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Final TNUoS Tariffs for 2019/20

National Grid Electricity System Operator

January 2019

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Contact us

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Executive summary

This document contains the Transmission Network Use of System (TNUoS) Final tariffs for 2019/20, which will become effective on 1 April 2019. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.

The tariffs for 2019/20 were last forecast in November 2018.

Total revenues to be recovered

We forecast the total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges to be £2,837.4m in 2019/20. This is £2.2m less than the Draft forecast. This change is caused by updated revenue forecast from onshore TOs and offshore transmission owners (OFTOs).

Small Generator Discount

The Small Generator Discount is defined in National Grid'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.

Previously our forecast did not include the Small Generator Discount, as the licence condition was due to expire on 31 March 2019.

These final tariffs now include the effect of the Small Generator Discount:

- The discount affects transmission connected generation <100MW, connected at 132kV, and is £11.81/kW;
- Demand tariffs are increased by:
    - £0.62/kW for Gross HH, and
    - 0.081p/kWh for NHH.

Demand tariffs in this report are inclusive of the effect of the Small Generator Discount.

Generation tariffs

The total revenue to be recovered from generation tariffs is £403.5m. This is unchanged since the June forecast. This is to ensure that average annual generation tariffs remain below the €2.50/MWh set by European Commission Regulation (EU) 838/2010 using the methodology defined in the Connection and Use of System Code (CUSC).

The chargeable TEC for 2019/20 is 73.3GW. This is a very small decrease since the Draft forecast, and is due to changes to the TEC register and our best view of generation. The average generation tariff is £5.50/kW. This is an increase of £0.001/kW since the Draft forecast, due to the decrease in the generation charging base.

Demand tariffs

The revenue to be recovered from demand tariffs is £2,434m in 2019/20. This value has decreased by £2.2m since Draft tariffs.

The chargeable demand used in the final tariffs is unchanged since our April forecast. We forecast a gross system peak of 51.3GW. Gross half-hourly (HH) demand is forecast to be 18GW and non-half-hourly (NHH) demand is forecast to be 25.5TWh. Embedded export volumes are forecast to be 7.8GW.

£111m will be payable through the Embedded Export Tariff (EET). This is unchanged since Draft tariffs, as the volume and tariffs are unchanged.

Not including the effect of the extension of the Small Generator Discount, the average gross HH demand tariff is £49.90/kW. The average EET is £14.26/kW. The average

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

NHH demand tariff is 6.45p/kWh. These demand tariffs have decreased marginally since the Draft tariffs due to the decrease in final revenue.

Drivers of changes to the Final tariffs

The only change to tariffs between Draft and Final tariffs is in the generator and demand residuals.

There are three drivers:

1. The generator residual is increased by £0.01/kW by a small decrease in chargeable generator TEC;
2. The demand residual is reduced by the revenue to be collected being finalised; and
3. The inclusion of the Small Generator Discount – which is the status quo from 2018/19, but different to our Draft tariffs for 2019/20.

Changes to the charging methodology affecting 2019/20 tariffs

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 except for the continuation of the Small Generator Discount.

Next tariff publication

Tariffs for 2019/20 are now fixed.

Our next TNUoS tariff publications will be the forecast of 2020/21 tariffs and the five-year view of TNUoS tariffs up to 2024/25 in March 2019.

We published our last five-year view of TNUoS tariffs up to 2023/24 in September 2018.

We published our timetable of forecasts for TNUoS tariffs for 2020/21 earlier in January, this is anailable on our website[2].

Feedback

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.

[2]https://www.nationalgrideso.com/sites/eso/files/documents/Timetable%20of%20TNUoS%20forecasts%20for%20202021.pdf

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.

The breakdown of the HH locational tariff into the peak and year round components can be found on page 36.

A. Summary of demand tariffs

HH Tariffs	2019/20 Draft	2019/20 Final	Change
Average Tariff (£/kW)	49.942761	49.900269	-0.042492
Residual (£/kW)	50.822881	50.780390	-0.042491
EET	**2019/20 Draft**	**2019/20 Final**	**Change**
Average Tariff (£/kW)	14.261808	14.261808	0.000000
Phased residual (£/kW)	14.650000	14.650000	0.000000
AGIC (£/kW)	3.327268	3.327268	0.000000
Embedded Export Volume (GW)	7.752808	7.752808	0.000000
Total Credit (£m)	110.569059	110.569059	0.000000
NHH Tariffs	**2019/20 Draft**	**2019/20 Final**	**Change**
Average (p/kWh)	6.456818	6.451269	-0.005549

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

B. Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	20.971270	2.820450	0.000000
2	Southern Scotland	30.755392	4.026035	0.000000
3	Northern	41.026683	5.213833	7.604902
4	North West	47.831581	6.202276	14.409800
5	Yorkshire	48.039318	6.116328	14.617537
6	N Wales & Mersey	49.345368	6.223760	15.923587
7	East Midlands	51.439770	6.738557	18.017989
8	Midlands	52.928066	6.977433	19.506286
9	Eastern	53.788327	7.496688	20.366546
10	South Wales	49.725642	5.873287	16.303862
11	South East	56.110850	7.945653	22.689070
12	London	59.175788	6.291396	25.754007
13	Southern	57.338781	7.586023	23.917000
14	South Western	55.686678	7.767486	22.264898

Residual charge for demand:	£	50.780390	
Tariffs include small gen tariff of:	£	0.618659	0.0807950

Please note these tariffs DO include the effect of the Small Generator Discount, see page 24.

2. Changes since the previous demand tariffs forecast

Since the implementation of CMP264/265 into the TNUoS methodology from the 2018/19 tariffs, the way in which HH demand is charged has changed. HH tariffs are now charged on a gross basis rather than net. A separate EET payment is made to embedded generators which generate over triad periods. Embedded exports, and small embedded generators do not pay generation TNUoS charges.

Demand tariffs have changed primarily due to the decrease in the residual, caused by a reduction in revenue to be recovered from demand. This is caused by an overall decrease in total revenue.

The average HH gross tariff is now £49.90/kW; compared to Draft tariffs this has decreased by £0.04/kW. The average NHH tariff is now 6.45p/kWh, a decrease of 0.006p/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 £14.26/kW which has not changed since Draft tariffs. The total revenue to be paid to embedded generators remains almost the same at £111m. This will be recovered through the demand tariffs.

3. Gross Half-Hourly demand tariffs

This table and chart show the gross HH demand tariffs for 2019/20 compared to the Draft tariffs.

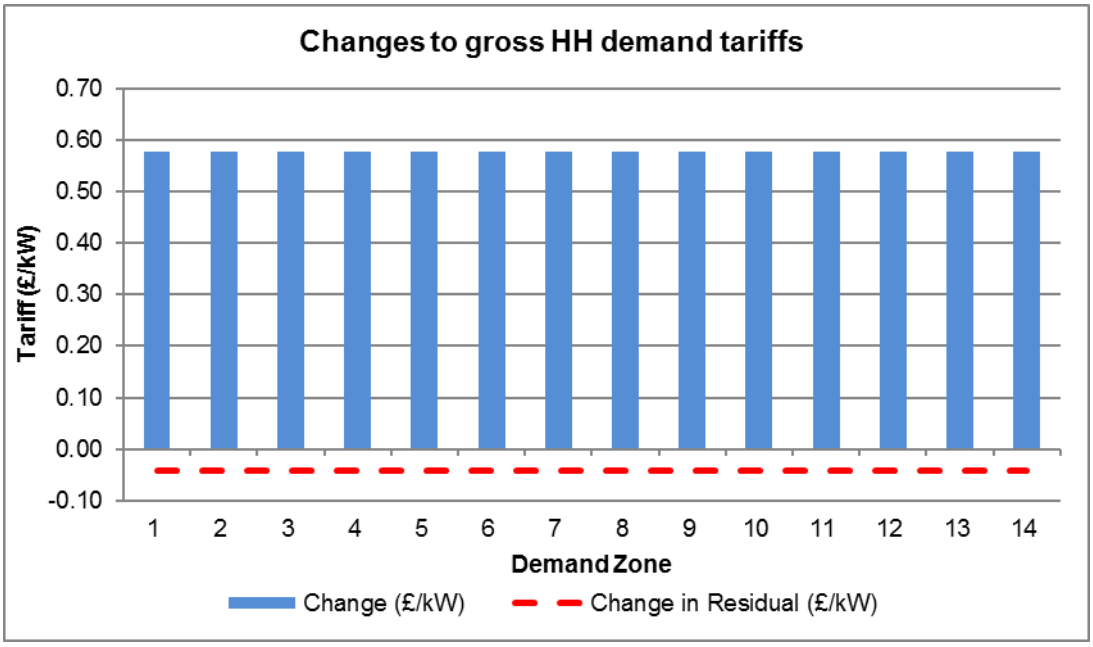
C. Gross Half-Hourly demand tariffs

Zone	Zone Name	2019/20 Draft (£/kW)	2019/20 Final (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	20.395103	20.971270	0.576167	-0.042491
2	Southern Scotland	30.179224	30.755392	0.576168	-0.042491
3	Northern	40.450515	41.026683	0.576168	-0.042491
4	North West	47.255413	47.831581	0.576168	-0.042491
5	Yorkshire	47.463150	48.039318	0.576168	-0.042491
6	N Wales & Mersey	48.769200	49.345368	0.576168	-0.042491
7	East Midlands	50.863602	51.439770	0.576168	-0.042491
8	Midlands	52.351899	52.928066	0.576167	-0.042491
9	Eastern	53.212159	53.788327	0.576168	-0.042491
10	South Wales	49.149475	49.725642	0.576167	-0.042491
11	South East	55.534682	56.110850	0.576168	-0.042491
12	London	58.599620	59.175788	0.576168	-0.042491
13	Southern	56.762613	57.338781	0.576168	-0.042491
14	South Western	55.110511	55.686678	0.576167	-0.042491

The breakdown of the locational elements of these tariffs is shown on page 36.

Please note these tariffs DO include the effect of the Small Generator Discount, see page 24.

D. Changes to gross Half-Hourly demand tariffs



The average HH gross demand tariff of £49.90/kW has decreased by £0.04/kW compared to Draft tariffs, this is due to the decrease in the residual caused by a decrease of the final revenue. Please note that the average HH gross demand tariff **does not** include the additional levy for the Small Generator Discount scheme. The level of gross HH chargeable demand has not changed since the June forecast and remains at 18GW.

