Draft TNUoS Tariffs for 2022/23

National Grid Electricity System Operator

November 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 the Draft Transmission Network Use of System (TNUoS) tariffs for year 2022/23 (November Tariffs) on our website[1].

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

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 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 gen cap calculation. Ofgem is aiming for the changes to be implemented for 2022/23[2].

Our forecast is based on the CUSC methodology and includes the potential impact of CMP368/369. 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, and the proceedings are underway. As a result, Ofgem have not made a decision on CMP368/369 which is dependent on CMP317/327 outcome[3].

In this report, our forecast on CMP368/369 figures (pre-existing assets and generation charges associated with large embedded generators) are indicative, and are based on the CMP368/369 original proposal, to provide early visibility of the potential impact of CMP368/369 on the tariffs. Our final tariffs will incorporate any relevant further changes following on from the conclusion of the JR and/or any relevant Ofgem decisions.

Transmission Demand Residual (TDR)

The implementation of the TDR banded charges methodology is not expected until charging year 2023/24 (as per Ofgem's latest minded to position for CMP343[4]) and has not been included in Draft tariffs for 2022/23. The 5-Year View published April 2021 shows the potential impact that TDR banding will have on forecast demand tariffs from 2023/24 which can be found on our website[5]. Currently we are expecting that our next 5-Year forecast (2023/24 to 2028/29) and following 2023/24 TNUoS tariff setting forecast, Draft and Final publications will include the impact of the TDR methodology changes. Further clarification and guidance for the potential change in methodology and impact on tariffs are to be included in these.

Total revenues to be recovered

The total TNUoS revenue to be collected is forecast at £3,604m, an increase of £170m from the August forecast. Contributing to this increase from the ESO are reviews of the Adjustment Term and pass-through items as actual data replaces forecast data (+£63.74) and the replacement of the Network Innovation Competition Fund with the Strategic Innovation Fund (-£12.85). There has also been a revision of the OFTO, Interconnector and TO Maximum Allowed Revenue (+£109m). The 2022/23 revenue forecast will be finalised by

1 https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-charges
2 https://www.ofgem.gov.uk/publications/cmp317-cmp327-excluding-assets-required-connection-and-removing-transmission-generator-residual
3 https://www.nationalgrideso.com/document/222786/download
4 https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/cmp343_minded-to_decision_consultation.pdf
5 https://www.nationalgrideso.com/document/191116/download

the January Final tariffs, based on onshore and offshore TOs' submissions.

Generation tariffs

The total revenue to be recovered from generators is £816.6m, a decrease of £18.6m since the August forecast.

The generation charging base has been updated to 72.9GW based on our best view on generation projects for 2022/23. This is a decrease of 0.5GW since the August forecast. This view will be further refined in the final tariffs. The average generation tariff is forecast at £11.26/kW, a decrease of £0.12/kW due to the decrease in the generation revenue.

Demand tariffs

Revenue to be collected through demand is forecast at £2,788m for 2022/23. This value has increased by £188m compared to the August forecast. The main drivers are the increased revenue to be collected in total through TNUoS and the reduction in revenue to be recovered through Generation charges.

The impact on the end consumer is forecast to be £39.09 in 2022/23, an increase of £2.53 from the August forecast. This is due to the aforementioned increase in the demand revenue.

In 2022/23 it is current forecast that £14.3m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), a reduction of £1.2m since the August forecast. This is due to the updated locational inputs. The average EET is forecast at £1.95/kW, which is a reduction of £0.28/kW, versus previous forecast.

Since the August forecast, the average gross HH demand tariff for 2022/23 is forecast to be £55.71/kW, an increase of £3.86/kW and the average NHH demand tariff forecast is at 6.98p/kWh, an increase of 0.45p/kWh.

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts for 2022/23 is available on our website[6].

Our next TNUoS tariff publication will be the Final 2022/23 tariffs in January 2022.

Feedback

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

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

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

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

Our contact details

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

Charging Methodology Changes

This Report

This report contains the Draft 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.

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

On 21 November 2019, Ofgem published their final decision[7] 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 propose 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. CMP317/327 means that all generation local tariffs and associated charges are not in scope, however Ofgem's final decision stated that a few exclusions need to be addressed. 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; In this forecast, we have incorporated the indicative figures calculated under the CMP368/369 original proposal, to illustrate the likely impact on TNUoS tariffs.
- 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. A few CUSC mods (CMP335/6, CMP340/3, CMP363/4) have been raised to implement TDR. The implementation of TDR is currently anticipated in April 2023, based on Ofgem's minded-to decision[8], and hence would have no impact on our tariff forecast for 2022/23.

Access SCR and TNUoS reform

In December 2018, Ofgem launched their Access SCR[9]. 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 implementation dates no earlier than 2023. On 1st October 2021, Ofgem published a call for evidence on TNUoS reform[10], which closed on 12th November. In the call for evidence, Ofgem indicated that any potential "quick wins" to change the TNUoS methodology, will still be subject to the usual decision-making process. We therefore don't expect any impact on the TNUoS methodology in 2022/23 tariffs by the Access SCR or potential TNUoS reform.

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

[8] https://www.ofgem.gov.uk/publications/cmp343-consultation-minded-decision-and-impact-assessment

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

[10] https://www.ofgem.gov.uk/publications/tnuos-reform-call-evidence

RIIO price control appeal

In March 2021, the CMA (Competition and Market Authority) received multiple appeals by nine energy companies over RIIO price control[11] decisions. The CMA have published their final determination on the appeals on 1st November 2021[12].

The final determination[13] means that onshore Transmission Owner's (TOs') revenue calculation will change from the figures that we used in this forecast. These upward changes will be reflected in the final 2022/23 tariffs after we receive the revised revenue submission from TOs. Due to the gen cap, changes to the TNUoS revenue figure will impact demand users only, via demand residual tariffs. The TOs have yet to confirm the actual impact in their January revenue submission, which will incorporate any potential downward changes (if applicable) as well as this upward change. 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 in each demand zone.

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 (except CMP368/369). These are summarised on the inflight modifications Table .

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 scarring' 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 slowly returning to similar levels forecast pre-COVID.

[11] https://www.gov.uk/cma-cases/energy-licence-modification-appeals-2021
[12] https://www.gov.uk/cma-cases/energy-licence-modification-appeals-2021
[13] https://assets.publishing.service.gov.uk/media/617fd1798fa8f529777ffd5e/ELMA_Final_Determination_Order_NON-CONFIDENTIAL.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 €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 ((pre-existing assets and generation charges associated with large embedded generators), in this forecast, we have included the indicative pre-existing local asset charges under the CMP368/369 original proposal. 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. Individual customers are not affected by CMP368/369, which (if approved) only changes the revenue split between generation and demand users. We estimate that generation revenue is reduced slightly (by just below £10m) under CMP368/369.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2022/23 August	2022/23 November	Change since last forecast
Adjustment	- 0.332681	- 0.292593	0.040088
Average Generation Tariff*	11.378736	11.258529	- 0.120207

*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 Commission Regulation (EU) 838/2010, which has been adopted in UK 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 the legislation. The implementation of CMP317/327 means that charges for local onshore and offshore tariffs are not included in the €2.50/MWh cap.

Average generation tariffs have decreased by £0.12/kW. There has been a decrease of £19m in the revenue to be collected from generation, causing the average generation tariff to decrease. The generation adjustment has increased by £0.04/kW to become slightly less negative. This is because the wider tariff has decreased meaning there is less of a requirement to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

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%. 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

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 40% Load Factor	Conventional Low Carbon 75% Load Factor	Intermittent 45% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	4.231137	19.441495	16.478675	-0.292593	18.306612	34.998340	24.934755
2	East Aberdeenshire	3.595971	9.835041	16.478675	-0.292593	13.828864	27.158334	20.611850
3	Western Highlands	3.962074	17.376252	15.600599	-0.292593	16.860221	32.302269	23.127319
4	Skye and Lochalsh	-0.601418	17.376252	17.177836	-0.292593	12.927624	29.316014	24.704556
5	Eastern Grampian and Tayside	4.943967	12.821537	12.811143	-0.292593	14.904446	27.078670	18.288242
6	Central Grampian	4.380376	13.178909	13.226515	-0.292593	14.649953	27.198480	18.864431
7	Argyll	2.838838	11.248312	18.630994	-0.292593	14.497967	29.613473	23.400141
8	The Trossachs	3.724789	11.248312	10.941171	-0.292593	12.307989	22.809601	15.710318
9	Stirlingshire and Fife	2.959815	10.850345	10.598142	-0.292593	11.246617	21.403123	15.188204
10	South West Scotlands	2.042597	11.107738	10.799382	-0.292593	10.512852	20.880190	15.505271
11	Lothian and Borders	4.493007	11.107738	5.791138	-0.292593	10.959964	18.322356	10.497027
12	Solway and Cheviot	2.232849	7.266862	6.089532	-0.292593	7.282814	13.479935	9.067027
13	North East England	4.582016	5.701097	4.052336	-0.292593	8.190796	12.617582	6.325237
14	North Lancashire and The Lakes	1.882159	5.701097	1.137655	-0.292593	4.325067	7.003044	3.410556
15	South Lancashire, Yorkshire and Humber	5.148777	1.864589	0.228974	-0.292593	5.693609	6.483600	0.775446
16	North Midlands and North Wales	3.968160	0.659309	-	-0.292593	3.939291	4.170049	0.004096
17	South Lincolnshire and North Norfolk	3.968712	-0.388826	-	-0.292593	3.520589	3.384500	-0.467565
18	Mid Wales and The Midlands	1.553684	1.312571	-	-0.292593	1.786119	2.245519	0.298064
19	Anglesey and Snowdon	5.458177	0.639424	-	-0.292593	5.421354	5.645152	-0.004852
20	Pembrokeshire	7.425030	-4.617907	-	-0.292593	5.285274	3.669007	-2.370651
21	South Wales & Gloucester	3.269195	-5.360609	-	-0.292593	0.832358	-1.043855	-2.704867
22	Cotswold	1.953578	3.087702	-7.008725	-0.292593	0.092576	-3.031964	-5.911852
23	Central London	-2.689760	3.087702	-9.825874	-0.292593	-5.677622	-10.492451	-8.729001
24	Essex and Kent	-2.964210	3.087702	-	-0.292593	-2.021722		1.096873
25	Oxfordshire, Surrey and Sussex	-1.744644	-0.857685	-	-0.292593	-2.380311	-2.680501	-0.678551
26	Somerset and Wessex	-3.460724	-2.141900	-	-0.292593	-4.610077	-5.359742	-1.256448
27	West Devon and Cornwall	-1.876325	-5.121571	-	-0.292593	-4.217546	-6.010096	-2.597300

