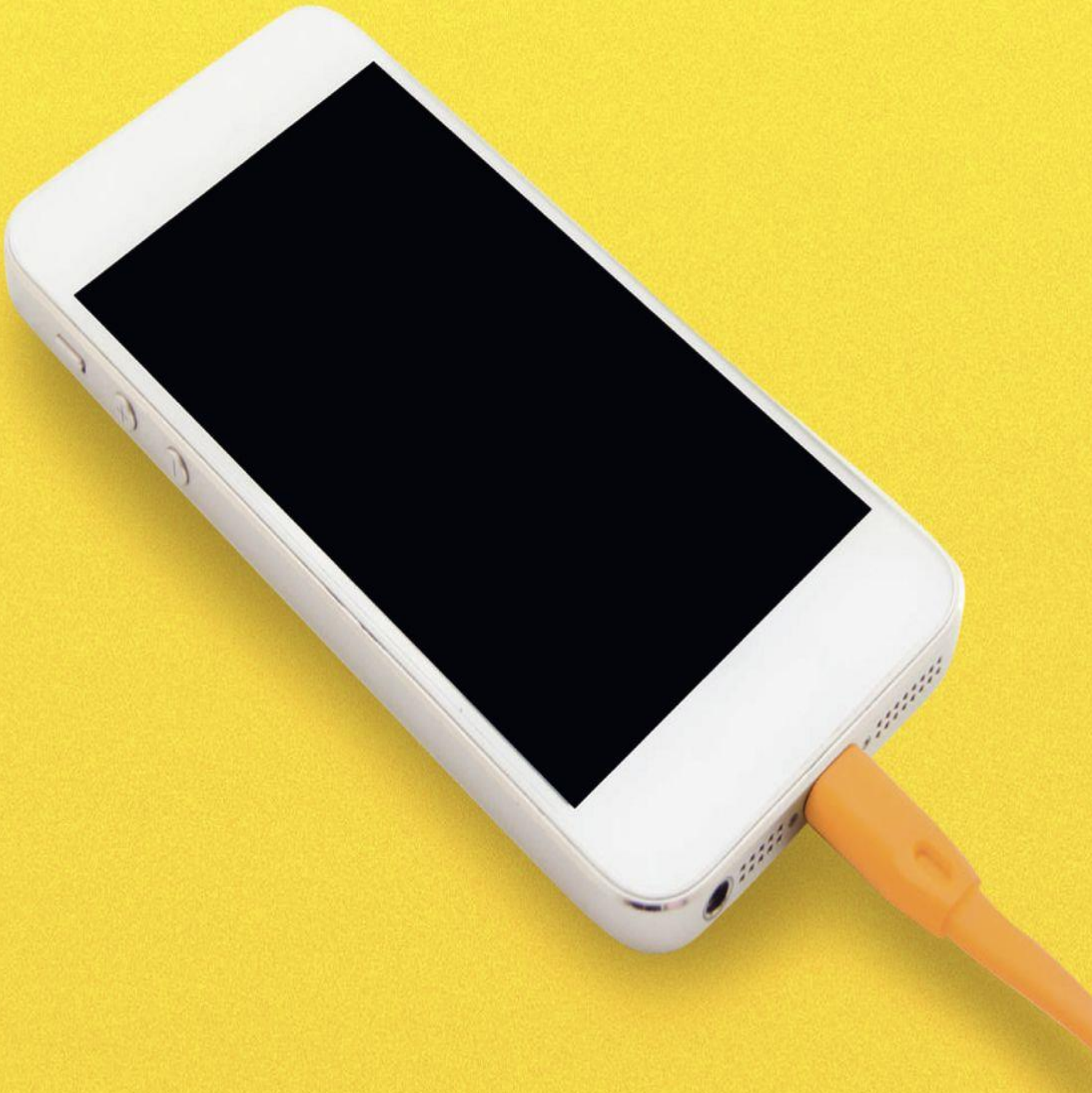
Draft TNUoS Tariffs for 2020/21

National Grid Electricity System Operator

November 2019



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Executive summary

This document contains the Draft forecast of the Transmission Network Use of System (TNUoS) Tariffs for 2020/21, which will be finalised by 31 January 2020. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB transmission networks.

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 report on the draft Transmission Network Use of System (TNUoS) tariffs for year 2020/21.

The tariffs for 2020/21 were last forecast in July 2019. The final tariffs for charging year 2020/21 will be published on 31 January 2020, which will be effective on 1 April 2020.

Total revenues to be recovered

We forecast the total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges to be £2,885.8m in 2020/21. This is £53.5m less than the July forecast as a result of updated revenue forecast from the TOs and revised financial parameters. This forecast is subject to further changes and will be finalised in the final tariffs to be published by the end of January 2020.

Small Generator Discount

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

On 24 January 2019, Ofgem announced the result of a statutory consultation[1] that the Small Generator Discount would be extended until 31 March 2021.

The Small Generator Discount reduces the tariff for transmission connected generation connected at 132kV and with TEC<100MW. Their generation tariffs are reduced by £11.78/kW.

As a result, demand tariffs are increased by £ 0.78/kW for HH, and 0.10p/kWh for NHH.

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 chargeable TEC (Transmission Entry Capacity) for 2020/21 is forecast to be 76.07GW. This is a significant increase since the July forecast, and is driven by changes to the TEC register. The average generation tariff is £4.93/kW. This is a decrease of £0.29/kW since the July forecast, mainly due to the increase in the generation chargeable TEC.

Compared to our July forecast, in general, the north-south difference in generation has increased.

Demand tariffs

The revenue to be recovered from demand tariffs is £2,510.9m in 2020/21. This value has decreased by £53.5m since July tariffs as a result of reduced TOs revenue forecast.

The chargeable demand has been updated since our July forecast to take into account CMP318[2] implementation.

The gross half-hourly (HH) demand forecast has decreased to 18.1GW and the non-half-hourly (NHH) demand forecast has increased to be 25.1TWh. Embedded export volumes have stayed the same and are forecast to be 7.2GW.

£17.2m will be payable through the Embedded Export Tariff (EET). This is a slight decrease since July tariffs due to changes to locational tariffs.

Not including the effect of the Small Generator Discount, the average gross HH demand tariff is £51.41/kW, a decrease of £0.70/kW. The average EET is £2.37/kW. The average NHH demand tariff is 6.43p/kWh, a decrease of 0.10p/kWh. The demand tariffs have slightly decreased since the July tariffs, due to the decrease in revenue to be collected from demand users.

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[1] https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd_decision_letter_final.pdf

[2] https://www.ofgem.gov.uk/publications-and-updates/cmp318-maintaining-non-half-hourly-nhh-charging-arrangements-measurement-classes-f-and-g

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

Key changes since the last forecast

Following revenue forecast submission from TOs, the total revenue forecast has reduced by £53.5m. As a result, demand tariffs decreased mainly due to revenue reduction.

Following DNOs' annual demand forecast update, zonal generator tariffs are showing greater north-south difference.

Average generation tariffs decreased by £0.29/kW to £4.93/kW, mainly due to the increased MW capacity of total generation.

Next tariff publication

The final tariffs for charging year 2020/21 will be published on the 31 January 2020.

For generation tariffs, the locational elements will be further updated in line with inflation.

We will update the non-locational (the residual) elements of generation and demand tariffs in light of the confirmed allowed revenue from the TOs. We may also update the chargeable demand to ensure we set the tariffs to recover total allowed revenue for TOs.

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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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 demand tariffs for Half-Hourly (HH), Embedded Export (EET) and Non-Half-Hourly (NHH) metered demand. A brief description of generation wider tariff structure can be found in appendix A.

The breakdown of the HH locational tariff into the peak and year round components can be found on page 38.

Table 1 Summary of demand tariffs

HH Tariffs	2020/21 July	2020/21 Draft	Change
Average Tariff (£/kW)	51.113949	50.413547	-0.700402
Residual (£/kW)	52.178588	51.881473	-0.297115
EET	**2020/21 July**	**2020/21 Draft**	**Change**
Average Tariff (£/kW)	2.524960	2.372907	-0.152053
Phased residual (£/kW)	0.000000	0.000000	0.000000
AGIC (£/kW)	3.426888	3.416495	-0.010393
Embedded Export Volume (GW)	7.091124	7.230000	0.138876
Total Credit (£m)	17.904800	17.156120	-0.748680
NHH Tariffs	**2020/21 July**	**2020/21 Draft**	**Change**
Average (p/kWh)	6.524630	6.425854	-0.098776

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

Table 2 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	22.039463	2.958074	0.000000
2	Southern Scotland	29.676415	3.806319	0.000000
3	Northern	40.943296	5.149410	0.000000
4	North West	47.599027	6.117466	0.000000
5	Yorkshire	48.759563	6.080959	0.000000
6	N Wales & Mersey	49.830330	6.234944	0.587871
7	East Midlands	52.314445	6.711382	3.071986
8	Midlands	53.575540	6.959651	4.333081
9	Eastern	54.415931	7.389274	5.173472
10	South Wales	51.539954	6.065145	2.297495
11	South East	57.430714	7.895471	8.188255
12	London	60.197138	6.472525	10.954679
13	Southern	58.701866	7.598027	9.459407
14	South Western	57.949506	7.979705	8.707047

Residual charge for demand:	£ 51.881473	
Tariffs include small gen tariff of:	£ 0.777481	0.0998870

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. Ofgem's decision to approve CMP318 has been taken into account in this forecast also. CMP 318 was to extend the treatment of measurement classes F and G to be charged as NHH rather than HH. The chargeable demand base has been updated to reflect this. This has decreased the NHH tariffs as there is a larger charging base.

