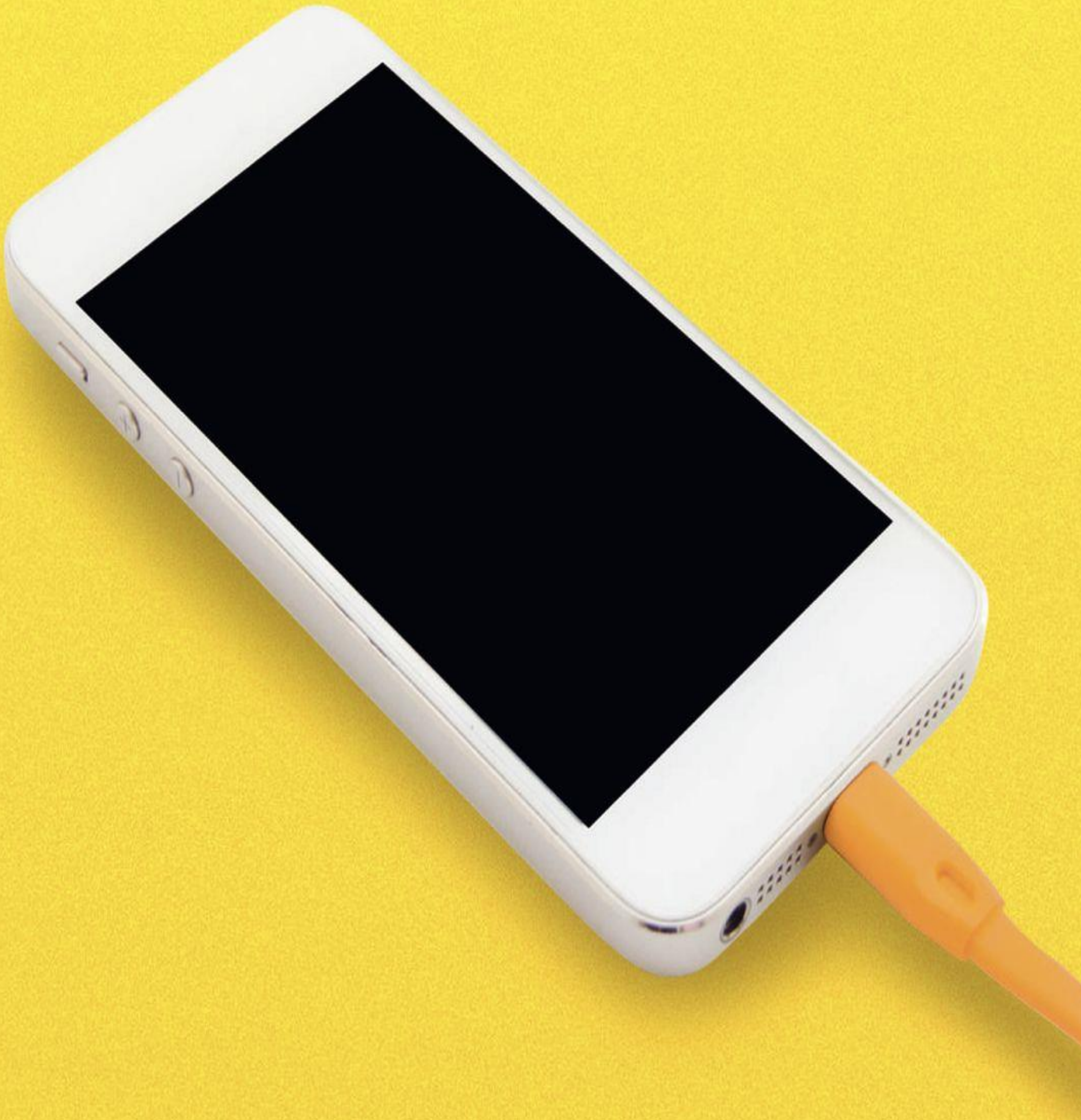
Final TNUoS Tariffs for 2021/22

National Grid Electricity System Operator

January 2021



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Executive summary

The Transmission Network Use of System (TNUoS) charge is designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. It is applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the Final TNUoS Tariffs for 2021/22.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish the Final TNUoS tariffs for year 2021/22 on our website[1].

These tariffs will take effect from 1st April 2021.

Price Control Impact

The charging year 2021/22 is the first year in the new RIIO-2 price control period for the transmission owners (TOs) and NGESO. In this report, the various parameters have been re-set in line with the CUSC. Please see New Price Control RIIO2 section on page 7 for details.

Regulatory Changes Implementation

A number of regulatory changes have been implemented in the Final Tariffs including, Transmission Generation Residual (TGR).

Ofgem's decision on the Targeted Charging Review (TCR) affects TNUoS tariffs in two aspects, TGR and the Transmission Demand Residual (TDR). The TGR changes are to be implemented from April 2021 and affect generation residual tariffs, while the TDR changes are expected to be implemented from April 2022. As such, we have incorporated the decision of CMP317/327 for TGR in the Final Tariffs.

In addition, we have also incorporated Ofgem's decisions on:

- CMP324/325 – Generation Rezoning
- CMP353 - Stabilising the Expansion Constant and non-specific Onshore Expansion Factors
- CMP355/356 – Updating the Indexation methodology for RIIO2
- CMP357 – To improve accuracy of the Locational Security Factor

COVID19 Impact

We have been closely monitoring the impact of COVID19 on the transmission networks. In these Final Tariffs, we have applied our best view on the demand and generation forecast.

We currently forecast -2.75% (~£77m) under-recovery of TNUoS for the current year 2020/21. This number will be revised at the next TNUoS tariff forecast. Any under-recovery will be recovered in charging year 2022/23.

Total TNUoS Revenue

Total revenue to be collected is £3,318m based on TOs' and OFTOs' final submissions. It is an increase from 2021/21 but a decrease of £92m compared to the Draft tariffs - following Ofgem's Final Determination on TOs' business plans.

Generation tariffs

The revenue to be recovered from generators is £774m, an increase of £399m from 2020/21 and a decrease of £39m since the Draft tariffs. This increase from 2020/21 is mainly driven by the implementation of TGR. Local tariffs have been removed from the EU generation cap calculation. The generation residual has been removed from TNUoS charge, but to ensure compliance with the EU generation cap, an adjustment element has been introduced instead.

The generation charging base has been updated to 70.1GW based on our best view on generation projects for 2021/22. This is a reduction of 1.6GW from the Draft tariffs.

With a decrease in revenue to be collected from generation, the average generation

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

tariff decreased by £0.32/kW to £11.04 /kW since the Draft tariffs and the adjustment tariff decreased by £0.40/kW to -£0.43/kW.

Small Generator Discount

As defined in the NGESO's licence, the Small Generator Discount (SGD) reduces the tariff for transmission connected generation connected at 132kV and with Transmission Export Capacity (TEC) <100MW. However, as the SGD will expire at the end of March 2021, this has not been included within the Final tariffs.

Demand tariffs

The revenue to be recovered through demand is £2,544.5m for 2021/22. This value has decreased by £52.1m compared to our Draft tariffs. This is mainly driven by the decreased revenue from TOs. As a result, the demand tariffs have decreased accordingly.

The average HH demand tariff is £51.36/kW, a decrease of £1.10/kW from the Draft tariffs and an increase of £1.80/kW from 2020/21 Final tariffs. The average NHH demand tariff is 6.50p/kWh, a decrease of 0.06p/kWh from Draft tariffs and increase of 0.48p/kWh from 2020/21 Final tariffs.

£14.91m will be payable through the Embedded Export Tariff (EET) a decrease of £0.23m from the Draft. The average EET has decreased by £0.13/kW to £2.14/kW. This decrease is due to the changes seen in locational demand and the updated Avoided GSP Infrastructure Credit (AGIC).

Consumer bill impact

TNUoS charge would have an impact of £36.41 on consumer bill, a decrease of £0.36 from the Draft tariffs. This is approximately 6% of an average consumer electricity bill. Our consumer bill calculation is only affected by NHH tariffs, and not by HH or generation tariffs.

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts throughout year 2022/23 is now available on our website.

Our next TNUoS tariff publication will be our initial forecast of 2022/23 tariffs and the 5 Year View of TNUoS tariffs, which will be published in March 2021.

Feedback

We welcome feedback on any aspect of this document and the tariff setting processes.

We are very aware that TNUoS charging is undergoing transition and there will be substantial changes to charging mechanisms over the next few years, either as a result of Ofgem's charging review or through CUSC modifications raised from time to time.

We strongly encourage all parties affected by the changes to the charging regime to engage with the Charging Futures Forum, or with the specific CUSC modification workgroups to flag any concerns and suggestions.

Please contact us if you have any further suggestions as to how we can better work with you to improve the tariff forecasting process.

Our contact details

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Charging Methodology Changes

TNUoS Charging Methodology

The TNUoS tariff setting methodology defined in the CUSC is subject to open governance. We are obliged to comply with the latest approved CUSC changes applicable from 1st April 2021 in the Final Tariffs for 2021/22. This section summarises the key changes to the methodology.

Ofgem's Targeted Charging Review (TCR)

On 21 November 2019, the Authority published their final decision[2] on the Targeted Charging Review (TCR) and issued Directions to NGESO to raise changes to the charging methodology to give effect to that final decision.

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

- The removal of the generation residual, which is currently used to keep total TNUoS recovery from generators within the range of €0-2.50/MWh. This change has been managed under CMP317/327, with the final decision being announced by Ofgem on 17 December 2020[3], which seeks to ensure ongoing compliance with European Regulation by establishing which charges are, and are not in scope of that range;
- The creation of specific NHH and HH demand residual charges, levied only to final demand (which is consumption not used either to operate a generating station, or to store and export), and on a 'site' basis. CMP332 (Transmission Demand Residual bandings and allocation) was raised and approved to modify the CUSC methodology accordingly. This is due to take effect from April 2022.

Our 2021/22 Final tariffs have implemented CMP317/327 which will take effect from April 2021. The TGR has been set to £0/kW but an adjustment has been introduced to ensure generation charges are still compliant with the cap. For the purposes of this report we have compared the adjustment to the generation residual published in the Draft tariffs.

As per Ofgem's decision on TGR, all Local Charges for Local Circuits and Local Substations paid by generators have been excluded for the purposes of assessing compliance with the €0-2.50/MWh range. We have also not included any BSC charges nor any elements of BSUoS Charges, like Congestion Management costs, in the generation cap.

Other Regulatory Changes

In addition to the above TGR changes, a number of CUSC modification proposals have been approved by Ofgem through the year and the changes have all been included in this Final Tariffs.

- CMP324/325 – Generation Rezoning. The generation zonal boundaries remain unchanged from RIIO-T1, as a result of CMP325.
- CMP353 - Stabilising the Expansion Constant and non-specific Onshore Expansion Factors. Under this mod, the expansion constant and generic onshore expansion factors will remain similar to the values used under RIIO-1.
- CMP355/356 – Updating the Indexation methodology for RIIO2. This mod has changed the inflation indexation, which underpins TNUoS charging parameters, from RPI to CPIH, in line with Ofgem's final determination on RIIO-2.
- CMP357 – To improve accuracy of the Locational Security Factor. The security factor for RIIO-2 was rounded to one decimal place at 1.8. Under this mod, 2d.p. is to be used, which changed the value of security factor to 1.76. This value will remain unchanged throughout RIIO-2 period.

Charging Parameters Reset

In accordance with the CUSC, at the start of the next price control in April 2021, various aspects of the TNUoS charging parameters are required to be re-set based on the data for the price-control and apply from 1 April 2021. The parameters and their changes are listed in the table below.

