Version 1.1

Forecast of TNUoS Tariffs for 2024/25

Electricity System Operator

July 2023

ESO

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Executive summary

Transmission Network Use of System (TNUoS) charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the July forecast of TNUoS Tariffs for 2024/25.

Under the National Grid Electricity System Operator (ESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 2024/25 on our website[1].

This forecast is for charging year 2024/25 and has no impact on 2023/24.

Total revenues to be recovered

The total TNUoS revenue is forecast at £4.61bn for FY24/25, (an increase of £30.45m from 5YV). This increase is mainly due to revisions to OFTO revenue inflation and forecast OFTO Asset Transfer Dates and NGET Revenue (NGETTOt) (+£12.17m). The 2024/25 revenue forecast will be updated later this year and finalised by January Final Tariffs based on Onshore and Offshore TOs' submissions.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.04bn for 2024/25, an increase of £26.6m since the Initial forecast. This is mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base has been updated to 84.7GW based on our best view on generation projects for 2024/25. This is an increase of 6.7GW since the Initial forecast. The average generation tariff is £12.23/kW, a decrease of £0.71/kW due to the increase in the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £3,570.5m for 2024/25, a £3.9m increase since the Initial tariffs. The main driver is the increase in revenue to be collected in total through TNUoS. Of this total, £3,484.7m is forecast to be collected via the Transmission Demand Residual.

The impact on the end consumer is forecast to be £46.55 for FY24/25 (4.36% of the average annual electricity consumer bill), a decrease of £0.05 from the 2024/25 initial forecast. This is due to the reduction in the average NHH tariff since the initial forecast.

In 2024/25 it is forecast that £16.86m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), a reduction of £3.06m since the Initial forecast. This is due to the reduction in the forecast charging base for Embedded Export and a reduction in the average locational tariffs. The average EET is forecast at £2.46/kW, which is a reduction of £0.34/kW versus Initial forecast.

The average gross HH demand tariff for 2024/25 is to be £5.69/kW, a reduction of £0.69/kW and the average NHH demand tariff forecast is at 0.28p/kWh, a reduction of 0.02p/kWh since Initial forecast.

Next TNUoS tariff publication

The timetable of TNUoS tariffs forecasts for 2024/25 is available on our website[2].

Our next TNUoS tariff publication will be the Draft 2024/25 tariffs, which will be published in November 2023.

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

[2] https://www.nationalgrideso.com/document/275691/download

Feedback

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

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

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

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

Our contact details

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Charging Methodology Changes

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This Report

This report contains the quarterly forecast of TNUoS tariffs for the charging year 2024/25.

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

We understand that the TNUoS and other charging methodologies are expected to change substantially over the next few years. Because of this, we have prepared this forecast using our best view of charging parameters, the latest available information and modification workgroup progress. Additionally, whenever we can, we have provided a series of sensitivity scenarios to help customers to understand the potential implications of changes to a number of variables that impact the charging methodology.

This section summarises any key changes to the methodology.

Charging methodology changes

There are a number of 'in-flight' proposals to change the charging methodologies, which may impact TNUoS tariffs and charges. These are summarised in the CUSC modifications Table 23.

TNUoS Task Force and electricity network charging

In May 2022, Ofgem published an open letter[7] outlining their latest thinking on the scope of the work to be undertaken by a Task Force, and asked the Electricity System Operator to work with industry to establish membership. In the letter, Ofgem clarified that the Task Forces will look at improvements to today's methodology whilst keeping its core assumptions and modelling approach unchanged. They stated that this does not rule out significant changes to elements of TNUoS, for example, the transport model, changes to the 'backgrounds' against which charges are calculated, or the approach to the demand-weighted distributed reference node.

Any CUSC changes recommended by the Task Force, will need to go through the usual CUSC modification process; proposed changes will be considered in future forecast publications once draft conclusions and/or sufficient information is available to quantify any potential changes.

We do not foresee any changes taken forward by the Task Force being implemented in the 2024/25 tariffs.

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 2024/25 and how these tariffs were calculated.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2024/25 Initial	2024/25 July	Change since last forecast
Adjustment	- 1.296387	- 2.206937	- 0.910550
Average Generation Tariff*	12.937121	12.230886	- 0.706235

*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 Limiting Regulation, 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, followed by the implementation of CMP391, means that charges for the "Connection Exclusion" (i.e. assets built for generation connection) are not included in the €2.50/MWh cap. In addition, TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap.

Average generation tariffs have decreased by £0.71/kW, due to an increase of 6.7GW in the generation charging base which outweighs the £26.7m increase in the revenue to be collected from generation compared to the Initial forecast. The generation adjustment has decreased by £0.91/kW, increasing in magnitude, to become more negative; this is mainly due to the increased error margin and exchange rate, which effectively reduce the revenue that can be recovered from generation since the initial forecast.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2024/25. 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 D.

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		
Battery storage		
Reactive Compensation		

Each forecast, we publish example tariffs for a generator of each technology type using an example ALF. The example 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	Example tariffs for a generator of each technology type: 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	3.219552	21.322008	18.230109	-2.206937	16.833462	35.234230	25.618076
2	East Aberdeenshire	4.721646	12.939105	18.230109	-2.206937	14.982395	30.449147	21.845769
3	Western Highlands	3.331293	20.840996	17.898136	-2.206937	16.620009	34.653239	25.069647
4	Skye and Lochalsh	3.267604	20.840996	24.778831	-2.206937	19.308598	41.470245	31.950342
5	Eastern Grampian and Tayside	5.988888	16.450257	14.199591	-2.206937	16.041890	30.319235	19.395270
6	Central Grampian	5.277108	16.650666	14.462196	-2.206937	15.515316	30.020367	19.748059
7	Argyll	3.798959	14.727521	20.739395	-2.206937	15.778788	33.377058	25.159842
8	The Trossachs	4.198704	14.727521	11.907093	-2.206937	12.645613	24.944501	16.327540
9	Stirlingshire and Fife	2.743508	14.469017	11.705282	-2.206937	11.006291	23.093616	16.009403
10	South West Scotlands	3.011147	14.040371	11.462760	-2.206937	11.005462	22.797248	15.573990
11	Lothian and Borders	2.735814	14.040371	5.567416	-2.206937	8.371992	16.626571	9.678646
12	Solway and Cheviot	1.956944	9.438390	6.772677	-2.206937	6.234434	13.601477	8.813016
13	North East England	3.663753	6.887546	4.088213	-2.206937	5.847120	10.710689	4.980672
14	North Lancashire and The Lakes	1.524434	6.887546	1.585044	-2.206937	2.706533	6.068201	2.477503
15	South Lancashire, Yorkshire and Humber	4.670006	3.046797	0.411988	-2.206937	3.846583	5.160155	-0.423890
16	North Midlands and North Wales	3.313285	1.531352	-	-2.206937	1.718889	2.254862	-1.517829
17	South Lincolnshire and North Norfolk	2.102638	3.944718	-	-2.206937	1.473588	2.854240	-0.431814
18	Mid Wales and The Midlands	1.367020	4.667493	-	-2.206937	1.027080	2.660703	-0.106565
19	Anglesey and Snowdon	4.936157	1.593701	-	-2.206937	3.366700	3.924496	-1.489772
20	Pembrokeshire	6.669373	-8.109466	-	-2.206937	1.218650	-1.619664	-5.856197
21	South Wales & Gloucester	2.439835	-8.549820	-	-2.206937	-3.187030	-6.179467	-6.054356
22	Cotswold	1.591550	5.586944	-12.902096	-2.206937	-3.541448	-9.327275	-12.594908
23	Central London	-2.910649	5.586944	-3.506805	-2.206937	-4.285530	-4.434183	-3.199617
24	Essex and Kent	-2.737896	5.586944	-	-2.206937	-2.710055	-0.754625	0.307188
25	Oxfordshire, Surrey and Sussex	-0.662082	-1.128910	-	-2.206937	-3.320583	-3.715702	-2.714947
26	Somerset and Wessex	-3.628310	-4.367753	-	-2.206937	-7.582348	-9.111062	-4.172426
27	West Devon and Cornwall	-4.192614	-10.774651	-	-2.206937	-10.709411	-14.480539	-7.055530

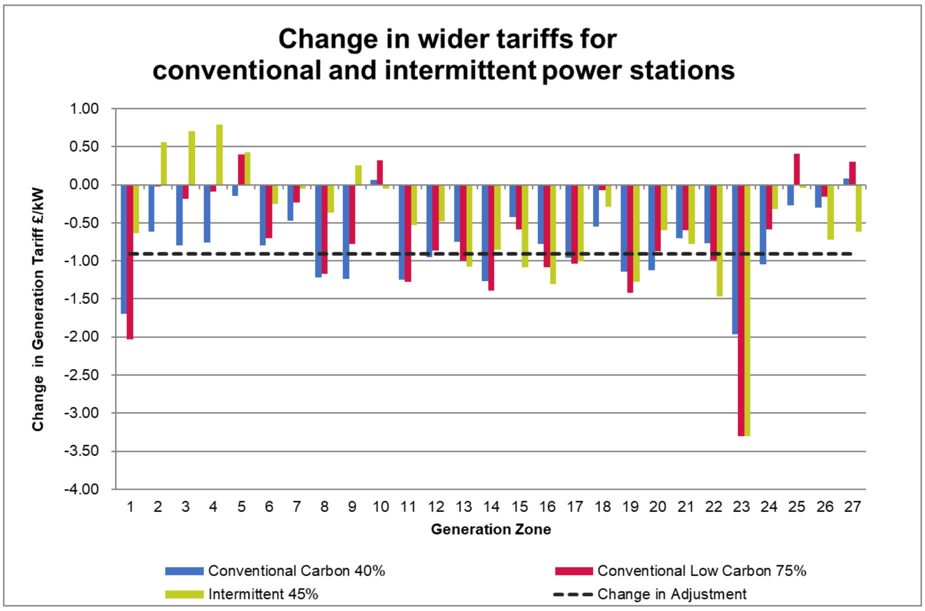
3. Changes to wider tariffs since the Initial Forecast

The following section provides details of the wider generation tariffs for 2024/25 and explains how these have changed since the Initial 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.