The average HH gross tariff is now £50.41/kW; compared to the July forecast, this has decreased by £0.70/kW. The average NHH tariff is now 6.43p/kWh, an increase of 0.10p/kWh.

Please note this does not include the effect of the Small Generator Discount, which increases HH and NHH tariffs (see the HH and NHH tariffs sections below for more information).

The average EET is £2.37/kW which has decreased by £0.15/kW due to the impact of the updates to locational inputs, including nodal demand and generation, and the slight decrease of the Avoided Grid Supply Point Infrastructure Credit (AGIC). The decrease in the EET has caused the total revenue to be paid to embedded generators to marginally decrease to £17.16m. Payment to embedded generators will be recovered through the demand tariffs.

3. Half-Hourly demand tariffs

This table and chart show the gross HH demand tariffs for 2020/21 in this Draft tariff forecast compared to the July 2019 forecast.

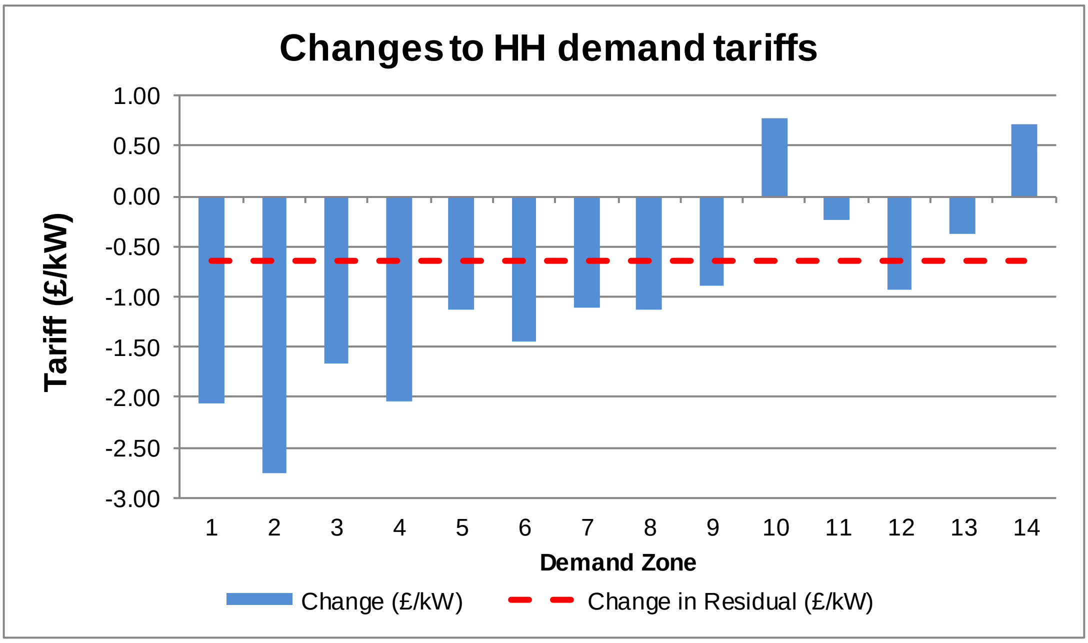
Table 3 Half-Hourly demand tariffs

Zone	Zone Name	2020/21 July (£/kW)	2020/21 Draft (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	24.098098	22.039463	-2.058635	-0.652134
2	Southern Scotland	32.442288	29.676415	-2.765873	-0.652134
3	Northern	42.615678	40.943296	-1.672382	-0.652134
4	North West	49.649333	47.599027	-2.050306	-0.652134
5	Yorkshire	49.885147	48.759563	-1.125584	-0.652134
6	N Wales & Mersey	51.270718	49.830330	-1.440388	-0.652134
7	East Midlands	53.418265	52.314445	-1.103820	-0.652134
8	Midlands	54.712695	53.575540	-1.137155	-0.652134
9	Eastern	55.300674	54.415931	-0.884743	-0.652134
10	South Wales	50.773870	51.539954	0.766084	-0.652134
11	South East	57.672224	57.430714	-0.241510	-0.652134
12	London	61.128120	60.197138	-0.930982	-0.652134
13	Southern	59.071027	58.701866	-0.369161	-0.652134
14	South Western	57.239363	57.949506	0.710143	-0.652134

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

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

Figure 1 Changes to gross Half-Hourly demand tariffs



As you can see form the figure above, for the majority of zones the HH demand tariff has decreased. The decrease is more prominent in the north than the south. This is due to the updated nodal demand data used to draft the tariffs. Overall the HH demand tariffs have decreased due to the decrease in overall revenue to be collected.

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 decreased by 1.1GW since the July forecast and is now 18.1GW due to the impact of CMP318.

The additional levy for the Small Generator Discount scheme increases the tariffs by £0.78/kW.

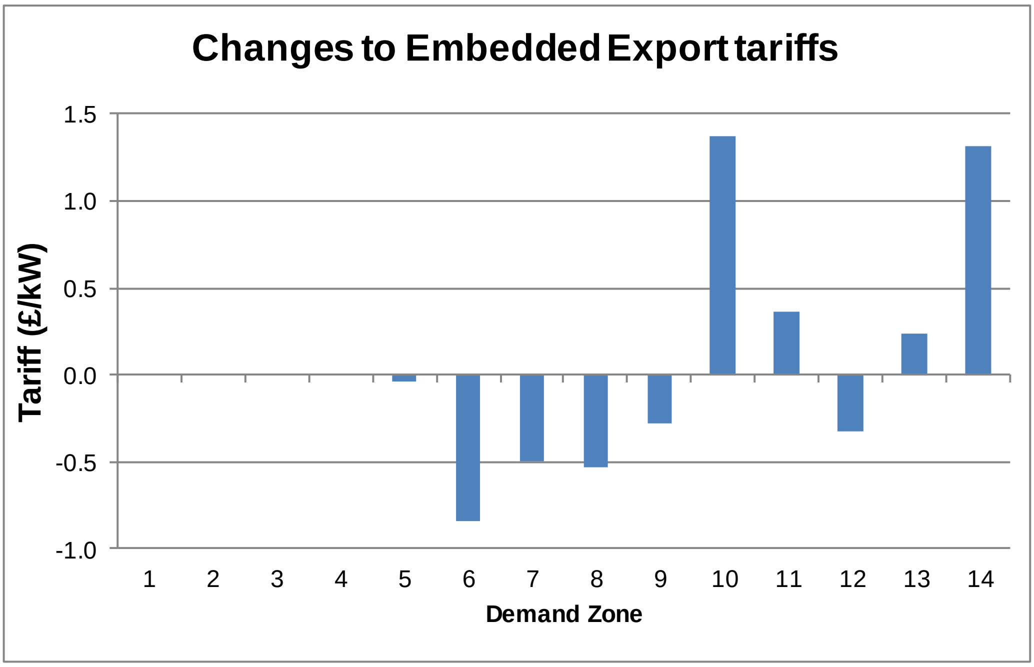
4. Embedded Export Tariffs (EET)

The next table and chart show the 2020/21 EET compared to the July forecast.

Table 4 Embedded Export Tariffs

Zone	Zone Name	2020/21 July (£/kW)	2020/21 Draft (£/kW)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.039960	0.000000	-0.039960
6	N Wales & Mersey	1.425532	0.587871	-0.837661
7	East Midlands	3.573079	3.071986	-0.501093
8	Midlands	4.867508	4.333081	-0.534427
9	Eastern	5.455488	5.173472	-0.282016
10	South Wales	0.928684	2.297495	1.368811
11	South East	7.827037	8.188255	0.361218
12	London	11.282933	10.954679	-0.328254
13	Southern	9.225840	9.459407	0.233567
14	South Western	7.394177	8.707047	1.312870

Figure 2 Embedded export tariff changes



The average EET has decreased by £0.15/kW to £2.37/kW since the July forecast due to the slight decrease in the AGIC and changes to the locational inputs. The EET charging base has not changed from 7.2GW. Due to decrease in the EET tariff, the forecasted EET revenue has decreased to £17.16m from £17.20m. The value of the AGIC (Avoided Grid Supply Point Infrastructure Credit) has marginally decreased since the July forecast.

The amount of metered embedded generation produced at triad 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, the phased reduction to the residual element of the EET will be set at £0/kW from 2020/21. From 2020/21, we expect the EET to be £0/kW in demand zones 1 to 5.

See page 38 for a breakdown of the EET.