[2] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review
[3] https://www.nationalgrideso.com/document/183141/download

Charging Parameters Re-set for RIIO-2

Component	Description	Res-set for 2021/22
Generation zones	Number of generation zones. It was 27 in RIIO1.	Following approval of CMP325, the generation zonal boundaries have been fixed and remain as 27.
Expansion Constant and Factors	The expansion constant and expansion factors need to be recalculated based on TOs' business plans and costs of investments. The expansion constant represents the cost of moving 1MW, 1km using 400kV OHL line. The expansion factors represent how many times more expensive moving 1MW, 1km is using different voltages and types of circuit.	In accordance with Ofgem's decision on CMP353 and CMP 355/356, the expansion constant for RIIO-1 (inflated by RPI from 2013/14 to 2020/21) continues with CPIH uplift from 1st April 2021 and that the expansion factors are unchanged.
Locational Onshore Security Factor	The security factor was 1.8 in RIIO1.	Following approval of CMP357 (improving accuracy of the security factor), we have applied 2 decimal places on the security factor, which is 1.76. This value will be fixed during the RIIO period.
Local Substation Tariffs	Local Substation tariffs will be recalculated in preparation for the start of the price control based on TO asset costs.	The local substation tariffs have been updated based on TOs data submitted as part of the RIIO-2 parameter refresh. The annuity and overhead factors that feed into these tariffs have been updated to reflect Ofgem's Final Determination.
Offshore Local tariffs	The elements for the offshore tariffs have been recalculated for the new price control, based on updated forecasts of OFTO revenue. It includes adjustments for differences in actual OFTO revenue to forecast revenue in RIIO-T1, including approved Income Adjusting Events and Exception Event Claims.	The offshore tariffs have been recalculated to adjust for differences in actual OFTO revenue to forecast revenue in RIIO-T1. We have recalculated the Offshore substation discount and included it in the offshore local tariffs in this report.
Avoided GSP Infrastructure Credit (AGIC)	The AGIC is a component of the Embedded Export Tariff, paid to 'exporting demand' at the time of Triad. It will be recalculated based on up to 20 schemes from the RIIO-2 price control period.	The RIIO-2 AGIC parameter has been updated for Final Tariffs, based on the final determination. From 1st April 2021, CPIH inflation will be applied.

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Generation tariffs

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

1. Generation tariffs summary

This section summarises the generation tariffs for 2021/22 and how these tariffs were calculated.

The tariffs include the implementation of Ofgem's decision for the Transmission Generation Residual (TGR) which does increase the amount generators pay for TNUoS compared to 2020/21.

As part of our tariff setting, we have excluded all local onshore and local offshore tariffs from the European €2.50/MWh cap for generator transmission charges and set the Generation Residual to £0/kW as agreed under CMP317/327. However, to ensure compliance with the EU cap there is a negative adjustment required. For the purpose of this report, we have compared the adjustment with the generation residual published in the Draft tariffs.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2021/22 Draft	2021/22 Final	Change since last forecast
Adjustment	- 0.027640	- 0.432600	- 0.404959
Average Generation Tariff*	11.351149	11.035859	- 0.315290

*N.B. These generation average tariffs include local tariffs

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

Average generation tariffs have decreased by £0.32/kW. This is mainly driven by a decrease in the generation output from 220TWh to 200TWh, which has taken into consideration of the COVID impact. These average tariffs include revenues from local tariffs.

Since the Draft tariffs the generation adjustment, previously known as the residual, has decreased to -0.40/kW due to the expected decrease in generation output in 2021/22.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2021/22. A brief description of generation wider tariff structure can be found in Appendix A.

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

The classifications of generator type are listed below:

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

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

Please note that the Small Generator Discount is discontinued from 1st April 2021 and has not been included in the tariffs.

Table 2 Generation wider tariffs

		Tariffs (£/kW)						
						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak	Shared Year Round	Not Shared Year Round	Adjustment	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	4.126082	19.849130	18.845468	- 0.432600	34.649160	38.418254	26.352520
2	East Aberdeenshire	3.151849	10.476562	18.845468	- 0.432600	26.176873	29.945967	22.603493
3	Western Highlands	3.841775	18.124856	18.137065	- 0.432600	32.418712	36.046125	24.954407
4	Skye and Lochalsh	- 0.600287	18.124856	19.911917	- 0.432600	29.396531	33.378915	26.729259
5	Eastern Grampian and Tayside	4.627928	13.372520	15.294671	- 0.432600	27.129081	30.188015	20.211079
6	Central Grampian	4.271604	14.302078	16.361775	- 0.432600	28.370086	31.642441	21.650006
7	Argyll	2.644528	12.371769	24.994839	- 0.432600	32.105214	37.104182	29.510947
8	The Trossachs	3.758239	12.371769	14.104429	- 0.432600	24.506597	27.327483	18.620537
9	Stirlingshire and Fife	2.666380	10.932125	12.879423	- 0.432600	21.283018	23.858903	16.819673
10	South West Scotlands	2.952740	11.283085	13.150169	- 0.432600	22.066743	24.696777	17.230803
11	Lothian and Borders	2.920257	11.283085	6.510723	- 0.432600	16.722703	18.024848	10.591357
12	Solway and Cheviot	2.524162	7.605300	7.294685	- 0.432600	14.011550	15.470487	9.904205
13	North East England	3.345180	5.886920	4.405551	- 0.432600	11.146557	12.027667	6.327719
14	North Lancashire and The Lakes	2.484799	5.886920	1.250164	- 0.432600	7.761866	8.011899	3.172332
15	South Lancashire, Yorkshire and Humber	3.791173	2.396756	0.347999	- 0.432600	5.554377	5.623977	0.874101
16	North Midlands and North Wales	3.167807	0.864623	-	- 0.432600	3.426905	3.426905	- 0.086751
17	South Lincolnshire and North Norfolk	1.311261	1.550670	-	- 0.432600	2.119197	2.119197	0.187668
18	Mid Wales and The Midlands	1.624967	1.788458	-	- 0.432600	2.623133	2.623133	0.282783
19	Anglesey and Snowdon	4.790020	1.007415	-	- 0.432600	5.163352	5.163352	- 0.029634
20	Pembrokeshire	7.437664	- 6.301681	-	- 0.432600	1.963719	1.963719	- 2.953272
21	South Wales & Gloucester	3.411188	- 6.636984	-	- 0.432600	- 2.330999	- 2.330999	- 3.087394
22	Cotswold	2.274785	3.515931	- 8.455582	- 0.432600	- 2.109536	- 3.800652	- 7.481810
23	Central London	- 3.681071	3.515931	- 5.511826	- 0.432600	- 5.710387	- 6.812752	- 4.538054
24	Essex and Kent	- 3.332257	3.515931	-	- 0.432600	- 0.952112	- 0.952112	0.973772
25	Oxfordshire, Surrey and Sussex	- 0.985430	- 1.875819	-	- 0.432600	- 2.918685	- 2.918685	- 1.182928
26	Somerset and Wessex	- 2.246762	- 3.309922	-	- 0.432600	- 5.327300	- 5.327300	- 1.756569
27	West Devon and Cornwall	- 2.524900	- 8.311269	-	- 0.432600	- 9.606515	- 9.606515	- 3.757108

3. Changes to wider tariffs since the Draft tariffs tariff forecast

The following section provides details of the wider and local generation tariffs in the Final tariffs for 2021/22 and explains how these have changed since the Draft tariffs.

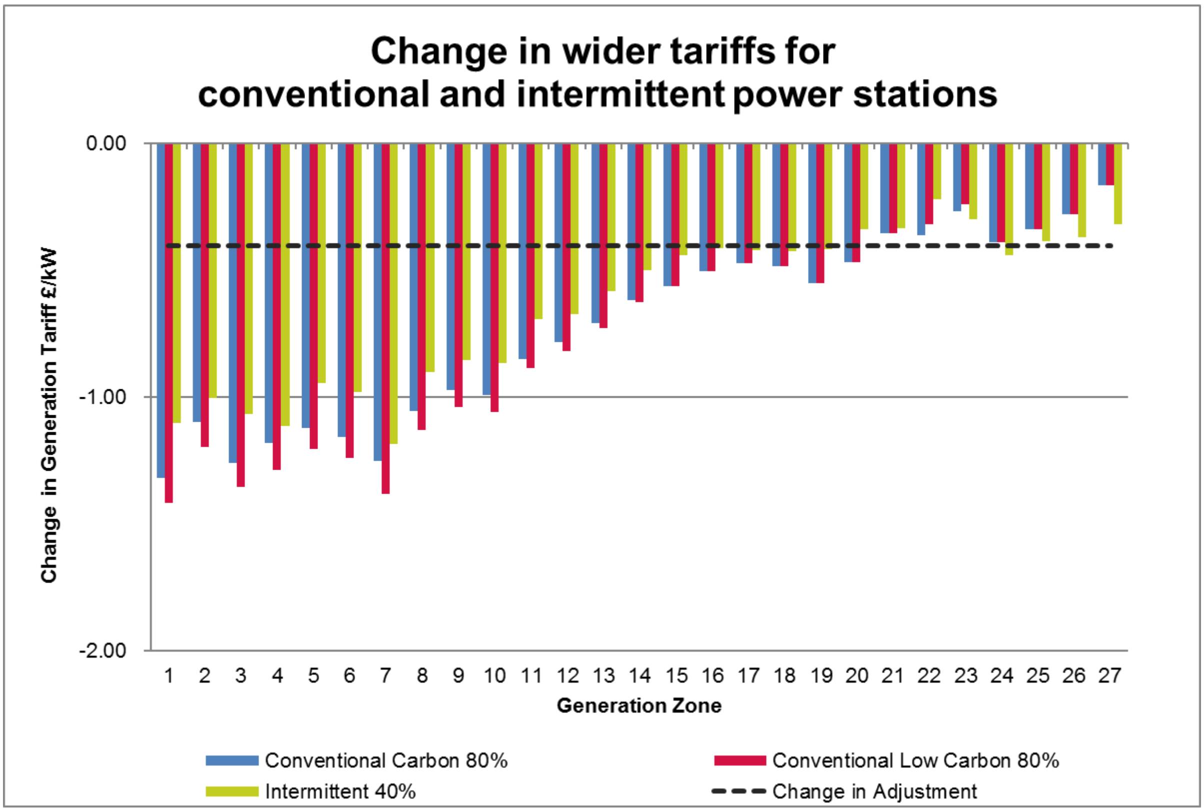
The next table and chart show the changes in wider generation TNUoS tariffs since the Draft tariffs with the example Conventional Carbon, Conventional Low Carbon and Intermittent tariffs. The Conventional tariffs use a load factor of 80%, and the Intermittent tariffs use a 40% load factor. All the examples are for illustration purposes only.

The Generation tariffs in the below table include the impact of the TCR, where the TGR has become £0/kW, and there is now a negative adjustment factor to ensure compliance with the European €2.50 cap.