The zonal HH demand tariffs has increased uniformly by £0.57/kW since Draft tariffs due to the inclusion of the additional levy for the small generator discount scheme, which increase tariffs by £0.61/kW, and the decrease of the residual by £0.04/kW.

4. Embedded Export Tariffs

This table and chart show the 2019/20 EET compared to the Draft tariffs.

E. Embedded Export Tariffs

Zone	Zone Name	2019/20 Draft (£/kW)	2019/20 Final (£/kW)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	7.604902	7.604902	0.000000
4	North West	14.409800	14.409800	0.000000
5	Yorkshire	14.617537	14.617537	0.000000
6	N Wales & Mersey	15.923587	15.923587	0.000000
7	East Midlands	18.017989	18.017989	0.000000
8	Midlands	19.506286	19.506286	0.000000
9	Eastern	20.366546	20.366546	0.000000
10	South Wales	16.303862	16.303862	0.000000
11	South East	22.689070	22.689070	0.000000
12	London	25.754007	25.754007	0.000000
13	Southern	23.917000	23.917000	0.000000
14	South Western	22.264898	22.264898	0.000000

The breakdown of the locational elements of these tariffs is shown on page 36.

There has been no change to the EET since the Draft tariffs.

The average EET has stayed the same at £14.26/kW since Draft tariffs. The EET charging base remains the same at 7.75GW and the forecasted EET revenue is still £111m. The value of the AGIC (Avoided GSP Infrastructure Credit) is the same as the June 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 value of the EET will steadily reduce until 2020/21. This is primarily a result of the phased reduction to the residual element of the EET, which is described in more detail in the September 2018 five-year view.[3] The value of the phased residual element of the tariffs in 2019/20 is £14.65/kW, which has reduced from £29.36/kW in 2018/19. From 2020/21 it will be £0/kW. The result of this is that from 2020/21 we expect the EET to be £0/kW in more demand zones.

See page 36 for a breakdown of the EET.

5. Non-Half-Hourly demand tariffs

This table and chart show the difference between the Final NHH demand tariffs and the 2019/20 Draft tariffs.

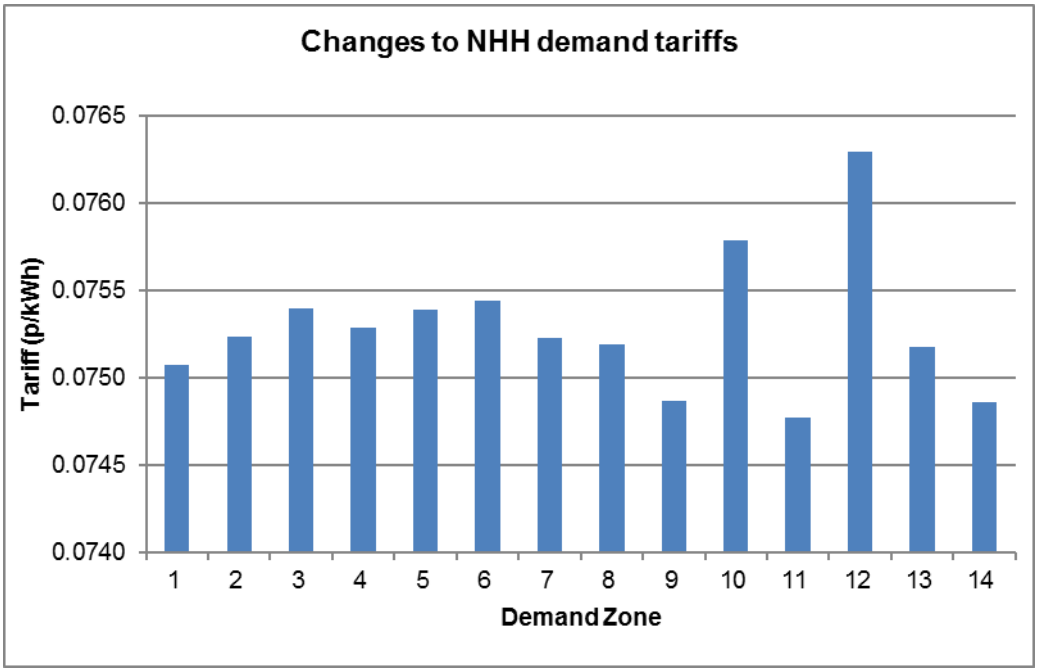
F. Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2019/20 Draft (p/kWh)	2019/20 Final (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.745374	2.820450	0.075076
2	Southern Scotland	3.950803	4.026035	0.075232
3	Northern	5.138436	5.213833	0.075397
4	North West	6.126991	6.202276	0.075285
5	Yorkshire	6.040941	6.116328	0.075387
6	N Wales & Mersey	6.148322	6.223760	0.075438
7	East Midlands	6.663329	6.738557	0.075228
8	Midlands	6.902240	6.977433	0.075193
9	Eastern	7.421820	7.496688	0.074868
10	South Wales	5.797504	5.873287	0.075783
11	South East	7.870880	7.945653	0.074773
12	London	6.215107	6.291396	0.076289
13	Southern	7.510850	7.586023	0.075173
14	South Western	7.692623	7.767486	0.074863

Please note these tariffs DO include the effect of the Small Generator Discount, see page 24.

[3] https://www.nationalgrid.com/sites/default/files/documents/Forecast%20from%202018-19%20to%202022-23%20%282%29.pdf pp.14-15.

G. Changes to Non-Half-Hourly demand tariffs



The weighted average NHH tariff is 0.006p/kWh lower than in the Draft tariffs. This is due to the overall decrease in revenue to be recovered from demand. The tariffs have increased in all zones due to the inclusion of the addition levy for Small Generation Discount scheme.

Generation tariffs

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

6. Generation tariffs summary

This section summarises the Final generation tariffs for 2019/20, how these tariffs were calculated and how they have changed since the Draft forecast.

H. Summary of generation tariffs

Generation Tariffs (£/kW)	2019/20 Draft	2019/20 Final	Change since last forecast
Residual	-3.537457	-3.527532	0.009925
Average Generation Tariff	5.503085	5.504586	0.001501

The average generation tariff is calculated by dividing the total revenue payable by generation by the generation charging base in GW. These generation average tariffs include revenues from local tariffs.

Average generation tariffs have increased by £0.002/kW. The generation residual has increased by £0.0099/kW as there has been a small decrease in the charging base (less than 50MW).

Please note these average generation tariffs DO NOT include the effect of the Small Generator Discount.

7. Generation wider tariffs

The following section summarises of how the wider generation tariffs have changed between the Draft forecast and these Final tariffs. The comparison uses example tariffs for Conventional Carbon generators with an Annual Load Factor (ALF) of 80%, Conventional Low Carbon generators with an ALF of 80%, and Intermittent generators with an ALF of 40%.

Under the current methodology, each generator has its own load factor as listed in page 40. These have been updated for the calculation of 2019/20 tariffs.

The classifications for different technology types are below:

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

I. 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	2.280543	17.691649	15.483854	-3.527532	25.293413	28.390184	19.032982
2	East Aberdeenshire	4.393220	9.220124	15.483854	-3.527532	20.628870	23.725641	15.644372
3	Western Highlands	1.436393	18.259144	15.522353	-3.527532	24.934059	28.038529	19.298479
4	Skye and Lochalsh	-2.864332	18.259144	17.231378	-3.527532	22.000554	25.446829	21.007504
5	Eastern Grampian and Tayside	2.043322	15.184507	14.767083	-3.527532	22.477062	25.430479	17.313354
6	Central Grampian	2.967375	14.208477	14.345112	-3.527532	22.282714	25.151737	16.500971
7	Argyll	2.973002	11.114505	24.583506	-3.527532	28.003879	32.920580	25.501776
8	The Trossachs	2.985196	11.114505	12.941107	-3.527532	18.702154	21.290375	13.859377
9	Stirlingshire and Fife	1.812251	8.514562	12.163013	-3.527532	14.826779	17.259382	12.041306
10	South West Scotlands	3.140376	9.845323	12.498708	-3.527532	17.488069	19.987810	12.909305
11	Lothian and Borders	3.851953	9.845323	6.686795	-3.527532	13.550115	14.887474	7.097392
12	Solway and Cheviot	2.070632	5.497614	7.254010	-3.527532	8.744399	10.195201	5.925524
13	North East England	4.306590	2.912948	3.907136	-3.527532	6.235125	7.016552	1.544783
14	North Lancashire and The Lakes	1.826522	2.912948	2.524088	-3.527532	2.648619	3.153436	0.161735
15	South Lancashire, Yorkshire and Humber	4.792817	0.495644	0.145609	-3.527532	1.778287	1.807409	-3.183665
16	North Midlands and North Wales	4.254582	-1.092088		-3.527532	-0.146620	-0.146620	-3.964367
17	South Lincolnshire and North Norfolk	2.412017	-0.604939		-3.527532	-1.599466	-1.599466	-3.769508
18	Mid Wales and The Midlands	1.511077	-0.155294		-3.527532	-2.140690	-2.140690	-3.589650
19	Anglesey and Snowdon	4.773680	-1.031192		-3.527532	0.421194	0.421194	-3.940009
20	Pembrokeshire	9.029701	-4.395975		-3.527532	1.985389	1.985389	-5.285922
21	South Wales & Gloucester	5.948658	-4.288358		-3.527532	-1.009560	-1.009560	-5.242875
22	Cotswold	2.744945	2.559043	-6.759012	-3.527532	-4.142562	-5.494365	-9.262927
23	Central London	-5.853432	2.559043	-6.745145	-3.527532	-12.729846	-14.078875	-9.249060
24	Essex and Kent	-3.866906	2.559043		-3.527532	-5.347204	-5.347204	-2.503915
25	Oxfordshire, Surrey and Sussex	-1.553471	-2.585615		-3.527532	-7.149495	-7.149495	-4.561778
26	Somerset and Wessex	-1.644081	-2.876601		-3.527532	-7.472894	-7.472894	-4.678172
27	West Devon and Cornwall	-0.094512	-5.153912		-3.527532	-7.745174	-7.745174	-5.589097

Small Generation Discount (£/kW)	11.813214

The 80% and 40% load factors used in this table are for illustration only. Tariffs for individual generators are calculated using their own ALF; see page 40 for specific ALFs.

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

8. Changes since the previous generation tariffs forecast

The following section provides details of the wider and local generation tariffs for 2019/20 and how these have changed compared with the Draft forecast.

