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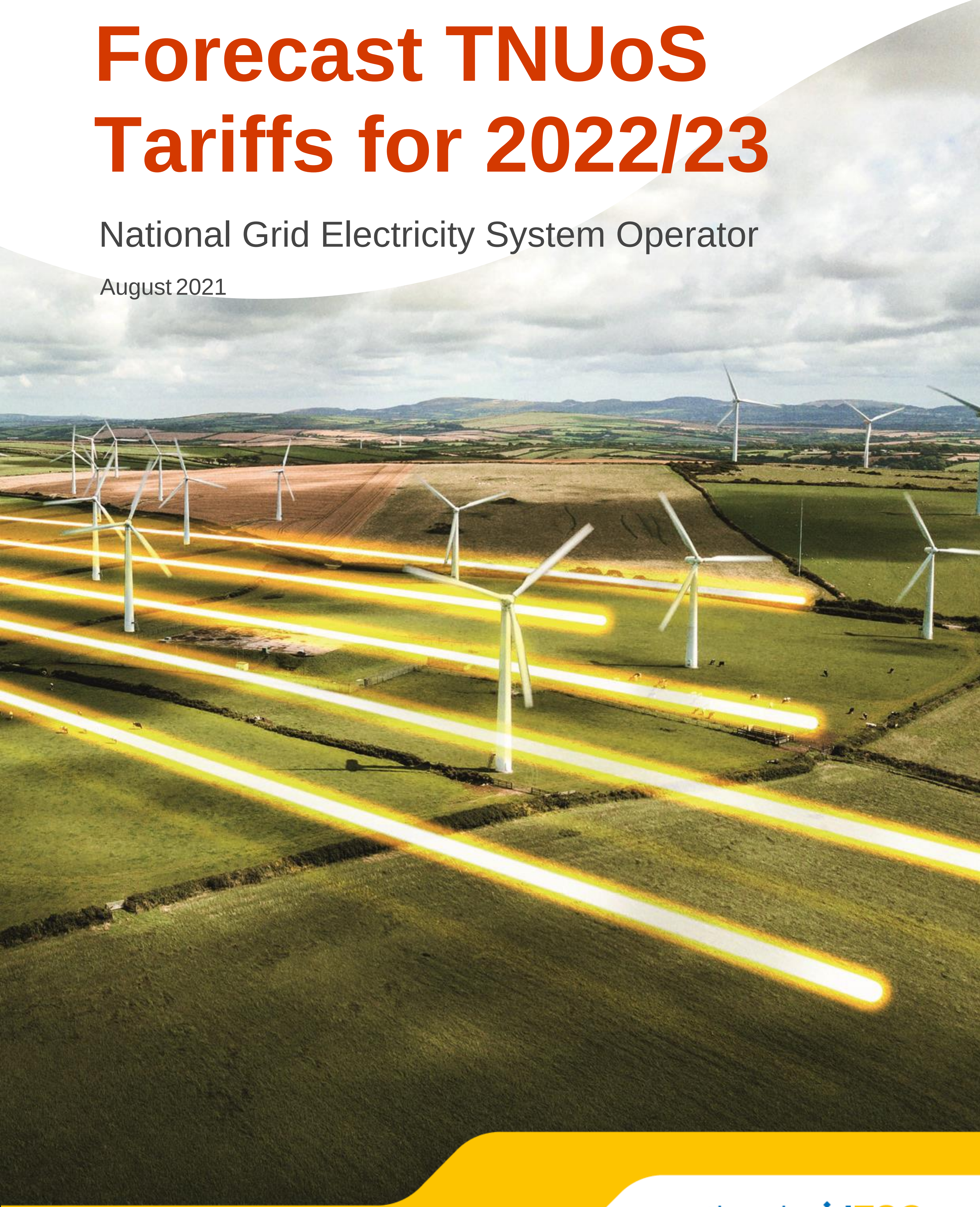
Forecast TNUoS Tariffs for 2022/23

National Grid Electricity System Operator

August 2021



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Executive summary

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 Forecast TNUoS Tariffs for 2022/23.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 2022/23 (August Tariffs) on our website[1].

This Forecast is for charging year 2022/23 and has no impact on 2021/22.

Major Regulatory Changes – CMP368/369

Following on Ofgem's decision on CMP317/327, the ESO raised CMP368/369 to revise the CUSC methodology that we use to calculate generation revenue associated with the €2.50/MWh cap (the EU gen cap).

The concept of "pre-existing assets" was introduced to separate generator local charge into two parts, where the part related to pre-existing assets will be included in the EU gen cap calculation. Ofgem is aiming for the changes to be implemented for 2022/23[2]. We therefore have set up a project team working on the implementation of CMP368/369.

Our forecast is based on the CUSC methodology and includes the potential impact of CMP368/369, but please note that leave has been granted for a judicial review of the Competition and Markets Authority (CMA) decision on the appeal to the CMA of the Ofgem's 2020 CMP317/327 decision.

In this report, our forecast on CMP368/369 figures (generation charges associated with large embedded generators and pre-existing assets) are still based on our initial understanding of the proposal in April. We intend update the indicative figures to align with the CMP368/369 original proposal in the November Draft tariffs to provide early visibility of the potential impact of CMP368/369 on the tariffs. Our final tariffs will incorporate any further changes following on the final decision of the judicial review.

Transmission Demand Residual (TDR)

The implementation of TDR banded charges methodology is not expected until 2023/24 so has not been included in this forecast. If you would like to see a forecast including TDR, please see our previous 5 Year View published in April 2021 on our website here.

Total revenues to be recovered

The total TNUoS revenue to be collected is forecast at £3,434m, an increase of £68m from the April forecast. This is due to inclusion of the K factor adjustment (+£41m) and a revision of the OFTO and TO Maximum Allowed Revenue (+£27m). The 2022/23 revenue forecast will be updated later this year and finalised by January Final Tariffs, based on onshore and offshore TOs' submissions.

Generation tariffs

The total revenue to be recovered from generators is £835m, a decrease of £1m since the April forecast.

The generation charging base has been updated to 73.4GW based on our best view on generation projects for 2022/23. This is a decrease of 1.5GW since the April forecast. This view will be further refined throughout the year. The average generation tariff is forecast at £11.38/kW, an increase of £0.32/kW due to the decrease in the generation charging base.

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

[2] https://www.ofgem.gov.uk/publications/cmp317-cmp327-excluding-assets-required-connection-and-removing-transmission-generator-residual

Demand tariffs

Revenue to be collected through demand is forecast at £2,599m for 2022/23. This value has increased by £70m compared to the April forecast. The main driver is the increased revenue to be collected in total through TNUoS.

The impact on the end consumer is forecast to be £36.56 per year, an increase of £0.18 from the initial forecast in April. This is due to the aforementioned increase in the demand revenue.

In 2022/23, £15.6m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £2m since the April forecast due to the updated locational inputs. The average EET is £2.22/kW, which is a slight increase of £0.08/kW since the April forecast.

The average gross HH demand tariff for 2022/23 is forecast to be £51.85/kW, an increase of £0.45/kW from April. The average NHH demand tariff is 6.53p/kWh, an increase of 0.03p/kWh since the April forecast.

Sensitivity Scenarios

We are conscious that there is uncertainty given the changes to the underlying framework. Having consulted the industry, we believe that it would be helpful to provide a sensitivity scenario to consider the potential upcoming changes to the Expansion Constant driven by code modifications CMP315 and CMP375. Although it is not anticipated that CMP315/375 would be implemented for 2022/23 charging year.

Improvements in the Report

We have gathered feedback from industry through our last webinar as well as the Transmission Charging Methodology Forum (TCMF) and have made several improvements to the tariff setting process and report.

- **Annual Load Factor (ALF) Examples** – we use examples ALFs to show potential generation tariffs for different fuel types. We have analysed specific and generic ALFs to find suitable ALFs to reflect the current market landscape to give a more accurate view of tariffs
- **Adjustment Tariff Calculation** –we have provided further information in Table 18 to make it possible for industry to recreate our adjustment tariff calculation
- **TO revenue breakdown** – we have included a full breakdown of TO revenues. This can be seen in Tables 24 to 27
- **K factor inclusion** – as requested through TCMF, we have included the K factor adjustment in the base case revenue for this forecast

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts for 2022/23 is available on our website[3].

Our next TNUoS tariff publication will be the Draft 2022/23 tariffs in November 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

Email: TNUoS.queries@nationalgrideso.com

[3] https://www.nationalgrideso.com/document/186171/download

Charging Methodology Changes

This Report

This report contains the quarterly forecast of TNUoS for the charging year 2022/23.

This report is published without prejudice. Whilst every effort has been made to ensure the accuracy of the information, it is subject to several estimations, assumptions and forecasts and may not bear relation to either the indicative or final tariffs we will publish at later dates.

We understand that the TNUoS and other charging methodologies will change substantially over the next few years. Because of this, we have prepared this forecast using our best view of current parameters, the latest available information and modification workgroup progress. Additionally, where we can we have included sensitivity scenarios to help industry to understand the potential implications of the ongoing charging methodology changes.

Changes to the methodology due to Ofgem's Targeted Charging Review (TCR)

On 21 November 2019, Ofgem published their final decision[4] 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. The changes have been implemented in April 2021 for the Transmission Generation Residual (TGR) changes in line with CMP317/327. Ofgem's minded-to position for the Transmission Demand Residual (TDR) changes is to implement in April 2023 and for this reason has not been included in this forecast.

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

- TGR - The removal of the generation residual, which was used to keep total TNUoS recovery from generators within the range of €0-2.50/MWh. This change was managed under CMP317/327, which sought to ensure ongoing compliance with European Regulation by establishing which charges are and are not in scope of that range. The final decision of CMP317/327 means that all local charges are not in scope but with a few exclusions. As a result, we have raised follow-up CUSC mod (CMP368/369), to exclude certain elements in local charges and generation volume and charges associated with TNUoS-liable embedded generators;
- TDR - The creation of demand residual charges, levied only to final demand (which is consumption used for purposes other than to operate a generating station, or to store and export), and on a 'site' basis. CMP343 (Transmission Demand Residual bandings and allocation) was raised to modify the CUSC methodology accordingly.

Under the existing TNUoS methodology, the demand charging base is one of the key inputs for setting the demand tariffs. Forecasting the demand charging base, in particular the system peak demand (Triads), at year ahead can be challenging. The variance between the demand forecasts used for tariff setting and outturn (actual demand) has been one of the biggest impacts on under/over recovery of TNUoS revenue. The under/over recovery of TNUoS revenue is defined as K factor in the electricity transmission licence.

Under the new TDR methodology, the demand forecast is not used in setting the demand residual tariff. Instead, the demand residual tariff requires an estimate of the number of sites in each band. The accuracy of the tariffs now depends on the quality of site count data which we would receive from the DNOs and iDNOs. We note that unlike demand outturns, we have no means to validate or verify the site data received from DNOs and iDNOs, and so the burden of ensuring accuracy in tariff setting does not lie solely with the ESO.

The locational demand charge is currently within scope of the Access and Forward-Looking Charges Significant Code Review led by Ofgem. The existing methodology requires the demand forecast for Triads in setting locational demand tariffs. Therefore under/over recovery of locational demand revenue is still affected by the accuracy of demand forecasts, albeit to a significantly lesser degree given the relative size of the locational and residual elements.

We intend to incorporate the CMP368/369 original proposal in the draft tariffs due November 2021 but the implementation of TDR implementation is currently anticipated in 2023 based on Ofgem's minded-to decision and hence would have no impact on our tariff forecast for 2022/23.

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

Changes to the methodology due to Ofgem's Review of Access and Forward-Looking Charges Significant Code Review (Access SCR)

In December 2018, Ofgem launched their Access SCR[5]. In scope is a review of the definition and choice of access rights for transmission and distribution users, a wide-ranging review of distribution network charges, a review of the distribution connection charging boundary and a focussed review of TNUoS charges.

In June 2021, Ofgem published a consultation on their Access SCR minded-to decision. The consultation closed on 26th August 2021. In their consultation document, Ofgem indicated a number of implementation approaches for Distributed Generation paying TNUoS, with no minded to decision yet published on locational demand TNUoS reforms. The earliest potential implementation date is April 2023, and therefore there is no impact on the TNUoS methodology in 2022/23 tariffs.

Potential changes to the TNUoS revenue parameters

In March 2021, CMA (Competition and Market Authority) received multiple appeals by nine energy companies over RIIO price control[6] decisions. CMA will make their final determination on the appeals by 30th October 2021. The CMA published their draft determination[7] on 11th August 2021 suggesting the appeals impacting TNUoS will not be approved.

If the appeals were approved, some underlying parameters for onshore TOs' revenue calculation (e.g. cost of equity and outperformance wedge) may change. The likely changes to TOs' revenue figures, as a result of alternative rate of return value, is unknown to the ESO, and to avoid confusing our customers, we have not attempted to undertake any revenue sensitivity analysis. Changes to the TNUoS revenue figure will impact demand users only, via demand residual tariffs. As a very high-level indication, assuming the total demand charging base is 50GW, if the revenue increases by £50m, the demand residual tariff will increase by £1/kW.

Charging methodology changes

There have been no changes that have been approved to the charging methodology since January when we published the Final 2021/22 tariffs.

There are a number of 'in-flight' proposals to change the charging methodologies, though none of these are expected to impact TNUoS tariffs for 2022/23. These are summarised on the inflight modifications Table 19.

COVID19 Impact

During 2020/21 we observed unprecedented levels of low demand in Great Britain due to the impact of COVID19 and the corresponding periods of lockdown. Along with the low levels of demand, there was a shift in HH and NHH consumptions, both of which created increased uncertainty in the demand forecast that feeds into TNUoS demand tariffs. Our view was that whilst it is anticipated that the impact of COVID19 on demand will continue into 2021/22 there will be a steady shift towards 'normal' demand levels as the year progresses, but 'economic scaring' will still be present.

In this forecast, the same approach/assumptions are applied for 2022/23, the return to 'normal' can be seen in the demand charging bases, with the average gross demand and HH demand at triad stabilising, as well as NHH returning to levels forecast pre-COVID. The indicative under recovery for 2020/21 is £41m which will be updated and finalised in November. The 2020/21 under recovery will be collected via 2022/23 TNUoS charges.

