Draft TNUoS Tariffs for 2019/20

National Grid Electricity System Operator (NGESO)

November 2018

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Contact us

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Executive summary

This document contains the latest forecast of the Transmission Network Use of System (TNUoS) tariffs for 2019/20. 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 June 2018. The final tariffs for charging year 2019/20 will be published on 31 January 2019.

Total revenues to be recovered

We forecast the total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges to be £2,839.6m in 2019/20. This is £39.7m less than the June forecast. This change is caused by updated revenue forecast from onshore TOs and offshore transmission owners (OFTOs). These figures will be further revised, and will be confirmed in the Final tariffs report.

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 CUSC. The error margin used in the calculation remains unchanged. The total revenue to be recovered from generation is now fixed.

The chargeable TEC for 2019/20, we forecast to be 73.32GW. This is an increase of 1.42GW compared to the June forecast, and is due to changes to the TEC register and our best view of generation. We forecast the average generation tariff to be £5.50/kW. This is a decrease of 11p/kW since the June forecast. This is due to the increase in the generation charging base.

The locational elements of the generation tariffs are now fixed. The residual element may change in Final tariffs.

Demand tariffs

We forecast the revenue to be recovered from demand tariffs to be £2,436m in 2019/20. This is a decrease of £39.7m compared to the June forecast, due to the decrease in the total revenue to be recovered.

The chargeable demand used in this forecast is unchanged from our April and June forecasts. 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.

We forecast that £111m will be payable through the Embedded Export Tariff (EET). This has only changed slightly compared to June due to the change in the demand locational tariffs which form part of the EET.

The average forecast gross HH demand tariff is £49.94/kW. The average forecast EET is £14.26/kW. The average forecast NHH demand tariff is 6.46p/kWh. Changes in total revenue mean that the average HH and NHH tariffs have decreased since June by £0.80/kW and 0.10p/kWh respectively. Our forecast of the average EET has decreased by 5p/kW compared to June, due to changes in locational demand tariffs.

The locational elements of the demand tariffs are now fixed. This means the EET tariffs will not change. The HH and NHH tariffs may change in the Final tariffs as the residual tariff is not yet fixed.

Small Generator Discount

The Small Generator Discount is defined in National Grid's licence condition C13. This licence condition expires on 31 March 2019. Previously a discount was applied to TNUoS tariffs for transmission connected generation <100MW, connected at 132kV.

On 28 November 2018, Ofgem have launched a statutory consultation[1] on their proposal to extend the discount until 31 March 2021. If approved, this will mean the Small Generator Discount will apply in 2019/20.

The tariffs in this report do not include the small generator discount, as the current arrangements see the modification lapsing.

If the small generator discount is extended using the same methodology, we forecast

- The discount to effected small generators to be £11.821356/kW
- The additional tariff to add to all demand tariffs:
  - HH: £0.635515/kW, and
  - NHH: 0.082997p/kWh.

Ofgem's consultation closes on 4 January 2019, and the updated position will be reflected in Final tariffs.

Drivers of changes to the tariff forecast

The principal drivers for change between our June and Draft tariff forecasts are:

Inclusion of the latest "Week 24" data from DNOs which is used to calculate locational tariffs. There have been significant changes in demand reported in several zones, with demand increases in Northern and Southern Scotland, but generally decreasing elsewhere. Overall the peak demand used in the transport model is lower than before. The result to tariffs is not significant except in Zone 2 (Southern Scotland) where demand tariffs have increased by £1.38/kW for HH and 0.18p/kWh for NHH. This is a result of the additional demand in Zones 1 and 2, and changes in the balance of demand in more southerly zones.

A decrease in total allowed revenue of approximately £39.7m leading to a reduction to the demand residual tariff by around £0.77/kW. We have included the latest revenue forecast from all Transmission Owners (TOs), and these figures will be updated and confirmed by 25 January 2019.

Changes to the Capacity Market

The European Court of Justice has announced they have annulled their previous decision to grant the GB Capacity Market State Aid coverage.

This means that all capacity market payments have ceased and the planned auctions for January and February will be suspended.

We are not forecasting any impact on TNUoS for 2019/20. As the impact of the capacity market changes on future plant build and operation decisions becomes clearer this may affect the previous assumptions used in our five-year view of TNUoS.

Future forecasts

On page 66 we show how we intend to update the various parameters which affect charging in future forecasts.

In this forecast, we have now **fixed the locational elements of the tariffs**. We have also left the total revenue to be paid by generation fixed from June, and the chargeable demand unchanged since the April forecast.

We do not intend to change the chargeable demand before the Final tariffs, however, to ensure we set tariffs to recover the total allowed revenue, we may need to do so. This is particularly the case given recent changes in market arrangements over the capacity market.

The residual tariffs will vary until our Final tariffs in January 2019, as final allowed revenue from each TO is only confirmed to NGESO in late January.

Changes to the charging methodology which may affect 2019/20 tariffs

The charging methodology can be changed through modifications to the CUSC. There are several proposals currently being considered. These are listed on page 38.

We do not consider any of the modifications currently being considered to have an impact on tariffs for 2019/20 at this stage.

Other modifications may still be proposed which affect tariffs from 2019/20.

[1] 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

Next tariff publication

Our next publication of 2019/20 TNUoS tariffs will be the Final tariffs by 31 January 2019.

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

We will publish our timetable of forecasts for TNUoS tariffs for 2020/21 before the end of January.

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.

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 41.

A. Summary of demand tariffs

HH Tariffs	2019/20 June	2019/20 Draft	Change
Average Tariff (£/kW)	50.745111	49.942761	-0.802350
Residual (£/kW)	51.697066	50.822881	-0.874185
EET	**2019/20 June**	**2019/20 Draft**	**Change**
Average Tariff (£/kW)	14.306876	14.261808	-0.045068
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)	110.918463	110.569059	-0.349403
NHH Tariffs	**2019/20 June**	**2019/20 Draft**	**Change**
Average (p/kWh)	6.557159	6.456818	-0.100341

B. Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	20.395103	2.745374	0.000000
2	Southern Scotland	30.179224	3.950803	0.000000
3	Northern	40.450515	5.138436	7.604902
4	North West	47.255413	6.126991	14.409800
5	Yorkshire	47.463150	6.040941	14.617537
6	N Wales & Mersey	48.769200	6.148322	15.923587
7	East Midlands	50.863602	6.663329	18.017989
8	Midlands	52.351899	6.902240	19.506286
9	Eastern	53.212159	7.421820	20.366546
10	South Wales	49.149475	5.797504	16.303862
11	South East	55.534682	7.870880	22.689070
12	London	58.599620	6.215107	25.754007
13	Southern	56.762613	7.510850	23.917000
14	South Western	55.110511	7.692623	22.264898

Residual charge for demand:	£ 50.822881

Please note these tariffs do not include the effect of the Small Generator Discount, see page 27.

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.

Demand tariffs have changed primarily due to the decrease in the residual, as revenue to recover from demand has gone down. This is caused by an overall decrease in revenue, and an increase in the proportion of revenue to be collected from generation.

The average HH gross tariff is now £49.94/kW; compared to the June forecast this has decreased by £0.80/kW. The average NHH tariff is now 6.46p/kWh, a decrease of 0.10p/kWh.

The average EET is £14.26/kW which has decreased by £0.04/kW. The total revenue to be paid to embedded generators remains almost the same at £111m. This will be recovered through the demand tariffs. More information on the causes of specific zonal fluctuations is detailed in the HH and NHH sections below.

3. Gross HH demand tariffs

This table and chart show the gross HH demand tariffs for 2019/20 in this Draft tariff forecast compared to the June forecast.