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

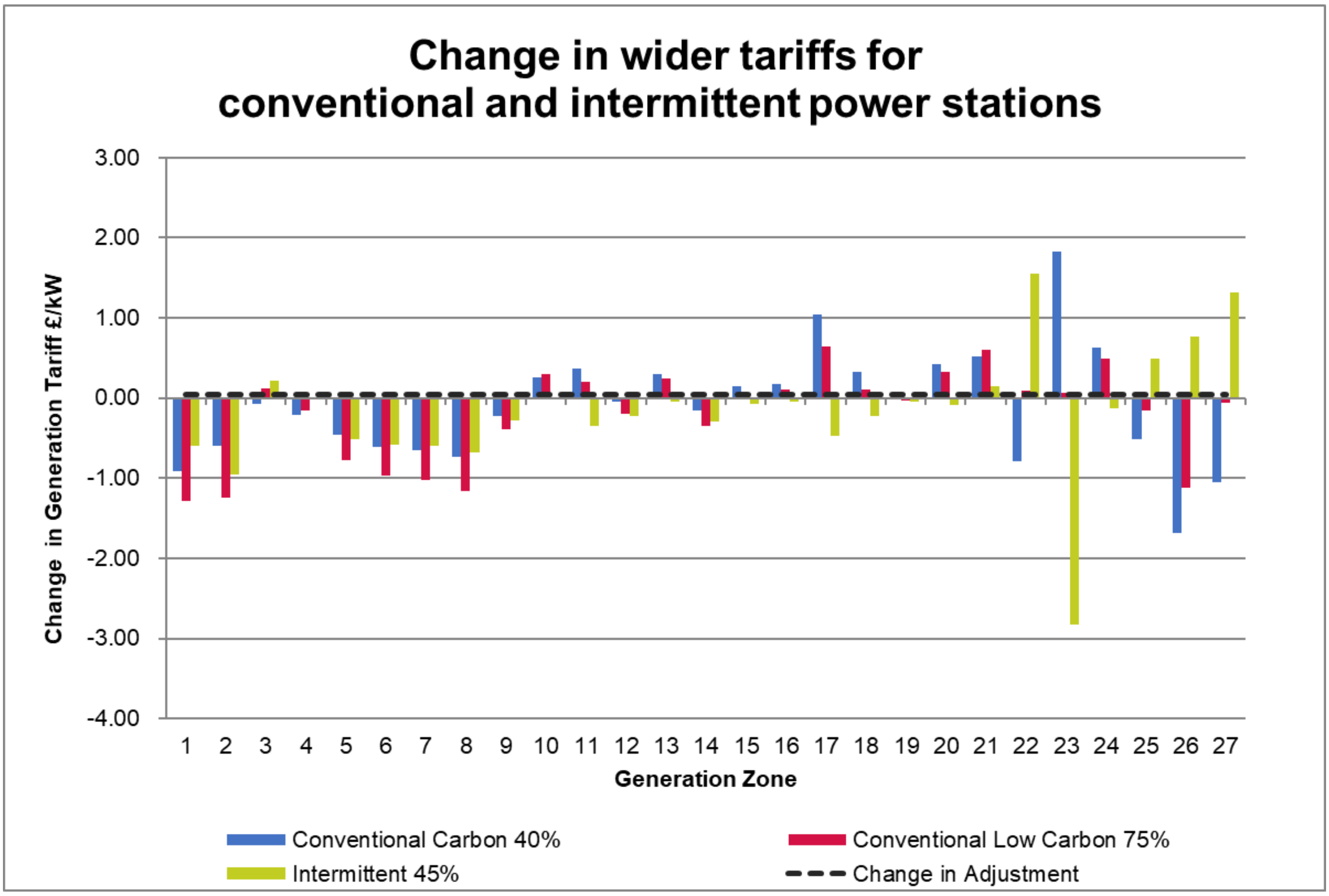
The following section provides details of the wider generation tariffs for 2022/23 and explains how these have changed since the August forecast. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent 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 €2.50/MWh cap.

Table 3 Generation wider tariff changes

Zone	Zone Name	Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			Change in Adjustment
		2022/23 August	2022/23 November	Change	2022/23 August	2022/23 November	Change	2022/23 August	2022/23 November	Change	
1	North Scotland	19.219041	18.306612	-0.912429	36.277734	34.998340	-1.279393	25.534198	24.934755	-0.599443	0.040088
2	East Aberdeenshire	14.423836	13.828864	-0.594971	28.400621	27.158334	-1.242287	21.571745	20.611850	-0.959895	0.040088
3	Western Highlands	16.932278	16.860221	-0.072057	32.186640	32.302269	0.115629	22.913680	23.127319	0.213639	0.040088
4	Skye and Lochalsh	13.136779	12.927624	-0.209154	29.472544	29.316014	-0.156530	24.716019	24.704556	-0.011463	0.040088
5	Eastern Grampian and Tayside	15.361343	14.904446	-0.456897	27.849381	27.078670	-0.770711	18.805318	18.288242	-0.517076	0.040088
6	Central Grampian	15.265595	14.649953	-0.615642	28.166023	27.198480	-0.967543	19.440978	18.864431	-0.576547	0.040088
7	Argyll	15.150766	14.497967	-0.652798	30.638843	29.613473	-1.025370	23.997994	23.400141	-0.597853	0.040088
8	The Trossachs	13.041158	12.307989	-0.733169	23.967993	22.809601	-1.158392	16.395923	15.710318	-0.685605	0.040088
9	Stirlingshire and Fife	11.473802	11.246617	-0.227185	21.786513	21.403123	-0.383391	15.465403	15.188204	-0.277199	0.040088
10	South West Scotlands	10.248810	10.512852	0.264042	20.578935	20.880190	0.301255	15.491632	15.505271	0.013639	0.040088
11	Lothian and Borders	10.586961	10.959964	0.373003	18.125418	18.322356	0.196938	10.838852	10.497027	-0.341825	0.040088
12	Solway and Cheviot	7.328713	7.282814	-0.045900	13.675401	13.479935	-0.195467	9.292804	9.067027	-0.225777	0.040088
13	North East England	7.892707	8.190796	0.298089	12.368496	12.617582	0.249086	6.373201	6.325237	-0.047964	0.040088
14	North Lancashire and The Lakes	4.482482	4.325067	-0.157415	7.356880	7.003044	-0.353837	3.704216	3.410556	-0.293660	0.040088
15	South Lancashire, Yorkshire and Humber	5.546561	5.693609	0.147048	6.419893	6.483600	0.063707	0.847400	0.775446	-0.071954	0.040088
16	North Midlands and North Wales	3.768334	3.939291	0.170957	4.069201	4.170049	0.100848	0.054148	0.004096	-0.050052	0.040088
17	South Lincolnshire and North Norfolk	2.476881	3.520589	1.043707	2.736015	3.384500	0.648485	0.000490	-0.467565	-0.468055	0.040088
18	Mid Wales and The Midlands	1.465375	1.786119	0.320745	2.133592	2.245519	0.111927	0.526455	0.298064	-0.228391	0.040088
19	Anglesey and Snowdon	5.377791	5.421354	0.043563	5.671102	5.645152	-0.025950	0.044433	-0.004852	-0.049285	0.040088
20	Pembrokeshire	4.862773	5.285274	0.422502	3.345808	3.669007	0.323199	-2.283065	-2.370651	-0.087586	0.040088
21	South Wales & Gloucester	0.309207	0.832358	0.523152	-1.652248	-1.043855	0.608393	-2.854551	-2.704867	0.149684	0.040088
22	Cotswold	0.877893	0.092576	-0.785318	-3.128490	-3.031964	0.096527	-7.470186	-5.911852	1.558334	0.040088
23	Central London	-7.500705	-5.677622	1.823083	-10.564004	-10.492451	0.071554	-5.898379	-8.729001	-2.830623	0.040088
24	Essex and Kent	-2.646413	-2.021722	0.624691	-1.438391	-0.941027	0.497365	1.220490	1.096873	-0.123618	0.040088
25	Oxfordshire, Surrey and Sussex	-1.867220	-2.380311	-0.513091	-2.519094	-2.680501	-0.161407	-1.170805	-0.678551	0.492253	0.040088
26	Somerset and Wessex	-2.928295	-4.610077	-1.681782	-4.240219	-5.359742	-1.119523	-2.019441	-1.256448	0.762993	0.040088
27	West Devon and Cornwall	-3.167437	-4.217546	-1.050109	-5.954566	-6.010096	-0.055530	-3.916132	-2.597300	1.318832	0.040088

Figure 1 Variation in generation wider zonal tariffs



Locational changes

Locational tariffs have been impacted by the update of various locational inputs, including the nodal generation and demand charging bases and the network model used to model flows.