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[5] https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision

[6] https://www.gov.uk/cma-cases/energy-licence-modification-appeals-2021

[7] https://assets.publishing.service.gov.uk/media/61136944d3bf7f04482f89ab/Summary_energy_Aug.pdf

Generation tariffs

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

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1. Generation tariffs summary

This section summarises our view of generation tariffs for 2022/23 and how these tariffs were calculated.

This forecast includes the implementation of the TGR via CMP317/327, which took effect from April 2021 i.e. all local onshore and local offshore tariffs are not included in the European €2.50/MWh cap for generator transmission charges. In line with the final decision on CMP317/327, a few exceptions need to be clarified under CMP368/389.

To provide an indicative view of the likely tariffs under CMP368/389, when calculating the generation adjustment tariff for the European cap compliance, we have included local charges associated with pre-existing transmission assets based on our preliminary understanding of the concept in April, and the available data to us. We will be updating our indicative value for CMP368/369 in our November Draft Tariffs to align with the proposals for CMP368/369. We have excluded wider charges associated with TNUoS-liable embedded generators in the total generation charge and excluded expected generation outputs from those chargeable embedded generators.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2022/23 April	2022/23 August	Change since last forecast
Adjustment	- 0.418310	- 0.332681	0.085629
Average Generation Tariff*	11.064100	11.378736	0.314637

*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. These average tariffs include revenues from local tariffs.

The generation adjustment is used to ensure generation tariffs are compliant with European Legislation, which requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. The adjustment tariff is currently negative to ensure Generation Tariffs are compliant with European Legislation. The implementation of CMP317/327 means that charges for local onshore and offshore tariffs are not included in the European €2.50/MWh cap.

Average generation tariffs have increased by £0.31/kW. This is mainly driven by the decrease in the generation charging base. The generation adjustment has increased by £0.08/kW, which is mainly due to the change in the error margin used to calculate the generation adjustment tariff, it has decreased from 20.8% to 14.2% since April.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2022/23. 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)		

Each forecast, we publish example tariffs for a generator of each technology type using an example ALF – Conventional Carbon 80%, Conventional Low Carbon 80% and Intermittent 40%. For this forecast we have reviewed the example ALFs we use for each fuel type to reflect the changing industry landscape and align to the ALFs we would expect to see based on the generic and specific ALFs we publish and use for charging. The ALFs we have used in this forecast are:

- **Conventional Carbon – 40%**
- **Conventional Low Carbon – 75%**
- **Intermittent – 45%**

The ALFs used in these examples are for illustration only. Tariffs for individual generators are calculated using their own ALFs where we have 3 or more years of data or the generic ALFs if we don't.

Table 2 Generation wider tariffs

Zone	Generation Tariffs Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
1	North Scotland	4.973915	19.232070	17.212447	-0.332681	19.219041	36.277734	25.534198
2	East Aberdeenshire	3.700890	10.426620	17.212447	-0.332681	14.423836	28.400621	21.571745
3	Western Highlands	4.373415	16.331816	15.897044	-0.332681	16.932278	32.186640	22.913680
4	Skye and Lochalsh	-0.143020	16.331816	17.699383	-0.332681	13.136779	29.472544	24.716019
5	Eastern Grampian and Tayside	5.274420	12.565477	13.483534	-0.332681	15.361343	27.849381	18.805318
6	Central Grampian	4.839171	12.952915	13.944847	-0.332681	15.265595	28.166023	19.440978
7	Argyll	3.304580	11.120894	19.326273	-0.332681	15.150766	30.638843	23.997994
8	The Trossachs	4.235801	11.120894	11.724202	-0.332681	13.041158	23.967993	16.395923
9	Stirlingshire and Fife	3.194131	10.423263	11.107616	-0.332681	11.473802	21.786513	15.465403
10	South West Scotlands	1.954041	10.444205	11.124421	-0.332681	10.248810	20.578935	15.491632
11	Lothian and Borders	4.153304	10.444205	6.471641	-0.332681	10.586961	18.125418	10.838852
12	Solway and Cheviot	2.239859	7.142460	6.411378	-0.332681	7.328713	13.675401	9.292804
13	North East England	4.299320	5.653251	4.161919	-0.332681	7.892707	12.368496	6.373201
14	North Lancashire and The Lakes	1.956689	5.653251	1.492934	-0.332681	4.482482	7.356880	3.704216
15	South Lancashire, Yorkshire and Humber	4.952681	2.066040	0.250363	-0.332681	5.546561	6.419893	0.847400
16	North Midlands and North Wales	3.757167	0.859620	-	-0.332681	3.768334	4.069201	0.054148
17	South Lincolnshire and North Norfolk	2.513410	0.740381	-	-0.332681	2.476881	2.736015	0.000490
18	Mid Wales and The Midlands	1.034379	1.909192	-	-0.332681	1.465375	2.133592	0.526455
19	Anglesey and Snowdon	5.375260	0.838030	-	-0.332681	5.377791	5.671102	0.044433
20	Pembrokeshire	6.929128	-4.334186	-	-0.332681	4.862773	3.345808	-2.283065
21	South Wales & Gloucester	2.883550	-5.604156	-	-0.332681	0.309207	-1.652248	-2.854551
22	Cotswold	3.306248	3.451492	-8.690676	-0.332681	0.877893	-3.128490	-7.470186
23	Central London	-5.701073	3.451492	-7.118869	-0.332681	-7.500705	-10.564004	-5.898379
24	Essex and Kent	-3.694329	3.451492	-	-0.332681	-2.646413		1.220490
25	Oxfordshire, Surrey and Sussex	-0.789540	-1.862497	-	-0.332681	-1.867220	-2.519094	-1.170805
26	Somerset and Wessex	-1.096272	-3.748355	-	-0.332681	-2.928295	-4.240219	-2.019441
27	West Devon and Cornwall	0.350534	-7.963225	-	-0.332681	-3.167437	-5.954566	-3.916132

3. Changes to wider tariffs since the April 21 generation tariffs forecast

The following section provides details of the wider generation tariffs for 2022/23 and explains how these have changed since the April forecast. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent generators with an ALF of 45% for illustration purposes only

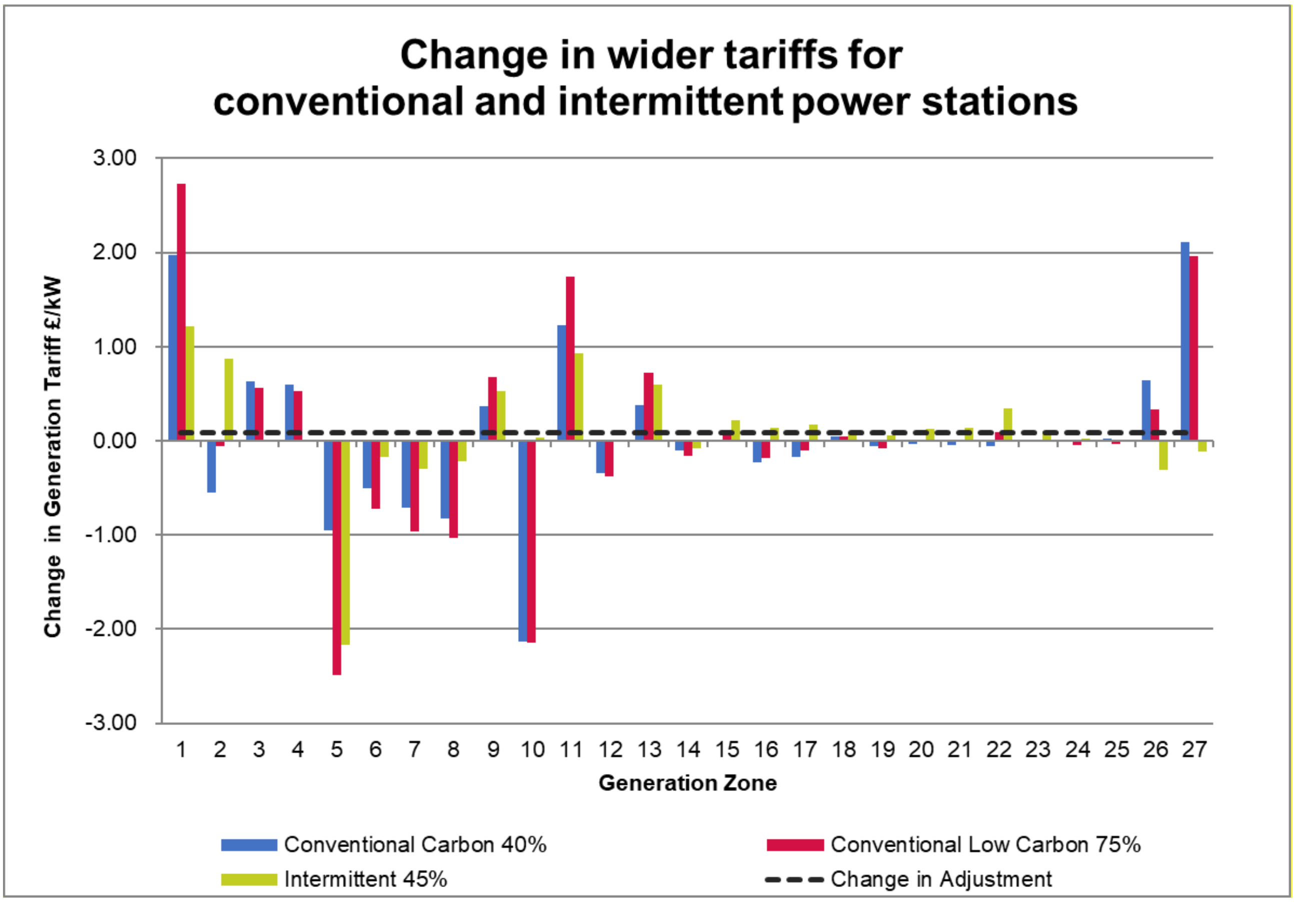
The Generation tariffs in the below tables include the implementation of the TCR, where the generation residual has increased and become less negative due to the exclusion of the local tariffs from the European €2.50 cap.

Table 3 Generation wider tariff changes

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			
Zone	Zone Name	2022/23 April	2022/23 August	Change	2022/23 April	2022/23 August	Change	2022/23 April	2022/23 August	Change	Change in Adjustment
1	North Scotland	17.244202	19.219041	1.974839	33.551139	36.277734	2.726594	24.320368	25.534198	1.213830	0.085629
2	East Aberdeenshire	14.973942	14.423836	-0.550106	28.463173	28.400621	-0.062552	20.697603	21.571745	0.874142	0.085629
3	Western Highlands	16.297692	16.932278	0.634586	31.622380	32.186640	0.564260	22.899723	22.913680	0.013957	0.085629
4	Skye and Lochalsh	12.534916	13.136779	0.601863	28.940990	29.472544	0.531554	24.702033	24.716019	0.013986	0.085629
5	Eastern Grampian and Tayside	16.312742	15.361343	-0.951399	30.339832	27.849381	-2.490451	20.978204	18.805318	-2.172886	0.085629
6	Central Grampian	15.772098	15.265595	-0.506503	28.891256	28.166023	-0.725233	19.610930	19.440978	-0.169952	0.085629
7	Argyll	15.858019	15.150766	-0.707253	31.596753	30.638843	-0.957910	24.291101	23.997994	-0.293106	0.085629
8	The Trossachs	13.864632	13.041158	-0.823474	24.998724	23.967993	-1.030731	16.616697	16.395923	-0.220773	0.085629
9	Stirlingshire and Fife	11.111188	11.473802	0.362614	21.107293	21.786513	0.679220	14.937059	15.465403	0.528344	0.085629
10	South West Scotlands	12.378055	10.248810	-2.129245	22.727874	20.578935	-2.148940	15.455235	15.491632	0.036397	0.085629
11	Lothian and Borders	9.355775	10.586961	1.231186	16.378445	18.125418	1.746973	9.909986	10.838852	0.928867	0.085629
12	Solway and Cheviot	7.668451	7.328713	-0.339738	14.057585	13.675401	-0.382184	9.294099	9.292804	-0.001295	0.085629
13	North East England	7.510496	7.892707	0.382211	11.644656	12.368496	0.723841	5.776276	6.373201	0.596925	0.085629
14	North Lancashire and The Lakes	4.581376	4.482482	-0.098894	7.521606	7.356880	-0.164725	3.786392	3.704216	-0.082176	0.085629
15	South Lancashire, Yorkshire and Humber	5.549229	5.546561	-0.002668	6.321294	6.419893	0.098599	0.625093	0.847400	0.222307	0.085629
16	North Midlands and North Wales	3.995433	3.768334	-0.227099	4.256669	4.069201	-0.187468	-0.082436	0.054148	0.136584	0.085629
17	South Lincolnshire and North Norfolk	2.650153	2.476881	-0.173271	2.842682	2.736015	-0.106667	-0.170773	0.000490	0.171264	0.085629
18	Mid Wales and The Midlands	1.424308	1.465375	0.041066	2.090450	2.133592	0.043142	0.438157	0.526455	0.088298	0.085629
19	Anglesey and Snowdon	5.433011	5.377791	-0.055220	5.751629	5.671102	-0.080527	-0.008658	0.044433	0.053091	0.085629
20	Pembrokeshire	4.897935	4.862773	-0.035163	3.348565	3.345808	-0.002758	-2.410357	-2.283065	0.127293	0.085629
21	South Wales & Gloucester	0.350185	0.309207	-0.040979	-1.654068	-1.652248	0.001820	-2.995208	-2.854551	0.140656	0.085629
22	Cotswold	0.930341	0.877893	-0.052448	-3.220382	-3.128490	0.091892	-7.814027	-7.470186	0.343842	0.085629
23	Central London	-7.499602	-7.500705	-0.001103	-10.562225	-10.564004	-0.001779	-6.000527	-5.898379	0.102149	0.085629
24	Essex and Kent	-2.648817	-2.646413	0.002404	-1.394475	-1.438391	-0.043916	1.194415	1.220490	0.026076	0.085629
25	Oxfordshire, Surrey and Sussex	-1.884996	-1.867220	0.017777	-2.480812	-2.519094	-0.038282	-1.184359	-1.170805	0.013554	0.085629
26	Somerset and Wessex	-3.567723	-2.928295	0.639428	-4.573788	-4.240219	0.333568	-1.711822	-2.019441	-0.307619	0.085629
27	West Devon and Cornwall	-5.278703	-3.167437	2.111266	-7.912186	-5.954566	1.957620	-3.804217	-3.916132	-0.111916	0.085629

Please note - we have updated the April tariffs to reflect the new ALFs used in the examples to be able to do a direct comparison. This means the tariffs will not match the ones in the 5 Year View for 2022/23 which we published in April.