5. Non-Half-Hourly demand tariffs

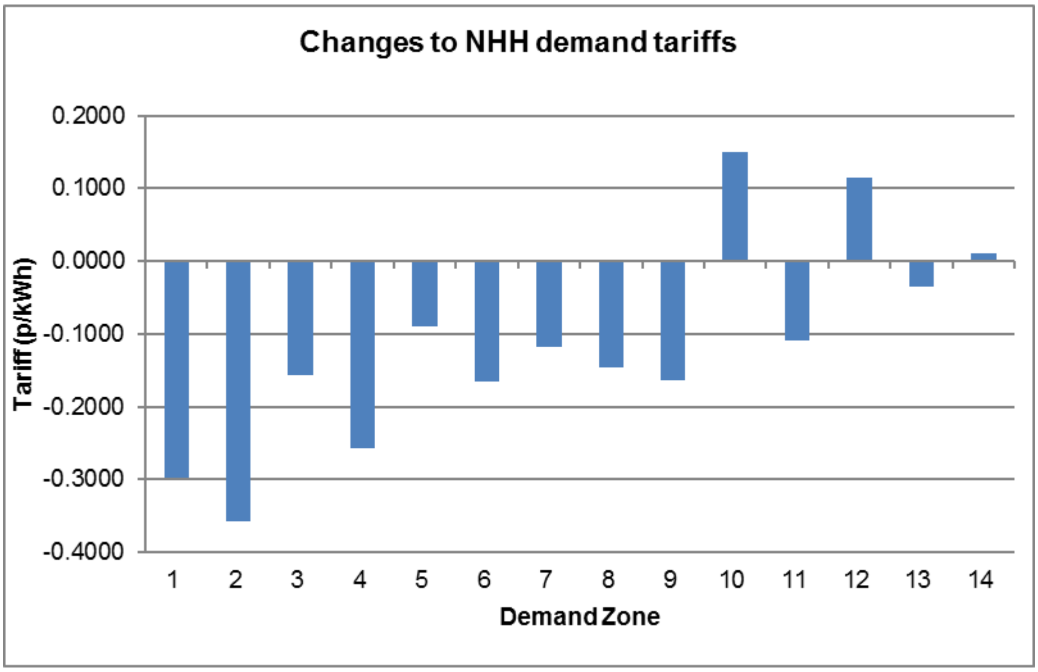
This table and chart show the difference between this forecast and the July 2019 forecast.

Table 5 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2020/21 July (p/kWh)	2020/21 Draft (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.256229	2.958074	-0.298155
2	Southern Scotland	4.163924	3.806319	-0.357605
3	Northern	5.306694	5.149410	-0.157284
4	North West	6.374698	6.117466	-0.257232
5	Yorkshire	6.170694	6.080959	-0.089735
6	N Wales & Mersey	6.400488	6.234944	-0.165544
7	East Midlands	6.828395	6.711382	-0.117013
8	Midlands	7.105347	6.959651	-0.145696
9	Eastern	7.553600	7.389274	-0.164326
10	South Wales	5.915328	6.065145	0.149817
11	South East	8.004151	7.895471	-0.108680
12	London	6.358193	6.472525	0.114332
13	Southern	7.633628	7.598027	-0.035601
14	South Western	7.968421	7.979705	0.011284

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 0.10p/kWh lower than in the July forecast. This is due to the decrease in the overall revenue to be recovered and the increase in the NHH charging base as a result of CMP318 implementation. This along with the changes to locational elements has caused the tariffs to drop in zones 1 to 9 and 11. The increase in zones 10, 12 and 14 is due to the updates to nodal demand data and locational generation inputs.

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 July forecast.

Table 6 Summary of generation tariffs

Generation Tariffs (£/kW)	2020/21 July	2020/21 Draft	Change since last forecast
Residual	-4.533500	-4.776901	-0.243401
Average Generation Tariff	5.221001	4.928537	-0.292464

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

Average generation tariffs have decreased by £0.29/kW. The generation residual has decreased by £0.24/kW. The decrease is mainly due to the increase in the generation charging base whilst the revenue to be collected from generation was fixed in the last forecast.

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 how the wider generation tariffs have changed since the July forecast. A brief description of generation wider tariff structure can be found in Appendix A.

Under the current methodology, each generator has its own load factor as listed in page 42.

The classifications for different technology types are 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

						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	2.757559	20.886179	15.020708	-4.776901	26.706168	29.710309	18.598279
2	East Aberdeenshire	4.935038	13.275963	15.020708	-4.776901	22.795474	25.799615	15.554192
3	Western Highlands	2.155259	19.437083	14.825085	-4.776901	24.788092	27.753109	17.823017
4	Skye and Lochalsh	-4.189858	19.437083	14.741196	-4.776901	18.375864	21.324103	17.739128
5	Eastern Grampian and Tayside	3.078284	17.730691	14.289595	-4.776901	23.917612	26.775531	16.604970
6	Central Grampian	3.776885	16.975371	13.911555	-4.776901	23.709525	26.491836	15.924802
7	Argyll	3.602373	13.849315	24.007837	-4.776901	29.111194	33.912761	24.770662
8	The Trossachs	3.681714	13.849315	12.279891	-4.776901	19.808178	22.264156	13.042716
9	Stirlingshire and Fife	2.449239	11.520782	11.460666	-4.776901	16.057496	18.349630	11.292078
10	South West Scotlands	2.865039	12.084807	11.630840	-4.776901	17.060656	19.386824	11.687862
11	Lothian and Borders	3.993917	12.084807	6.034676	-4.776901	13.712602	14.919538	6.091698
12	Solway and Cheviot	1.799361	7.648421	6.433424	-4.776901	8.287936	9.574621	4.715891
13	North East England	3.911277	5.863045	4.261189	-4.776901	7.233763	8.086001	1.829506
14	North Lancashire and The Lakes	1.912857	5.863045	0.871521	-4.776901	2.523609	2.697913	-1.560162
15	South Lancashire, Yorkshire and Humber	4.634233	1.427700	0.133586	-4.776901	1.106361	1.133078	-4.072235
16	North Midlands and North Wales	3.366464	0.356219	0.000000	-4.776901	-1.125462	-1.125462	-4.634413
17	South Lincolnshire and North Norfolk	1.773741	0.373111	0.000000	-4.776901	-2.704671	-2.704671	-4.627657
18	Mid Wales and The Midlands	1.029303	1.033669	0.000000	-4.776901	-2.920663	-2.920663	-4.363433
19	Anglesey and Snowdon	3.478105	1.652149	0.000000	-4.776901	0.022923	0.022923	-4.116041
20	Pembrokeshire	9.120854	-4.821634	0.000000	-4.776901	0.486646	0.486646	-6.705555
21	South Wales & Gloucester	5.847330	-4.943502	0.000000	-4.776901	-2.884373	-2.884373	-6.754302
22	Cotswold	2.545923	2.903884	-7.889268	-4.776901	-6.219285	-7.797139	-11.504615
23	Central London	-5.774827	2.903884	-7.143155	-4.776901	-13.943145	-15.371776	-10.758502
24	Essex and Kent	-3.808707	2.903884	0.000000	-4.776901	-6.262501	-6.262501	-3.615347
25	Oxfordshire, Surrey and Sussex	-0.933905	-2.367562	0.000000	-4.776901	-7.604856	-7.604856	-5.723926
26	Somerset and Wessex	-1.797376	-3.218074	0.000000	-4.776901	-9.148736	-9.148736	-6.064131
27	West Devon and Cornwall	-0.261669	-5.786841	0.000000	-4.776901	-9.668043	-9.668043	-7.091637

Small Generator Discount (£/kW)	11.776143

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; see page 42 for specific ALFs.

Please note that the Small Generator Discount has been extended until 31 March 2021, see section 22 for more information.

8. Changes since the previous generation tariffs forecast

The following section provides details of the wider and local generation draft tariffs for 2020/21 and how these have changed compared with the July forecast.

