Version 2.0

Draft TNUoS Tariffs for 2024/25

Electricity System Operator

November 2023

ESO

List of Tables and Figures

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 Draft 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 £4.01bn for FY24/25, (a decrease of £593m from the July forecast). This decrease is mainly due to the October submissions of Allowed Revenue from the TOs which are the first full submissions since January 2023. As such the Allowed Revenue has changed for NGET (-£394.5m), SPT (-£51.2m) and SHET (-£248.1m). The 2024/25 revenue forecast will be finalised by January Final Tariffs based on Onshore and Offshore TOs' final submissions.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.05bn for 2024/25, an increase of £14.7m since the July forecast. This is mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base has been updated to 85.23GW based on our best view on generation projects for 2024/25. This is an increase of 0.5GW since the July forecast. The average generation tariff is £12.33/kW, an increase of £0.09/kW due to the increase in revenue to be collected from generation outweighing the increase to the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £2,963m for 2024/25, a £607m decrease since the July tariffs. This is driven by the reduction of total TNUoS revenue of (£593m) and a reduction of percentage of revenue recovered from demand since July forecast. Of this total, £2,869m is forecast to be collected via the Transmission Demand Residual.

The impact on the end consumer is forecast to be £37.14 for FY24/25 (3.34% of the average annual electricity consumer bill), a decrease of £9.09 from the 2024/25 July forecast. This is due to the reduction of the domestic transmission demand residual charge since the July forecast.

In 2024/25 it is forecast that £19.29m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £2.43m since the July forecast. This is due to the increase in the forecast charging base for Embedded Export and an increase in the average locational tariffs. The average EET is forecast at £2.58/kW, which is an increase of £0.12/kW versus July forecast.

The average gross HH demand tariff for 2024/25 is to be £6.51/kW, an increase of £0.82/kW and the average NHH demand tariff forecast is at 0.33p/kWh, an increase of 0.04p/kWh since July 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 Final 2024/25 tariffs, which will be published in January 2024.

[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.

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Charging Methodology Changes

ESO

This Report

This report contains the Draft 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 the final tariffs we will publish at a later date.

This section summarises any key changes to the methodology.

Charging methodology changes

The Authority has directed that CMP292: 'Introducing a Section 8 cut-off date for changes to the Charging Methodologies' should be implemented on 1st April 2024. This modification introduces a deadline of 30 September (year t) for the approval of any CUSC charging modification with an implementation date of the following charging year (t+1). It does not affect the charging methodology itself, but it is worth noting that since it is not implemented until 1st April 2024, it means that decisions can still be made in the interim period that may affect the 2024/25 charging year.

On 27th October 2023, the Authority also directed that CMP379: 'Determining TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)' be implemented on 1st April 2024. The modification proposes that where a transmission site has a local GSP which connects to and feeds multiple DNO networks, Demand Tariffs will be derived from the average zonal tariffs from the relevant DNO zones. Unfortunately, it has not been possible to include this change within these Draft tariffs, but the change will be incorporated in the Final tariffs (which will be published in January).

There are also 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[3] 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.

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[3] https://www.ofgem.gov.uk/publications/tnuos-task-forces

Generation tariffs

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

ESO

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 July	2024/25 November	Change since last forecast
Adjustment	- 2.206937	- 1.717191	0.489746
Average Generation Tariff*	12.230886	12.325803	0.094917

*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 increased by £0.09/kW, due to an increase of £14.7m in the revenue to be collected from generation which outweighs the 0.5GW increase in the generation charging base, compared to the July forecast. The generation adjustment has increased by £0.49/kW, decreasing in magnitude, to become less negative; this is because the wider tariff components have decreased for most zones since the July forecast, meaning there is less of an adjustment required to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 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