Generation wider zonal tariffs

This table and chart show the changes in wider generation TNUoS tariffs between the Draft forecast and Final 2019/20 tariffs.

J. 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	2019/20 Draft (£/kW)	2019/20 Final (£/kW)	Change (£/kW)	2019/20 Draft (£/kW)	2019/20 Final (£/kW)	Change (£/kW)	2019/20 Draft (£/kW)	2019/20 Final (£/kW)	Change (£/kW)	
1	North Scotland	25.283488	25.293413	0.009925	28.380259	28.390184	0.009925	19.023057	19.032982	0.009925	0.009925
2	East Aberdeenshire	20.618945	20.628870	0.009925	23.715716	23.725641	0.009925	15.634447	15.644372	0.009925	0.009925
3	Western Highlands	24.924134	24.934059	0.009925	28.028604	28.038529	0.009925	19.288554	19.298479	0.009925	0.009925
4	Skye and Lochalsh	21.990629	22.000554	0.009925	25.436904	25.446829	0.009925	20.997579	21.007504	0.009925	0.009925
5	Eastern Grampian and Tayside	22.467137	22.477062	0.009925	25.420554	25.430479	0.009925	17.303429	17.313354	0.009925	0.009925
6	Central Grampian	22.272789	22.282714	0.009925	25.141812	25.151737	0.009925	16.491046	16.500971	0.009925	0.009925
7	Argyll	27.993954	28.003879	0.009925	32.910655	32.920580	0.009925	25.491851	25.501776	0.009925	0.009925
8	The Trossachs	18.692229	18.702154	0.009925	21.280450	21.290375	0.009925	13.849452	13.859377	0.009925	0.009925
9	Stirlingshire and Fife	14.816854	14.826779	0.009925	17.249457	17.259382	0.009925	12.031381	12.041306	0.009925	0.009925
10	South West Scotlands	17.478144	17.488069	0.009925	19.977885	19.987810	0.009925	12.899380	12.909305	0.009925	0.009925
11	Lothian and Borders	13.540190	13.550115	0.009925	14.877549	14.887474	0.009925	7.087467	7.097392	0.009925	0.009925
12	Solway and Cheviot	8.734474	8.744399	0.009925	10.185276	10.195201	0.009925	5.915599	5.925524	0.009925	0.009925
13	North East England	6.225200	6.235125	0.009925	7.006627	7.016552	0.009925	1.534858	1.544783	0.009925	0.009925
14	North Lancashire and The Lakes	2.638694	2.648619	0.009925	3.143511	3.153436	0.009925	0.151810	0.161735	0.009925	0.009925
15	South Lancashire, Yorkshire and Humber	1.768362	1.778287	0.009925	1.797484	1.807409	0.009925	-3.193590	-3.183665	0.009925	0.009925
16	North Midlands and North Wales	-0.156545	-0.146620	0.009925	-0.156545	-0.146620	0.009925	-3.974292	-3.964367	0.009925	0.009925
17	South Lincolnshire and North Norfolk	-1.609391	-1.599466	0.009925	-1.609391	-1.599466	0.009925	-3.779433	-3.769508	0.009925	0.009925
18	Mid Wales and The Midlands	-2.150615	-2.140690	0.009925	-2.150615	-2.140690	0.009925	-3.599575	-3.589650	0.009925	0.009925
19	Anglesey and Snowdon	0.411269	0.421194	0.009925	0.411269	0.421194	0.009925	-3.949934	-3.940009	0.009925	0.009925
20	Pembrokeshire	1.975464	1.985389	0.009925	1.975464	1.985389	0.009925	-5.295847	-5.285922	0.009925	0.009925
21	South Wales & Gloucester	-1.019485	-1.009560	0.009925	-1.019485	-1.009560	0.009925	-5.252800	-5.242875	0.009925	0.009925
22	Cotswold	-4.152487	-4.142562	0.009925	-5.504290	-5.494365	0.009925	-9.272852	-9.262927	0.009925	0.009925
23	Central London	-12.739771	-12.729846	0.009925	-14.088800	-14.078875	0.009925	-9.258985	-9.249060	0.009925	0.009925
24	Essex and Kent	-5.357129	-5.347204	0.009925	-5.357129	-5.347204	0.009925	-2.513840	-2.503915	0.009925	0.009925
25	Oxfordshire, Surrey and Sussex	-7.159420	-7.149495	0.009925	-7.159420	-7.149495	0.009925	-4.571703	-4.561778	0.009925	0.009925
26	Somerset and Wessex	-7.482819	-7.472894	0.009925	-7.482819	-7.472894	0.009925	-4.688097	-4.678172	0.009925	0.009925
27	West Devon and Cornwall	-7.755099	-7.745174	0.009925	-7.755099	-7.745174	0.009925	-5.599022	-5.589097	0.009925	0.009925

All generation tariffs have increased by £0.009925/kW, caused by the increase to the residual. The locational parts of wider generation tariffs have not changed as they were fixed in the Draft forecast.

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 increased each year by the average May to October RPI. These tariffs reflect actual RPI for the period May 2018 to October 2018, and so have not changed since the Draft forecast.

K. Local substation tariffs

2019/20 Local Substation Tariffs (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.197964	0.113248	0.081598
<1320 MW	Redundancy	0.436098	0.269817	0.196232
>=1320 MW	No redundancy	0	0.355083	0.256797
>=1320 MW	Redundancy	0	0.582955	0.425509

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 flows and RPI. If you require further information about a particular local circuit tariff, please feel free to contact us using the contact details on page 3.

Some generator users have their local circuits tariffs revised through an additional one-off charge. These are listed in the CMP203: Circuits subject to one-off charges table below (table M).

L. Onshore local circuit tariffs

The onshore local circuit tariffs have not changed from those published in the Draft forecast. The exception is a correction to the parameters used to calculate Hadyard Hill.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	4.233666	Dunhill	1.412272	Lochay	0.360820
Aberdeen Bay	2.570844	Dunlaw Extension	1.481497	Luichart	0.565969
Aigas	0.644872	Edinbane	6.749147	Marchwood	0.376298
An Suidhe	3.002388	Ewe Hill	2.399796	Mark Hill	0.863311
Arecleoch	2.047871	Fallago	0.018259	Middle Muir	1.954443
Baglan Bay	0.750267	Farr	3.515507	Middleton	0.110030
Beinneun Wind Farm	1.480658	Fernoch	4.337076	Millennium South	0.928980
Bhlaraidh Wind Farm	0.648821	Ffestiniogg	0.249457	Millennium Wind	1.800496
Black Hill	1.531255	Finlarig	0.315718	Moffat	0.177954
Black Law	1.722917	Foyers	0.742448	Mossford	2.839493
BlackCraig Wind Farm	6.206946	Galawhistle	1.458315	Nant	-1.211205
BlackLaw Extension	3.653668	Gills Bay	2.483116	Necton	1.108759
Clyde (North)	0.108132	Glendoe	1.813672	Rhigos	0.100477
Clyde (South)	0.125049	Glenglass	4.744186	Rocksavage	0.017459
Corriegarth	3.108511	Gordonbush	1.169225	Saltend	0.336368
Corriemoillie	1.640955	Griffin Wind	9.565045	South Humber Bank	0.938014
Coryton	0.052904	Hadyard Hill	2.729153	Spalding	0.276480
Cruachan	1.798572	Harestanes	2.482693	Strathbrora	0.779835
Crystal Rig	-0.048382	Hartlepool	0.596300	Strathy Wind	2.003637
Culligran	1.708927	Hedon	0.178507	Stronelairg	1.413146
Deanie	2.807523	Invergarry	-0.675138	Wester Dod	0.287131
Dersalloch	2.375095	Kilgallioch	1.037718	Whitelee	0.104644
Didcot	0.519707	Killingholme	0.704527	Whitelee Extension	0.290910
Dinorwig	2.365700	Kilmorack	0.194729		
Dorenell	2.069263	Kype Muir	1.462492		
Dumnaglass	1.830606	Langage	0.648712		

M. CMP203: Circuits subject to one-off charges

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way 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 onwards.

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

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 by average May to October RPI each year. The tariffs have not changed since the Draft forecast.

Offshore local generation tariffs associated with projects due to transfer in 2019/20 will be confirmed once asset transfer has taken place.

N. Offshore local tariffs 2019/20

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.977330	41.737380	1.036396
Burbo Bank	10.335699	19.789101	0.000000
Dudgeon	14.972203	23.345723	0.000000
Greater Gabbard	14.956555	34.368691	0.000000
Gunfleet	17.264666	15.850315	2.962515
Gwynt Y Mor	18.214690	17.943720	0.000000
Humber Gateway	14.494729	32.704941	0.000000
Lincs	14.908307	58.369428	0.000000
London Array	10.148476	34.565143	0.000000
Ormonde	24.661619	45.942286	0.366121
Robin Rigg East	-0.456207	30.219789	9.366504
Robin Rigg West	-0.456207	30.219789	9.366504
Sheringham Shoal	23.827399	27.943956	0.607419
Thanet	18.145429	33.811421	0.813960
Walney 1	21.284146	42.387322	0.000000
Walney 2	21.129352	42.760756	0.000000
West of Duddon Sands	8.212971	40.525921	0.000000
Westermost Rough	17.293756	29.253635	0.000000

Updates to revenue and the charging model since the last forecast

Since the Draft forecast tariffs were published, we have updated allowed revenue for some Transmission Owners, the local circuits model, the generation background and demand charging bases and RPI.

There have been no changes to the inputs used to calculate the proportion of revenue to be recovered from generation and demand (G/D split).

We have updated the circuits required to simulate system flows in the transport model.

12. Changes affecting the locational element of tariffs

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

- Contracted generation and demand as of 31 October 2018;
- Local and MITS circuits; and
- RPI (which increases the expansion constant).

O. Contracted and modelled TEC

Contracted TEC is the volume of TEC with connection agreements for the 2019/20 period, which can be found on the TEC register.[4] Modelled TEC is the amount of TEC we have entered into the Transport model to calculate system flows, which includes interconnector TEC.

Chargeable TEC is our best view of the likely volume of generation that will be connected to the system during 2019/20 and liable to pay generation TNUoS charges. Chargeable TEC volumes are always based on NGESO's best view of the likely volume of generation TEC connected to the system in the relevant charging year.

Chargeable TEC has reduced by less than 50MW since the Draft forecast.

