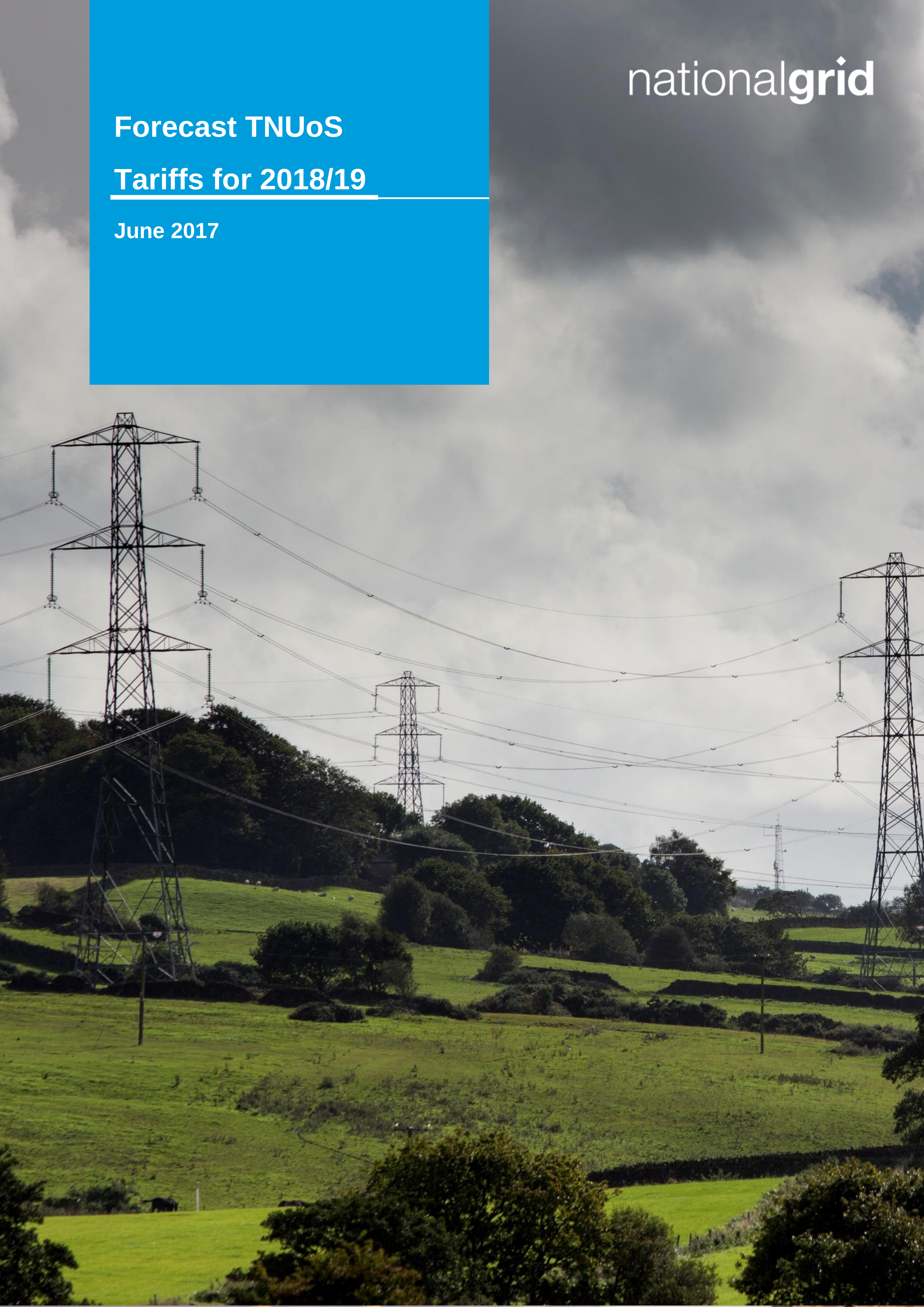
Forecast TNUoS

Tariffs for 2018/19

June 2017



Forecast TNUoS Tariffs for 2018/19

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

June 2017

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Contact Us

If you have any comments or questions on the contents or format of this report, please don’t hesitate to get in touch with us.

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Executive Summary

This document contains the latest draft of the Transmission Network Use of System (TNUoS) tariffs for 2018/19, which will become effective on 1 April 2018. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.

Total Revenues to be recovered

Total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges is forecast to be £2,820m in 2018/19, a decrease of £13m from the five year forecast published in February 2017.

Generation Tariffs

Generation tariffs have been set to recover £430.1m to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010. This is a £3.2m increase in generation revenue compared to the February forecast, which reflects an increase in the forecast generation output. However, this is offset by an increase in the generation charging base of circa 3GW and an increase in the Euro exchange rate, resulting in an overall average decrease of £0.21/kW to generation tariffs. The Error Margin element of the tariff forecast which is used to calculate the split of revenue to be recovered from generation and demand (the G/D split) remains fixed at 21%.

Demand Tariffs

Demand tariffs have been set to recover £2,389.6m of revenue, a decrease of £17m from the February forecast. This reflects the above reduction in overall revenue for GB Transmission Owners, and the increased proportion of revenue to be collected from generators.

Modelling Changes

We have further developed our demand forecasting capability that we began in 2016/17. The demand model takes into account the significant increase in distributed generation in recent years and its potential variability. For 2018/19 we are forecasting average triad demand of 46 GW, average Half-Hour (HH) triad demand of 13.2GW and Non-Half-Hour (NHH) demand of 24.2TWh.

These chargeable demand numbers, G/D split and updated TO revenues mean that the average HH demand tariff has reduced by £0.57/kW and the average NHH demand tariff has increased by 0.05p/kWh compared to the February forecast.

Drivers of changes to the Tariff forecast

Changes to these forecast tariffs in relation to our February tariff forecast have predominantly been influenced by a reduction in total revenue and a new demand forecast, which has altered the balance between HH and NHH demand. Updated generation output data and the forecast £:€ exchange rate from the OBR Spring Forecast have further changed the proportions of revenue to be recovered from generaton and demand.

CMP264/265 and future changes to the methodology

Please note that this tariff forecast has been undertaken in accordance with the current CUSC charging methodology and therefore no current charging modifications are taken into account in these tariffs. There has not been enough time since Ofgem's recent decision on CMP264/265[1] for us to recalculate these tariffs in accordance with the new methodology, however we have revised our forecasts schedule and will publish our first tariff forecast in compliance with CMP264/265 in October 2017.[2] More details on ongoing charging modifications can be found on the National Grid website[3].

CMP282

We are also aware of an issue with the methodology leading to a potentially incorrect signal in the Final Zonal Locational Demand Tariff. This is currently manifesting itself in North Scotland (Zone 1), where the locational demand tariff, when calculated, is being affected by nodes which are exporting. The calculation in the methodology requires taking a zonal weighted demand, and this is affecting the cost reflectivity of the final tariffs.

To address this issue, CUSC Modification CMP282 - The Effect Negative Demand has on Zonal Locational Demand Tariffs has been raised by National Grid at the June CUSC Panel. The modification is proposed to be treated as urgent, with a view to revising the charging methodology from 1 April 2018, and be reflected in our tariff forecasts later this year.

Feedback

This tariff forecast is the first in our new report format, which has been redesigned in order to be easier to navigate and read for all interested parties. We welcome feedback on any aspect of this document and the

[1] *https://www.ofgem.gov.uk/system/files/docs/2017/06/impact_assessment_and_decision_on_industry_cmp264265.pdf*

[2] *Our revised forecast publication timetable is available on our website: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940926*

[3] *Please find further information here: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/*

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, if you have any questions on this document or whether you still welcome webinar sessions following each forecast.

Next forecast

Following the Ofgem decision on CMP264/265, NGET will publish the new "Avoided GSP Infrastructure Credit" (AGIC) figure in September, which will then be used in the forecast for 2018/19 tariffs in October 2017 and also for tariffs in the updated five year forecast due to be published in November 2017.

Following this, we will publish draft tariffs in December 2017 and final tariffs in January 2018.

The latest timetable can be found on our website.[4]

[4] *Our revised forecast publication timetable is available on our website: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940926*

Demand Tariffs

Table 1: Demand Tariffs

The breakdown of the HH tariff into the peak and year round components are found in Appendix A (page 30).

Please note that these tariffs do not take into account the changes to the charging methodology directed by CMP264/265.

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	52.136314	10.184611
2	Southern Scotland	33.996249	4.711528
3	Northern	43.488827	6.143092
4	North West	50.229757	6.512836
5	Yorkshire	49.861241	6.776159
6	N Wales & Mersey	51.571129	7.081867
7	East Midlands	52.800186	7.009019
8	Midlands	54.548379	7.115274
9	Eastern	54.385826	7.782534
10	South Wales	50.953376	6.519821
11	South East	57.217814	8.184488
12	London	59.695139	6.091993
13	Southern	58.571055	7.772624
14	South Western	58.296471	8.233390

Tariffs include small gen tariff of:	0.808401	0.109642
Residual charge for demand:	£ 52.204555	

1.1. Changes Since The Previous Demand Tariffs Forecast

On the whole, demand tariffs remain relatively stable when compared to those forecast in February, with the exception of certain zones which have felt the impact of reduced generation (HH), or a change to the demand forecast in that particular zone (NHH).

The average HH tariff has reduced by £0.57/kW compared to February, and the average NHH tariff has increased by a modest 0.05p/kW. More information on the causes of specific zonal fluctuations are detailed in the HH and NHH sections below.