						Example tariffs for a generator of each technology type		
Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 40% Load Factor	Conventional Low Carbon 75% Load Factor	Intermittent 45% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.996130	20.547337	18.248646	-1.717191	16.797332	34.938088	25.777757
2	East Aberdeenshire	4.134330	11.778569	18.248646	-1.717191	14.428025	29.499712	21.831811
3	Western Highlands	3.230485	20.305203	18.076420	-1.717191	16.865943	34.818616	25.496570
4	Skye and Lochalsh	-1.989329	20.305203	19.870000	-1.717191	12.363561	31.392382	27.290150
5	Eastern Grampian and Tayside	5.853910	15.742150	14.103528	-1.717191	16.074990	30.046860	19.470305
6	Central Grampian	4.942104	15.970825	14.409646	-1.717191	15.377101	29.612678	19.879326
7	Argyll	3.157627	14.100590	20.444992	-1.717191	15.258669	32.460871	25.073067
8	The Trossachs	3.944171	14.100590	11.871885	-1.717191	12.615970	24.674308	16.499960
9	Stirlingshire and Fife	2.474974	13.819136	11.646784	-1.717191	10.944151	22.768919	16.148204
10	South West Scotlands	2.707958	13.364268	11.382199	-1.717191	10.889354	22.396167	15.678929
11	Lothian and Borders	2.408183	13.364268	5.302762	-1.717191	8.157804	16.016955	9.599492
12	Solway and Cheviot	1.636696	8.689986	6.607014	-1.717191	6.038305	13.044009	8.800317
13	North East England	3.319860	6.079623	3.852638	-1.717191	5.575573	10.015024	4.871277
14	North Lancashire and The Lakes	1.255369	6.079623	1.383497	-1.717191	2.523426	5.481392	2.402136
15	South Lancashire, Yorkshire and Humber	4.196040	2.039166	0.341717	-1.717191	3.431202	4.349941	-0.457849
16	North Midlands and North Wales	2.996034	0.468680	-	-1.717191	1.466315	1.630353	-1.506285
17	South Lincolnshire and North Norfolk	1.263625	2.464145	-	-1.717191	0.532092	1.394543	-0.608326
18	Mid Wales and The Midlands	1.291875	4.206972	-	-1.717191	1.257473	2.729913	0.175946
19	Anglesey and Snowdon	4.761625	0.614075	-	-1.717191	3.290064	3.504990	-1.440857
20	Pembrokeshire	8.245736	-8.308040	-	-1.717191	3.205329	0.297515	-5.455809
21	South Wales & Gloucester	3.945510	-8.526869	-	-1.717191	-1.182429	-4.166833	-5.554282
22	Cotswold	3.461436	4.275751	-10.960559	-1.717191	-0.929678	-6.009501	-10.753662
23	Central London	-3.403205	4.275751	-3.548596	-1.717191	-4.829534	-5.462179	-3.341699
24	Essex and Kent	-3.148861	4.275751	-	-1.717191	-3.155752	-1.659239	0.206897
25	Oxfordshire, Surrey and Sussex	-0.703694	-2.203398	-	-1.717191	-3.302244	-4.073434	-2.708720
26	Somerset and Wessex	-1.116080	-4.720326	-	-1.717191	-4.721401	-6.373516	-3.841338
27	West Devon and Cornwall	-0.429421	-9.779350	-	-1.717191	-6.058352	-9.481125	-6.117899

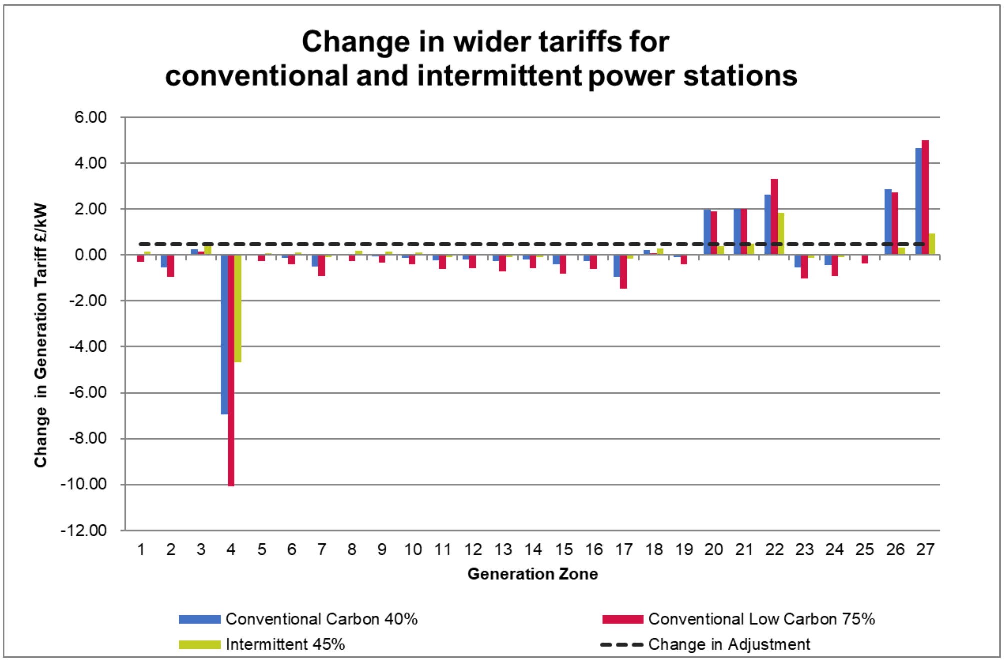
3. Changes to wider tariffs since the July Forecast