Generation wider zonal tariffs

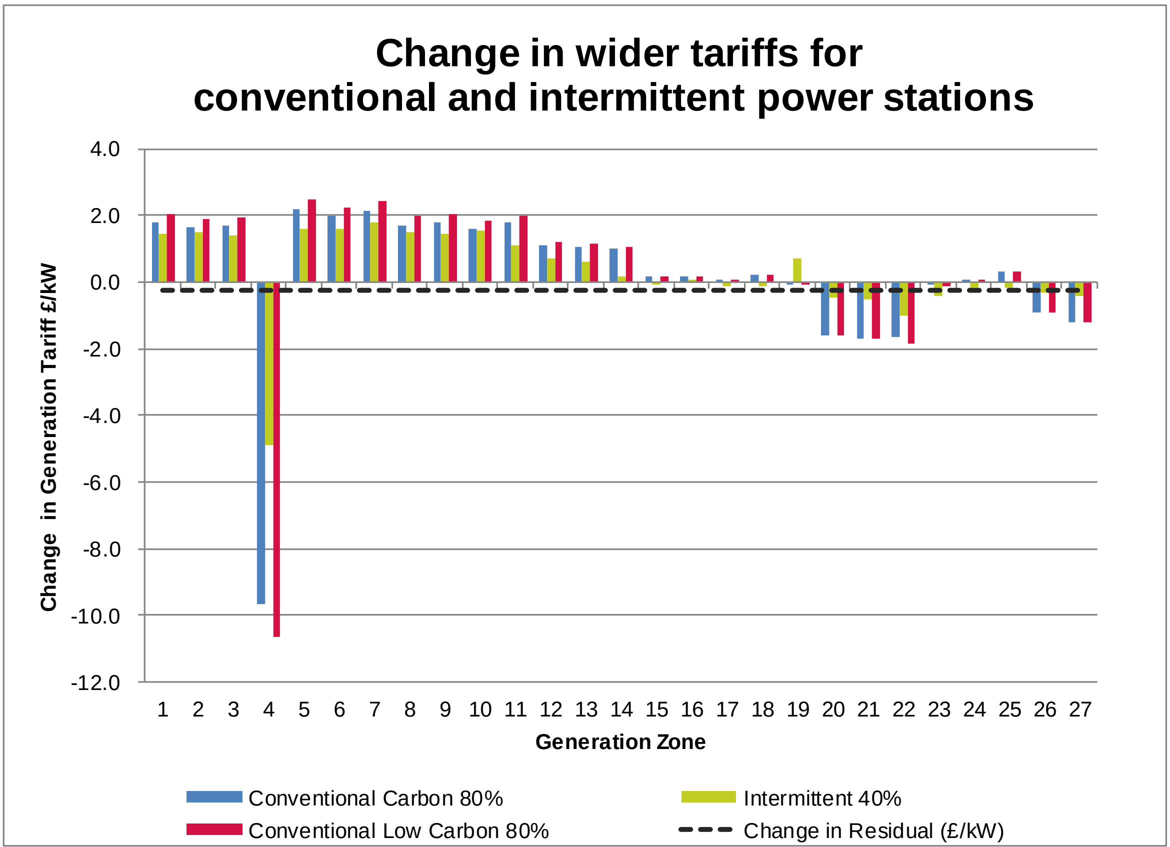
The next table and chart show the changes in wider generation TNUoS tariffs since the July forecast.

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)
Zone	Zone Name	2020/21 July (£/kW)	2020/21 Draft (£/kW)	Change (£/kW)	2020/21 July (£/kW)	2020/21 Draft (£/kW)	Change (£/kW)	2020/21 July (£/kW)	2020/21 Draft (£/kW)	Change (£/kW)	
1	North Scotland	24.928081	26.706168	1.778087	27.666246	29.710309	2.044063	17.156900	18.598279	1.441379	-0.243401
2	East Aberdeenshire	21.157654	22.795474	1.637820	23.895819	25.799615	1.903796	14.074940	15.554192	1.479253	-0.243401
3	Western Highlands	23.099251	24.788092	1.688842	25.802071	27.753109	1.951038	16.421216	17.823017	1.401802	-0.243401
4	Skye and Lochalsh	28.024185	18.375864	-9.648321	31.970473	21.324103	-10.646370	22.638554	17.739128	-4.899425	-0.243401
5	Eastern Grampian and Tayside	21.718486	23.917612	2.199125	24.300522	26.775531	2.475009	15.025999	16.604970	1.578972	-0.243401
6	Central Grampian	21.735210	23.709525	1.974315	24.240104	26.491836	2.251731	14.326695	15.924802	1.598107	-0.243401
7	Argyll	26.980469	29.111194	2.130724	31.454984	33.912761	2.457777	22.954723	24.770662	1.815939	-0.243401
8	The Trossachs	18.086011	19.808178	1.722167	20.277698	22.264156	1.986458	11.540584	13.042716	1.502132	-0.243401
9	Stirlingshire and Fife	14.282707	16.057496	1.774789	16.317774	18.349630	2.031856	9.850180	11.292078	1.441898	-0.243401
10	South West Scotlands	15.458968	17.060656	1.601688	17.517710	19.386824	1.869114	10.156968	11.687862	1.530894	-0.243401
11	Lothian and Borders	11.918312	13.712602	1.794290	12.937842	14.919538	1.981696	4.960904	6.091698	1.130794	-0.243401
12	Solway and Cheviot	7.189677	8.287936	1.098259	8.345742	9.574621	1.228879	3.980889	4.715891	0.735002	-0.243401
13	North East England	6.194982	7.233763	1.038781	6.943931	8.086001	1.142070	1.219918	1.829506	0.609588	-0.243401
14	North Lancashire and The Lakes	1.488045	2.523609	1.035564	1.641222	2.697913	1.056691	-1.758944	-1.560162	0.198782	-0.243401
15	South Lancashire, Yorkshire and Humber	0.950138	1.106361	0.156223	0.977271	1.133078	0.155807	-4.018838	-4.072235	-0.053397	-0.243401
16	North Midlands and North Wales	-1.280242	-1.125462	0.154780	-1.280242	-1.125462	0.154780	-4.695132	-4.634413	0.060719	-0.243401
17	South Lincolnshire and North Norfolk	-2.788834	-2.704671	0.084163	-2.788834	-2.704671	0.084163	-4.527796	-4.627657	-0.099860	-0.243401
18	Mid Wales and The Midlands	-3.165166	-2.920663	0.244503	-3.165166	-2.920663	0.244503	-4.263390	-4.363433	-0.100044	-0.243401
19	Anglesey and Snowdon	0.065480	0.022923	-0.042557	0.065480	0.022923	-0.042557	-4.841014	-4.116041	0.724972	-0.243401
20	Pembrokeshire	2.060196	0.486646	-1.573550	2.060196	0.486646	-1.573550	-6.227747	-6.705555	-0.477807	-0.243401
21	South Wales & Gloucester	-1.207258	-2.884373	-1.677115	-1.207258	-2.884373	-1.677115	-6.251790	-6.754302	-0.502512	-0.243401
22	Cotswold	-4.563269	-6.219285	-1.656016	-5.970376	-7.797139	-1.826763	-10.492158	-11.504615	-1.012458	-0.243401
23	Central London	-13.884545	-13.943145	-0.058600	-15.258603	-15.371776	-0.113173	-10.326916	-10.758502	-0.431587	-0.243401
24	Essex and Kent	-6.338677	-6.262501	0.076176	-6.338677	-6.262501	0.076176	-3.456624	-3.615347	-0.158724	-0.243401
25	Oxfordshire, Surrey and Sussex	-7.947013	-7.604856	0.342158	-7.947013	-7.604856	0.342158	-5.577931	-5.723926	-0.145995	-0.243401
26	Somerset and Wessex	-8.225457	-9.148736	-0.923279	-8.225457	-9.148736	-0.923279	-5.734227	-6.064131	-0.329903	-0.243401
27	West Devon and Cornwall	-8.488103	-9.668043	-1.179939	-8.488103	-9.668043	-1.179939	-6.694881	-7.091637	-0.396756	-0.243401

Figure 4 Variation in generation zonal tariffs



Generation tariffs have become more polarised, mainly due to the circuit updates and nodal demand updates made in the network model.

A large decrease in the generation tariffs can be seen in zone 4. There are very few generators and very long radial circuits in this area, making this zone sensitive to any locational input changes.

Onshore local tariffs for generation

9. Onshore local substation tariffs

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 reflect forecast average RPI for the period May 2019 to October 2019, and so have slightly changed since the July forecast.

Table 9 Local substation tariffs

2020/21 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.203273	0.116285	0.083786
<1320 MW	Redundancy	0.447793	0.277053	0.201494
>=1320 MW	No redundancy	n/a	0.364605	0.263683
>=1320 MW	Redundancy	n/a	0.598588	0.436920

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 MW flows and inflation.

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

Onshore local circuit tariffs have been updated with the latest RPI forecast, and for most users, the changes are minimal since the July forecast. Updates to the circuit model have led to changes to a few tariffs. Onshore local circuit tariffs are listed in Table 10 here.

Table 10 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.675570	Dunhill	1.450145	Mark Hill	0.886463
Aberdeen Bay	2.639786	Dunlaw Extension	1.526907	Middle Muir	2.006855
Achruach	4.347087	Edinbane	6.930671	Middleton	0.150344
Aigas	0.662166	Ewe Hill	2.464151	Millennium Wind	1.849065
An Suidhe	-0.969882	Fallago	0.438903	Moffat	0.189349
Arecleoch	2.102788	Farr	3.609781	Mossford	2.916851
Baglan Bay	0.770367	Fernoch	4.453448	Nant	-1.243879
Beinneun Wind Farm	1.520651	Ffestiniogg	0.256147	Necton	1.137456
Bhlaraidh Wind Farm	0.653686	Finlarig	0.324184	New Deer	0.762358
Black Hill	1.572318	Foyers	0.296562	Rhigos	0.102893
Black Law	1.769120	Galawhistle	3.542645	Rocksavage	0.017920
BlackCraig Wind Farm	6.373397	Glendoe	1.862309	Saltend	0.017566
BlackLaw Extension	3.751647	Glenglass	4.871410	South Humber Bank	0.418835
Clyde (North)	0.111032	Gordonbush	0.241630	Spalding	0.286943
Clyde (South)	0.128403	Griffin Wind	9.834415	Strathbrora	0.109632
Corriegarth	2.933096	Hadyard Hill	2.802340	Strathy Wind	1.899306
Corriemoillie	1.686171	Harestanes	2.555894	Stronelairg	1.089127
Coryton	0.049999	Hartlepool	0.207993	Wester Dod	0.481789
Cruachan	1.847528	Invergarry	0.370496	Whitelee	0.107450
Crystal Rig	0.137279	Kilgallioch	1.065546	Whitelee Extension	0.298711
Culligran	1.754755	Kilmorack	0.199951		
Deanie	2.882812	Kype Muir	1.501711		
Dersalloch	2.438788	Langage	0.665887		
Dinorwig	2.429140	Lochay	0.370496		
Dorenell	2.124754	Luichart	0.582358		
Dumnaglass	1.147510	Marchwood	0.386386		

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 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 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. There is a slight variation for each tariff since the July forecast, where the tariffs were indexed by the average May to October RPI.