The contracted TEC volumes used in this Draft 2018 forecast were based on the TEC register from 31 October 2018, in accordance with CUSC section 14.15.6. This has not changed since the Draft forecast.

Generation (GW)	2018/19	2019/20 Initial Forecast	2019/20 April Forecast	2019/20 June Forecast	2019/20 Draft Tariffs	2019/20 Final Tariffs
Contracted TEC	79.0	85.5	85.9	83.9	80.6	80.6
Modelled Best View TEC	79.0	77.7	77.5	77.7	80.6	80.6
Chargeable TEC	71.9	73.8	71.7	71.9	73.3	73.3

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.

[4] See the Registers, Reports and Updates section at https://www.nationalgrid.com/uk/electricity/connections/after-you-have-connected

P. Interconnectors

The table below reflects the contracted position of interconnectors for 2019/20 in the interconnector register as of 31 October 2018.

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
IFA2	Chilling 400kV	France	26	0	1100	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	1000	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	307	0

14. RPI

The RPI index for the components detailed below is calculated based on the average May to October RPI for 2018. Because of this, they have not changed since the Draft forecast.

15. Expansion Constant

The expansion constant is 14.55225089. This reflects our latest view of RPI and has not changed since the Draft forecast.

16. Onshore substation and offshore substation tariffs

Local onshore substation tariffs are indexed by the average May 2018 to October 2018 RPI. Offshore substation tariffs have not changed since the Draft forecast.

17. Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Compared to the Draft forecast, tariffs have now been calculated to recover £2,837.4m of revenue, a decrease of £2.2m.

Q. Allowed revenues

£m Nominal Value	2019/20 TNUoS Revenue	
	Nov Draft	Jan 2019 Final
National Grid Electricity Transmission		
Price controlled revenue	*1,737.7*	1,728.5
Less income from connections	*31.6*	*30.8*
Income from TNUoS	**1,706.1**	**1,697.6**
Scottish Power Transmission		
Price controlled revenue	*397.5*	*392.2*
Less income from connections	*14.5*	*12.9*
Income from TNUoS	**383.0**	**379.3**
SHE Transmission		
Price controlled revenue	*341.2*	*352.8*
Less income from connections	*3.4*	*3.4*
Income from TNUoS	**337.8**	**349.4**
Offshore	*388.4*	**390.6**
Network Innovation Competition	*32.7*	**31.6**
Interconnectors (Cap & Floor)	*(8.4)*	**(8.4)**
Other pass-through items		**(2.8)**
Total to Collect from TNUoS	**2,839.6**	**2,837.4**

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The G/D split has not changed since the June tariff forecast. The proportion of revenue to be recovered from generation remains 14.2% of total revenue.

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

Exchange Rate

As prescribed by the TNUoS charging methodology, the exchange rate for 2019/20 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2018. The value published is €1.124927/£.

Generation Output

The forecast output of generation is 229.8TWh. This figure has been updated using the average of the four scenarios in the latest Future Energy Scenarios publication, using April to March data.

Error Margin

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

R. Generation and demand revenue proportions

		2019/20 Draft	2019/20 Final	Change
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	0.00
y	Error Margin	21.0%	21.0%	0.0%
ER	Exchange Rate (€/£)	1.12	1.12	0.00
MAR	Total Revenue (£m)	2,839.6	2,837.4	-2.2
GO	Generation Output (TWh)	229.8	229.8	0.0
G	% of revenue from generation	14.2%	14.2%	0.0%
D	% of revenue from demand	85.8%	85.8%	0.0%
G.MAR	Revenue recovered from generation (£m)	403.5	403.5	0.0
D.MAR	Revenue recovered from demand (£m)	2436.0	2433.9	-2.2

19.Charging bases for 2019/20

Generation

The generation charging base we are forecasting is less than contracted TEC. It excludes interconnectors, which are not chargeable, and generation that we do not expect to be contracted during the charging year due to closure, termination or delay. 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 the appendices.

Demand

Our forecasts of demand and embedded generation have not been updated since the April tariff forecast.

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 2018)
- 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 2017/18 compared to previous years. We also recognise there will be an expected demand shift between NHH to HH under BSC modification P339 (see page 34 for more information). These changes in our outturn charging base have been factored into our projections for 2019/20 and future years.

Overall, we assume that recent historical trends in steadily declining volumes will continue due to several factors including the growth in distributed generation and “behind the meter” microgeneration.

S. Charging bases

Charging bases	2019/20 Draft	2019/20 Final	Change
Generation (GW)	73.3	73.3	-0.02
NHH Demand (4pm-7pm TWh)	25.5	25.5	0.00
Net charging			
Total Average Net Triad (GW)	43.6	43.6	0.00
HH Demand Average Net Triad (GW)	10.3	10.3	0.00
Gross charging			
Total Average Gross Triad (GW)	51.3	51.3	0.00
HH Demand Average Gross Triad	18.0	18.0	0.00
Embedded Generation Export (GW)	7.8	7.8	0.00

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 2019/20 ALFs, based upon data from 2013/14 to 2017/18 available from the National Grid ESO website.[5]

21. Generation and demand residuals

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

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

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

Where

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

[5] https://www.nationalgrideso.com/sites/eso/files/documents/Final%20ALFs%20for%202019-20.pdf

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.

T. Residual components calculation

	Component	2019/20 Draft	2019/20 Final	Change
G	Proportion of revenue recovered from generation (%)	14.2%	14.2%	0.0%
D	Proportion of revenue recovered from demand (%)	85.8%	85.8%	0.0%
R	Total TNUoS revenue (£m)	2,839.6	2,837.4	-2.2
Generation residual				
R_G	Generator residual tariff (£/kW)	-3.54	-3.53	0.01
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	333.6	333.2	-0.5
O	Revenue recovered from offshore local tariffs (£m)	289.0	289.0	0.0
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.4	19.4	0.0
S_G	Revenue recovered from onshore local circuit tariffs (£m)	20.9	20.6	-0.3
B_G	Generator charging base (GW)	73.3	73.3	0.0
Gross demand residual				
R_D	Demand residual tariff (£/kW)	50.82	50.78	-0.04
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-61.9	-61.9	0.0
EE	Amount to be paid to Embedded Export Tariffs (£m)	110.6	110.6	0.0
B_D	Demand Gross charging base (GW)	51.3	51.3	0.0

22.Small Generator Discount

The Small Generator Discount is defined in National Grid's Electricity Transmission licence condition C13. This licence condition was due to expire on 31 March 2019, but the deadline has now been extended to 31 March 2021[7] following an Ofgem statutory consultation[8] on the proposal.

A discount will continue to be applied to TNUoS tariffs for transmission connected generation <100MW, connected at 132kV until 31 March 2021.

These Final tariffs now include the effect of the Small Generator Discount:

[6] Avoided Grid Supply Point Infrastructure Credit

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

[8] 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

- The discount to affected small generators is £11.813214/kW
- The additional tariff to add to all demand tariffs:
    - HH: £0.618659/kW, and
    - NHH: 0.080795p/kWh.

U. Small Generator Discount calculation

Small Generator Discount calculation		
Generator Residual (£/kW)	G	-3.53
Demand Residual (£/kW)	D	50.78
Small Generator Discount (£/kW)	T = (G + D)/4	11.81
Forecast Small Generator Volume (kW)	V	2,759,260
SGD cost (£)	V x T	32,595,729
Prior year reconcilation (£)	R	842,672
Total SGD Cost (£)	C = (V x T) - R	31,753,057
Total System Triad Demand (kW)	TD	51,325,630
Total HH Triad Demand (kW)	HHD	18,007,450
Total NHH Consumption (kWh)	NHHD	25,512,098,981
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.618659
Total Cost to HH Customers (£)	HHC = HHT * HHD	11,140,469
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.080795
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	20,612,588

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 Final tariffs on Wednesday 6 February 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 2019/20 forecasts:

https://www.nationalgrideso.com/tnuos

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A

Appendix A: Background to TNUoS charging

23.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.

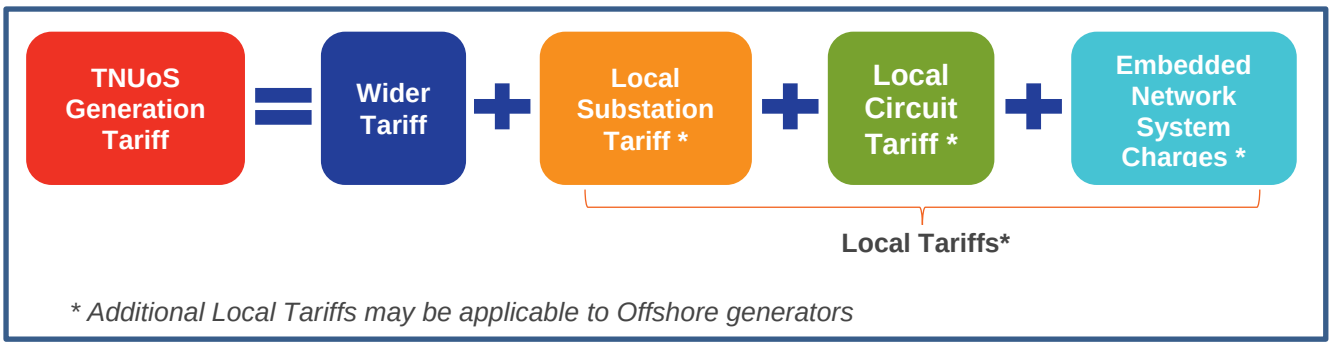
Generation charging principles

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**.



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

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

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

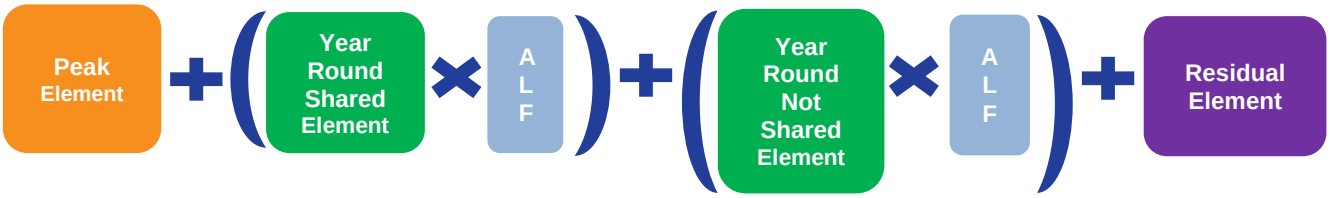
The Wider tariff

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

Following the implementation of CUSC Modification CMP268, generators classed as Conventional Carbon pay the Year Round Not Shared element in proportion to their ALF.