The update to the week 24 nodal demand data has had the biggest impact on the generation tariffs, causing a decrease in majority of the northern zones, due to the decrease in locational demand.

In the south, the changes to the tariffs are less uniform due to some zones forecasted to have an increase in demand, causing an increase in the tariff and vice versa. The changes in the south are also caused by some large changes in the contracted TEC, with the delay of Damhead Creek 2, a 1.8GW CCGT in zone 24 causing some tariffs to increase, and the inclusion of Shoreham, a 0.4GW CCGT in zone 25 which caused a slight decrease in some conventional generation tariffs.

Adjustment tariff changes

The adjustment tariff has been implemented through CMP317/327, where the generation residual has been removed. However, to ensure compliance with the gen cap there is still a requirement for an adjustment tariff. The adjustment tariff is currently 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 £0.04/kW since the August forecast due to the decrease in the average wider tariff. This causes the adjustment to go less negative as there is less adjustment require to ensure charges are within the gen cap. There would have been further increase, however the update to the euro exchange rate decreased the generation cap revenue which counteracted the increase. For a full breakdown of the generation revenues, please see Table 19.

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 were recalculated in preparation for the start of each 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-T2. The CPIH figure has been finalised, and therefore onshore local substation tariffs are finalised for charging year 2022/23.

Table 4 Local substation tariffs

2022/23 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.150770	0.075388	0.051999
<1320 MW	Redundancy	0.317689	0.161359	0.114575
>=1320 MW	No redundancy	-	0.221489	0.157694
>=1320 MW	Redundancy	-	0.333303	0.239726

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.

In this forecast, we have updated the onshore network model, including wider network and local networks associated with those generators, and have re-calculated local circuit tariffs. The 2022/23 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	2.671000	Edinbane	7.171952	Middle Muir	2.407415
Achruach	-2.616183	Ewe Hill	1.558191	Middleton	0.154351
Aigas	0.685223	Fallago	-0.067057	Millennium South	0.494319
An Suidhe	-0.979562	Farr	3.652465	Millennium Wind	1.720497
Arecleoch	2.176008	Fernoch	4.608469	Moffat	-
Beinneun Wind Farm	1.380647	Ffestiniogg	0.259176	Mossford	2.951276
Bhlaraidh Wind Farm	0.676448	Finlarig	0.335473	Nant	-1.287043
Black Hill	1.590910	Foyers	0.300069	Necton	1.165832
Black Law	1.830721	Galawhistle	-	Rhigos	0.108099
Blackcraig Wind Farm	6.089148	Glen Kyllachy	0.479246	Rocksavage	0.018502
Blacklaw Extension	3.882282	Glendoe	1.927155	Saltend	0.017775
Clyde (North)	0.114898	Glenglass	4.929012	Sandy Knowe	5.244576
Clyde (South)	0.132874	Gordonbush	1.268972	South Humber Bank	-0.190400
Corriegarth	3.035227	Griffin Wind	9.937485	Spalding	0.274972
Corriemoillie	1.706045	Hadyard Hill	2.899919	Strathbrora	0.859979
Coryton	0.047861	Harestanes	2.448949	Strathy Wind	2.031118
Creag Riabhach	3.514474	Hartlepool	0.091475	Stronelairg	1.114291
Cruachan	1.869759	Invergarry	0.383397	Wester Dod	0.356506
Culligran	1.815856	Kilgallioch	1.102649	Whitelee	0.111191
Deanie	2.983193	Kilmorack	0.206913	Whitelee Extension	0.309112
Dersalloch	2.523707	Kype Muir	1.554002		
Dinorwig	2.457864	Langage	0.674171		
Dorenell	2.149878	Lochay	0.383397		
Dumnaglass	1.187466	Luichart	0.589179		
Dunhill	1.467292	Marchwood	0.391622		
Dunlaw Extension	1.553989	Mark Hill	0.917330		

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, paragraph 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
Bhlaraidh 132kV	Glenmoriston 132kV	7.4km of cable	7.4km of OHL	Bhlaraidh
Coalburn 132kV	Cumberhead collector 132kV	9.7km cable	0km	Cumberhead
Coalburn 132kV	Cumberhead collector 132kV	9.7km cable	0km	Galawhistle
Coalburn 132kV	Kype Muir 132kV	17km cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km cable	13km OHL	Middle Muir
Crystal Rig 132kV	Wester Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
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
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	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes
Sandy Knowe 132kV	Glen Glass 132kV	7km of cable	7km of OHL	Sandy Knowe
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw

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 a price control 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 August, 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 August Tariff Component (£/kW)			2022/23 November Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	9.067773	47.904577	1.189536	9.152308	48.351171	1.200626	0.084535	0.446594	0.011090
Beatrice				7.738282	21.105031	-			
Burbo Bank	11.349149	21.934427	-	11.581837	22.384141	-	0.232688	0.449714	-
Dudgeon	16.599924	26.045535	-	16.940266	26.579538	-	0.340342	0.534003	-
Galloper	16.992267	26.875018	-	17.340653	27.426026	-	0.348386	0.551008	-
Greater Gabbard	16.892743	39.091506	-	17.050227	39.455940	-	0.157484	0.364434	-
Gunfleet	19.733401	18.197736	3.401261	19.917368	18.367386	3.432970	0.183967	0.169650	0.031709
Gwynt y mor	21.312321	21.071110	-	21.749280	21.503123	-	0.436959	0.432013	-
Hornsea 1A	7.500569	26.538185	-	7.654351	27.082288	-	0.153782	0.544103	-
Hornsea 1B	7.500569	26.538185	-	7.654351	27.082288	-	0.153782	0.544103	-
Hornsea 1C	7.500569	26.538185	-	7.654351	27.082288	-	0.153782	0.544103	-
Humber Gateway	12.542420	28.776625	-	12.799572	29.366622	-	0.257152	0.589997	-
Lincs	17.411874	68.474947	-	17.768864	69.878865	-	0.356990	1.403918	-
London Array	11.816070	40.512775	-	12.058331	41.343394	-	0.242261	0.830619	-
Ormonde	27.879465	52.112764	0.415295	28.139373	52.598589	0.419167	0.259908	0.485825	0.003872
Race Bank	10.052457	27.920291	-	10.258559	28.492731	-	0.206102	0.572440	-
Robin Rigg	-0.611919	34.733786	11.128484	-0.617624	35.057595	11.232230	-0.005705	0.323809	0.103746
Robin Rigg West	-0.611919	34.733786	11.128484	-0.617624	35.057595	11.232230	-0.005705	0.323809	0.103746
Sheringham Shoal	26.083405	30.719913	0.667761	26.326570	31.006302	0.673986	0.243165	0.286389	0.006225
Thanet	19.917957	37.316338	0.898336	20.103644	37.664222	0.906711	0.185687	0.347884	0.008375
Walney 1	24.079432	48.140906	-	24.303914	48.589703	-	0.224482	0.448797	-
Walney 2	22.402379	45.591074	-	22.611227	46.016100	-	0.208848	0.425026	-
Walney 3	10.325940	20.919735	-	10.537649	21.348645	-	0.211709	0.428910	-
Walney 4	10.325940	20.919735	-	10.537649	21.348645	-	0.211709	0.428910	-
West of Duddon Sands	9.234736	46.033950	-	9.424073	46.977768	-	0.189337	0.943818	-
Westermost Rough	18.777289	31.956559	-	19.162273	32.611753	-	0.384984	0.655194	-

Generation charges associated with pre-existing assets and CMP368/369

Following TCR (Targeted Charging Review), NGESO raised CMP317/327 to remove TNUoS generation residual (TGR), by revising the CUSC calculation of the gen cap (2.5 Euro/MWh) applicable on TNUoS gen charge. Under CMP317/327, generation local charges are excluded from calculation of the gen cap, as they were viewed as charges related to assets required for connection (called Connection Exclusion).

On 17 December 2020, Ofgem approved CMP317/327 and in their decision letter they directed the ESO to raise a CUSC mod on some outstanding CUSC issues. CMP368/9 was raised to address these issues. Under CMP368/9 (the original proposal), there are two main changes to the calculation of the gen cap –

- Introduction of the concept of “pre-existing assets”, to separate generator local charge into two parts, where local charges associated with the assets that already exist when a generator wishes to connect, will be included in the gen cap calculation, and the rest are still treated as charges associated to assets required for connection and are thus excluded from the gen cap.
- Exclusion of TNUoS-liable embedded generators (>=100MW) from the gen cap. TNUoS generation charges and TWh output associated with these generators, will be excluded from the calculation of the gen cap.

In this forecast, we have undertaken a preliminary assessment of the gen cap under CMP368/9, based on the original proposal. There are no local charges associated with pre-existing assets for offshore generators so far; for onshore generators paying local charges, we have processed around 85% of historical data and have calculated the indicative charges (pre-existing charges). The indicative local circuit/substation charges associated with pre-existing assets are listed by individual generator projects, and can be found in Table AB and Table AC. For simplicity, we only listed those with non-zero pre-existing charges.