Table 3 Generation wider tariff changes since Draft tariffs

Zone	Zone Name	Wider Generation Tariffs (£/kW) – Conventional Carbon 80%: 2021/22 Draft	Conventional Carbon 80%: 2021/22 Final	Conventional Carbon 80%: Change	Conventional Low Carbon 80%: 2021/22 Draft	Conventional Low Carbon 80%: 2021/22 Final	Conventional Low Carbon 80%: Change	Intermittent 40%: 2021/22 Draft	Intermittent 40%: 2021/22 Final	Intermittent 40%: Change	Change in Adjustment
1	North Scotland	35.967563	34.649160	- 1.318403	39.834795	38.418254	- 1.416541	27.454899	26.352520	- 1.102379	- 0.404959
2	East Aberdeenshire	27.274678	26.176873	- 1.097805	31.141910	29.945967	- 1.195943	23.608256	22.603493	- 1.004764	- 0.404959
3	Western Highlands	33.679039	32.418712	- 1.260327	37.400901	36.046125	- 1.354776	26.020383	24.954407	- 1.065975	- 0.404959
4	Skye and Lochalsh	30.578168	29.396531	- 1.181636	34.664243	33.378915	- 1.285328	27.841447	26.729259	- 1.112187	- 0.404959
5	Eastern Grampian and Tayside	28.251680	27.129081	- 1.122599	31.390261	30.188015	- 1.202246	21.153550	20.211079	- 0.942471	- 0.404959
6	Central Grampian	29.524998	28.370086	- 1.154912	32.882557	31.642441	- 1.240116	22.629944	21.650006	- 0.979937	- 0.404959
7	Argyll	33.357379	32.105214	- 1.252164	38.486507	37.104182	- 1.382325	30.695563	29.510947	- 1.184616	- 0.404959
8	The Trossachs	25.560912	24.506597	- 1.054314	28.455246	27.327483	- 1.127763	19.521593	18.620537	- 0.901056	- 0.404959
9	Stirlingshire and Fife	22.253400	21.283018	- 0.970381	24.896354	23.858903	- 1.037451	17.673839	16.819673	- 0.854166	- 0.404959
10	South West Scotlands	23.057531	22.066743	- 0.990788	25.756044	24.696777	- 1.059267	18.095675	17.230803	- 0.864872	- 0.404959
11	Lothian and Borders	17.574346	16.722703	- 0.851643	18.910395	18.024848	- 0.885547	11.283354	10.591357	- 0.691997	- 0.404959
12	Solway and Cheviot	14.792599	14.011550	- 0.781049	16.289523	15.470487	- 0.819036	10.578309	9.904205	- 0.674104	- 0.404959
13	North East England	11.853010	11.146557	- 0.706453	12.757062	12.027667	- 0.729395	6.908701	6.327719	- 0.580982	- 0.404959
14	North Lancashire and The Lakes	8.380190	7.761866	- 0.618324	8.636733	8.011899	- 0.624834	3.671155	3.172332	- 0.498823	- 0.404959
15	South Lancashire, Yorkshire and Humber	6.115224	5.554377	- 0.560847	6.186636	5.623977	- 0.562659	1.313085	0.874101	- 0.438983	- 0.404959
16	North Midlands and North Wales	3.932358	3.426905	- 0.505452	3.932358	3.426905	- 0.505452	0.327214	- 0.086751	- 0.413965	- 0.404959
17	South Lincolnshire and North Norfolk	2.590600	2.119197	- 0.471403	2.590600	2.119197	- 0.471403	0.608778	0.187668	- 0.421110	- 0.404959
18	Mid Wales and The Midlands	3.107657	2.623133	- 0.484524	3.107657	2.623133	- 0.484524	0.706370	0.282783	- 0.423587	- 0.404959
19	Anglesey and Snowdon	5.714017	5.163352	- 0.550665	5.714017	5.163352	- 0.550665	0.385818	- 0.029634	- 0.415452	- 0.404959
20	Pembrokeshire	2.431074	1.963719	- 0.467355	2.431074	1.963719	- 0.467355	- 2.613944	- 2.953272	- 0.339328	- 0.404959
21	South Wales & Gloucester	- 1.975469	- 2.330999	- 0.355530	- 1.975469	- 2.330999	- 0.355530	- 2.751558	- 3.087394	- 0.335836	- 0.404959
22	Cotswold	- 1.748240	- 2.109536	- 0.361296	- 3.483388	- 3.800652	- 0.317264	- 7.260393	- 7.481810	- 0.221416	- 0.404959
23	Central London	- 5.442847	- 5.710387	- 0.267540	- 6.573915	- 6.812752	- 0.238837	- 4.239989	- 4.538054	- 0.298064	- 0.404959
24	Essex and Kent	- 0.560679	- 0.952112	- 0.391433	- 0.560679	- 0.952112	- 0.391433	1.415351	0.973772	- 0.441578	- 0.404959
25	Oxfordshire, Surrey and Sussex	- 2.578457	- 2.918685	- 0.340228	- 2.578457	- 2.918685	- 0.340228	- 0.797504	- 1.182928	- 0.385423	- 0.404959
26	Somerset and Wessex	- 5.049785	- 5.327300	- 0.277514	- 5.049785	- 5.327300	- 0.277514	- 1.386082	- 1.756569	- 0.370487	- 0.404959
27	West Devon and Cornwall	- 9.440421	- 9.606515	- 0.166094	- 9.440421	- 9.606515	- 0.166094	- 3.438710	- 3.757108	- 0.318398	- 0.404959

Figure 1 Variation in generation zonal tariffs



Locational changes

The locational tariffs have changed since the Draft tariffs due to the update in indexation of the Expansion Factor from RPI to CPIH as per Ofgem's Final Determinations via CMP355/356 and the slight decrease in Security Factor, which has been changed to 2 decimal places (from 1.8 to 1.76). This resulted in the locational tariffs becoming less polarised, decreasing in the North and becoming less negative in the South.

Adjustment changes

The Adjustment has replaced the Generation Residual to ensure compliance with the European €2.50 cap as part of CMP317/327. In the Draft tariffs we still referred to the Adjustment as the Residual, so in this report we are comparing the Adjustment to the Residual published in the Draft tariffs.

There has been a decrease in the Adjustment compared to Draft tariffs. This has mainly been driven by the decrease in generation output, from 220TWh to 200MWh, to take into consideration the impact of COVID in majority of the zones.

The change in the locational tariffs combined with the decrease in the Adjustment has overall meant a decrease in tariffs across all zones. This has resulted in £39m less revenue being collected from generators.

Onshore local tariffs for generation

4. Onshore local substation tariffs

Onshore local substation tariffs reflect the cost of the first transmission substation that each transmission connected generator connects to. They are recalculated in preparation for the start of the price control based on TO asset costs and then inflated each year by the average May to October CPIH (changed from RPI through Ofgem's decision in Final Determination and through CMP355/356) for the rest of the price control period.

There have been two key factors in the reduction these tariffs. Since the publishing of the Draft Tariffs, there has been an update and recalculation of the TO's input data that feeds into the resetting of the local substation tariffs, which has resulting in an overall reduction. In addition to this, the change from RPI to CPIH has also reduced tariffs. These reductions have been offset by a slight increase in the annuity factor that is used as part of the local substation tariffs calculation. This increase is due to the change in the TO's WACC from the Draft Determination to the Final Determination.

Table 4 Local substation tariffs

2021/22 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.146752	0.073379	0.050613
<1320 MW	Redundancy	0.309223	0.157059	0.111522
>=1320 MW	No redundancy	n/a	0.215587	0.153492
>=1320 MW	Redundancy	n/a	0.324421	0.233338

5. Onshore local circuit tariffs

Where a transmission-connected generator is not directly connected to the Main Interconnected Transmission System (MITS) nodes, the onshore local circuit tariffs reflect the cost and flows on circuits between its connection and the MITS nodes. Local circuit tariffs can change as a result of system power flows and TNUoS parameters.

Depending on the topology, onshore local circuits with circuit redundancy had tariff changes as a result of CMP357, which changed with the security factor from 1.8 to 1.76.

Onshore local circuit tariffs are listed in the table below.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.687707	Dunhill	1.428190	Marchwood	0.380561
Aberdeen Bay	2.599821	Dunlaw Extension	1.506420	Mark Hill	0.892884
Achruach	4.281723	Edinbane	6.979995	Middle Muir	2.343260
Aigas	0.666962	Ewe Hill	2.482000	Middleton	0.151561
An Suidhe	-0.957481	Fallago	0.436827	Millennium South	- 0.466475
Arecleoch	2.118020	Farr	3.555132	Millennium Wind	1.861916
Baglan Bay	-0.144809	Fernoch	4.485470	Moffat	0.194223
Beinneun Wind Farm	1.531122	Ffestiniogg	0.252269	Mossford	2.870988
Bhlaraidh Wind Farm	0.658421	Finlarig	0.326533	Nant	- 1.252189
Black Hill	1.548514	Foyers	0.292072	Necton	1.120435
Black Law	1.781935	Galawhistle	3.568307	New Deer	0.189751
BlackCraig Wind Farm	6.419564	Glen Kyllachy	- 0.466475	Rhigos	0.105170
BlackLaw Extension	3.778824	Glendoe	1.875799	Rocksavage	0.018050
Clyde (North)	0.111836	Glenglass	4.797660	Saltend	0.017301
Clyde (South)	0.129333	Gordonbush	0.069371	Sandy Knowe	2.378871
Corriegarth	2.954342	Griffin Wind	9.683862	South Humber Bank	- 0.184873
Corriemoillie	1.658940	Hadyard Hill	2.822639	Spalding	0.282588
Coryton	0.050448	Harestanes	2.577911	Strathbrora	- 0.048161
Cruachan	1.819382	Hartlepool	0.088865	Strathy Wind	1.778564
Crystal Rig	0.140871	Invergarry	0.373180	Stronelairg	1.089736
Culligran	1.767466	Kilgallioch	1.073265	Wester Dod	0.487877
Deanie	2.903694	Kilmorack	0.201399	Whitelee	0.108228
Dersalloch	2.456454	Kype Muir	1.512589	Whitelee Extension	0.300875
Dinorwig	2.392364	Langage	- 0.336194		
Dorenell	2.092586	Lochay	0.373180		
Dumnaglass	1.155822	Luichart	0.571838		

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way they are modelled in the Transport and Tariff model. This table shows the circuits which have been amended in the model to account for the one-off charges that have already been made to the generators. For more information please see CUSC sections 2.14.4, 14.4, and 14.15.15.

Table 6 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
Crystal Rig 132kV	Wester Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Elvanfoot 275kV	Clyde North 275kV	6.2km of Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km of Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Coalburn 132kV	Galawhistle 132kV	9.7km cable	9.7km OHL	Galawhistle II
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes
Coalburn 132kV	Kype Muir 132kV	17km cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km cable	13km OHL	Middle Muir
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
East Kilbride South 275kV	Whitelee 275kV	6km of Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km of Cable	16.68km of OHL	Whitelee Extension
Sandy Knowe 132kV	Glen Glass 132kV	7km of cable	7km of OHL	Sandy Knowe

Offshore local tariffs for generation

6. Offshore local generation tariffs

The local offshore tariffs (substation, circuit and Embedded Transmission Use of System) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of price review or on transfer to the offshore transmission owner (OFTO). The tariffs are subsequently indexed each year, in line with the licence of the associated Offshore Transmission Owner.

The offshore tariffs have been recalculated, in preparation for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting, including any approved Exceptional Events. The Offshore substation discount has also been recalculated for the RIIO-2 period.

Offshore local generation tariffs associated with projects due to transfer in 2021/22 will be confirmed once asset transfer has taken place.

Table 7 Offshore local tariffs 2021/22

Offshore Generator	Final 2021/22 Tariff Component (£/kW)			Changes since Draft Tariffs Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	8.836174	46.681052	1.159154	-0.011169	0.005825	0.000145
Burbo Bank	11.045154	21.346898	-	-0.012174	0.000316	-
Dudgeon	16.155283	25.347887	-	-0.058259	-0.069474	-
Galloper	16.537117	26.155151	-	-0.012373	-0.000042	-
Greater Gabbard	16.473633	38.093075	-	0.018327	0.047959	-
Gunfleet	19.229393	17.732950	3.314390	-0.009615	0.002443	0.000457
Gwynt Y Mor	20.741455	20.506705	-	2.897083	2.796115	-
Humber Gateway	12.206462	28.005823	-	0.018135	0.066676	-
Lincs	16.957830	66.640797	-	-	-	-
London Array	11.499568	39.427611	-	0.024165	0.119010	-
Ormonde	27.167399	50.781758	0.404688	-0.008049	0.007858	0.000063
Race Bank	9.783195	27.172426	-	-0.011638	0.001853	-
Robin Rigg	-0.596290	33.846655	10.844253	-0.012346	0.003951	0.001266
Robin Rigg West	-0.596290	33.846655	10.844253	-0.012346	0.003951	0.001266
Sheringham Shoal	25.417212	29.935300	0.650705	-0.012146	0.000230	0.000005
Thanet	19.409235	36.363246	0.875391	0.026651	0.070884	0.001706
Walney 1	23.46442	46.91135	-	-0.01163	0.00139	-
Walney 2	21.83020	44.42664	-	-0.01231	0.00007	-
Walney 3	10.04935	20.35939	-	-0.01235	-	-
Walney 4	10.04935	20.35939	-	-0.01235	-	-
West of Duddon Sands	8.98738	44.80090	-	0.09090	0.48263	-
Westermost Rough	18.27433	31.10058	-	-0.01188	0.00076	-

The final offshore tariffs have been updated with the latest OFTO revenue forecasts. This has caused the offshore local circuit and ETUoS tariffs to increase slightly. The onshore substation civils discount has been updated which has caused the offshore substation tariffs to decrease for most offshore generators.