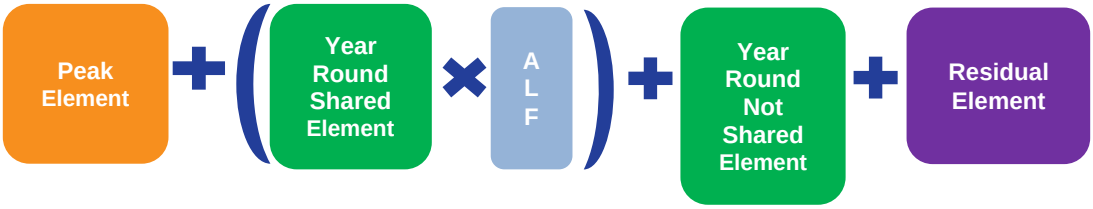
Conventional Carbon Generators

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



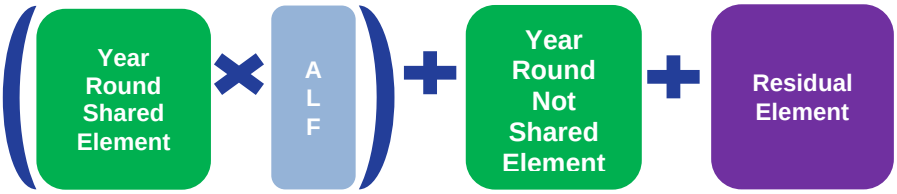
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

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

The ALFs used in these tariffs are listed from page 27.

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[9] if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS[10] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

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

Click here to find out more about DNO regions.

Offshore local tariffs

Where an offshore generator's connection assets have been transferred to the ownership of an OFTO (Offshore Transmission Owner), there will be additional **Offshore substation** and **Offshore circuit** tariffs specific to that OFTO.[11]

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:

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

All tariffs are in £/kW of 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

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

relevant charging year. Each settlement period must be separated by at least ten clear days. Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

For more details, please see CUSC 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.[12] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is available, via the NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[13].

Embedded export tariffs

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[14].

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, 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.

[12] https://www.nationalgrideso.com/charging/charging-policy-and-guidance#triads
[13] https://www.nationalgrideso.com/charging/charging-policy-and-guidance#triads
[14] [14] https://www.nationalgrideso.com/charging/charging-policy-and-guidance#triads

B

Appendix B: TNUoS Settlement for Measurements Classes F and G

24. TNUoS settlement for measurements classes F and G for 2019/20 and 2020/21

All demand meters in GB are divided into classifications of capacity and HH/NHH functionality. Due to the rollout of smart meters which can record data on a HH basis, several of these classes are changing from being settled as NHH to being settled HH. This will change the TNUoS demand tariff they are liable to pay.

- HH treated demand is charged average triad consumption in £/kW
- NHH treated demand is charged on annual 4pm-7pm consumption in p/kWh

The two classes principally affected by this change are classes F and G, which typically cover large properties. The detailed CUSC text can be found at 14.17.29.8 – 11.[15]

The table below shows the classes, their specifications, and how they will be settled in 2019/20, and in future years.

V. Treatment of metering classes for demand charging from 2019/20 onwards

Measurement class	Description	Settlement in 2019/20	2020/21 onwards
A	Non Half Hourly metered	NHH	NHH
B	Non Half Hourly unmetered	NHH	NHH
C	Half Hourly metered in 100kW premises	HH	HH
D	Half Hourly unmetered	HH	HH
E	Half Hourly metering equipment below 100kW with current transformer	HH	HH
F	Half Hourly metering equipment below 100kW with current transformer or whole current, at domestic premises	NHH	HH
G	Half Hourly metering equipment below 100kW with current transformer or whole current, NOT at domestic premises	NHH	HH

[15] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc?code-documents

C

Appendix C: Breakdown of locational HH and EE tariffs

25.Breakdown of HH and EET locational tariffs

W. HH 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.

Zone	2019/20 Draft		2019/20 Final		Changes	
	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	-1.523975	-28.903803	-1.523975	-28.903803	0.000000	0.000000
2	-1.800826	-18.842831	-1.800826	-18.842831	0.000000	0.000000
3	-3.900602	-6.471764	-3.900602	-6.471764	0.000000	0.000000
4	-1.432273	-2.135195	-1.432273	-2.135195	0.000000	0.000000
5	-3.268569	-0.091162	-3.268569	-0.091162	0.000000	0.000000
6	-2.505479	0.451798	-2.505479	0.451798	0.000000	0.000000
7	-2.525629	2.566350	-2.525629	2.566350	0.000000	0.000000
8	-1.718495	3.247513	-1.718495	3.247513	0.000000	0.000000
9	1.367046	1.022232	1.367046	1.022232	0.000000	0.000000
10	-5.996327	4.322921	-5.996327	4.322921	0.000000	0.000000
11	3.956929	0.754873	3.956929	0.754873	0.000000	0.000000
12	5.735163	2.041577	5.735163	2.041577	0.000000	0.000000
13	1.918498	4.021235	1.918498	4.021235	0.000000	0.000000
14	-0.680238	4.967867	-0.680238	4.967867	0.000000	0.000000

X. Breakdown of the EET

This table shows the breakdown of the components that make up the EET.

Demand Zone		2019/20 Draft			2019/20 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	-30.427778	3.327268	14.65	-30.427778	3.327268	14.65	0.000000	0.000000	0.00
2	Southern Scotland	-20.643657	3.327268	14.65	-20.643657	3.327268	14.65	0.000000	0.000000	0.00
3	Northern	-10.372366	3.327268	14.65	-10.372366	3.327268	14.65	0.000000	0.000000	0.00
4	North West	-3.567468	3.327268	14.65	-3.567468	3.327268	14.65	0.000000	0.000000	0.00
5	Yorkshire	-3.359731	3.327268	14.65	-3.359731	3.327268	14.65	0.000000	0.000000	0.00
6	N Wales & Mersey	-2.053681	3.327268	14.65	-2.053681	3.327268	14.65	0.000000	0.000000	0.00
7	East Midlands	0.040721	3.327268	14.65	0.040721	3.327268	14.65	0.000000	0.000000	0.00
8	Midlands	1.529018	3.327268	14.65	1.529018	3.327268	14.65	0.000000	0.000000	0.00
9	Eastern	2.389278	3.327268	14.65	2.389278	3.327268	14.65	0.000000	0.000000	0.00
10	South Wales	-1.673406	3.327268	14.65	-1.673406	3.327268	14.65	0.000000	0.000000	0.00
11	South East	4.711802	3.327268	14.65	4.711802	3.327268	14.65	0.000000	0.000000	0.00
12	London	7.776739	3.327268	14.65	7.776739	3.327268	14.65	0.000000	0.000000	0.00
13	Southern	5.939732	3.327268	14.65	5.939732	3.327268	14.65	0.000000	0.000000	0.00
14	South Western	4.287630	3.327268	14.65	4.287630	3.327268	14.65	0.000000	0.000000	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 (grid supply point) 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

26.Locational demand profiles

The table below shows the latest demand forecast used in the Final tariffs. These have not been changed since Draft tariffs.

Gross tariff model peak demand remains the same as the June forecast at 51.3GW. Overall net peak demand remains at 43.6GW.

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

Y. Demand profiles

Zone	Zone Name	2019/20 Draft					2019/20 Final				
		Transport 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)	Transport Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	716	1,483	428	0.78	958	716	1,483	428	0.78	958
2	Southern Scotland	2,961	3,444	1,126	1.77	678	2,961	3,444	1,126	1.77	678
3	Northern	2,018	2,576	902	1.32	439	2,018	2,576	902	1.32	439
4	North West	3,103	4,037	1,413	2.02	410	3,103	4,037	1,413	2.02	410
5	Yorkshire	3,417	3,818	1,495	1.83	808	3,417	3,818	1,495	1.83	808
6	N Wales & Mersey	2,217	2,628	991	1.30	550	2,217	2,628	991	1.30	550
7	East Midlands	5,407	4,651	1,717	2.24	639	5,407	4,651	1,717	2.24	639
8	Midlands	4,777	4,251	1,389	2.17	335	4,777	4,251	1,389	2.17	335
9	Eastern	5,122	6,447	1,931	3.24	806	5,122	6,447	1,931	3.24	806
10	South Wales	1,371	1,822	779	0.88	510	1,371	1,822	779	0.88	510
11	South East	3,611	3,906	1,060	2.01	411	3,611	3,906	1,060	2.01	411
12	London	5,444	4,187	2,203	1.87	171	5,444	4,187	2,203	1.87	171
13	Southern	7,342	5,476	1,933	2.68	693	7,342	5,476	1,933	2.68	693
14	South Western	2,030	2,597	641	1.40	345	2,030	2,597	641	1.40	345
Total		**49,536**	**51,326**	**18,007**	**25.51**	**7,753**	**49,536**	**51,326**	**18,007**	**25.51**	**7,753**

E

Appendix E: Annual Load Factors

27.Specific ALFs

Z. Specific Annual Load Factors

The table below lists the Annual Load Factors (ALFs) of generators expected to be liable for generator charges during 2019/20. 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 2013/14 to 2017/18. Generators which commissioned after 1 April 2015 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 2019/20 also use the Generic ALF for their first year of operation.

These ALFs were finalised in November 2018.

