
18	Mid Wales and The Midlands	1.028830	1.033194	-	- 4.849145	- 2.993760	- 2.993760	- 4.435867
19	Anglesey and Snowdon	3.476508	1.651390	-	- 4.849145	- 0.051525	- 0.051525	- 4.188589
20	Pembrokeshire	9.116666	- 4.819420	-	- 4.849145	0.411985	0.411985	- 6.776913
21	South Wales & Gloucester	5.844645	- 4.941232	-	- 4.849145	- 2.957486	- 2.957486	- 6.825638
22	Cotswold	2.544754	2.902551	- 7.885646	- 4.849145	- 6.290867	- 7.867996	-11.573771
23	Central London	- 5.772175	2.902551	- 7.139875	- 4.849145	-14.011179	-15.439154	-10.828000
24	Essex and Kent	- 3.806958	2.902551	-	- 4.849145	- 6.334062	- 6.334062	- 3.688125
25	Oxfordshire, Surrey and Sussex	- 0.933476	- 2.366475	-	- 4.849145	- 7.675801	- 7.675801	- 5.795735
26	Somerset and Wessex	- 1.796550	- 3.216596	-	- 4.849145	- 9.218972	- 9.218972	- 6.135783
27	West Devon and Cornwall	- 0.261549	- 5.784184	-	- 4.849145	- 9.738041	- 9.738041	- 7.162819

Small Generator Discount (£/kW)	11.545625

The 80% and 40% ALFs used in this table for the Conventional Carbon, Conventional Low Carbon and Intermittent example tariffs are for illustration only. Tariffs for individual generators are calculated using their own ALF.

8. Changes since the previous generation tariffs forecast

The following section provides details of the wider and local generation final tariffs for 2020/21 and explains how these have changed since the Draft Tariffs.

Generation wider zonal tariffs

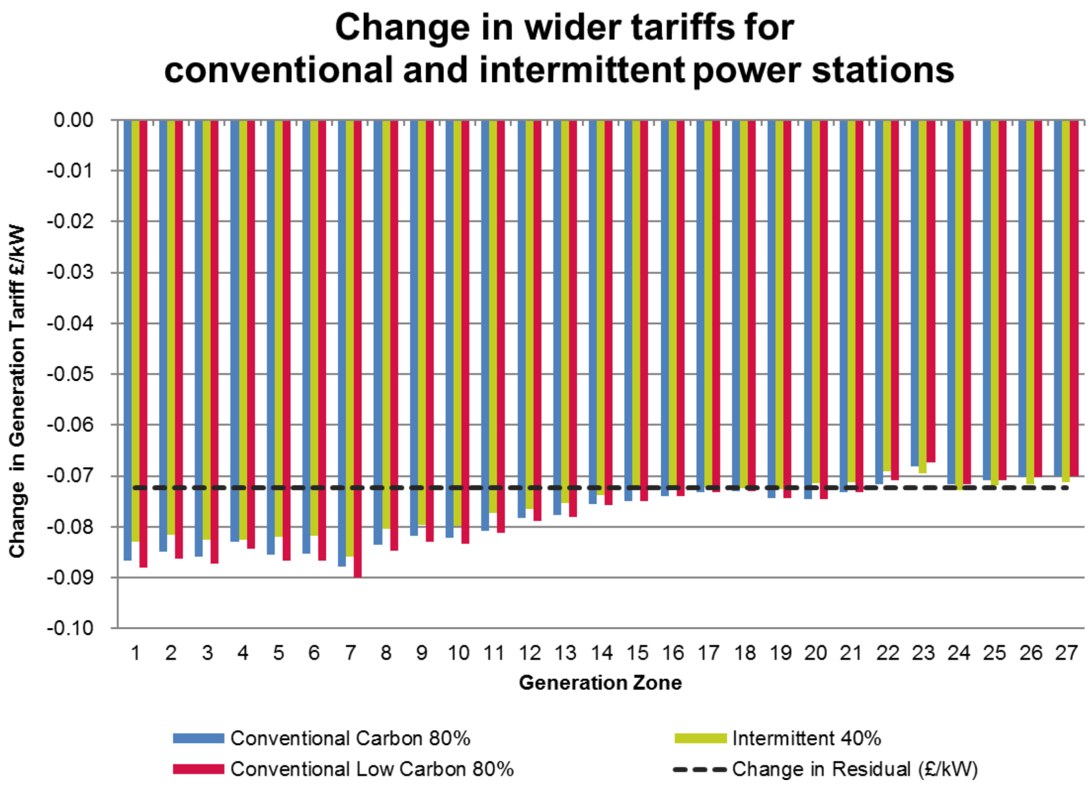
The next table and chart show the changes in wider generation TNUoS tariffs since the Draft Tariffs.

Table 8 Generation wider tariff changes

The table and chart 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 tariffs use a 40% load factor as an example.