Figure 1 Variation in generation zonal tariffs



Locational changes

Locational tariffs have been impacted by the update of the generation charging base; since the April forecast, in our best view there has been a large decrease (1GW) on the west side of Scotland and a large increase (1GW) on the east side of Scotland. This has impacted the flows across Scotland impacting the locational tariffs. It has caused a decrease in tariffs for zones 5 to 8 and 10 for all fuel types and an increase in zones 1,3,4,9 and 11.

Since April, there has generally been very little change in locational tariffs in the south. Zones 26 and 27 are showing increases, again due to the impact of the updated generation charging base. A decrease of 1.5GW in the Midlands has caused the flows from zones 26 and 27 to increase to supply peak demand near London, this has caused the peak tariff to increase in zones 26 and 27 causing tariffs for carbon and conventional carbon generators to increase.

Adjustment tariff changes

The adjustment tariff has been implemented through CMP317/327, where the generation residual has been removed which meant there is a need for an adjustment tariff to ensure compliance with the European cap. The adjustment tariff is forecast to be negative due to the wider tariffs causing the average generation charge to breach the cap.

The adjustment tariff is forecast to increase by £0.08/kW since the April forecast due to the change in the error margin, which has decreased from 20.8% to 14.2%. This causes the adjustment to go less negative to ensure charges are within the EU cap. For a full breakdown of the generation revenues, please see Table 23.

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 for the rest of the price control period.

For this forecast, we have applied CPIH to the onshore substation tariffs set in RIIO-2. We will further refine the value throughout the year with the latest available information. The inflation indices have been published in Table 25.

Table 4 Local substation tariffs

2022/23 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.149145	0.074575	0.051438
<1320 MW	Redundancy	0.314264	0.159620	0.113340
>=1320 MW	No redundancy	-	0.219102	0.155994
>=1320 MW	Redundancy	-	0.329710	0.237142

5. Onshore local circuit tariffs

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

There are minimal changes to the onshore local circuit tariffs barring inflation. Therefore, we have not updated associated local network models that we use to calculate local circuit tariffs. We will update the network model and the tariffs in the November Draft tariffs after we have received the latest circuit data from the TOs. The 2022/23 indicative Onshore local circuit tariffs are listed in below in Table 5.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberdeen Bay	2.642208	Edinbane	7.093998	Middle Muir	2.381463
Achruach	- 2.591303	Ewe Hill	1.541395	Middleton	0.153643
Aigas	0.677836	Fallago	- 0.063282	Millennium South	0.489266
An Suidhe	- 0.972316	Farr	3.613093	Millennium Wind	1.892283
Arecleoch	2.152552	Fernoch	4.558633	Moffat	0.197628
Beinneun Wind Farm	1.556096	Ffestiniogg	0.256382	Mossford	2.917799
Bhlaraidh Wind Farm	0.669156	Finlarig	0.331856	Nant	- 1.272706
Black Hill	1.573760	Foyers	0.296834	Necton	1.153314
Black Law	1.810987	Galawhistle	3.626483	Rhigos	0.107010
Blackcraig Wind Farm	6.524226	Glen Kyllachy	- 0.474080	Rocksavage	0.018345
Blacklaw Extension	3.840432	Glendoe	1.906381	Saltend	0.017583
Clyde (North)	0.113659	Glenglass	4.875879	Sandy Knowe	5.188041
Clyde (South)	0.131441	Gordonbush	0.055580	South Humber Bank	- 0.187905
Corriegarth	3.002509	Griffin Wind	9.840450	Spalding	0.275029
Corriemoillie	1.685991	Hadyard Hill	2.868658	Strathbrora	- 0.062721
Coryton	0.055907	Harestanes	2.620179	Strathy Wind	1.795537
Creag Riabhach	3.476589	Hartlepool	0.090602	Stronelairg	1.108790
Cruachan	1.849163	Invergarry	0.379264	Wester Dod	0.352663
Culligran	1.796282	Kilgallioch	1.090763	Whitelee	0.109993
Deanie	2.951035	Kilmorack	0.204682	Whitelee Extension	0.305780
Dersalloch	2.496503	Kype Muir	1.537250		
Dinorwig	2.431369	Langage	- 0.341923		
Dorenell	2.126703	Lochay	0.379264		
Dunmaglass	1.174666	Luichart	0.581165		
Dunhill	1.451475	Marchwood	0.386803		
Dunlaw Extension	1.531128	Mark Hill	0.907441		

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, paragraph14.4, 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 revenue of the associated Offshore Transmission Owner. Since April, the forecast has been updated with the latest inflation indices.

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 2022/23

Offshore Generator	2022/23 April Tariff Component (£/kW)			2022/23 August Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	8.981363	47.448077	1.178201	9.067773	47.904577	1.189536	0.086410	0.456500	0.011335
Burbo Bank	11.349149	21.934427	-	11.349149	21.934427	-	-	-	-
Dudgeon	16.599924	26.045535	-	16.599924	26.045535	-	-	-	-
Galloper	16.992267	26.875018	-	16.992267	26.875018	-	-	-	-
Greater Gabbard	16.731766	38.718989	-	16.892743	39.091506	-	0.160977	0.372517	-
Gunfleet	19.545355	18.024323	3.368849	19.733401	18.197736	3.401261	0.188046	0.173413	0.032412
Gwynt Y Mor	21.312321	21.071110	-	21.312321	21.071110	-	-	-	-
Hornsea 1A	7.500569	26.538185	-	7.500569	26.538185	-			
Hornsea 1B	7.500569	26.538185	-	7.500569	26.538185	-			
Hornsea 1C	7.500569	26.538185	-	7.500569	26.538185	-			
Humber Gateway	12.542420	28.776625	-	12.542420	28.776625	-	-	-	-
Lincs	17.411874	68.474947	-	17.411874	68.474947	-	-	-	-
London Array	11.816070	40.512775	-	11.816070	40.512775	-	-	-	-
Ormonde	27.613792	51.616163	0.411338	27.879465	52.112764	0.415295	0.265673	0.496601	0.003957
Race Bank	10.052457	27.920291	-	10.052457	27.920291	-	-	-	-
Robin Rigg	- 0.606088	34.402796	11.022437	- 0.611919	34.733786	11.128484	- 0.005831	0.330990	0.106047
Robin Rigg West	- 0.606088	34.402796	11.022437	- 0.611919	34.733786	11.128484	- 0.005831	0.330990	0.106047
Sheringham Shoal	25.834847	30.427173	0.661397	26.083405	30.719913	0.667761	0.248558	0.292740	0.006364
Thanet	19.728152	36.960737	0.889775	19.917957	37.316338	0.898336	0.189805	0.355601	0.008561
Walney 1	23.849970	47.682154	-	24.079432	48.140906	-	0.229462	0.458752	-
Walney 2	22.188899	45.156621	-	22.402379	45.591074	-	0.213480	0.434453	-
Walney 3	10.325940	20.919735	-	10.325940	20.919735	-	-	-	-
Walney 4	10.325940	20.919735	-	10.325940	20.919735	-	-	-	-
West of Duddon Sands	9.234736	46.033950	-	9.234736	46.033950	-	-	-	-
Westermost Rough	18.777289	31.956559	-	18.777289	31.956559	-	-	-	-

Demand Tariffs

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

nationalgridESO

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).

For 2022/23, the methodology for demand tariffs remains unchanged. Ofgem have published a 'minded to position' delaying implementation of the Transmission Demand Residual (TDR) bandings until 2023/24. With the implementation of demand residual banded charges, there will be changes to the demand tariffs, the existing non-locational element in demand tariffs (the demand residual tariff) will be replaced with a new pounds per site per year (pence per site per day) charge. 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. The methodology for demand locational tariffs would continue as is, however the flooring / non-flooring of negative locational tariffs is subject to Ofgem's final decision, though Ofgem's minded-to position is to floor the locational tariffs.

Table 8 Summary of demand tariffs

HH Tariffs	2022/23 April	2022/23 August	Change
Average Tariff (£/kW)	51.392313	51.847329	0.455016
Residual (£/kW)	53.285456	53.772794	0.487338
EET	**2022/23 April**	**2022/23 August**	**Change**
Average Tariff (£/kW)	2.138861	2.223457	0.084596
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.316267	2.319241	0.002974
Embedded Export Volume (GW)	6.536476	7.005698	0.469221
Total Credit (£m)	13.980615	15.576867	1.596252
NHH Tariffs	**2022/23 April**	**2022/23 August**	**Change**
Average (p/kWh)	6.495929	6.527043	0.031114

Demand tariffs have been forecast to increase marginally, the main impact being the increase in total revenue and the subsequent increase in the revenue to be recovered through demand.

The average HH gross tariff is forecast at £51.85/kW, an increase of £0.45/kW compared to the 2022/23 Initial Tariffs in April. The average NHH tariff is forecast at 6.50p/kWh, an increase of 0.31p/kWh.

The Small Generator Discount (SGD) ended 31 March 2021. As such the figures shown in this forecast do not include the Small Generator Discount levy.

There is an increase in the Embedded Export Volume of 0.47GW to 7.82GW compared to the April forecast, which increase the total credit to £15.7m (previously £14m). There is a slight increase to the AGIC of £0.002/kW to £2.32/kW due to an increase in forecast inflation. The overall impact of this change as well as changes to location demand gives a £0.08/kW increase of the average EET at £2.22/kW.

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	23.066212	3.016852	-
2	Southern Scotland	32.098648	4.054787	-
3	Northern	41.517582	5.075388	-
4	North West	48.016201	6.067730	-
5	Yorkshire	48.497771	5.900569	-
6	N Wales & Mersey	49.484986	6.028570	-
7	East Midlands	52.479595	6.617207	1.026042
8	Midlands	54.039843	6.906122	2.586290
9	Eastern	55.067333	7.463089	3.613781
10	South Wales	55.565014	6.343088	4.111461
11	South East	57.418465	7.822213	5.964912
12	London	60.555540	6.345094	9.101988
13	Southern	59.122777	7.578782	7.669225
14	South Western	60.455151	8.356490	9.001599

Residual charge for demand:	53.772794

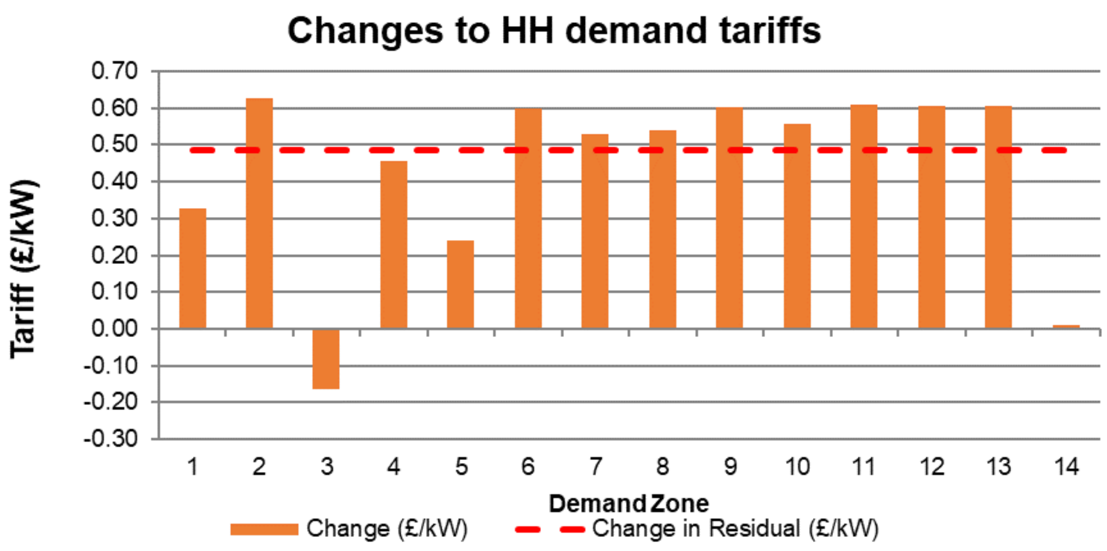
8. Half-Hourly demand tariffs

This table and chart show the August forecast gross HH demand tariffs for 2022/23 compared to the 2022/23 Initial Tariffs.

Table 10 Half-Hourly demand tariffs

Zone	Zone Name	2022/23 April (£/kW)	2022/23 August (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	22.740255	23.066212	0.325957	0.487337
2	Southern Scotland	31.470820	32.098648	0.627828	0.487337
3	Northern	41.680268	41.517582	- 0.162686	0.487337
4	North West	47.559033	48.016201	0.457168	0.487337
5	Yorkshire	48.256053	48.497771	0.241718	0.487337
6	N Wales & Mersey	48.884841	49.484986	0.600145	0.487337
7	East Midlands	51.948679	52.479595	0.530916	0.487337
8	Midlands	53.500361	54.039843	0.539482	0.487337
9	Eastern	54.465861	55.067333	0.601472	0.487337
10	South Wales	55.008036	55.565014	0.556978	0.487337
11	South East	56.810225	57.418465	0.608240	0.487337
12	London	59.948874	60.555540	0.606666	0.487337
13	Southern	58.515282	59.122777	0.607495	0.487337
14	South Western	60.445976	60.455151	0.009175	0.487337

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the HH demand tariffs have increased across all zones, excluding zone 3 where there has been a slight reduction. The increase is spread relatively equal across zones 6 to 13 in line with the increase in the residual. With zones 1 to 5 and zone 14 there are variations in change that are a result of fluctuations in the locational signal and the locational tariff element of the demand tariffs.

The forecast level of gross HH chargeable demand has increased by 0.1GW in comparison with the 2022/23 Initial Tariffs and is currently forecast at 19.17GW.