Due to the inclusion of approved Exceptional Event in the OFTO revenue, the offshore substation and circuit tariffs for the relevant offshore generators have increased accordingly.

3

Demand tariffs

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

7. Demand tariffs summary

There are two types of demand Half-Hourly (HH) and Non-Half-Hourly (NHH). The section shows the tariffs for HH and NHH as well as the tariffs for Embedded Export (EET).

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

Table 8 Summary of demand tariffs

HH Tariffs	2021/22 Draft	2021/22 Final	Change
Average Tariff (£/kW)	52.460812	51.360891	- 1.099921
Residual (£/kW)	54.342512	53.231669	- 1.110843
EET	**2021/22 Draft**	**2021/22 Final**	**Change**
Average Tariff (£/kW)	2.272481	2.144791	- 0.127690
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.282952	2.282036	- 0.000916
Embedded Export Volume (GW)	6.658889	6.949440	0.290551
Total Credit (£m)	15.132202	14.905099	- 0.227103
NHH Tariffs	**2021/22 Draft**	**2021/22 Final**	**Change**
Average (p/kWh)	6.563620	6.500873	- 0.062747

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	20.376396	2.723726	-
2	Southern Scotland	29.300172	3.712996	-
3	Northern	41.444048	5.139134	-
4	North West	48.036551	6.039881	-
5	Yorkshire	48.696198	5.963751	-
6	N Wales & Mersey	49.452722	6.060647	-
7	East Midlands	52.428151	6.641922	1.478519
8	Midlands	53.959972	6.937534	3.010340
9	Eastern	54.283935	7.355652	3.334302
10	South Wales	56.236808	6.514291	5.287175
11	South East	56.772103	7.738980	5.822471
12	London	59.186350	6.378699	8.236717
13	Southern	58.865203	7.574864	7.915570
14	South Western	61.676796	8.488355	10.727163

Residual charge for demand:	53.231669

8. Changes since Draft Tariffs

Overall the demand tariffs have reduced marginally since the Draft, mainly driven by the decrease in the total revenue from the TOs.

The average HH tariff is set at £51.36/kW, a decrease of £1.10/kW. The average NHH tariff is set at 6.50p/kWh, a decrease of 0.06p/kWh.

The average Embedded Export Tariff is £2.14/kW, a decrease of £0.13/kW, due to the updated locational demand tariffs. The total credit for embedded export has seen a smaller reduction to £14.91m since the Draft, due to an increase in the forecasted Embedded Export volumes.

The Small Generator Discount (SGD) will end on the 31st March 2021. As such SGD is not included in the Final Tariffs.

Below is a breakdown of the key changes that have impacted HH and NHH demand tariffs:

- Reduction in TO revenue results in lower demand revenue and subsequently decreased demand residual and average tariff
- Taking into account of COVID19 impact, HH demand charging base have been reduced whilst the NHH demand has increased.
- The combination of reduced average HH tariffs and HH demand volumes have reduced revenue from HH demand
- NHH revenue has not changed, as the overall reduction in demand revenue has been offset by the reduction in HH revenue.
- Change in locational demand profile across zones due to the reduction in Expansion Constant and Security Factor.

Details on the updates to the demand charging bases and the rationale behind them can be found in the demand charging base section on page **Error! Bookmark not defined.**

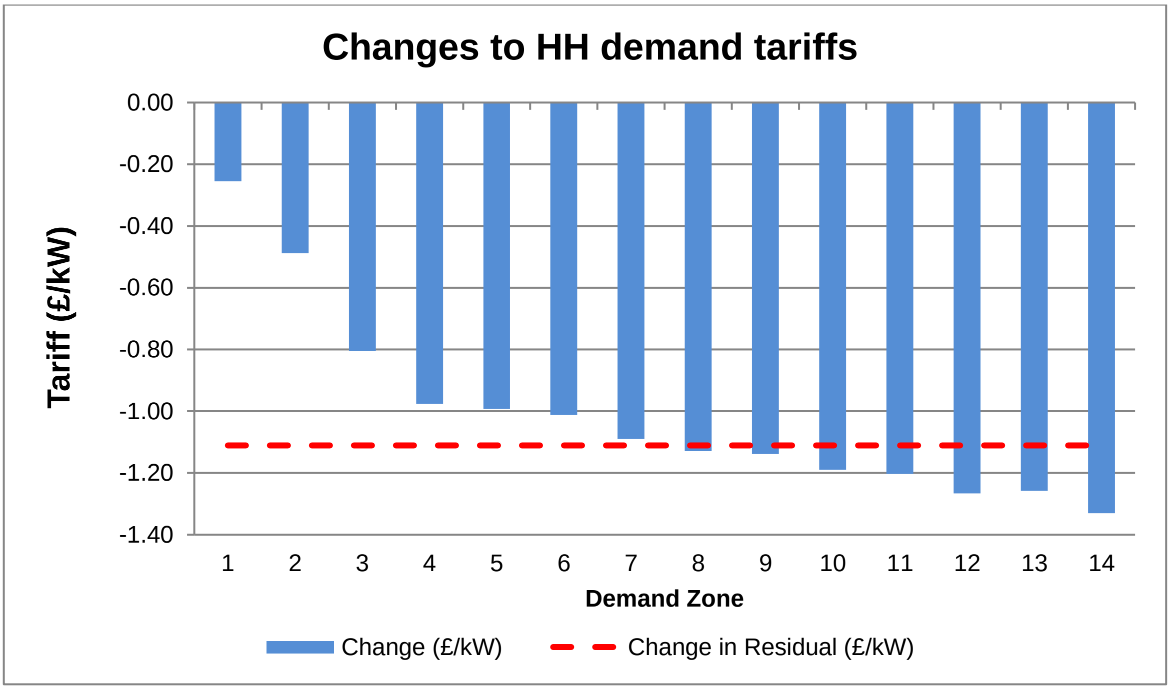
9. Half-Hourly demand tariffs

This table and chart show the forecast HH demand Final tariffs for 2021/22 compared to the 2021/22 Draft Tariffs.

Table 10 Half-Hourly demand tariffs

Zone	Zone Name	2021/22 Draft (£/kW)	2021/22 Final (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	20.631769	20.376396	- 0.255373	- 1.110843
2	Southern Scotland	29.787898	29.300172	- 0.487726	- 1.110843
3	Northern	42.247971	41.444048	- 0.803923	- 1.110843
4	North West	49.012126	48.036551	- 0.975575	- 1.110843
5	Yorkshire	49.688949	48.696198	- 0.992751	- 1.110843
6	N Wales & Mersey	50.465171	49.452722	- 1.012449	- 1.110843
7	East Midlands	53.518073	52.428151	- 1.089922	- 1.110843
8	Midlands	55.089779	53.959972	- 1.129807	- 1.110843
9	Eastern	55.422177	54.283935	- 1.138242	- 1.110843
10	South Wales	57.425898	56.236808	- 1.189090	- 1.110843
11	South East	57.975131	56.772103	- 1.203028	- 1.110843
12	London	60.452238	59.186350	- 1.265888	- 1.110843
13	Southern	60.122730	58.865203	- 1.257527	- 1.110843
14	South Western	63.007529	61.676796	- 1.330733	- 1.110843

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the HH demand tariff has decreased across all zones due to the reduction in overall demand revenue. The variation across the zones is mainly driven by the reduction to the expansion constant (EC) value, switching the indexation from RPI to CPIH for 2021/22 and the adjustment of the security factor (SF). The impact is seen in the locational element of demand tariffs, which forms part of the HH tariff as lower the EC reduces the polarising impact of demand tariffs across the demand zones.

Having considered the latest available metering data for this winter, the gross HH chargeable demand has decreased by 0.7GW in comparison with the Draft tariffs and is set at 18.3GW.

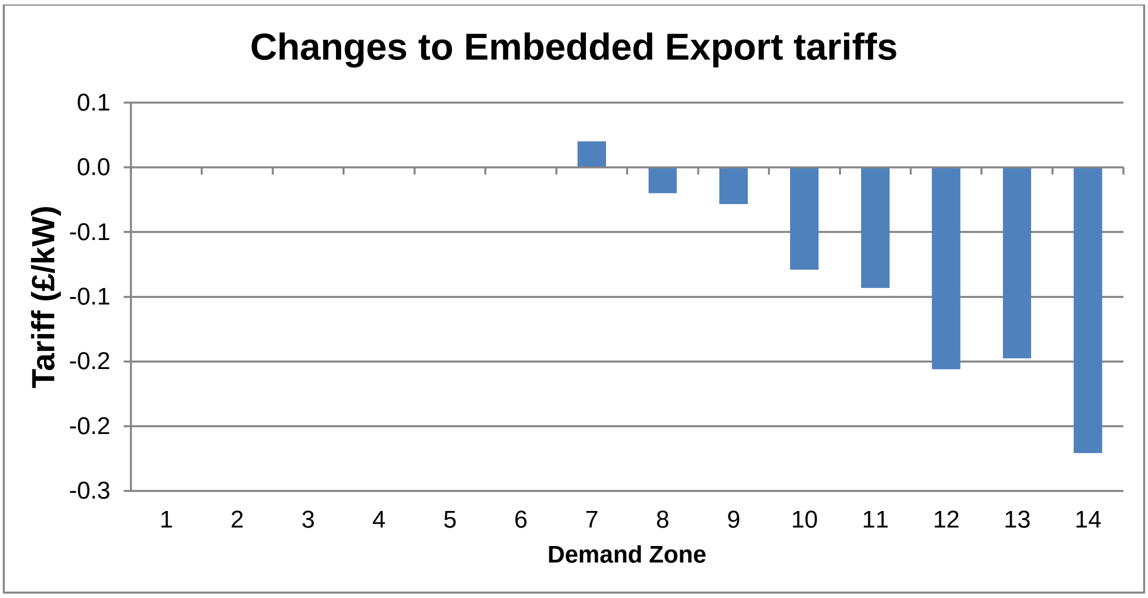
10. Embedded Export Tariffs (EET)

The next table and figure shows the final 2021/22 EET compared to the draft tariffs.

Table 11 Embedded Export Tariffs

Zone	Zone Name	2021/22 Draft (£/kW)	2021/22 Final (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	1.458513	1.478519	0.020006
8	Midlands	3.030219	3.010340	- 0.019879
9	Eastern	3.362617	3.334302	- 0.028315
10	South Wales	5.366338	5.287175	- 0.079163
11	South East	5.915571	5.822471	- 0.093100
12	London	8.392678	8.236717	- 0.155961
13	Southern	8.063170	7.915570	- 0.147600
14	South Western	10.947969	10.727163	- 0.220806

Figure 3 Embedded export tariff changes



The average EET tariffs is £2.14/kW, a small reduction of £0.13/kW, compared to the Draft. As stated previously, the change in locational demand and the zonal variance is driven by the updates made to the EC and SF.

Overall, with the reduction in average tariffs and the increase in Embedded export volumes, the forecasted EET revenue has reduced by £0.23m to £14.91m. There has been a minimal impact to the AGIC (Avoided Grid Supply Point Infrastructure Credit).

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

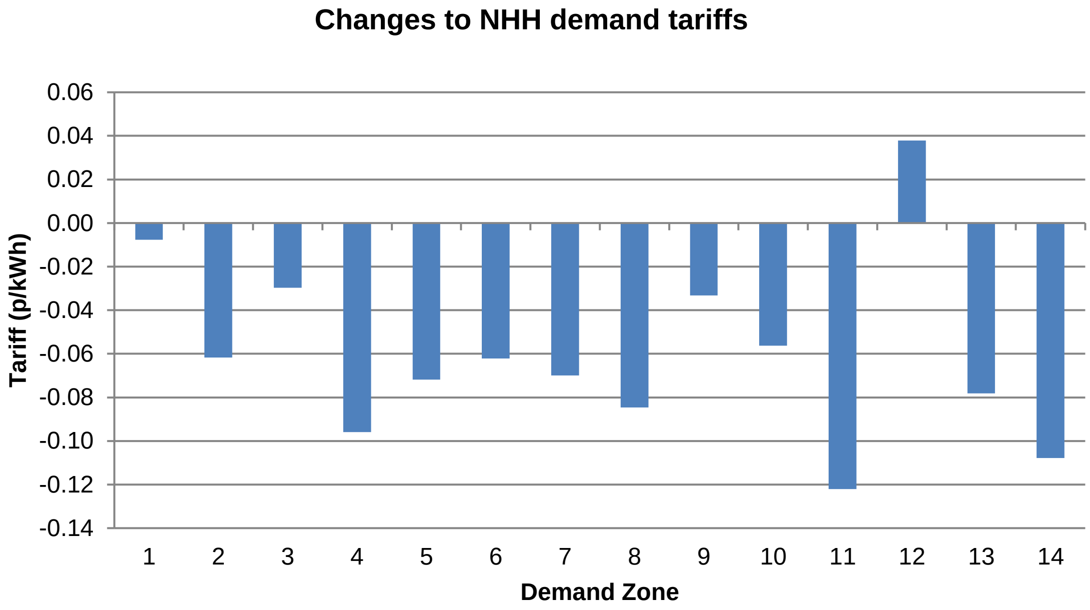
11. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2021/22 Final tariffs and the Draft tariffs.