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
		2024/25 Initial	2024/25 July	Change	2024/25 Initial	2024/25 July	Change	2024/25 Initial	2024/25 July	Change	
1	North Scotland	18.533113	16.833462	- 1.699652	37.265855	35.234230	- 2.031625	26.249709	25.618076	- 0.631633	- 0.910550
2	East Aberdeenshire	15.596109	14.982395	- 0.613715	30.468027	30.449147	- 0.018880	21.285792	21.845769	0.559977	- 0.910550
3	Western Highlands	17.417265	16.620009	- 0.797256	34.835200	34.653239	- 0.181960	24.365661	25.069647	0.703986	- 0.910550
4	Skye and Lochalsh	20.072041	19.308598	- 0.763444	41.563855	41.470245	- 0.093609	31.155459	31.950342	0.794883	- 0.910550
5	Eastern Grampian and Tayside	16.187076	16.041890	- 0.145186	29.924976	30.319235	0.394259	18.970797	19.395270	0.424473	- 0.910550
6	Central Grampian	16.314862	15.515316	- 0.799546	30.724728	30.020367	- 0.704362	19.996743	19.748059	- 0.248684	- 0.910550
7	Argyll	16.253130	15.778788	- 0.474341	33.613732	33.377058	- 0.236674	25.213275	25.159842	- 0.053433	- 0.910550
8	The Trossachs	13.865036	12.645613	- 1.219423	26.114781	24.944501	- 1.170280	16.695180	16.327540	- 0.367640	- 0.910550
9	Stirlingshire and Fife	12.246079	11.006291	- 1.239788	23.872568	23.093616	- 0.778952	15.758982	16.009403	0.250421	- 0.910550
10	South West Scotlands	10.943221	11.005462	0.062242	22.478777	22.797248	0.318472	15.630064	15.573990	- 0.056074	- 0.910550
11	Lothian and Borders	9.620438	8.371992	- 1.248446	17.903037	16.626571	- 1.276465	10.208469	9.678646	- 0.529823	- 0.910550
12	Solway and Cheviot	7.188150	6.234434	- 0.953716	14.468391	13.601477	- 0.866914	9.292766	8.813016	- 0.479750	- 0.910550
13	North East England	6.594626	5.847120	- 0.747506	11.710989	10.710689	- 1.000300	6.060435	4.980672	- 1.079763	- 0.910550
14	North Lancashire and The Lakes	3.976850	2.706533	- 1.270317	7.456773	6.068201	- 1.388572	3.333034	2.477503	- 0.855531	- 0.910550
15	South Lancashire, Yorkshire and Humber	4.268919	3.846583	- 0.422336	5.746402	5.160155	- 0.586247	0.661399	- 0.423890	- 1.085289	- 0.910550
16	North Midlands and North Wales	2.496314	1.718889	- 0.777425	3.339217	2.254862	- 1.084355	- 0.212655	- 1.517829	- 1.305174	- 0.910550
17	South Lincolnshire and North Norfolk	2.433153	1.473588	- 0.959565	3.888798	2.854240	- 1.034559	0.575157	- 0.431814	- 1.006971	- 0.910550
18	Mid Wales and The Midlands	1.577698	1.027080	- 0.550618	2.728720	2.660703	- 0.068017	0.183498	- 0.106565	- 0.290063	- 0.910550
19	Anglesey and Snowdon	4.505781	3.366700	- 1.139081	5.344316	3.924496	- 1.419821	- 0.218270	- 1.489772	- 1.271501	- 0.910550
20	Pembrokeshire	2.337011	1.218650	- 1.118361	- 0.746314	- 1.619664	- 0.873350	- 5.260661	- 5.856197	- 0.595536	- 0.910550
21	South Wales & Gloucester	- 2.485229	- 3.187030	- 0.701801	- 5.582223	- 6.179467	- 0.597245	- 5.278236	- 6.054356	- 0.776120	- 0.910550
22	Cotswold	- 2.775416	- 3.541448	- 0.766031	- 8.334715	- 9.327275	- 0.992561	- 11.131043	- 12.594908	- 1.463866	- 0.910550
23	Central London	- 2.316557	- 4.285530	- 1.968974	- 1.133422	- 4.434183	- 3.300762	0.106347	- 3.199617	- 3.305964	- 0.910550
24	Essex and Kent	- 1.663759	- 2.710055	- 1.046296	- 0.169717	- 0.754625	- 0.584908	0.624524	0.307188	- 0.317336	- 0.910550
25	Oxfordshire, Surrey and Sussex	- 3.053662	- 3.320583	- 0.266921	- 4.128054	- 3.715702	0.412353	- 2.677748	- 2.714947	- 0.037198	- 0.910550
26	Somerset and Wessex	- 7.279723	- 7.582348	- 0.302626	- 8.955435	- 9.111062	- 0.155627	- 3.450874	- 4.172426	- 0.721552	- 0.910550
27	West Devon and Cornwall	- 10.787225	- 10.709411	0.077813	- 14.786452	- 14.480539	0.305913	- 6.438251	- 7.055530	- 0.617279	- 0.910550

Figure 1 Variation in generation wider zonal tariffs



Locational changes

The generation tariffs have changed since the Initial tariffs, mainly due to revised view on the likely October contractual TEC (which will be used to set the locational elements in the final tariffs), and the decrease in the adjustment tariff (which has increased in magnitude to become more negative).

This means that there have been changes in the overall tariffs across each generation zone. Using the example ALFs[3], many zones have seen a decrease in tariffs for all technology types.

The decrease which can be seen in generation zone 23 (Central London) is due to a correction to an existing node, which had previously been mapped to another generation zone. Although the amount of generation associated with the node is fairly small (<50MW), it is one of only two relevant nodes that set the zone 23 tariff, consequently the tariff has changed significantly.

Adjustment tariff changes

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 has decreased by £0.91/kW since the Initial forecast, increasing in magnitude, to become more negative. This is mainly due to the increased error margin and exchange rate, which effectively reduce the revenue that can be recovered from generation. These changes cause the adjustment to go more negative as there is more adjustment required to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see Table 22.

Onshore local tariffs for generation

4. Onshore local substation tariffs

Onshore local substation tariffs reflect the cost of the first transmission substation that each transmission connected generator connects to. They are recalculated in preparation for the start of 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.

The CPIH figure used in the calculation of local substation tariffs has been updated and will be finalised once the October index is known.

Table 4 Local substation tariffs

2024/25 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.173781	0.086894	0.059936
<1320 MW	Redundancy	0.366176	0.185986	0.132061
>=1320 MW	No redundancy	-	0.255293	0.181762
>=1320 MW	Redundancy	-	0.384173	0.276314

[3] *The above examples can be misleading and are only to be used as a guide, as changes to ALFs can cause tariff variances to increase/decrease/reverses and the magnitude of this can fluctuate across zones and technology type.*

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, the 2024/25 onshore local circuit tariffs have been updated, and will be finalised by January 2024. The updated tariffs are listed below in Table 5.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	0.920651	Dorenell	2.477999	Langage	- 0.400744
Aberdeen Bay	3.240691	Douglas North	0.736521	Limekilns	2.147241
Achruach	- 3.003677	Dumnaglass	1.052611	Lochay	0.368260
Aigas	0.818714	Dunhill	1.734599	Luichart	0.685082
An Suidhe	- 1.119003	Dunlaw Extension	1.695154	Marchwood	- 0.284535
Arecleoch	2.909317	Edinbane	8.287128	Mark Hill	1.068016
Arecleoch extension	3.104255	Enoch Hill	1.609721	Middle Muir	2.761953
ayrshire grid collector	0.163657	Ewe Hill	1.685815	Middleton	0.181531
Beinneun Wind Farm	1.632870	Fallago	- 0.069755	Millennium South	0.527493
Benbrack	0.881779	Farr	4.209916	Millennium Wind	1.897721
Bhlaraidh Wind Farm	0.737544	Fernoch	5.188844	Mossford	3.628226
Black Hill	1.858499	Ffestiniogg	0.263159	Nant	2.979294
Black Law	2.025432	Fife Grid Services	0.183735	Necton	0.512274
BlackCraig Wind Farm	6.281972	Finlarig	0.368260	Rhigos	0.126247
BlackLaw Extension	4.405844	Foyers	0.338347	Rocksavage	- 0.017774
Broken Cross	1.208088	Galawhistle	1.264361	Saltend	- 0.018778
Chirmorie	2.672456	Glen Kyllachy	0.552391	Sandy Knowe	3.896463
Clyde (North)	0.128162	Glendoe	2.221284	Sanquhar II	8.375285
Clyde (South)	0.149522	Glenglass	5.542176	Shepherds rig	0.088408
Corriegarth	2.946083	Gordonbush	- 0.076162	South Humber Bank	- 0.214639
Corriemoillie	1.924171	Griffin Wind	11.474942	Spalding	0.326254
Coryton	0.053136	Hadyard Hill	3.314343	Stranoch	3.703585
CREAG RIABHACH	4.050864	Harestanes	2.761953	Strathbrora	- 0.193452
Cruachan	2.156274	Hartlepool	0.040147	Strathy Wind	1.946668
Culligran	2.092998	Invergarry	0.368260	Stronelairg	1.295183
Cumberhead Collector	0.842907	Kennoxhead	4.924064	Wester Dod	0.421454
Cumberhead West	4.466976	Kergord	58.788142	Whitelee	0.128162
Deanie	3.438497	Kilgallioch	1.281619	Whitelee Extension	0.363125
Dersalloch	2.714502	Kilmorack	0.149500		
Dinorwig	2.854276	Kype Muir	1.791178		

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 applied to 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 Cable	7.4km OHL	Bhlaraidh
Enoch Hill 132kV	New Cumnock 132kV	4.4km Cable	4.4km OHL	Enoch Hill
Glen Glass 132kV	Sandy Knowe132kV	4km Cable	4km OHL	Sandy Knowe
Coalburn 132kV	Cumberhead Collector 132kV	8.01km Cable	8.01km OHL	Dalquhandy
Cumberhead Collector 132k	Galawhistle 132kV	3.69km Cable	3.69km OHL	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 Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km Cable	9.5km of OHL	Aberdeen Bay
East Kilbride South 275kV	Whitelee 275kV	6km Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km 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
Arecleoch 132kV	Arecleoch Tee 132kV	2.5km Cable	2.5km OHL	Arecleoch
Wishaw 132kV	Blacklaw 132kV	11.46km 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 the April, the forecast has been updated with the latest inflation indices.

Offshore local generation tariffs associated with projects due to transfer in 2023/24 or 2024/25 will be confirmed once asset transfer has taken place and tariffs have been set.