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 80%			Conventional Low Carbon 80%			Intermittent 40%			Change in Residual (£/kW)
Generation Zone		2020/21 Draft	2020/21 Final	Change (£/kW)	2020/21 Draft	2020/21 Final	Change (£/kW)	2020/21 Draft	2020/21 Final	Change (£/kW)	
1	North Scotland	26.706168	26.619468	- 0.086700	29.710309	29.622230	- 0.088079	18.598279	18.515302	- 0.082977	- 0.072245
2	East Aberdeenshire	22.795474	22.710569	- 0.084905	25.799615	25.713331	- 0.086285	15.554192	15.472612	- 0.081580	- 0.072245
3	Western Highlands	24.788092	24.702272	- 0.085820	27.753109	27.665928	- 0.087182	17.823017	17.740395	- 0.082622	- 0.072245
4	Skye and Lochalsh	18.375864	18.292988	- 0.082876	21.324103	21.239874	- 0.084230	17.739128	17.656545	- 0.082583	- 0.072245
5	Eastern Grampian and Tayside	23.917612	23.832192	- 0.085420	26.775531	26.688798	- 0.086733	16.604970	16.522908	- 0.082063	- 0.072245
6	Central Grampian	23.709525	23.624199	- 0.085325	26.491836	26.405233	- 0.086603	15.924802	15.843052	- 0.081750	- 0.072245
7	Argyll	29.111194	29.023388	- 0.087805	33.912761	33.822751	- 0.090010	24.770662	24.684850	- 0.085812	- 0.072245
8	The Trossachs	19.808178	19.724644	- 0.083534	22.264156	22.179494	- 0.084662	13.042716	12.962289	- 0.080427	- 0.072245
9	Stirlingshire and Fife	16.057496	15.975685	- 0.081811	18.349630	18.266766	- 0.082864	11.292078	11.212455	- 0.079623	- 0.072245
10	South West Scotlands	17.060656	16.978384	- 0.082272	19.386824	19.303483	- 0.083340	11.687862	11.608057	- 0.079805	- 0.072245
11	Lothian and Borders	13.712602	13.631868	- 0.080734	14.919538	14.838249	- 0.081288	6.091698	6.014463	- 0.077235	- 0.072245
12	Solway and Cheviot	8.287936	8.209692	- 0.078244	9.574621	9.495786	- 0.078835	4.715891	4.639289	- 0.076603	- 0.072245
13	North East England	7.233763	7.156004	- 0.077759	8.086001	8.007850	- 0.078151	1.829506	1.754228	- 0.075278	- 0.072245
14	North Lancashire and The Lakes	2.523609	2.448012	- 0.075597	2.697913	2.622236	- 0.075677	- 1.560162	- 1.633883	- 0.073721	- 0.072245
15	South Lancashire, Yorkshire and Humber	1.106361	1.031415	- 0.074946	1.133078	1.058120	- 0.074958	- 4.072235	- 4.144802	- 0.072567	- 0.072245
16	North Midlands and North Wales	- 1.125462	- 1.199383	- 0.073921	- 1.125462	- 1.199383	- 0.073921	- 4.634413	- 4.706723	- 0.072310	- 0.072245
17	South Lincolnshire and North Norfolk	- 2.704671	- 2.777867	- 0.073196	- 2.704671	- 2.777867	- 0.073196	- 4.627657	- 4.699969	- 0.072312	- 0.072245
18	Mid Wales and The Midlands	- 2.920663	- 2.993760	- 0.073097	- 2.920663	- 2.993760	- 0.073097	- 4.363433	- 4.435867	- 0.072434	- 0.072245
19	Anglesey and Snowdon	0.022923	- 0.051525	- 0.074448	0.022923	- 0.051525	- 0.074448	- 4.116041	- 4.188589	- 0.072548	- 0.072245
20	Pembrokeshire	0.486646	0.411985	- 0.074661	0.486646	0.411985	- 0.074661	- 6.705555	- 6.776913	- 0.071358	- 0.072245
21	South Wales & Gloucester	- 2.884373	- 2.957486	- 0.073113	- 2.884373	- 2.957486	- 0.073113	- 6.754302	- 6.825638	- 0.071336	- 0.072245
22	Cotswold	- 6.219285	- 6.290867	- 0.071582	- 7.797139	- 7.867996	- 0.070857	-11.504615	-11.573771	- 0.069155	- 0.072245
23	Central London	-13.943145	-14.011179	- 0.068034	-15.371776	-15.439154	- 0.067378	-10.758502	-10.828000	- 0.069497	- 0.072245
24	Essex and Kent	- 6.262501	- 6.334062	- 0.071561	- 6.262501	- 6.334062	- 0.071561	- 3.615347	- 3.688125	- 0.072777	- 0.072245
25	Oxfordshire, Surrey and Sussex	- 7.604856	- 7.675801	- 0.070945	- 7.604856	- 7.675801	- 0.070945	- 5.723926	- 5.795735	- 0.071809	- 0.072245
26	Somerset and Wessex	- 9.148736	- 9.218972	- 0.070236	- 9.148736	- 9.218972	- 0.070236	- 6.064131	- 6.135783	- 0.071653	- 0.072245
27	West Devon and Cornwall	- 9.668043	- 9.738041	- 0.069998	- 9.668043	- 9.738041	- 0.069998	- 7.091637	- 7.162819	- 0.071181	- 0.072245

Figure 4 Variation in generation zonal tariffs



Due to the decrease in the generation charging base, the generation residual has decreased which accounts for majority of changes in the generation tariffs. The wider tariffs in all zones have decreased due to the updated RPI with very slightly deviations between zones.

Onshore local tariffs for generation

9. Onshore local substation tariffs

Onshore local substation tariffs reflect the cost of the first transmission substation that each transmission connected generator connects to. They are inflated each year by the average May to October RPI. These tariffs have slightly updated since the Draft Tariffs due to RPI update.

Table 9 Onshore local substation tariffs

2020/21 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.203179	0.116232	0.083748
<1320 MW	Redundancy	0.447587	0.276925	0.201402
>=1320 MW	No redundancy	N/A	0.364438	0.263562
>=1320 MW	Redundancy	N/A	0.598313	0.436719

10. 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 power flows and inflation.

Onshore local circuit tariffs have been updated with the latest RPI forecast, and for most users, the changes are minimal since the Draft Tariffs. Onshore local circuit tariffs are listed in .

Some generators can have their local circuits tariffs revised through an additional one-off charge. These are listed in Table 11.

Table *10*.

Some generators can have their local circuits tariffs revised through an additional one-off charge. These are listed in Table 11.

Table 10 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.674800	Dunhill	1.449479	Mark Hill	0.886056
Aberdeen Bay	2.638574	Dunlaw Extension	1.526206	Middle Muir	2.005933
Achruach	4.345091	Edinbane	6.927489	Middleton	0.150275
Aigas	0.661862	Ewe Hill	2.463019	Millennium Wind	1.848216
An Suidhe	- 0.969437	Fallago	0.438701	Moffat	0.189262
Arecleoch	2.101823	Farr	3.608124	Mossford	2.915511
Baglan Bay	0.770013	Fernoch	4.451403	Nant	- 1.243308
Beinneun Wind Farm	1.519952	Ffestiniogg	0.256029	Necton	1.136934
Bhlaraidh Wind Farm	0.653386	Finlarig	0.324035	New Deer	0.762008
Black Hill	1.571596	Foyers	0.296426	Rhigos	0.102846
Black Law	1.768307	Galawhistle	3.541018	Rocksavage	0.017912
BlackCraig Wind Farm	6.370470	Glendoe	1.861454	Saltend	0.017558
BlackLaw Extension	3.749925	Glenglass	4.869173	South Humber Bank	0.418643
Clyde (North)	0.110981	Gordonbush	0.241519	Spalding	0.286811
Clyde (South)	0.128344	Griffin Wind	9.829899	Strathbrora	0.109582
Corriegarth	2.931749	Hadyard Hill	2.801053	Strathy Wind	1.898434
Corriemoillie	1.685397	Harestanes	2.554720	Stronelairg	1.088627
Coryton	0.049976	Hartlepool	0.207898	Wester Dod	0.481568
Cruachan	1.846679	Invergarry	0.370326	Whitelee	0.107401
Crystal Rig	0.137216	Kilgallioch	1.065057	Whitelee Extension	0.298574
Culligran	1.753949	Kilmorack	0.199859		
Deanie	2.881488	Kype Muir	1.501022		
Dersalloch	2.437668	Langage	0.665581		
Dinorwig	2.428025	Lochay	0.370326		
Dorenell	2.123778	Luichart	0.582090		
Dumnaglass	1.146983	Marchwood	0.386209		

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way they are modelled in the Transport and Tariff model. This table shows the circuits 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 sections 2.14.4, 14.4, and 14.15.15.

Table 11 Circuits subject to one-off charges

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

11. Offshore local generation tariffs

The local offshore tariffs (substation, circuit and Embedded Transmission Use of System) 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). The tariffs are subsequently indexed each year, in line with the revenue of the associated Offshore Transmission Owner.

Offshore local generation tariffs associated with projects due to transfer in 2020/21 will be confirmed once asset transfer has taken place.

Table 12 Offshore local tariffs 2020/21

	Tariff Component (£/kW)		
Offshore Generator	**Substation**	**Circuit**	**ETUoS**
Barrow	8.162444	42.705899	1.060446
Burbo Bank	10.580601	20.257999	-
Dudgeon	15.326966	23.898895	-
Greater Gabbard	15.324099	35.213271	-
Gunfleet	17.665294	16.218123	3.031261
Gwynt Y Mor	18.654651	18.377138	-
Humber Gateway	15.005644	33.857735	-
Lincs	15.268405	59.779295	-
London Array	10.412718	35.465138	-
Ormonde	25.233893	47.008379	0.374617
Race Bank	9.624985	26.420532	-
Robin Rigg	- 0.466793	30.921041	9.583854
Robin Rigg West	- 0.466793	30.921041	9.583854
Sheringham Shoal	24.410421	28.627705	0.622282
Thanet	18.575960	34.613653	0.833273
Walney 1	21.778046	43.370922	-
Walney 2	21.619660	43.753022	-
West of Duddon Sands	8.423723	41.565850	-
Westermost Rough	17.737529	30.004308	-

Updates to revenue and the charging model since the last forecast

Since the Draft Tariffs were published, we have updated allowed revenue for Transmission Owners, the generation background, the zonal demand charging base, and RPI.