Table 12 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2021/22 Draft (p/kWh)	2021/22 Final (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.731383	2.723726	- 0.007657
2	Southern Scotland	3.774643	3.712996	- 0.061647
3	Northern	5.168770	5.139134	- 0.029636
4	North West	6.135768	6.039881	- 0.095887
5	Yorkshire	6.035617	5.963751	- 0.071866
6	N Wales & Mersey	6.122775	6.060647	- 0.062128
7	East Midlands	6.711876	6.641922	- 0.069954
8	Midlands	7.022124	6.937534	- 0.084590
9	Eastern	7.388941	7.355652	- 0.033289
10	South Wales	6.570524	6.514291	- 0.056233
11	South East	7.861029	7.738980	- 0.122049
12	London	6.340861	6.378699	0.037838
13	Southern	7.653066	7.574864	- 0.078202
14	South Western	8.596217	8.488355	- 0.107862

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2021/22 is set at 6.50p/kWh, which is a 0.06p/kWh decrease compared to Draft tariffs. For NHH, the reduction in overall demand revenue has been offset by the reduction in HH revenue, meaning that the total revenue for NHH has stayed roughly the same for Final Tariffs (£1,618m). The slight increase in NHH demand volumes is the main driver for the change in average NHH tariff. The change in locational demand and the variations in the forecasted HH and NHH demand volumes at a zonal level has meant that 13 of the 14 zones tariffs have reduced by varying amounts. However, NHH tariff for zone 12 (London) is showing a slight increase. The reduction of the HH revenue in zone 12 means that despite of increase in the NHH demand, the NHH tariff needs to increase to recover increased NHH revenue in zone 12.

4

Overview of data input

Since the Draft tariffs published in November 2020, we have updated:

- Allowed revenue to be recovered through TNUoS
- The local substation tariffs
- The zonal demand and generation charging bases, and
- Inflation to CPIH for some of the financial parameters, including expansion factor, local substation revenue, AGIC and onshore civils discount.
- The overhead & annuity factors that feed into certain RIIO-2 parameter calculations

For details changes to TNUoS parameters through the regular forecast cycle, please see Appendix J.

12. Changes affecting the locational element of tariffs

The 2021/22 locational element of generation and demand tariffs is based upon:

- Contracted generation and nodal demand as of 31 October 2020;
- Local and MITS circuits as stated in the ETYS; and
- Inflation

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2021/22 period, which can be found on the TEC register.[4] The contracted TEC volumes are based on the 31 October 2020 TEC register.

Modelled TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. We have forecast our best view of modelled TEC based on the 31 October 2020 TEC register, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the likely volume of generation that will be connected to the system during 2021/22 and are liable to pay generation TNUoS charges. We have reviewed our forecast of Chargeable TEC since the Draft tariffs. As a result, the Chargeable TEC is reduced by 1.6WG to 70.1GW.

Table 13 Contracted TEC

	2020/21	2021/22 Tariffs			
Generation (GW)	Final	March	August	Draft	Final
Contracted TEC	84.9	93.6	92.7	89.9	89.9
Modelled Best View TEC	84.9	85.8	86.7	89.9	89.9
Chargeable TEC	70.7	76.8	76.9	71.7	70.1

13. Adjustments for interconnectors

When modelling flows on the transmission system, interconnector flows are not included in the Peak model but are included in the Year Round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the calculations of chargeable TEC for either the generation or demand charging bases.

The table below reflects the contracted position of interconnectors for 2021/22 in the interconnector register as of 31 October 2020,

[4] See the Registers, Reports and Updates section at https://data.nationalgrideso.com/data-groups/connection-registers

Table 14 Interconnectors

Interconnector	Site	Interconnected System	Generation MW			
			Generation Zone	Transport Model Peak	Transport Model Year Round	Charging Base
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
BritNed	Grain 400kV	Netherlands	24	0	1200	0
Belgium Interconnector (Nemo)	Richborough 400kV	Belgium	24	0	1020	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
IFA2 Interconnector	Chilling 400KV Substation	France	26	0	1100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	490	0
NS Link	Blyth	Norway	13	0	1400	0

14. Expansion Constant

The expansion constant is the annuitized value of the cost required to transport 1 MW over 1 km. The 2021/22 Expansion Constant is set to £ 15.050736/MWkm. This is based on the 2020/21 RIIO-1 value (as proposed in CMP353) uplifted by CPIH (as per CMP355/356).

15. Onshore substation tariffs

Onshore Local Substation tariffs have been updated for 2021/22 as part of the RIIO-2 parameter refresh. They are set in 2020/21 prices and have been uplifted by CPIH for 2021/22 (as per CMP355/356).

16. Offshore local tariffs

Local offshore circuit tariffs, local offshore substation tariffs and the ETUoS tariff are indexed in line with the revenue of the relevant Offshore Transmission Owner. These tariffs have been recalculated, in preparation for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting. These recalculations use the latest forecast of the relevant inflation terms.

17. Allowed transmission revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Some other revenue (for example, Network Innovation Competition for network companies including ESO, TOs and DNOs and interconnector revenue adjustment) are also collected from network users via TNUoS.

Year 2021/22 is the start of RIIO-2 price control period. On 8th December, Ofgem published the RIIO-2 final determination (FD) for onshore TOs and the ESO[5]. Onshore TOs' and the ESO have since updated their revenue forecast, under the calculation methodology as set out in their updated draft transmission licences, which is incorporated in the Final Tariffs.

[5] https://www.ofgem.gov.uk/publications-and-updates/riio-2-final-determinations-transmission-and-gas-distribution-network-companies-and-electricity-system-operator

CACM pilot project costs

On 22nd January, Ofgem published their decision on costs recovery of some historical CACM (Capacity Allocation and Congestion Management) pilot projects from TNUoS charges[6]. The decision sets out the amount to be paid to IFA, BritNed, Nemo Link via the 2021/22 TNUoS. In the Final tariffs, we have included the amount of CACM costs in the TNUoS revenue.

Bad debt

In accordance with Ofgem's Final Determination, the ESO is permitted to recover the TNUoS bad debt effectively occurred during RIIO1 and forecast bad debt for 2021/2022 via the TNUoS charge. As such, the bad debt value is included in the Final Tariffs.

Other revenue items in the ESO's RIIO-2 licence

Following legal separation of the ESO from National Grid Electricity Transmission in 2019, a few revenue items which was set up in RIIO-T1, and was related to the system operator's function, were carried over in NGET's licence for two years, and will now be handed over back to the ESO under RIIO-2. These items include the legacy adjustments term, licence fee, business rate etc. The ESO revenue breakdown table has been updated to reflect the updated ESO licence.

For more details on the breakdown of the TNUoS Revenue, please refer to Appendix G.

[6] https://www.ofgem.gov.uk/system/files/docs/2021/01/decision_on_assessment_of_ifa_britned_and_nemo_links_pilot_project_and_interim_period_cost_recovery_submissions_under_the_capacity_allocation_and_congestion_management_cacm_regulation_0.pdf

Table 15 Allowed revenues

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The revenue to be collected from generators and demand suppliers has be updated and finalised in the Final Tariffs.

The “EU gen cap”

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges in Great Britain to €2.5/MWh. The revenue that can be recovered from generation dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin of 20.8% is also applied to reflect revenue and output forecasting accuracy. This revenue figure is normally referred to as the “EU gen cap”.

The EU generation cap calculation has been updated from the Draft Tariffs due to a reduction in generation output taking into account COVID19 impact. For details please see the “Generation Output” paragraph.

TCR implementation - TNUoS generation residual (TGR) change

On 21 November 2019, the Authority published their final decision on the Targeted Charging Review (TCR) and issued Directions to NGESO to raise changes to the charging methodology to give effect to that final decision. This includes, among other changes, the removal of generation residual, which will take effect from April 2021.

This change has been managed under CUSC modification proposals CMP317/327, which seeks to establish which charges are, and are not in scope of the EU gen cap. The CUSC mods were approved by Ofgem on 17 December 2020.

Under the CMP317/327 option approved by Ofgem, charges that are collected via generator local tariffs (including onshore and offshore local substation charges, and onshore and offshore local circuit charges), will be excluded from the EU gen cap. Therefore, the EU gen cap is only applicable for charges that are collected via generation wider tariffs.

Due to this TGR change, revenue collected from generators (via wider tariffs and local tariffs) is much higher compared to 2020/21. In the Final Tariffs, generation revenue is set at £774m, an increase of £399m from £375m for 2020/21.

Exchange Rate

According to the CUSC methodology, the exchange rate for 2021/22 was taken from the Economic and Fiscal Outlook, and remains unchanged from Draft tariffs, in line with the CUSC methodology. The value is €1.210793 /£.

Generation Output

We received comments during the Draft Tariffs webinar, asking us to re-assess the generation output figure of 222.8TWh. The original forecast was based on the 2020 Future Energy Scenarios which did not take into account of Covid-19 impacts. Since then, we have carefully considered the COVID19 impacts on generation and demand. In light of observed delays in new connections and continued demand suppression, we have revised generation output to 200.0TWh in the Final Tariffs.

Error Margin

The error margin remains unchanged from Draft tariffs at 20.8%.

The parameters used to calculate the proportions of revenue collected from generation and demand are shown in the table below.

Table 16 Generation and demand revenue proportions

		2021/22 Tariffs			
Code	**Revenue**	**March**	**August**	**Draft**	**Final**
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50
y	Error Margin	16.0%	20.8%	20.8%	20.8%
ER	Exchange Rate (€/£)	1.12	1.21	1.21	1.21
MAR	Total Revenue (£m)	3,053.1	3,048.6	3,410.2	3,318.5
GO	Generation Output (TWh)	199.8	222.8	222.8	200.0
	Wider locational generator Revenue (£m)	403.0	382.3	366.4	357.4
	Charges on assets required for connection (£m)	445.6	462.0	449.3	446.9
G	% of revenue from generation	26.9%	27.1%	23.9%	23.3%
D	% of revenue from demand	73.1%	72.9%	76.1%	76.7%
G.R	Revenue recovered from generation including adjustment revenue(£m)	820.6	826.4	813.7	774.0
D.R	Revenue recovered from demand (£m)	2,232.6	2,222.2	2,596.5	2,544.5

19. Charging bases for 2020/21

Generation

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

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

The generation charging base is 70.1GW based on our internal view of what generation we expect to connect in 2021/22.

Demand

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

- Historical gross metered demand and embedded export volumes (up to December 2020)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

The impact of demand suppression due to COVID-19 has been reviewed further for the demand charging bases in the Final Tariffs. Overall, our view is that gross Triad Demand suppression continues but not as much as this winter. HH demand improves from this winter but still sees significant reduction compared to pre-covid due to economic scarring. NHH demand reduces from this Winter as a result of returning to some level of normality.