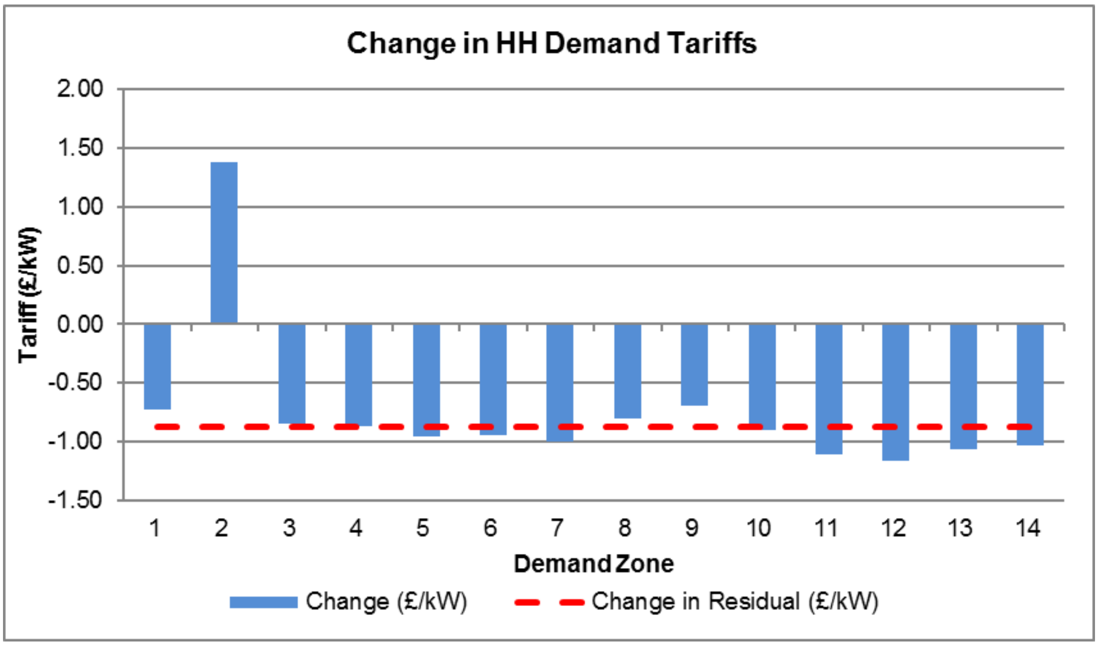
C. Gross HH demand tariffs

Zone	Zone Name	2019/20 June (£/kW)	2019/20 Draft (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	21.117249	20.395103	-0.722146	-0.874185
2	Southern Scotland	28.797132	30.179224	1.382092	-0.874185
3	Northern	41.292129	40.450515	-0.841614	-0.874185
4	North West	48.128953	47.255413	-0.873540	-0.874185
5	Yorkshire	48.421349	47.463150	-0.958199	-0.874185
6	N Wales & Mersey	49.711398	48.769200	-0.942198	-0.874185
7	East Midlands	51.861094	50.863602	-0.997492	-0.874185
8	Midlands	53.158467	52.351899	-0.806568	-0.874185
9	Eastern	53.903967	53.212159	-0.691808	-0.874185
10	South Wales	50.052639	49.149475	-0.903164	-0.874185
11	South East	56.648128	55.534682	-1.113446	-0.874185
12	London	59.762093	58.599620	-1.162473	-0.874185
13	Southern	57.828962	56.762613	-1.066349	-0.874185
14	South Western	56.141034	55.110511	-1.030523	-0.874185

The breakdown of the locational elements of these tariffs is shown on page 41.

Please note these tariffs do not include the effect of the Small Generator Discount, see page 27.

D. Changes to gross HH demand tariffs



The average HH gross demand tariff of £49.94/kW has decreased by £0.80/kW compared to June, this is almost entirely due to a decrease in the residual of £0.87/kW. The level of gross HH chargeable demand has not changed since the last forecast and remains at 18GW.

Generation updates and updates to the Week 24 demand data, which is used to calculate locational tariffs, have caused changes to system flows resulting in significant zonal variations to tariffs. Week 24 data is submitted by distribution network owners (DNOs) once per year as their forecast of peak demand in their region.

Demand increases in Scotland, and generally decreasing demand elsewhere has caused changes to the tariffs that are not significant except in Zone 2 (Southern Scotland) where demand tariffs have increased by £1.38/kW for HH tariffs. This is due to the additional demand in Zones 1 and 2, and changes in the balance of demand in more southerly zones. The tariffs in all other zones have decreased by between £0.69/kW and £1.16/kW.

The residual element of the tariff has decreased by £0.87/kW, this is due to a decrease to overall revenue.

4. EET

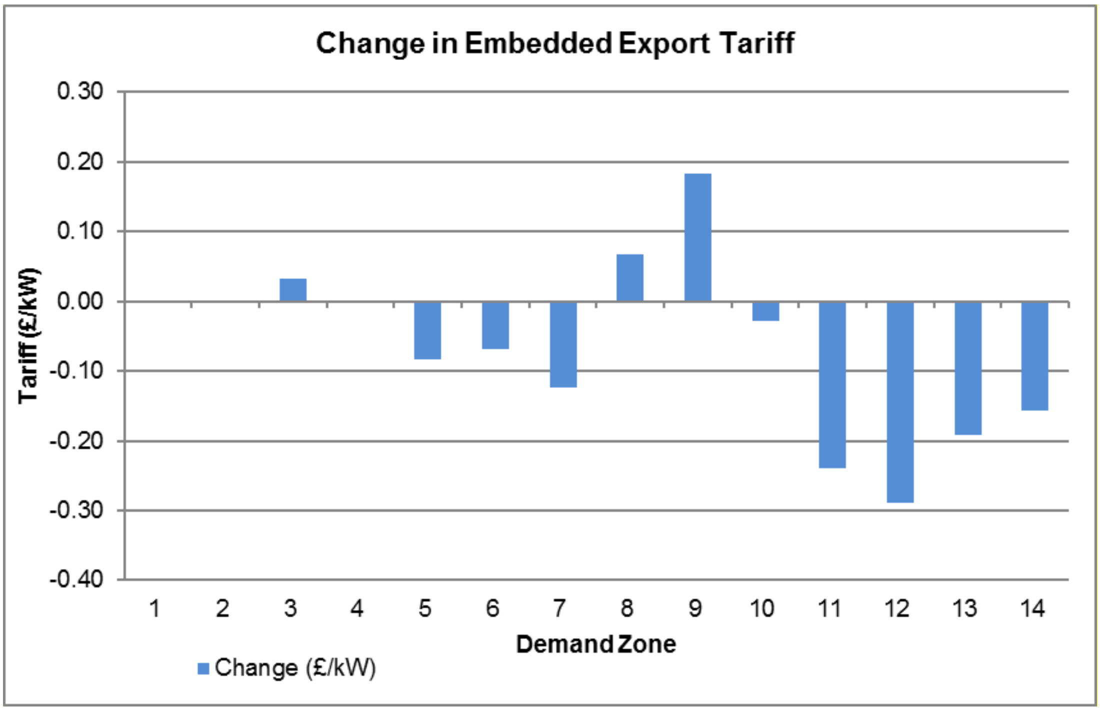
This table and chart show the EETs in the 2019/20 Draft tariffs forecast compared to the June forecast.

E. EET

Zone	Zone Name	2019/20 June (£/kW)	2019/20 Draft (£/kW)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	7.572331	7.604902	0.032571
4	North West	14.409155	14.409800	0.000645
5	Yorkshire	14.701551	14.617537	-0.084014
6	N Wales & Mersey	15.991600	15.923587	-0.068013
7	East Midlands	18.141296	18.017989	-0.123307
8	Midlands	19.438669	19.506286	0.067617
9	Eastern	20.184169	20.366546	0.182377
10	South Wales	16.332841	16.303862	-0.028979
11	South East	22.928330	22.689070	-0.239260
12	London	26.042296	25.754007	-0.288289
13	Southern	24.109165	23.917000	-0.192165
14	South Western	22.421236	22.264898	-0.156338

The breakdown of the locational elements of these tariffs is shown on page 41.

F. Changes to the EET



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.

The average EET has decreased by £0.04/kW to £14.26/kW. 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) has been kept the same as the June forecast.

The change in the EET is due to the change in the demand locational tariffs. Changes in demand locational tariffs are due to the relative position of demand and generation, which has been revised in this forecast.

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 November 2017 five-year forecast.[2] 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 41 for a breakdown of the EET.

5. NHH demand tariffs

This table and chart show the difference between the NHH demand tariffs forecast in June and this 2019/20 Draft tariffs forecast.