There have been no changes to the TNUoS revenue from generation.

For details about quarterly updates to TNUoS parameters, please see Appendix J.

12. Changes affecting the locational element of tariffs

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

- Contracted generation and nodal demand as of 31 October 2019;
- Local and MITS circuits as set in the Draft Tariffs; and
- Inflation, which decreases the expansion constant

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2020/21 period, which can be found on the TEC register.[2]

In accordance with CUSC 14.15.6, the contracted TEC volumes used in the Draft Tariffs were based on the TEC register 31 October 2019, and have remained unchanged in the Final Tariffs.

Modelled TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. In our forecasts prior to November, modelled TEC was based on our best view of the likely Contracted TEC on 31 October, after which the modelled TEC was locked down.

Chargeable TEC is our best view of the likely volume of generation that will be connected to the system during 2020/21 and are liable to pay generation TNUoS charges. The Chargeable TEC volumes have been revised for the Final Tariffs, to ensure we recover TOs' revenue.

Chargeable TEC has decreased by 5.3GW to 70.7GW since the Draft Tariffs.

Table 13 Contracted TEC

	2019/20	2020/21 Tariffs			
Generation (GW)	Final	March	July	Draft	Final
Contracted TEC	80.6	90.8	84.3	84.9	84.9
Modelled Best View TEC	80.6	82.6	80.7	84.9	84.9
Chargeable TEC	73.3	74.1	71.8	76.0	70.7

13. 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.

The table below reflects the contracted position of interconnectors for 2020/21 in the interconnector register as of 31 October 2019.

[2] See the Registers, Reports and Updates section at https://www.nationalgrideso.com/connections/after-you-have-connected

Table 14 Interconnectors

Interconnector	Site	Interconnected System	Generation MW: Generation Zone	Generation MW: Transport Model Peak	Generation MW: Transport Model Year Round	Generation MW: Charging Base
IFA	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
BritNed	Grain 400kV	Netherlands	24	0	1200	0
Nemo	Richborough 400kV	Belgium	24	0	1020	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
IFA2	Chilling 400kV	France	26	0	1100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	637	0
NS Link	Blyth	Norway	13	0	1400	0

14. Expansion Constant and RPI

The expansion constant is the annuitised value of the cost required to transport 1 MW over 1 km. The 2020/21 Expansion Constant is £14.935634 /MWkm. This reflects the average May to October RPI, and has decreased slightly since the Draft Tariffs.

15. Onshore substation

Local onshore substation tariffs are indexed by the average May to October RPI, and have been updated to take into account the actual RPI.

16. Offshore local tariffs

Local offshore circuit tariffs, local offshore substation tariffs and the ETUoS tariff are indexed in line with the revenue of the relevant Offshore Transmission Owner, and have been updated using the relevant inflation term.

17. Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Some other revenue (for example, Network Innovation Competition) are also collected from network users via TNUoS. The total amount recovered is adjusted for interconnector revenue recovery or redistribution. This Final Tariffs have taken into account adjustments for the Cap and Floor regime and contributions from the IFA Use of Revenues framework.

Compared to the Draft Tariffs, tariffs have now been calculated to recover £2,843m of revenue, a decrease of £42.8m. Of the £42.8m of reduction, £11m is attributed to TOs' allowed revenue reduction, and the rest are due to pass-through items adjustment particularly the Network Innovation Competition (NIC) fund. For more details on TOs allowed revenues, please refer to Appendix K.

Table 15 Allowed revenues

£m Nominal	TNUoS Revenue 2020/21 March Forecast	July Forecast	Nov Draft	Jan Final
National Grid Electricity Transmission				
Price controlled revenue	*1,782.4*	*1,777.7*	*1,705.3*	*1,691.1*
Less income from connections	*31.0*	*31.0*	*31.3*	*29.8*
NGET Income from TNUoS	**1,751.4**	**1,746.7**	**1,674.0**	**1,661.3**
Scottish Power Transmission				
Price controlled revenue	*381.6*	*379.7*	*380.4*	*384.0*
Less income from connections	*12.9*	*12.9*	*12.4*	*19.7*
SPT Income from TNUoS	**368.7**	**366.8**	**368.0**	**364.3**
SHE Transmission				
Price controlled revenue	*361.6*	*360.0*	*369.4*	*377.2*
Less income from connections	*3.4*	*3.4*	*3.4*	*3.4*
SHE Income from TNUoS	**358.2**	**356.6**	**365.9**	**373.8**
National Grid Electricity System Operator				
Other Pass-through from TNUoS	**41.4**	**41.7**	**43.9**	**12.2**
Offshore (offset by IFA contribution)	**431.0**	**427.4**	**433.9**	**431.5**
Total to Collect from TNUoS	**2,950.8**	**2,939.3**	**2,885.8**	**2,843.0**

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The revenue to be collected from generators has been locked down since the July tariff forecast, and didn't change in the Final Tariffs.

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges in Great Britain to €2.5/MWh. The 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 of 16% is also applied to reflect revenue and output forecasting accuracy.

Exchange Rate

As prescribed by the TNUoS charging methodology, the exchange rate for 2020/21 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in July 2019. The value published is €1.119217/£.

Generation Output

The forecast output of generation has stayed the same at 199.8TWh. This figure is the average of the four scenarios in the latest Future Energy Scenarios publication.

Error Margin

The error margin remains unchanged from the July forecast at 16%. The parameters used to calculate the proportions of revenue collected from generation and demand are shown in the table below.

Table 16 Generation and demand revenue proportions

Code	Revenue	2020/21 Tariffs March	July	Draft	Final
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	2.5
y	Error Margin	16.0%	16.0%	16.0%	16.0%
ER	Exchange Rate (€/£)	1.1	1.1	1.1	1.1
MAR	Total Revenue (£m)	2,950.8	2,939.3	2,885.8	2,843.0
GO	Generation Output (TWh)	221.2	199.8	199.8	199.8
G	% of revenue from generation	14.1%	12.8%	13.0%	13.2%
D	% of revenue from demand	85.9%	87.2%	87.0%	86.8%
G.R	Revenue recovered from generation (£m)	415.1	374.9	374.9	374.9
D.R	Revenue recovered from demand (£m)	2,535.7	2,564.3	2,510.9	2,468.1

19. Charging bases for 2020/21

Generation

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

We are unable to break down our best view of generation as some of the information used to derive it could be commercially sensitive.

The generation charging base has been decrease by 5.3GW to 70.7GW due to our updated internal view of what generation we expect to connect in the next financial year.

Demand

Our forecasts of embedded generation have not been updated since the July forecast, and our NHH demand charging base has not been updated since November Draft, when it was updated due to the implementation of CMP318[3].

Our forecast of HH demand charging base has been updated since the Draft Tariffs, taking into account year on year trend, relevant code modifications (CMP266[4]) and out turn data for the current winter period so far. The HH demand charging base has been increase from 18.1GW to 19.6GW. This has resulted in reduction in TNUoS revenue from NHH demand and tariffs.