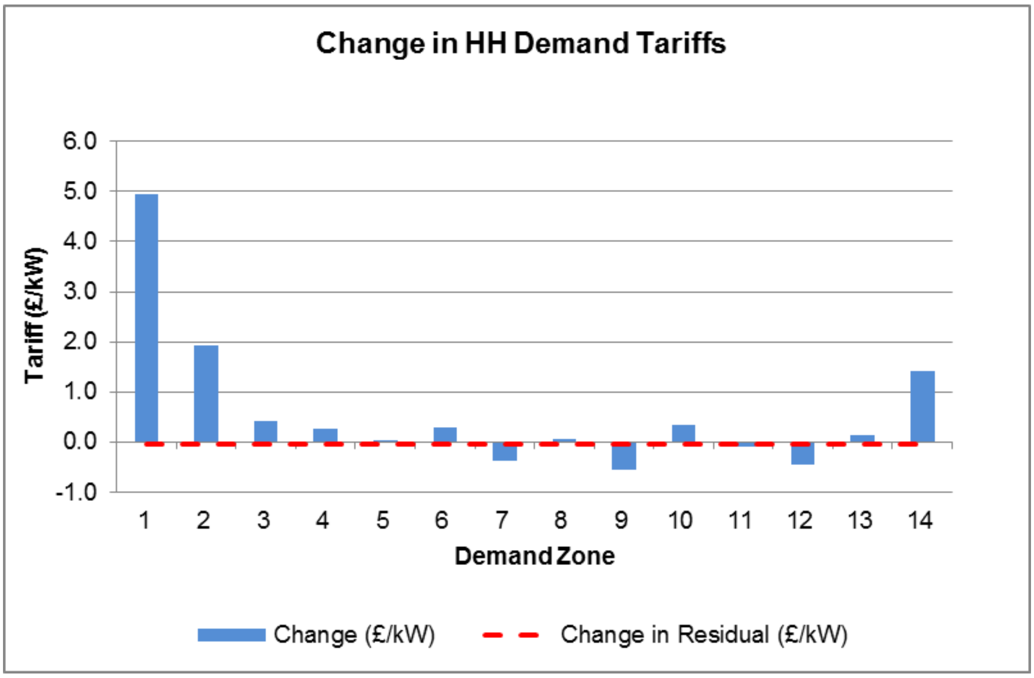
1.2. Half-Hourly Demand Tariffs

Table 2 and Figure 1 show the difference between the Half-Hourly (HH) demand tariffs forecast in February and this 2018/19 forecast in June.

Table 2 - Change in HH Demand Tariffs

Zone	Zone Name	2018/19 Feb Forecast (£/kW)	2018/19 June (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	47.20	52.14	4.94	-0.04
2	Southern Scotland	32.07	34.00	1.93	-0.04
3	Northern	43.06	43.49	0.43	-0.04
4	North West	49.96	50.23	0.27	-0.04
5	Yorkshire	49.84	49.86	0.02	-0.04
6	N Wales & Mersey	51.29	51.57	0.28	-0.04
7	East Midlands	53.18	52.80	-0.38	-0.04
8	Midlands	54.49	54.55	0.06	-0.04
9	Eastern	54.95	54.39	-0.56	-0.04
10	South Wales	50.61	50.95	0.34	-0.04
11	South East	57.31	57.22	-0.09	-0.04
12	London	60.16	59.70	-0.46	-0.04
13	Southern	58.44	58.57	0.13	-0.04
14	South Western	56.89	58.30	1.41	-0.04

Figure 1 - Change in HH Demand Tariffs



Although the demand charging base has reduced slightly by 0.4GW, the average HH demand tariff has decreased by £0.57/kW. This is largely due to a decrease in the total revenue forecast to be recovered, as well as a decrease in the share of that revenue being recovered from demand customers compared to the February forecast.

The decrease in demand share is a direct result of an increase in the share of revenue to be recovered from generation, which went up because of an increase in the forecast generation output assumptions used to calculate the €2.5/MWh cap on average annual generation tariffs.

The residual element of the tariff has decreased very slightly by £0.04/kW. As the locational element of HH demand tariffs is typically very small compared to the residual element, changes to HH demand tariffs were therefore negligible in most zones.

Exceptions to this were zones 1 and 2 (Scotland), which increased by £5/kW and £2/kW respectively due to the loss of generation from Peterhead, and zone 14 (Southwest), which increased by £1.40/kW due to the loss of generation from Rampion offshore wind farm and Taylors Lane. An additional 3GW of generation largely in the Midlands has shifted the concentration of generation volumes further towards the middle of England and Wales, affecting both the northern and southern extremities of the network..

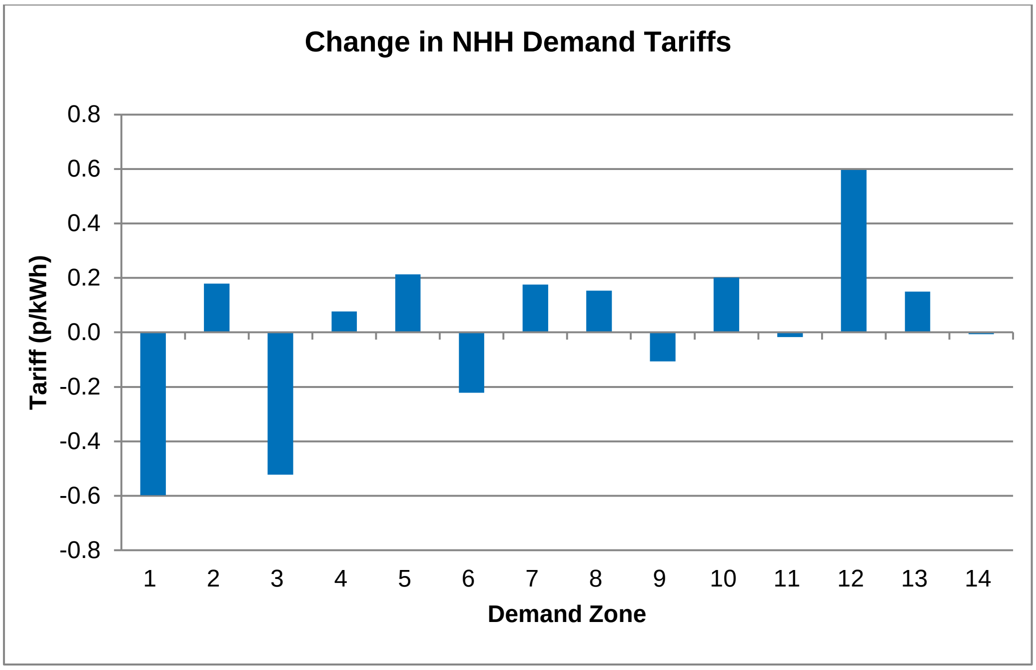
1.3. Non Half-Hourly demand tariffs

Table 3 and Figure 2 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in February and this 2018/19 in June.

Table 3 - NHH Demand Tariff Changes

Zone	Zone Name	2018/19 Feb Forecast (p/kWh)	2018/19 June (p/kWh)	Change (p/kWh)
1	Northern Scotland	10.78	10.18	-0.60
2	Southern Scotland	4.53	4.71	0.18
3	Northern	6.67	6.14	-0.52
4	North West	6.44	6.51	0.08
5	Yorkshire	6.56	6.78	0.21
6	N Wales & Mersey	7.30	7.08	-0.22
7	East Midlands	6.83	7.01	0.18
8	Midlands	6.96	7.12	0.15
9	Eastern	7.89	7.78	-0.11
10	South Wales	6.32	6.52	0.20
11	South East	8.20	8.18	-0.02
12	London	5.50	6.09	0.60
13	Southern	7.62	7.77	0.15
14	South Western	8.24	8.23	-0.01

Figure 2 - NHH Tariff Demand Changes



The weighted average Non Half Hour tariff is 0.05p/kWh higher than in the February forecast. This slight increase is attributable to the reduction in revenue being collected from HH demand compared to February. The decrease in revenue collected from HH is offset slightly by the increase in the NHH charging base, which reduces the average NHH tariff.

The variations year on year across the zones are attributable to changes in our demand forecast modelling approach which seeks, in particular, to more accurately capture variations in embedded renewable generation across GB. Compared to the February forecast, the most notable zones affected by these variations are 1, 3 and 12. In zones 1 and 3 the tariffs have reduced due to increases to forecast HH demand in those zones, and conversely in zone12 the tariff has increased due to a reduction in forecast HH demand in that zone.

Generation Tariffs

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

1.4. Wider Generation Tariffs

Table 4 - Wider Generation Tariffs

Under the current methodology** each generator has its own load factor as listed in Appendix C. The 80% and 40% loads factors used in this table are only for illustration.

Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	-0.210520	8.076163	23.626623	-3.282083	26.594951	23.575006
2	East Aberdeenshire	-0.406648	8.076163	17.446444	-3.282083	20.218644	17.394827
3	Western Highlands	0.515407	7.693754	22.936170	-3.282083	26.324497	22.731589
4	Skye and Lochalsh	0.515316	7.693754	28.540867	-3.282083	31.929103	28.336285
5	Eastern Grampian and Tayside	1.779736	6.930762	20.887562	-3.282083	24.929824	20.377784
6	Central Grampian	2.080116	6.963769	21.006585	-3.282083	25.375633	20.510010
7	Argyll	1.344614	6.227895	28.944261	-3.282083	31.989108	28.153336
8	The Trossachs	1.864294	6.227895	18.275168	-3.282083	21.839694	17.484243
9	Stirlingshire and Fife	0.201519	4.300650	15.627707	-3.282083	15.987664	14.065884
10	South West Scotlands	2.025923	5.076922	16.491119	-3.282083	19.296497	15.239805
11	Lothian and Borders	2.833709	5.076922	11.276474	-3.282083	14.889638	10.025160
12	Solway and Cheviot	1.310078	3.171855	9.102346	-3.282083	9.667825	7.089006
13	North East England	3.306996	2.129538	4.827436	-3.282083	6.555980	2.397168
14	North Lancashire and The Lakes	1.075453	2.129538	3.281384	-3.282083	2.778385	0.851117
15	South Lancashire, Yorkshire and Humber	4.171561	0.890570	0.169359	-3.282083	1.771293	-2.756496
16	North Midlands and North Wales	3.802341	-0.519620		-3.282083	0.104562	-3.489931
17	South Lincolnshire and North Norfolk	2.206630	0.131157		-3.282083	-0.970527	-3.229620
18	Mid Wales and The Midlands	1.209259	0.487865		-3.282083	-1.682532	-3.086937
19	Anglesey and Snowdon	3.932905	-0.760159		-3.282083	0.042695	-3.586146
20	Pembrokeshire	9.062924	-3.935393		-3.282083	2.632527	-4.856240
21	South Wales & Gloucester	5.996536	-4.063952		-3.282083	-0.536708	-4.907664
22	Cotswold	2.831022	2.748226	-6.915651	-3.282083	-5.168131	-9.098443
23	Central London	-4.831293	2.748226	-5.749784	-3.282083	-11.664579	-7.932577
24	Essex and Kent	-3.698006	2.748226		-3.282083	-4.781509	-2.182793
25	Oxfordshire, Surrey and Sussex	-1.041279	-2.185686		-3.282083	-6.071910	-4.156357
26	Somerset and Wessex	-1.654810	-4.099243		-3.282083	-8.216287	-4.921780
27	West Devon and Cornwall	-1.024845	-6.380280		-3.282083	-9.411151	-5.834195
		Small Generation Discount (£/kW)			12.230618		

1.5. Changes Since The Last Generation Tariffs Forecast

The following section provides details of the wider and local generation tariffs for 2018/19 and how these have changed compared with the February forecast.