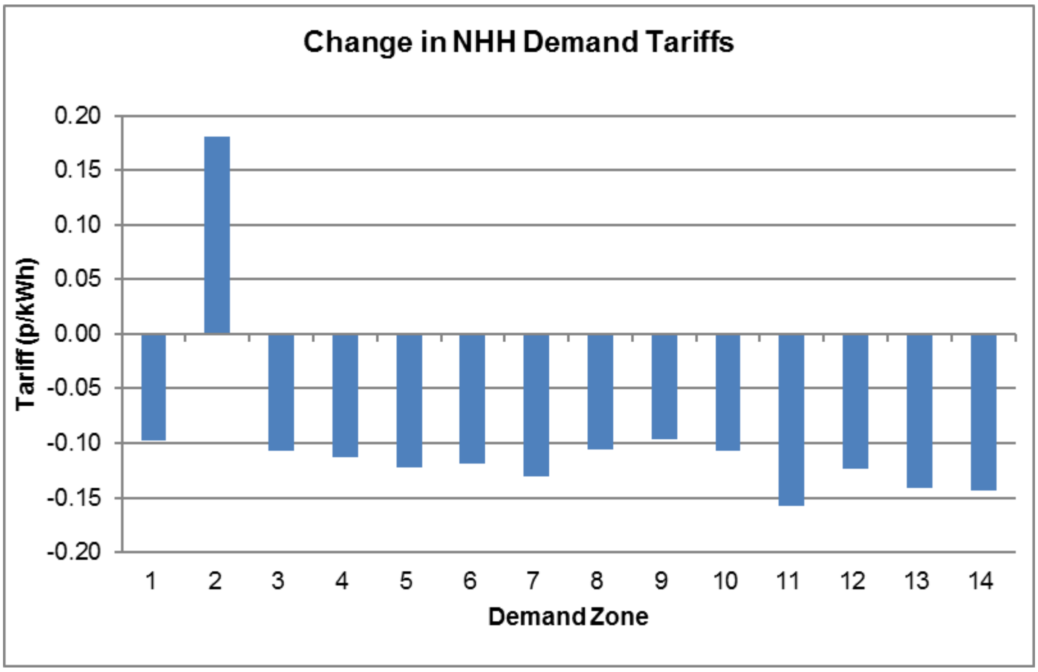
G. Changes to NHH demand tariffs

Zone	Zone Name	2019/20 June (p/kWh)	2019/20 Draft (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.842582	2.745374	-0.097208
2	Southern Scotland	3.769871	3.950803	0.180932
3	Northern	5.245346	5.138436	-0.106910
4	North West	6.240251	6.126991	-0.113260
5	Yorkshire	6.162897	6.040941	-0.121956
6	N Wales & Mersey	6.267104	6.148322	-0.118782
7	East Midlands	6.794004	6.663329	-0.130675
8	Midlands	7.008581	6.902240	-0.106341
9	Eastern	7.518310	7.421820	-0.096490
10	South Wales	5.904038	5.797504	-0.106534
11	South East	8.028688	7.870880	-0.157808
12	London	6.338400	6.215107	-0.123293
13	Southern	7.651950	7.510850	-0.141100
14	South Western	7.836469	7.692623	-0.143846

Please note these tariffs do not include the effect of the Small Generator Discount, see page 27.

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

H. Changes to NHH demand tariffs



The weighted average NHH tariff is 0.10p/kWh lower than in the June forecast. This is due to the overall decrease in revenue to be recovered from demand. The tariffs have decreased in nearly all zones except for zone 2 which has increased by 0.18p/kWh, which reflects the changes in HH zonal tariffs.

Generation tariffs

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

6. Generation tariffs summary

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

I. Summary of generation tariffs

Generation Tariffs (£/kW)	2019/20 June	2019/20 Draft	Change since last forecast
Residual	-3.613060	-3.537457	0.075604
Average Generation Tariff	5.611270	5.503085	-0.108185

These generation average tariffs include local tariffs.

Average generation tariffs have decreased by £0.11/kW, due to the increase in the generation charging base. The generation residual has increased by £0.07/kW due to a slight reduction in revenue to be recovered from generation local charges, and the increased charging base.

7. Generation wider tariffs

The following section provides a summary of how the wider generation tariffs have changed between the June forecast and this Draft forecast. 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 45. 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)		

J. 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	-3.537457	25.283488	28.380259	19.023057
2	East Aberdeenshire	4.393220	9.220124	15.483854	-3.537457	20.618945	23.715716	15.634447
3	Western Highlands	1.436393	18.259144	15.522353	-3.537457	24.924134	28.028604	19.288554
4	Skye and Lochalsh	-2.864332	18.259144	17.231378	-3.537457	21.990629	25.436904	20.997579
5	Eastern Grampian and Tayside	2.043322	15.184507	14.767083	-3.537457	22.467137	25.420554	17.303429
6	Central Grampian	2.967375	14.208477	14.345112	-3.537457	22.272789	25.141812	16.491046
7	Argyll	2.973002	11.114505	24.583506	-3.537457	27.993954	32.910655	25.491851
8	The Trossachs	2.985196	11.114505	12.941107	-3.537457	18.692229	21.280450	13.849452
9	Stirlingshire and Fife	1.812251	8.514562	12.163013	-3.537457	14.816854	17.249457	12.031381
10	South West Scotlands	3.140376	9.845323	12.498708	-3.537457	17.478144	19.977885	12.899380
11	Lothian and Borders	3.851953	9.845323	6.686795	-3.537457	13.540190	14.877549	7.087467
12	Solway and Cheviot	2.070632	5.497614	7.254010	-3.537457	8.734474	10.185276	5.915599
13	North East England	4.306590	2.912948	3.907136	-3.537457	6.225200	7.006627	1.534858
14	North Lancashire and The Lakes	1.826522	2.912948	2.524088	-3.537457	2.638694	3.143511	0.151810
15	South Lancashire, Yorkshire and Humber	4.792817	0.495644	0.145609	-3.537457	1.768362	1.797484	-3.193590
16	North Midlands and North Wales	4.254582	-1.092088		-3.537457	-0.156545	-0.156545	-3.974292
17	South Lincolnshire and North Norfolk	2.412017	-0.604939		-3.537457	-1.609391	-1.609391	-3.779433
18	Mid Wales and The Midlands	1.511077	-0.155294		-3.537457	-2.150615	-2.150615	-3.599575
19	Anglesey and Snowdon	4.773680	-1.031192		-3.537457	0.411269	0.411269	-3.949934
20	Pembrokeshire	9.029701	-4.395975		-3.537457	1.975464	1.975464	-5.295847
21	South Wales & Gloucester	5.948658	-4.288358		-3.537457	-1.019485	-1.019485	-5.252800
22	Cotswold	2.744945	2.559043	-6.759012	-3.537457	-4.152487	-5.504290	-9.272852
23	Central London	-5.853432	2.559043	-6.745145	-3.537457	-12.739771	-14.088800	-9.258985
24	Essex and Kent	-3.866906	2.559043		-3.537457	-5.357129	-5.357129	-2.513840
25	Oxfordshire, Surrey and Sussex	-1.553471	-2.585615		-3.537457	-7.159420	-7.159420	-4.571703
26	Somerset and Wessex	-1.644081	-2.876601		-3.537457	-7.482819	-7.482819	-4.688097
27	West Devon and Cornwall	-0.094512	-5.153912		-3.537457	-7.755099	-7.755099	-5.599022

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 45 for specific ALFs.

Please note these tariffs do not include the effect of the Small Generator Discount, see page 27.

8. Changes since the last 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 June forecast.

Generation wider zonal tariffs

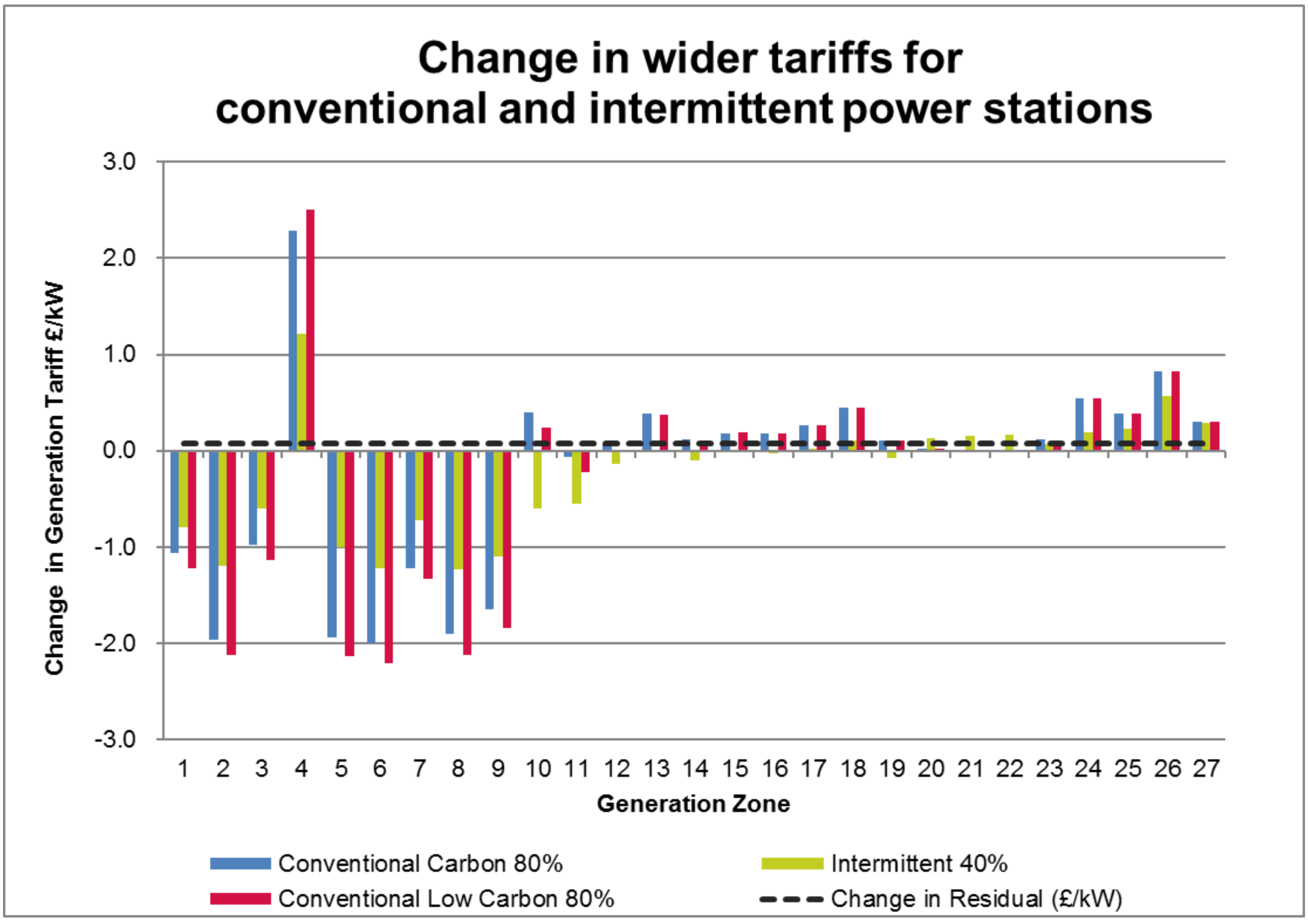
This table and chart show the changes in wider generation TNUoS tariffs between June and this Draft 2019/20 forecast.