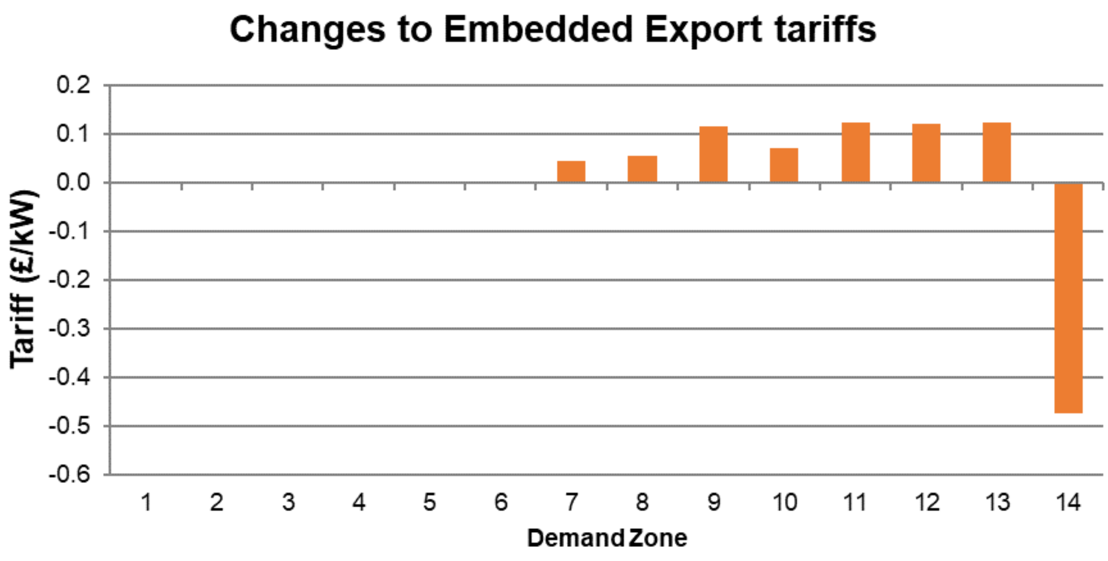
9. Embedded Export Tariffs (EET)

The next table and figure show the difference between the April forecast for 2022/23 EET and this August forecast.

Table 11 Embedded Export Tariffs

Zone	Zone Name	2022/23 April (£/kW)	2022/23 August (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	0.979490	1.026042	0.046552
8	Midlands	2.531172	2.586290	0.055118
9	Eastern	3.496672	3.613781	0.117109
10	South Wales	4.038846	4.111461	0.072615
11	South East	5.841035	5.964912	0.123877
12	London	8.979685	9.101988	0.122303
13	Southern	7.546093	7.669225	0.123132
14	South Western	9.476786	9.001599	- 0.475187

Figure 3 Embedded export tariff changes



There is an increase in the Embedded Export Volume of 0.47GW to 7.82GW compared to the 2022/23 Initial Tariffs, which increase the total credit to £15.7m (previously £14m). There is a slight increase to the AGIC of £0.002/kW to £2.32/kW due to an increase in forecast inflation. The overall impact of this change as well as changes to location demand gives a £0.08/kW increase of the average EET at £2.22/kW. The fluctuation in tariffs across each zone is linked to the changes seen in the locational element of demand charges.

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.

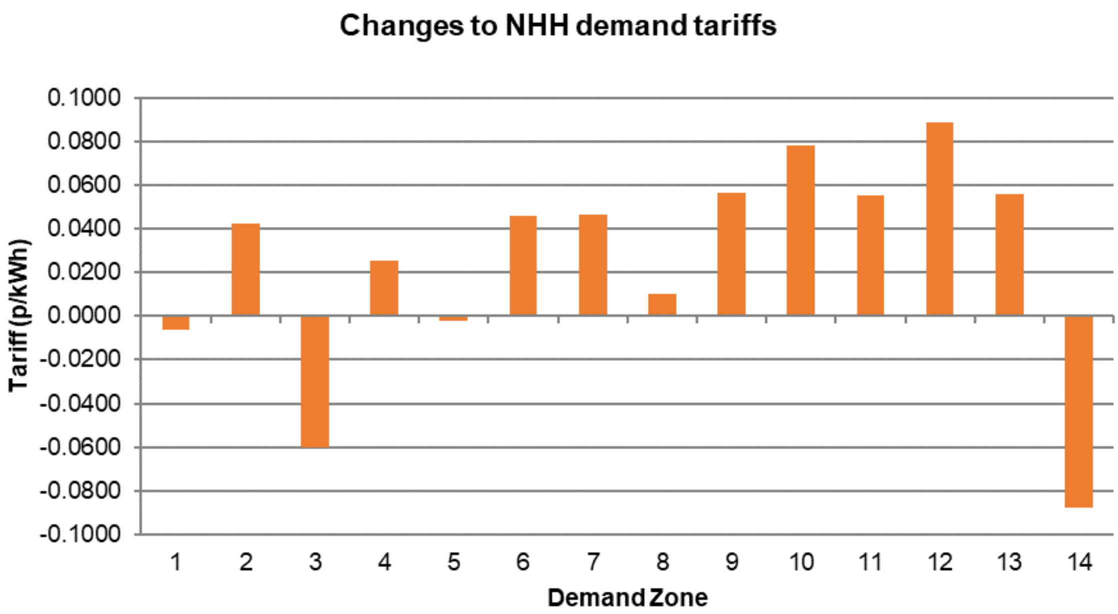
10. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2022/23 August Tariffs and the 2022/23 Initial Tariffs.

Table 12 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2022/23 April (p/kWh)	2022/23 August (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.022811	3.016852	- 0.005959
2	Southern Scotland	4.012326	4.054787	0.042461
3	Northern	5.135737	5.075388	- 0.060349
4	North West	6.042024	6.067730	0.025706
5	Yorkshire	5.902938	5.900569	- 0.002369
6	N Wales & Mersey	5.982738	6.028570	0.045832
7	East Midlands	6.570820	6.617207	0.046387
8	Midlands	6.896029	6.906122	0.010093
9	Eastern	7.406702	7.463089	0.056387
10	South Wales	6.264584	6.343088	0.078504
11	South East	7.766608	7.822213	0.055605
12	London	6.256171	6.345094	0.088923
13	Southern	7.523025	7.578782	0.055757
14	South Western	8.444260	8.356490	- 0.087770

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2022/23 is forecast at 6.53p/kWh, which is a 0.03p/kWh increase compared to the 2022/23 Initial Tariffs. The reason for the slight increase in the average is due to the total revenue to be collected. There have been adjustments to the HH and NHH charging bases which will impact the NHH tariffs, however the impact of this on the tariff is also minimal. As can be seen in the figure above, the majority of the zones have increased. As is with the HH tariffs and EET, fluctuations in the peak and year-round demand location tariffs have offset this, causing zones 3 and 14 tariffs to reduce slightly.

Overview of data inputs

This section explains the changes to the input data which are fed into this quarterly forecast.

11. Inputs affecting the locational element of tariffs

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

- Best view of generation (until October 2021 when it will be based on contracted TEC);
- Nodal demand;
- Local and MITS circuits as set in the Draft Tariffs;
- Inflation;
- Locational security factor
- Expansion constant

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2022/23 period onwards, which can be found on the TEC register.[8] The contracted TEC volumes are based on the July 2021 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 forecast our best view of modelled TEC and use the TEC as published in the latest TEC register. For our November Draft Tariffs and January Final Tariffs we will use the TEC register as of 31st October 2021, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 2022/23 and are liable to pay generation TNUoS charges. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2022.

Table 13 Contracted TEC

	2021/22	2022/23 Tariffs		
Generation (GW)	Final	Initial	August	Change
Contracted TEC	89.90	89.91	87.66	-2.25
Modelled Best View TEC	89.90	84.32	82.79	-1.53
Chargeable TEC	70.10	74.93	73.40	-1.53

12. 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 2022/23 onwards as stated in the interconnector register as of July 2021.

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

Table 14 Interconnectors

Interconnector	Site	Interconnected System	Generation MW			
			Generation Zone	Transport Model Peak	Transport Model Year Round	Charging Base
Greenlink	Pembroke 400kV	Republic of Irelanc	20	0	504	0
BritNed	Grain 400kV	Netherlands	24	0	1,200	0
IFA Interconnector	Sellindge 400kV	France	24	0	2,000	0
IFA2 Interconnector	Chilling 400KV Substatio	France	26	0	1,100	0
East - West	Connah's Quay 400kV	Republic of Irelanc	16	0	505	0
ElecLink	Sellindge 400kV	France	24	0	1,000	0
NS Link	Blyth	Norway	13	0	1,400	0
Nemo Link	Richborough 400kV	Belgium	24	0	1,020	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	660	0

13. Expansion Constant and RPI

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. With the approval of CMP353 the current EC value is based on the RIIO-1 value set back in 2013/14 and will continue to increase in-line with inflation (switched from RPI to CPIH in 2021/22). A review on the methodology of the EC and the expansion factors is ongoing with the industry (CMP315/375). But it is currently not anticipated that the new methodology would be implemented for 2022/23.

14. Locational onshore security factor

The locational onshore security factor (also called the global security factor), currently at 1.76, is applied to locational tariffs, and approximately represent the redundant network capacity to secure energy flows under network contingencies. This parameter has been reviewed last year and will be fixed for the RIIO-2 duration.

15. Onshore substation

Local onshore substation tariffs are reviewed and updated at each price control as part of the TNUoS tariff parameter refresh. Once set for the first year of that price control, the tariffs are then indexed by the average May to October CPIH (actuals and forecast), as per the CUSC requirements, for the subsequent years within that price control period

For this quarterly forecast, onshore substation tariffs are based on the values set for RIIO-2 inflated by CPIH.

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 OFTO. These tariffs were recalculated 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.

17. Allowed revenues

The majority of the TNUoS charges is to recover the allowed revenue for the onshore and offshore TOs in Great Britain. It also recovers some other revenue for example, Network Innovation Competition. The total amount recovered is adjusted for interconnector revenue recovery or redistribution.

For onshore TOs, the allowed revenues have been based on TOs forecast reflecting Ofgem's final determination on their RIIO-2 parameters including project spending profiles, rate of return and inflation index. The 2022/23 revenue figures will be updated by November Draft tariffs and finalised by January 2022 in the Final tariffs.

The three onshore TOs have appealed to CMA against Ofgem's RIIO-T2 determination, and challenged a few parameters including cost of equity and outperformance wedge. CMA have published their draft determinations with their minded-to position to not approve the appeals impacting TNUoS tariffs. CMA will make a final decision on the appeals by 30th October 2021. If the appeals are approved, onshore TOs may update their revenue forecast according to the timetable as specified under the STC (SO-TO code), and we will then include the updated revenue figures in our TNUoS forecast.

For more details on TNUoS revenue breakdown, please refer to Appendix G.

Table 15 Allowed revenues

	2022/23 TNUoS Revenue			
£m Nominal	April Initial Forecast	August Forecast	November Draft	January Final
TO Income from TNUoS				
National Grid Electricity Transmission	1,764.46	1,764.46	-	-
Scottish Power Transmission	348.71	371.85	-	-
SHE Transmission	632.65	632.61	-	-
SPT Income from TNUoS	**2,745.83**	**2,768.92**	**-**	**-**
National Grid Electricity System Operator				
Other Pass-through from TNUoS	67.33	108.46	-	-
Offshore (plus interconnector contribution / allowance)	552.85	557.23	-	-
Total to Collect from TNUoS	**3,366.00**	**3,434.62**	**-**	**-**

Please note these figures are rounded to two decimal place.

18. Generation / Demand (G/D) Split

The G/D split forecast is shown in **Error! Reference source not found.**. In this forecast, we continue a ssuming that CMP368/369 (chargeable embedded generators and pre-existing assets charges for gen cap) is in 22/23 tariff methodology, and have continued using the same calculation approach as that in the April forecast. The April forecast approach is not aligned with the CMP368/369 original proposal in terms of onshore local charges associated with pre-existing assets. We aim to align the calculation methodology with the original CMP368/369 proposal once we have processed the relevant data, and to publish the updated indicative figures in November.

Table 16 Generation and demand revenue proportions

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 is dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin is also applied to reflect revenue and output forecasting accuracy. This revenue limit figure is normally referred to as the "EU gen cap".

TNUoS generation residual (TGR) change

CUSC modification proposals CMP317/327 was approved in December 2020 and was included in the 2021/22 final tariffs. Under CMP317/327, charges that are collected via generator local tariffs (including onshore and offshore local substation charges, and onshore and offshore local circuit charges) were excluded from the EU gen cap. Therefore, the EU gen cap is only applicable for charges that are collected via generation wider tariffs.

When approving CMP317/327, Ofgem also directed the ESO to raise a CUSC mod, to update charges for the physical assets required for connection, generation output and Generator charges for the purpose of maintaining compliance with the limiting regulation (the [0 ~ €2.50]/MWh range). The ESO has raised this CUSC mod (CMP368/369)[9], and options have been developed by the workgroup. The mod is under consultation, before being submitted to Ofgem for a decision by later this year. In this forecast, we have continued using the calculation approach as in the Initial forecast, however we plan to refine the approach and to align it with the CMP368/389 original proposal by November.

Exchange Rate

As prescribed by the TNUoS charging methodology, the exchange rate for 2022/23 has been taken from the Economic and Fiscal Outlook, published by the Office of Budgetary Responsibility in March 2021. The exchange rate was already used in the Initial forecast, and will be used in the quarterly forecasts including the Final 2022/23 tariffs. The value is €1.127740/£.

Generation Output

The forecast output of generation is 196.38TWh. This figure is the average of the four scenarios (plus the central case) in the 2021 Future Energy Scenarios publication, and is the final value to be used to set tariffs for 2022/23.

Error Margin

The error margin has decreased to from 20.8 to 14.2% following publication of the outturn of 2020/21 data. The error margin is derived from historical data in the past five whole years (thus for year 2022/23, we use data from years 2016/17 – 2020/21). By excluding year 2015/16 data which had the highest forecasting error on generation output, the error margin for year 2022/23 has decreased to 14.2%. Table 17 shows the error margin calculation.

Table 17 Generation revenue error margin calculation

Calculation for	2022/23		
	Revenue inputs		Generation output variance
Data from year:	Revenue variance	Adjusted variance	
2016/17	-5.1%	4.4%	-7.9%
2017/18	-5.2%	4.3%	-1.5%
2018/19	-9.2%	0.3%	-7.5%
2019/20	-14.6%	-5.2%	-4.1%
2020/21	-13.2%	-3.7%	7.5%
Systemic error:	-9.5%		
Adjusted error:		5.2%	7.9%
Error margin =			14.2%

Adjusted variance = the revenue variance - systemic error
Systemic error = the average of all the values in the series
Adjusted error = the maximum of the (absolute) values in the series

[9] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp368-cmp369

19. Charging bases for 2022/23

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 for 2022/23 is forecast at 73.4GW and is based on our internal view of what generation we expect to connect next financial year. This is a decrease of 1.5GW since the April forecast which is mainly driven by the contracted changes of Hunterston (termination of 1GW) and a TEC decrease of 1.1GW at West Burton A. This has been offset in our best view by 0.5GW being brought forward due to a generator no longer considering delaying their connection date.