Table 7 Offshore local tariffs 2024/25

Offshore Generator	2024/25 Initial Tariff Component (£/kW)			2024/25 July Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.134985	58.825554	1.460719	11.247564	59.420300	1.475487	0.112579	0.594746	0.014768
Beatrice	9.010706	24.705826	-	9.099927	24.950455	-	0.089221	0.244629	-
Burbo Bank	13.995676	27.049353	-	14.134257	27.317187	-	0.138581	0.267834	-
Dudgeon	20.470887	32.119137	-	20.673584	32.437170	-	0.202697	0.318033	-
East Anglia 1	12.117844	51.140519	-	12.237831	51.646896	-	0.119987	0.506377	-
Galloper	20.954722	33.142047	-	21.162209	33.470209	-	0.207487	0.328162	-
Greater Gabbard	20.746588	48.009690	-	20.956342	48.495084	-	0.209754	0.485394	-
Gunfleet	24.232095	22.346339	4.176659	24.477090	22.572268	4.218886	0.244995	0.225929	0.042227
Gwynt y mor	26.282176	25.984717	-	26.542414	26.242009	-	0.260238	0.257292	-
Hornsea 1A	9.354532	33.097796	-	9.447158	33.425519	-	0.092626	0.327723	-
Hornsea 1B	9.354532	33.097796	-	9.447158	33.425519	-	0.092626	0.327723	-
Hornsea 1C	9.354532	33.097796	-	9.447158	33.425519	-	0.092626	0.327723	-
Humber Gateway	15.467207	35.487094	-	15.620359	35.838476	-	0.153152	0.351382	-
Lincs	21.472178	84.442733	-	21.684789	85.278858	-	0.212611	0.836125	-
London Array	14.571479	49.960015	-	14.715761	50.454704	-	0.144282	0.494689	-
Ormonde	34.235246	63.993096	0.509971	34.581376	64.640088	0.515127	0.346130	0.646992	0.005156
Race Bank	12.396606	34.431070	-	12.519354	34.771995	-	0.122748	0.340925	-
Rampion	10.126833	26.491366	-	10.227106	26.753675	-	0.100273	0.262309	-
Robin Rigg	- 0.751420	42.652171	13.665484	- 0.759017	43.083399	13.803647	- 0.007597	0.431228	0.138163
Robin Rigg West	- 0.751420	42.652171	13.665484	- 0.759017	43.083399	13.803647	- 0.007597	0.431228	0.138163
Sheringham Shoal	32.029732	37.723242	0.819992	32.353563	38.104636	0.828283	0.323831	0.381394	0.008291
Thanet	24.458725	45.823477	1.103133	24.706011	46.286767	1.114286	0.247286	0.463290	0.011153
Walney 1	29.568906	59.115760	-	29.867857	59.713440	-	0.298951	0.597680	-
Walney 2	27.509530	55.984634	-	27.787660	56.550657	-	0.278130	0.566023	-
Walney 3	12.733863	25.798043	-	12.859949	26.053487	-	0.126086	0.255444	-
Walney 4	12.733863	25.798043	-	12.859949	26.053487	-	0.126086	0.255444	-
West of Duddon Sands	11.388199	56.768683	-	11.500962	57.330789	-	0.112763	0.562106	-
Westermost Rough	23.155996	39.408562	-	23.385279	39.798773	-	0.229283	0.390211	-

Demand Tariffs

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

ESO

7. Demand tariffs summary

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

The demand residual banded charges will now make up majority of the TNUoS demand charge in the form of a set of daily charge per site across the banding categories and thresholds.

Table 8 Summary of demand tariffs

Non-locational Banded Tariffs	2024/25 Initial	2024/25 July	Change
Average (£/site/annum)	108.416621	108.871088	0.454467
Unmetered (p/kWh/annum)	1.281006	1.283777	0.002771
Demand Residual (£m)	3,470.1	3,484.7	14.5

HH Tariffs (Locational)	2024/25 Initial	2024/25 July	Change
Average Tariff (£/kW)	6.380539	5.689196	- 0.691344

EET	2024/25 Initial	2024/25 July	Change
Average Tariff (£/kW)	2.803593	2.458701	- 0.344892
AGIC (£/kW)	2.679246	2.702342	0.023096
Embedded Export Volume (GW)	7.109080	6.857899	- 0.251181
Total Credit (£m)	19.930967	16.861525	- 3.069441

NHH Tariffs (locational)	2024/25 Initial	2024/25 July	Change
Average (p/kWh)	0.304654	0.280371	- 0.024282

Since the publication of the Initial forecast, both the average HH & NHH demand tariffs have seen a decrease. the main driver being the decrease in the total amount of revenue to be recovered through TNUoS locational element of demand tariffs. The current July tariffs for 2024/25 indicate that 77.5% of total revenue is to be recovered through demand, a decrease of 0.4% since Initial forecast, with overall demand revenue set at £3,570.5m (an increase of £3.9m from Initial tariffs).

The average HH gross tariff is set at £5.69/kW, a decrease of £0.69/kW compared to Initial forecast. The average NHH tariff is forecast at 0.28p/kWh, a decrease of 0.02p/kWh.

Embedded Export Volume 6.86GW is a decrease of 0.25GW compared to Initial forecast. The total credit paid out to embedded generators (<100MW) is currently forecast at £16.86m, a reduction of £3.07m. This is driven by a reduction in export volumes for the Zones whose tariffs are not floored. The average EET is now forecast at £2.46/kW a reduction of £0.34/kW compared to the Initial forecast.

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	1.272676
8	Midlands	2.090372	0.270342	4.792714
9	Eastern	-	-	2.077003
10	South Wales	6.075306	0.713381	8.777648
11	South East	2.520346	0.345266	5.222688
12	London	3.028687	0.318591	5.731029
13	Southern	6.127129	0.794154	8.829471
14	South Western	12.883741	1.793581	15.586083

8. Demand Residual Banding Tariffs

We have used the agreed distribution connected bandings and unmetered demand for the demand residual tariffs. A breakdown of the banding thresholds, consumptions, consumption proportions and site count for the demand residual banded charges can be seen in Table TB.

Below in Table 10 are the forecast demand residual banded tariffs across each of the banding criteria. These tariffs will apply to HH and NHH demand as well the locational HH and NHH tariffs (where applicable).

Table 10 Non-Locational demand residual banded charges

Band		2024/25 Initial	2024/25 July	Change
Domestic	Tariff - £/Site/Day	0.122804	0.123070	0.000266
LV_NoMIC_1		0.062712	0.062848	0.000136
LV_NoMIC_2		0.285396	0.286013	0.000617
LV_NoMIC_3		0.680577	0.682049	0.001472
LV_NoMIC_4		2.113158	2.117729	0.004571
LV1		3.413915	3.421300	0.007385
LV2		6.267853	6.281411	0.013558
LV3		10.200939	10.223005	0.022066
LV4		22.978865	23.028571	0.049706
HV1		17.780681	17.819143	0.038462
HV2		57.233281	57.357083	0.123802
HV3		112.375399	112.618479	0.243080
HV4		285.210732	285.827674	0.616942
EHV1		134.582173	134.873289	0.291116
EHV2		661.728347	663.159738	1.431391
EHV3		1334.256581	1337.142725	2.886144
EHV4		3633.571743	3641.431558	7.859815
T-Demand1		346.713214	503.117244	156.404030
T-Demand2		1431.991398	1851.779425	419.788027
T-Demand3		3990.924147	4572.834315	581.910168
T-Demand4		10429.434588	10332.780846	-96.653742
Unmetered demand		**p/kWh**	**p/kWh**	
Unmetered		1.281006	1.283777	0.002771
Demand Residual (£m)		**3470.11**	**3484.66**	**14.55**

The above tariffs are calculated based on the approved published distribution banding thresholds (LV No MIC through to EHV) for RIIO-2, there are 4 transmission connected bands. The thresholds for the T-connected bands are based on average transmission connected consumption data from 2021/22 to 2022/23 and the sites connected over that time. The transmission thresholds will remain the same for the duration of the price control period. The consumption, consumption proportions and site counts used in the calculation of the above tariffs and are based on the out-turn data from 2021/22 provided by the DNO/IDNO's latest submission in October/November 2022. We will be provided with the out-turn data for 2022/23 by the DNO/IDNO's in October 2023. The transmission connected out-turn demand data for 2022/23 which the ESO produces will also be made available at the same time. These updated values will be included in the Draft forecast and Final tariffs for 2024/25. We currently have no mechanism for forecasting future consumption and site counts across demand residual bands, therefore the only impact on the annual variance in tariffs is the change in the revenue to be recovered through demand residual, which can be seen at the bottom of the above table.

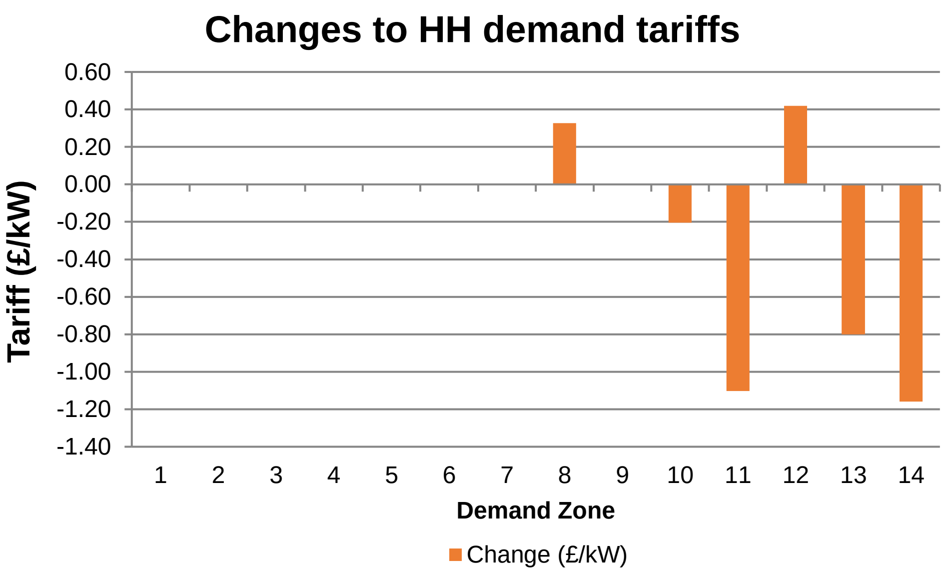
9. Half-Hourly demand tariffs

The table below shows the forecast of gross HH demand tariffs for 2024/25 compared to the Initial forecast.