Wider zonal generation tariffs

** https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

Table and Figure 3 show the changes in generation wider TNUoS tariffs between February and this June 2018/19 forecast.

The key changes between the two years are due to several factors. Plant closures and TEC reductions in northern Scotland and south west England have the effect of concentrating the volume of conventional generation in the Midlands. This has slightly increased the Not Shared element of the generation tariffs in zones 1 – 12, and has caused the Peak element of the tariffs to increase in zones 1-16. The Year Round Shared element has decreased in zones 1-14. The effect in the south of England has been a further reduction in generation tariffs overall for zones 26 and 27 due to the reduction in conventional generation in southern England.

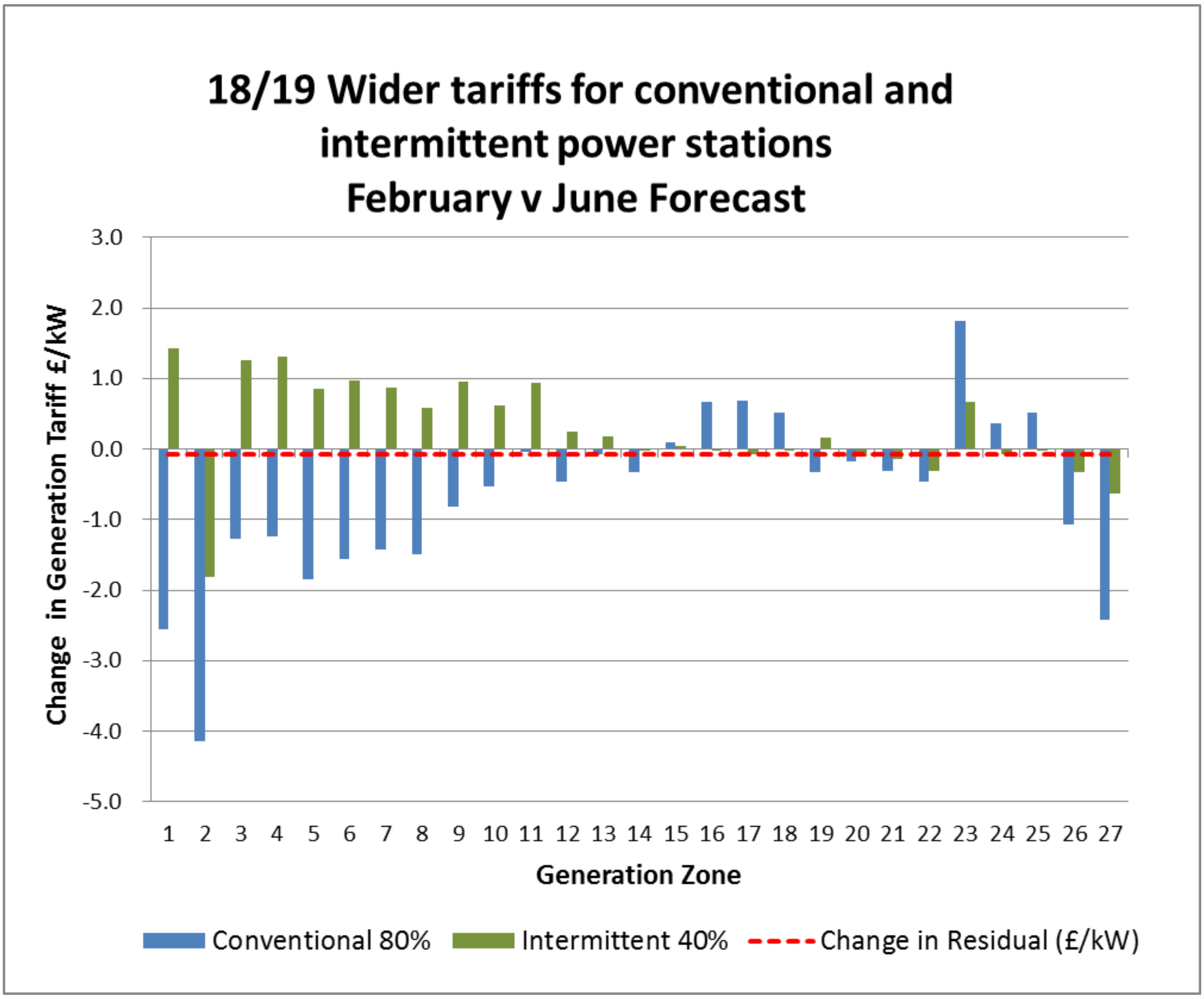
As an example, Table 5 and Figure 3 show how the tariffs change for a conventional generator with an 80% load factor and an intermittent generator with a 40% load factor. Under the Transmit methodology each generator has its own load factor and the 80% and 40% load factors used here are only for illustration.

On average generation tariffs have reduced by £0.21/kW due to an increase in the generation charging base of just under 3GW and a stronger Euro compared to the February forecast. This has been offset slightly by the increase in revenue to be recovered from generation within the €2.5/MWh cap on average annual generator charges, caused by a higher total forecast generation output (TWh) than in the February forecast.

Table 5 – Generation tariff changes

		Wider Generation Tariffs (£/kW)						
		Conventional 80%			Intermittent 40%			
Zone	Zone Name	2018/19 February tariffs (£/kW)	2018/19 June tariffs (£/kW)	Change (£/kW)	2018/19 February tariffs (£/kW)	2018/19 June tariffs (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	29.15	26.59	-2.55	22.14	23.58	1.43	-0.08
2	East Aberdeenshire	24.36	20.22	-4.14	19.22	17.39	-1.82	-0.08
3	Western Highlands	27.61	26.32	-1.28	21.47	22.73	1.26	-0.08
4	Skye and Lochalsh	33.17	31.93	-1.25	27.03	28.34	1.30	-0.08
5	Eastern Grampian and Tayside	26.77	24.93	-1.84	19.53	20.38	0.85	-0.08
6	Central Grampian	26.93	25.38	-1.56	19.54	20.51	0.97	-0.08
7	Argyll	33.41	31.99	-1.42	27.28	28.15	0.87	-0.08
8	The Trossachs	23.33	21.84	-1.49	16.90	17.48	0.58	-0.08
9	Stirlingshire and Fife	16.81	15.99	-0.82	13.12	14.07	0.95	-0.08
10	South West Scotlands	19.83	19.30	-0.53	14.62	15.24	0.62	-0.08
11	Lothian and Borders	14.93	14.89	-0.04	9.09	10.03	0.94	-0.08
12	Solway and Cheviot	10.12	9.67	-0.46	6.84	7.09	0.25	-0.08
13	North East England	6.63	6.56	-0.08	2.21	2.40	0.19	-0.08
14	North Lancashire and The Lakes	3.10	2.78	-0.33	0.88	0.85	-0.03	-0.08
15	South Lancashire, Yorkshire and Humber	1.68	1.77	0.09	-2.79	-2.76	0.04	-0.08
16	North Midlands and North Wales	-0.57	0.10	0.68	-3.47	-3.49	-0.02	-0.08
17	South Lincolnshire and North Norfolk	-1.65	-0.97	0.68	-3.16	-3.23	-0.07	-0.08
18	Mid Wales and The Midlands	-2.20	-1.68	0.52	-3.07	-3.09	-0.01	-0.08
19	Anglesey and Snowdon	0.37	0.04	-0.33	-3.75	-3.59	0.17	-0.08
20	Pembrokeshire	2.80	2.63	-0.17	-4.75	-4.86	-0.11	-0.08
21	South Wales & Gloucester	-0.23	-0.54	-0.31	-4.77	-4.91	-0.14	-0.08
22	Cotswold	-4.70	-5.17	-0.47	-8.79	-9.10	-0.31	-0.08
23	Central London	-13.47	-11.66	1.81	-8.60	-7.93	0.67	-0.08
24	Essex and Kent	-5.14	-4.78	0.36	-2.11	-2.18	-0.07	-0.08
25	Oxfordshire, Surrey and Sussex	-6.59	-6.07	0.52	-4.14	-4.16	-0.02	-0.08
26	Somerset and Wessex	-7.15	-8.22	-1.07	-4.59	-4.92	-0.33	-0.08
27	West Devon and Cornwall	-6.99	-9.41	-2.42	-5.20	-5.83	-0.64	-0.08

Figure 3 - Variation in Generation Zonal Tariffs



Local Substation and Circuit Tariffs for generation

2.1. Onshore Local Substation Tariffs

Onshore local substation tariffs

Local substation tariffs reflect the cost of the first transmission substation to which transmission connected generators connect. They are increased each year by Average May – October RPI, so have been updated from the February forecast to reflect latest forecast RPI for the period May 17 – October 17.