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated for 2022/23.

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

- Historical gross metered demand and embedded export volumes (August 2014 -July 2021)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

Overall, we assume that recent historical trends (excluding the impact of COVID) demand volumes will stay consistent over the next few years. This is due to the culmination of growth in distributed generation and "behind the meter" microgeneration offset by the increase in electric vehicles and heat pumps. However, it is anticipated that demand will begin to gradually increase again in future years. The impact of COVID-19 continues to be tracked and adjustments have been made in our forecast since April for 2022/23 based on the latest demand outturn data up to July 2021 showing recovery from COVID. Please refer to **table TAA** in the published tables spreadsheet for a detailed breakdown of the changes to the demand changing bases.

Table 18 Charging bases

	2022/23 Tariffs		
Charging Bases	Initial	August	Change
Generation (GW)	74.93	73.40	-1.53
NHH Demand (4pm-7pm TWh)	24.18	24.84	0.65
Gross charging			
Total Average Gross Triad (GW)	49.83	50.61	0.77
HH Demand Average Gross Triad (GW)	19.07	19.17	0.10
Embedded Generation Export (GW)	6.54	7.01	0.47

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2021/22 ALFs. ALFs are explained in more detail in Appendix E of this report, and the full list of power station ALFs are available on the National Grid ESO website.[10]

[10] https://www.nationalgrideso.com/document/186166/download

The ALFs applied to 2022/23 TNUoS Tariffs will be updated and included in the Draft tariffs in November 2021.

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

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

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 took effect from April 2021 for the Transmission Generation Residual (TGR).

Subsequently CMP317/327 was raised to implement the TCR decision. Under CMP317/327, generation residual has been removed but to ensure compliance with the EU cap within the range of €0-2.50/MWh, an adjustment mechanism has been introduced. It has confirmed that all local onshore and local offshore tariffs are not included in the EU cap, i.e. removing these from the definition of 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[11] and phased residual.

Ofgem's minded-to decision is that changes to the demand residual tariffs will apply in 2023/24, 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 2023, they have not been included in this 2022/23 forecast.

Table 19 Residual & Adjustment components calculation

Component		2022/23 Tariffs Initial	2022/23 Tariffs August
G	Proportion of revenue recovered from generation (%)	24.84%	24.32%
D	Proportion of revenue recovered from demand (%)	75.16%	75.68%
R	Total TNUoS revenue (£m)	3,366.00	3,434.62
Generation revenue breakdown (without adjustment)			
Z_G	Revenue recovered from the wider locational element of generator tariff	389.9	387.4
O	Revenue recovered from offshore local tariffs (£m)	451.0	446.8
L_G	Revenue recovered from onshore local substation tariffs (£m)	10.5	9.9
S_G	Revenue recovered from onshore local circuit tariffs (£m)	16.1	15.6
	Revenue from large embedded generation (£m)	7.1	7.1
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	1.9	1.9
Generation adjustment tariff calculation			
	Limit on generation tariff (€/MWh)	2.5	2.5
	Error Margin	20.8%	14.2%
	Exchange Rate (€/£)	1.13	1.13
	Total generation Output (TWh)	210.0	196.4
	Generation Output from TNUoS chargeable EGs (TWh)	8.3	8.3
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	353.4	357.8
	Adjustment Revenue (£m)	-31.3	-24.4
BG	Generator charging base (GW)	74.9	73.4
AdjTariff	Generator adjusment tariff (£/kW)	-0.42	-0.33
Gross demand residual			
R_D	Demand residual tariff (£/kW)	53.14	53.77
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-104.39	-106.27
EE	Amount to be paid to Embedded Export Tariffs (£m)	13.98	15.58
B_D	Demand Gross charging base (GW)	49.83	50.61

[11] Avoided Grid Supply Point Infrastructure Credit

Expansion Constant Sensitivity Analysis

nationalgridESO

Purpose

We are conscious that there are uncertainties with the charging methodologies over the next couple of years. To help the industry to understand the potential implications of the ongoing proposed changes, we have undertaken further modelling around the methodology changes arising from CUSC modifications CMP315 and CMP375 which aims to review the Expansion Constant.

Caveats

The methodology is subject to changes including TCR and other ongoing CUSC modification proposals. All tariffs in this section are to illustrate mathematically how tariffs may evolve. In presenting sensitivities under certain CUSC mod options, it does not infer about our view of the future, likelihoods of certain scenarios or changes to policy.

Whilst every effort is made to ensure the accuracy of the information, it is subject to several estimates and forecasts, and may not bear relation to neither the indicative nor future tariffs we will publish at a later date.

22. Expansion Constant (EC) Sensitivity

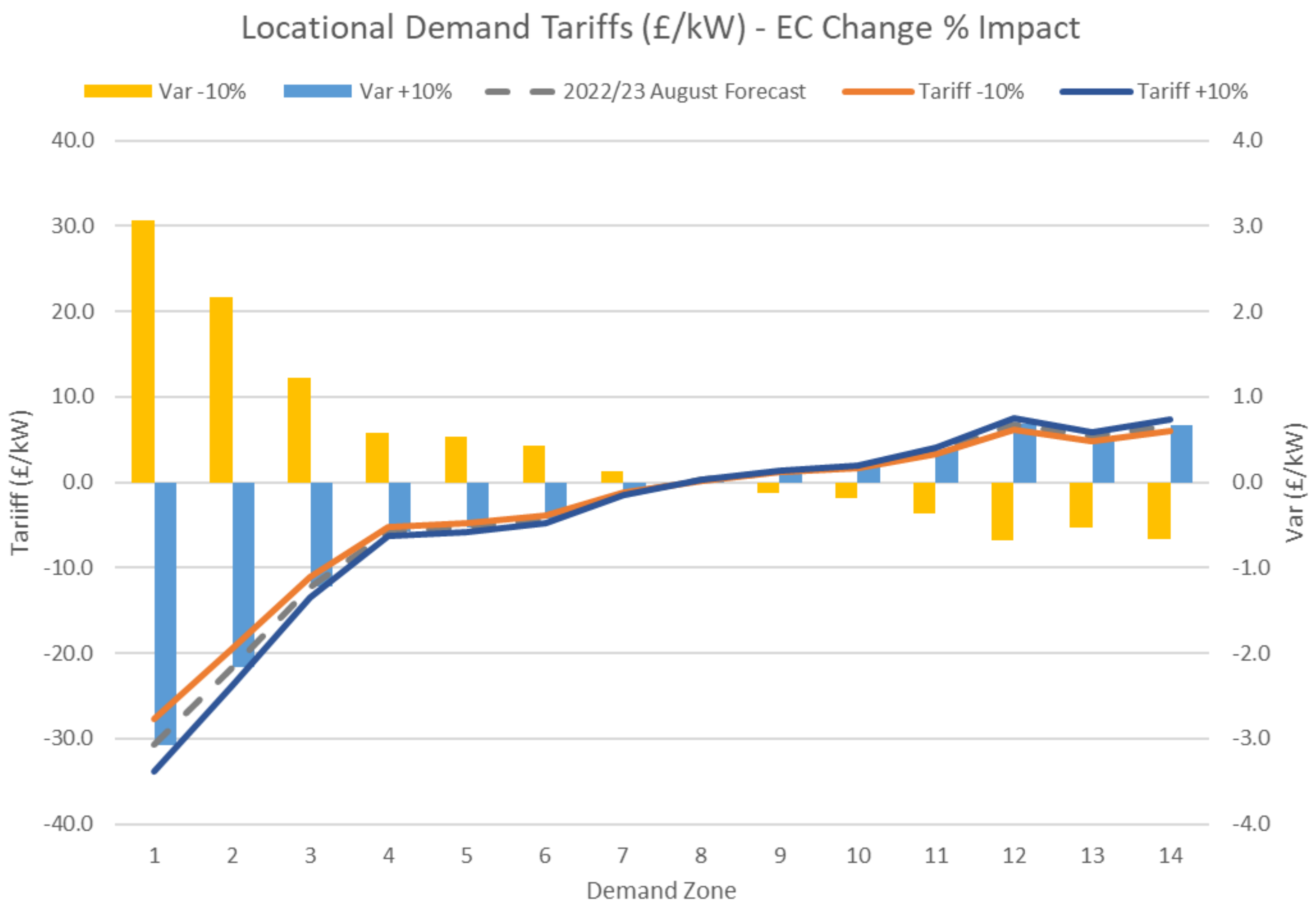
In this sensitivity we have provided an overview of the impact the EC has on Demand and Generation tariffs. The current EC value is based on the value set at the beginning of RIIO-1 (as per CMP353). The EC will then change year-on-year in-line with inflation. However, with the CUSC modification proposals (CMP315/375) under review, the current methodology for the EC and Expansion Factors may change. The following tables and figures show a fluctuation of the EC of +/- 10% from our current forecast value of the EC for 2022/23. It is worth highlighting that in this sensitivity the expansion factors remain the same and have not been adjusted. In the event that the methodology changes or the data used to calculate the EC changes, the Expansion Factors would also be updated.

Table S1 Impact of change in EC on Locational Demand Tariffs

Locational Demand Tariffs* (£/kW)		Change in EC				
			Tariff		Variance	
Demand Zone		-10%	2022/23 August Forecast	+10%	-10%	+10%
1	Northern Scotland	-27.635923	-30.706581	-33.777240	3.070658	-3.070658
2	Southern Scotland	-19.506731	-21.674146	-23.841561	2.167415	-2.167415
3	Northern	-11.029690	-12.255211	-13.480733	1.225521	-1.225521
4	North West	-5.180933	-5.756592	-6.332252	0.575659	-0.575659
5	Yorkshire	-4.747520	-5.275023	-5.802525	0.527502	-0.527502
6	N Wales & Mersey	-3.859027	-4.287808	-4.716589	0.428781	-0.428781
7	East Midlands	-1.163879	-1.293199	-1.422519	0.129320	-0.129320
8	Midlands	0.240344	0.267049	0.293754	-0.026705	0.026705
9	Eastern	1.165086	1.294540	1.423994	-0.129454	0.129454
10	South Wales	1.612998	1.792220	1.971442	-0.179222	0.179222
11	South East	3.281104	3.645671	4.010238	-0.364567	0.364567
12	London	6.104472	6.782747	7.461021	-0.678275	0.678275
13	Southern	4.814985	5.349984	5.884982	-0.534998	0.534998
14	South Western	6.014122	6.682358	7.350593	-0.668236	0.668236
	EC Value (£/MWkm)	13.766504	15.296116	16.825728		
	Demand Residual (£/kW)	53.860764	53.772794	53.953688		

*Peak Security & Year-Round (not including demand residual). Demand residual shown at bottom of table.

Figure S1 Impact of change in EC on Locational Demand Tariffs



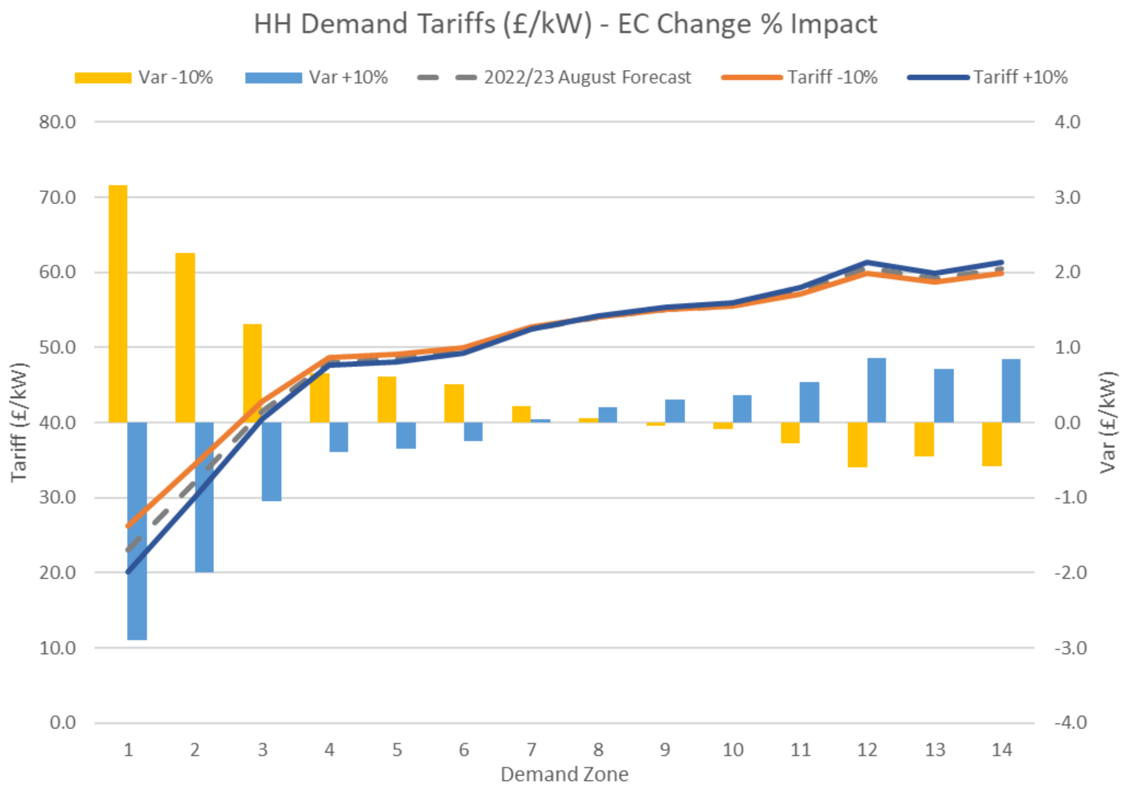
The above figure shows the change in locational demand tariffs compared to the August base case.

The line graph aligns to the left side axis and shows a comparison of the locational demand tariffs for the base case and each of the EC scenarios. The bar chart aligns to the right side axis and shows the change in tariff between each of the scenarios.