K. Generation 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 June (£/kW)	2019/20 Draft (£/kW)	Change (£/kW)	2019/20 June (£/kW)	2019/20 Draft (£/kW)	Change (£/kW)	2019/20 June (£/kW)	2019/20 Draft (£/kW)	Change (£/kW)	
1	North Scotland	26.345708	25.283488	-1.062219	29.603820	28.380259	-1.223561	19.823923	19.023057	-0.800867	0.075603
2	East Aberdeenshire	22.587712	20.618945	-1.968767	25.845825	23.715716	-2.130109	16.833454	15.634447	-1.199008	0.075603
3	Western Highlands	25.908858	24.924134	-0.984724	29.169042	28.028604	-1.140438	19.895350	19.288554	-0.606796	0.075603
4	Skye and Lochalsh	19.699681	21.990629	2.290948	22.936847	25.436904	2.500057	19.780259	20.997579	1.217320	0.075603
5	Eastern Grampian and Tayside	24.414331	22.467137	-1.947194	27.553368	25.420554	-2.132814	18.303259	17.303429	-0.999830	0.075603
6	Central Grampian	24.275302	22.272789	-2.002513	27.352947	25.141812	-2.211136	17.712305	16.491046	-1.221259	0.075603
7	Argyll	29.220503	27.993954	-1.226549	34.245640	32.910655	-1.334985	26.219877	25.491851	-0.728026	0.075603
8	The Trossachs	20.601689	18.692229	-1.909460	23.400278	21.280450	-2.119828	15.087139	13.849452	-1.237687	0.075603
9	Stirlingshire and Fife	16.465625	14.816854	-1.648771	19.096667	17.249457	-1.847211	13.129724	12.031381	-1.098343	0.075603
10	South West Scotlands	17.079496	17.478144	0.398648	19.738803	19.977885	0.239083	13.495129	12.899380	-0.595749	0.075603
11	Lothian and Borders	13.610148	13.540190	-0.069958	15.097716	14.877549	-0.220166	7.636435	7.087467	-0.548968	0.075603
12	Solway and Cheviot	8.671828	8.734474	0.062646	10.172830	10.185276	0.012446	6.049626	5.915599	-0.134028	0.075603
13	North East England	5.839479	6.225200	0.385721	6.628095	7.006627	0.378532	1.536079	1.534858	-0.001221	0.075603
14	North Lancashire and The Lakes	2.515855	2.638694	0.122839	3.047320	3.143511	0.096191	0.250327	0.151810	-0.098517	0.075603
15	South Lancashire, Yorkshire and Humber	1.584518	1.768362	0.183845	1.608031	1.797484	0.189454	-3.182217	-3.193590	-0.011373	0.075603
16	North Midlands and North Wales	-0.334770	-0.156545	0.178225	-0.334770	-0.156545	0.178225	-3.945256	-3.974292	-0.029036	0.075603
17	South Lincolnshire and North Norfolk	-1.873027	-1.609391	0.263636	-1.873027	-1.609391	0.263636	-3.802778	-3.779433	0.023346	0.075603
18	Mid Wales and The Midlands	-2.598338	-2.150615	0.447723	-2.598338	-2.150615	0.447723	-3.710072	-3.599575	0.110497	0.075603
19	Anglesey and Snowdon	0.306670	0.411269	0.104599	0.306670	0.411269	0.104599	-3.873250	-3.949934	-0.076683	0.075603
20	Pembrokeshire	1.960401	1.975464	0.015063	1.960401	1.975464	0.015063	-5.419900	-5.295847	0.124053	0.075603
21	South Wales & Gloucester	-1.019434	-1.019485	-0.000051	-1.019434	-1.019485	-0.000051	-5.409209	-5.252800	0.156409	0.075603
22	Cotswold	-4.145800	-4.152487	-0.006687	-5.490958	-5.504290	-0.013331	-9.435387	-9.272852	0.162535	0.075603
23	Central London	-12.861636	-12.739771	0.121865	-14.184247	-14.088800	0.095448	-9.322652	-9.258985	0.063667	0.075603
24	Essex and Kent	-5.895761	-5.357129	0.538633	-5.895761	-5.357129	0.538633	-2.709596	-2.513840	0.195756	0.075603
25	Oxfordshire, Surrey and Sussex	-7.541737	-7.159420	0.382317	-7.541737	-7.159420	0.382317	-4.793508	-4.571703	0.221805	0.075603
26	Somerset and Wessex	-8.311909	-7.482819	0.829091	-8.311909	-7.482819	0.829091	-5.258619	-4.688097	0.570522	0.075603
27	West Devon and Cornwall	-8.051818	-7.755099	0.296720	-8.051818	-7.755099	0.296720	-5.884142	-5.599022	0.285120	0.075603

L. Variation in generation zonal tariffs



The new Week 24 data received from the DNOs has influenced system flows, particularly in Scotland. The DNOs have forecasted an increase in demand in demand zones 1 and 2 (generation zones 1-12) which has caused the majority of Scottish generation tariffs to reduce, except for zone 4. Zone 4 is volatile as it contains just one circuit which makes it sensitive to system flows in zone 3 and beyond.

Decreased Week 24 demand in demand zones 11 and 12 (London and South East) and significantly increased demand in zone 13 (Southern) have altered the balance of flows in southern England. The result is that there are some small rises in generation tariffs in zones 24-27.

Generation tariffs in the centre of Great Britain remain stable despite a 2.6GW reduction in Week 24 demand between Yorkshire and the South East.

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 average May to October RPI, and have been updated from the June forecast to reflect actual RPI for the period May 2018 to October 2018.

M. Local substation tariffs

2019/20 Local Substation Tariff (£/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	0.000000	0.355083	0.256797
>=1320 MW	Redundancy	0.000000	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 around a particular local circuit tariff, please feel free to contact us.

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 (table O).

N. Onshore local circuit tariffs

Most changes to local circuit tariffs have been very small, due to a small decrease in the expansion constant caused by RPI.

A few sites have seen significant changes to the local circuit tariffs, driven by the wider system flows or local generation/demand balance. In addition, we have updated circuit parameters as per the latest ETYS (ETYS 2018), which has led to changes to some 132kV circuit tariffs.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberdeen Bay	2.570844	Dunhill	1.412272	Lochay	0.360820
Achruach	4.233666	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	5.937499	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		

O. 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 2.14.4, 14.4, and 14.15.15 onwards.

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

Offshore local tariffs for generation

11. Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of price review or on transfer to the offshore transmission owner (OFTO). The tariffs are subsequently indexed by average May to October RPI each year. Offshore local generation tariffs associated with projects due to transfer in 2019/20 will be confirmed once asset transfer has taken place.

P. 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 June 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).

Q. 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.[3] 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.

The contracted TEC volumes used in this Draft 2018 forecast were based on the TEC register from 31 October 2018, in accordance with CUSC 14.15.6. This will not be updated in the Final tariffs to be published on 31 January 2019.

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

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

R. Interconnectors

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

15. Expansion Constant

The expansion constant has decreased from 14.552251 to 14.55225089. This reflects our latest view of RPI.

16. Local substation and offshore substation tariffs

Local onshore substation tariffs are indexed by average May to October RPI as are offshore local circuit tariffs, so these have been updated from the June forecast to reflect actual RPI for the period May 2018 to October 2018.

17. Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Compared to the June forecast, tariffs have now been calculated to recover £2,839.6m of revenue. This is a decrease of £39.7m from the June forecast of £2,879.3m, mainly due to revised forecast by Transmission Owners (TOs) on their allowed revenue figures (indicative figure only, and is subject to further changes until 25 January 2019).