Table 6 - Local Substation Tariffs

2018/19		Local Substation Tariff (£/kW)		
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.191626	0.109622	0.078985
<1320 MW	Redundancy	0.422136	0.261178	0.18995
>=1320 MW	No redundancy	0	0.343714	0.248575
>=1320 MW	Redundancy	0	0.564291	0.411885

2.2. Onshore Local Circuit Tariffs

Onshore local circuit tariffs

Where a transmission connected generator is not directly connected to the Main Interconnected Transmission System (MITS) the Onshore Local Circuit Tariffs reflect the cost and flows on circuits between its connection and the MITS. Local circuit tariffs can change as a result of system flows and RPI. If you require further information around a particular local circuit tariff please feel free to contact us.

Some local circuits have been charged through a one off charge, these are listed below.

Table 7 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	4.088272	Dinorwig	2.289959	Kilmorack	0.188494	Kype Muir	1.415669
Aigas	0.624226	Dunlaw Extension	1.433394	Langage	0.627545	Middle Muir	1.891869
An Suidhe	2.926238	Dunhill	1.367057	Lochay	0.349268	Dorenell	2.003013
Arecleoch	1.982306	Dumnaglass	1.771997	Luichart	0.548757	Millennium South	0.899366
Baglan Bay	0.725716	Edinbane	6.534536	Mark Hill	0.835672	Aberdeen Bay	2.488536
Beinneun Wind Farm	1.433253	Earlshaugh Wind Farm	3.598510	Margree	5.746273	Killingholme	0.694025
Bhlaraidh Wind Farm	0.616232	Ewe Hill	1.311575	Marchwood	0.364401	Middleton	0.107546
Black Hill	0.823461	Fallago	0.940587	Millennium Wind	1.742851		
BlackCraig Wind Farm	6.008224	Farr	3.402954	Moffat	0.164241		
Black Law	1.667756	Fernoch	4.198828	Mossford	2.749491		
BlackLaw Extension	3.536692	Ffestiniogg	0.241471	Nant	2.395831		
Bodelwyddan	0.109817	Finlarig	0.305610	Necton	1.073272		
Carrington	-0.030919	Foyers	0.718678	Rhigos	0.096786		
Clyde (North)	0.104670	Galawhistle	1.411626	Rocksavage	0.016889		
Clyde (South)	0.121046	Glendoe	1.755605	Saltend	0.325438		
Corriegarth	3.008988	Glenglass	9.268419	South Humber Bank	0.903127		
Corriemoillie	1.589326	Gordonbush	1.114121	Spalding	0.266324		
Coryton	0.049614	Griffin Wind	-0.874657	Strathbrora	0.738476		
Cruachan	1.748267	Hadyard Hill	2.641776	Stronelairg	1.374793		
Crystal Rig	0.348083	Harestanes	2.395192	Strathy Wind	1.970846		
Culligran	1.654214	Hartlepool	0.573752	Wester Dodds	0.672854		
Deanie	2.717637	Hedon	0.172703	Whitelee	0.101294		
Dersalloch	2.299054	Invergarry	1.354828	Whitelee Extension	0.281596		
Didcot	0.496808	Kilgallioch	1.004494	Gills Bay	2.403616		

Table 8 - CMP203: Circuits subject to one off charges

As part of their connection offer, generators can agree to undertake one-off payments for connection assets, which affect the way that they are modelled in the Transport and Tariff model. This table shows the lines which have been amended in the model to account for the one-off charges that have already been made ot 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
Crystal Rig 132kV	Western 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
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

3.1. Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of price review or on transfer to the offshore transmission owner (OFTO) and indexed by average May to October RPI each year, so have been updated from the February forecast to reflect latest forecast RPI for the period May 17 – October 17. Offshore local generation tariffs associated with Offshore Transmission Owners yet to be appointed will be calculated following their appointment.

Table 9 - Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.721927	40.401113	1.003215
Greater Gabbard	14.477705	33.268340	0.000000
Gunfleet	16.711919	15.342850	2.867667
Gwynt Y Mor	17.631527	17.369232	0.000000
Lincs	14.431001	56.500667	0.000000
London Array	9.823561	33.458502	0.000000
Ormonde	23.872050	41.391724	0.000000
Robin Rigg East	-0.441601	29.252269	9.066625
Robin Rigg West	-0.441601	29.252269	9.066625
Sheringham Shoal	23.064538	27.049300	0.587972
Thanet	17.564484	32.728911	0.787900
Walney 1	20.602711	41.030246	0.000000
Walney 2	20.452873	41.391724	0.000000
West of Duddon Sands	7.950024	39.228440	0.000000
Westermost Rough	16.740078	28.317048	0.000000
Humber Gateway	14.030665	31.657856	0.000000

Background to TNUoS Charging

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

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

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

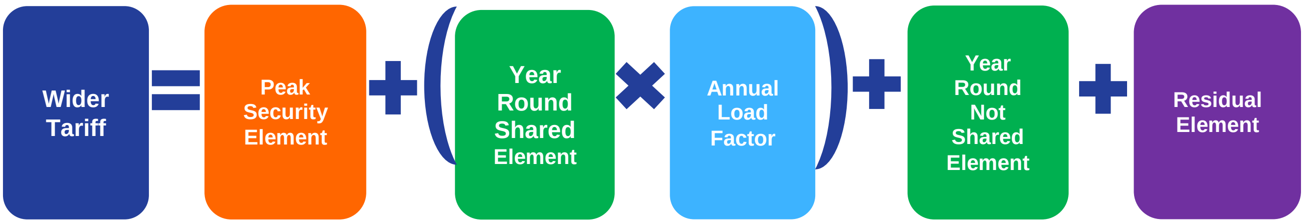
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and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

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

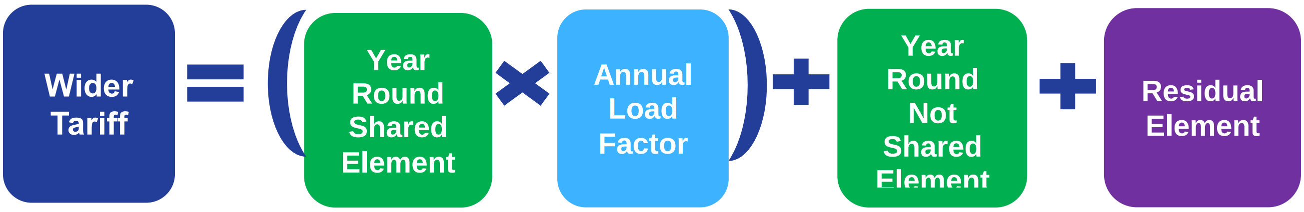
4.1. Generation Charging Principles

Under the current methodology there are 27 generation zones, and each zone has four tariffs. A generator's liability is dependent upon its type of generation. Coal, Nuclear, Gas, Pumped Storage, Peaking and Hydro are classed as conventional and wind is intermittent. Liability for each tariff component is shown below:

Conventional Generator **(Coal, Nuclear, Gas, Pumped Storage, Peaking and Hydro)**



Intermittent Generator (wind)



Each generator has a specific Annual Load Factor based on its performance over the last five years. Where new plant does not have at least three complete charging year's history then generic load factors specific to the technology are also used. The Annual Load Factors used in the June tariffs are listed in paragraph 5.7 and section 7.1.

4.2. Demand Charging Principles

Demand is charged in different ways depending on what kind of meter the end user has. HH meters have one specific tariff, and NHH have another specific tariff.

4.3. HH Demand Tariffs

HH demand tariffs are charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest demand between November and February inclusive each year. They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is available, via the NGET website.[††] The tariff is charged on a £/kW basis.

HH metered customers tend to be large industrial users, however as the rollout of smart meters progresses, more domestic demand will become HH metered.

4.4. NHH Demand Tariffs

NHH metered customers are charged based on their average demand usage between 16:00 – 19:00 on every day of the year. NHH customers must submit forecasts throughout the year as to what their expected demand volumes will be in each demand zone. The tariff is charged on a p/kWh basis

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

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.

4.5. CMP264/265

This June forecast does not take into account the changes to the charging methodology based on CUSC modifications CMP264/265.

Currently, HH demand is treated on a net basis and is charged at the Grid Supply Point (GSP), where the transmission network connects to the distribution network, or directly to the customer in question.

There have been concerns within the industry that embedded generators are benefiting from large payments from electricity suppliers by generating during peak times thereby helping to reduce the supplier's exposure to HH demand costs at triad. Ofgem has reacted by approving CUSC modifications 264 and 265 which change the way that HH demand customers are charged.

In future, HH triad demand will be treated as two separate amounts instead of a net GSP demand: a gross demand volume (demand without any embedded generation included), and an embedded generation demand volume. A new tariff will be calculated, called the Embedded Export Tariff, which will be payable to embedded generation in return for the volumes they deliver at triad. This tariff will reduce gradually over the next three years.

As is the case now, the revenue not recovered from HH metered demand will be recovered from NHH metered customers. The way NHH demand is charged will not be affected by CMP264/265.

Updates To Revenue & The Charging Model Since The Last Forecast

Since the February forecast tariffs were published we have updated allowed revenue for NGET and offshore Transmission Owners, the demand and generation charging bases, transport model generation and circuits, as well as RPI and exchange rates.

There have been no changes to the charging methodology, transport model demand, or the error margin that is used to calculate the proportion of revenue to be recovered from generation and demand (G/D split).

5.1. Changes affecting the locational element of tariffs

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

- Contracted generation as of May 2017;
- The network model;
- Demand data provided under the Grid Code, which includes week 24 demand forecast data provided by the Distribution Network Operators (DNO), forecasts of demand at directly connected demand sites such as steelworks and railways and the effect of some embedded generation; and
- RPI (which increases the expansion constant).