Table AB Local circuit tariffs associated with pre-existing assets

Project Name	Pre-existing local circuit tariff (£/kW)	Aggregated pre-existing TEC (MW)
Aigas (part of the Beauly Cascade)	0.685223	13,334
Aikengall IIa Wind Farm	0.356506	
An Suidhe Wind Farm - Argyll (SRO)	- 0.979562	
Blackcraig Wind Farm	6.089148	
Corriemoillie Wind Farm	1.706045	
Culligran (part of the Beauly Cascade)	1.815856	
Deanie (part of the Beauly Cascade)	2.983193	
Edinbane Wind - Skye	7.171952	
Farr Wind Farm - Tomatin	3.652465	
Ffestiniog	0.259176	
Finlarig	0.335473	
Foyers	0.300069	
Glendoe	1.927155	
Hirwaun Power Station	0.108099	
Invergarry (part of the Garry Cascade)	0.383397	
Keith Hill Wind Farm	1.553989	
Kilbraur Wind Farm	0.859979	
Kilgallioch	1.102649	
Luichart (part of the Conon Cascade)	0.589179	
Mark Hill Wind Farm	0.917330	
Millennium South	0.494319	
Mossford (part of the Conon Cascade)	2.951276	
Nant	- 1.287043	
Rocksavage	0.018502	
Saltend	0.017775	
South Humber Bank	- 0.190400	
Spalding	0.274972	
Strathy North Wind	2.031118	
Tralorg Wind Farm	0.917330	

Table AC Local substation tariffs associated with pre-existing assets

Project Name	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	0.317689	41.7
Toddleburn Wind Farm	0.317689	
Keith Hill Wind Farm	-	

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).

As per our August forecast, the methodology for 2022/23 demand tariffs remains unchanged. There has been no update since Ofgem published their ‘minded to position’ on CMP343 to delay the implementation of the Transmission Demand Residual (TDR) banded charges until 2023/24.

Table 8 Summary of demand tariffs

HH Tariffs	2022/23 August	2022/23 November	Change
Average Tariff (£/kW)	51.847329	55.709982	3.862653
Residual (£/kW)	53.772794	57.495438	3.722644

EET	2022/23 August	2022/23 November	Change
Average Tariff (£/kW)	2.223457	1.947578	- 0.275879
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.319241	2.344515	0.025274
Embedded Export Volume (GW)	7.005698	7.361318	0.355620
Total Credit (£m)	15.576867	14.336744	- 1.240123

NHH Tariffs	2022/23 August	2022/23 November	Change
Average (p/kWh)	6.527043	6.977935	0.450892

Demand tariffs are forecast to increase, the main driver being the increase in total revenue and the subsequent increase in the revenue to be recovered through demand. There has also been a slight reduction in the amount of revenue to be recovered through generation tariffs, increasing the proportion of the revenue recovered through demand. Draft tariffs for 2022/23 indicate that 77.3% of total revenue is to be recovered through demand, an increase of 1.7% since the August forecast, with overall demand revenue at £2,788m.

The average HH gross tariff is forecast at £55.71/kW, an increase of £3.86/kW compared to the August forecast. Similarly, the average NHH tariff is forecast at 6.98p/kWh, an increase of 0.45p/kWh.

There has been an increase in forecasted Embedded Export Volume of 0.35GW to 7.36GW compared to the August forecast. However, there has been a noticeable drop in the total credit paid out to embedded generators (<100MW), which is currently forecast at £14.3m, a reduction of £1.2m. This is due to a change in locational tariffs and the average EET is now forecast at £1.95/kW a reduction of £0.28/kW versus August forecast.

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	28.251379	3.754234	-
2	Southern Scotland	36.260171	4.556094	-
3	Northern	45.349736	5.426633	-
4	North West	52.013201	6.558575	-
5	Yorkshire	52.475528	6.348318	-
6	N Wales & Mersey	53.757604	6.617061	-
7	East Midlands	56.176808	7.106220	1.025885
8	Midlands	57.845875	7.325327	2.694952
9	Eastern	58.601706	7.846331	3.450783
10	South Wales	59.112712	6.847104	3.961789
11	South East	60.848236	8.243977	5.697313
12	London	64.336288	6.602228	9.185365
13	Southern	62.913261	8.031774	7.762338
14	South Western	64.397959	8.883631	9.247037

Residual charge for demand:	57.495438

Residual charge impact included in tariff calculation

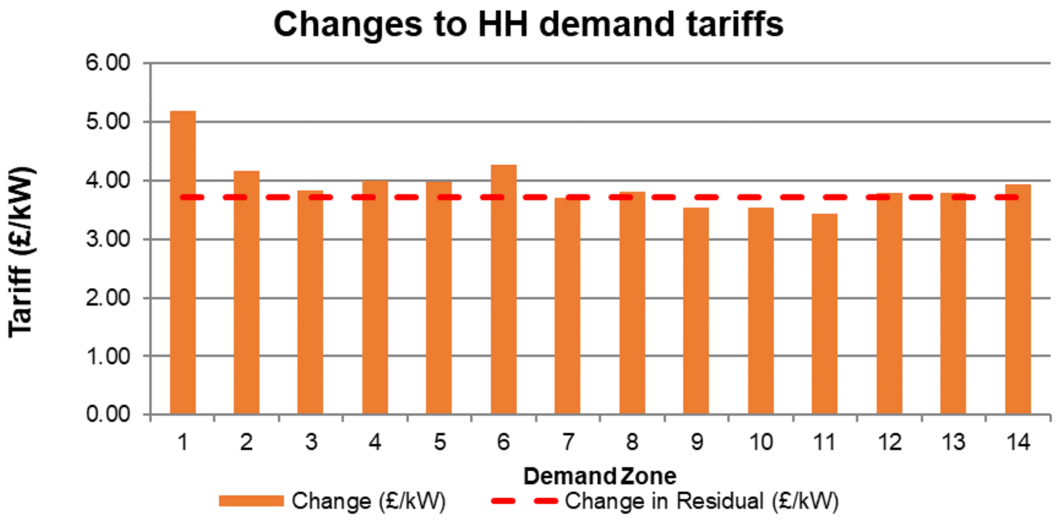
8. Half-Hourly demand tariffs

The table and figure below show the November Draft gross HH demand tariffs for 2022/23 compared to the 2022/23 August forecast Tariffs as well as the change in demand residual tariff (value is consistent across all zones).

Table 10 Half-Hourly demand tariffs

Zone	Zone Name	2022/23 August (£/kW)	2022/23 November (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	23.066212	28.251379	5.185167	3.722644
2	Southern Scotland	32.098648	36.260171	4.161523	3.722644
3	Northern	41.517582	45.349736	3.832154	3.722644
4	North West	48.016201	52.013201	3.997000	3.722644
5	Yorkshire	48.497771	52.475528	3.977757	3.722644
6	N Wales & Mersey	49.484986	53.757604	4.272618	3.722644
7	East Midlands	52.479595	56.176808	3.697213	3.722644
8	Midlands	54.039843	57.845875	3.806032	3.722644
9	Eastern	55.067333	58.601706	3.534373	3.722644
10	South Wales	55.565014	59.112712	3.547698	3.722644
11	South East	57.418465	60.848236	3.429771	3.722644
12	London	60.555540	64.336288	3.780748	3.722644
13	Southern	59.122777	62.913261	3.790484	3.722644
14	South Western	60.455151	64.397959	3.942808	3.722644

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the HH demand tariffs have increased across all zones. This is mainly due to the overall increase in the demand residual of £3.72/kW. The update to the Week 24 nodal demand and the corresponding changes to locational signals can also be seen (to a lesser extent than to the residual impact) in locational tariffs (see Table

The forecast level of gross HH chargeable demand has increased by 0.2GW in comparison with the August forecast and is currently forecast at 19.36GW.

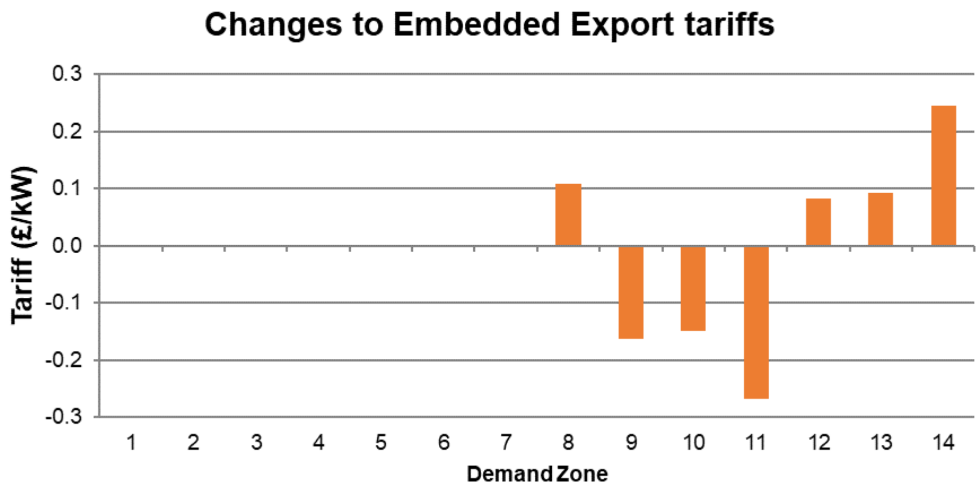
9. Embedded Export Tariffs (EET)

The next table and figure show the difference between the August forecast and current Draft tariffs.