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

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	8.169274	42.741635	1.061333
Burbo Bank	10.580601	20.257999	0.000000
Dudgeon	15.326966	23.898895	0.000000
Greater Gabbard	15.338330	35.245971	0.000000
Gunfleet	17.680076	16.231694	3.033797
Gwynt Y Mor	18.654651	18.377138	0.000000
Humber Gateway	15.005644	33.857735	0.000000
Lincs	15.268405	59.779295	0.000000
London Array	10.412718	35.465138	0.000000
Ormonde	25.255009	47.047715	0.374931
Race Bank	9.624985	26.420532	0.000000
Robin Rigg	-0.467184	30.946915	9.591874
Robin Rigg West	-0.467184	30.946915	9.591874
Sheringham Shoal	24.430847	28.651661	0.622803
Thanet	18.591504	34.642618	0.833970
Walney 1	21.796270	43.407215	0.000000
Walney 2	21.637751	43.789634	0.000000
West of Duddon Sands	8.423723	41.565850	0.000000
Westermost Rough	17.737529	30.004308	0.000000

Updates to revenue and the charging model since the last forecast

Since July forecast, we have updated:

- Allowed revenue forecast
- The local and MITS circuits in the transport model
- The generation background
- The nodal GSP demand in the transport model
- The zonal demand charging base, and
- Inflation forecast

There has been no change to the total revenue from generation charges.

For details about quarterly updates to TNUoS parameters, please see appendix K.

12. Changes affecting the locational element of tariffs

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

- Expected contracted generation and demand as of 31 October 2019;
- Local and MITS circuits; and
- Inflation

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.[3] In appendix G, we listed changes to the TEC register since the July forecast.

In accordance with CUSC 14.15.6, the contracted TEC volumes used in the Draft Tariffs were based on the TEC register 31 October, and will remain 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 will be 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 liable to pay generation TNUoS charges. Chargeable TEC volumes will be refined until the Final tariffs, to ensure we recover TOs' revenue.

Chargeable TEC has increased by 4.2GW to 76.0GW since the July forecast.

Table 13 Contracted TEC

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

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.

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

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

Table 14 Interconnectors

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
Belgium Interconnector (Nemo)	Richborough 400kV	Belgium	24	0	1020	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
IFA2 Interconnector	Chilling 400KV Substation	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

The expansion constant is the annuitised value of the cost required to transport 1 MW over 1 km. The forecast Expansion Constant is £14.942495/MWkm. This reflects the latest view of RPI (the average May to October RPI), and has decreased slightly since the July forecast. Please note the actual October RPI has not been included, and the Expansion Constant will be finalised in the Final Tariffs.

15. Onshore substation

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

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, so have been updated using an updated forecast of the relevant inflation term. The relevant inflation term has been updated in line with the relevant inflation term in the relevant OFTO licence. This is a slight variation for each tariff since those published in the July forecast, where the tariffs were indexed by the average May to October RPI.

17. Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Some other fundings (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 (based on adjustments to account for the Cap and Floor regime and contributions from the IFA Use of Revenues framework).

Compared to the July forecast, tariffs have now been calculated to recover £2,885.8m of revenue, a decrease of £53.5m. This is mainly due to revised forecast from the TOs. For more details on TOs' allowed revenues, please refer to appendix H.

Table 15 Allowed revenues

£m Nominal	2020/21 TNUoS Revenue March Forecast	July Forecast	Nov Draft	Jan Final
National Grid Electricity Transmission				
Price controlled revenue	*1782.4*	*1777.7*	*1,705.3*	
Less income from connections	*31.0*	*31.0*	*31.3*	
NGET Income from TNUoS	**1,751.4**	**1,746.7**	**1,674.0**	
Scottish Power Transmission				
Price controlled revenue	*381.6*	*379.7*	*380.4*	
Less income from connections	*12.9*	*12.9*	*12.4*	
SPT Income from TNUoS	**368.7**	**366.8**	**368.0**	
SHE Transmission				
Price controlled revenue	*361.6*	*360.0*	*369.4*	
Less income from connections	*3.4*	*3.4*	*3.4*	
SHE Income from TNUoS	**358.2**	**356.6**	**365.9**	
National Grid Electricity System Operator				
Other Pass-through from TNUoS	*41.4*	*41.7*	*43.9*	
Offshore (offset by IFA contribution)	*431.0*	*427.4*	*433.9*	
Total to Collect from TNUoS	**2,950.8**	**2,939.3**	**2,885.8**	

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 will not 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 July Future Energy Scenarios publication, using April to July data.

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

		2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	
y	Error Margin	16.0%	16.0%	16%	
ER	Exchange Rate (€/£)	1.12	1.12	1.12	
MAR	Total Revenue (£m)	2950.8	2,939.3	2885.8	
GO	Generation Output (TWh)	221.2	199.8	199.8	
G	% of revenue from generation	14.1%	12.8%	13.0%	
D	% of revenue from demand	85.9%	87.2%	87.0%	
G.R	Revenue recovered from generation (£m)	415.1	374.9	374.9	
D.R	Revenue recovered from demand (£m)	2535.7	2564.3	2510.9	

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 change in contracted TEC, as per the TEC register is shown in appendix G.

Demand

Our forecasts of embedded generation has not been updated since the July tariff forecast, however our demand forecast has been updated due to CMP 318. The forecast considers the outturn metering data for the full year of 2018/19.

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-July 2019)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation.

Following our review of the metered demand and export data, we have seen a relatively high level of embedded export volumes over triads in 2018/19 compared to previous years.

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 gradual increase again in future years.

Table 17 Charging bases

Charging Bases	2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
Generation (GW)	74.11	71.81	76.1	
NHH Demand (4pm-7pm TWh)	24.13	24.31	25.1	
Net Charging				
Total Average Net Triad (GW)	43.16	43.17	43.2	
HH Demand Average Net Triad (GW)	12.07	11.99	10.9	
Gross charging				
Total Average Gross Triad (GW)	50.25	50.40	50.4	
HH Demand Average Gross Triad (GW)	19.16	19.22	18.1	
Embedded Generation Export (GW)	7.09	7.23	7.2	

20. 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 2020/21 ALFs, based upon data from 2014/15 to 2018/19. Generic ALFs can be found in Appendix F of this report, and the full list of power station ALFs are available on the National Grid ESO website.[4]

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)

[4]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)

$\mathbf{Z_G}$, $\mathbf{Z_D}$, $\mathbf{L_C}$, **and EE** are determined by the locational elements of tariffs. The EE is also affected by the value of the AGIC[5] and phased residual.

Table 18 Residual components calculation

	Component	2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
G	Proportion of revenue recovered from generation (%)	14.1%	12.8%	13.0%	
D	Proportion of revenue recovered from demand (%)	85.9%	87.2%	87.0%	
R	Total TNUoS revenue (£m)	2,951	2,939	2,886	
Generation Residual					
R_G	Generator residual tariff (£/kW)	-4.0	-4.53	-4.78	
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	331.7	326.39	356.9	
O	Revenue recovered from offshore local tariffs (£m)	339.1	337.45	343.5	
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.4	18.8	20.0	
S_G	Revenue recovered from onshore local circuit tariffs (£m)	18.1	17.9	17.9	
B_G	Generator charging base (GW)	74.1	71.8	76.1	
Gross Demand Residual					
R_D	Demand residual tariff (£/kW)	52.2	52.5	51.9	
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-68.2	-66.2	-86.8	
EE	Amount to be paid to Embedded Export Tariffs (£m)	17.9	17.2	17.2	
B_D	Demand Gross charging base (GW)	50.2	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 was due to expire on 31 March 2019, but the deadline has been extended to 31 March 2021[6] following an Ofgem statutory consultation[7] on the proposal.

The Small Generator Discount reduces the tariff for transmission connected generation connected at 132kV and with TEC<100MW. Their generation tariffs are reduced by £11.78/kW.

As a result, demand tariffs are increased by £0.78/kW for HH demand, and 0.10p/kWh for NHH demand.