S. Allowed revenues

£m Nominal Value	2018/19 TNUoS Revenue	2019/20 TNUoS Revenue				
	2018/19 (fixed forecast)	Initial Forecast	April Forecast	June Forecast	Nov Draft	Jan 2019 Final
National Grid						
Price controlled revenue	*1,653.9*	*1768.5*	*1728.1*	*1,770.6*	*1,737.7*	
Less income from connections	*44.0*	*41.9*	*44.0*	*44.0*	*31.6*	
Income from TNUoS	**1,609.9**	**1,726.6**	**1,684.1**	**1,726.6**	**1,706.1**	
Scottish Power Transmission						
Price controlled revenue	*364.8*	*404.5*	*404.5*	*404.5*	*397.5*	
Less income from connections	*14.9*	*14.5*	*14.5*	*14.5*	*14.5*	
Income from TNUoS	**350.0**	**390.0**	**390.0**	**390.0**	**383.0**	
SHE Transmission						
Price controlled revenue	*369.8*	*352.9*	*352.9*	*352.9*	*341.2*	
Less income from connections	*3.4*	*3.5*	*3.5*	*3.5*	*3.4*	
Income from TNUoS	**366.4**	**349.4**	**349.4**	**349.4**	**337.8**	
Offshore	*318.1*	*466.7*	*386.5*	*387.4*	*388.4*	
Network Innovation Competition	*32.7*	*42.5*	*32.7*	*32.7*	*32.7*	
Interconnectors (Cap & Floor)	*(6.8)*	*(6.8)*	*(6.8)*	*(6.8)*	*(8.4)*	
Total to Collect from TNUoS	**2,670.3**	**2,968.4**	**2,835.8**	**2,879.3**	**2,839.6**	

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 has decreased by 1.2% to 14% 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 below.

T. Generation and demand revenue proportions

		2019/20 June	2019/20 Draft
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50
y	Error Margin	21.0%	21.0%
ER	Exchange Rate (€/£)	1.12	1.12
MAR	Total Revenue (£m)	2,879.3	2,839.6
GO	Generation Output (TWh)	229.8	229.8
G	% of revenue from generation	14.0%	14.2%
D	% of revenue from demand	86.0%	85.8%
G.MAR	Revenue recovered from generation (£m)	403.5	403.5
D.MAR	Revenue recovered from demand (£m)	2475.7	2436.0

The total revenue paid by generation, £403.5m, is fixed for 2019/20 TNUoS tariffs.

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. We currently do not intend to update these forecasts again, but we reserve the right to do so before the publication of Final 2019/20 tariffs if we believe it necessary to ensure more accurate revenue recovery.

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. 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.

U. Charging bases

Charging Bases	2019/20 June	2019/20 Draft
Generation (GW)	71.9	73.3
NHH Demand (4pm-7pm TWh)	25.5	25.5
Net Charging		
Total Average Net Triad (GW)	43.6	43.6
HH Demand Average Net Triad (GW)	10.3	10.3
Gross charging		
Total Average Gross Triad (GW)	51.3	51.3
HH Demand Average Gross Triad (GW)	18.0	18.0
Embedded Generation Export (GW)	7.8	7.8

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 website.[4]

21. Generation and demand residuals

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

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

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

Where

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

[4] https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.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, and for EE the value of the AGIC[5] and phased residual.

V. Residual calculation

	Component	2019/20 June	2019/20 Draft
G	Proportion of revenue recovered from generation (%)	14.0%	14.2%
D	Proportion of revenue recovered from demand (%)	86.0%	85.8%
R	Total TNUoS revenue (£m)	2,879	2,840
Generation Residual			
R_G	Generator residual tariff (£/kW)	-3.61	-3.54
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	329.1	333.6
O	Revenue recovered from offshore local tariffs (£m)	296.0	289.0
L_S	Revenue recovered from onshore local substation tariffs (£m)	19.2	19.4
L_C	Revenue recovered from onshore local circuit tariffs (£m)	19.0	20.9
B_G	Generator charging base (GW)	71.9	73.3
Gross Demand Residual			
R_D	Demand residual tariff (£/kW)	51.70	50.82
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-66.7	-61.9
EE	Amount to be paid to Embedded Exports (£m)	110.9	110.6
B_D	Demand gross charging base	51.3	51.3

22.Small Generator Discount

The Small Generator Discount is defined in National Grid's licence condition C13. This licence condition expires on 31 March 2019. Previously a discount was applied to TNUoS tariffs for transmission connected generation <100MW, connected at 132kV.

[5] Avoided grid supply point infrastructure credit

As we have previously highlighted in the April and June forecasts[6] and the November 2017 and September 2018 five-year forecasts[7], there will be no Small Generator Discount from 1 April 2019. Therefore, applicable generators will no longer receive the discount to their TNUoS tariffs. Similarly, there will be no additional charge added to demand tariffs to recover the cost of the scheme. The tariffs in this report do not include the Small Generator Discount.

On 28 November 2018, Ofgem have launched a statutory consultation[8] on their proposal to extend the discount until 31 March 2021. If approved, this will mean the Small Generator Discount will apply in 2019/20.

If the Small Generator Discount is extended using the same methodology, we forecast

- The discount to affected small generators to be £11.821356/kW
- The additional tariff to add to all demand tariffs:
    - HH: £0.635515/kW, and
    - NHH: 0.082997p/kWh.

W. Small Generator Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-3.54
Demand Residual (£/kW)	D	50.82
Small Generator Discount (£/kW)	T = (G + D)/4	11.82
Forecast Small Generator Volume (kW)	V	2,759,260
2017/18 SGD cost (£)	V x T	32,618,195
Prior year reconcilation (£)	R	-
Total SGD Cost (£)	C = (V x T) + R	32,618,195
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	0.635515
Total Cost to HH Customers (£)	HHC = HHT * HHD	11,444,000
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.082997
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	21,174,194

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.

Ofgem's consultation closes on 4 January 2019, and the updated position will be reflected in Final tariffs.

6 https://www.nationalgrid.com/sites/default/files/documents/Forecast%20TNUoS%20Tariffs%20for%202019-20%20-%20Report_0.pdf p.31.
7 https://www.nationalgrid.com/sites/default/files/documents/Forecast%20from%202018-19%20to%202022-23%20%282%29.pdf p.26.
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

Tools and Supporting Information

Further information

We are keen to ensure that customers understand the current charging arrangements and the reason why tariffs change. If you have specific queries on this forecast, please contact us using the details below. Feedback on the content and format of this forecast is also welcome. We are particularly interested to hear how accessible you find the report and if it provides the right level of detail.

Charging forums

We will hold a webinar for the April tariffs on Friday 6 July 2018 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 should you wish to do so.

Charging models

We can provide a copy of our charging model. If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website 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 sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, National Grid determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: peak demand and year round. Where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced. To calculate flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on ‘standard’ conditions, which means that they reflect the cost of replacing assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational “residual” tariff elements are included in the generation and demand tariffs. The residual is also used to ensure the correct proportion of revenue is collected from generation and demand. The locational and residual tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate.

For generation customers, local tariffs are also calculated. These reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the main interconnected transmission system (MITS), the cost of local circuits that the generator uses to export onto the MITS. This allows the charges to reflect the cost and design of local connections and vary from project to project. For offshore generators, these local charges reflect revenue allowances.

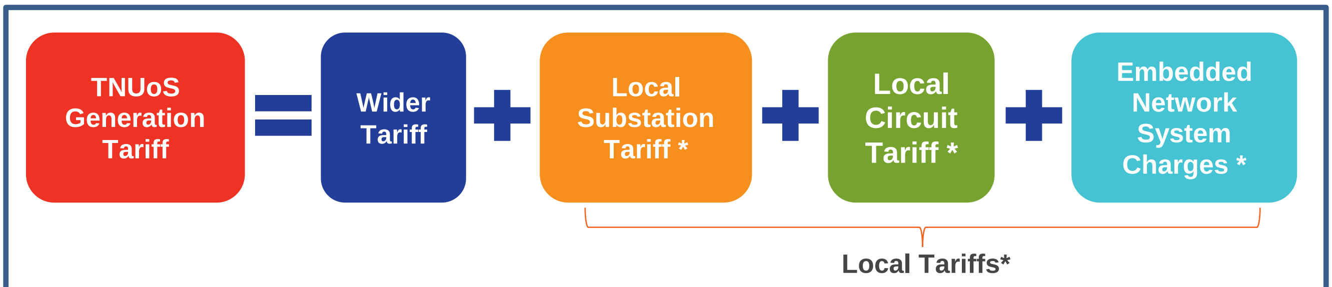
Generation charging principles

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

The TNUoS tariff specific to each generator depends on many factors, including the location, type of connection, connection voltage, plant type and volume of TEC (Transmission Entry Capacity) held by the generator. The TEC figure is equal to the maximum volume of MW the generator is allowed to output onto the transmission network.