Table 11 Embedded Export Tariffs

Zone	Zone Name	2022/23 August (£/kW)	2022/23 November (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	1.026042	1.025885	- 0.000157
8	Midlands	2.586290	2.694952	0.108662
9	Eastern	3.613781	3.450783	- 0.162998
10	South Wales	4.111461	3.961789	- 0.149672
11	South East	5.964912	5.697313	- 0.267599
12	London	9.101988	9.185365	0.083377
13	Southern	7.669225	7.762338	0.093113
14	South Western	9.001599	9.247037	0.245438

Figure 3 Embedded export tariff changes



In this tariff update there has been quite a significant change to the average EET versus the August forecast. This is primarily due to a change in locational demand and a change in forecast Embedded Export Volumes. The changes in locational demand tariffs and the corresponding impact of the update to Week 24 demand data can be seen in Table 22. The Embedded Export Volume has increased by 0.35GW to 7.36GW compared to the previous forecast. There has also been a slight increase to the avoided GSP Infrastructure Costs (AGIC) of £0.03/kW to £2.34/kW due to an increase in inflation for 2022/23. The overall impact of these changes has reduced the average EET by £0.28/kW to £1.95/kW.

As can be seen in the figure above there has been minimal change in zone 7, a reduction in Zones 9 – 11 and an increase in Zones 12 – 14. Zones 1-6 remain floored at £0/kW and have subsequently no movement.

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.

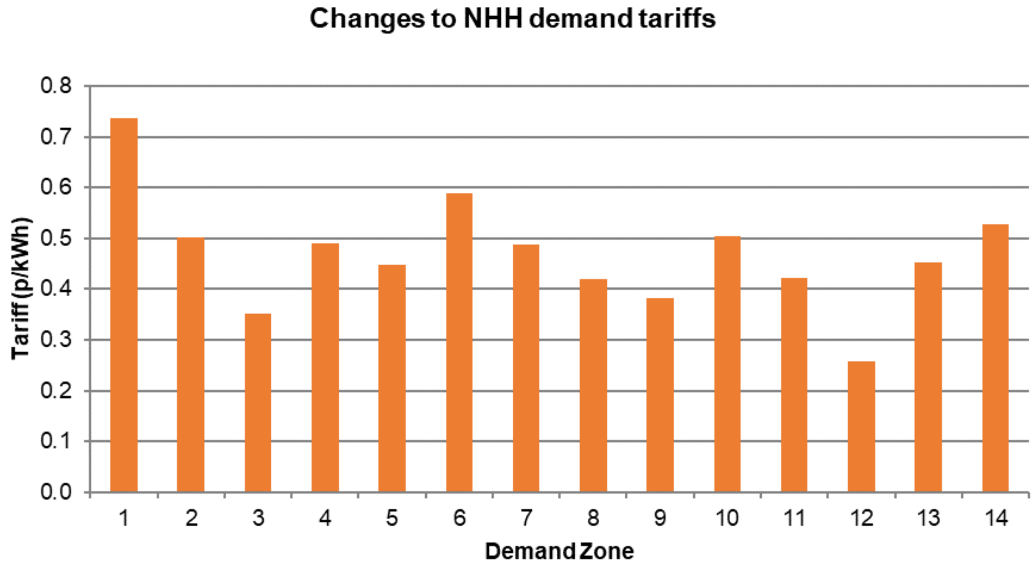
10. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2022/23 Draft tariffs and the August forecast.

Table 12 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2022/23 August (p/kWh)	2022/23 November (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.016852	3.754234	0.737382
2	Southern Scotland	4.054787	4.556094	0.501307
3	Northern	5.075388	5.426633	0.351245
4	North West	6.067730	6.558575	0.490845
5	Yorkshire	5.900569	6.348318	0.447749
6	N Wales & Mersey	6.028570	6.617061	0.588491
7	East Midlands	6.617207	7.106220	0.489013
8	Midlands	6.906122	7.325327	0.419205
9	Eastern	7.463089	7.846331	0.383242
10	South Wales	6.343088	6.847104	0.504016
11	South East	7.822213	8.243977	0.421764
12	London	6.345094	6.602228	0.257134
13	Southern	7.578782	8.031774	0.452992
14	South Western	8.356490	8.883631	0.527141

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2022/23 Draft tariffs is forecast at 6.98p/kWh, a 0.45p/kWh increase compared to the August forecast Tariffs. There are several factors which have impacted the change in NHH tariffs and as stated for demand tariffs as a whole, the main driver has been due the overall increase revenue to be recovered.

Another key factor is the change/variances to HH and NHH charging bases versus the August forecast, which subsequently has offset the overall increase in revenue to be recovered through NHH tariffs. The change in HH and NHH charging bases will also impact NHH tariffs at zonal level, this will either have the effect of offsetting or compounding tariffs across each zone depending on the variances within each zone.

The final driver to mention, is the knock-on effect of locational demand changes and the effect this has on locational tariffs. This is primarily related to the update to the Week 24 demand data that feeds into the Transport model. Whilst the impact of this change can be seen more clearly in HH tariffs and the EET, the impact on NHH tariffs is not as clear due to the other factors mentioned above.

As can be seen in the figure above, tariffs across all zones have increased, however due to the multiple factors impacting NHH tariffs there are noticeable fluctuations across zones. As with the HH tariffs and EET, fluctuations in the peak and year-round demand location tariffs have offset/compounded the overall increase. Changes in HH and NHH charging bases will have a greater impact across zonas for NHH tariffs in comparison to HH tariffs and EET.

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:

- Contracted position of generation;
- Nodal demand;
- Local and MITS circuits;
- 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.[14] 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. For the initial and August forecasts, we forecasted our best view of modelled TEC. However, for our November Draft tariffs and January Final tariffs we use the contracted TEC position as published in 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	Draft
Contracted TEC	89.90	89.91	87.66	85.88
Modelled Best View TEC	89.90	84.32	82.79	85.88
Chargeable TEC	70.10	74.93	73.40	72.91

12. Adjustments for interconnectors

When modelling flows on the transmission system in order to set locational tariffs, 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 31st October 2021.

[14] 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 Ireland	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 Ireland	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	975	0

13. Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. The 2022/23 Expansion Constant is £15.462801 /MWkm. 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-T1 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), at 1.76 for the duration of RIIO-T2, is applied to locational tariffs. This parameter approximately represents the redundant network capacity to secure energy flows under network contingencies. A guidance to the onshore security factor calculation is published on our website https://www.nationalgrideso.com/document/183406/download

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-T2 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-T2 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, Strategic Innovation Fund. 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-T2 parameters including project spending profiles, rate of return and inflation index. The 2022/23 revenue figures will be finalised by January 2022 in the Final tariffs.

The impact of the CMA (further discussed within the "Potential changes to the TNUoS revenue parameters" section of the "Charging Methodology Changes" chapter) on the allowed revenue is so far unknown but will be included within the January Final Tariffs whereby the onshore TOs will update their revenue forecast according to the timetable as specified under the STC (SO-TO code).

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

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	1,764.5	1,764.5	1,863.6	-
Scottish Power Transmission	348.7	371.9	350.5	-
SHE Transmission	632.7	632.6	652.8	-
Total TO Income from TNUoS	**2,745.8**	**2,768.9**	**2,866.9**	**-**
Other Income from TNUoS				
Other Pass-through from TNUoS	67.3	108.5	169.3	-
Offshore (plus interconnector contribution / allowance)	552.8	557.2	568.0	-
Total Other Income from TNUoS	**620.2**	**665.7**	**737.4**	**-**
Total to Collect from TNUoS	**3,366.0**	**3,434.6**	**3,604.3**	**-**

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The G/D split forecast is shown in table 16.

In this forecast, we continue assuming that CMP368/369 (chargeable embedded generators and pre-existing assets charges for gen cap) is in the 22/23 tariff methodology and have aligned the calculation methodology with the original CMP368/369 proposal. We have processed part of the data, and therefore the charges associated with pre-existing assets are still indicative. The decision on CMP368/369 will be made after the conclusion of the JR on CMP317/327 decision, and our final tariffs will incorporate any relevant further changes following any relevant Ofgem decisions.

Table 16 Generation and demand revenue proportions

Code	Revenue	2022/23 Tariffs April Initial	August Forecast	November Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	
y	Error Margin	20.8%	14.2%	14.2%	
ER	Exchange Rate (€/£)	1.13	1.13	1.17	
MAR	Total Revenue (£m)	3,366.0	3,434.6	3,604.3	
GO	Generation Output (TWh)	210.0	196.4	196.4	
G	% of revenue from generation	24.84%	24.32%	22.66%	
D	% of revenue from demand	75.16%	75.68%	77.34%	
G.R	Revenue recovered from generation (£m)	836.2	835.2	816.6	
D.R	Revenue recovered from demand (£m)	2,529.8	2,599.4	2,787.7	
Breakdown of generation revenue					
	Revenue from the Peak element	138.2	124.3	129.4	
	Revenue from the Year Round Shared element	108.4	112.1	105.1	
	Revenue from the Year Round Not Shared element	143.3	151.0	137.7	
	Revenue from Onshore Local Circuit tariffs	16.1	15.6	16.3	
	Revenue from Onshore Local Substation tariffs	10.5	9.9	9.9	
	Revenue from Offshore Local tariffs	451.0	446.8	439.5	
	Revenue from the adjustment element	-31.3	-24.4	-21.2	
G.MAR	Total Revenue recovered from generation (£m)	836.2	835.2	816.6	
	Revenue from large embedded generation (£m)	7.1	7.1	8.7	
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	1.9	1.9	2.4	

The “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 was referred to as the “EU gen cap” and now as the “gen cap”, as the €[0~2.5]/MWh is now part of the UK law following Brexit.