Table 10 - Contracted and Modelled TEC

This was fixed based on the TEC register from May 2017.

(GW)	2017/18	2018/19 Initial Forecast	2018/19 June Forecast
Contracted TEC	72.2	79.6	78.8
Modelled Best ViewTEC	72.2	72.6	75.5

5.2. Adjustments for Interconnectors

When modelling flows on the transmission system, interconnectors 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 generation or demand charging bases.

Table 11 – Interconnectors

The table below reflects the contracted position of interconnectors in May 2017; there has been no change since the February draft forecast.

Interconnector	Site	Interconnected System	Generation Zone	Transport Model (Generation MW) Peak	Transport Model (Generation MW) Year Round	Charging Base (Generation MW)
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
Britned	Grain 400kV	Netherlands	24	0	1200	0
East - West	Deesside 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	80	0

5.3. RPI

The RPI index for the components detailed below is derived as the percentage increase of the average May – October RPI for 2017/18 compared to 2016/17.

Expansion Constant

The expansion constant has increased to £14.086345MWkm from £13.57449607/MWkm in the February tariffs, to reflect higher than previously forecast RPI. This has had a very small impact on tariffs in all zones, increasing the stretch of the system circuit lengths and so increasing the magnitude of locational tariffs, i.e. positive tariffs more positive and negative tariffs more negative.

Local substation and offshore substation tariffs

Local onshore substation tariffs are indexed by May - October RPI as are offshore local circuit tariffs, so have been updated from the February forecast to reflect latest forecast RPI for ther period May 17 – October 17.

5.4. Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Table 12 shows the forecast 2018/19 revenues that have been used in calculating the June tariffs.

The Scottish Hydro Electricity Transmission revenue and Scottish Power Transmission revenue have not changed since the February forecast.

The OFTO revenue has reduced by £7m due to a delay to Race Bank.

National Grid Electricity Transmission revenue has reduced by £8.7m. This is largely due to reductions in business rates and licence fees, offset slightly by increases in RPI.

Tariffs have therefore been calculated to recover £2,819.8m of revenue. This is a reduction of £13m from the February forecast of £2,833.6m.

Table 12 – Allowed Revenues

£m Nominal Value	2017/18 TNUoS Revenue	2018/19 TNUoS Revenue				
	Jan 2017 Final	Feb 2017 Initial View	June 2017 Update	Oct 2017 Update	Dec 2017 Draft	Jan 2018 Final
National Grid						
Price controlled revenue	*1,748.8*	*1,727.8*	*1,719.0*			
Less income from connections	*41.9*	*41.9*	*41.9*			
Income from TNUoS	**1,706.9**	**1,685.9**	**1,677.2**	**-**	**-**	**-**
Scottish Power Transmission						
Price controlled revenue	*333.7*	*390.5*	*377.7*	-	-	-
Less income from connections	*12.8*	*26.8*	*14.0*			
Income from TNUoS	**321.0**	**363.8**	**363.8**			
SHE Transmission						
Price controlled revenue	*304.7*	*366.5*	*366.7*	-	-	-
Less income from connections	*3.4*	*3.2*	*3.6*			
Income from TNUoS	**301.4**	**363.2**	**363.1**			
Offshore	**270.2**	**380.2**	**373.2**			
Network Innovation Competition	**32.1**	**40.5**	**40.5**			
Transmission EDR			**2.0**			
Total to Collect from TNUoS	**2,631.5**	**2,833.6**	**2,819.8**	**-**	**-**	**-**

National Grid Electricity Transmission's deferral of £480m of RIIO-T1 allowances

This June forecast of tariffs is not affected by Ofgem's open letter dated 13 June 2017[‡‡] detailing the proposed timetable for implementing NGET's deferral of £480 of RIIO-T1 allowed revenue. The deferral (in 2009/10 prices) will lead to lower Electricity Transmission revenues in RIIO T1 of approximately £100m in total, phased across fiscal years 2019/20 and 2020/21. Consumers will receive the remaining benefit from reduced allowances beyond 2021 (i.e. RIIO-T2 and beyond).

5.5. Generation: Demand (G/D) Split

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

Exchange Rate

As prescribed by the Use of System charging methodology, the exchange rate for 2018/19 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2016. The value published is €1.16/£, which has increased since the February tariffs.

[‡‡] *https://www.ofgem.gov.uk/system/files/docs/2017/06/nget480_open_letter_final_0.pdf*

Generation Output

The forecast output of generation is aligned with Future Energy Scenario Generation output forecasts. Our forecast of 253TWh reflects our view of the total generation of generators that are liable for generation TNUoS charges during 2018/19, and has increased since the February tariffs. More information on how the generation forecast modelling has changed will be available in the FES publication available in July 2017.[§§]

Error Margin

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

Table 13 - Generation and Demand revenue proportions

		2017/18 Final	2018/19 Initial	2018/19 June
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5	2.5
y	Error Margin	21%	21%	21%
ER	Exchange Rate (€/£)	1.27	1.11	1.16
MAR	Total Revenue (£m)	2,631	2,833	2,820
GO	Generation Output (TWh)	251	240	253
G	% of revenue from generation	14.8%	15.1%	15.3%
D	% of revenue from demand	85.2%	84.9%	84.7%
G.R	Revenue recovered from generation (£m)	390	427	430
D.R	Revenue recovered from demand (£m)	2,241	2,407	2,390

5.6. Charging bases for 2018/19

Generation

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

We are unable to breakdown our best view of generation as some of the information used to derive it could be commercially sensitive. The change in contracted TEC, as per the TEC register is shown in the appendices.

Demand

Our forecast of system demand at Triad in Winter 2018/19 is 46GW. Our forecast of Half-Hour metered demand at triad is 13.2GW. The forecast of Non Half-Hour demand during 2018/19 is 24.2TWh. These numbers have been updated from the February tariff forecast using improved demand forecasting methodology which we began using in 2016/17 for the 2017/18 tariffs.

Table 14 - Charging Base

[§§] *http://fes.nationalgrid.com/*

Charging Base	2017/18	2018/19 Initial	2018/19 June
Generation (GW)	67.6	66.8	69.7
Total Average Triad (GW)	47.7	46.4	46.0
HH Demand Average Triad (GW)	13.2	14.3	13.2
NHH Demand (4pm-7pm TWh)	25.3	23.7	24.2

5.7. 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 2017/18 ALFs, based upon data from 2011/12 - 2015/16, and were published on 25 January 2017 and are available from the National Grid website.[***] We will recalculate ALFs in time for the December forecast. The final ALFs for 2017/18 can be found in section 7.1.

5.8. 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

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

The Demand Residual = (Total demand revenue less revenue recovered from locational demand tariffs) divided by total system triad demand

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

Where:

- R_G is the Generation residual tariff (£/kW)
- R_D is the Demand residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from Generation
- D is the proportion of TNUoS revenue recovered from Demand

[***] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from Generation locational zonal tariffs (£m)
- Z_D is the TNUoS revenue recovered from Demand 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)
- B_D is the Demand charging base (Half-hour equivalent GW)

$\mathbf{Z_G}$, $\mathbf{Z_D}$ and $\mathbf{L_C}$ are determined by the locational elements of tariffs.

Table 15 - Residual Calculation

	Component	2017/18	2018/19 Initial	2018/19 June
R_G	Generator residual tariff (£/kW)	-1.85	-3.20	-3.28
R_D	Demand residual tariff (£/kW)	47.26	52.24	52.20
G	Proportion of revenue recovered from generation (%)	14.8%	15.1%	15.3%
D	Proportion of revenue recovered from demand (%)	85.2%	84.9%	84.7%
R	Total TNUoS revenue (£m)	2,631	2,833	2,820
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	275.0	313.2	334.0
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-12.4	-19.0	-12.0
O	Revenue recovered from offshore local tariffs (£m)	208.5	293.9	288.4
L_G	Revenue recovered from onshore local substation tariffs (£m)	17.5	17.0	17.8
S_G	Revenue recovered from onshore local circuit tariffs (£m)	14.6	16.9	18.5
B_G	Generator charging base (GW)	67.6	66.8	69.7
B_D	Demand charging base (GW)	47.7	46.4	46.0

5.9. Small Generators Discount

The small generators discount has been calculated as £ 12.230618 /kW. This equates to a forecast of £29.9m which is recovered from Suppliers through the HH and NHH tariffs.

Table 16 – Small Generators Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-3.28
Demand Residual (£/kW)	D	52.20
Small Generator Discount (£/kW)	T = (G + D)/4	12.23
Forecast Small Generator Volume (kW)	V	2,745,910
2017/18 SGD cost (£)	V x T	33,584,176
Prior year reconcilation (£)	R	- 3,605,528
Total SGD Cost (£)	C = (V x T) + R	29,978,649
Total System Triad Demand (kW)	TD	46,004,028
Total HH Triad Demand (kW)	HHD	13,186,729
Total NHH Consumption (kWh)	NHHD	24,196,416,903
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.65
Total Cost to HH Customers (£)	HHC = HHT * HHD	8,593,167
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.09
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	21,385,482

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 June tariffs on Friday 7 July from 10:30 to 11:30. If you wish to join the webinar, please contact us using the details below.

We always welcome questions and are happy to discuss specific aspects of the material contained in the June 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:

http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

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

Appendices

Appendix A: Locational Demand Charges

6.1. Locational Demand Charges

Table 17 - Demand Profiles

The table below shows the latest demand forecast used in the June Tariff forecast.

There is no change to Locational Model Demand profiles between the February and June tariffs.

Overall Peak Demand has reduced from the February forecast by 0.4GW to 46GW, and HH demand has reduced from 14.3GW to 13.2GW, with notable increases in zones 1, 3 and 6; and decreases in all other zones.