To forecast chargeable HH and NHH demand and EET volumes, we use a Monte Carlo modelling approach. This incorporates our latest data including:

- Historical gross metered demand and embedded export volumes (August 2014-March 2019)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation.

Overall, we assume that recent historical trends in steadily declining demand volumes will continue due to several factors, including the growth in distributed generation and "behind the meter" microgeneration. But due to the increase in electric vehicles and heat pumps, demand will begin to gradually increase again in future years.

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[3] Ofgem's decision on CMP318 https://www.ofgem.gov.uk/publications-and-updates/cmp318-maintaining-non-half-hourly-nhh-charging-arrangements-measurement-classes-f-and-g

[4] Ofgem's decision on CMP266 https://www.ofgem.gov.uk/publications-and-updates/connection-and-use-system-code-cmp266-removal-demand-tnuos-charging-barrier-future-elective-half-hourly-settlement

Table 17 Charging bases

Charging Bases	2020/21 Tariffs March	July	Draft	Final
Generation (GW)	74.1	71.8	76.1	70.7
NHH Demand (4pm-7pm TWh)	24.1	24.3	25.1	25.1
Net Charging				
Total Average Net Triad (GW)	43.2	43.2	43.2	43.2
HH Demand Average Net Triad (GW)	12.1	12.0	10.9	12.4
Gross charging				
Total Average Gross Triad (GW)	50.2	50.4	50.4	50.4
HH Demand Average Gross Triad (GW)	19.2	19.2	18.1	19.6
Embedded Generation Export (GW)	7.1	7.2	7.2	7.2

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of the Final Tariffs, we have used the final version of the 2020/21 ALFs, based upon data from 2014/15 to 2018/19. ALFs is explained in more detail in Appendix E of this report, and the full list of power station ALFs are available on the National Grid ESO website.[5]

21. Generation and demand residuals

The residual element of tariffs is calculated using the formulae below.

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)

[5]https://www.nationalgrideso.com/document/157476/download

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 (HH equivalent GW)

Z_G, Z_D, L_C, and EE are determined by the locational elements of tariffs. The EE is also affected by the value of the AGIC[6] and phased residual.

Table 18 Residual components calculation

		2020/21 Tariffs			
Component		**March**	**July**	**Draft**	**Final**
G	Proportion of revenue recovered from generation (%)	14.1%	12.8%	13.0%	13.2%
D	Proportion of revenue recovered from demand (%)	85.9%	87.2%	87.0%	86.8%
R	Total TNUoS revenue (£m)	2,950.8	2,939.3	2,885.8	2,843.0
Generation Residual					
R_G	Generator residual tariff (£/kW)	- 4.0	- 4.5	- 4.8	- 4.8
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	331.7	326.4	356.9	340.3
O	Revenue recovered from offshore local tariffs (£m)	339.1	337.4	343.5	342.2
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.4	18.8	20.0	18.0
S_G	Revenue recovered from onshore local circuit tariffs (£m)	18.1	17.9	17.9	17.5
B_G	Generator charging base (GW)	74.1	71.8	76.1	70.7
Gross Demand Residual					
R_D	Demand residual tariff (£/kW)	52.2	52.5	51.9	51.0
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	- 68.2	- 66.2	- 86.8	- 86.8
EE	Amount to be paid to Embedded Export Tariffs (£m)	17.9	17.2	17.2	17.1
B_D	Demand Gross charging base (GW)	50.2	50.4	50.4	50.4

22. Small Generator Discount

The Small Generator Discount is defined in National Grid ESO's Electricity Transmission licence condition C13. This licence condition is due to expire on 31 March 2021.

The Small Generator Discount reduces the tariff for transmission connected generation connected at 132kV and with TEC<100MW. The Discount is £11.55/kW.

In order to cover the Small Generator Discount payment, demand tariffs are increased by £0.70/kW for HH demand, and 0.09p/kWh for NHH demand.

[6] Avoided Grid Supply Point Infrastructure Credit

Table 19 Small Generator Discount calculation

Small Generator Discount calculation		
Generator Residual (£/kW)	G	- 4.85
Demand Residual (£/kW)	D	51.03
Small Generator Discount (£/kW)	T = (G + D)/4	11.55
Forecast Small Generator Volume (kW)	V	3,085,040
2019/20 Final SGD cost (£)	V x T	35,618,715
Prior year reconcilation (£)	R	306,706
Total SGD Cost (£)	C = (V x T) - R	35,312,009
Total System Triad Demand (kW)	TD	50,400,000
Total HH Triad Demand (kW)	HHD	19,606,954
Total NHH Consumption (kWh)	NHHD	25,126,417,525
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.700635
Total Cost to HH Customers (£)	HHC = HHT * HHD	13,737,321
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.085865
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	21,574,689

The generator discount rate is subtracted from the applicable TNUoS tariff for affected generators. The HH and NHH rates are added to all demand tariffs.

Tools and supporting information

Further information

We would like to ensure that customers understand the current charging arrangements and the reasons 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 webinars

We will hold a webinar for the Final 2020/21 tariffs on Thursday 6 February 2020 from 10:30 to 11:30. If you wish to join the webinar, please use this registration link (register).

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

Charging model copies available

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 under 2020/21 forecasts:

https://www.nationalgrideso.com/tnuos

Contact Us

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.

Our contact details -

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A

Appendix A: Background to TNUoS charging

Background to TNUoS charging

National Grid ESO 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, NGESO 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 revenue allowances.

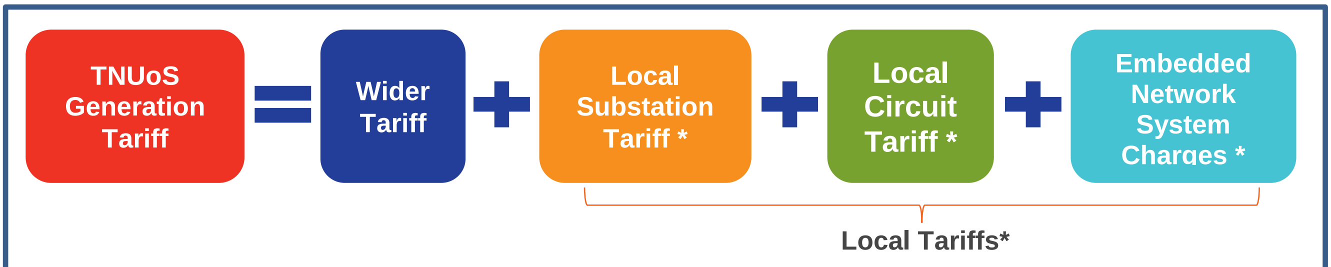
Generation charging principles

Generators pay TNUoS (Transmission Network Use of System) tariffs to allow NGESO 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 export 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 offshore generators whose host OFTO are not directly connected to the onshore 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.

Conventional Carbon Generators

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

Peak Element + (Year Round Shared Element × ALF) + (Year Round Not Shared Element × ALF) + Residual Element

Conventional Low Carbon Generators

(Hydro, Nuclear)

Peak Element + (Year Round Shared Element × ALF) + Year Round Not Shared Element + Residual Element

Intermittent Generators

(Wind, Wave, Tidal)

(Year Round Shared Element × ALF) + Year Round Not Shared Element + Residual Element

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 ALFs used in these tariffs are listed from page 42.

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 need to have a BEGA[7] if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS[8] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

Offshore generators connecting to embedded OFTO will need to pay an estimated DUoS charge to NGET through TNUoS tariffs to cover DNO charges.