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

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



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

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

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

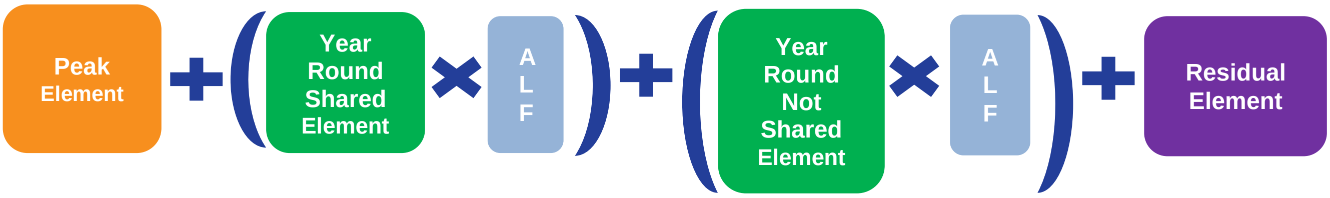
The Wider tariff

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

As CUSC Modification CMP268 has added an extra variation to the calculation formula, generators classed as Conventional Carbon now pay the Year Round Not Shared element in proportion to their ALF.

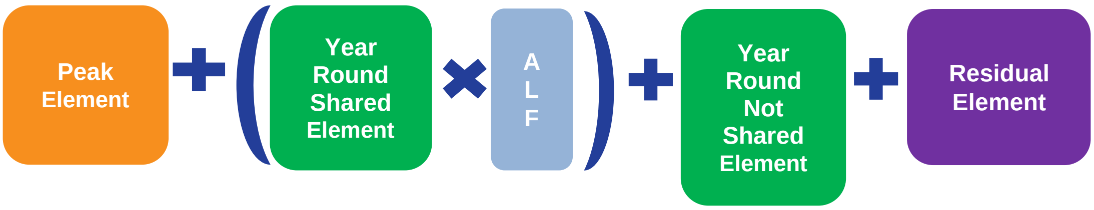
Conventional Carbon Generators

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



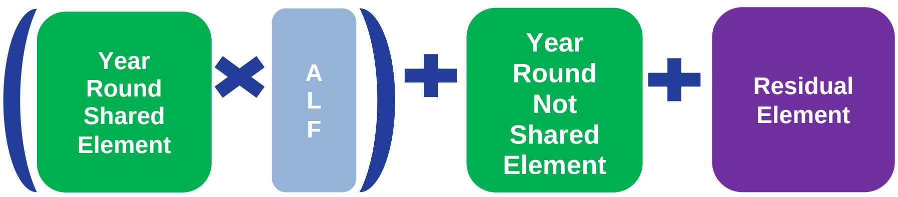
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

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

The 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 liability is as follows:

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

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 reconciliation, when the true amount to be paid to the generator is recalculated.

The value used for this reconciliation is the average output of the individual generator over the three settlement periods of highest output between 1 November and the end of February of the relevant charging year. Each settlement period must be separated by at least ten clear days.

[9] 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.

Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

For more details, please see CUSC 14.18.13–17.

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers now have two specific tariffs following the implementation of CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff.

HH gross demand tariffs

HH gross demand tariffs are charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.[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 NGET website. The tariff is charged on a £/kW basis. On triads, HH customers are charged the HH gross demand tariff against their gross demand volumes.

HH metered customers tend to be large industrial users, however as the rollout of smart meters progresses, more domestic demand will become HH metered as we have forecasted in the 2019/20 charging base under P339.

Embedded export tariffs

The EET is a new tariff 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 as to what their expected demand volumes will be. Customers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon (up to 16 months after the financial year in question).

Please note that if a supplier's forecast of embedded export volumes across their whole portfolio exceed the volume of HH gross demand in that zone, then they will be billed zero (instead of being paid on a monthly basis for their embedded export volumes).

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 showing their expected demand volumes will be in each demand zone. The tariff is charged on a p/kWh basis. The NHH methodology remains the same under CMP264/265.

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

Suppliers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon up to 16 months after the financial year in question.

B

Appendix B: Changes and proposed changes to the charging methodology

24. Changes and proposed changes to the charging methodology for 2019/20 and future years

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2019/20 onwards. All these modifications are subject to whether they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

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

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

A summary of the modifications already in progress which could affect the 2019/20 TNUoS tariffs and their status are listed below.

Other modifications may be raised throughout the year which may impact tariffs for 2019/20.

X. Summary of CUSC modifications affecting 2019/20 TNUoS Tariffs

Mod Number	Description	Status	Status in the Draft Tariffs
Modifications being considered by CUSC Workgroups which may affect tariffs from 1 April 2019, but are unlikely to reach a decision to impact 2019/20			
CMP280	Creation of a New Generator TNUoS Demand Tariff Which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users	At workgroup	Not implemented, as no decision yet published by Ofgem
CMP301	Clarification on the treatment of project costs associated with HVDC and subsea circuits	Sent back by Ofgem for further information in the Final Modifcation Report	Not implemented, as no decision yet published by Ofgem
CMP303	Improving local circuit charge cost-reflectivity	At workgroup	Not implemented as no decision yet published by Ofgem
CMP302	Extend the small generator discount until an enduring solution acknowledging the discrepancy between England and Wales, and Scotland is implemented	See page 27 of this report for the latest on the Small Generator Discount for 2019/20	
Modifications being considered by CUSC Workgroups which may affect the tariff setting process, having a consequential impact on how/when tariffs are known			
CMP286	Improving TNUoS Predictability through Increased Notice of the Target Revenue used in the TNUoS Tariff Setting Process	At workgroup	N/A
CMP287	Improving TNUoS Predictability Through Increased Notice of Inputs Used in the TNUoS Tariff Setting Process	At workgroup	N/A
CMP292	Introducing a Section 8 cut-off date for changes to the Charging Methodologies	At workgroup	N/A

C

Appendix C: Breakdown of HH and EET locational tariffs

25.Breakdown of HH and EET locational tariffs

Y. 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 June forecast to the Draft tariffs forecast.

Zone	2019/20 June		2019/20 Draft		Changes	
	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	-2.041245	-28.538572	-1.523975	-28.903803	0.517270	-0.365232
2	-2.244736	-20.655199	-1.800826	-18.842831	0.443910	1.812368
3	-3.578833	-6.826104	-3.900602	-6.471764	-0.321769	0.354340
4	-1.124121	-2.443992	-1.432273	-2.135195	-0.308152	0.308797
5	-2.839206	-0.436511	-3.268569	-0.091162	-0.429364	0.345349
6	-2.259558	0.273890	-2.505479	0.451798	-0.245921	0.177908
7	-2.158902	2.322930	-2.525629	2.566350	-0.366727	0.243420
8	-1.436307	2.897707	-1.718495	3.247513	-0.282189	0.349806
9	1.359903	0.846998	1.367046	1.022232	0.007143	0.175234
10	-6.144324	4.499897	-5.996327	4.322921	0.147997	-0.176977
11	4.213772	0.737291	3.956929	0.754873	-0.256843	0.017582
12	5.656190	2.408838	5.735163	2.041577	0.078973	-0.367261
13	1.816925	4.314972	1.918498	4.021235	0.101573	-0.293737
14	-0.955920	5.399888	-0.680238	4.967867	0.275682	-0.432021

Z. Breakdown of EET

This table shows the breakdown of the components that make up the embedded export tariff.

Demand Zone		2019/20 June			2019/20 Draft			Changes		
		Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)
1	Northern Scotland	-30.579817	3.327268	14.65	-30.427778	3.327268	14.65	0.152038	0.000000	0.00
2	Southern Scotland	-22.899934	3.327268	14.65	-20.643657	3.327268	14.65	2.256277	0.000000	0.00
3	Northern	-10.404937	3.327268	14.65	-10.372366	3.327268	14.65	0.032571	0.000000	0.00
4	North West	-3.568113	3.327268	14.65	-3.567468	3.327268	14.65	0.000645	0.000000	0.00
5	Yorkshire	-3.275717	3.327268	14.65	-3.359731	3.327268	14.65	-0.084014	0.000000	0.00
6	N Wales & Mersey	-1.985668	3.327268	14.65	-2.053681	3.327268	14.65	-0.068013	0.000000	0.00
7	East Midlands	0.164028	3.327268	14.65	0.040721	3.327268	14.65	-0.123307	0.000000	0.00
8	Midlands	1.461401	3.327268	14.65	1.529018	3.327268	14.65	0.067617	0.000000	0.00
9	Eastern	2.206901	3.327268	14.65	2.389278	3.327268	14.65	0.182377	0.000000	0.00
10	South Wales	-1.644427	3.327268	14.65	-1.673406	3.327268	14.65	-0.028979	0.000000	0.00
11	South East	4.951062	3.327268	14.65	4.711802	3.327268	14.65	-0.239261	0.000000	0.00
12	London	8.065028	3.327268	14.65	7.776739	3.327268	14.65	-0.288288	0.000000	0.00
13	Southern	6.131897	3.327268	14.65	5.939732	3.327268	14.65	-0.192164	0.000000	0.00
14	South Western	4.443968	3.327268	14.65	4.287630	3.327268	14.65	-0.156339	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 Draft tariff forecast.