Table 11 Half-Hourly demand tariffs

Zone	Zone Name	2024/25 Initial (£/kW)	2024/25 July (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	-
8	Midlands	1.763180	2.090372	0.327192
9	Eastern	-	-	-
10	South Wales	6.278841	6.075306	- 0.203535
11	South East	3.623300	2.520346	- 1.102954
12	London	2.609311	3.028687	0.419376
13	Southern	6.926894	6.127129	- 0.799765
14	South Western	14.042811	12.883741	- 1.159070

Figure 2 Changes to gross Half-Hourly demand tariffs



The HH tariffs have decreased in 4 of the 6 regions since the Initial forecast. Both the peak security transport zonal tariff and year-round transport zonal tariffs being lower since the Initial forecast have impacted the reduction in HH zonal tariffs.

The forecast level of gross HH chargeable demand has reduced by 0.23GW in comparison with the Initial forecast and is currently forecast at 17.93GW.

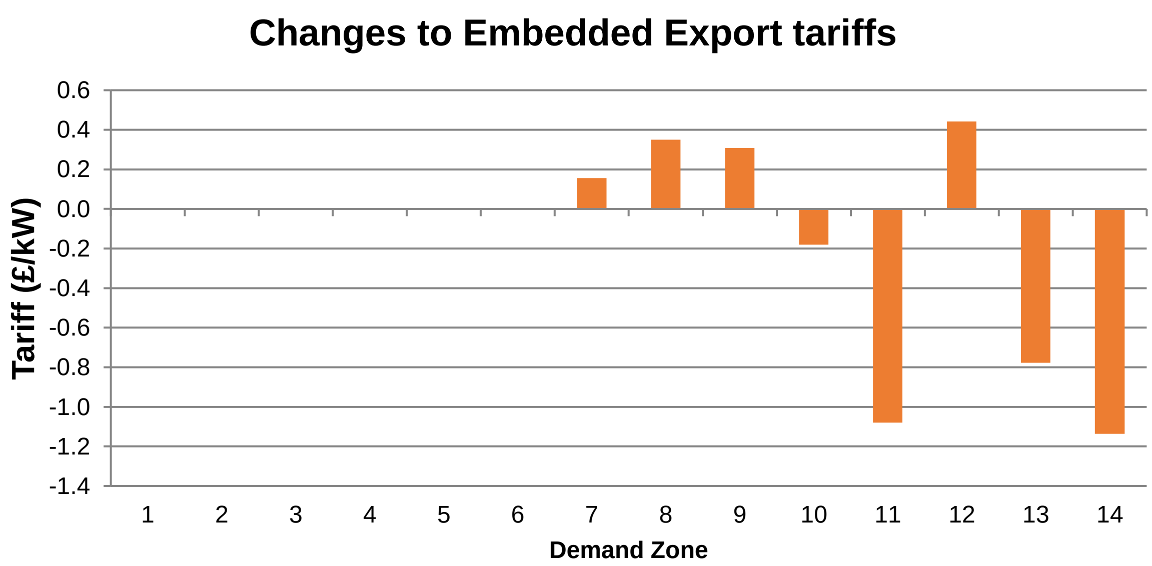
10. Embedded Export Tariffs (EET)

The next table shows the difference between the Initial and July forecast.

Table 12 Embedded Export Tariffs

Zone	Zone Name	2024/25 Initial (£/kW)	2024/25 July (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	1.116608	1.272676	0.156068
8	Midlands	4.442426	4.792714	0.350288
9	Eastern	1.769153	2.077003	0.307850
10	South Wales	8.958087	8.777648	- 0.180439
11	South East	6.302546	5.222688	- 1.079858
12	London	5.288557	5.731029	0.442472
13	Southern	9.606140	8.829471	- 0.776669
14	South Western	16.722057	15.586083	- 1.135974

Figure 3 Embedded export tariff changes



There has been a reduction in EET tariffs in 4 regions (10,11,13 & 14) and an increase in 4 regions (7,8,9 & 12).

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

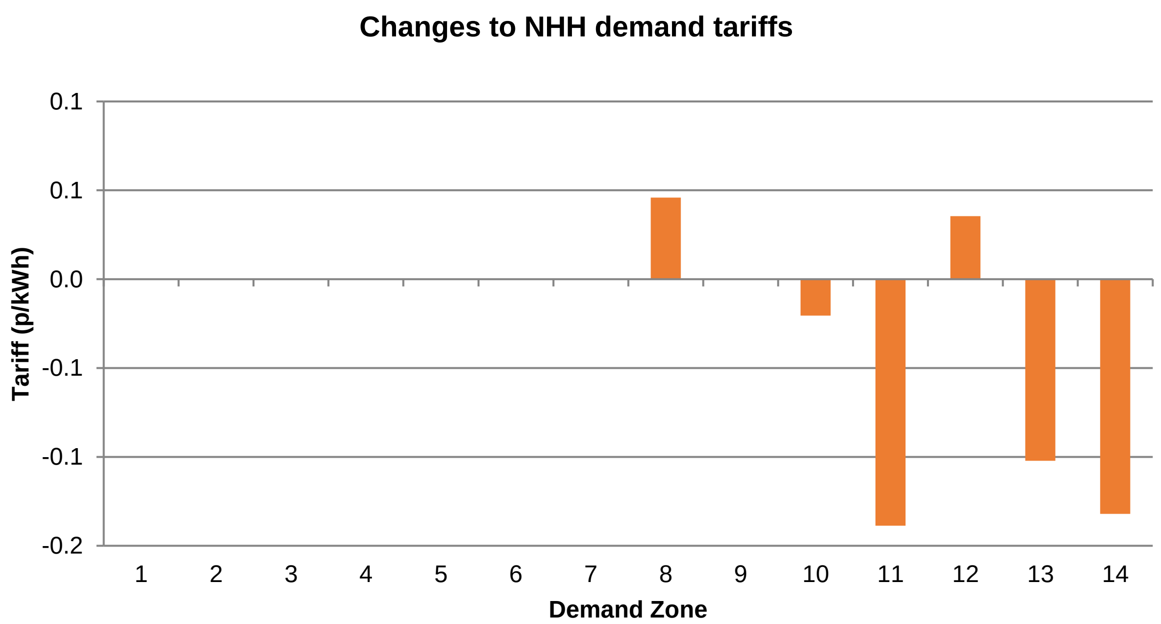
11. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2024/25 Initial forecast compared to the July forecast.

Table 13 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2024/25 Initial (p/kWh)	2024/25 July (p/kWh)	Change (p/kWh)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	-
8	Midlands	0.224463	0.270342	0.045879
9	Eastern	-	-	-
10	South Wales	0.733922	0.713381	- 0.020541
11	South East	0.484006	0.345266	- 0.138740
12	London	0.283072	0.318591	0.035519
13	Southern	0.896341	0.794154	- 0.102187
14	South Western	1.925577	1.793581	- 0.131996

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2024/25 July forecast is set at 0.28p/kWh, a 0.02p/kWh decrease compared to Initial forecast. The fluctuations to NHH tariffs since Initial forecast have been the decrease in changes to Demand Charging Base.

Overview of data inputs

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

12. Inputs affecting the locational element of tariffs

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

- Expected contracted generation (until October 2023 when it will be based on contracted TEC);
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor
- Expansion constant

Contracted, Modelled and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2024/25 period, which can be found on the TEC register.[4] The contracted TEC volumes are based on the 14th June 2023 TEC register.

Modelled Best View 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 July forecasts, we have forecast our best view of modelled TEC. However, for our November Draft tariffs and January Final tariffs we will use the contracted TEC position as published in TEC register as of 31st October 2023, 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 2024/25 and liable to pay generation TNUoS charges.

Table 14 Contracted, Modelled & Chargeable TEC

	2024/25 Tariffs			
Generation (GW)	Initial	July	Draft	Final
Contracted TEC	104.55	102.94		
Modelled Best View TEC	89.63	99.92	*For input to locational tariffs post 31st October please see Contracted TEC*	
Chargeable TEC	78.00	84.69		

13. 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 2024/25 onwards as stated in the interconnector register as of 14th June 2023.

[4] See the Registers, Reports and Updates section at https://www.nationalgrideso.com/industry-information/connections/reports-and-registers

Table 15 Interconnectors

Interconnector	Node	Interconnected System	Generation MW			
			Generation Zone	Transport Model Peak	Transport Model Year Round	Charging Base
Britned	Grain 400kV Substation	Netherlands	24	0	1,200	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
ElecLink	Sellindge 400kV Substation	France	24	0	1,000	0
EuroLink	Friston 400kV Substation	Netherlands	18	0	1,600	0
Greenlink	Pembroke 400kV Substation	Republic of Ireland	20	0	504	0
Gridlink	Kingsnorth 400kV Substation	France	24	0	1,500	0
IFA Interconnector	Sellindge 400kV Substation	France	24	0	2,000	0
IFA2 Interconnector	Chilling 400kV Substation	France	26	0	1,100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	500	0
Nemo Link	Richborough 400kV Substatio	Belgium	24	0	1,020	0
NeuConnect	Grain West 400kV Substation	Germany	24	0	1,400	0
NS Link	Blyth GSP	Norway	13	0	1,400	0
Viking Link	Bicker Fen 400kV Substation	Denmark	17	5	1,500	0

14. Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. The 2024/25 Expansion Constant is forecast to be £17.822781/MWkm. 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. A review of the EC methodology and the expansion factors is ongoing with the industry (CMP315/375), any impact will be included in our forecast publications once the modification has concluded.

15. Locational onshore security factor

The locational onshore security factor (also called the global security factor), set at 1.76 for the duration of RIIO-2, is applied to locational tariffs. This parameter approximately represents the redundant network capacity to secure energy flows under network contingencies. A guide to the onshore security factor calculation is published on our website https://www.nationalgrideso.com/document/183406/download

16. Onshore substation tariffs

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 publication, onshore substation tariffs are based on the values set for RIIO-2, inflated by CPIH.

17. Offshore local tariffs

Local offshore circuit tariffs, local offshore substation tariffs and the ETUoS tariff are indexed in line with the revenue of the relevant OFTO. These tariffs were recalculated for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting.