[5] Avoided Grid Supply Point Infrastructure Credit
[6] https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd_decision_letter_final.pdf
[7] https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-our-proposal-modify-standard-licence-condition-c13-adjustment-use-system-charges-small-generators-electricity-transmission-licence

Table 19 Small Generator Discount calculation

Small Generator Discount calculation		
Generator Residual (£/kW)	G	- 4.78
Demand Residual (£/kW)	D	51.88
Small Generator Discount (£/kW)	T = (G + D)/4	11.78
Forecast Small Generator Volume (kW)	V	3,228,640
2019/20 Final SGD cost (£)	V x T	38,020,926
Prior year reconcilation (£)	R	- 1,164,104
Total SGD Cost (£)	C = (V x T) - R	39,185,030
Total System Triad Demand (kW)	TD	50,400,000
Total HH Triad Demand (kW)	HHD	18,118,698
Total NHH Consumption (kWh)	NHHD	25,126,417,525
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.777481
Total Cost to HH Customers (£)	HHC = HHT * HHD	14,086,939
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.099887
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	25,098,092

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 are keen 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 Draft 2020/21 tariffs on Thursday 5 December 2019 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.

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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.

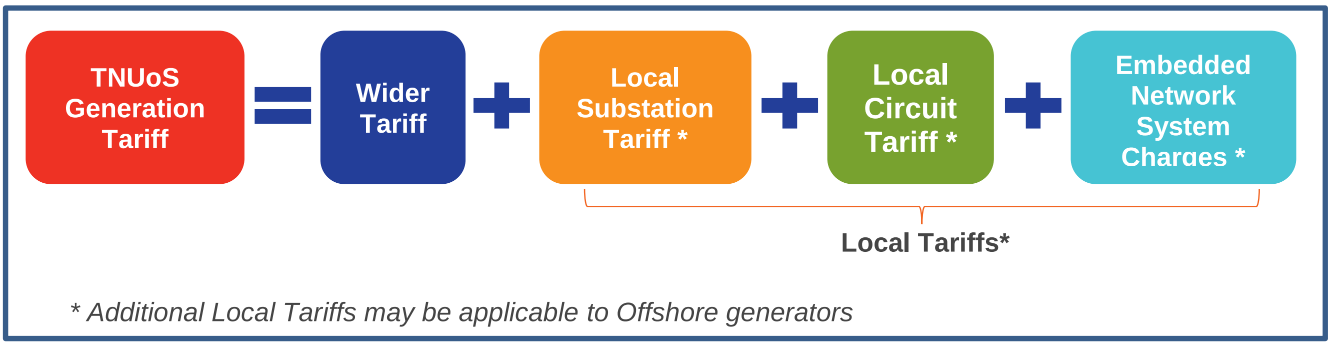
Generation charging principles

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 output onto the transmission network.

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

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



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

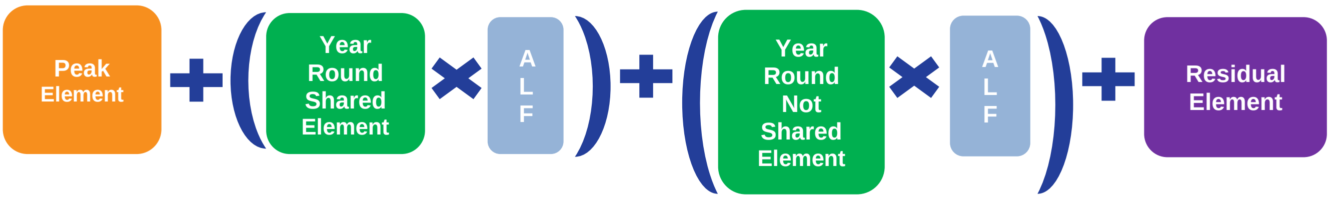
*Embedded network system charges are only payable by generators that are not directly connected to the transmission network and are not applicable to all generators.

The Wider tariff

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

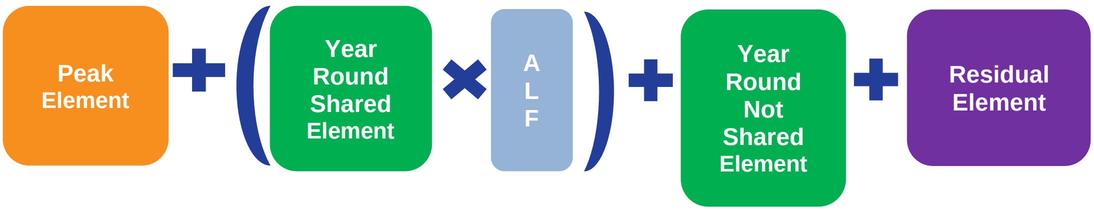
Conventional Carbon Generators

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



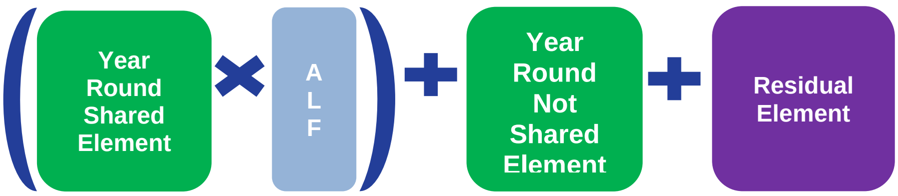
Conventional Low Carbon Generators

(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 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[8] if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS[9] 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.[10]

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 July). This means that if a generator holds 100MW in TEC from 1 April to 31 January, then 350MW from 1 February to 31 July, 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.

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[8] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website:
https://www.nationalgrid.com/uk/electricity/connections/applying-connection
[9] Distribution network Use of System charges
[10] 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.[11] 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 July once final Elexon data is 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[12].

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[13].

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.

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2020/21 onwards. All these modifications are subject to whether they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

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

https://www.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.

Table 20 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP306	Align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital	Potentially reduce the 2021/22 TNUoS revenue by less than £20m due to a one-off adjustment	April 2021 if approved
CMP310	CUSC section 14 changes in the event the UK leaves the EU without an agreement	Modify existing references to EU regulations to reflect the changes as foreseen in the relevant Statutory Instruments.	As soon as practicable following UK's exit from the EU, in the event no agreement is in place
CMP315	Review of the expansion constant	Review how the expansion constant is determined such that it best reflects the costs involved	If approved, implementation from the first complete charging year
CMP316	TNUoS Arrangements for co-located generation sites	Develop a cost-reflective TNUoS arrangement for generation sites with multiple technology types	April 2021, if approved
CMP317	Identification and exclusion of Assets Required for Connection when setting TNUoS charges	Removal of revenue linked to "generator only spurs" from the calculation of generation revenue cap under the EU rules.	TBC, phased implementation if approved
CMP324 & CMP325	Generation Re-zoning	Revise TNUoS generation zoning methodology	April 2021, if approved
Future CMP	Implementation of TCR Decision - TDR	Establish NHH locational methodology, allocate residual between HH/NHH, create charging 'bands'	April 2021, if approved
Future CMP	Implementation of TCR Decision - TGR	Removing TGR subject to compliance with cap/collar	April 2021, if approved

The Targeted Charging Review

On 21 November 2019, the Authority published their final decision[14] 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, therefore they don't affect 2020/21 tariffs.

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

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 alongside CMP317, 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.

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

Ongoing CUSC modification will not be implemented until they are approved. Tariffs beyond 2020/21 will be dependent on the result of CMP317, the TCR implementation, CMP324/325(rezoning) and other in-flight CUSC changes.

For the TCR decision, we have insufficient data at this moment to establish the likely effects of the creation of 'bands' for demand charging, but are working with industry to understand the timescales for obtaining this information, and will incorporate TCR changes into our tariff publications in due course.

D

Appendix D: 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 July forecast to the Draft tariffs.

Table 21 Demand HH locational tariffs

Demand Zone		2020/21 July		2020/21 Draft		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.224713	-26.949461	-2.181691	-28.437800	0.043022	-1.488338
2	Southern Scotland	-2.048723	-18.781262	-2.146788	-20.835750	-0.098065	-2.054489
3	Northern	-3.417947	-7.238647	-3.619288	-8.096370	-0.201341	-0.857722
4	North West	-0.993447	-2.629492	-1.690502	-3.369425	-0.697055	-0.739933
5	Yorkshire	-2.521422	-0.865703	-2.525794	-1.373597	-0.004371	-0.507894
6	N Wales & Mersey	-1.896626	-0.104928	-1.841014	-0.987611	0.055613	-0.882683
7	East Midlands	-2.112883	2.258876	-2.244514	1.900005	-0.131631	-0.358871
8	Midlands	-1.745226	3.185648	-1.927185	2.843771	-0.181959	-0.341877
9	Eastern	1.498903	0.529498	1.390005	0.366972	-0.108898	-0.162526
10	South Wales	-6.773399	4.274997	-6.027019	4.908020	0.746380	0.633022
11	South East	3.985662	0.414289	3.908384	0.863376	-0.077278	0.449087
12	London	5.885575	1.970272	5.778801	1.759382	-0.106774	-0.210890
13	Southern	1.692800	4.105955	1.975370	4.067541	0.282571	-0.038413
14	South Western	-1.243175	5.210266	-0.466281	5.756832	0.776894	0.546567

Table 22 shows the breakdown of the components that make up the EET.