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
ABERTHAW	Coal	Actual	Actual	Actual	Actual	Actual	65.5413%	59.0043%	54.2611%	50.8335%	5.0742%	54.6997%
ACHRUACH	Onshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	33.6464%	36.7140%	44.3464%	38.2356%
AFTON	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	34.8738%	37.2641%
AIKENGALL II	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.5082%	36.8089%
AN SUIDHE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	41.5843%	36.9422%	35.4900%	34.0938%	41.2323%	37.8882%
ARECLEOCH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	33.8296%	29.7298%	36.8612%	19.7246%	35.1728%	32.9108%
BAGLAN BAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.4106%	37.9194%	29.1228%	55.2030%	24.2891%	30.4438%
BARROW	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	54.1080%	47.0231%	47.1791%	44.2584%	47.0417%	47.0813%
BARRY	CCGT_CHP	Actual	Actual	Actual	Partial	Actual	1.2989%	0.4003%	2.1727%	24.3468%	0.5407%	1.3374%
BEAULY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	35.6683%	37.1167%	35.0094%	30.4872%	21.9937%	33.7216%
BEINNEUN	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	30.9623%	25.8214%	31.7476%
BHLARAIDH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.4339%	46.3209%	39.4047%
BLACK LAW	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.9648%	26.7881%	26.9035%	23.4623%	21.2137%	25.7180%
BLACKCRAIG WINDFARM	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	36.0208%	37.6465%
BLACKLAW EXTENSION	Onshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	33.4635%	13.1095%	30.4870%	25.6867%
BRIMSDOWN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.7645%	11.1229%	16.4463%	45.0615%	27.6168%	20.9426%
BURBO BANK EXT	Offshore_Wind	Generic	Generic	Actual	Actual	Actual	0.0000%	0.0000%	16.7781%	25.0233%	49.3850%	30.3955%
CARRAIG GHEAL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	45.2760%	48.9277%	45.6254%	40.4211%	45.5371%	45.4795%
CARRINGTON	CCGT_CHP	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	38.7318%	58.0115%	58.8066%	51.8500%
CLUNIE	Hydro	Actual	Actual	Actual	Actual	Actual	45.3256%	43.2488%	47.9711%	32.8297%	32.1699%	40.4681%
CLYDE (NORTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	42.6598%	36.8882%	41.4120%	26.8858%	39.2619%	39.1873%
CLYDE (SOUTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	39.8941%	29.4115%	39.9615%	34.8751%	39.1634%	37.9775%
CONNAHS QUAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	12.8233%	18.3739%	28.2713%	37.4588%	20.0846%	22.2433%
CONON CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	54.2820%	55.5287%	58.9860%	48.6782%	50.8547%	53.5551%
CORBY	CCGT_CHP	Actual	Actual	Actual	Generic	Partial	8.0834%	9.6755%	4.5411%	0.0000%	44.6503%	7.4333%
CORRIEGARTH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	22.5645%	41.2013%	34.0750%
CORRIEMOILLIE	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	32.2316%	30.4210%	33.7040%
CORYTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	9.7852%	17.5123%	26.4000%	63.0383%	16.4022%	20.1048%
COTTAM	Coal	Actual	Actual	Actual	Actual	Actual	67.3951%	51.4426%	34.4157%	14.9387%	21.6580%	35.8388%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
COTTAM DEVELOPMENT CENTRE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.0249%	31.3132%	28.2382%	67.2482%	56.3007%	38.6174%
COUR	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.3247%	55.4273%	44.0704%
COWES	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0956%	0.3135%	0.4912%	0.5319%	0.6942%	0.4456%
CRUACHAN	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	9.6969%	9.0516%	8.8673%	7.1914%	9.6225%	9.1805%
CRYSTAL RIG II	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	50.2549%	47.5958%	48.3836%	40.2679%	52.5802%	48.7447%
CRYSTAL RIG III	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	39.9503%	51.9020%	43.4372%
DAMHEAD CREEK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	77.1783%	67.4641%	64.8983%	68.1119%	63.5108%	66.8248%
DEESIDE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	17.3035%	13.9018%	17.4579%	27.1090%	20.8164%	18.5259%
DERSALLOCH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.7728%	39.8576%	37.3632%
DIDCOT B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.6624%	25.5345%	41.1389%	50.1358%	44.1234%	36.9322%
DIDCOT GTS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0902%	0.2843%	0.4861%	0.0452%	0.6337%	0.2869%
DINORWIG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	15.0898%	15.0650%	14.6353%	15.9596%	14.9467%	15.0338%
DRAX	Coal	Actual	Actual	Actual	Actual	Actual	80.5151%	82.2149%	76.2030%	62.2705%	55.8896%	72.9962%
DUDGEON	Offshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	42.4791%	46.9782%	46.3364%
DUNGENESS B	Nuclear	Actual	Actual	Actual	Actual	Actual	61.0068%	54.6917%	70.7617%	79.3403%	68.2086%	66.6590%
DUNLAW EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	34.8226%	30.0797%	29.1203%	26.5549%	31.0840%	30.0947%
DUNMAGLASS	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.9713%	75.6936%	51.0414%
EDINBANE WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	39.4785%	31.2458%	35.5937%	32.5009%	34.5929%	34.2292%
EGGBOROUGH	Coal	Actual	Actual	Actual	Partial	Actual	72.1843%	45.7421%	27.0157%	40.0283%	7.1715%	48.3140%
ERROCHTY	Hydro	Actual	Actual	Actual	Actual	Actual	28.2628%	25.3585%	28.1507%	16.1775%	13.6081%	23.2289%
EWE HILL	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.3314%	33.1849%	34.9919%
FALLAGO	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	54.8683%	44.7267%	55.7992%	43.2176%	49.4158%	49.6703%
FARR WINDFARM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	44.7212%	38.5712%	40.9963%	34.1766%	38.3046%	39.2907%
FASNAKYLE G1 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	35.3695%	57.4834%	53.1573%	30.9768%	38.1673%	42.2314%
FAWLEY CHP	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	63.3619%	72.8484%	57.6978%	63.2006%	76.0793%	66.4703%
FFESTINIOG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	5.4631%	4.3251%	3.4113%	5.6749%	4.2118%	4.6667%
FIDDLERS FERRY	Coal	Actual	Actual	Actual	Actual	Actual	49.0374%	45.2435%	27.4591%	8.2478%	13.9908%	28.8978%
FINLARIG	Hydro	Actual	Actual	Actual	Actual	Actual	59.9142%	59.4092%	65.1349%	49.6402%	52.6415%	57.3216%
FOYERS	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	14.7097%	12.3048%	15.4323%	11.3046%	14.5333%	13.8493%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
FREASDAIL	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	32.5600%	38.9709%	36.6634%
GALAWHISTLE	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	34.9765%	42.4455%	38.6271%
GALLOPER	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	54.7593%	51.2877%
GARRY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	55.9308%	64.3828%	60.2772%	61.0498%	60.0010%	60.4426%
GLANDFORD BRIGG	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	1.5673%	0.5401%	1.8191%	2.7682%	1.8418%	1.7427%
GLEN APP	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	25.1373%	24.8393%	29.4787%
GLENDOE	Hydro	Actual	Actual	Actual	Actual	Actual	36.3802%	32.3494%	34.8532%	23.8605%	24.0105%	30.4044%
GLENMORISTON	Hydro	Actual	Actual	Actual	Actual	Actual	44.4594%	48.7487%	50.6921%	34.6709%	44.3960%	45.8680%
GORDONBUSH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	46.5594%	47.7981%	47.7161%	50.4126%	34.1762%	47.3579%
GRAIN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.3833%	44.0031%	39.7895%	53.8227%	39.7755%	41.7253%
GRANGEMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	55.9047%	62.6168%	59.8274%	51.4558%	58.9786%	58.2369%
GREAT YARMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.7409%	18.6633%	59.8957%	63.5120%	50.1521%	43.5962%
GREATER GABBARD	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	48.3038%	42.1327%	50.2468%	43.1132%	46.4939%	45.9703%
GRIFFIN WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.9566%	31.3152%	31.0284%	25.8228%	28.8970%	30.4135%
GUNFLEET SANDS I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	56.6472%	47.0132%	50.4650%	45.7940%	47.3019%	48.2600%
GUNFLEET SANDS II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	52.2361%	44.7211%	49.0521%	43.9893%	46.9928%	46.9220%
GWYNT Y MOR	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	8.0036%	61.6185%	63.1276%	44.8323%	50.4031%	52.2846%
HADYARD HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.9488%	27.7635%	36.6527%	31.4364%	34.0375%	32.4742%
HARESTANES	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	24.1419%	28.6355%	27.8093%	22.5464%	29.0125%	28.4858%
HARTLEPOOL	Nuclear	Actual	Actual	Actual	Actual	Actual	73.7557%	56.2803%	53.8666%	78.0390%	80.6218%	69.3583%
HEYSHAM	Nuclear	Actual	Actual	Actual	Actual	Actual	73.3628%	68.8252%	72.7344%	79.6169%	85.1617%	75.2380%
HINKLEY POINT B	Nuclear	Actual	Actual	Actual	Actual	Actual	68.8664%	70.1411%	67.6412%	71.2265%	83.4643%	70.0780%
HUMBER GATEWAY	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	43.9343%	62.9631%	59.7195%	54.9913%	59.2246%
HUNTERSTON	Nuclear	Actual	Actual	Actual	Actual	Actual	84.7953%	79.1368%	82.1786%	83.2939%	79.8644%	81.7790%
IMMINGHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	37.8219%	56.8316%	69.4686%	71.9550%	64.3175%	63.5392%
INDIAN QUEENS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.2321%	0.0876%	0.0723%	0.0847%	0.0740%	0.0821%
KEADBY	CCGT_CHP	Actual	Generic	Partial	Actual	Actual	0.0001%	0.0000%	35.1858%	28.6076%	38.6957%	22.4345%
KEITH HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	36.9858%	37.9681%
KILBRAUR	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	51.3777%	54.3550%	50.3807%	46.5342%	56.7501%	52.0378%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
KILGALLIOCH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	25.2739%	25.3254%	29.6862%
KILLIN CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	45.5356%	44.8205%	53.2348%	27.4962%	34.9231%	41.7597%
KILLINGHOLME (POWERGEN)	Gas_Oil	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	0.5443%	0.3624%
LANGAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	40.8749%	34.8629%	16.5310%	44.5413%	42.3368%	39.3582%
LINCS WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	46.5987%	43.8178%	49.1306%	44.5192%	51.0911%	46.7495%
LITTLE BARFORD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	33.6286%	49.6644%	39.9829%	64.8597%	66.3067%	51.5023%
LOCHLUICHART	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	27.6728%	20.2103%	29.2663%	31.6897%	34.3322%	31.7627%
LONDON ARRAY	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	51.2703%	64.0880%	66.8682%	53.6245%	50.5515%	56.3276%
LYNEMOUTH	Coal	Generic	Generic	Partial	Generic	Actual	0.0000%	0.0000%	68.0196%	0.0000%	1.0783%	35.5714%
MARCHWOOD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	48.6845%	66.4021%	55.0879%	75.4248%	67.3692%	62.9531%
MARK HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	30.2863%	26.7942%	34.0227%	21.9653%	31.0915%	29.3907%
MEDWAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	14.5545%	28.0962%	34.1799%	35.1505%	36.7261%	32.4756%
MILLENNIUM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	52.6618%	53.2636%	48.4038%	44.9764%	53.6488%	51.4431%
MINNYGAP	Onshore_Wind	Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	30.9962%	35.9716%
NANT	Hydro	Actual	Actual	Actual	Actual	Actual	35.5883%	36.4040%	37.3788%	30.6350%	34.9026%	35.6317%
ORMONDE	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	49.6561%	42.8711%	47.1986%	41.2188%	37.7162%	43.7628%
PEMBROKE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	60.3928%	67.5346%	64.5596%	77.6478%	70.2866%	67.4603%
PEN Y CYMOEDD	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	26.9446%	36.0948%	33.8329%
PETERBOROUGH	CCGT_CHP	Actual	Actual	Partial	Actual	Actual	1.8311%	1.0929%	4.1032%	1.7914%	0.4349%	1.5718%
PETERHEAD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.8811%	0.4858%	23.3813%	42.2292%	65.7808%	35.8305%
RACE BANK	Offshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	45.3062%	38.1978%	44.3520%
RAMPION	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	40.9885%	46.6974%
RATCLIFFE-ON-SOAR	Coal	Actual	Actual	Actual	Actual	Actual	71.7403%	56.1767%	19.6814%	15.4657%	19.3780%	31.7454%
ROBIN RIGG EAST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	46.7562%	55.3209%	51.9700%	50.5096%	42.5599%	49.7453%
ROBIN RIGG WEST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	48.0629%	53.4150%	56.0881%	51.5383%	47.3991%	51.0054%
ROCKSAVAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	2.6155%	4.4252%	19.8061%	58.6806%	29.8122%	18.0145%
RYE HOUSE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	7.4695%	5.3701%	7.7906%	15.6538%	13.4736%	9.5779%
SALTEND	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	69.0062%	67.9518%	55.6228%	77.4019%	70.1596%	69.0392%
SANQUHAR	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	35.2098%	37.3761%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
SEABANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.2781%	25.6956%	27.2136%	41.6815%	55.4606%	31.5303%
SELLAFIELD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	25.0221%	18.9719%	28.6790%	19.8588%	13.6007%	21.2842%
SEVERN POWER	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	32.4163%	24.6354%	18.3226%	64.4246%	55.6920%	37.5812%
SHERINGHAM SHOAL	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	49.3517%	46.2286%	53.6184%	46.9715%	54.3071%	49.9805%
SHOREHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.7501%	10.2239%	48.9514%	68.9863%	64.2994%	44.6670%
SIZEWELL B	Nuclear	Actual	Actual	Actual	Actual	Actual	82.5051%	84.7924%	98.7826%	81.6359%	73.3708%	82.9778%
SLOY G2 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	14.3471%	15.5941%	13.9439%	8.1782%	12.0303%	13.4404%
SOUTH HUMBER BANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	24.3373%	34.4673%	48.6753%	55.3419%	34.6174%	39.2533%
SPALDING	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	33.4800%	39.3092%	47.9407%	60.9748%	52.9683%	46.7394%
STAYTHORPE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	37.6216%	56.6148%	69.4422%	65.7791%	52.0701%	58.1547%
STRATHY NORTH & SOUTH	Onshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	49.6340%	36.1987%	40.2313%	42.0213%
STRONELAIRG	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	37.5366%	38.1517%
SUTTON BRIDGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	9.4124%	17.2025%	13.1999%	38.0184%	29.1878%	19.8634%
TAYLORS LANE	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0483%	0.0640%	0.1708%	0.8047%	1.1712%	0.3465%
THANET	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	39.7489%	35.5935%	41.3434%	33.7132%	38.5069%	37.9498%
TODDLEBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	39.5374%	33.7211%	35.0823%	31.3435%	38.0158%	35.6064%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	86.4669%	91.4945%	85.7725%	97.9942%	86.4413%	88.1343%
USKMOUTH	Coal	Actual	Partial	Actual	Actual	Actual	38.9899%	46.9428%	25.5184%	24.3304%	0.1000%	29.6129%
WALNEY 4	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	45.2033%	48.1024%
WALNEY I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	57.7046%	52.0555%	50.7535%	47.4617%	55.9472%	52.9187%
WALNEY II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	61.9219%	58.2355%	35.7988%	54.9727%	62.8290%	58.3767%
WALNEY III	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	50.1762%	49.7600%
WEST BURTON	Coal	Actual	Actual	Actual	Actual	Actual	68.9176%	61.5364%	32.7325%	10.1071%	11.8199%	35.3629%
WEST BURTON B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	30.3021%	46.8421%	59.3477%	54.2878%	63.2420%	53.4925%
WEST OF DUDDON SANDS	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	40.4810%	40.0506%	48.7540%	48.7691%	55.4034%	50.9755%
WESTERMOST ROUGH	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	26.2900%	54.8014%	58.1061%	63.4740%	58.7938%
WHITELEE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	35.1074%	29.8105%	31.8773%	27.2893%	29.6336%	30.4405%
WHITELEE EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	27.0102%	27.7787%	26.7655%	23.5253%	25.1664%	26.3140%
WHITESIDE HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.3704%	38.4297%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
WILTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	4.4941%	21.5867%	16.1379%	14.4130%	15.5750%	15.3753%
WINDY STANDARD II	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	43.2981%	40.0722%