For this publication, offshore local tariffs are based on the values set for RIIO-2, inflated in line with the relevant OFTO's revenue.

18. Allowed revenues

The majority of the TNUoS charges look 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 and interconnector revenue recovery or redistribution.

For onshore TOs, the allowed revenues are subject to Ofgem's price control (RIIO-T2 period spans across 2021/22 – 2025/26), and parameters including project spending profiles, rate of return and inflation index are set at the beginning of each price control period. Onshore TOs' allowed revenue figures are published annually on Ofgem's website after the Annual Iteration Process (AIP).

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

The TOs will provide the ESO with their revenue forecast under the agreed timeline as specified in the STC (SO-TO Code). The 2024/25 revenue forecast will be updated later this year and finalised by January Final Tariffs based on Onshore and Offshore TOs' submissions.

Table 16 Allowed revenues

	2024/25 TNUoS Revenue			
£m Nominal	Initial Forecast	July Forecast	November Draft	January Final
TO Income from TNUoS				
National Grid Electricity Transmission	2,223.1	2,235.3	-	-
Scottish Power Transmission	500.9	503.6	-	-
SHE Transmission	979.8	984.9	-	-
Total TO Income from TNUoS	**3,703.8**	**3,723.8**	**-**	**-**
Other Income from TNUoS				
Other Pass-through from TNUoS	107.3	96.7	-	-
Offshore (plus interconnector contribution / allowance)	764.8	785.9	-	-
Total Other Income from TNUoS	**872.1**	**882.5**	**-**	**-**
Total to Collect from TNUoS	**4,575.9**	**4,606.3**	**-**	**-**

Please note these figures are rounded to one decimal place.

19. Generation / Demand (G/D) Split

The G/D split forecast is shown in Table 17.

CMP391 (definition of the term "Charges for Physical Assets Required for Connection") is incorporated in the July forecast. Majority of TNUoS local charges (including onshore and offshore local charges) fall into the definition of Charges for Physical Assets Required for Connection (PARC), however, a small part of the TNUoS onshore local charges (about £3.1m in the Initial forecast) are categorised as charges associated with pre-existing assets, and are therefore not PARC. There has been a small change of +£4.4m of local charge associated with pre-existing assets, due to progress made to update the pre-existing asset database, and inflation on the expansion constant.

In line with the Limiting Regulation, average TNUoS generation charge (excluding local charges associated with PARC) should be kept within the range of €0 – 2.50/MWh. We have therefore calculated the expected local charges associated with pre-existing assets and have included this amount when considering the expected average TNUoS generation charges.

Table 17 Generation and demand revenue proportions

		2024/25 Tariffs			
Code	Revenue	Initial Forecast	July Forecast	November Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50		
y	Error Margin	23.6%	31.4%		
ER	Exchange Rate (€/£)	1.12	1.12		
MAR	Total Revenue (£m)	4,575.9	4,606.3		
GO	Generation Output (TWh)	189.9	204.0		
G	% of revenue from generation	22.06%	22.49%		
D	% of revenue from demand	77.94%	77.51%		
G.R	Revenue recovered from generation (£m)	1,009.3	1,035.8		
D.R	Revenue recovered from demand (£m)	3,566.6	3,570.5		
Breakdown of generation revenue					
	Revenue from the Peak element	103.0	111.1		
	Revenue from the Year Round Shared element	187.0	180.0		
	Revenue from the Year Round Not Shared element	132.6	201.4		
	Revenue from Onshore Local Circuit tariffs	19.6	45.0		
	Revenue from Onshore Local Substation tariffs	12.0	12.5		
	Revenue from Offshore Local tariffs	656.1	672.8		
	Revenue from the adjustment element	-101.1	-186.9		
G.MAR	Total Revenue recovered from generation (£m)	1,009.3	1,035.8		
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	7.5		

*Not applicable for this publication

The "gen cap"

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges to €0 - 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 "gen cap" which is part of the UK law (the "Limiting Regulation"). In this report, the term "gen cap" is used to refer to the "upper limit of the Limiting Regulation" in the CUSC.

TNUoS generation residual (TGR) change

CUSC modification proposals CMP317/327 were approved in December 2020 and were included in the 2021/22 final tariffs. When approving CMP317/327, Ofgem also directed the ESO to raise a CUSC mod, to update CUSC for the purpose of maintaining compliance with the Limiting Regulation (the [0 ~ €2.50]/MWh range). Following CMA's Order[5] on 20 May 2022, we have incorporated CMP391 in the calculation of generation revenue (inclusion of local charges associated with pre-existing assets, in the gen cap compliance calculation).

[5] https://assets.publishing.service.gov.uk/media/6286586a8fa8f556203eb44d/Order_SSE_.pdf

Exchange Rate

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. The figure has been finalised, as per OBR's March EFO, at €1.193850/£.

Generation Output

The forecast output of generation is 204TWh. This figure is the average of the four scenarios (plus the central case) in the 2023 Future Energy Scenarios and the value is finalised for 2024/25 tariffs.

Error Margin

The error margin has been updated in this forecast, following publication of the outturn of 2022/23 data. The error margin is derived from historical data in the past five whole years (thus for year 2024/25 July forecast, we use data from years 2018/19 – 2022/23).

Table 18 Generation revenue error margin calculation

Calculation for	2024/25		
	Revenue inputs		Generation output variance
Data from year:	Revenue variance	Adjusted variance	
2018/19	-9.2%	-4.5%	-7.5%
2019/20	-14.6%	-10.0%	-4.1%
2020/21	-13.2%	-8.5%	7.5%
2021/22	4.3%	8.9%	9.5%
2022/23	9.5%	14.2%	13.1%
Systemic error:	-4.6%		
Adjusted error:		14.2%	13.1%
Error margin =			31.4%

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

Onshore local charges associated with Pre-existing assets

Following implementation of CMP391 (Charges for Physical Assets Required for Connection), we have published two sets of pre-existing tariffs. These are TNUoS local tariffs associated with pre-existing circuits and pre-existing substation bays respectively.

Onshore local circuit tariff reflects the impact of the generator on its local network (before reaching the MITS – Main Interconnected Transmission System). If some of the circuits in the local network already existed prior to the generator coming along and applying for connection to the transmission network, and the TO did not identify any need to reinforce these circuits in order to provide adequate capacity for this generator, these circuits are deemed "pre-existing", and the local circuit tariff elements that are associated with these pre-existing assets, are not charges associated with PARC.

Table 19 lists out the onshore local circuit tariff elements associated with pre-existing assets. Individual users who pay onshore local circuit tariffs are not affected by CMP391, as the tariffs in Table 19 are only used for the purpose of calculating the gen cap.

Table 19 Onshore local circuit tariff elements associated with pre-existing assets

Project Name	Pre-existing local circuit tariff (£/kW)	Aggregated pre-existing TEC (MW)
A'Chruach Wind Farm	0.000000	15646.9
Glen App Windfarm	1.841302	
Beinneun Wind Farm	0.057313	
Afton Wind Farm	-0.000000	
benbrack wind farm	0.421454	
Blacklaw Extension	0.000000	
Blacklaw	0.000000	
Clyde North	0.000000	
Clyde South	0.000000	
Corriegarth	0.000000	
Lochluichart	0.000000	
Coryton	0.000000	
Cruachan	0.000000	
Dersalloch Wind Farm	0.000000	
Dinorwig	0.000000	
Aberarder Wind Farm	0.000000	
Edinbane Windfarm	0.000000	
Ewe Hill	0.000000	
Fallago Rig Wind Farm	0.000000	
Carraig Gheal Wind Farm	5.188760	
Ffestiniog	0.000000	
Foyers	0.000000	
Hartlepool	0.000000	
Marchwood	0.000000	
Pen Y Cymoedd Wind Farm	0.000000	
Rocksavage	0.000000	
Saltend	0.000000	
Spalding	0.000000	
Stronelairg	0.241549	
Aikengall II Windfarm	0.000000	
Whitelee Extension	0.000000	
Bhlaraidh Wind Farm	0.000000	
Dorenell Windfarm	1.239000	
Harting Rig Wind Farm	0.000000	
Middle Muir Wind Farm	0.000000	
Aberdeen Offshore Wind Farm	0.000000	
Glen Kyllachy Wind Farm	0.000000	
Enoch Hill	0.000000	
Galawhistle Wind Farm	0.000000	
Kennoxhead Wind Farm	0.000000	
Broken Cross Windfarm	0.000000	
Hunterston Energy Storage Facility	0.000000	
Kincardine Battery Storage Facility	0.000000	
Limekiln	0.000000	
Arecleoch Windfarm Extension	2.036239	
Sanquhar Wind Farm	3.683676	
Chirmorie Wind Farm	-3.003677	
Sandy Knowe Wind Farm	2.909317	
Douglas West	1.632870	
Dalquhandy Wind Farm	-0.000000	
Stranoch Wind Farm	2.617217	
Twentyshilling Wind Farm	3.683676	
Whiteside Hill Wind Farm	3.683676	
Windy Rig Wind Farm	-0.000000	
Pencloe Windfarm	-0.000000	
Glenmuckloch Wind Farm	3.414694	
Windy Standard III Wind Farm	-0.000000	

Onshore local substation tariffs reflect the cost of accommodating the generator to its local substation. It is very rare for generators to have local substation tariff associated with pre-existing assets, as usually each generator has triggered its own dedicated bay at the local substation. Table 20 lists out the onshore local substation tariffs associated with pre-existing assets.

Table 20 Onshore local substation tariffs associated with pre-existing assets

Project Name	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	0.345168	41.7
Toddleburn Wind Farm	0.345168	
Keith Hill Wind Farm	-	

20. Charging bases for 2023/24

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 2024/25 tariffs is forecast at 84.69GW, which is an increase of 6.7GW since the initial forecast. It is based on our internal view of what generation we expect to connect next financial year.

For the Final Tariffs, in line with the CUSC, we will use the contracted TEC position as of 31st October 2023 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 2024/25.

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 2021 -March 2023)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

We assume that with recent historical trends and forward-looking assumptions (excluding the impact of COVID-19) demand volumes will plateau over the next couple of years because of the downturn in the economy. Adjustments have been made in our forecast since the 5yv forecast for 2024/25 based on the latest demand outturn data up to end of March 2023. Please refer to table TAA in the published tables spreadsheet for a detailed breakdown of the changes to the demand changing bases.