Table 17 Charging bases

	2021/22 Tariffs			
Charging Bases	**March**	**August**	**Draft**	**Final**
Generation (GW)	76.8	76.9	71.7	70.1
NHH Demand (4pm-7pm TWh)	24.0	24.4	24.6	24.9
Net Charging				
Total Average Net Triad (GW)	43.2	42.8	43.3	43.0
HH Demand Average Net Triad (GW)	12.6	11.6	12.3	11.4
Gross charging				
Total Average Gross Triad (GW)	50.0	50.2	50.0	50.0
HH Demand Average Gross Triad (GW)	19.4	18.9	19.0	18.3
Embedded Generation Export (GW)	6.8	7.3	6.7	6.9

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate their generation tariffs. The ALFs for 2021/22[7], based upon data from 2015/16 to 2019/20, have been finalised and are included in the Final Tariffs. The full list of the final ALFs for 2021/22 are available on the National Grid ESO website. Further details of the ALFs are explained in Appendix E.

21. Generation adjustment and demand residual

Under the existing CUSC methodology, the adjustment and residual elements of tariffs are calculated using the formulae below.

Generation Adjustment = (Total Money collected from generators as determined by G/D split less money recovered through location tariffs) divided by the total chargeable TEC

[7] Final ALFs for 2021/22

$$A_G = \frac{G.R - Z_G}{B_G}$$

Where

- A_G is the generation adjustment tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from generation (the G/D split percentage)
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from generation locational tariffs (£m), including wider zonal tariffs and project-specific local tariffs
- B_G is the generator charging base (GW)

On 21 November 2019, Ofgem published their final decision on the Targeted Charging Review (TCR) and issued Directions to NGESO to raise changes to the charging methodology to give effect to that final decision. These changes will take effect from April 2021 for the Transmission Generation Residual (TGR).

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

Ofgem announced their decision on CMP317/327 and concluded that the generation will be £0/kW form April 2021 and that there is an adjustment mechanism to ensure compliance with the European Regulation. It has also been announced that all local onshore and local offshore tariffs are not included in the EU cap, so removing these from Z_G.

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, and EE are determined by the locational elements of tariffs. The EE is also affected by the value of the AGIC[8] and phased residual.

Under the TDR, Ofgem also decided on some changes to the demand residual tariffs to apply in 2022, i.e. the existing demand non-locational tariff will be replaced with a new set of £/site charges on final demand users, based on site banding. As the changes do not apply until April 2022, they have not been included in the Final Tariffs for 2021/22.

[8] Avoided Grid Supply Point Infrastructure Credit

Final demand in principle is consumption used for purposes other than to operate a generating station, or to store and export, and is defined in the CUSC through the approved CMP334. Each final demand site will be allocated to a "band" that is based on its capacity, annual energy consumption or other criteria, and all sites within the same band pay the same demand residual tariffs (£/site) each year.

Demand customers will continue paying the locational elements of demand tariffs, based on their triad demand for HH demand or their aggregated annual consumption during 4-7pm each day for their NHH demand. Under the CUSC modification proposal CMP343, options are being considered as to whether to "floor" the demand locational tariffs to zero in areas where the demand locational tariffs are negative. In this report, we assumed the "floored" option, and negative HH and NHH demand locational tariffs are floored at zero.

Table 18 Residual components calculation

		2021/22 Tariffs			
Component		**March**	**August**	**Draft**	**Final**
G	Proportion of revenue recovered from generation (%)	26.9%	12.0%	23.9%	23.3%
D	Proportion of revenue recovered from demand (%)	73.1%	88.0%	76.1%	76.7%
R	Total TNUoS revenue (£m)	3,053.1	3,048.6	3,410.2	3,318.5
Generation adjustment					
R_G	Generator residual tariff (£/kW)	- 0.37	- 0.23	- 0.03	- 0.43
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	403.0	382.3	366.4	357.4
O	Revenue recovered from offshore local tariffs (£m)	408.2	426.9	422.7	422.6
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.5	19.6	11.4	9.5
S_G	Revenue recovered from onshore local circuit tariffs (£m)	17.9	15.6	15.2	14.9
B_G	Generator charging base (GW)	76.8	76.9	71.7	70.1
Gross Demand Residual					
R_D	Demand residual tariff (£/kW)	46.8	46.6	54.3	53.2
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	- 92.4	- 99.2	- 104.5	- 102.0
EE	Amount to be paid to Embedded Export Tariffs (£m)	17.2	13.6	15.1	14.9
B_D	Demand Gross charging base (GW)	50.0	50.2	50.0	50.0

Tools and supporting information

Further information

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

Charging webinars

We will be hosting a webinar on this Final TNUoS tariffs for 2021/22 w/c 15 February 2021 during our Charging Forum. The webinar will be published on our website and a communication will be sent out when it is available.

Charging model copies available

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

Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website under 2021/22 forecasts:

https://www.nationalgrideso.com/tnuos

We have also created datasets for the tariffs which are published on to our new Data Portal website. It will be appended to for each publication going forward. These data sets can also be utilised through an API:

https://data.nationalgrideso.com/network-charges/transmission-network-use-of-system-tnuos-tariffs

Contact Us

We welcome feedback on any aspect of this document and the tariff setting processes.

Do let us know if you have any further suggestions as to how we can better work with you to improve the tariff forecasting process.

Our contact details

Email: TNUoS.queries@nationalgrideso.com

A

Appendix A: Background to TNUoS charging

Background to TNUoS charging

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

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

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

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

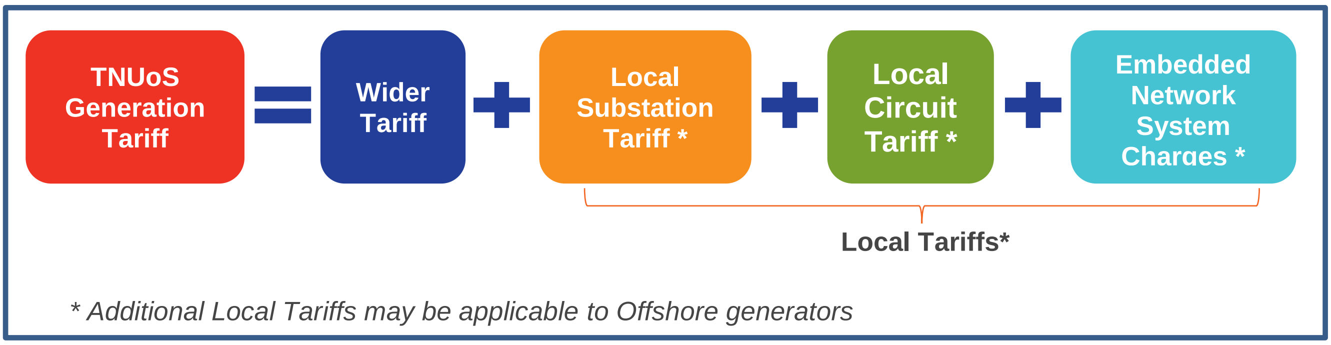
Generation charging principles

Transmission connected generators (and embedded generators with TEC >= 100MW) are subject to the generation TNUoS charges.

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

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

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



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

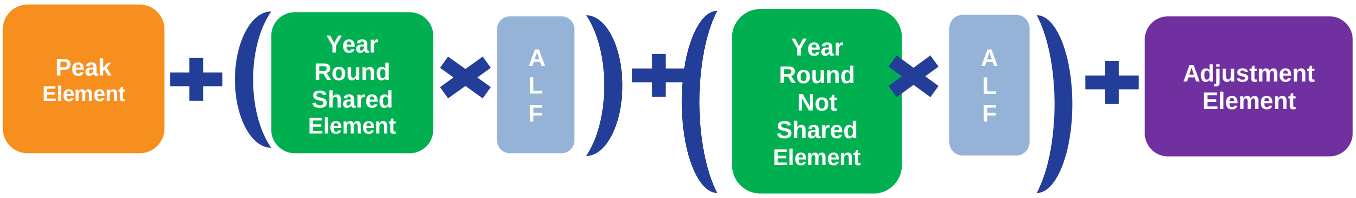
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

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

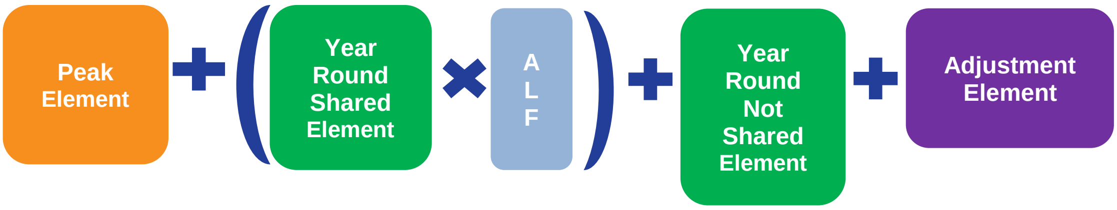
Conventional Carbon Generators

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



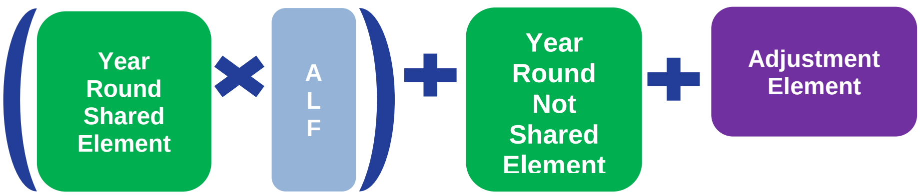
Conventional Low Carbon Generators

(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 ALFs used in these tariffs are listed from page 45.

The **Adjustment** 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 adjustment charge is also used to ensure generator charges are compliant with European legislation, which requires total TNUoS recovery from generators to be within the range of €0-

2.50/MWh on average. For this report, all local onshore tariffs (circuit and substation) and Offshore tariffs are excluded from the €2.50/MWh cap in line with Ofgem's decision on code modification CMP317/327. There is still a requirement for a negative adjustment as part of the outcome for CMP317/327 when the TGR is set to £0/kW.

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 increased by CPIH each year from the start of the RIIO-2 price control period.

Local circuit tariffs

If the first onshore substation which the generator connects to is categorised as a MITS (Main Interconnected Transmission System) node in accordance with CUSC 14.15.33, then there is no Local Circuit charge. Where the first onshore substation is not classified as MITS node, 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.

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

Click here to find out more about DNO regions.

Offshore local tariffs

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

Billing

TNUoS is charged annually and costs are calculated on the highest level of TEC held by the generator during the year. (A TNUoS charging year runs from 1 April to 31 March). This means that if a generator holds 100MW in TEC from 1 April to 31 January, then 350MW from 1 February to 31 March, the generator will be charged for 350MW of TEC for that charging year.

The calculation for TNUoS generator monthly liability is as follows:

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

All tariffs are in £/kW of contracted TEC held by the generator.

TNUoS charges are billed each month for the month ahead.

Generators with negative TNUoS tariffs

Where a generator's specific tariff is negative, the generator will be paid during the year based on their highest TEC for that year. After the end of the year, there is a reconciliation, when the true amount to be paid to the generator is recalculated.

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

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

For more details, please see CUSC section 14.18.13–17.

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers 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 made up of locational and residual charges which are currently charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.[11] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data are available, via the NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[12].

Embedded Export Tariffs (EET)

The EET was introduced under CMP264/265 and is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

This tariff contains the locational demand elements and an Avoided GSP Infrastructure Credit. The final zonal EET is floored at £0/kW for the avoidance of negative tariffs and is applied to the metered triad volumes of embedded exports for each demand zone. The money to be paid out through the EET will be recovered through demand tariffs.

Customers must now submit forecasts for both HH gross demand and embedded export volumes. Customers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon (up to 16 months after the financial year in question).

For more information on forecasts and billing, please see our guide for new suppliers on our website[13].

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

Note: HH demand and embedded export is charged at the GSP group, where the transmission network connects to the distribution network, or directly to the customer in question.

NHH demand tariffs

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

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

[11] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data

[12] https://www.nationalgrideso.com/document/130641/download

[13] https://www.nationalgrideso.com/charging/charging-guidance

TCR changes on Transmission Demand Residual (TDR) tariffs

For 2021/22, the current calculation methodology for demand tariffs remains the same. As of 2022/23, through the implementation of TDR, there will be changes to the demand tariffs i.e. the existing non-locational element in demand tariffs (the demand residual) will be replaced with a new set of £/site/year non-locational demand tariffs. The demand residual tariffs will be based on banding and applied to final demand. Final demand is the consumption used for purposes other than to operate a generating station, or to store and export.