28. Generic ALFs

AA. Generic ALFs

Technology	Generic ALF
Gas_Oil #	0.2715%
Pumped_Storage	10.6826%
Tidal *	18.9000%
Biomass	26.8847%
Wave *	31.0000%
Onshore_Wind	38.4593%
CCGT_CHP	48.6379%
Hydro	42.4165%
Offshore_Wind	49.5519%
Coal	37.6162%
Nuclear	76.3178%

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 14.15.109. The Biomass ALF for 2017/18 has been copied from the 2015/16 year due to there not being any single majority biomass-fired stations operating since that period.

F

Appendix F: Contracted generation changes since the Draft forecast

The contracted generation used in the Transport model was fixed at the Draft forecast of 2019/20 tariffs, using the TEC register as of 31 October 2018 as stated by the CUSC[16]. There are no changes to the Transport model (affecting locational tariffs) in these Final tariffs for 2019/20.

Both Eggborough and Carnedd Wen appeared on the 31 October 2018 version of the TEC register, but publicly available information on these two large projects shows that they will not be connected to the system in 2019/20, and so these generators have not been included in the TNUoS model for this forecast.

[16] CUSC 14.15.6

G

Appendix G: Transmission company revenues

29.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.

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.

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

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 other 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.

30.NGET & NGESO revenue forecasts

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

In addition, NGESO will collect 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 have been collected by NGET under its licence condition, and this function will also be transferred to NGESO. The revenue breakdown table below shows details of the pass-through items under NGESO's licence conditions.

BB. Revenue breakdown

Description			National Grid Electricity Transmission		NGESO TNUoS Pass-Through	Scottish Power Transmission		SHE Transmission		Notes
Regulatory Year		Licence Term	Nov Draft	NGET Jan Final	NGESO TNUoS Jan Final	Nov Draft	Jan Final	Nov Draft	Jan Final	
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1585.2	1585.2		256.4	256.4	122.1	122.1	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-376.6	-378.0		2.7	-1.8	71.0	76.8	From PCFM
RPI True Up	A3	TRUt	3.3	3.3		0.7	0.7	0.6	0.6	Forecast
RPI Forecast	A4	RPIFt	1.3570	1.3580	1.3580	1.3570	1.3600	1.3560	1.3560	Using HM Treasury Forecast. For SPT and SHET, It and RPIF were draft values at the time of submission, and were then updated by NGESO to align three onshore Tos
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1644.5**	**1643.8**	**0.0**	**352.5**	**347.2**	**262.9**	**270.5**	
Pass-Through Business Rates	B1	RBt	35.1	35.1		4.3	4.3	21.7	21.7	Forecast
Temporary Physical Disconnection	B2	TPDt	0.4	0.4		0.0	0.0	0.0	0.0	Forecast
Licence Fee	B3	LFt	4.3	4.3						Forecast
Inter TSO Compensation	B4	ITCt	-5.2	-5.2						Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0		0.0					Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.6		0.6					Forecast
Interconnectors Cap&Floor Revenue Adjustment	B10	TICFt + TICPt	-8.4		-8.4					Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**26.7**	**34.6**	**-7.8**	**4.3**	**4.3**	**21.7**	**21.7**	
Reliability Incentive Adjustment	C1	RIt	3.8	3.8		3.2	3.2	1.4	1.4	Incentie Revenue as result of 2017/18 performance
Stakeholder Satisfaction Adjustment	C2	SSOt	7.2	9.3		2.8	2.8	-0.1	-0.1	Incentie Revenue as result of 2017/18 performance
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3.1	3.1		0.4	0.4	0.0	0.0	Incentie Revenue as result of 2017/18 performance
Awarded Environmental Discretionary Rewards	C4	EDRt	0.0	0.0		0.0	0.0	0.0	4.0	Incentie Revenue as result of 2017/18 performance
Financial Incentive for Timely Connections Output	C5	-CONADJt				0.0	0.0			Incentie Revenue as result of 2017/18 performance
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**14.0**	**16.2**	**0.0**	**6.4**	**6.4**	**1.3**	**5.3**	
Network Innovation Allowance	D	NIAt	10.4	7.4	3.0	1.1	1.1	0.9	0.9	Forecast
Network Innovation Competition	E	NICFt	32.7		31.6					Forecast
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0		33.0	33.0	83.4	83.4	From Ofgem Decision
Scottish Site Specific Adjustment	H	DISt	0.0		-15.9					Forecast
Scottish Terminations Adjustment	I	TSt	0.0		2.4					Forecast
Correction Factor	K	-Kt	33.6	33.6		0.2	0.2	-29.0	-29.0	Correction of 2017/18 collected revenue v.s. allowed revenue
Financial Facilities	J	FINt		-7.2	7.2					Forecast
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**1762.0**	**1728.5**	**20.4**	**397.5**	**392.2**	**341.2**	**352.8**	
Pre-vesting connection charges	S1		30.9	30.2						Forecast
Rental Site	S2		0.7	0.6						Forecast
Post Vesting, Pre-BETTA connection charges	S					14.5	12.9	3.4	3.4	Forecast
TNUoS Collected Revenue onshore TO [T=M-B5-S]	**T**		**1730.4**	**1697.6**	**20.4**	**383.0**	**379.3**	**337.8**	**349.4**	
Offshore Transmission Pass-through		**TOFTOt**	**388.4**		**390.6**					

31. Scottish Power Transmission revenue forecast

The Scottish Power Transmission revenue forecast has been updated since the Draft tariffs, and has now been finalised. The indicative Scottish Power Transmission revenue to be collected via TNUoS for 2019/20 is £379.3m.