Table 21 Charging bases

	2024/25 Tariffs			
Charging Bases	Initial	July	Draft	Final
Generation (GW)	78.00	84.69		
NHH Demand (4pm-7pm TWh)	24.91	23.05		
Gross charging				
Total Average Gross Triad (GW)	49.65	47.45		
HH Demand Average Gross Triad (GW)	18.16	17.93		
Embedded Generation Export (GW)	7.11	6.86		

21. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2023/24 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 ESO website.[6]

22. Generation adjustment and demand residual

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

Adjustment Tariff = (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 adjustment tariff (£/kW)

G is the proportion of TNUoS revenue recovered from generation (the G/D split percentage)

R is the total TNUoS revenue to be recovered (£m)

Z_G is the TNUoS revenue recovered from generation locational tariffs (£m), including wider zonal tariffs and project-specific local tariffs

B_G is the generator charging base (GW)

A_G cannot be positive and is capped at 0.

Demand residual banded charges

Through the approval and decision of CMP343 the demand residual tariff will no longer exist and will not be included in locational tariffs. The revenue to be recovered through the demand residual will now be recovered by a set of p/site/day charges on final demand users (both HH and NHH), based on site specific banded charges.

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

Demand customers will continue paying the locational elements of demand tariffs, based on their triad demand for HH demand or their aggregated annual consumption during 4-7pm each day for their NHH demand. As per CMP343, HH and NHH demand locational tariffs are floored at zero from 2023/24, there will be no negative demand locational tariffs.

[6] https://www.nationalgrideso.com/document/275686/download

Table 22 Residual & Adjustment components calculation

		2024/25 Tariffs			
Component		Initial	July	Draft	Final
G	Proportion of revenue recovered from generation (%)	22.06%	22.49%		
D	Proportion of revenue recovered from demand (%)	77.94%	77.51%		
R	Total TNUoS revenue (£m)	4,575.9	4,606.3		
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	422.5	492.5		
O	Revenue recovered from offshore local tariffs (£m)	656.1	672.8		
L_G	Revenue recovered from onshore local substation tariffs (£m)	12.0	12.5		
S_G	Revenue recovered from onshore local circuit tariffs (£m)	19.6	45.0		
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	7.5		
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5		
	Error Margin	23.6%	31.4%		
	Exchange Rate (€/£)	1.12	1.12		
	Total generation Output (TWh)	189.9	204.0		
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	324.5	313.0		
	Adjustment Revenue (£m)	-101.1	-186.9		
BG	Generator charging base (GW)	78.0	84.7		
AdjTariff	Generator adjusment tariff (£/kW)	-1.30	-2.21		
Gross demand residual					
R_D	Demand residual (£m)	3,470.1	3,484.7		
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	115.9	102.0		
EE	Amount to be paid to Embedded Export Tariffs (£m)	-19.9	-16.9		
B_D	Demand Gross charging base (GW)	49.6	47.4		

*Not applicable for this publication

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 July Quarterly Forecast on Tuesday 15th August. We will be sending out a communication to those who subscribe to our updates via the ESO website, providing details on the upcoming webinar and how to register. 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/285181/download

This data can also be accessed via our Data Portal:

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

Please allow up to two weeks after the publication for the data portal to be updated.

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

ESO

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, ESO 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” elements are included in the generation and demand tariffs. The demand residual banded charges for demand, and adjustment tariff for generation, is also used to ensure the correct proportion of revenue is collected from demand and generation. The locational and adjustment tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff. Since April 2023, demand has a locational HH and NHH demand tariffs split across demand zones and with approval of CMP343 ‘demand residual banded charges’ the demand residual element is charged across a range of banded annual site charges for HH and NHH demand.

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

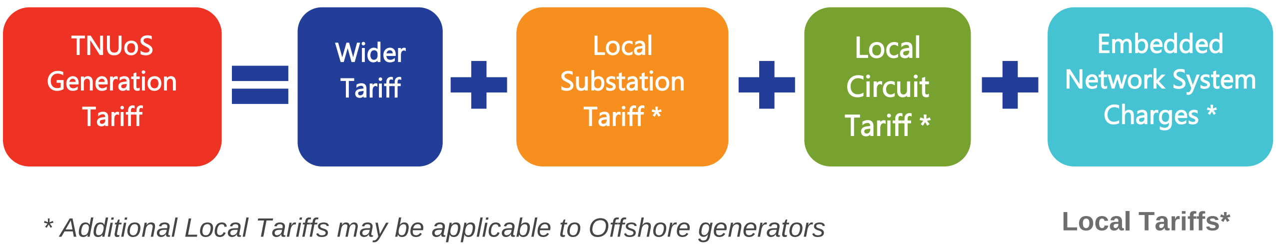
Generation charging principles

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

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

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

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



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

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

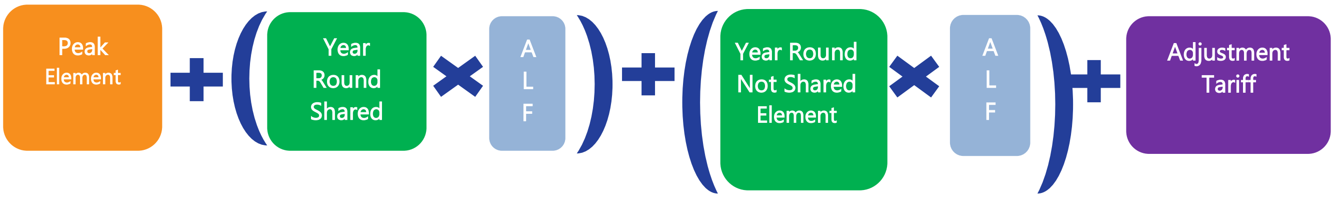
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

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

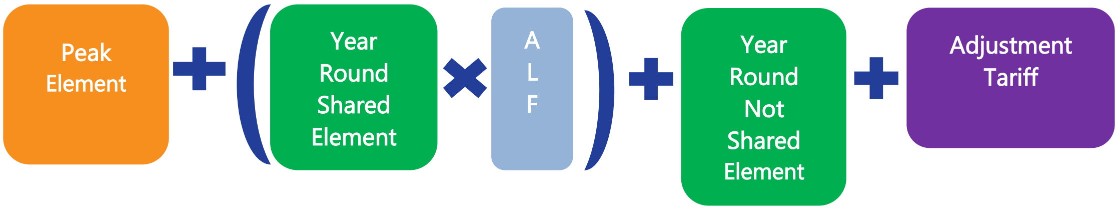
Conventional Carbon Generators

(e.g. Biomass, CHP, Coal, Gas, Pumped Storage, Battery)



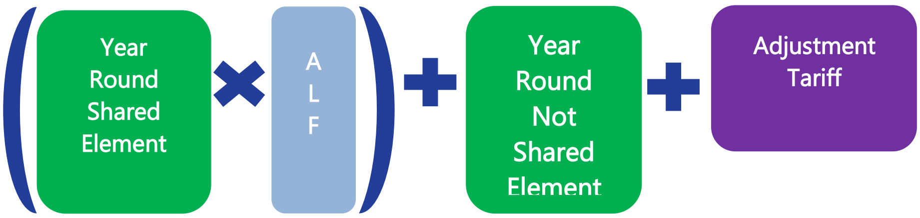
Conventional Low Carbon Generators

(e.g. Hydro, Nuclear)



Intermittent Generators

(e.g. Wind, Wave, Tidal, Solar)



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 filled using the generic ALF calculated for that generator type.

The **Adjustment Tariff** 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 tariff is also used to ensure generator charges are compliant with the Limiting Regulation. This requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average.

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 for each year within the 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[7] if they want to export power onto the transmission system from the distribution network using “firm” transmission network capacity. Generators will incur local DUoS[8] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

Transmission-connected 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 on the first of each month, for the month in question.

[7] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: https://www.nationalgrideso.com/industry-information/connections

[8] 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. With the implementation of CMP343, the demand residual element of the demand charge is split out (previously included in the HH and NHH locational charges) and an additional set off banded charges are to apply to HH and NHH demand.

HH gross demand tariffs

HH gross demand tariffs are made up of locational 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.[9] 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 ESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[10], however this will need to be updated with the introduction of CMP343 and the demand residual banded charges. This guidance will be updated in due course.

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[11].

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 the ESO. 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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9 https://www.nationalgrideso.com/industry-information/charging/triads-data

10 https://www.nationalgrideso.com/document/130641/download

11 https://www.nationalgrideso.com/industry-information/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

Demand residual banded charges

The demand residual banded charges will now make up majority of the TNUoS demand charge in the form of a set of daily charge per site across the banding categories and thresholds.

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariffs for financial year 2024/25.

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

https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc/cusc-modifications

A summary of the modifications already in progress, which could potentially affect 2024/25 TNUoS tariffs and their status, are listed below.

Table 23 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP292	Introducing a Section 8 cut-off date for changes to the Charging Methodologies	Introducing a cut off date for implementation of CUSC changes affecting tariffs	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
CMP315/375	Expansion Constant & Expansion Factors review	Affect TNUoS locational tariffs for generators and demand users	
CMP316	TNUoS Arrangements for Co-located Generation Sites	Affect TNUoS locational tariffs	
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	
CMP331	Option to replace generic Annual Load Factors (ALFs) with site specific ALFs	Introduce an option for site specific ALFs	
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.	
CMP379	CMP379: Determining TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)	Determine demand zones for transmission-connected demand users at multiple DNO sites	
CMP392	Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation	Identifying whether (or not) particular charges fall within the Connection Exclusion	
CMP393	Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage	Change ALF calculation methodology	

Please note that we have not included the CUSC mods which may have a small or localised impact on the TNUoS charge in our forecast or in the above list.

The TNUoS charging methodology is also subject to change under fundamental review programmes. A few of the recent and future fundamental reviews or Significant Code Reviews are discussed in the Charging methodology changes section of this report. To effect change to the charging methodology, these review programmes would result in CUSC modifications being raised.