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.[9]

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 monthly liability is as follows:

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

All tariffs are in £/kW of contracted 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 a 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 individual 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.

[7] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website:
https://www.nationalgrid.com/uk/electricity/connections/applying-connection
[8] Distribution network Use of System charges
[9] These specific charges include any onshore local circuit and substation charges.

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 section 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.[10] 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 are available, via the NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[11].

Embedded Export Tariffs (EET)

The EET was introduced under CMP264/265 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. 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 more information on forecasts and billing, please see our guide for new suppliers on our website[12].

Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by National Grid. Payments for embedded exports from SVA registered embedded generators will be paid to their registered supplier.

Note: HH demand and embedded export is charged at the GSP group, 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 every day of the year. Suppliers must submit forecasts throughout the year of their expected demand volumes in each demand zone. The tariff is charged on a p/kWh basis.

Suppliers are billed against these forecast volumes, and two reconciliations of the amounts paid against their actual metered output take place, the second of which is once the final metering data is available from Elexon up to 16 months after the financial year in question.

[10] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data
[11] https://www.nationalgrideso.com/document/130641/download
[12] https://www.nationalgrideso.com/charging/charging-guidance

B

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology for 2020/21

The charging methodology can be changed through modifications to the CUSC and the licence.

There have been no changes to the charging methodology in Final Tariffs compared to the Draft forecast.

Changes and proposed changes to the charging methodology for 2021/22 and future years

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for future years. All these modifications are subject to whether they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

All these modifications in this section do not affect TNUoS tariffs for year 2020/21.

More information about current modifications can be found at the following location:

https://www.nationalgrideso.com/uk/electricity/codes/connection-and-use-system-code?mods

A summary of the modifications already in progress which could affect future TNUoS tariffs and their status are listed below.

The Targeted Charging Review

On 21 November 2019, the Authority published their final decision[13] on the Targeted Charging Review (TCR) and issued Directions to NGESO to raise changes to the charging methodology to give effect to that final decision. These changes will take effect from April 2021.

Under the TCR, the two changes for TNUoS tariff setting and charges are:

- The removal of the generation residual, which is currently used to keep total TNUoS recovery from generators within the range of €0-2.50/MWh. This change will be managed under CMP317/327, which seeks to ensure ongoing compliance with European Regulation by establishing which charges are, and are not in scope of that range; and

- The creation of specific NHH and HH demand residual charges, levied only to final demand (which is consumption not used either to operate a generating station, or to store and export), and on a 'site' basis. CMP332 (Transmission Demand Residual bandings and allocation) was raised to modify the CUSC methodology accordingly.

Our tariff forecasts will be based on the approved methodology in the CUSC.

We have created a joint project initiation document with the DNOs about how we will be able to deliver the TCR for April 2021. In this we have noted that we require a decision from Ofgem in June 2020 to allow changes to both transmission and distribution charging systems. The plan also shows all of the interdependencies and risks associated with this delivery date, which we will continue to review with Ofgem throughout the year. A link to the document can be found here:

http://www.chargingfutures.com/media/1390/tcr-joint-eso-dno-pid-v10.pdf

RIIO-2 Parameter Updates

A number of key parameters that are used to calculate TNUoS Tariffs will also be reset in preparation for RIIO-2, to apply from 1 April 2021. This includes Generation Zones & Connectivity, Expansion Constant and Factors, Local Onshore Security Factor, Offshore Local Tariffs and the Avoided GSP Infrastructure Credit. Input data is required from a number of sources and will become available at different stages throughout 2020.

[13] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

The following CUSC Modifications have been raised to change the generation zones and the underlying methodology used to establish them:

CMP324 - 'Generation Zones – changes for RIIO-T2' & CMP325 - 'Rezoning – CMP324 expansion'

The Small Generator Discount

The Small Generator Discount is defined in National Grid ESO's Electricity Transmission licence condition C13. This licence condition is due to expire on 31 March 2021 in line with the implementation of TCR.

C

Appendix C: Breakdown of locational HH and EE tariffs

Breakdown of HH and EET locational tariffs

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 Draft Tariffs to the Final Tariffs.

Table 20 Demand HH locational tariffs

Demand Zone		Draft		Final		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	- 2.181691	- 28.437800	- 2.180689	- 28.424741	0.001002	0.013058
2	Southern Scotland	- 2.146788	- 20.835750	- 2.145803	- 20.826183	0.000986	0.009568
3	Northern	- 3.619288	- 8.096370	- 3.617626	- 8.092652	0.001662	0.003718
4	North West	- 1.690502	- 3.369425	- 1.689726	- 3.367878	0.000776	0.001547
5	Yorkshire	- 2.525794	- 1.373597	- 2.524634	- 1.372967	0.001160	0.000631
6	N Wales & Mersey	- 1.841014	- 0.987611	- 1.840168	- 0.987157	0.000845	0.000454
7	East Midlands	- 2.244514	1.900005	- 2.243484	1.899133	0.001031	- 0.000872
8	Midlands	- 1.927185	2.843771	- 1.926300	2.842465	0.000885	- 0.001306
9	Eastern	1.390005	0.366972	1.389367	0.366804	- 0.000638	- 0.000169
10	South Wales	- 6.027019	4.908020	- 6.024252	4.905766	0.002768	- 0.002254
11	South East	3.908384	0.863376	3.906590	0.862979	- 0.001795	- 0.000396
12	London	5.778801	1.759382	5.776148	1.758574	- 0.002654	- 0.000808
13	Southern	1.975370	4.067541	1.974463	4.065673	- 0.000907	- 0.001868
14	South Western	- 0.466281	5.756832	- 0.466066	5.754189	0.000214	- 0.002643

Table 20 shows the breakdown of the components that make up the EET.

Table 21 Breakdown of the EET

Demand Zone		2020/21 Draft			2020/21 Final			Changes		
		Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)
1	Northern Scotland	- 30.61949	3.41650	-	- 30.60543	3.41493	-	0.01406	- 0.00157	-
2	Southern Scotland	- 22.98254	3.41650	-	- 22.97199	3.41493	-	0.01055	- 0.00157	-
3	Northern	- 11.71566	3.41650	-	- 11.71028	3.41493	-	0.00538	- 0.00157	-
4	North West	- 5.05993	3.41650	-	- 5.05760	3.41493	-	0.00232	- 0.00157	-
5	Yorkshire	- 3.89939	3.41650	-	- 3.89760	3.41493	-	0.00179	- 0.00157	-
6	N Wales & Mersey	- 2.82862	3.41650	-	- 2.82733	3.41493	-	0.00130	- 0.00157	-
7	East Midlands	- 0.34451	3.41650	-	- 0.34435	3.41493	-	0.00016	- 0.00157	-
8	Midlands	0.91659	3.41650	-	0.91617	3.41493	-	- 0.00042	- 0.00157	-
9	Eastern	1.75698	3.41650	-	1.75617	3.41493	-	- 0.00081	- 0.00157	-
10	South Wales	- 1.11900	3.41650	-	- 1.11849	3.41493	-	0.00051	- 0.00157	-
11	South East	4.77176	3.41650	-	4.76957	3.41493	-	- 0.00219	- 0.00157	-
12	London	7.53818	3.41650	-	7.53472	3.41493	-	- 0.00346	- 0.00157	-
13	Southern	6.04291	3.41650	-	6.04014	3.41493	-	- 0.00277	- 0.00157	-
14	South Western	5.29055	3.41650	-	5.28812	3.41493	-	- 0.00243	- 0.00157	-

The locational element is the sum of the peak and year round elements for the HH tariff in that zone (see the table above).