B

Appendix B: Changes and proposed changes to the charging methodology

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

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

This section focuses on approved CUSC modifications which impact on the TNUoS tariff calculation methodology for 2021/22.

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 recently approved modifications which affect 2021/22 TNUoS tariffs are listed below.

The Small Generator Discount

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

Table 19 Summary of concluded CUSC modification proposals impacting 2021/22 tariffs

Name	Title	Effect of proposed change	Implementation
CMP317 & CMP327	Identification and exclusion of Assets Required for Connection when setting TNUoS charges	Removal of revenue linked to "generator only spurs" from the calculation of generation revenue cap under the EU rules, and setting generation residual tariff to 0	April 2021
CMP324 & CMP325	Generation Re-zoning	Keeping the existing TNUoS generation zones and their boundaries	April 2021
CMP353	Stabilising the Expansion Constant and non-specific Onshore Expansion Factors from 1st April 2021	Retaining the existing expansion constant and non-specific onshore expansion factors	April 2021
CMP355& CMP356	Updating the Indexation methodology used in TNUoS and Transmission Connection Asset charges for RIIO2 (CMP355) & Definition changes for CMP355 (CMP356)	Using CPIH inflation indexation for charging parameters under RIIO-2	April 2021
CMP357	To improve the accuracy of the TNUoS Locational Onshore Security Factor for the RIIO2 Period	Changing the global security factor from 1.8 in RIIO-1 to 1.76 in RIIO-2	April 2021

C

Appendix C: Breakdown of locational HH and EE tariffs

Breakdown of HH and EET locational tariffs

The table below shows the locational demand tariff elements used in the gross HH demand tariff and the EET, and the associated changes from the Draft tariffs to the Final tariffs.

Table 20 Demand HH locational tariffs

Demand Zone		2021/22 Draft		2021/22 Final		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.065765	-31.644978	-2.013342	-30.841930	0.052422	0.803048
2	Southern Scotland	-2.680634	-21.873981	-2.612608	-21.318889	0.068026	0.555091
3	Northern	-3.292852	-8.801690	-3.209290	-8.578331	0.083562	0.223359
4	North West	-2.307845	-3.022541	-2.249279	-2.945839	0.058566	0.076702
5	Yorkshire	-2.510350	-2.143213	-2.446646	-2.088825	0.063705	0.054388
6	N Wales & Mersey	-2.395844	-1.481497	-2.335045	-1.443902	0.060799	0.037596
7	East Midlands	-2.374727	1.550288	-2.314464	1.510947	0.060263	-0.039341
8	Midlands	-1.926371	2.673638	-1.877486	2.605789	0.048885	-0.067848
9	Eastern	1.312462	-0.232797	1.279156	-0.226889	-0.033306	0.005908
10	South Wales	-3.943770	7.027156	-3.843690	6.848829	0.100080	-0.178327
11	South East	3.707807	-0.075189	3.613715	-0.073281	-0.094092	0.001908
12	London	5.131544	0.978182	5.001322	0.953359	-0.130222	-0.024823
13	Southern	1.985722	3.794496	1.935331	3.698204	-0.050391	-0.096292
14	South Western	1.486458	7.178559	1.448736	6.996391	-0.037722	-0.182169

Table 21 shows the breakdown of the components that make up the EET.

Table 21 Breakdown of the EET

Demand Zone		2021/22 Draft		2021/22 Final		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-33.71074	2.28295	-32.85527	2.28204	0.85547	-0.00092
2	Southern Scotland	-24.55461	2.28295	-23.93150	2.28204	0.62312	-0.00092
3	Northern	-12.09454	2.28295	-11.78762	2.28204	0.30692	-0.00092
4	North West	-5.33039	2.28295	-5.19512	2.28204	0.13527	-0.00092
5	Yorkshire	-4.65356	2.28295	-4.53547	2.28204	0.11809	-0.00092
6	N Wales & Mersey	-3.87734	2.28295	-3.77895	2.28204	0.09839	-0.00092
7	East Midlands	-0.82444	2.28295	-0.80352	2.28204	0.02092	-0.00092
8	Midlands	0.74727	2.28295	0.72830	2.28204	-0.01896	-0.00092
9	Eastern	1.07966	2.28295	1.05227	2.28204	-0.02740	-0.00092
10	South Wales	3.08339	2.28295	3.00514	2.28204	-0.07825	-0.00092
11	South East	3.63262	2.28295	3.54043	2.28204	-0.09218	-0.00092
12	London	6.10973	2.28295	5.95468	2.28204	-0.15505	-0.00092
13	Southern	5.78022	2.28295	5.63353	2.28204	-0.14668	-0.00092
14	South Western	8.66502	2.28295	8.44513	2.28204	-0.21989	-0.00092

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

The AGIC is the Avoided GSP Infrastructure Credit, which is indexed by average May to October CPIH each year for the RIIO-2 price control as per Ofgem's Final Determinations.

D

Appendix D: Locational demand profiles

Locational demand profiles

The table below shows the locational demand and demand charging base used for the 2021/22 Final tariffs which has taken into account of the impact of COVID19 on demand.

The gross half-hourly (HH) demand forecast has decreased slightly to 18.3GW and the non-half-hourly (NHH) demand forecast has increased to 25.0TWh. Embedded export volumes have decreased and are forecast to be 6.7GW.

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

Table 22 Demand profile

Zone	Zone Name	2021/22 Draft					2021/22 Final				
		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	122	1,436	437	0.76	1,025	122	1,446	425	0.76	1,238
2	Southern Scotland	1,977	3,308	1,201	1.66	630	1,977	3,306	1,177	1.68	743
3	Northern	2,037	2,487	1,030	1.19	411	2,037	2,489	996	1.20	416
4	North West	2,183	3,900	1,445	1.96	369	2,183	3,906	1,406	1.99	378
5	Yorkshire	4,062	3,741	1,547	1.81	671	4,062	3,739	1,503	1.83	694
6	N Wales & Mersey	2,568	2,544	1,017	1.26	533	2,568	2,543	985	1.27	541
7	East Midlands	5,059	4,573	1,757	2.25	504	5,059	4,576	1,702	2.27	513
8	Midlands	4,198	4,137	1,551	2.03	262	4,198	4,144	1,510	2.05	266
9	Eastern	5,301	6,305	2,120	3.14	772	5,301	6,285	1,989	3.17	628
10	South Wales	1,821	1,761	788	0.85	366	1,821	1,762	765	0.86	374
11	South East	3,400	3,803	1,147	1.96	326	3,400	3,806	1,113	1.98	330
12	London	4,657	4,094	2,173	1.83	130	4,657	4,084	2,090	1.85	134
13	Southern	6,553	5,358	2,004	2.64	413	6,553	5,370	1,947	2.66	424
14	South Western	2,412	2,534	737	1.32	246	2,412	2,543	708	1.33	270
Total		**46,350**	**49,982**	**18,954**	**24.64**	**6,659**	**46,350**	**49,997**	**18,316**	**24.90**	**6,949**

E

Appendix E: Annual Load Factors

ALFs

ALFs are used to scale the Shared Year Round element of tariffs for each generator, and the year round not shared for Conventional Carbon generators, so that each has a tariff appropriate to its historical load factor.

We have incorporated the final version of the 2021/22 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2015/16 to 2019/20. Generators which were commissioned after 1 April 2018, including new Generators expected to commission during 2021/22, will use Generic ALFs until data available after three full years of operation.

The specific and generic ALFs that will apply to 2021/22 TNUoS Tariffs, have been finalised and published on our website.

Generic ALFs for 2021/22

We have created a new category (Solar) in generic ALFs. Transmission connected solar plants will have TNUoS generation charge based on the generic solar ALF, for the first three years of operation.

Transmission connected battery storage plants, will have TNUoS generation charge based on the generic ALF for Pumped Storage, for the first three years of operation.

Table 23 Generic ALFs for 2021/22

Technology	Generic ALF
Gas_Oil	0.4602%
Pumped_Storage	9.7926%
Tidal	23.1000%
Biomass	49.5396%
Wave	2.9000%
Onshore_Wind	36.0719%
CCGT_CHP	51.0635%
Hydro	41.8887%
Offshore_Wind	49.4981%
Coal	20.3859%
Nuclear	75.8434%
Solar	10.8000%

[#] Includes OCGTs (Open Cycle Gas Turbine generating plant).

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

These Generic ALFs are calculated in accordance with CUSC 14.15.110.

F

Appendix F: Contracted generation changes since the Draft tariffs

The contracted generation used in the Transport model was fixed at the Draft forecast of 2021/22 tariffs, using the TEC register as of 31 October 2020, as stated in the CUSC 14.15.6. There are no changes to the Transport model (affecting locational tariffs) in these Final Tariffs for 2021/22.

G

Appendix G Transmission company revenues

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have submitted their revenue final forecast for year 2021/22 to us. 2021/22 is the start of RIIO-T2 price control, and Ofgem have published their final determination on onshore TOs' RIIO-T2 business plan, which is reflected in onshore TOs' revenue figures.

In addition to TOs' revenue, there are some pass-through items that are to be collected by NGESO via TNUoS charges, including the Network Innovation Competition (NIC) fund, contribution made from IFA, and site-specific adjustments by TOs etc. these figures are included in the Final tariffs.

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

Notes:

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

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

NGESO TNUoS revenue pass-through items under RIIO-2 licence

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

The NGESO TNUoS revenue has been calculated under the draft NGESO licence for RIIO-2, published on Ofgem's website on 17th December. The revenue breakdown table shows details of the pass-through TNUoS revenue items under NGESO's draft licence conditions.

Table 24 NGESO revenue breakdown

	NGESO TNUoS Other Pass-Through			
Term	**March Forecast**	**August Forecast**	**Nov Draft**	**Jan Final**
Embedded Offshore Pass-Through (OFETt)	0.6	0.6	0.6	0.6
Network Innovation Competition (NICFt)	13.9	13.9	13.9	30.5
ESO Network Innovation Allowance (NIAt)	3.0	3.0	-	
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	529.9	555.8	545.6	534.2
Interconnectors CACM Cost Recovery (ICPt)				21.0
Financial facility (FINt)		-	-	
Site Specific Charges Discrepancy (DISt)		-	-	
Termination Sums (TSt)		-	-	
NGET revenue pass-through (NGETTOt)*	1,754.9	1,723.9	1,919.9	1,755.3
SPT revenue pass-through (TSPt)	376.7	371.5	390.6	375.8
SHETL revenue pass-through (TSHt)	374.0	380.0	539.7	582.6
ESO Bad debt (BDt)				4.2
ESO other pass-through items (LFt + ITCt etc)				32.6
ESO legacy adjustment (LARt)				- 18.2
Total	**3,053.1**	**3,048.6**	**3,410.2**	**3,318.5**

Onshore TOs (NGET, SPT and SHETL) revenue final forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have finalised their revenue forecast for year 2021/22, based on Ofgem's RIIO-2 final determination (FD).

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2021/22 is forecast to be £549m.

Since year 2018/19, under CMP283, TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework. In addition, Ofgem had directed that some CACM cost will be recovered via 2021/22 TNUoS revenue, as a one-off adjustment. The total amount of interconnector adjustment has been finalised in January and was included in this report.