Table 22 Breakdown of the EET

Demand Zone		2020/21 July			2020/21 Draft			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	-29.174175	3.427086	0.00	-30.619491	3.416495	0.00	-1.445316	-0.010591	0.00
2	Southern Scotland	-20.829985	3.427086	0.00	-22.982539	3.416495	0.00	-2.152554	-0.010591	0.00
3	Northern	-10.656594	3.427086	0.00	-11.715658	3.416495	0.00	-1.059064	-0.010591	0.00
4	North West	-3.622940	3.427086	0.00	-5.059927	3.416495	0.00	-1.436988	-0.010591	0.00
5	Yorkshire	-3.387126	3.427086	0.00	-3.899391	3.416495	0.00	-0.512265	-0.010591	0.00
6	N Wales & Mersey	-2.001554	3.427086	0.00	-2.828624	3.416495	0.00	-0.827070	-0.010591	0.00
7	East Midlands	0.145993	3.427086	0.00	-0.344509	3.416495	0.00	-0.490502	-0.010591	0.00
8	Midlands	1.440422	3.427086	0.00	0.916586	3.416495	0.00	-0.523836	-0.010591	0.00
9	Eastern	2.028402	3.427086	0.00	1.756977	3.416495	0.00	-0.271425	-0.010591	0.00
10	South Wales	-2.498402	3.427086	0.00	-1.119000	3.416495	0.00	1.379402	-0.010591	0.00
11	South East	4.399951	3.427086	0.00	4.771760	3.416495	0.00	0.371809	-0.010591	0.00
12	London	7.855847	3.427086	0.00	7.538184	3.416495	0.00	-0.317664	-0.010591	0.00
13	Southern	5.798754	3.427086	0.00	6.042912	3.416495	0.00	0.244157	-0.010591	0.00
14	South Western	3.967091	3.427086	0.00	5.290552	3.416495	0.00	1.323461	-0.010591	0.00

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.

E

Appendix E: Locational demand profiles

Locational demand profiles

The table below shows the latest locational demand and demand charging base forecast used for the Draft tariffs. Locational nodal demand has been updated since July tariffs. The zonal demand charging base forecast has also been updated due to the approval of CMP318 which extends the treatment of measurement classes F and G as NHH from 2020/21 onwards.

The gross half-hourly (HH) demand forecast has decreased to 18.1GW and the non-half-hourly (NHH) demand forecast has increased to be 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 so the negative demand caused by embedded generation is listed separately.

Table 23 Demand profile

Zone	Zone Name	2020/21 July					2020/21 Draft				
		Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)	Locational Model Demand (MW)	GROSS Tariff model Peak Demand	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	362	1,470	441	0.76	1,330	266	1,470	416	0.78	1,330
2	Southern Scotland	2,644	3,360	1,229	1.66	870	2,399	3,360	1,159	1.72	870
3	Northern	2,649	2,510	1,041	1.18	470	2,031	2,510	982	1.22	470
4	North West	3,169	3,950	1,459	1.94	380	2,869	3,950	1,376	2.00	380
5	Yorkshire	4,388	3,770	1,582	1.77	710	3,984	3,770	1,491	1.83	710
6	N Wales & Mersey	2,394	2,570	1,035	1.23	580	2,788	2,570	976	1.27	580
7	East Midlands	5,296	4,590	1,778	2.20	550	5,279	4,590	1,676	2.27	550
8	Midlands	4,410	4,170	1,585	1.99	240	4,433	4,170	1,494	2.06	240
9	Eastern	6,097	6,340	2,089	3.11	610	5,601	6,340	1,969	3.22	610
10	South Wales	1,666	1,780	803	0.84	380	1,604	1,780	757	0.87	380
11	South East	3,813	3,830	1,163	1.92	330	3,194	3,830	1,096	1.99	330
12	London	5,380	4,120	2,232	1.82	120	5,056	4,120	2,105	1.88	120
13	Southern	6,220	5,390	2,043	2.59	390	7,178	5,390	1,926	2.68	390
14	South Western	2,244	2,550	738	1.30	270	2,151	2,550	696	1.35	270
Total		**50,731**	**50,400**	**19,219**	**24.31**	**7,230**	**48,833**	**50,400**	**18,119**	**25.13**	**7,230**

F

Appendix F: 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 24 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.

G

Appendix G: Contracted generation changes since the July forecast

The table below shows the TEC changes notified between the July forecast and Draft tariffs. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

Table 25 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Aikengall II Windfarm	-76	WDOD10	11
Aikengall IIa Wind Farm	81	WDOD10	11
Bad a Cheo Wind Farm	-3	MYBS11	1
BP Grangemouth (correction)	-120	GRMO20	9
Bramford	-50	BRFO40	18
Enfield	27	BRIM2A_LPN	24
Ffestiniog	360	FFES20	16
Halsary Wind Farm	29	SPIT10	1
Keadby II	41	KEAD40	16
Spalding Energy Expansion (correction)	300	SPLN40	17

The contracted generation used in the Transport model is now be fixed and will not be changed for the Final tariffs which will be published on 31 January 2020. The contracted generation has been fixed using the TEC register as of 31 October 2019, as stated by the CUSC 14.15.6. This update has also included two corrections from the last forecast.

H

Appendix H: 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 in October 2019.

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.

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

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 26 NGESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through			
	March Forecast	July Forecast	Nov Draft	Jan Final
Embedded Offshore Pass-Through (OFETt)	0.6	0.6	0.6	
Network Innovation Competition (NICFt)	31.6	31.6	31.6	
Interconnectors Cap&Floor Revenue Adjustment (TICFt)	-10.8	-10.8	-12.3	
ESO Network Innovation Allowance (NIAt)	3.0	3.2	3.0	
Offshore Transmission Revenue (OFTOt)	441.8	438.2	446.2	
Financial facility (FINt)	6.3	6.3	8.8	
Site Specific Charges Discrepancy (DISt)			0	
Termination Sums (TSt)			0	
NGET revenue pas-through (NGETTOt)	1751.4	1746.7	1674.0	
SPT revenue pass-through (TSPt)	368.7	366.8	368.0	
SHETL revenue pass-through (TSHt)	358.2	356.6	365.9	
Total	**2950.8**	**2939.3**	**2885.8**	

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. For Draft tariffs the financial parameters and a few minor items have been updated.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue forecast has been updated for the Draft tariffs, and will be finalised by 25 January 2020. The indicative OFTO revenue to be collected via TNUoS for 2020/21 is £446.2m, an increase of £8m from July. 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 27 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	
Price Control Financial Model Iteration Adjustment	A2	MODt	-338.3	-338.3	-379.2	
RPI True Up	A3	TRUt	1.0	1.0	-1.0	
RPI Forecast	A4	RPIFt	1.3990	1.3940	1.3870	
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1726.8**	**1720.6**	**1652.4**	
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	26.3	26.3	40.3	
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	1.6	
Inter TSO Compensation	B4	ITCt	0.0	0.0	-2.7	
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**26.3**	**26.3**	**39.1**	
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	
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**15.9**	**15.9**	**17.4**	
Network Innovation Allowance	D	NIAt	6.3	7.8	7.4	
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0	0.4	
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	
Correction Factor	-K	-K	13.4	13.4	-2.7	
Financial Facility	FINt		-6.3	-6.3	-8.8	
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**1782.4**	**1777.7**	**1705.3**	
Pre-vesting connection charges	S1		30.3	30.3	30.7	
Rental Site	S2		0.7	0.7	0.6	
TNUoS Collected Revenue [T=M-B5-P]	**T**		**1751.4**	**1746.7**	**1674.0**	

Table 28 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	
Price Control Financial Model Iteration Adjustment	A2	MODt	-7.4	-7.4	-6.3	
RPI True Up	A3	TRUt	0.7	0.7	-0.2	
RPI Forecast	A4	RPIFt	1.4020	1.3940	1.3870	
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**347.0**	**345.0**	**343.6**	
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	4.2	4.2	4.3	
Temporary Physical Disconnection	B2	TPDt	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**	
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	
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**2.6**	**2.6**	**5.2**	
Network Innovation Allowance	D	NIAt	1.1	1.1	1.1	
Future Environmental Discretionary Rewards	F	EDRt	0.5	0.5	0.0	
Transmission Investment for Renewable Generation	G	TIRGt	26.3	26.3	33.0	
Correction Factor	-K	-K	0.0	0.0	-6.8	
Financial Facility	FINt					
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**381.6**	**379.7**	**380.4**	
Pre-vesting connection charges	S1		12.9	12.9	12.4	
Rental Site	S2					
TNUoS Collected Revenue [T=M-B5-P]	**T**		**368.7**	**366.8**	**368.0**	

Table 29 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	
Price Control Financial Model Iteration Adjustment	A2	MODt	79.2	78.5	85.0	
RPI True Up	A3	TRUt	-0.9	-0.9	-0.2	
RPI Forecast	A4	RPIFt	1.3970	1.3940	1.3870	
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**280.5**	**278.9**	**287.6**	
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	26.0	26.0	25.9	
Temporary Physical Disconnection	B2	TPDt	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**	
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	
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**1.9**	**1.9**	**2.8**	
Network Innovation Allowance	D	NIAt	0.9	0.9	0.9	
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0	0.0	
Transmission Investment for Renewable Generation	G	TIRGt	82.3	82.3	82.4	
Correction Factor	-K	-K	-30.0	-30.0	-30.2	
Financial Facility	FINt					
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**361.6**	**360.0**	**369.4**	
Pre-vesting connection charges	S1		3.4	3.4	3.4	
Rental Site	S2					
TNUoS Collected Revenue [T=M-B5-P]	**T**		**358.2**	**356.6**	**365.9**	