The AGIC is the Avoided GSP Infrastructure Credit, which is indexed by average May to October RPI each year.

The phased residual is the amount of the HH residual due as a payment to the embedded generator each year. This will reduce to zero by 2020/21.

D

Appendix D: Locational demand profiles

Locational demand profiles

The table below shows the latest locational demand and demand charging base forecast used for the Final Tariffs. Locational nodal demand has been locked down since the Draft Tariffs. The zonal demand charging base forecast has been updated, taking into account the year on year trend and outturn data so far for the current winter period.

The gross half-hourly (HH) demand forecast has increased to 19.6GW and the non-half-hourly (NHH) demand forecast has remained unchanged at 25.1TWh. Embedded export volumes have stayed the same and are forecast to be 7.2GW.

HH demand is calculated on a gross basis rather than net, and the negative demand caused by embedded generation is listed separately.

Table 22 Demand profile

		2020/21 Draft			2020/21 Final						
Demand Zone		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)	GROSS Tariff Model HH Demand (MW)	GROSS Tariff Model HH Demand (MW)
1	Northern Scotland	266	1,470	416	0.78	1,330	266	1,470	450	0.78	1,330
2	Southern Scotland	2,399	3,360	1,159	1.72	870	2,399	3,360	1,254	1.72	870
3	Northern	2,031	2,510	982	1.22	470	2,031	2,510	1,062	1.22	470
4	North West	2,869	3,950	1,376	2.00	380	2,869	3,950	1,489	2.00	380
5	Yorkshire	3,984	3,770	1,491	1.83	710	3,984	3,770	1,614	1.83	710
6	N Wales & Mersey	2,788	2,570	976	1.27	580	2,788	2,570	1,056	1.27	580
7	East Midlands	5,279	4,590	1,676	2.27	550	5,279	4,590	1,814	2.27	550
8	Midlands	4,433	4,170	1,494	2.06	240	4,433	4,170	1,617	2.06	240
9	Eastern	5,601	6,340	1,969	3.22	610	5,601	6,340	2,131	3.22	610
10	South Wales	1,604	1,780	757	0.87	380	1,604	1,780	819	0.87	380
11	South East	3,194	3,830	1,096	1.99	330	3,194	3,830	1,186	1.99	330
12	London	5,056	4,120	2,105	1.88	120	5,056	4,120	2,277	1.88	120
13	Southern	7,178	5,390	1,926	2.68	390	7,178	5,390	2,084	2.68	390
14	South Western	2,151	2,550	696	1.35	270	2,151	2,550	753	1.35	270
Total		**48,833**	**50,400**	**18,119**	**25.13**	**7,230**	**48,833**	**50,400**	**19,607**	**25.13**	**7,230**

E

Appendix E: Annual Load Factors

Specific ALFs

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 2014/15 to 2018/19. Generators which commissioned after 1 April 2016 will have fewer than three complete years of data, so the appropriate Generic ALF listed below is added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2020/21 also use the Generic ALF for their first year of operation.

The specific and generic ALFs for 2020/21 tariffs have been finalised and are published here

https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges

Generic ALFs

Table 23 Generic ALFs

Technology	Generic ALF
Gas_Oil #	0.3935%
Pumped_Storage	10.2893%
Tidal *	18.9000%
Biomass	39.8387%
Wave *	31.0000%
Onshore_Wind	35.6660%
CCGT_CHP	50.9470%
Hydro	41.7886%
Offshore_Wind	48.3204%
Coal	27.7372%
Nuclear	77.5645%

Includes OCGTs (Open Cycle Gas Turbine generating plant).

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

These Generic ALFs are calculated in accordance with CUSC 14.15.110.

F

Appendix F: Contracted generation changes since the Draft Tariffs

The contracted generation used in the Transport model was fixed at the Draft forecast of 2020/21 tariffs, using the TEC register as of 31 October 2019, as stated in the CUSC 14.15.6. There are no changes to the Transport model (affecting locational tariffs) in these Final Tariffs for 2020/21.

G

Appendix G Transmission company revenues

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have updated us with their latest revenue forecast by 25 January 2020. In addition, pass-through revenue that are to be collected by NGESO via TNUoS charges, have also been updated. These include the Network Innovation Competition (NIC) fund, contribution made from IFA, and site-specific adjustments by TOs etc.

Revenue for offshore networks is included with forecasts by NGESO 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.

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

NGESO TNUoS revenue pass-through items forecasts

From April 2019, a new, legally separate electricity system operator (NGESO) was established within National Grid Group, separate from National Grid Electricity Transmission (NGET). As a result, the allowed TNUoS revenue under NGET's licence, is collected by NGESO and passed through to NGET, in the same way to the arrangement with Scottish TOs and OFTOs.

In addition, NGESO collects Network Innovation Competition (NIC) Funding, and pass through the money to network licensees (including TOs, OFTOs and DNOs). There are also a few miscellaneous pass-through items that had been collected by NGET under its licence condition, and this function was also transferred to NGESO. The revenue breakdown table below shows details of the pass-through TNUoS revenue items under NGESO's licence conditions.

Table 24 NGESO revenue breakdown

	NGESO TNUoS Other Pass-Through			
Term	**March Forecast**	**July Forecast**	**Nov Draft**	**Jan Final**
Embedded Offshore Pass-Through (OFETt)	0.6	0.6	0.6	0.6
Network Innovation Competition (NICFt)	31.6	31.6	31.6	13.9
Interconnectors Cap&Floor Revenue Adjustment (TICFt)	- 10.8	- 10.8	- 12.3	- 12.3
ESO Network Innovation Allowance (NIAt)	3.0	3.2	3.0	3.0
Offshore Transmission Revenue (OFTOt)	441.8	438.2	446.2	443.8
Financial facility (FINt)	6.3	6.3	8.8	8.7
Site Specific Charges Discrepancy (DISt)			-	- 9.4
Termination Sums (TSt)			-	- 4.5
NGET revenue pas-through (NGETTOt)*	1,751.4	1,746.7	1,674.0	1,661.3
SPT revenue pass-through (TSPt)	368.7	366.8	368.0	364.3
SHETL revenue pass-through (TSHt)	358.2	356.6	365.9	373.8
Total	**2,950.8**	**2,939.3**	**2,885.8**	**2,843.0**

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided an update to NGESO with their 2020/21 revenue forecast. The forecast have now been locked down for the final tariffs.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2020/21 is £443.8m, a decrease of £2.4m from Draft Tariffs. Revenues have been adjusted to take into account an updated RPI forecast (as part of the calculation of the inflation term, as defined in the relevant OFTO licence).

Since year 2018/19, 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, and redistribution of revenue through IFA's Use of Revenues framework. The latest interconnector revenue forecast shows it reduces 2020/21 TNUoS revenue by around £12.3m.