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

Locational model 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.

AA.Demand profiles

Zone	Zone Name	2019/20 June					2019/20 Draft				
		Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)	Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	499	1,483	428	0.78	958	716	1,483	428	0.78	958
2	Southern Scotland	2,695	3,444	1,126	1.77	678	2,961	3,444	1,126	1.77	678
3	Northern	2,702	2,576	902	1.32	439	2,018	2,576	902	1.32	439
4	North West	3,067	4,037	1,413	2.02	410	3,103	4,037	1,413	2.02	410
5	Yorkshire	4,384	3,818	1,495	1.83	808	3,417	3,818	1,495	1.83	808
6	N Wales & Mersey	2,558	2,628	991	1.30	550	2,217	2,628	991	1.30	550
7	East Midlands	5,376	4,651	1,717	2.24	639	5,407	4,651	1,717	2.24	639
8	Midlands	4,425	4,251	1,389	2.17	335	4,777	4,251	1,389	2.17	335
9	Eastern	6,238	6,447	1,931	3.24	806	5,122	6,447	1,931	3.24	806
10	South Wales	1,674	1,822	779	0.88	510	1,371	1,822	779	0.88	510
11	South East	3,871	3,906	1,060	2.01	411	3,611	3,906	1,060	2.01	411
12	London	5,599	4,187	2,203	1.87	171	5,444	4,187	2,203	1.87	171
13	Southern	6,566	5,476	1,933	2.68	693	7,342	5,476	1,933	2.68	693
14	South Western	2,210	2,597	641	1.40	345	2,030	2,597	641	1.40	345
Total		**51,865**	**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

BB.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 Generic ALF listed below are 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.

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

CC.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 June forecast

This table shows the TEC changes notified between June 2018 and these Draft tariffs. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

The tariffs in this forecast are based on National Grid ESO's best view and therefore may include different generation to that shown below.

This table shows only the changes to the version of the TEC register used in this Draft forecast from 31 October 2018 compared to the TEC register used for the June forecast.

DD. Contracted generation TEC changes

Power Station	MW Change	Node	Generation Zone
Auchencrosh (interconnector CCT)	227.00	AUCH20	10
Carnedd Wen Wind Farm	-150.00	TRAW40	18
CDCL	50.00	COTT40	16
Crookedstane Windfarm	-26.80	CLYS2R	11
Eggborough	-1870.00	EGGB40	15
Holyhead	-210.00	WYLF40	19
Marex	-1500.00	CONQ40	16
Millennium South	-25.00	MILS1Q	3
Pogbie Wind Farm	-2.20	DUNE10	11
Robin Rigg East Offshore Wind Farm	6.00	HARK40	12
Spalding	70.00	SPLN40	17
Spalding Energy Expansion	-0.01	SPLN40	17
Whitson Substation	49.90	WHSO20	21

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.

G

Appendix G: Transmission company revenues

29. National Grid ETO (NGETO) revenue forecast

All onshore TOs (National Grid ETO, 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.

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

All reasonable care has been taken in the preparation of these illustrative tables and the data therein. NGETO and other 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 NGETO 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.

EE. Indicative NGETO revenue forecast

Description								Notes
Regulatory Year		**Licence Term**	**2018/19 (fixed forecast)**	**Initial Forecast**	**April Forecast**	**June Forecast**	**Nov Draft**	
Actual RPI								April to March average
RPI Actual		RPIAt						Office of National Statistics
Assumed Interest Rate		It	0.71%	0.56%	1.16%	1.16%	1.09%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1587.6	1585.2	1585.2	1585.2	1585.2	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-310.2	-334.0	-334.0	-334.0	-376.6	Forecast
RPI True Up	A3	TRUt	-6.1	3.3	3.3	3.3	3.3	Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.60%	3.50%	3.50%	3.50%	3.33%	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	3.40%	3.00%	3.00%	3.00%	3.08%	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.10%	3.00%	3.00%	3.00%	3.40%	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.3140	1.3570	1.3570	1.3570	1.3570	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1670.5**	**1702.3**	**1702.3**	**1702.3**	**1644.5**	
Pass-Through Business Rates	B1	RBt	1.6	35.1	0.0	0.0	35.1	Forecast
Temporary Physical Disconnection	B2	TPDt	0.7	0.0	0.0	0.0	0.4	Forecast
Licence Fee	B3	LFt	-0.4	4.5	0.0	0.0	4.3	Forecast
Inter TSO Compensation	B4	ITCt	1.3	0.8	0.0	0.0	-5.2	Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	0.0	0.0	Forecast
SP Transmission Pass-Through	B6	TSPt	350.0	390.0	390.0	390.0	383.0	Forecast
SHE Transmission Pass-Through	B7	TSHt	366.4	349.4	349.4	349.4	337.8	Forecast
Offshore Transmission Pass-Through	B8	TOFTOt	318.1	459.9	386.5	387.4	388.4	Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.5	0.6	0.6	0.6	0.6	Forecast
Interconnectors Cap&Floor Revenue Adjustment	B10	TICFt	-6.8		-6.8	-6.8	-8.4	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**1031.5**	**1240.2**	**1119.6**	**1120.6**	**1135.9**	
Reliability Incentive Adjustment	C1	RIt	4.1	4.2	4.2	4.2	3.8	Forecast
Stakeholder Satisfaction Adjustment	C2	SSOt	9.3	8.6	8.6	8.6	7.2	Forecast
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	1.4	1.6	1.6	1.6	3.1	Forecast
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**14.8**	**14.4**	**14.5**	**14.5**	**14.0**	
Network Innovation Allowance	D	NIAt	10.5	10.7	10.7	10.7	10.4	Forecast
Network Innovation Competition	E	NICFt	32.7	40.5	32.7	32.7	32.7	Forecast
Future Environmental Discretionary Rewards	F	EDRt	0.0	2.0	0.0	0.0	0.0	Forecast
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	0.0	0.0	Forecast
Scottish Site Specific Adjustment	H	DISt	6.6	0.0	0.0	0.0	0.0	Forecast
Scottish Terminations Adjustment	I	TSt	3.1	0.0	0.0	0.0	0.0	Forecast
Correction Factor	K	-Kt	-55.5	0.0	0.0	42.5	33.6	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2714.3**	**3010.2**	**2879.8**	**2923.3**	**2871.2**	
Pre-vesting connection charges	P		44.0	41.9	44.0	44.0	31.6	Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2670.3**	**2968.4**	**2835.8**	**2879.3**	**2839.6**	

30.Scottish Power Transmission revenue forecast

The Scottish Power Transmission revenue forecast has been updated for the Draft tariffs, and will be updated and finalised by 25 January 2019. The indicative Scottish Power Transmission revenue to be collected via TNUoS for 2019/20 is £383m.

31.SHE Transmission revenue forecast

The Scottish Hydro Electric Transmission (SHE Transmission) revenue forecast has been updated for the Draft tariffs, and will be updated and finalised by 25 January 2019. The indicative SHET Transmission revenue to be collected via TNUoS for 2019/20 is £338m.

32.Offshore Transmission Owner & Interconnector revenues

The Offshore Transmission Owner revenue forecast will be finalised by 25 January 2019. The indicative OFTO revenue to be collected via TNUoS for 2019/20 is £388.4m, an increase of £1m from June. Revenues have been adjusted to take into account an updated RPI forecast.

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 will be updated and confirmed by 25 January 2019. The interconnector revenue is currently forecast to reduce TNUoS revenues by around £8.4m (indicative figure only, and will be updated by 25 January 2019).