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 gen cap. Therefore, the 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)[15], and options have been developed by the workgroup, and the mod was submitted to Ofgem for a decision. The decision will not be known until next year[16] . We have included CMP368/9 in the baseline forecast and have calculated the indicative charges under CMP368/9 original proposal. Our final tariffs will incorporate any relevant further changes following on from the conclusion of the JR and/or any relevant Ofgem decisions.

Exchange Rate

Following CMP317/327, the exchange rate for gen cap calculation is based on the latest Economic and Fiscal Outlook (EFO), published by the Office of Budgetary Responsibility (OBR), and published prior to 31st October. In this forecast, we have updated the exchange rate with the October EFO, and the value has increased from €1.127740/£ in the March EFO forecast, to €1.168093/£ in the October EFO forecast. This has reduced the total revenue to be collected from generators by around £12m.

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

[16] https://www.nationalgrideso.com/document/222786/download

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 been recalculated in the August forecast, 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).

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

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 72.9GW and is based on our internal view of what generation we expect to connect next financial year. This is a decrease of 0.5GW since the August forecast which is mainly driven by the delay in connection date of a couple of small generators.

For the Draft Tariffs, in line with the CUSC, we use the contracted TEC position to set locational tariffs in the Transport model; our best view is used to set the adjustment tariff in the Tariff model.

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 (April 2018 -October 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 August for 2022/23 based on the latest demand outturn data up to October 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	Draft
Generation (GW)	74.93	73.40	72.91
NHH Demand (4pm-7pm TWh)	24.18	24.84	24.70
Gross charging			
Total Average Gross Triad (GW)	49.83	50.61	50.47
HH Demand Average Gross Triad (GW)	19.07	19.17	19.36
Embedded Generation Export (GW)	6.54	7.01	7.36

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 draft version of the 2022/23 ALFs. ALFs are explained in more detail in Appendix D of this report, and the full list of power station ALFs are available on the National Grid ESO website.[17]

The ALFs applied to 2022/23 TNUoS Tariffs may still be updated again for the Final tariffs in January 2022, depending on industry response to draft ALFs.

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)

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

- 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 gen 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 gen cap, i.e. removing these from the definition of Z_G. please also note that some outstanding issues in calculating the gen cap, are being addressed through CMP368/369.

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[18] 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 2022/23 Draft Tariff forecast.

[18] Avoided Grid Supply Point Infrastructure Credit

Table 19 Residual & Adjustment components calculation

	Component	2022/23 Tariffs Initial	August	Draft	Final
G	Proportion of revenue recovered from generation (%)	24.84%	24.32%	22.66%	
D	Proportion of revenue recovered from demand (%)	75.16%	75.68%	77.34%	
R	Total TNUoS revenue (£m)	3,366.00	3,434.62	3,604.29	
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariff	389.9	387.4	372.2	
O	Revenue recovered from offshore local tariffs (£m)	451.0	446.8	439.5	
L_G	Revenue recovered from onshore local substation tariffs (£m)	10.5	9.9	9.9	
S_G	Revenue recovered from onshore local circuit tariffs (£m)	16.1	15.6	16.3	
	Revenue from large embedded generation (£m)	7.1	7.1	8.7	
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	1.9	1.9	2.4	
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	
	Error Margin	20.8%	14.2%	14.2%	
	Exchange Rate (€/£)	1.13	1.13	1.17	
	Total generation Output (TWh)	210.0	196.4	196.4	
	Generation Output from TNUoS chargeable EGs (TWh)	0.0	8.3	8.7	
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	367.9	357.8	344.6	
	Adjustment Revenue (£m)	-16.8	-24.4	-21.2	
BG	Generator charging base (GW)	74.9	73.4	72.5	
AdjTariff	Generator adjusment tariff (£/kW)	-0.22	-0.33	-0.29	
Gross demand residual					
R_D	Demand residual tariff (£/kW)	53.14	53.77	57.50	
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-104.39	-106.27	-99.98	
EE	Amount to be paid to Embedded Export Tariffs (£m)	13.98	15.58	14.34	
B_D	Demand Gross charging base (GW)	49.83	50.61	50.47	

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 Draft Forecast on Tuesday 14th December. 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:

https://www.nationalgrideso.com/document/223556/download

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

nationalgridESO

Background to TNUoS charging

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

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

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

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

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

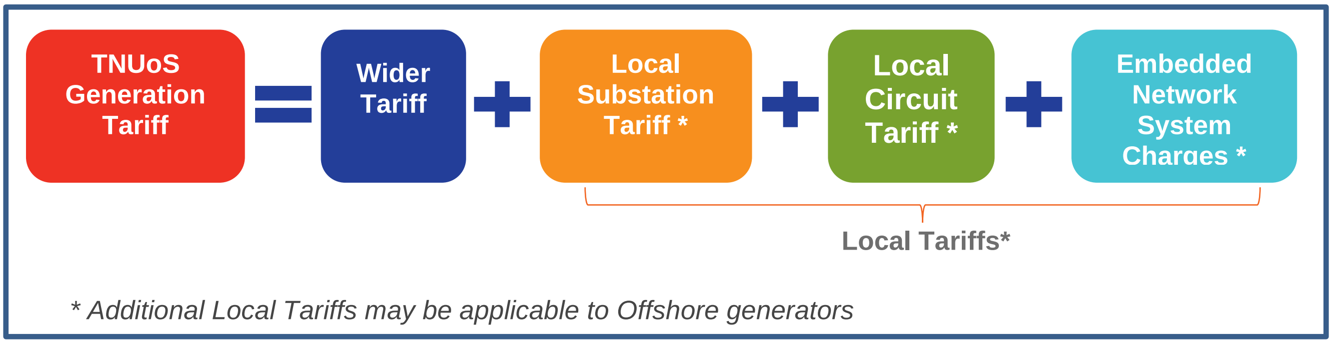
Generation charging principles

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

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

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

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



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

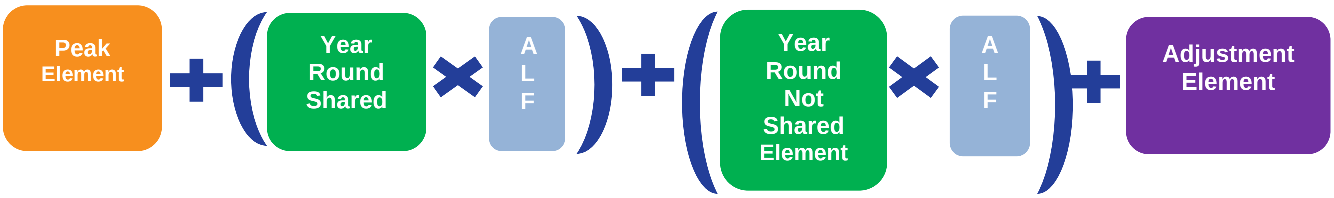
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

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

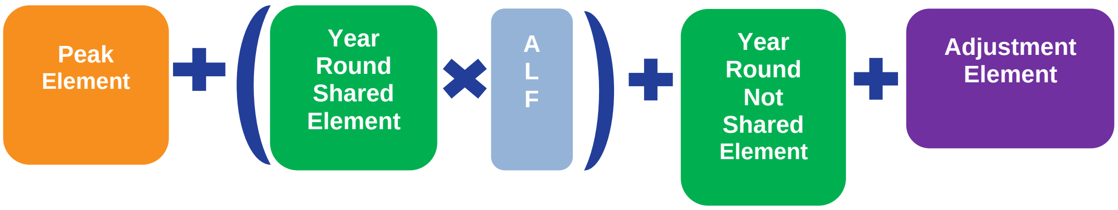
Conventional Carbon Generators

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



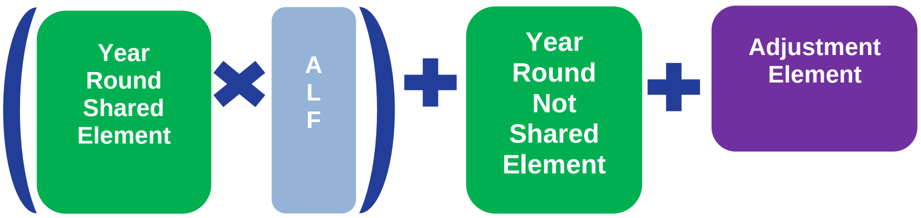
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

The **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 Commission Regulation (EU) 838/2010, which has been adopted in UK legislation. This requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. For this report, most 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, however, a small part of generation local charges are included from the gen cap calculation, as under the original proposal of CMP368/9.

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-T2 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[19] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[20] 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 an embedded OFTO may need to pay an Embedded Transmission Use of System charge through TNUoS tariffs to cover DNO charges that form part of the OFTO's tender revenue stream.

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.

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

[20] 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.[21] 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[22].

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[23].

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.

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

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

[23] 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.