Table 25 NGET revenue breakdown

2020/21 Revenue Description		Licence Term	National Grid Electricity Transmission			
Regulatory Year			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1571.6	1571.6	1571.6	1571.6
Price Control Financial Model Iteration Adjustment	A2	MODt	-338.3	-338.3	-379.2	-382.4
RPI True Up	A3	TRUt	1.0	1.0	-1.0	-1.0
RPI Forecast	A4	RPIFt	1.3990	1.3940	1.3870	1.3800
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1726.8**	**1720.6**	**1652.4**	**1639.6**
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	26.3	26.3	40.3	37.0
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	1.6	4.7
Inter TSO Compensation	B4	ITCt	0.0	0.0	-2.7	-2.7
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**26.3**	**26.3**	**39.1**	**39.0**
Financial Incentive for Timely Connections Output	C5	-CONADJt				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	15.9	15.9	17.4	16.7
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**15.9**	**15.9**	**17.4**	**16.7**
Network Innovation Allowance	D	NIAt	6.3	7.8	7.4	7.4
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0	0.4	0.0
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	0.0
Correction Factor	-K	-K	13.4	13.4	-2.7	-2.8
Financial Facility	FINt	FINt	-6.3	-6.3	-8.8	-8.7
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**1782.4**	**1777.7**	**1705.3**	**1691.1**
Pre-vesting connection charges	S1		30.3	30.3	30.7	29.7
Rental Site	S2		0.7	0.7	0.6	0.1
TNUoS Collected Revenue [T=M-B5-P]	**T**		**1751.4**	**1746.7**	**1674.0**	**1661.3**

Table 26 SPT revenue breakdown

2020/21 Revenue Description		Licence Term	Scottish Power Transmission			
Regulatory Year			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	254.2	254.2	254.2	254.2
Price Control Financial Model Iteration Adjustment	A2	MODt	-7.4	-7.4	-6.3	-3.0
RPI True Up	A3	TRUt	0.7	0.7	-0.2	-0.2
RPI Forecast	A4	RPIFt	1.4020	1.3940	1.3870	1.3800
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**347.0**	**345.0**	**343.6**	**346.4**
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	4.2	4.2	4.3	4.3
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	0.0	0.0
Inter TSO Compensation	B4	ITCt				
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**4.2**	**4.2**	**4.3**	**4.3**
Financial Incentive for Timely Connections Output	C5	-CONADJt			0.0	
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	2.6	2.6	5.2	5.2
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**2.6**	**2.6**	**5.2**	**5.2**
Network Innovation Allowance	D	NIAt	1.1	1.1	1.1	1.1
Future Environmental Discretionary Rewards	F	EDRt	0.5	0.5	0.0	1.0
Transmission Investment for Renewable Generation	G	TIRGt	26.3	26.3	33.0	32.8
Correction Factor	-K	-K	0.0	0.0	-6.8	-6.8
Financial Facility	FINt	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**381.6**	**379.7**	**380.4**	**384.0**
Pre-vesting connection charges	S1		12.9	12.9	12.4	19.7
Rental Site	S2					
TNUoS Collected Revenue [T=M-B5-P]	**T**		**368.7**	**366.8**	**368.0**	**364.3**

Table 27 SHETL revenue breakdown

2020/21 Revenue Description		Licence Term	SHE Transmission			
Regulatory Year			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	122.5	122.5	122.5	122.5
Price Control Financial Model Iteration Adjustment	A2	MODt	79.2	78.5	85.0	88.6
RPI True Up	A3	TRUt	-0.9	-0.9	-0.2	-0.2
RPI Forecast	A4	RPIFt	1.3970	1.3940	1.3870	1.3800
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**280.5**	**278.9**	**287.6**	**291.1**
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	26.0	26.0	25.9	25.6
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	0.0	0.0
Inter TSO Compensation	B4	ITCt				
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**26.0**	**26.0**	**25.9**	**25.6**
Financial Incentive for Timely Connections Output	C5	-CONADJt			0.0	
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	1.9	1.9	2.8	2.8
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**1.9**	**1.9**	**2.8**	**2.8**
Network Innovation Allowance	D	NIAt	0.9	0.9	0.9	0.9
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0	0.0	1.0
Transmission Investment for Renewable Generation	G	TIRGt	82.3	82.3	82.4	81.4
Correction Factor	-K	-K	-30.0	-30.0	-30.2	-25.6
Financial Facility	FINt	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**361.6**	**360.0**	**369.4**	**377.2**
Pre-vesting connection charges	S1		3.4	3.4	3.4	3.4
Rental Site	S2					
TNUoS Collected Revenue [T=M-B5-P]	**T**		**358.2**	**356.6**	**365.9**	**373.8**

Table 28 Offshore revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="7">27/01/2020</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>2019/20</th><th>2020/21</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>6.3</td><td>6.4</td><td>6.6</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>8.1</td><td>8.2</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>14.7</td><td>15.1</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>9.1</td><td>9.3</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>14.5</td><td>14.9</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>21.4</td><td>22.9</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>13.9</td><td>13.9</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>29.3</td><td>31.6</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>43.3</td><td>44.3</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>19.2</td><td>19.7</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>29.2</td><td>29.7</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>34.0</td><td>18.9</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>23.6</td><td>23.1</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>12.5</td><td>11.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td></td><td>11.6</td><td>13.2</td><td>13.6</td><td>13.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Burbo Bank</td><td></td><td></td><td></td><td></td><td rowspan="3">34.3</td><td>13.1</td><td>12.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Dudgeon</td><td></td><td></td><td></td><td></td><td>18.7</td><td>19.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Race Bank</td><td></td><td></td><td></td><td></td><td rowspan="2">66.0</td><td>26.7</td><td>Current revenues plus indexation</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>37.8</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></td><td>63.9</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>317.9</td><td>390.6</td><td>443.8</td><td></td></tr>
</table>

Notes:

Figures for historic years represent National Grid's forecast of OFTO revenues at the time final tariffs were calculated for each charging year rather than our current best view.