Table S2 Impact of change in EC on HH Demand Tariffs

HH Demand Tariff (£/kW)		Change in EC				
			Tariff		Variance	
Demand Zone		-10%	2022/23 August Forecast	+10%	-10%	+10%
1	Northern Scotland	26.224841	23.066212	20.176449	3.158628	-2.889764
2	Southern Scotland	34.354033	32.098648	30.112128	2.255385	-1.986520
3	Northern	42.831074	41.517582	40.472956	1.313491	-1.044627
4	North West	48.679831	48.016201	47.621437	0.663630	-0.394765
5	Yorkshire	49.113244	48.497771	48.151163	0.615473	-0.346608
6	N Wales & Mersey	50.001737	49.484986	49.237099	0.516751	-0.247886
7	East Midlands	52.696885	52.479595	52.531170	0.217290	0.051575
8	Midlands	54.101108	54.039843	54.247442	0.061265	0.207600
9	Eastern	55.025850	55.067333	55.377682	-0.041484	0.310349
10	South Wales	55.473762	55.565014	55.925130	-0.091252	0.360117
11	South East	57.141868	57.418465	57.963926	-0.276597	0.545462
12	London	59.965236	60.555540	61.414710	-0.590304	0.859169
13	Southern	58.675749	59.122777	59.838670	-0.447028	0.715893
14	South Western	59.874886	60.455151	61.304282	-0.580265	0.849130
	EC Value (£/MWkm)	13.766504	15.296116	16.825728		

Figure S2 Impact of change in EC on HH Demand Tariffs

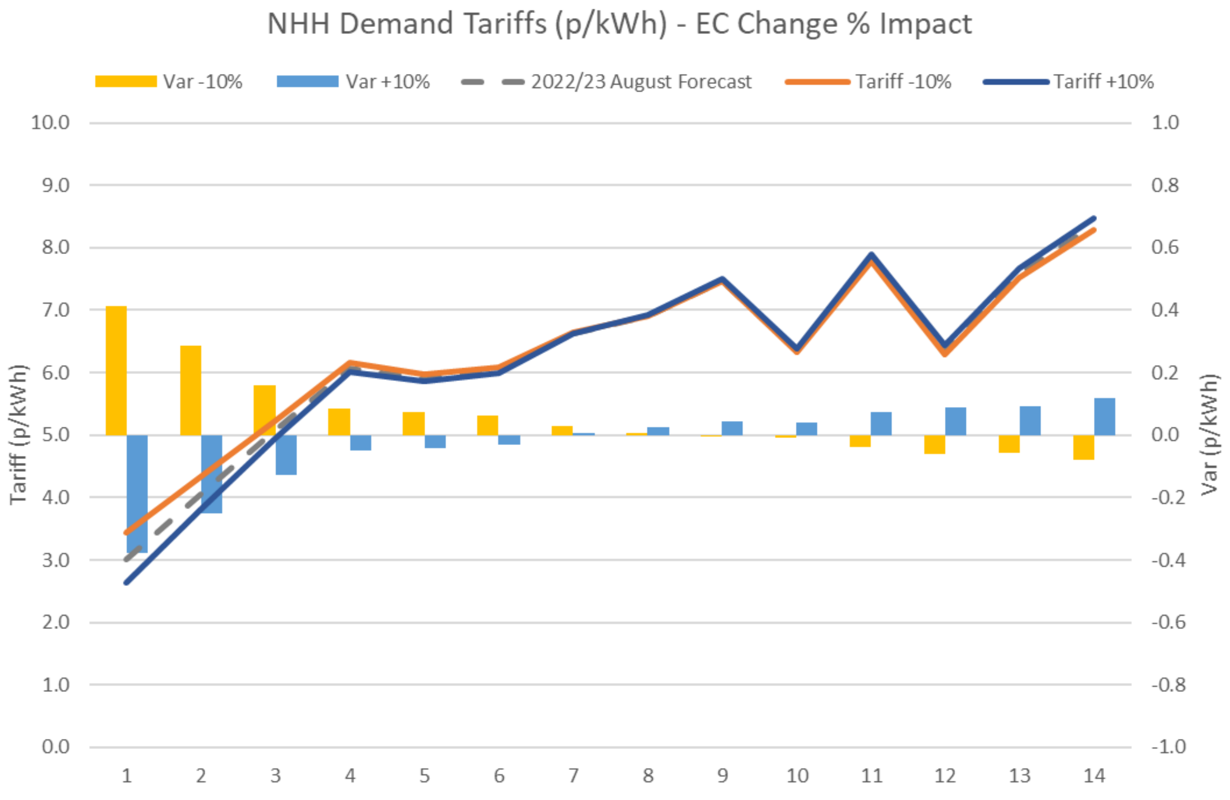


Note – The axes in this figure are not normalised at 0£/kW as the tariff values across each zone are positive

Table S3 Impact of change in EC on NHH Demand Tariffs

NHH Demand Tariff* (p/kWh)		Change in EC				
			Tariff		Variance	
Demand Zone		-10%	2022/23 August Forecast	+10%	-10%	+10%
1	Northern Scotland	3.429972	3.016852	2.638897	0.413120	-0.377955
2	Southern Scotland	4.339694	4.054787	3.803845	0.284907	-0.250942
3	Northern	5.235958	5.075388	4.947686	0.160570	-0.127702
4	North West	6.151592	6.067730	6.017844	0.083862	-0.049886
5	Yorkshire	5.975451	5.900569	5.858398	0.074882	-0.042171
6	N Wales & Mersey	6.091523	6.028570	5.998371	0.062953	-0.030199
7	East Midlands	6.644605	6.617207	6.623710	0.027398	0.006503
8	Midlands	6.913951	6.906122	6.932652	0.007829	0.026530
9	Eastern	7.457467	7.463089	7.505149	-0.005622	0.042060
10	South Wales	6.332671	6.343088	6.384198	-0.010417	0.041110
11	South East	7.784531	7.822213	7.896522	-0.037682	0.074309
12	London	6.283241	6.345094	6.435118	-0.061853	0.090024
13	Southern	7.521479	7.578782	7.670550	-0.057303	0.091768
14	South Western	8.276282	8.356490	8.473862	-0.080208	0.117372
	EC Value (£/MWkm)	13.766504	15.296116	16.825728		

Figure S3 Impact of change in EC on NHH Demand Tariffs



Note – The axes in this figure are not normalised at 0£/kW as the tariff values across each zone are positive

Table S4 Impact of change in EC on Generation Tariffs

Generation Tariffs - 100% ALF (£/kW)		Change in EC				
Demand Zone		-10%	Tariff 2022/23 August Forecast	+10%	Variance -10%	Variance +10%
1	North Scotland	37.276588	41.085751	44.709546	-3.809163	3.623795
2	East Aberdeenshire	28.205961	31.007276	33.623224	-2.801315	2.615948
3	Western Highlands	32.942047	36.269594	39.411775	-3.327547	3.142181
4	Skye and Lochalsh	30.499360	33.555498	36.426269	-3.056138	2.870771
5	Eastern Grampian and Tayside	28.191088	30.990750	33.605046	-2.799662	2.614296
6	Central Grampian	28.563240	31.404252	34.059898	-2.841012	2.655646
7	Argyll	30.376572	33.419066	36.276193	-3.042494	2.857127
8	The Trossachs	24.372808	26.748216	28.938259	-2.375408	2.190043
9	Stirlingshire and Fife	22.252510	24.392329	26.346784	-2.139819	1.954455
10	South West Scotlands	21.170400	23.189986	25.024206	-2.019586	1.834220
11	Lothian and Borders	18.962236	20.736469	22.325338	-1.774233	1.588869
12	Solway and Cheviot	14.214327	15.461016	16.522339	-1.246689	1.061323
13	North East England	12.703041	13.781809	14.675211	-1.078768	0.893402
14	North Lancashire and The Lakes	8.192588	8.770193	9.162433	-0.577605	0.392240
15	South Lancs, Yorkshire and Humber	6.542175	6.936403	7.145264	-0.394228	0.208861
16	North Midlands and North Wales	4.155108	4.284106	4.227738	-0.128998	-0.056368
17	South Lincolnshire and North Norfolk	2.928412	2.921110	2.728443	0.007302	-0.192667
18	Mid Wales and The Midlands	2.649214	2.610890	2.387200	0.038324	-0.223690
19	Anglesey and Snowdon	5.591961	5.880609	5.983891	-0.288648	0.103282
20	Pembrokeshire	2.335448	2.262261	2.003709	0.073187	-0.258552
21	South Wales & Gloucester	-2.448545	-3.053287	-3.843393	0.604742	-0.790106
22	Cotswold	-1.739642	-2.265617	-2.976958	0.525975	-0.711341
23	Central London	-8.431604	-9.701131	-11.156023	1.269527	-1.454892
24	Essex and Kent	-0.218553	-0.575518	-1.117849	0.356965	-0.542331
25	Oxfordshire, Surrey and Sussex	-2.386833	-2.984718	-3.767969	0.597885	-0.783251
26	Somerset and Wessex	-4.360165	-5.177308	-6.179818	0.817143	-1.002510
27	West Devon and Cornwall	-6.851422	-7.945372	-9.224689	1.093950	-1.279317

	-10%	Tariff 2022/23 August Forecast	+10%
EC Value (£/MWkm)	13.766504	15.296116	16.825728
Adjustment Value (£/kW)	0.000000	-0.332681	-0.850728

Figure S4 Impact of change in EC on Generation Tariffs

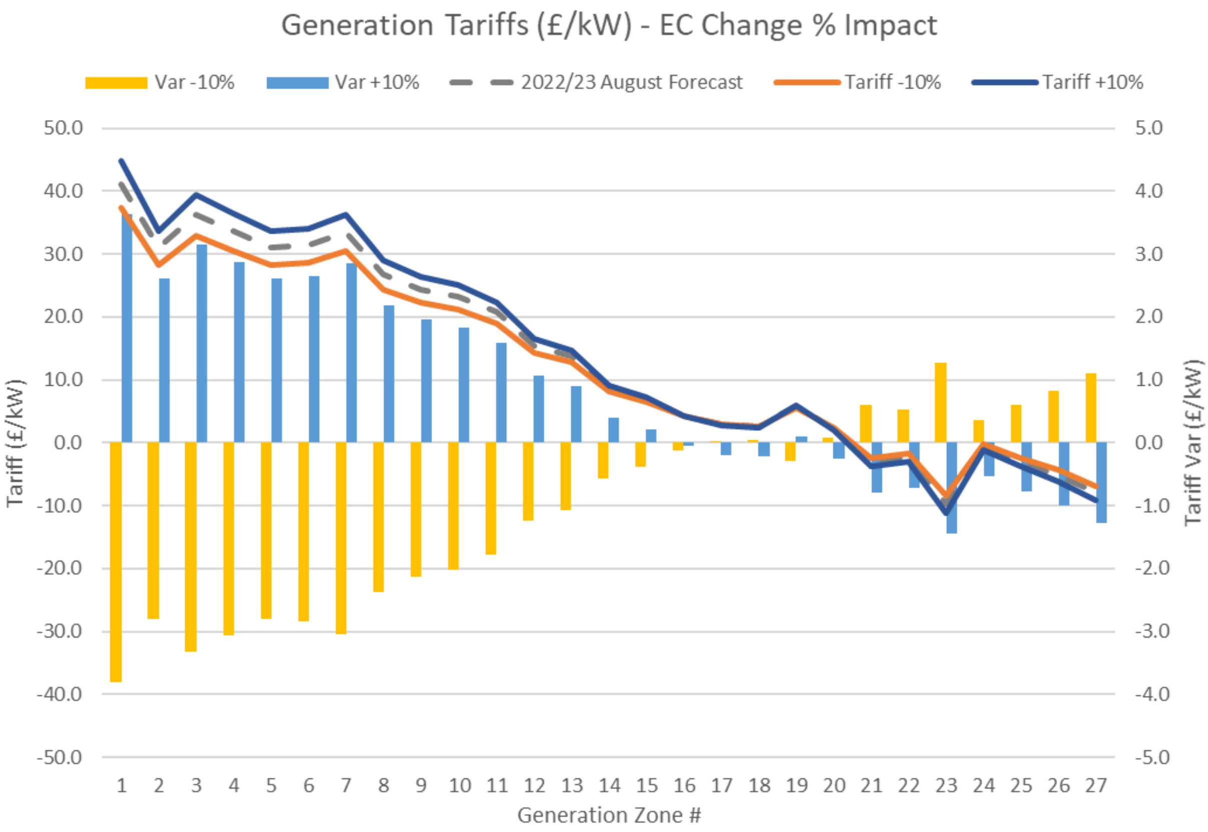


Table S5 Impact of EC on Revenue, Residual and Adjustment Calculation

Component		Change in EC -10%	Tariff 2022/23 August Forecast	Change in EC +10%	Variance -10%	Variance +10%
Proportion of revenue recovered from generation	%	23.9%	24.3%	24.4%	-0.5%	0.1%
Revenue recovered from generation	£m	819.3	835.2	837.5	-15.9	2.3
Proportion of revenue recovered from demand	%	76.1%	75.7%	75.6%	0.5%	-0.1%
Revenue recovered from demand	£m	2,615.3	2,599.4	2,597.1	15.9	-2.3
Total TNUoS revenue	£m		3,434.6			
Generation revenue breakdown (without adjustment)						
Revenue recovered from the wider locational element of tariffs	£m	348.6	387.4	426.1	-38.7	38.7
Revenue recovered from offshore local tariffs	£m		446.8			
Revenue recovered from onshore local substation tariffs	£m		9.9			
Revenue recovered from onshore local circuit tariffs	£m	14.0	15.6	17.1	-1.6	1.6
Revenue from large embedded generation	£m	6.4	7.1	7.8	-0.7	0.7
Revenue from local charges associated with pre-existing assets (indi	£m		1.9			
Generation adjustment tariff calculation						
Limit on generation tariff	€/MWh		2.50			
Error Margin	%		14%			
Exchange Rate	€/£		1.13			
Total generation Output	TWh		196.4			
Generation Output from TNUoS chargeable Egs	TWh		8.28			
Generation revenue subject to the [0,2.50]Euro/MWh range	£m		357.8			
Adjustment Revenue	£m	0.0	-24.4	-62.4	24.4	-38.0
Generator charging base	GW		73.4			
Generator adjustment tariff	£/kW	0.0	-0.3	-0.9	0.3	-0.5
Gross demand residual						
Revenue to be recovered through demand residual	£m	2,710.9	2,705.7	2,714.0	5.2	8.4
Demand residual tariff	£/kW	53.9	53.8	54.0	0.1	0.2
Revenue recovered from the locational element of demand tariffs	£m	-95.6	-106.3	-116.9	10.6	-10.6
Amount to be paid to Embedded Export Tariffs	£m	14.8	15.6	16.4	-0.8	0.8
Demand Gross charging base	GW		50.6			

The above table shows that a change in the EC impacts the locational element of tariffs for both Demand and Generation, which then causes a change in the residual and adjustment tariffs due to the impact on revenues. It is worth highlighting that the cap on the Generation tariffs and the subsequent adjustment that is applied is impacted with the change in EC. The knock-on effect passes through to the demand revenue and offsets the change in the locational element of the demand tariffs. Resulting in an increase in the overall revenue to be collected through the residual in both scenarios where the EC is increased or decreased.