Appendix B: Changes and proposed changes to the charging methodology

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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
CMP315/375	Expansion Constant & Expansion Factors review	Affect TNUoS locational tariffs for generators and demand users	to be confirmed
CMP316	TNUoS Arrangements for Co-located Generation Sites	Affect TNUoS locational tariffs	to be confirmed
CMP330/374	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 other 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 (EET), 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 August		2022/23 November		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.530283	-28.176298	-2.378353	-26.865706	0.151930	1.310592
2	Southern Scotland	-2.906114	-18.768032	-2.666540	-18.568727	0.239574	0.199304
3	Northern	-4.039251	-8.215961	-4.209072	-7.936630	-0.169822	0.279331
4	North West	-1.590788	-4.165804	-1.526881	-3.955356	0.063907	0.210448
5	Yorkshire	-3.023749	-2.251273	-3.069356	-1.950554	-0.045607	0.300719
6	N Wales & Mersey	-2.342178	-1.945630	-2.178954	-1.558879	0.163224	0.386750
7	East Midlands	-2.435861	1.142662	-2.747019	1.428389	-0.311158	0.285727
8	Midlands	-1.450358	1.717408	-1.364659	1.715097	0.085699	-0.002311
9	Eastern	1.389653	-0.095113	0.473848	0.632420	-0.915805	0.727534
10	South Wales	-3.403533	5.195753	-3.503913	5.121186	-0.100380	-0.074566
11	South East	3.762870	-0.117199	3.648368	-0.295570	-0.114502	-0.178371
12	London	5.672933	1.109813	4.511476	2.329373	-1.161457	1.219560
13	Southern	1.733821	3.616163	2.541405	2.876418	0.807584	-0.739745
14	South Western	-0.368576	7.050934	1.925710	4.976812	2.294286	-2.074122

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

Demand Zone		2022/23 August		2022/23 November		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-30.706581	2.319241	-29.244059	2.344515	1.462522	0.025274
2	Southern Scotland	-21.674146	2.319241	-21.235267	2.344515	0.438879	0.025274
3	Northern	-12.255211	2.319241	-12.145702	2.344515	0.109509	0.025274
4	North West	-5.756592	2.319241	-5.482237	2.344515	0.274355	0.025274
5	Yorkshire	-5.275023	2.319241	-5.019910	2.344515	0.255113	0.025274
6	N Wales & Mersey	-4.287808	2.319241	-3.737834	2.344515	0.549974	0.025274
7	East Midlands	-1.293199	2.319241	-1.318630	2.344515	-0.025431	0.025274
8	Midlands	0.267049	2.319241	0.350437	2.344515	0.083388	0.025274
9	Eastern	1.294540	2.319241	1.106268	2.344515	-0.188272	0.025274
10	South Wales	1.792220	2.319241	1.617274	2.344515	-0.174946	0.025274
11	South East	3.645671	2.319241	3.352798	2.344515	-0.292873	0.025274
12	London	6.782747	2.319241	6.840850	2.344515	0.058103	0.025274
13	Southern	5.349984	2.319241	5.417823	2.344515	0.067839	0.025274
14	South Western	6.682358	2.319241	6.902522	2.344515	0.220164	0.025274

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 draft version of the 2022/23 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2016/17 to 2020/21. Generators which commissioned after 1 April 2018 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 2022/23 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 have been updated with the recently released draft ALFs. These are available for industry consultation until Tuesday 14th December, after which they will become final. It is feasible that the ALFs may therefore change ahead of the January Final tariffs following this consultation period. The specific and generic draft ALFs for 2022/23 tariffs, as used in this forecast, are published here: https://www.nationalgrideso.com/document/221426/download

Generic ALFs

Table 23 Generic ALFs

Technology	Generic ALF
Gas_Oil	0.4627%
Pumped_Storage	9.0321%
Tidal	12.8000%
Biomass	43.1684%
Wave	2.9000%
Onshore_Wind	35.5062%
CCGT_CHP	51.3589%
Hydro	40.9203%
Offshore_Wind	48.2161%
Coal	14.0552%
Nuclear	70.2612%
Solar	10.9000%

*Note: ALF figures for Wave, Tidal and Solar 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

The data in Table 24 is taken from the TEC register from 31st October 2021.

The contracted TEC volumes are used to set locational tariffs; however, we model our best view of chargeable TEC which feeds into the Tariff model to set the generation adjustment tariff. We are unable to share our best view of chargeable TEC in this report, as they may be commercially sensitive.

The contracted generation used in the Transport model is now fixed 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
Moyle Interconnector	315	AUCH20	10
Axminster Tertiary	-50	AXMI40_SEP	26
Bolney	-50	BOLN40	25
Capenhurst 275KV Substation	50	CAPE20	16
Capenhurst Tertiary Connection (formerly Capenhurst Gas)	-50	CAPE20	16
Coopers Lane Kirkby	-50	KIBY20	15
Crookedstane Windfarm	-25	CLYS2R	11
Damhead Creek 2	-1,800	KINO40	24
Dun Law Ext Repower	30	DUNE10	11
Dunlaw Extension	-30	DUNE10	11
Iron Acton Tertiary Connection	-50	IROA20_WPDSW	21
Legacy Tertiary Connection (formerly Legacy Gas)	-50	WBUR40	16
Limekiln	-84	LIMK10	1
Monets Garden	50	OSBA40	15
Monk Fryston Tertiary Connection	-50	MONF20	15
Neilston 132kV	-17	NEIL10	11
Norwich	-50	NORM40	18
Ocker Hill Tertiary Connection	-50	OCKH20	18
Osbaldwick	-50	OSBA40	15
Sanquhar Wind Farm	-2	GLGL1Q	10
Shoreham	420	BOLN40	25
Sundon ENSO Green	-40	SUND40	18
Sundon Pivoted Power	-50	SUND40	18
Twentyshilling Wind Farm	-38	GLGL1Q	10
Weirs Drove	50	BURW40	18
Whitegate Tertiary Connection	-50	WHGA20	15

Appendix F: Transmission company revenues

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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 again in January 2022. In addition, there are some pass-through items that are to be collected by NGESO via TNUoS charges, including the Strategic Innovation Fund (SIF), 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 the Strategic Innovation Fund (SIF), and passes 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 August forecast, it can be observed that there is an additional £61m of pass-through revenue. This increase is due to the revision of forecasts of bad-debt as actual data becomes available, the inclusion of a forecast for RIIO-ET1 pass-through items. the impact of interest rate increases and the continued assessment of the adjustment factor (ADJ_t) as more actual data becomes available for the FY21 year.

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	0.58	
Network Innovation Competition Fund (NICFt)	30.89	30.89	0.00	
Strategic Innovation Fund (SIFt)	0.00	0.00	18.04	
The Adjustment Term (ADJt)	0.00	0.00	63.04	
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	552.85	557.23	568.05	
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00	
Financial facility (FINt)	0.00	0.00	0.00	
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.37	
Termination Sums (TSt)	0.00	0.00	0.00	
NGET revenue pas-through (NGETTOt)*	1,764.46	1,764.46	1,863.63	
SPT revenue pass-through (TSPt)	348.71	371.85	350.45	
SHETL revenue pass-through (TSHt)	632.65	632.61	652.85	
ESO Bad debt (BDt)	3.30	3.30	7.20	
ESO other pass-through items (LFt + ITCt etc)	32.56	32.56	42.53	
ESO legacy adjustment (LARt)	0.00	41.13	37.55	
Total	**3,366.00**	**3,434.62**	**3,604.29**	

A few items (including FINt and TSt) are set to zero in the November forecast cycle. FINt was introduced as a “bridging” financial facility, following the legal separation of ESO from NGET, and has been removed for RIIO-T2. TSt is based on the 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

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their revenue breakdown and will next update them in January 2022.The current forecasts include updates in correction term data, refreshed forecasts of interest rates and the addition of some RIIO-T1 items into pass-through. The data is liable to change as interest rate parameters are updated. It should also be noted that these forecasts were provided before the recent CMA determination which we anticipate may increase the allowed revenues. The allowed revenue figures will be finalised in the January submission by TOs, and will incorporate any potential upward and downward changes.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2022/23 is forecast to be £568.05m, a decrease of £5.6m from the August forecast. 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	309.79	309.79
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	1,634.08	1,669.51	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00	73.50	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	1,745.64	1,899.06	
SONIA	B1	It-1	n/a	0.05%	0.07%	
Allowed Revenue	B2	ARt-1	n/a	1,755.30	1,749.23	
Recovered Revenue	B4	RRt-1	n/a	1,755.30	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	-6.14	
Legacy pass-through	C1	LPt	n/a	0.00	3.78	
Legacy MOD	C2	LMODt	n/a	21.43	-32.65	
Legacy K correction	C3	LKt	n/a	0.00	0.00	
Legacy TRU term	C4	LTRUt	n/a	-2.60	-23.28	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	0.00	17.55	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions inc	C7	LSFIt	n/a	0.00	0.84	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	0.00	4.48	
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	0.00	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	-29.28	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	1,764.46	1,764.46	1,863.63	

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	309.79	309.79
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	345.77	328.98	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00	-8.10	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	369.38	351.63	
SONIA	B1	It-1	n/a	0.09%	0.07%	
Allowed Revenue	B2	ARt-1	n/a	371.85	376.93	
Recovered Revenue	B4	RRt-1	n/a	371.85	373.12	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00	3.86	
Legacy pass-through	C1	LPt	n/a	0.00	3.65	
Legacy MOD	C2	LMODt	n/a	2.48	-8.83	
Legacy K correction	C3	LKt	n/a	0.00	0.00	
Legacy TRU term	C4	LTRUt	n/a	0.00	-5.36	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	0.00	2.64	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions inc	C7	LSFIt	n/a	0.00	0.17	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	0.00	2.68	
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	0.00	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	-5.04	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	348.71	371.85	350.45	