FF. Offshore revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="6">23/11/2018</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th><th>2017/18</th><th>2018/19</th><th>2019/20</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</td><td>6.3</td><td>6.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>7.4</td><td>7.8</td><td>8.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>13.1</td><td>13.6</td><td>14.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>8.4</td><td>8.7</td><td>9.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>12.5</td><td>12.3</td><td>16.3</td><td>14.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.0</td><td>20.7</td><td>21.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>12.2</td><td>12.6</td><td>13.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>27.3</td><td>28.4</td><td>29.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>39.5</td><td>39.5</td><td>41.8</td><td>43.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>15.7</td><td>19.5</td><td>18.6</td><td>19.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>25.6</td><td>26.7</td><td>27.2</td><td>28.2</td><td>29.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.6</td><td>29.3</td><td>32.7</td><td>34.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.3</td><td>22.0</td><td>22.6</td><td>22.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td></td><td rowspan="2">29.3</td><td>9.7</td><td>12.1</td><td>12.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td></td><td>11.6</td><td>13.2</td><td>13.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Burbo Bank</td><td></td><td></td><td></td><td></td><td rowspan="2">34.3</td><td>13.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Dudgeon</td><td></td><td></td><td></td><td></td><td rowspan="2">84.4</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2019/20</td><td></td><td></td><td></td><td></td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>260.8</td><td>265.5</td><td>317.9</td><td>388.4</td><td></td></tr>
</table>

Notes:

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

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

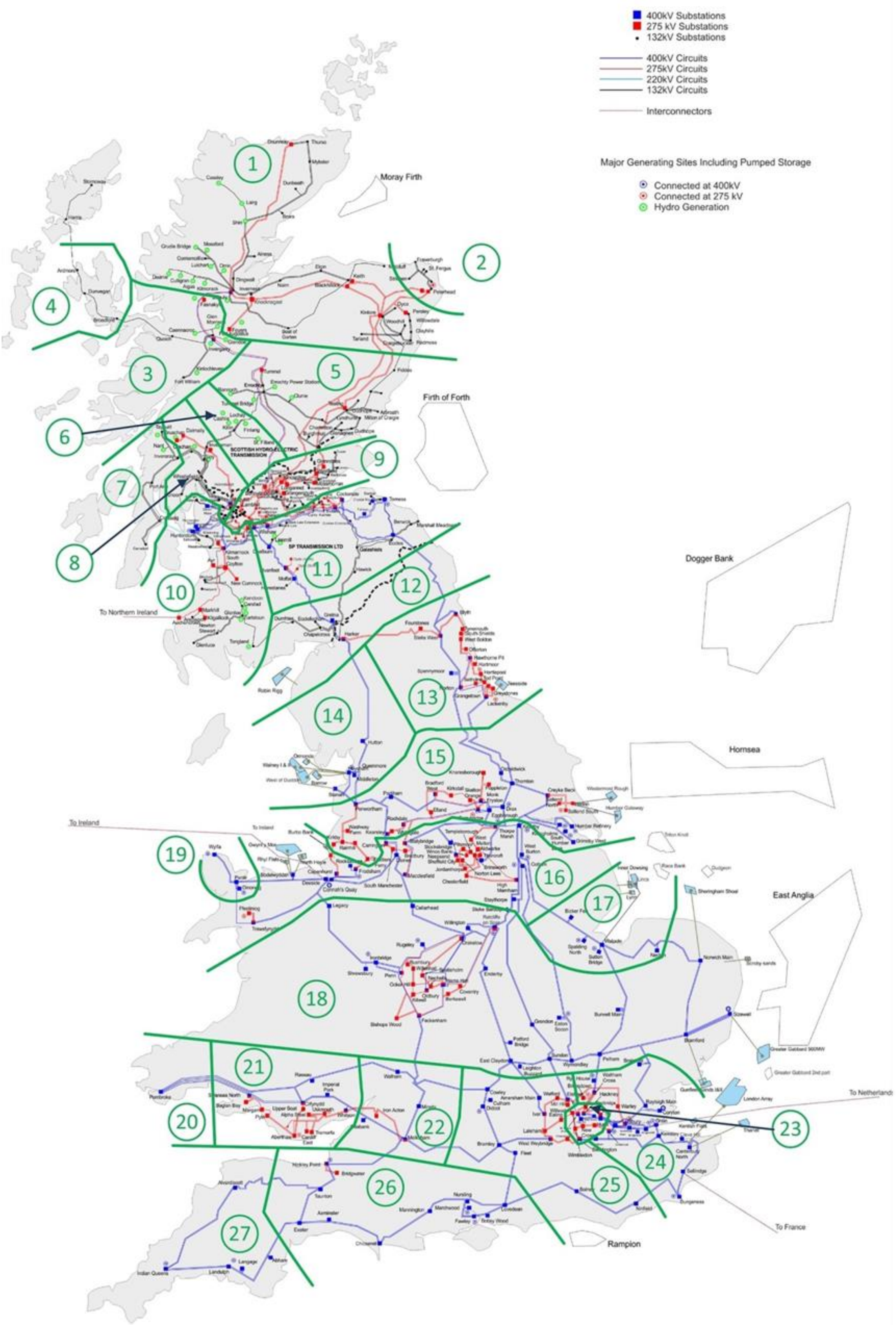
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formula are constructed

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

H

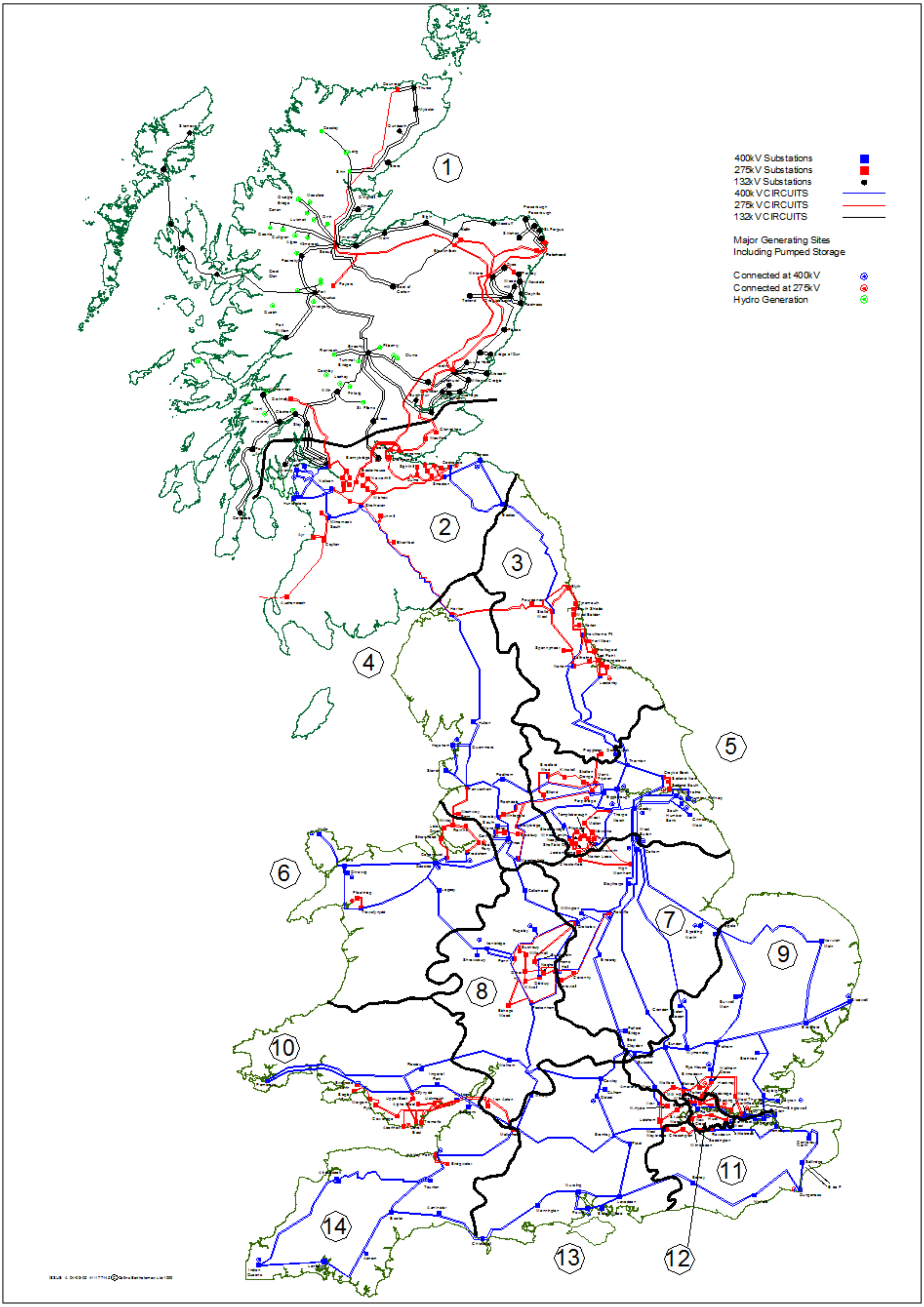
Appendix H: Generation zones map

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
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11
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14

J

Appendix J: Future changes to TNUoS parameters

33.Parameters affecting TNUoS tariffs

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

Our intention is to have already fixed the demand charging base at this forecast. However there has been increasing volatility in many of the inputs in recent years (for example, the high winter 2017/18 embedded export volume). This means we may need to adjust the values later to ensure we set tariffs to recover the total allowed revenue.

2019/20 TNUoS Tariff Forecast						
		November 2017	April 2018	June 2018	Draft tariffs THIS FORECAST	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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