32. SHE Transmission revenue forecast

The Scottish Hydro Electric Transmission (SHE Transmission) revenue forecast has been updated since the Draft tariffs, and has now been finalised. The indicative SHET Transmission revenue to be collected via TNUoS for 2019/20 is £349.4m.

33. Offshore Transmission Owner & Interconnector revenues

The Offshore Transmission Owner revenue to be collected via TNUoS for 2019/20 is £390.6m, an increase of £2.2m compared to the Draft forecast. Revenues have been adjusted to take into account the final determinations by Ofgem on the revenues allowed to the OFTOs.

Under CMP283, TNUoS charges can be adjusted by an amount determined by Ofgem to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime. The interconnector revenue forecast has been updated in this Draft tariff forecast, and has now been finalised. Interconnector revenue reduces TNUoS revenues by around £8.4m.

CC. Offshore revenues

Offshore Transmission Revenue (£m)	25/01/2019						
Regulatory Year	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	Current revenues plus indexation
Thanet	78.9	17.5	15.7	19.5	18.6	19.2	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	Current revenues plus indexation
Burbo Bank					34.3	13.1	Current revenues plus indexation
Dudgeon						18.7	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2019/20						66.0	National Grid Forecast
Offshore Transmission Pass-Through (B7)	**218.4**	**248.4**	**260.8**	**265.5**	**317.9**	**390.6**	

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

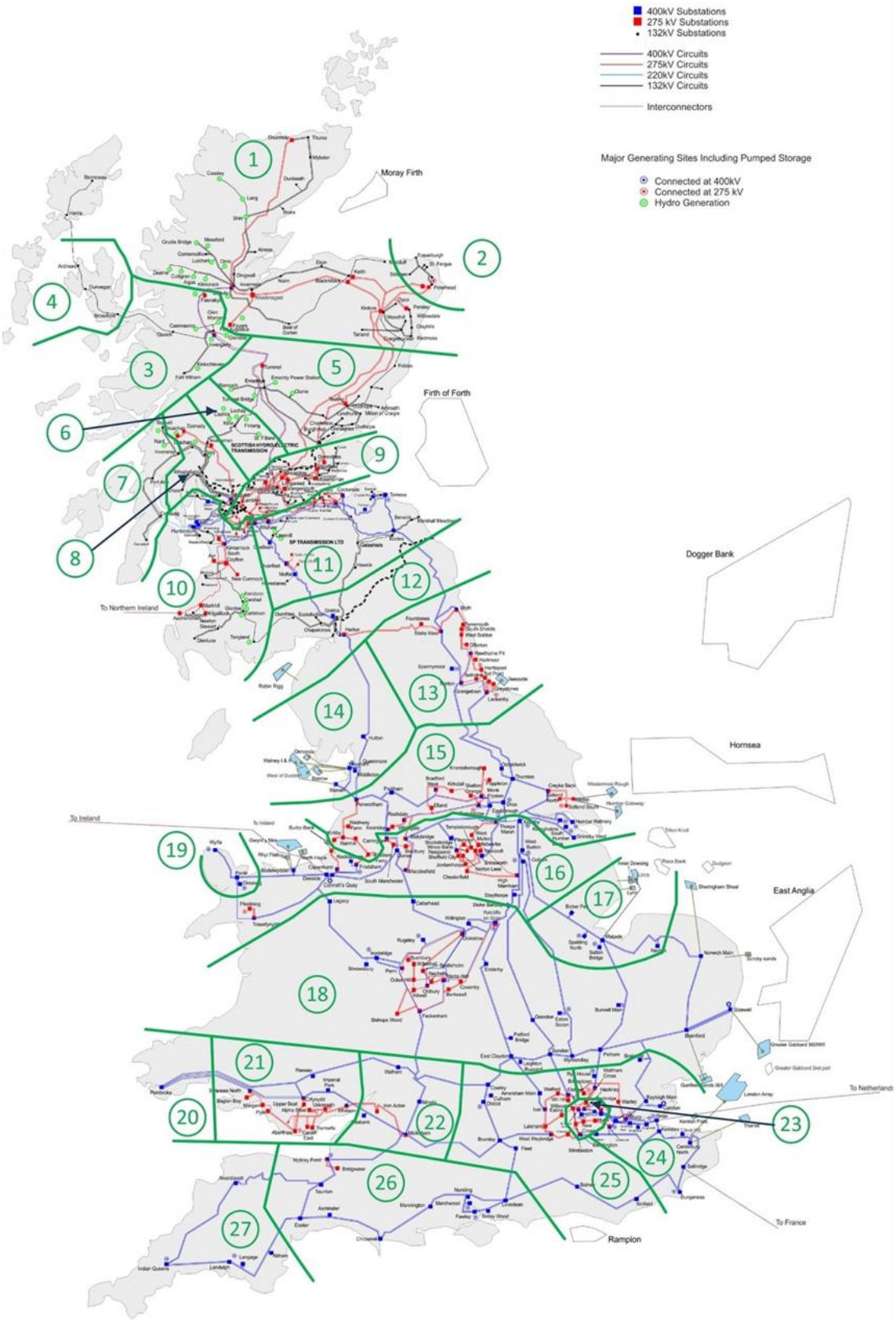
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formula are constructed

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

H

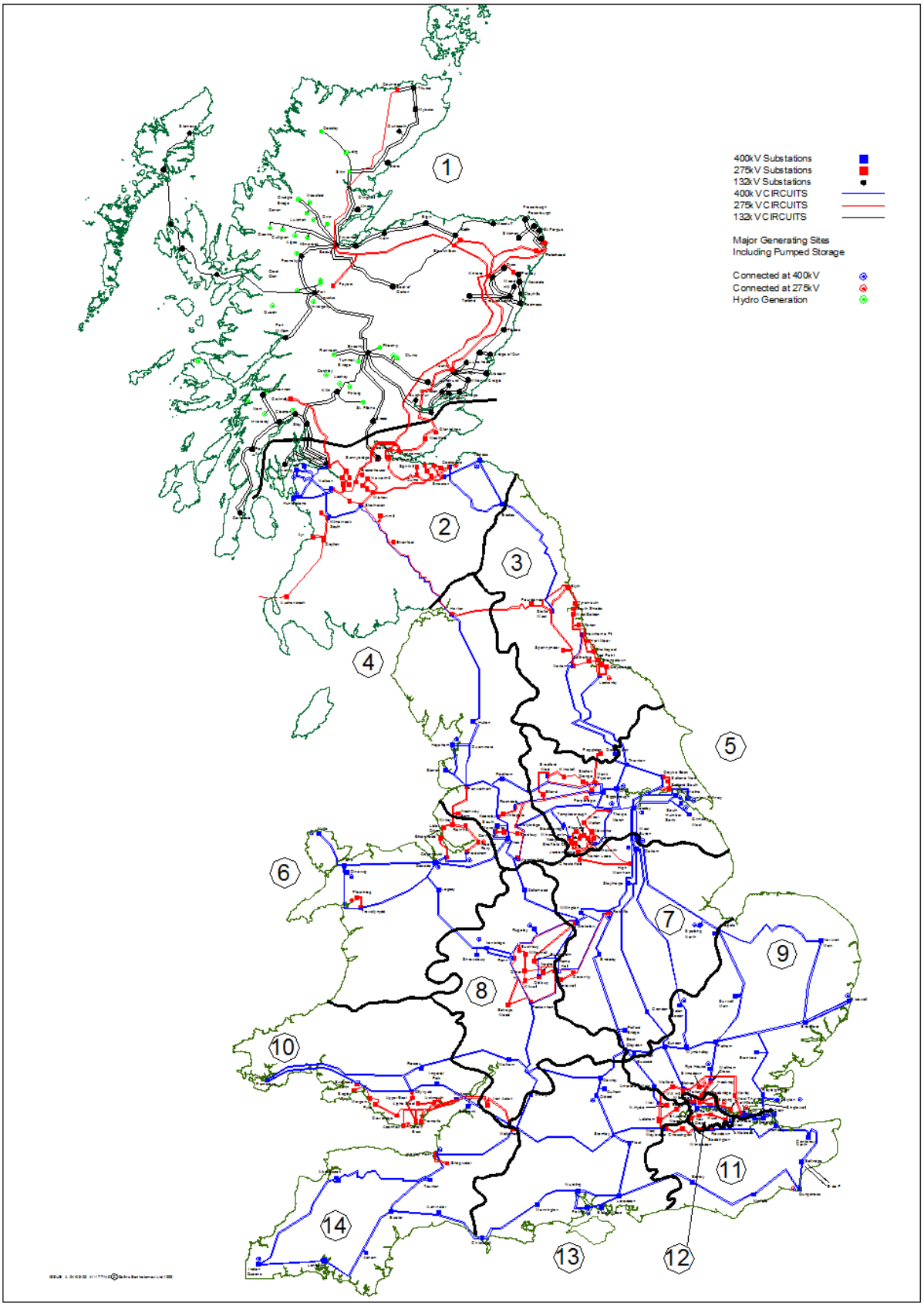
Appendix H: Generation zones map

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
1
2
3
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5
6
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14

J

Appendix J: Changes to TNUoS parameters

34.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.

2019/20 TNUoS Tariff Forecast						
		November 2017	**April 2018**	**June 2018**	**Draft tariffs November 2018**	**January 2019 Final tariffs**
Methodology		*Open to industry governance*				
LOCATIONAL	**DNO/DCC Demand Data**	Previous year			Week 24 updated	
	Contracted TEC	Latest TEC Register	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	Forecast	NG Best View
	Allowed Revenue *(non OFTO changes)*	Update financial parameters	Update financial parameters	Latest onshore TO Forecasts	Latest TO Forecasts	From TOs
	Demand Charging Bases	Previous Year	Revised Forecast	Final Forecast	*By exception*	*By exception*
	Generation Charging Base	NG Best View	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	Forecast	Generation revenue fixed		

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