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

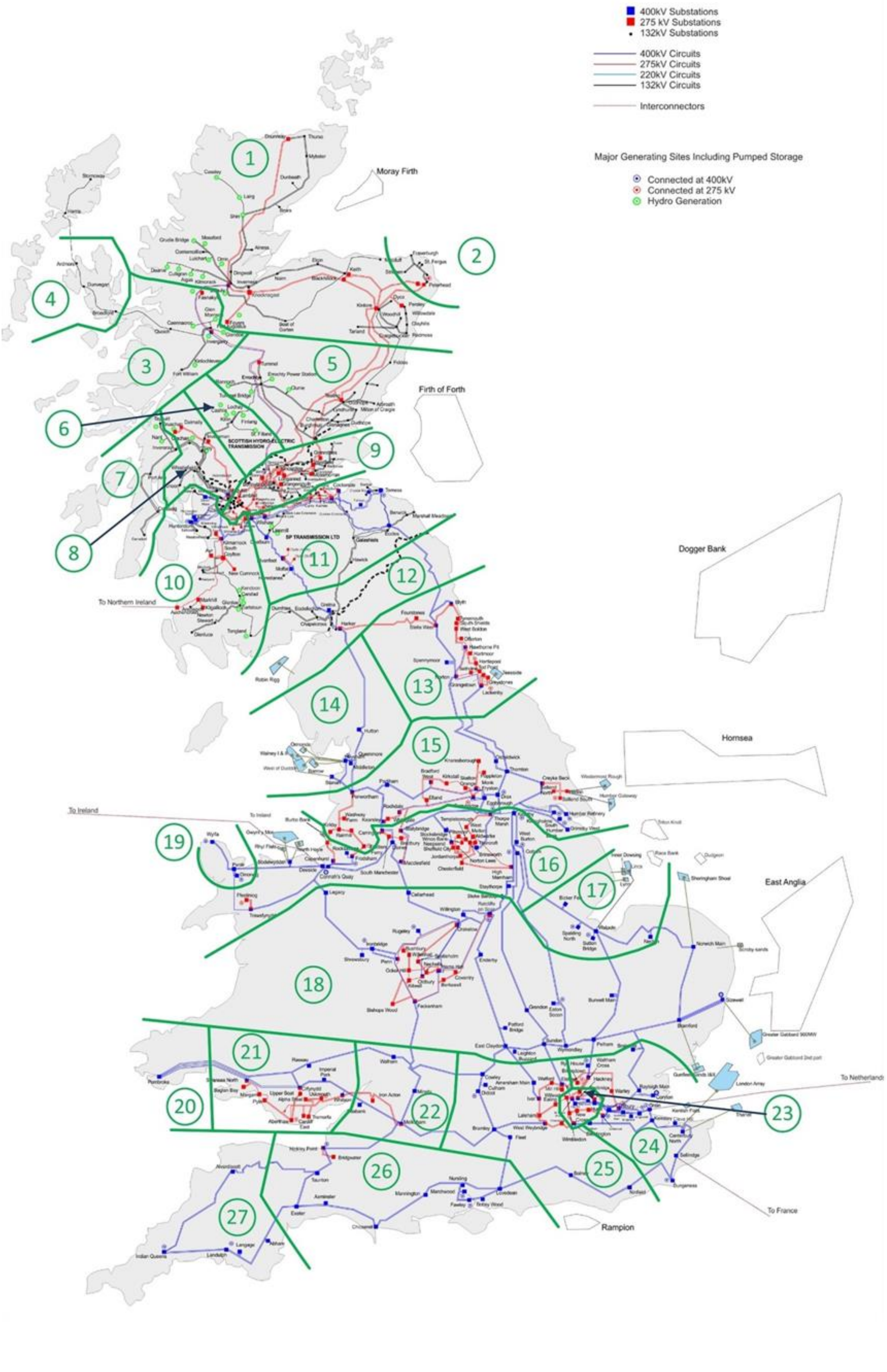
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed

NIC payments are not included as they do not form part of OFTO Maximum Revenue

H

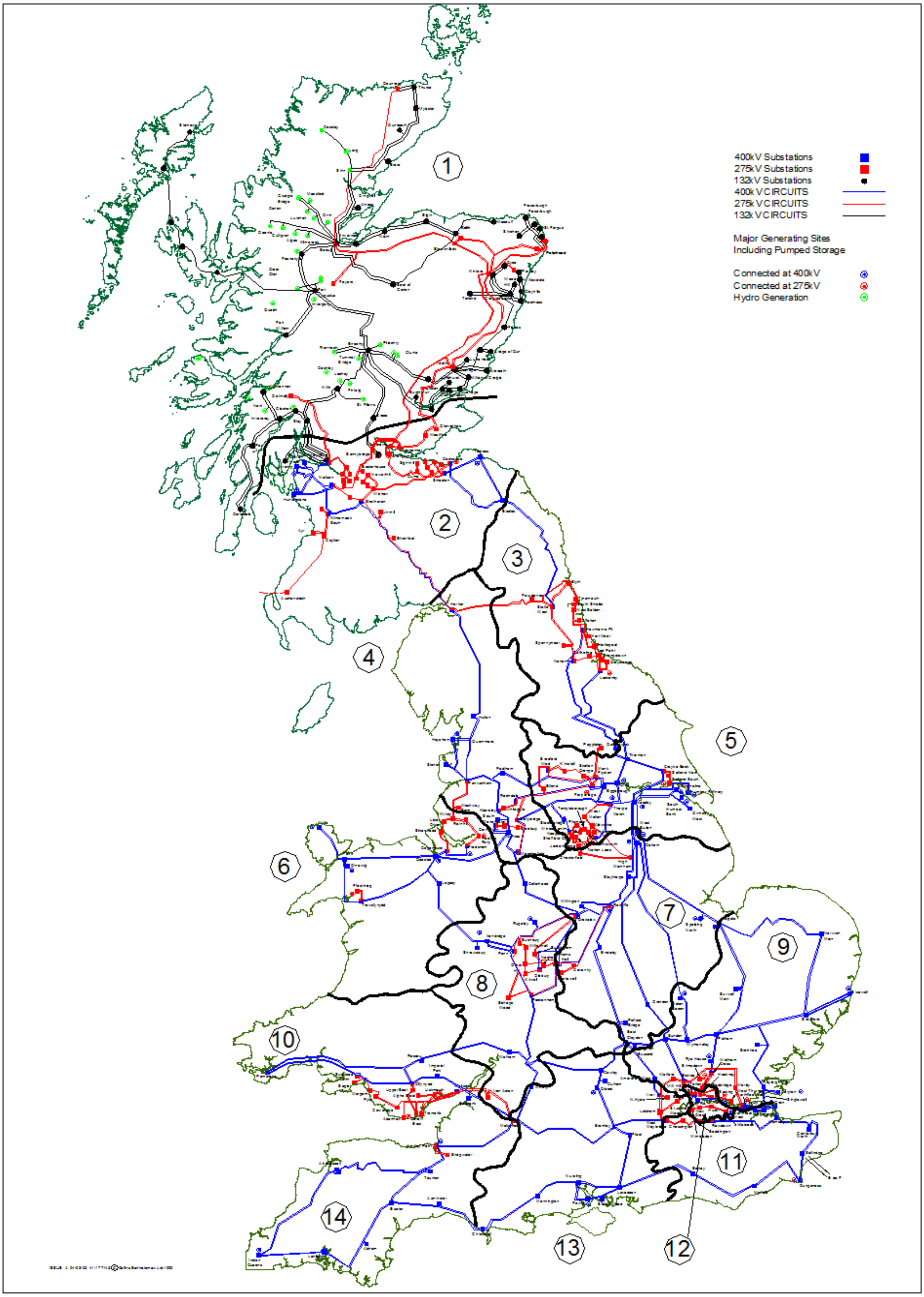
Appendix H: Generation zones map

Figure A2: GB Existing Transmission System



I

Appendix I: Demand zones map


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
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Appendix J: Quarterly Changes to TNUoS parameters

Parameters affecting TNUoS tariffs

The following table summarises the various inputs to the tariff calculations, indicating which updates are provided in each forecast during the year. Purple highlighting indicates that parameter are fixed from that forecast onwards.

2020/21 TNUoS Tariff Forecast		March 2019	July 2019	**Draft Tariffs November 2019**	Final Tariffs January 2020
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Previous year		Week 24 updated	
LOCATIONAL	**Contracted TEC**	Latest TEC Register	Latest TEC Register	TEC Register Frozen at 31 October	
LOCATIONAL	**Network Model**	Previous year (except local circuit changes)		Latest version based on ETYS	
LOCATIONAL	**RPI**	forecast			actual
RESIDUAL	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	NG best view
RESIDUAL	**Allowed Revenue** *(non OFTO changes)*	Update financial parameters	Update financial parameters	Latest TO forecasts	From TOs
RESIDUAL	**Demand Charging Bases**	Previous year	Revised forecast	*Revised forecast due to CMP318*	Revised forecast due to additional information
RESIDUAL	**Generation Charging Base**	NG best view	NG best view	NG best view	NG final best view
RESIDUAL	**Generation ALFs**	Previous year		New ALFs published	
RESIDUAL	**Generation Revenue** (G/D split)	Forecast	Generation revenue £m fixed		

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