		2018/19 February				2018/19 June			
Zone	Zone Name	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)
1	Northern Scotland	227	899	-720	0.70	227	928	-530	0.74
2	Southern Scotland	2,820	3,027	691	1.65	2,820	2,999	662	1.69
3	Northern	2,508	2,207	339	1.20	2,508	2,241	526	1.21
4	North West	3,234	3,753	1,265	1.93	3,234	3,685	1,167	1.94
5	Yorkshire	4,347	3,472	1,192	1.73	4,347	3,395	1,007	1.76
6	N Wales & Mersey	2,831	2,288	560	1.21	2,831	2,281	594	1.23
7	East Midlands	5,333	4,245	1,569	2.08	5,333	4,228	1,376	2.15
8	Midlands	4,594	4,016	1,509	1.96	4,594	3,960	1,354	2.00
9	Eastern	5,843	5,877	1,587	2.99	5,843	5,829	1,429	3.07
10	South Wales	1,969	1,613	597	0.81	1,969	1,592	526	0.83
11	South East	3,355	3,614	938	1.87	3,355	3,579	838	1.92
12	London	5,271	4,004	2,364	1.81	5,271	3,918	2,068	1.82
13	Southern	5,668	5,043	1,777	2.51	5,668	5,014	1,617	2.56
14	South Western	2,609	2,372	582	1.23	2,609	2,355	554	1.27
Total		**50,609**	**46,430**	**14,250**	**23.70**	**50,609**	**46,004**	**13,187**	**24.20**

Appendix B: Breakdown of Demand Tariffs

Table 18 – Demand Tariffs with breakdown of peak security and year round elements

Zone	Zone Name	Peak Security Tariff	Year Round Tariff	Residual	Small Generators Discount	HH Demand Tariff (£/kW)
1	Northern Scotland	5.43	-6.30	52.20	0.81	52.14
2	Southern Scotland	-0.36	-18.66	52.20	0.81	34.00
3	Northern	-2.84	-6.69	52.20	0.81	43.49
4	North West	-0.65	-2.13	52.20	0.81	50.23
5	Yorkshire	-2.51	-0.64	52.20	0.81	49.86
6	N Wales & Mersey	-1.92	0.48	52.20	0.81	51.57
7	East Midlands	-2.09	1.88	52.20	0.81	52.80
8	Midlands	-1.25	2.78	52.20	0.81	54.55
9	Eastern	1.08	0.29	52.20	0.81	54.39
10	South Wales	-6.08	4.02	52.20	0.81	50.95
11	South East	3.54	0.66	52.20	0.81	57.22
12	London	5.06	1.62	52.20	0.81	59.70
13	Southern	1.78	3.78	52.20	0.81	58.57
14	South Western	-0.28	5.57	52.20	0.81	58.30

Appendix C: Annual Load Factors

7.1. ALFs

Table 19 lists the Annual Load Factors (ALF) of generators expected to be liable for generator charges during 2018/19. ALFs are used to scale the Shared Year Round element of tariffs so each generator 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 2011/12 to 2015/16. Generators which commissioned after 1 April 2013 will have fewer than three complete years of data so the Generic ALF listed below are added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2018/19 also use the Generic ALF.

These ALFs will be updated for the Draft and Final Tariffs published in December and January respectively.[†††]