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	309.79	309.79
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	540.60	544.75	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00	0.00	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	577.51	595.66	
SONIA	B1	It-1	n/a	0.05%	0.07%	
Allowed Revenue	B2	ARt-1	n/a	582.60	584.75	
Recovered Revenue	B4	RRt-1	n/a	582.60	582.90	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00	1.88	
Legacy pass-through	C1	LPt	n/a	30.30	30.00	
Legacy MOD	C2	LMODt	n/a	20.80	20.44	
Legacy K correction	C3	LKt	n/a	0.00	5.27	
Legacy TRU term	C4	LTRUt	n/a	-0.40	-3.69	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	1.60	1.60	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	1.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions inc	C7	LSFIt	n/a	0.00	-0.11	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	1.80	1.79	
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	0.00	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	55.31	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	632.65	632.61	652.85	

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	7.0	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.4	8.7	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	9.8	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	16.2	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	24.2	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.1	14.6	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.1	33.0	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.7	46.7	Current revenues plus indexation
Thanet	78.9	17.4	15.7	19.5	18.6	19.2	19.7	20.8	21.5	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.0	32.7	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	18.9	32.9	31.8	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	25.3	25.1	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	14.4	13.5	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.1	14.7	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	14.7	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	20.8	Current revenues plus indexation
Race Bank						66.0	26.7	27.4	28.9	Current revenues plus indexation
Galloper							16.1	17.1	17.8	Current revenues plus indexation
Walney 3							28.8	13.5	14.1	Current revenues plus indexation
Walney 4								13.5	14.1	Current revenues plus indexation
Hornsea 1A								137.1	18.5	Current revenues plus indexation
Hornsea 1B									18.5	Current revenues plus indexation
Hornsea 1C									18.5	Current revenues plus indexation
Beatrice									21.2	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2021/22									25.0	National Grid Forecast
Forecast to asset transfer to OFTO in 2022/23									40.7	National Grid Forecast
Offshore Transmission Pass-Through (B7)	218.4	248.3	260.8	265.5	318.0	390.6	387.0	549.0	568.0	

Notes:

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

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

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

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

Appendix G: Generation zones map

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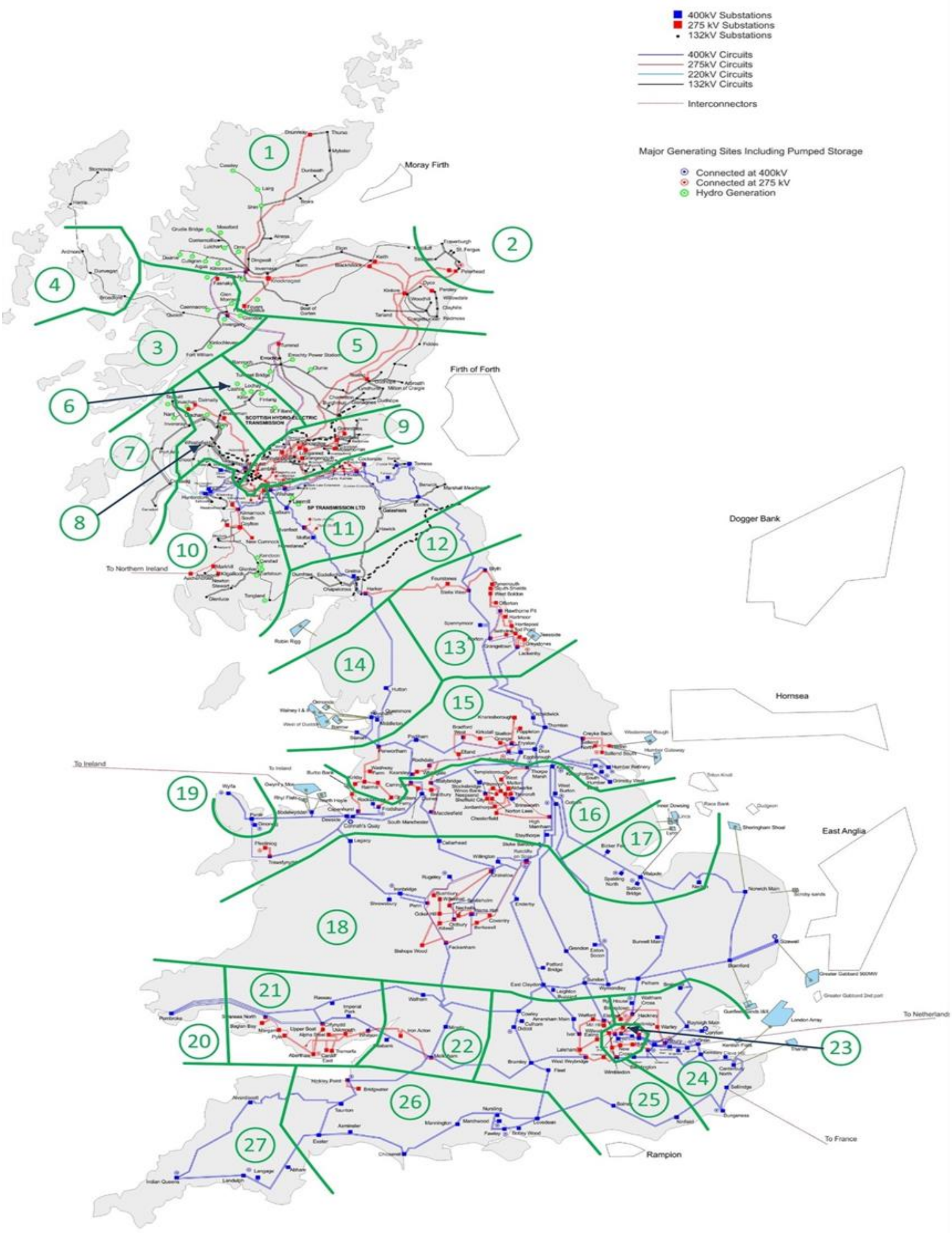
Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



Appendix H: Demand zones map

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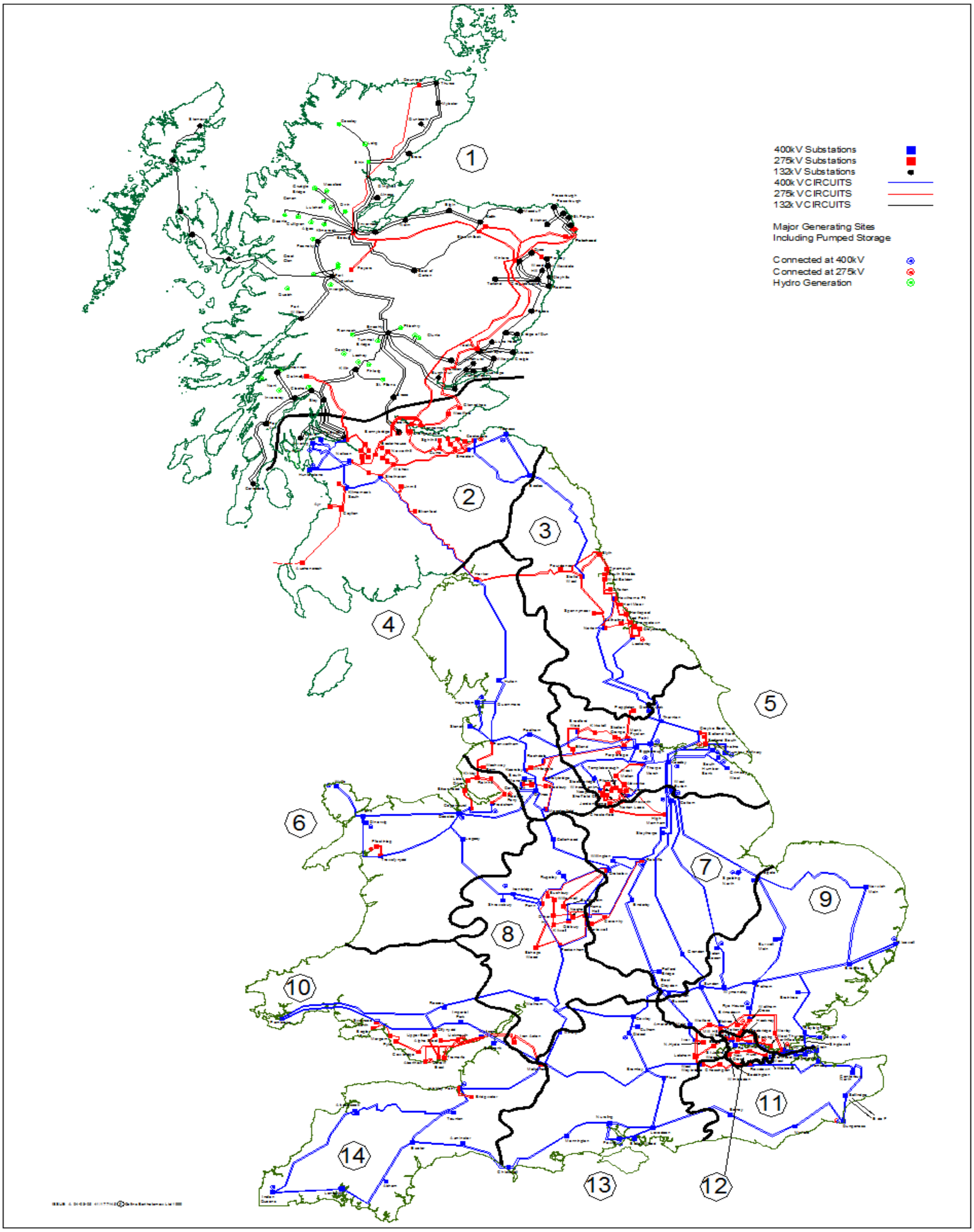

Appendix I: Changes to TNUoS parameters

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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