Appendix C: Breakdown of locational HH and EE tariffs

ESO

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 24 Location elements of the HH demand tariff for 2024/25

Demand Zone		2024/25 Initial		2024/25 July		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.709210	-34.479070	-2.582460	-34.697917	0.126750	-0.218847
2	Southern Scotland	-2.363530	-23.246140	-2.681924	-22.654641	-0.318394	0.591498
3	Northern	-2.724913	-10.441542	-3.371713	-9.833545	-0.646800	0.607997
4	North West	-0.845292	-6.114376	-0.985879	-5.234037	-0.140587	0.880338
5	Yorkshire	-1.747052	-3.913080	-2.422038	-3.304541	-0.674986	0.608539
6	N Wales & Mersey	-1.794419	-3.004907	-1.849476	-2.158502	-0.055057	0.846405
7	East Midlands	-2.268629	0.705991	-2.348905	0.919239	-0.080276	0.213248
8	Midlands	-1.120264	2.883444	-1.158415	3.248787	-0.038151	0.365343
9	Eastern	0.268640	-1.178732	0.836906	-1.462245	0.568266	-0.283513
10	South Wales	-3.014696	9.293537	-2.622397	8.697703	0.392299	-0.595834
11	South East	3.345551	0.277749	3.450012	-0.929665	0.104461	-1.207414
12	London	3.230126	-0.620816	3.759636	-0.730949	0.529510	-0.110133
13	Southern	2.044662	4.882232	2.069160	4.057969	0.024498	-0.824263
14	South Western	3.787237	10.255574	3.512459	9.371282	-0.274779	-0.884291

Table 25 Elements of the Embedded Export Tariff for 2024/25

Demand Zone		2024/25 Initial		2024/25 July		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-37.188280	2.679246	-37.280376	2.702342	-0.092097	0.023096
2	Southern Scotland	-25.609670	2.679246	-25.336565	2.702342	0.273104	0.023096
3	Northern	-13.166456	2.679246	-13.205259	2.702342	-0.038803	0.023096
4	North West	-6.959667	2.679246	-6.219916	2.702342	0.739751	0.023096
5	Yorkshire	-5.660132	2.679246	-5.726579	2.702342	-0.066447	0.023096
6	N Wales & Mersey	-4.799327	2.679246	-4.007978	2.702342	0.791348	0.023096
7	East Midlands	-1.562638	2.679246	-1.429666	2.702342	0.132972	0.023096
8	Midlands	1.763180	2.679246	2.090372	2.702342	0.327192	0.023096
9	Eastern	-0.910093	2.679246	-0.625339	2.702342	0.284754	0.023096
10	South Wales	6.278841	2.679246	6.075306	2.702342	-0.203534	0.023096
11	South East	3.623300	2.679246	2.520346	2.702342	-1.102953	0.023096
12	London	2.609311	2.679246	3.028687	2.702342	0.419377	0.023096
13	Southern	6.926894	2.679246	6.127129	2.702342	-0.799765	0.023096
14	South Western	14.042811	2.679246	12.883741	2.702342	-1.159070	0.023096

Appendix D: Annual Load Factors

ESO

ALFs

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

For the purposes of this forecast, we have used the final version of the 2023/24 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2017/18 to 2021/22. Generators which commissioned after 1 April 2019 will have fewer than three complete years of data, so the appropriate Generic ALF listed below is incorporated to create three complete years from which the ALF can be calculated. Generators expected to commission during 2023/24 also use the Generic ALF (in whole or in combination with their actual data) until they have three complete years' worth of operational data to use in the calculations.

The specific and generic ALFs that will apply to the 2024/25 TNUoS Tariffs will be updated by our Draft Tariffs publication in November 2023. The specific and generic ALFs, as used in this forecast, are published here, with specific ALFs in excel format here.

Generic ALFs

Table 26 Generic ALFs

Technology	Generic ALF
Battery	1.2391%
Biomass	43.9150%
CCGT_CHP	49.3613%
Coal	17.6627%
Gas_Oil	0.4762%
Hydro	41.6409%
Nuclear	68.2026%
Offshore_Wind	46.9350%
Onshore_Wind	39.4259%
Pumped_Storage	8.5995%
Reactive_Compensation	0.0000%
Solar	10.9000%
Tidal	11.6000%
Wave	2.9000%

Please note: ALF figures for Wave, Tidal and Solar technology are generic figures published by BEIS due to no metered data being available.

These Generic ALFs are calculated in accordance with CUSC 14.15.111.

Appendix E: Contracted generation

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

The contracted generation used in the Transport model will be fixed using the TEC register as of 31 October 2023, as stated by the CUSC 14.15.6 and no further changes to Contracted TEC will be made.

Table 27 shows the contracted generation changes notified since the initial forecast using data from the June 2023 TEC register. Please note that stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

Table 27 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Bicker Fen 1 Solar	-50	BICF4A	17
Bicker Fen 2 Solar	-49.995	BICF4A	17
Creag Riabhach Wind Farm	92	CREA10	1
Cumberhead	50	CCSS10	11
Elstree 2 (Tertiary)	-50	ELST40	25
Fferm Solar Pentir	-57	PENT40	19
JG Pears	-403	HIGM40	16
Lister Drive Shaw	-57	LISD20	15
Minety Tertiary(2)	-2	MITY40	22
North Killingholme Power Project	-540	KILL40	15
Plas Power Estate North Tertiary	-57	LEGA40	18
Project Yare	49.5	NORM40	18
Staythorpe	-437	STAY40	16
Templeborough	-49.5	TEMP2A	16
Warley	8	WARL20	24
Wishaw Energy Storage Facility	49.95	WISH10	11
Zenobe Kilmarnock South	-100	KILS40	10

Appendix F: Transmission company revenues

ESO

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have not updated us with their revenue forecast for year 2024/25. We do not anticipate an update until late October. Therefore, the current update includes using Onshore and offshore revenue figures from the Initial forecast. The notable difference in this forecast is the inclusion of updated CPIH figures and forecast OFTO Asset Transfer Dates.

Revenue for offshore networks is included with forecasts by ESO 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. ESO 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 ESO 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.

ESO TNUoS revenue pass-through items forecasts

From April 2019, a new, legally separate electricity system operator (ESO) 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 ESO and passed through to NGET, in the same way to the arrangement with Scottish TOs and OFTOs.

In addition, ESO 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 ESO. The revenue breakdown table below shows details of the pass-through TNUoS revenue items under ESO's licence conditions.

Since our initial forecast, it can be observed that there have been small changes (see table 28) with the most variations being seen with an increase in Offshore Transmission Revenue (OFTOt) and Interconnectors Cap & Floor Revenue Adjustment (TICFt) (+£21.05m) and NGET Revenue pass-through (NGETTOt) (+£12.17m). This is offset by variations in ESO other pass-through items (LFt + ITCt etc) (-£4.17m).

Table 28 ESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through		
	Initial Forecast	July Forecast	Variance
Embedded Offshore Pass-Through (OFETt)	0.70	0.69	0.00
Network Innovation Competition Fund (NICFt)	3.00	3.00	0.00
Strategic Innovation Fund (SIFt)	45.50	45.50	0.00
The Adjustment Term (ADJt)	0.00	-8.67	-8.67
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	764.80	785.85	21.05
Interconnectors CACM Cost Recovery (ICPt)	-12.88	-12.88	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00
Termination Sums (TSt)	25.00	25.00	0.00
NGET revenue pass-through (NGETTOt)*	2,223.09	2,235.26	12.17
SPT revenue pass-through (TSPt)	500.87	503.60	2.73
SHETL revenue pass-through (TSHt)	979.83	984.94	5.11
ESO Bad debt (BDt)	3.58	3.12	-0.46
ESO other pass-through items (LFt + ITCt etc)	42.38	38.21	-4.17
ESO legacy adjustment (LARt)	0.00	2.69	2.69
Total	**4,575.87**	**4,606.32**	**30.45**

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 not provided us with their forecasted revenue breakdown for 2024/25. We have therefore used the previous actual revenue forecast submission and applied the latest CPIH for this forecast.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2024/25 is forecast to be £861.0m, an increase of £21.1m since the initial forecast. Revenues have been adjusted using latest RPI data (as part of the calculation of the inflation term, as defined in the relevant OFTO licence).

Interconnector adjustment

Since year 2018/19, under CMP283, TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework, and interconnectors' Cap & Floor framework. There have been no updates to the Interconnector Adjustment forecast since January, however we expect interconnectors will notify us with the latest adjustment figures by October, which will be included in the Draft forecast.

Table 29 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	352.77	354.65		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,840.10	1,840.10		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**2,291.27**	**2,303.45**		
SONIA	B1	It-1	4.78%	4.78%		
Allowed Revenue	B2	ARt-1	2,397.06	2,397.06		
Recovered Revenue	B4	RRt-1	2,397.06	2,397.06		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	-56.66	-56.66		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	-11.52	-11.52		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	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**	**-68.18**	**-68.18**		
Site Rental Charges			**0.00**	**0.00**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**2,223.09**	**2,235.26**		

Table 30 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	352.77	354.65		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	412.42	412.42		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**513.55**	**516.27**		
SONIA	B1	It-1	4.78%	4.78%		
Allowed Revenue	B2	ARt-1	0.00	0.00		
Recovered Revenue	B4	RRt-1	0.00	0.00		
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	-12.06	-12.06		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	-0.70	-0.70		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.09	0.09		
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**	**-12.67**	**-12.67**		
Site Rental Charges				**0.00**		
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**500.87**	**503.60**		

Table 31 SHETL revenue breakdown

Transmission Revenue Forecast			SHE Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	352.77	354.65		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	772.70	772.70		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**962.16**	**967.27**		
SONIA	B1	It-1	4.78%	4.78%		
Allowed Revenue	B2	ARt-1	859.13	859.13		
Recovered Revenue	B4	RRt-1	859.13	859.13		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	14.50	14.50		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	3.17	3.17		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	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**	**17.68**	**17.68**		
Site Rental Charges				**0.00**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**979.83**	**984.94**		