Tools and supporting information

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

Charging webinars

We will be hosting a webinar for the August Quarterly Forecast on Tuesday 14th September. We will send out a communication to provide details on the webinar. For any questions please see our contact details below.

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 2022/23 forecasts:

https://www.nationalgrideso.com/tnuos

It can also be downloaded from our Data Portal:

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

Appendix A: Background to TNUoS charging

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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.

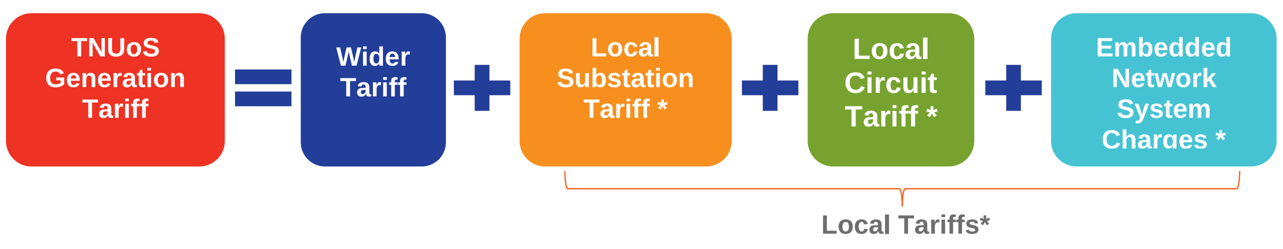
Generation charging principles

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**.



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

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

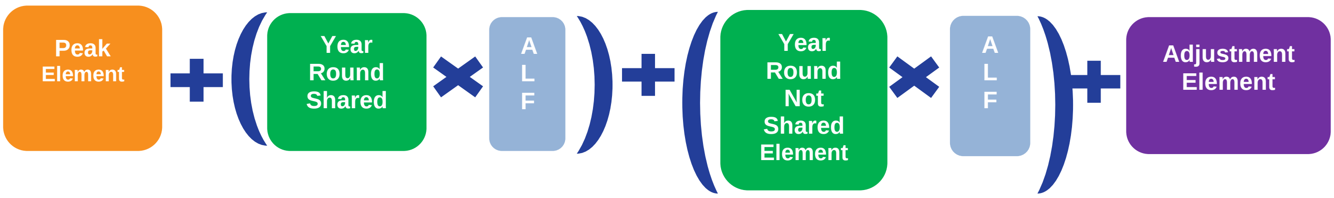
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

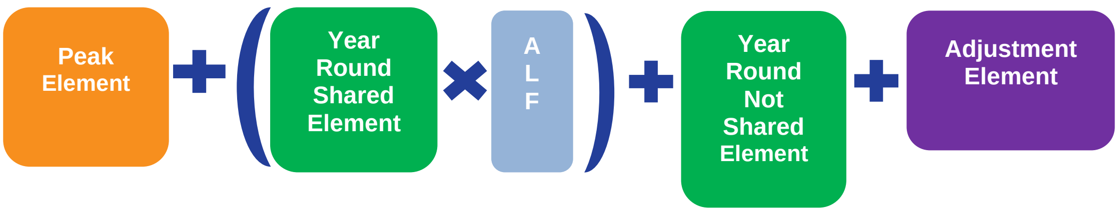
Conventional Carbon Generators

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



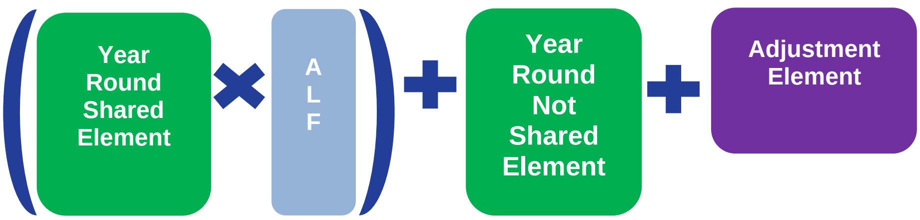
Conventional Low Carbon Generators

(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 **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[12] if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS[13] 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:

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

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

TNUoS charges are billed each month for the month ahead.

[12] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: https://www.nationalgrid.com/uk/electricity/connections/applying-connection

[13] Distribution network Use of System charges

Generators with negative TNUoS tariffs

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

The value used for this reconciliation is the average output of the individual generator over the three settlement periods of highest output between 1 November and the end of February of the relevant charging year. Each settlement period must be separated by at least ten clear days. 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.[14] 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[15].

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[16].

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.

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

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

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

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.

TCR changes on Transmission Demand Residual (TDR) tariffs

For 2022/23, the current calculation methodology for demand tariffs remains the same. As of 2023/24, 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.

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology in the next few years. All these modifications are subject to whether they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

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

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

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

Table 20 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP286/287	Improving TNUoS Predictability Through Increased Notice	Increase notice period of tariff setting input data	to be confirmed
CMP330	Allowing new Transmission Connected parties to build Connection Assets greater than 2km in length	Change CUSC section 14 to enable connection assets greater than 2km in length	to be confirmed
CMP331	Option to replace generic Annual Load Factors (ALFs) with site specific ALFs	Introduce an option for site specific ALFs	to be confirmed
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.	to be confirmed
CMP368/369	Charges for the Physical Assets Required for Connection	Part of the Transmission Generation Residual (TGR)	April 2022, if approved

We are aware of some CUSC mods that will affect TNUoS. As their impacts are in a small or localised way, they may not be included in our forecast or in the list.

Appendix C: Breakdown of locational HH and EE tariffs

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Locational components of demand tariffs

The following tables show the locational components of the HH demand charge (Peak and Year-Round) and the changes between forecasts. The residual is added to these values to give the overall HH tariff

For the Embedded Export Tariffs, the demand locational elements (peak security and year-round) are added together. The AGIC is then also added and the resulting tariff floored at zero to avoid negative tariffs (charges).

Table 21 Location elements of the HH demand tariff for 2022/23

Demand Zone		2022/23 April		2022/23 August		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-3.116462	-27.428739	-2.530283	-28.176298	0.586178	-0.747559
2	Southern Scotland	-3.215416	-18.599220	-2.906114	-18.768032	0.309302	-0.168812
3	Northern	-4.063048	-7.542140	-4.039251	-8.215961	0.023798	-0.673821
4	North West	-1.585722	-4.140701	-1.590788	-4.165804	-0.005066	-0.025104
5	Yorkshire	-3.215572	-1.813832	-3.023749	-2.251273	0.191823	-0.437442
6	N Wales & Mersey	-2.412292	-1.988324	-2.342178	-1.945630	0.070113	0.042694
7	East Midlands	-2.487282	1.150504	-2.435861	1.142662	0.051420	-0.007842
8	Midlands	-1.419253	1.634158	-1.450358	1.717408	-0.031105	0.083249
9	Eastern	1.249970	-0.069565	1.389653	-0.095113	0.139683	-0.025548
10	South Wales	-3.583402	5.305982	-3.403533	5.195753	0.179869	-0.110229
11	South East	3.790322	-0.265553	3.762870	-0.117199	-0.027452	0.148355
12	London	5.603960	1.059458	5.672933	1.109813	0.068973	0.050355
13	Southern	1.809885	3.419941	1.733821	3.616163	-0.076065	0.196222
14	South Western	0.780133	6.380386	-0.368576	7.050934	-1.148709	0.670547

Table 22 Elements of the Embedded Export Tariff for 2022/23

Demand Zone		2022/23 April		2022/23 August		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-30.545201	2.316267	-30.706581	2.319241	-0.161380	0.002974
2	Southern Scotland	-21.814636	2.316267	-21.674146	2.319241	0.140490	0.002974
3	Northern	-11.605188	2.316267	-12.255211	2.319241	-0.650023	0.002974
4	North West	-5.726423	2.316267	-5.756592	2.319241	-0.030169	0.002974
5	Yorkshire	-5.029404	2.316267	-5.275023	2.319241	-0.245619	0.002974
6	N Wales & Mersey	-4.400615	2.316267	-4.287808	2.319241	0.112807	0.002974
7	East Midlands	-1.336777	2.316267	-1.293199	2.319241	0.043579	0.002974
8	Midlands	0.214905	2.316267	0.267049	2.319241	0.052144	0.002974
9	Eastern	1.180405	2.316267	1.294540	2.319241	0.114135	0.002974
10	South Wales	1.722579	2.316267	1.792220	2.319241	0.069641	0.002974
11	South East	3.524768	2.316267	3.645671	2.319241	0.120903	0.002974
12	London	6.663418	2.316267	6.782747	2.319241	0.119329	0.002974
13	Southern	5.229826	2.316267	5.349984	2.319241	0.120158	0.002974
14	South Western	7.160519	2.316267	6.682358	2.319241	-0.478162	0.002974

Appendix D: Annual Load Factors

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Specific ALFs

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

For the purposes of this forecast, we have used 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 commissioned after 1 April 2017 will have fewer than three complete years of data, so the appropriate Generic ALF listed below is added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2021/22 also use the Generic ALF for their first three years of operation.

The specific and generic ALFs that will apply to 2022/23 TNUoS Tariffs will be updated by November Draft tariffs 2021. The specific and generic ALFs for 2021/22 tariffs, as used in this forecast, are published here: https://www.nationalgrideso.com/document/186166/download.

Generic ALFs

Table 23 Generic ALFs

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 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.

Appendix E: Contracted generation

For the complete breakdown of Contracted TEC per generator for each year, please see Table A Contracted TEC by Generator in the Tables spreadsheet published on our website here, under 2022/23 tariffs. The data in Table 24 is taken from the TEC register from July 2021.

Please note that these values were not used for generation volumes in the best view models and were not used to derive the tariffs in this report, as they may be commercially sensitive.

The contracted generation used in the Transport model will be fixed at the November forecast of 2022/23 tariffs, using the TEC register as of 31 October 2021, as stated by the CUSC 14.15.6.

Table 24 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Aberthaw	-50	ABTH20	21
Hunterston	-1,000	HUER40	10
Legacy Tertiary Connection (formerly Legacy Gas)	50	WBUR40	16
Lincs Offshore Wind Farm	9	WALP40_EME	17
Neilston 132kV	17	NEIL10	11
Pencloe Windfarm	-80	BLAH10	10
Sundon	-50	SUND40	18
Triton Knoll Offshore Wind Farm	-76	BICF4A	17
West Burton A	-1,075	WBUR40	16

Appendix F: Transmission company revenues

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have updated us with their revenue forecast for year 2022/23, and the revenue forecasts will be updated later this year. In addition, 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.

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 two 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 forecasts

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

In addition, NGESO collects Network Innovation Competition (NIC) Funding, and pass through the money to network licensees (including TOs, OFTOs and DNOs). There are also a few miscellaneous pass-through items that had been collected by NGET under its licence condition, and this function was also transferred to NGESO. The revenue breakdown table below shows details of the pass-through TNUoS revenue items under NGESO's licence conditions.

Since our April forecast, it can be observed that there is an additional £41.13m of pass through from the introduction of the adjustment factor. This is normally updated in the November draft forecast but following customer feedback we will now also be updating this pass-through item throughout the prior forecasts. An additional £23m comes from a revised forecast from SPT which, as with all TO forecasts, will be subject to change in the November draft.

Table 25 NGESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through			
	Initial Forecast	August Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.58	0.58		
Network Innovation Competition (NICFt)	30.89	30.89		
ESO Network Innovation Allowance (NIAt)				
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	552.85	557.23		
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00		
Financial facility (FINt)	0.00	0.00		
Site Specific Charges Discrepancy (DISt)	0.00	0.00		
Termination Sums (TSt)	0.00	0.00		
NGET revenue pas-through (NGETTOt)*	1,764.46	1,764.46		
SPT revenue pass-through (TSPt)	348.71	371.85		
SHETL revenue pass-through (TSHt)	632.65	632.61		
ESO Bad debt (BDt)	3.30	3.30		
ESO other pass-through items (LFt + ITCt etc)	32.56	32.56		
ESO legacy adjustment (LARt)	0.00	41.13		
Total	**3,366.00**	**3,434.62**	**0.00**	**0.00**

A few items (including FINt, DISt and TSt) are set to zero in the August forecast cycle. FINt was introduced as a "bridging" financial facility, following the legal separation of ESO from NGET, and has been removed for RIIO-2. DISt and TSt are based on forecast of TOs' ad-hoc activities during the year 2022/23, and at this stage, no information is available.

Onshore TOs (NGET, SPT and SHETL) revenue forecast

Following a recent update to the SO-TO-Code procedure (STCP24-1), and the feedback we had from the April tariff 5 year view webinar, the three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their revenue breakdown, as per their January revenue forecast (for the year 2022/23). These revenue forecasts will be updated in the November forecast.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2022/23 is forecast to be £573.63m, an increase of £68m compared to 2021/22. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to our RPI forecast (as part of the calculation of the inflation term, as defined in the relevant OFTO licence).