Table 19: Specific Annual Load Factors

[†††] *The Final ALFs report for 2017-18 can be found here:*
http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
ABERTHAW	Coal	Yes	Actual	Actual	Actual	Actual	Actual	44.5767%	74.0137%	65.5413%	59.0043%	54.2611%	**59.6022%**
ACHRUACH	Onshore_Wind		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.6463%	**36.4210%**
AN SUIDHE WIND FARM	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	34.8406%	31.6380%	41.5843%	36.9422%	35.4900%	**35.7576%**
ARECLEOCH	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	35.1282%	32.4826%	33.8296%	29.7298%	36.8612%	**33.8135%**
BAGLAN BAY	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	61.0787%	27.5756%	16.4106%	37.9194%	29.1228%	**31.5393%**
BARKING	CCGT_CHP		Actual	Actual	Actual	Partial	Generic	20.8541%	2.3383%	1.8802%	13.2096%	0.0000%	**8.3575%**
BARROW OFFSHORE WIND LTD	Offshore_Wind	Yes	Partial	Actual	Actual	Actual	Actual	51.5009%	42.8840%	54.1080%	47.0231%	47.1791%	**49.4368%**
BARRY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	8.2014%	0.6999%	1.2989%	0.4003%	2.1727%	**1.3905%**
BEAULY CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	44.8523%	25.4532%	35.6683%	37.1167%	35.0094%	**35.9315%**
BLACK LAW	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	32.5465%	22.0683%	31.9648%	26.7881%	26.9035%	**28.5521%**
BLACKLAW EXTENSION	Onshore_Wind		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.4635%	**36.3601%**
BRIMSDOWN	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	39.5562%	21.8759%	18.7645%	11.1229%	16.4463%	**19.0289%**
BURBO BANK	Offshore_Wind		Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	16.7781%	**37.5881%**
CARRAIG GHEAL	Onshore_Wind		Generic	Partial	Actual	Actual	Actual	0.0000%	32.7219%	45.2760%	48.9277%	45.6254%	**46.6097%**
CARRINGTON	CCGT_CHP		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.7318%	**38.8663%**
CLUNIE SCHEME	Hydro		Actual	Actual	Actual	Actual	Actual	50.3272%	33.4563%	45.3256%	43.2488%	47.9711%	**45.5152%**
CLYDE (NORTH)	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	23.1890%	28.5345%	42.6598%	36.8882%	41.4120%	**40.3200%**
CLYDE (SOUTH)	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	21.1154%	31.6084%	39.8941%	29.4115%	39.9615%	**33.6380%**
CONNAHS QUAY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	33.6741%	18.5104%	12.8233%	18.3739%	28.2713%	**21.7185%**
CONON CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	62.1102%	47.5286%	54.2820%	55.5287%	58.9860%	**56.2656%**
CORBY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	8.1854%	3.4375%	8.0834%	9.6755%	4.5411%	**6.9366%**
CORYTON	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	40.7480%	15.6869%	9.7852%	17.5123%	26.4000%	**19.8664%**
COTTAM	Coal	Yes	Actual	Actual	Actual	Actual	Actual	61.2151%	65.0700%	67.3951%	51.4426%	34.4157%	**59.2426%**
COTTAM DEVELOPMENT CENTRE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	46.0664%	13.7361%	16.0249%	31.3132%	28.2382%	**25.1921%**
COWES	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.2783%	0.1743%	0.0956%	0.3135%	0.4912%	**0.2554%**
CRUACHAN	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	8.9462%	8.4281%	9.6969%	9.0516%	8.8673%	**8.9550%**
CRYSTAL RIG II	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	49.3600%	40.6845%	50.2549%	47.5958%	48.3836%	**48.4464%**
DAMHEAD CREEK	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	77.3504%	45.0617%	77.1783%	67.4641%	64.8983%	**69.8469%**
DEESIDE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	35.4538%	19.7551%	17.3035%	13.9018%	17.4579%	**18.1722%**
DIDCOT B	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	56.8079%	49.0134%	18.6624%	25.5345%	41.1389%	**38.5623%**
DIDCOT GTS	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.1401%	0.0720%	0.0902%	0.2843%	0.4861%	**0.1715%**
DINORWIG	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	15.0985%	15.0990%	15.0898%	15.0650%	14.6353%	**15.0844%**
DRAX	Coal	Yes	Actual	Actual	Actual	Actual	Actual	81.1523%	82.4774%	80.5151%	82.2149%	76.2030%	**81.2941%**
DUNGENESS B	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	11.6712%	59.8295%	61.0068%	54.6917%	70.7617%	**58.5094%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
DUNLAW EXTENSION	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	37.7664%	32.3771%	34.8226%	30.0797%	29.1203%	**32.4265%**
EDINBANE WIND	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	52.8496%	29.3933%	39.4785%	31.2458%	35.5937%	**35.4393%**
EGGBOROUGH	Coal	Yes	Actual	Actual	Actual	Actual	Actual	41.4851%	72.6884%	72.1843%	45.7421%	27.0157%	**53.1372%**
ERROCHTY	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	25.1643%	14.5869%	28.2628%	25.3585%	28.1507%	**26.2245%**
FALLAGO	Onshore_Wind		Generic	Partial	Actual	Actual	Actual	0.0000%	35.7448%	54.8683%	44.7267%	55.7992%	**51.7981%**
FARR WINDFARM TOMATIN	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	43.3953%	34.0149%	44.7212%	38.5712%	40.9963%	**40.9876%**
FASNAKYLE G1 & G3	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	39.9896%	22.1176%	35.3695%	57.4834%	53.1573%	**42.8388%**
FAWLEY CHP	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	71.5686%	61.1362%	63.3619%	72.8484%	57.6978%	**65.3556%**
FFESTINIOGG	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	3.3676%	2.9286%	5.4631%	4.3251%	3.4113%	**3.7013%**
FIDDLERS FERRY	Coal	Yes	Actual	Actual	Actual	Actual	Actual	52.0973%	61.6386%	49.0374%	45.2435%	27.4591%	**48.7927%**
FINLARIG	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	67.9805%	40.2952%	59.9142%	59.4092%	65.1349%	**61.4861%**
FOYERS	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	18.9885%	13.4800%	14.7097%	12.3048%	15.4323%	**14.5407%**
GARRY CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	70.4039%	48.5993%	55.9308%	64.3828%	60.2772%	**60.1969%**
GLANDFORD BRIGG	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	0.9617%	0.3336%	1.5673%	0.5401%	1.8191%	**1.0230%**
GLENDOE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	0.0000%	17.3350%	36.3802%	32.3494%	34.8532%	**28.1792%**
GLENMORISTON	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	58.0412%	36.3045%	44.4594%	48.7487%	50.6921%	**47.9668%**
GORDONBUSH	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	33.5929%	37.8930%	46.5594%	47.7981%	47.7161%	**47.3579%**
GRAIN	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	29.4910%	25.4580%	41.3833%	44.0031%	39.7895%	**36.8879%**
GRANGEMOUTH	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	67.5783%	52.8594%	55.9047%	62.6168%	59.8274%	**59.4496%**
GREAT YARMOUTH	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	45.0785%	19.0270%	20.7409%	18.6633%	59.8957%	**28.2821%**
GREATER GABBARD OFFSHORE WIND FARM	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	17.8601%	40.1778%	48.3038%	42.1327%	50.2468%	**43.5381%**
GRIFFIN WIND	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	14.0338%	17.9885%	31.9566%	31.3152%	31.0284%	**31.4334%**
GUNFLEET SANDS I	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	43.7552%	50.1496%	56.6472%	47.0132%	50.4650%	**49.2093%**
GUNFLEET SANDS II	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	41.4244%	45.0132%	52.2361%	44.7211%	49.0521%	**46.2622%**
GWYNT Y MOR	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	18.2777%	8.0036%	61.6185%	63.1276%	**44.2499%**
HADYARD HILL	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	38.9802%	27.6927%	31.9488%	27.7635%	36.6527%	**32.1217%**
HARESTANES	Onshore_Wind		Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	23.8423%	28.6355%	27.8093%	**26.7624%**
HARTLEPOOL	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	71.1712%	80.2632%	73.7557%	56.2803%	53.8666%	**67.0691%**
HEYSHAM	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	83.7012%	83.3828%	73.3628%	68.8252%	72.7344%	**76.4933%**
HINKLEY POINT B	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	56.9291%	61.7582%	68.8664%	70.1411%	67.6412%	**66.0886%**
HUMBER GATEWAY OFFSHORE WIND FARM	Offshore_Wind		Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	62.9631%	**52.9831%**
HUNTERSTON	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	75.3474%	73.5984%	84.7953%	79.1368%	82.1786%	**78.8876%**
IMMINGHAM	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	73.3041%	50.1793%	37.8219%	56.8316%	69.4686%	**58.8265%**
INDIAN QUEENS	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	1.3382%	0.3423%	0.2321%	0.0876%	0.0723%	**0.2207%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
IRONBRIDGE	Biomass	Yes	Generic	Generic	Actual	Actual	Actual	0.0000%	0.0000%	11.0838%	30.9006%	38.6698%	**26.8847%**
KEADBY	CCGT_CHP		Actual	Actual	Actual	Generic	Partial	49.8412%	4.6125%	0.0001%	0.0000%	35.1858%	**18.1513%**
KILBRAUR	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	45.1817%	45.2306%	51.3777%	54.3550%	50.3807%	**48.9964%**
KILLIN CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	53.0410%	32.3429%	45.5356%	44.8205%	53.2348%	**47.7990%**
KINGS LYNN A	CCGT_CHP		Actual	Actual	Actual	Actual	Generic	15.6080%	0.0003%	0.0000%	0.0000%	0.0000%	**5.2027%**
LANGAGE	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	60.7905%	41.9115%	40.8749%	34.8629%	16.5310%	**39.2164%**
LINCS WIND FARM	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	19.8148%	46.5987%	43.8178%	49.1306%	**46.5157%**
LITTLE BARFORD	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	11.8210%	16.3807%	33.6286%	49.6644%	39.9829%	**29.9974%**
LITTLEBROOK D	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.1055%	0.0588%	0.0201%	0.1394%	0.0000%	**0.0615%**
LOCHLUICHART	Onshore_Wind		Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	6.4399%	20.2103%	29.2663%	**18.6388%**
LONDON ARRAY	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	47.9931%	51.2703%	64.0880%	66.8682%	**60.7422%**
LYNEMOUTH	Coal		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	83.7381%	**65.8960%**
MARCHWOOD	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	66.1953%	43.3537%	48.6845%	66.4021%	55.0879%	**56.6559%**
MARK HILL	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	26.3795%	30.1675%	30.2863%	26.7942%	34.0227%	**29.0827%**
MEDWAY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	42.4273%	1.0718%	14.5545%	28.0962%	34.1799%	**25.6102%**
MILLENNIUM	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	47.2065%	42.1318%	52.6618%	53.2636%	48.4038%	**49.4240%**
NANT	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	42.4480%	20.8965%	35.5883%	36.4040%	37.3788%	**36.4571%**
ORMONDE	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	48.5898%	49.6561%	42.8711%	47.1986%	**46.5753%**
PEMBROKE	CCGT_CHP		Generic	Actual	Actual	Actual	Actual	0.0000%	61.5434%	60.3928%	67.5346%	64.5596%	**64.5459%**
PETERBOROUGH	CCGT_CHP		Actual	Actual	Actual	Actual	Partial	3.4546%	0.9506%	1.8311%	1.0929%	0.9933%	**2.1262%**
PETERHEAD	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	66.1917%	31.3766%	41.8811%	0.4858%	23.3813%	**32.2130%**
RATCLIFFE-ON-SOAR	Coal	Yes	Actual	Actual	Actual	Actual	Actual	53.5677%	66.7461%	71.7403%	56.1767%	19.6814%	**58.8302%**
ROBIN RIGG EAST	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	41.4118%	37.4157%	46.7562%	55.3209%	51.9700%	**46.7127%**
ROBIN RIGG WEST	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	44.4918%	38.2254%	48.0629%	53.4150%	56.0881%	**48.6565%**
ROCKSAVAGE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	47.7376%	41.4820%	2.6155%	4.4252%	19.8061%	**21.9044%**
RYE HOUSE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	20.4253%	10.7188%	7.4695%	5.3701%	7.7906%	**8.6596%**
SALTEND	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	90.6801%	81.5834%	69.0062%	67.9518%	55.6228%	**72.8471%**
SEABANK	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	34.5669%	15.2311%	18.2781%	25.6956%	27.2136%	**23.7291%**
SELLAFIELD	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	4.1046%	14.0549%	25.0221%	18.9719%	28.6790%	**19.3496%**
SEVERN POWER	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	32.2421%	27.7976%	32.4163%	24.6354%	18.3226%	**28.2250%**
SHERINGHAM SHOAL	Offshore_Wind	Yes	Partial	Actual	Actual	Actual	Actual	3.2831%	36.6431%	49.3517%	46.2286%	53.6184%	**49.7329%**
SHOREHAM	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	65.7100%	0.0000%	20.7501%	10.2239%	48.9514%	**26.6418%**
SIZEWELL B	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	77.3818%	96.7260%	82.5051%	84.7924%	98.7826%	**88.0078%**
SLOY G2 & G3	Hydro		Actual	Actual	Actual	Actual	Actual	15.0995%	9.1252%	14.3471%	15.5941%	13.9439%	**14.4635%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
SOUTH HUMBER BANK	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	33.8760%	27.9763%	24.3373%	34.4673%	48.6753%	**32.1065%**
SPALDING	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	65.1849%	34.6976%	33.4800%	39.3092%	47.9407%	**40.6492%**
STAYTHORPE	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	58.4594%	54.4117%	37.6216%	56.6148%	69.4422%	**56.4953%**
STRATHY NORTH & SOUTH	Onshore_Wind		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	53.5472%	**43.0546%**
SUTTON BRIDGE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	64.8794%	20.1652%	9.4124%	17.2025%	13.1999%	**16.8559%**
TAYLORS LANE	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.1048%	0.2037%	0.0483%	0.0640%	0.1708%	**0.1132%**
THANET OFFSHORE WIND FARM	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	32.4868%	41.1093%	39.7489%	35.5935%	41.3434%	**38.8172%**
TODDLEBURN	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	38.1923%	32.7175%	39.5374%	33.7211%	35.0823%	**35.6652%**
TORNESS	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	90.0662%	84.8669%	86.4669%	91.4945%	85.7725%	**87.4352%**
USKMOUTH	Coal	Yes	Actual	Actual	Actual	Partial	Actual	19.2655%	45.1938%	38.9899%	6.1403%	25.5184%	**36.5674%**
WALNEY I	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	45.6003%	44.2799%	57.7046%	52.0555%	50.7535%	**49.4697%**
WALNEY II	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	60.2829%	61.9219%	58.2355%	35.7988%	**51.9854%**
WEST BURTON	Coal	Yes	Actual	Actual	Actual	Actual	Actual	44.5447%	70.5868%	68.9176%	61.5364%	32.7325%	**58.3329%**
WEST BURTON B	CCGT_CHP		Generic	Partial	Actual	Actual	Actual	0.0000%	38.9336%	30.3021%	46.8421%	59.3477%	**45.4973%**
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind		Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	47.9931%	40.0506%	48.7540%	**45.5992%**
WESTERMOST ROUGH	Offshore_Wind		Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	13.1278%	54.8014%	**38.6408%**
WHITELEE	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	31.7670%	28.2265%	35.1074%	29.8105%	31.8773%	**31.1516%**
WHITELEE EXTENSION	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	0.3067%	12.4146%	27.0102%	27.7787%	26.7655%	**27.1848%**
WILTON	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	12.6949%	3.4258%	4.4941%	21.5867%	16.1379%	**11.1090%**
WYLFA	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	79.4968%	60.0463%	84.4883%	83.5566%	86.5533%	**82.5139%**

Table 20: Generic Annual Load Factors

Technology	Generic ALF
Gas_Oil	0.1645%
Pumped_Storage	10.5704%
Tidal	18.9000%
Biomass	26.8847%
Wave	31.0000%
Onshore_Wind	37.8084%
CCGT_CHP	38.9336%
Hydro	44.3345%
Offshore_Wind	47.9931%
Coal	56.9749%
Nuclear	75.6256%

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

Appendix D: Generation Changes Since The February Forecast

Table 21 shows the TEC changes notified between February 2017 (used as the basis for the initial forecast) and June 2017. 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's best view and therefore may include different generation to that shown below.