Table 30 Offshore revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="7">26/11/2019</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>9.2</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>13.8</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>44.2</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>29.5</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>19.8</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>22.1</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>12.4</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>19.5</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>37.6</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>65.8</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>446.2</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

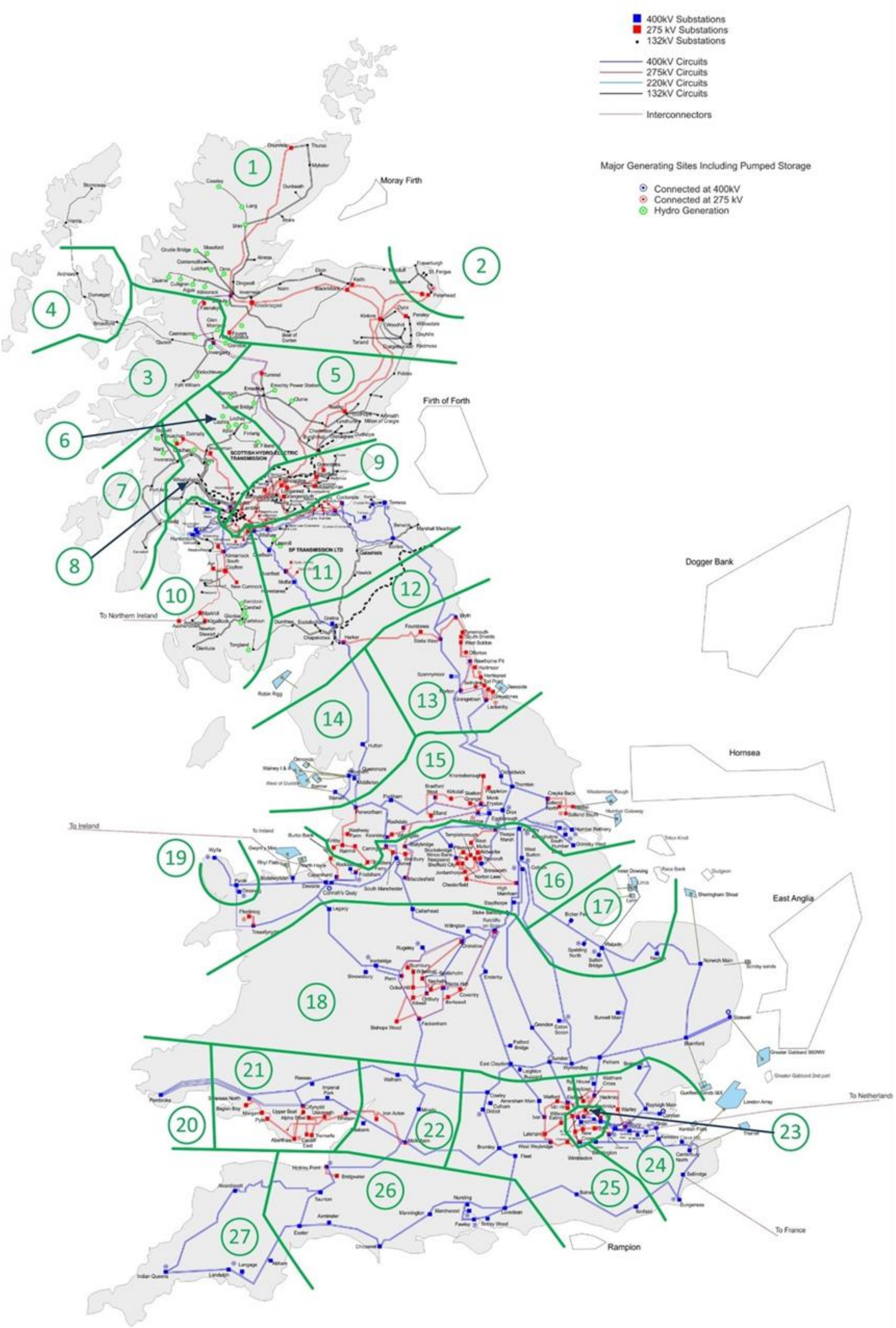
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed

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

I

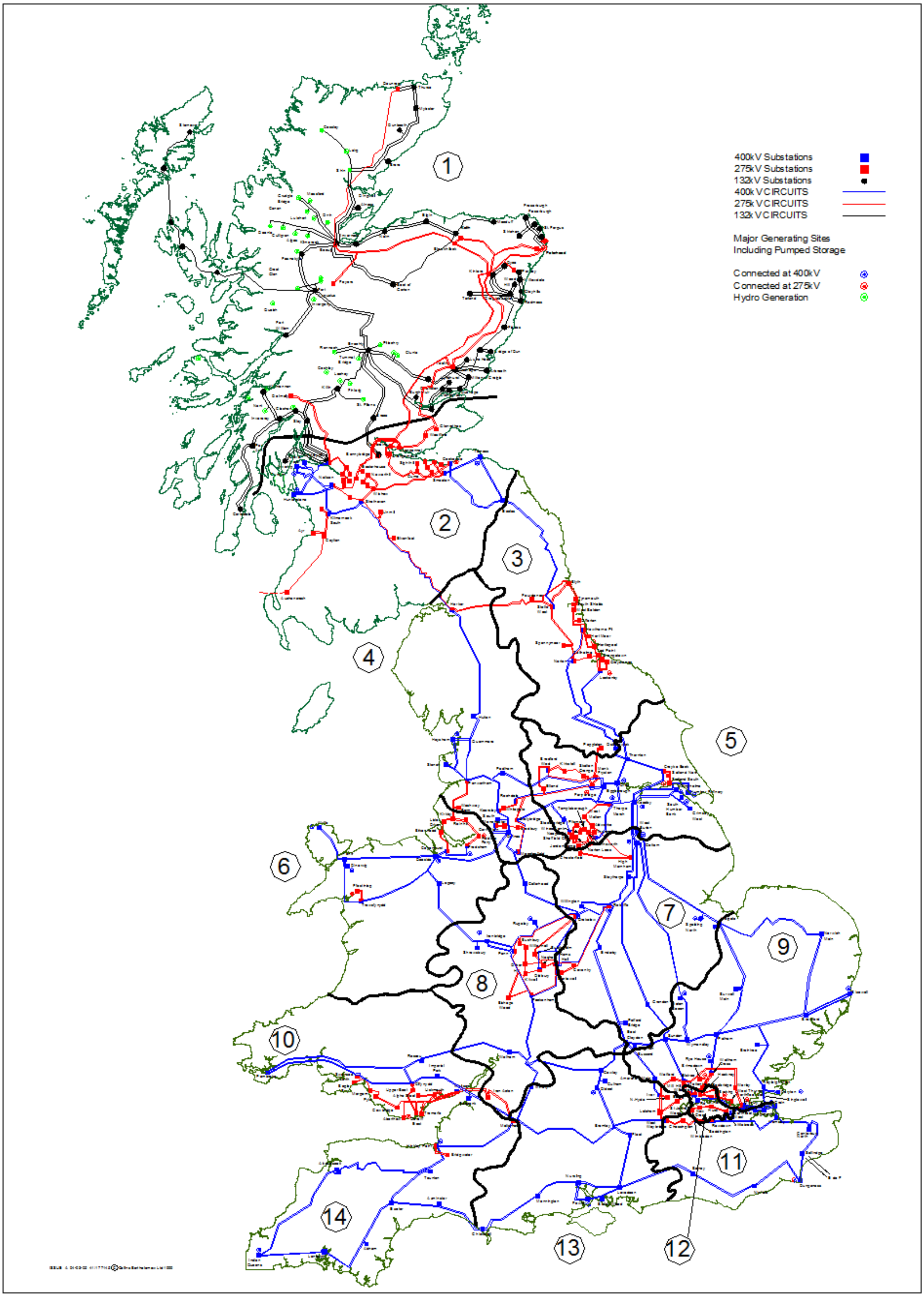
Appendix I: Generation zones map

Figure A2: GB Existing Transmission System



J

Appendix J: 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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K

Appendix K: 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 will be 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	
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen at 31 October	
	Network Model	Previous year (except local circuit changes)		Latest version based on ETYS	
RESIDUAL	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	NG Best View
	Allowed Revenue *(non OFTO changes)*	Update financial parameters	Update financial parameters	Latest TO Forecasts	From TOs
	Demand Charging Bases	Previous Year	Revised Forecast	*By exception*	*By exception*
	Generation Charging Base	NG Best View	NG Best View	NG Best View	NG Final Best View
	Generation ALFs	Previous year		New ALFs published	
	Generation Revenue (G/D split)	Forecast	Generation revenue £m fixed		

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