Table 32 Offshore revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="4">Year</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2021/22</th><th>2022/23</th><th>2023/24</th><th>2024/25</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>6.7</td><td>7.0</td><td>7.8</td><td>8.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>8.4</td><td>8.7</td><td>9.7</td><td>10.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>15.3</td><td>15.6</td><td>17.8</td><td>19.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>9.4</td><td>9.8</td><td>10.9</td><td>12.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>15.1</td><td>16.3</td><td>18.3</td><td>19.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>23.4</td><td>24.2</td><td>26.7</td><td>29.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>14.1</td><td>14.7</td><td>16.2</td><td>17.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>32.1</td><td>33.2</td><td>37.0</td><td>40.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>44.7</td><td>46.8</td><td>52.6</td><td>56.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td>20.8</td><td>21.6</td><td>24.0</td><td>26.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>30.0</td><td>32.5</td><td>34.0</td><td>38.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>32.9</td><td>39.8</td><td>37.6</td><td>38.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td>25.3</td><td>25.5</td><td>28.5</td><td>31.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>14.4</td><td>13.3</td><td>15.0</td><td>16.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>14.1</td><td>14.7</td><td>16.5</td><td>18.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Burbo Bank</td><td>14.1</td><td>14.7</td><td>16.4</td><td>17.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Dudgeon</td><td>19.6</td><td>20.8</td><td>22.6</td><td>24.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Race Bank</td><td>27.4</td><td>28.9</td><td>32.5</td><td>35.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Galloper</td><td>17.1</td><td>17.8</td><td>20.1</td><td>21.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 3</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 4</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1A</td><td rowspan="5">137.1</td><td>18.4</td><td>20.6</td><td>22.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1B</td><td>18.4</td><td>20.6</td><td>22.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1C</td><td>18.4</td><td>20.6</td><td>22.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Beatrice</td><td>21.1</td><td>24.4</td><td>26.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Rampion</td><td>15.5</td><td>17.4</td><td>19.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>East Anglia 1</td><td></td><td rowspan="2">68.3</td><td>47.4</td><td>53.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2023/24</td><td></td><td>138.7</td><td>164.0</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2024/25</td><td></td><td></td><td></td><td>14.3</td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>549.0</td><td>594.3</td><td>765.6</td><td>861.0</td><td></td></tr>
</table>

Notes:

Figures for historic years represent ESO's forecast of OFTO revenues at the time final tariffs were calculated for each charging year rather than our current best view. It is possible that anticipated asset transfer dates moved between charging years in which case where a previous year shows a forecast for multiple sites, other sites may also have been included in addition to the ones shown.

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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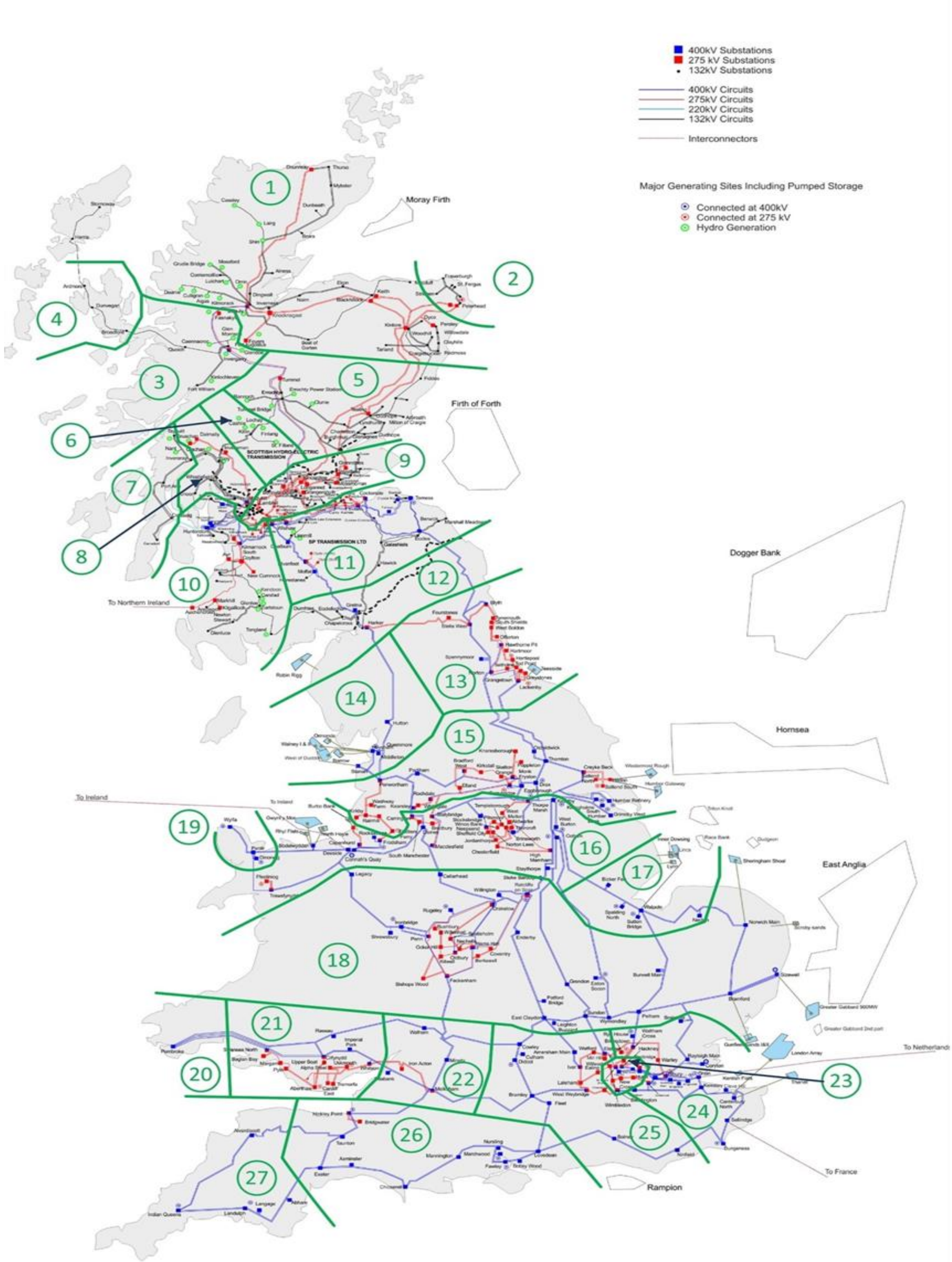
Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to [ETYS 2022 AppA__diagrams]

Appendix H: Demand zones map

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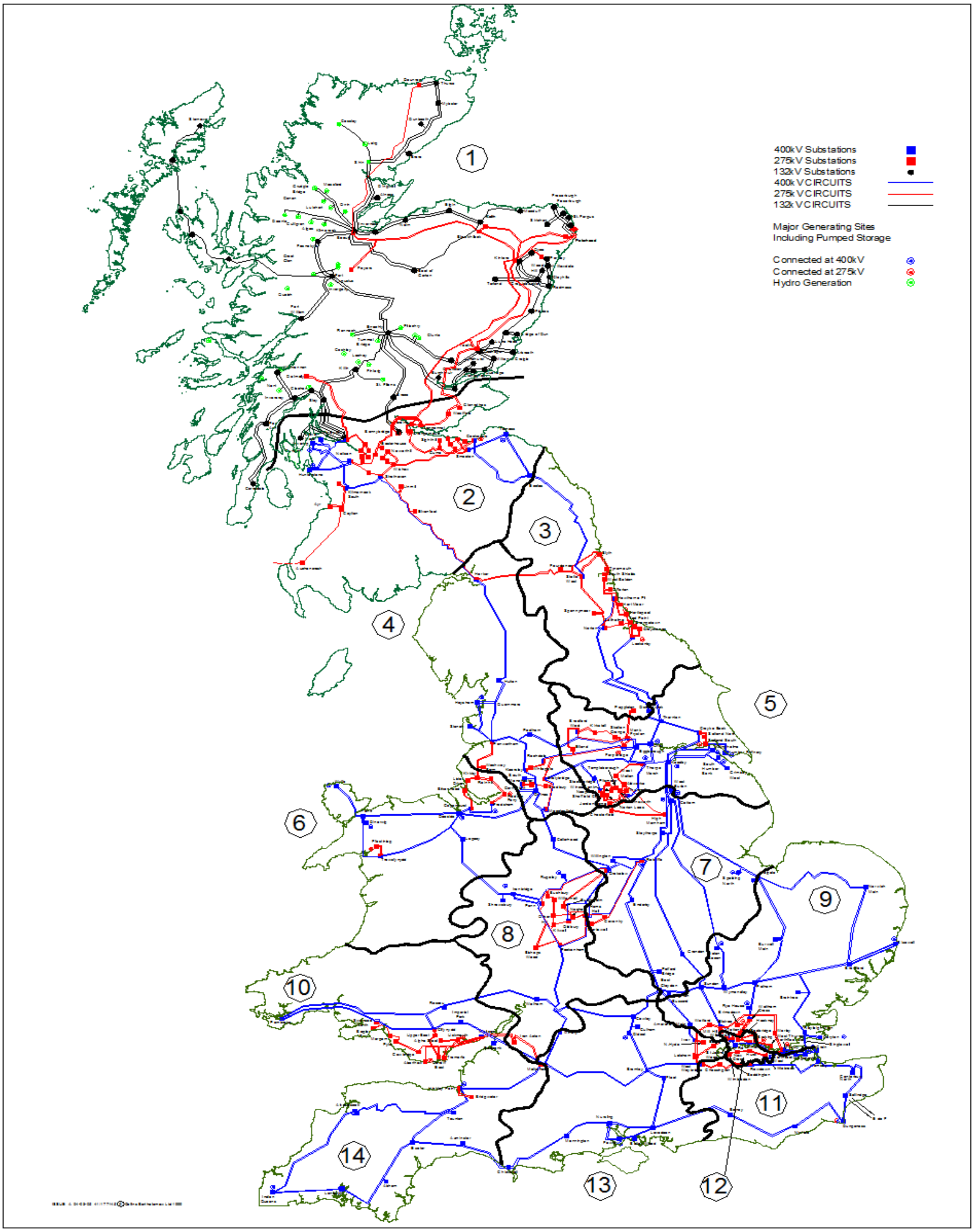
400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
1
2
3
4
5
6
7
8
9
10
11
12
13
14

Appendix I: Changes to TNUoS parameters

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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.

2024/25 TNUoS Tariff Forecast					
		April 2023	July 2023	Draft Tariffs November 2023	Final Tariffs January 2024
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 on 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	
	Inflation	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
	Banding Data	Previous year's data source		DNO/IDNO consumption and site data updated	
				Transmission Data updated	Transmission Data finalised
	Generation Charging Base	NG best view	NG best view	NG best view	NG final best view
	Generation ALFs	Previous year's data source		Draft ALFs published	Final ALFs published
	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

Document Revision History

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Document Revision History

Version Number	Date of Issue	Notes
1.0	31st July 2023	Publication of Quarterly Forecast of 2024/25 TNUoS Tariffs
1.1	1st August 2023	Minor amendments to correct links within footnotes on pages 38 and 39 Added document revision history

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