Table 26 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission			
			Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	n/a	283.31	283.31	283.31
Inflation		PI_t	n/a	302.65	302.65	302.65
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	1,634.08		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	1,745.64		
SONIA	B1	It-1	n/a	0.05%		
Allowed Revenue	B2	ARt-1	n/a	1,755.30		
Recovered Revenue	B4	RRt-1	n/a	1,755.30		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00		
Legacy pass-through	C1	LPt	n/a	0.00		
Legacy MOD	C2	LMODt	n/a	21.43		
Legacy K correction	C3	LKt	n/a	0.00		
Legacy TRU term	C4	LTRUt	n/a	-2.60		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	n/a	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	0.00		
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	C	LAR_t	n/a	18.82		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	1,764.46	1,764.46		

Table 27 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission			
			Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	n/a	283.31	283.31	283.31
Inflation		PI_t	n/a	302.65	302.65	302.65
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	345.77		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**n/a**	**369.38**		
SONIA	B1	It-1	n/a	0.05%		
Allowed Revenue	B2	ARt-1	n/a	371.85		
Recovered Revenue	B4	RRt-1	n/a	371.85		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	n/a	0.00		
Legacy MOD	C2	LMODt	n/a	2.48		
Legacy K correction	C3	LKt	n/a	0.00		
Legacy TRU term	C4	LTRUt	n/a	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	n/a	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	0.00		
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**n/a**	**2.48**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**348.71**	**371.85**		

Table 28 SHETL revenue breakdown

Transmission Revenue Forecast			SHE Transmission Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	n/a	283.31	283.31	283.31
Inflation		PI_t	n/a	302.65	302.65	302.65
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	540.60		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**n/a**	**577.51**		
SONIA	B1	It-1	n/a	0.05%		
Allowed Revenue	B2	ARt-1	n/a	582.60		
Recovered Revenue	B4	RRt-1	n/a	582.60		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	n/a	30.30		
Legacy MOD	C2	LMODt	n/a	20.80		
Legacy K correction	C3	LKt	n/a	0.00		
Legacy TRU term	C4	LTRUt	n/a	-0.40		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	1.60		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	1.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	n/a	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	1.80		
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	0.00		
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**n/a**	**55.10**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**632.65**	**632.61**		

Table 29 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	Year									
Regulatory Year	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.6	6.7	6.9	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.4	8.6	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.3	15.7	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.4	9.7	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	16.0	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	24.0	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.1	14.5	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.1	32.8	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.7	45.6	Current revenues plus indexation
Thanet	78.9	17.4	15.7	19.5	18.6	19.2	19.7	20.8	21.3	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.0	31.1	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	18.9	32.9	31.4	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	25.3	24.9	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	14.4	13.3	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.1	14.5	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	14.5	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	20.5	Current revenues plus indexation
Race Bank						66.0	26.7	27.4	28.4	Current revenues plus indexation
Galloper							16.1	17.1	17.5	Current revenues plus indexation
Walney 3							28.8	13.5	13.9	Current revenues plus indexation
Walney 4								13.5	13.9	Current revenues plus indexation
Hornsea 1A								137.1	17.3	Current revenues plus indexation
Hornsea 1B									17.3	Current revenues plus indexation
Hornsea 1C									17.3	Current revenues plus indexation
Beatrice									20.5	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2021/22									68.4	National Grid Forecast
Forecast to asset transfer to OFTO in 2022/23									13.7	National Grid Forecast
Offshore Transmission Pass-Through (B7)	218.4	248.3	260.8	265.5	318.0	390.6	387.0	549.0	573.6	

Notes:

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

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

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

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

Appendix G: Generation zones map

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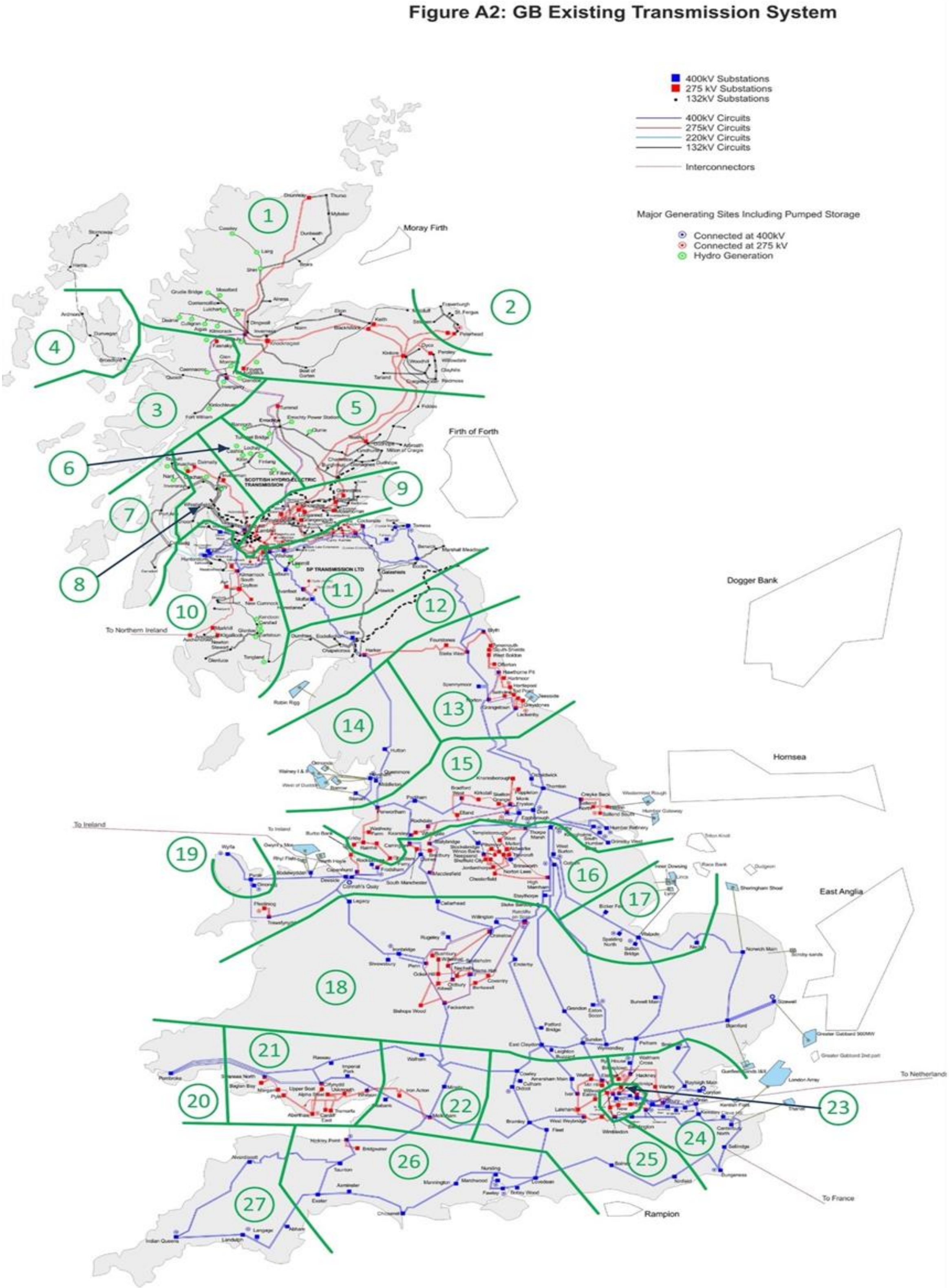
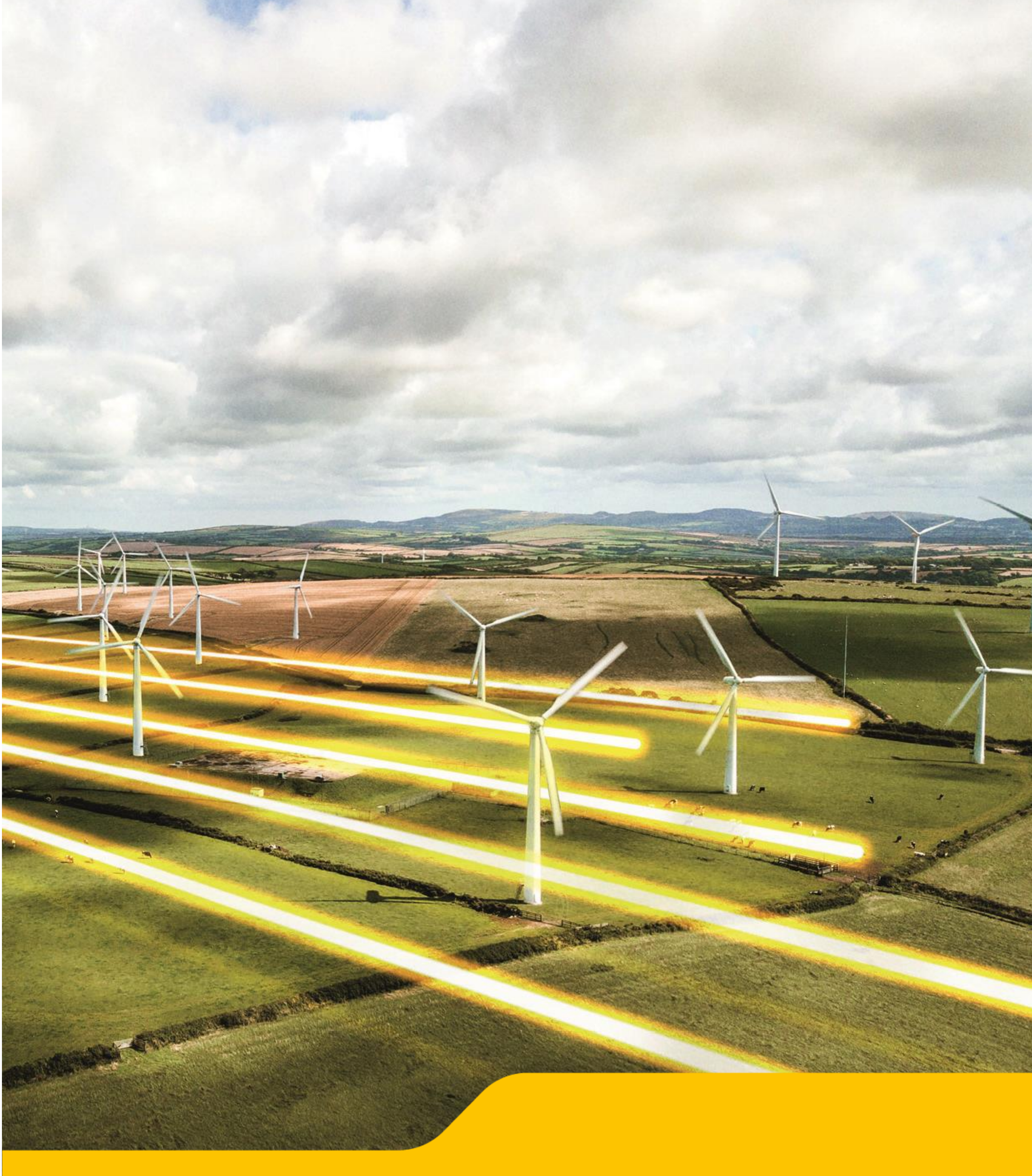
Appendix G: Generation zones map





Appendix H: Demand zones map

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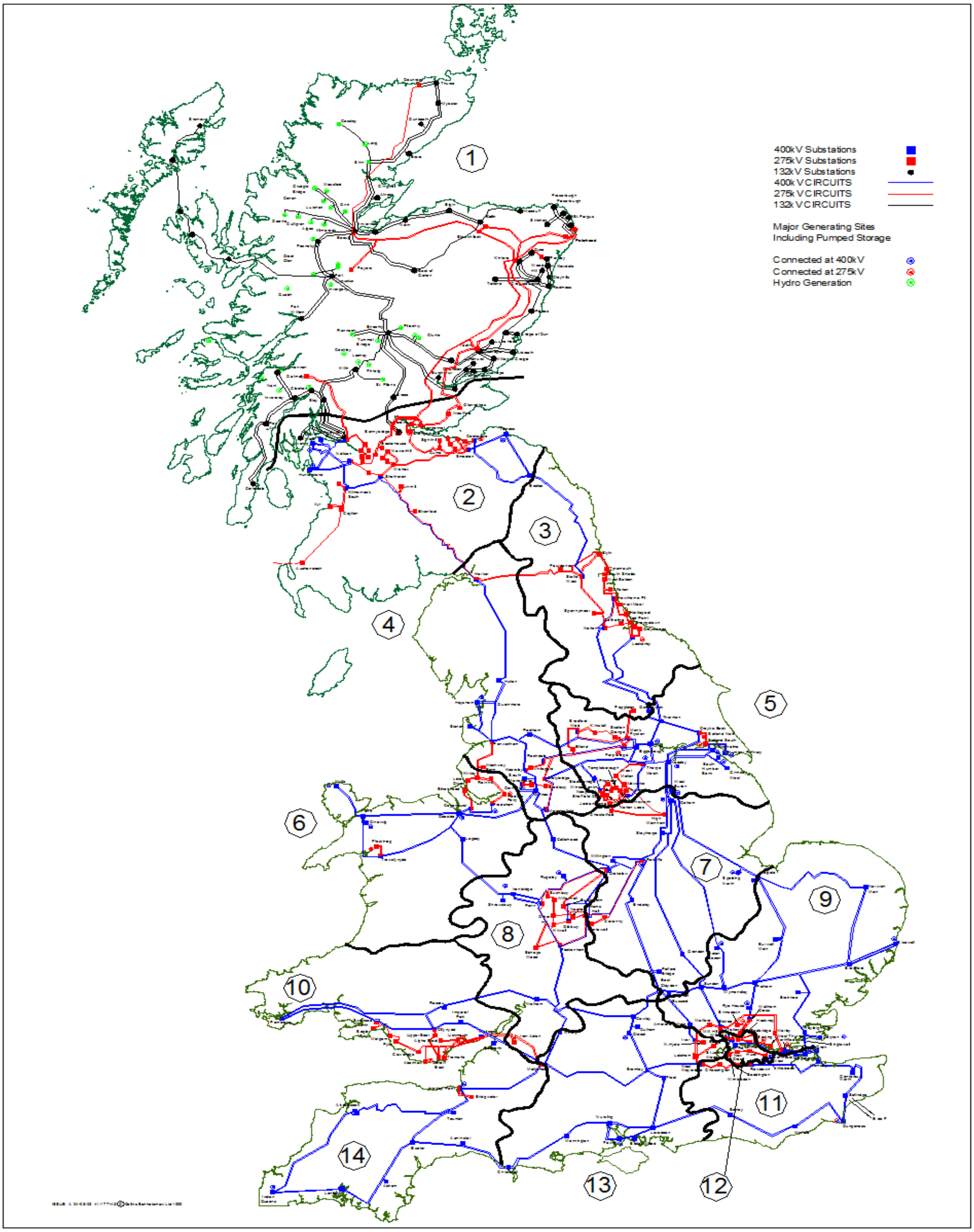

Appendix I Changes to TNUoS parameters

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.

2022/23TNUoS Tariff Forecast					
		April 2021	**August 2021**	**Draft Tariffs November 2021**	**Final Tariffs January 2022**
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 / ADJUSTMENT	**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 by exception
	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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