Table 21: Generation TEC Changes

Power Station	Node	MW Change	Generation Zone
Aikengall II Windfarm	WDOD10	-140.00	11
CDCL	COTT40	50.00	16
Crookedstane Windfarm	CLYS2R	-18.40	11
Edinbane Wind, Skye	EDIN10	1.35	4
Galloper Wind Farm	LEIS10	-70.00	18
Heysham Power Station	HEYS40	-33.00	14
Hunterston	HUER40	-54.00	10
Keith Hill Wind Farm	DUNE10	-4.50	11
Killingholme	KILL40	600.00	15
Lynemouth Power Station	BLYT20	20.00	13
Margree	MARG10	0.50	10
Peterhead	PEHE20	-400.00	2
Pogbie Wind Farm	DUNE10	-11.80	11
Race Bank Wind Farm	WALP40_EME	-160.00	17
Rampion Offshore Wind Farm	BOLN40	-400.00	25
Taylors Lane	WISD20_LPN	-144.00	23
Tom Na Clach	TOMN1J	-39.10	1
Torness	TORN40	35.00	11
West Burton B	WBUR40	38.00	16
Windy Standard II (Brockloch Rig 1) Wind Farm	DUNH1R	-13.50	10

Appendix E: Transmission Company Revenues

8.1. National Grid TO Revenue Forecast

We seek to provide the detail behind price control revenue forecasts for National Grid, Scottish Power Transmission and SHE Transmission, however, the contractual position between NGSO and TOs does not presently require a breakdown to the TO final position.

Revenue for offshore networks is included with forecasts by National Grid where the Offshore Transmission Owner has yet to be appointed.

Notes:

All monies are quoted in millions of pounds, accurate to one decimal place and are in nominal 'money of the day' prices unless stated otherwise.

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

Network Innovation Competition Funding is included in the National Grid price control but is additional to the price controls of onshore and offshore Transmission Owners who receive funding. NIC funding is therefore only shown in the National Grid table.

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

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

Within the bounds of commercial confidentiality these forecasts provide as much information as possible. Generally allowances determined by Ofgem are shown, whilst those for which Ofgem determinations are expected are not. This respects commercial confidentiality and disclosure considerations and actual revenues may vary for these forecasts.

It is assumed that there is only one set of price changes each year on 1 April.

Table 22 - National Grid Revenue Forecast

Description			28/06/2017					Notes
			Licence Term		Yr t+1			
Regulatory Year			2014/15	2015/16	2016/17	2017/18	2018/19	
Actual RPI			256.67					April to March average
RPI Actual		RPIAt	1.190					Office of National Statistics
Assumed Interest Rate		It	0.50%	0.70%	95.00%	0.20%	0.25%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1,443.8	1,475.6	1,571.4	1554.9	1587.6	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.5	-114.4	-185.4	-253.3	-290.0	Detered by Ofgem
RPI True Up	A3	TRUt	-0.5	4.7	-19.9	-31.4	-6.1	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.1%	2.5%	1.0%	1.8%	3.5%	HM Treasury Actual/Forecast
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	3.5%	3.1%	HM Treasury Actual/Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	3.1%	3.0%	HM Treasury Actual/Forecast
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	1.2710	1.3090	HM Treasury Actual/Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1732.7**	**1675.5**	**1684.4**	**1614.5**	**1690.6**	
Pass-Through Business Rates	B1	RBt		1.2	1.5	2.7	1.5	Actual
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	0.0	0.0	Actual
Licence Fee	B3	LFt		2.0	2.7	3.2	-0.4	Actual
Inter TSO Compensation	B4	ITCt		3.8	2.7	0.5	0.7	Actual
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	294.6	321.0	363.8	TSP submission for invoicing
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	301.4	363.1	TSH submission for invoicing
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	0.0	0.0	OFTO invoicing submissions plus NGSO forecast of expected transfers
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	0.5	0.5	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**745.1**	**890.0**	**885.9**	**629.2**	**729.3**	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	4.0	4.2	Actual
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	8.6	8.5	Actual
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	2.6	2.7	Actual
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	0.0	0.0	Actual
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0.0**	**13.9**	**18.7**	**15.3**	**15.4**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.2	10.7	Forecast
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	32.1	40.5	Determined by Ofgem
Future Environmental Discretionary Rewards	F	EDRt				0.0	2.0	Actual
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	0.0	0.0	Determined by Ofgem
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.9	6.1	0.0	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	-1.1	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt		56.4	104.0	97.0	0.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2524.3**	**2681.6**	**2751.3**	**2403.2**	**2488.5**	
Termination Charges	B5		0.0	0.0	0.0	0.0	0.0	
Pre-vesting connection charges	P		47.0	45.0	42.7	41.9	41.9	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2361.3**	**2446.6**	
Final Collected Revenue	U	TNRt	2375.9	2592.7				Actual
Forecast percentage change to Maximum Revenue M			**0.0%**	**6.2%**	**2.6%**	**-1.5%**	**3.5%**	
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**6.4%**	**2.7%**	**-1.6%**	**3.6%**	

8.2. Scottish Power Transmission Revenue Forecast

Table 23 - Scottish Power Revenue Forecast

A breakdown of Scottish Power Revenue has not been made available to NGET.

8.3. SHE Transmission Revenue Forecast

Table 24 - SHE Transmission Revenue Forecast

A breakdown of SHE Transmission Revenue has not been made available to NGET.

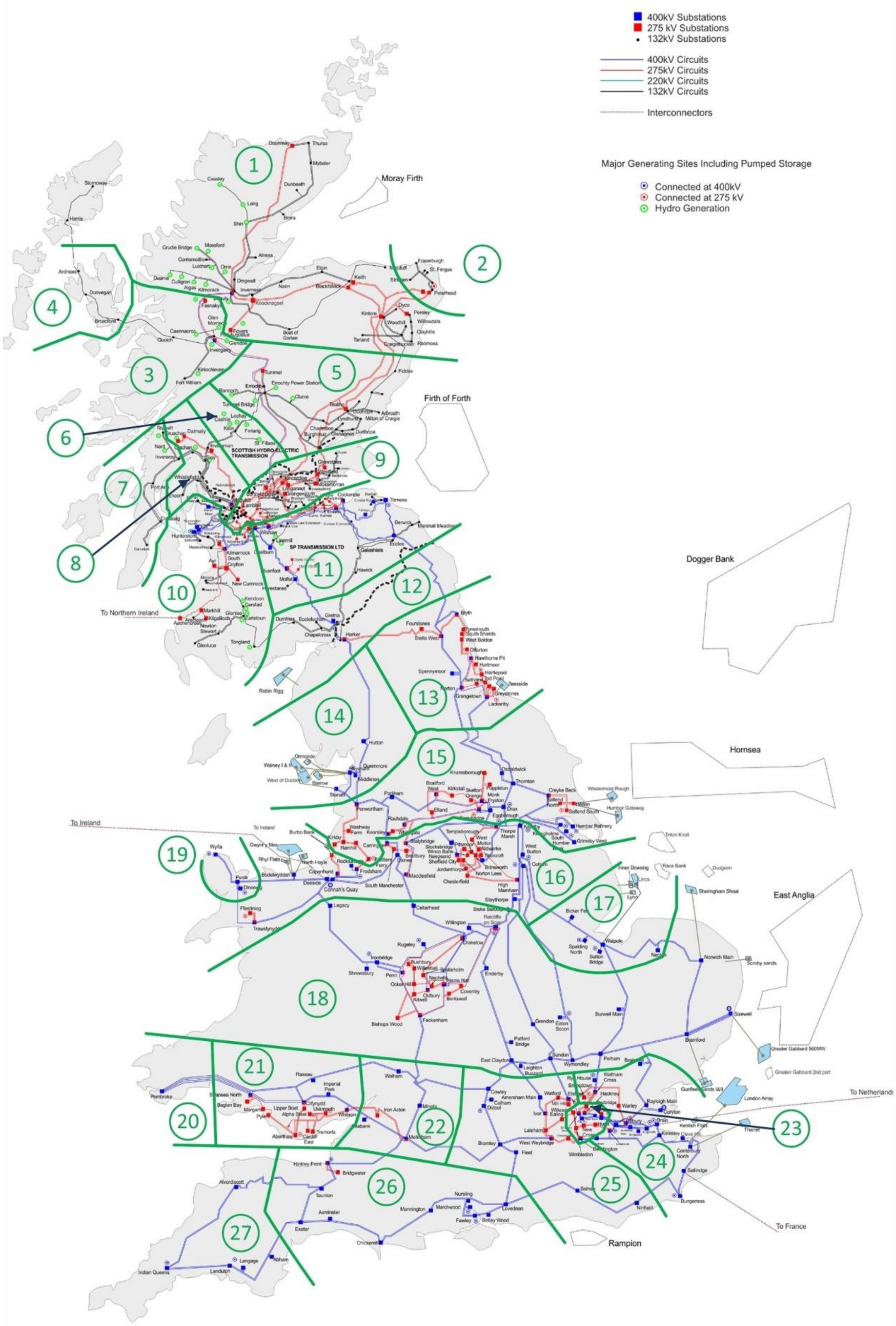
8.4. Offshore Transmission Owner Revenues

Table 25 - Offshore Transmission Owner Revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast</th><th colspan="5">28/06/2017</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>Notes</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</td><td>6.0</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>7.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>13.1</td><td>13.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>8.4</td><td>8.4</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>14.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.0</td><td>20.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>12.2</td><td>12.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>27.3</td><td>28.3</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>40.0</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>18.5</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>26.8</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>28.1</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>22.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>0.0</td><td rowspan="2">29.3</td><td>9.7</td><td>11.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>0.0</td><td>11.6</td><td>13.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2017/18</td><td>0.0</td><td>0.0</td><td>0.0</td><td>4.7</td><td>18.5</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2018/19</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>82.8</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2019/20</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2020/21</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2021/22</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>260.8</td><td>270.2</td><td>373.2</td><td></td></tr>
</table>

Appendix F: Generation Zones Map

Figure A2: GB Existing Transmission System



Appendix G: Demand Zones Map