Table 25 NGET revenue breakdown

2021/22 Revenue Description		Licence Term	National Grid Electricity Transmission			
Regulatory Year			March Forecast	August Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 1,585.1			
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (393.9)			
RPI True Up	A3	TRUt	£ (1.1)			
RPI Forecast	A4	RPIFt	1.420			
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 1,690.0**	**£ 1,688.8**	**£ 1,961.8**	
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ 38.1			
Temporary Physical Disconnection	B2	TPDt	£ 4.8			
Inter TSO Compensation	B4	ITCt	£ (2.8)			
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ 40.2**	**£ 40.2**	**£ -**	
Financial Incentive for Timely Connections Output	C5	-CONADJt				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ 17.2	£ 17.2		
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ 17.2**	**£ 17.2**	**£ -**	
Network Innovation Allowance	D	NIAt	£ 7.6	£ 7.6		
Future Environmental Discretionary Rewards	F	EDRt				
Transmission Investment for Renewable Generation	G	TIRGt				
Correction Factor	-K	-K			£ (12.1)	
Financial Facility	FINt	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 1,754.9**	**£ 1,753.7**	**£ 1,949.7**	
Pre-vesting connection charges	S1		£ -	£ 29.7	£ 29.7	
Rental Site	S2		£ -	£ 0.1	£ 0.1	
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 1,754.9**	**£ 1,723.9**	**£ 1,919.9**	**£ 1,755.3**

Table 26 SPT revenue breakdown

2021/22 Revenue Description		Licence Term	Scottish Power Transmission			
Regulatory Year			March Forecast	August Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 261.9			
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (8.5)			
RPI True Up	A3	TRUt	£ (2.1)			
RPI Forecast	A4	RPIFt	£ 1.4			
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 356.9**	**£ 351.6**	**£ 378.2**	
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ 4.1	£ 4.1		
Temporary Physical Disconnection	B2	TPDt	£ -			
Inter TSO Compensation	B4	ITCt				
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ 4.1**	**£ 4.1**		
Financial Incentive for Timely Connections Output	C5	-CONADJt				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ 3.4			
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ 3.4**	**£ 3.4**		
Network Innovation Allowance	D	NIAt	£ -			
Future Environmental Discretionary Rewards	F	EDRt	£ -			
Transmission Investment for Renewable Generation	G	TIRGt	£ 32.5	£ 32.5	£ 31.9	
Correction Factor	-K	-K	£ (7.4)	£ (7.4)		
Financial Facility	FINt	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 389.5**	**£ 384.2**	**£ 410.1**	
Pre-vesting connection charges	S1		£ 12.7	£ 12.7	£ 19.46	
Rental Site	S2					
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 376.7**	**£ 371.5**	**£ 390.6**	**£ 375.8**

Table 27 SHETL revenue breakdown

2021/22 Revenue Description		Licence Term	SHE Transmission			
Regulatory Year			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 273.4			
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (8.2)			
RPI True Up	A3	TRUt	£ -			
RPI Forecast	A4	RPIFt	£ 1.4			
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 376.6**	**£ 382.50**		
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ -			
Temporary Physical Disconnection	B2	TPDt	£ -			
Inter TSO Compensation	B4	ITCt				
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ -**			
Financial Incentive for Timely Connections Output	C5	-CONADJt				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ -			
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ -**			
Network Innovation Allowance	D	NIAt	£ 0.9	£ 0.9		
Future Environmental Discretionary Rewards	F	EDRt	£ -			
Transmission Investment for Renewable Generation	G	TIRGt	£ -			
Correction Factor	-K	-K	£ -			
Financial Facility	FINt	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 377.5**	**£ 383.4**	**£ 542.64**	
Pre-vesting connection charges	S1		£ 3.4	£ 3.4	£ 2.90	
Rental Site	S2					
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 374.0**	**£ 380.0**	**£ 539.7**	**£ 582.6**

Table 28 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	25/01/2021								
Regulatory Year	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.6	6.7	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.4	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.3	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.4	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.1	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.1	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.7	Current revenues plus indexation
Thanet	78.9	17.5	15.7	19.5	18.6	19.2	19.7	20.8	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.0	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	18.9	32.9	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	25.3	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	14.4	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.1	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	Current revenues plus indexation
Race Bank						66.0	26.7	27.4	Current revenues plus indexation
Galloper							37.8	17.1	Current revenues plus indexation
Walney 3								13.5	Current revenues plus indexation
Walney 4								13.5	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2020/21							63.9	105.3	National Grid Forecast
Forecast to asset transfer to OFTO in 2021/22								31.8	National Grid Forecast
Offshore Transmission Pass-Through (B7)	**218.4**	**248.4**	**260.8**	**265.5**	**317.9**	**390.6**	**443.8**	**549.0**	

Notes:

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

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

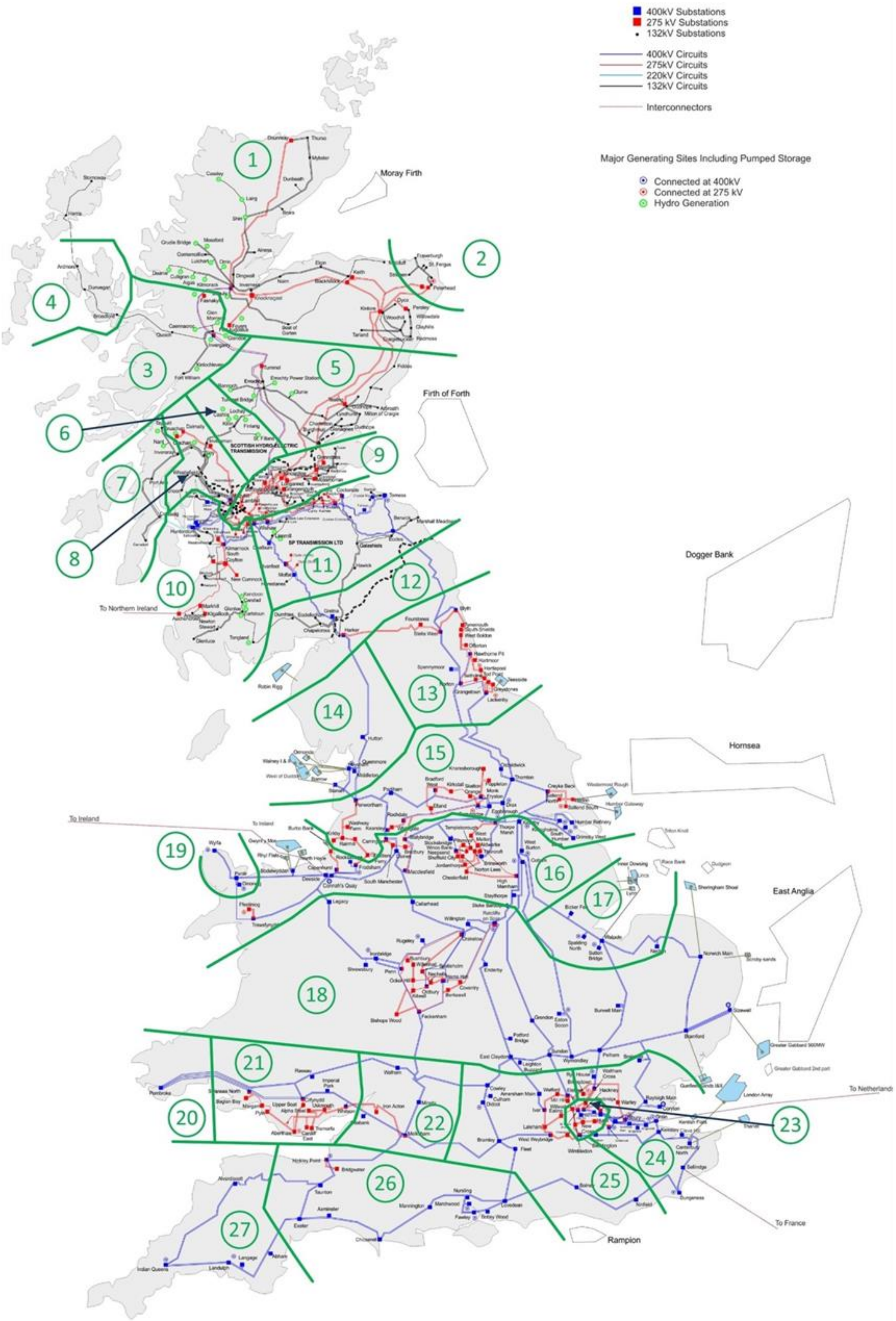
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed

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

H

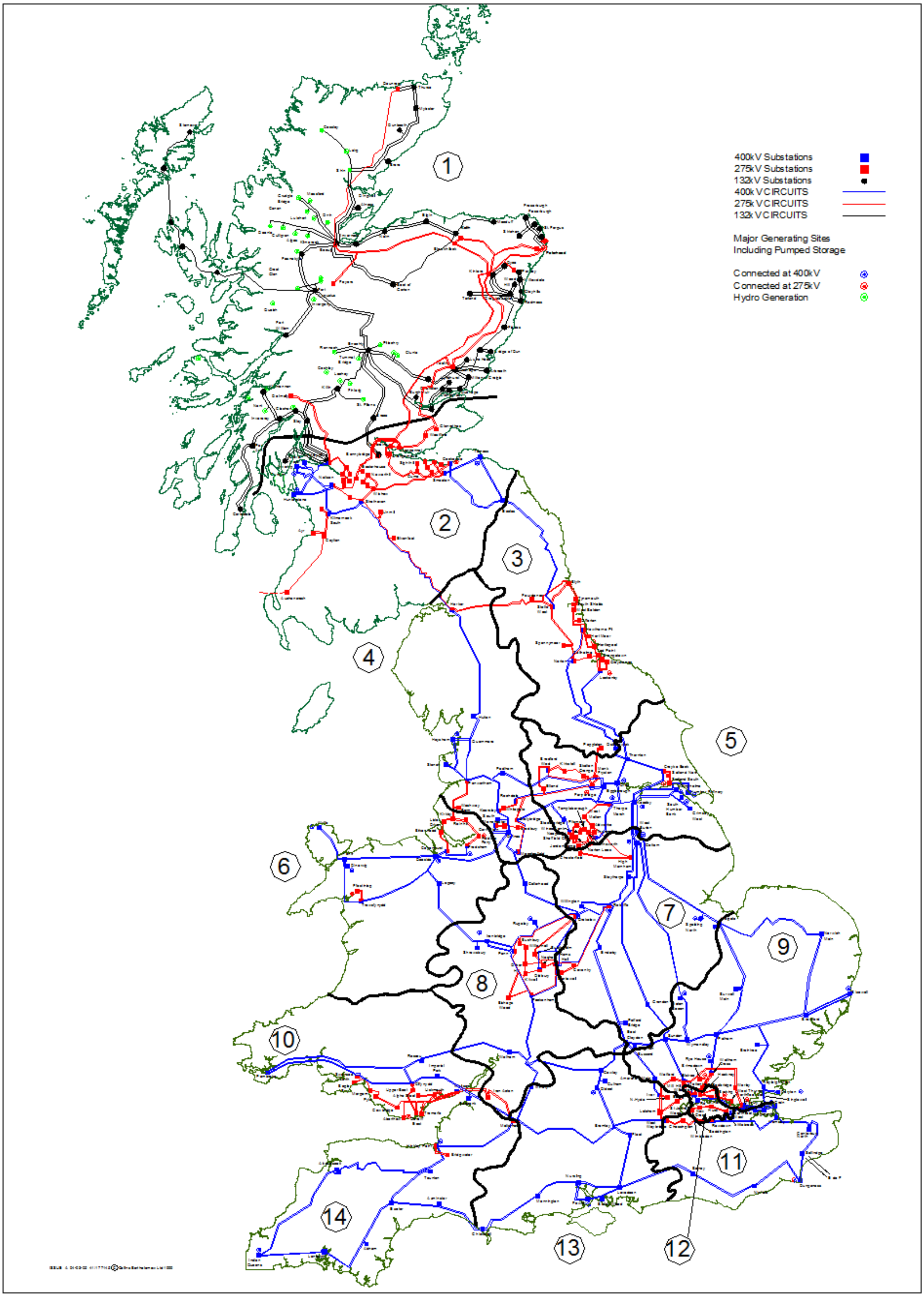
Appendix H: Generation zones map

Figure A2: GB Existing Transmission System



I

Appendix I: Demand zones map


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
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J

Appendix J: Quarterly Changes to TNUoS parameters

Parameters affecting TNUoS tariffs

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

2021/22TNUoS Tariff Forecast					
		March 2020	**August 2020**	**Draft Tariffs November 2020**	**Final Tariffs January 2021**
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen at 31 October	
	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
	CPIH	forecast			Actual
RESIDUAL	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	NG best view
	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
	Demand Charging Bases	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised forecast to include COVID impact
	Generation Charging Base	NG best view	NG best view	NG best view	NG final best view
	Generation ALFs	Previous year's data source			New ALFs published
	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

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