The following section provides details of the wider generation tariffs for 2024/25 and explains how these have changed since the July 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 July	2024/25 November	Change	2024/25 July	2024/25 November	Change	2024/25 July	2024/25 November	Change	
1	North Scotland	16.833462	16.797332	-0.036130	35.234230	34.938088	-0.296142	25.618076	25.777757	0.159681	0.489746
2	East Aberdeenshire	14.982395	14.428025	-0.554370	30.449147	29.499712	-0.949435	21.845769	21.831811	-0.013958	0.489746
3	Western Highlands	16.620009	16.865943	0.245934	34.653239	34.818616	0.165377	25.069647	25.496570	0.426923	0.489746
4	Skye and Lochalsh	19.308598	12.363561	-6.945037	41.470245	31.392382	-10.077863	31.950342	27.290150	-4.660192	0.489746
5	Eastern Grampian and Tayside	16.041890	16.074990	0.033100	30.319235	30.046860	-0.272375	19.395270	19.470305	0.075035	0.489746
6	Central Grampian	15.515316	15.377101	-0.138214	30.020367	29.612678	-0.407689	19.748059	19.879326	0.131268	0.489746
7	Argyll	15.778788	15.258669	-0.520120	33.377058	32.460871	-0.916187	25.159842	25.073067	-0.086776	0.489746
8	The Trossachs	12.645613	12.615970	-0.029643	24.944501	24.674308	-0.270193	16.327540	16.499960	0.172419	0.489746
9	Stirlingshire and Fife	11.006291	10.944151	-0.062140	23.093616	22.768919	-0.324697	16.009403	16.148204	0.138802	0.489746
10	South West Scotlands	11.005462	10.889354	-0.116109	22.797248	22.396167	-0.401081	15.573990	15.678929	0.104939	0.489746
11	Lothian and Borders	8.371992	8.157804	-0.214188	16.626571	16.016955	-0.609616	9.678646	9.599492	-0.079154	0.489746
12	Solway and Cheviot	6.234434	6.038305	-0.196129	13.601477	13.044009	-0.557468	8.813016	8.800317	-0.012699	0.489746
13	North East England	5.847120	5.575573	-0.271546	10.710689	10.015024	-0.695664	4.980672	4.871277	-0.109394	0.489746
14	North Lancashire and The Lakes	2.706533	2.523426	-0.183107	6.068201	5.481392	-0.586808	2.477503	2.402136	-0.075366	0.489746
15	South Lancashire, Yorkshire and Humber	3.846583	3.431202	-0.415381	5.160155	4.349941	-0.810214	-0.423890	-0.457849	-0.033959	0.489746
16	North Midlands and North Wales	1.718889	1.466315	-0.252574	2.254862	1.630353	-0.624509	-1.517829	-1.506285	0.011544	0.489746
17	South Lincolnshire and North Norfolk	1.473588	0.532092	-0.941496	2.854240	1.394543	-1.459697	-0.431814	-0.608326	-0.176512	0.489746
18	Mid Wales and The Midlands	1.027080	1.257473	0.230393	2.660703	2.729913	0.069210	-0.106565	0.175946	0.282512	0.489746
19	Anglesey and Snowdon	3.366700	3.290064	-0.076636	3.924496	3.504990	-0.419506	-1.489772	-1.440857	0.048914	0.489746
20	Pembrokeshire	1.218650	3.205329	1.986679	-1.619664	0.297515	1.917179	-5.856197	-5.455809	0.400388	0.489746
21	South Wales & Gloucester	-3.187030	-1.182429	2.004601	-6.179467	-4.166833	2.012634	-6.054356	-5.554282	0.500074	0.489746
22	Cotswold	-3.541448	-0.929678	2.611770	-9.327275	-6.009501	3.317774	-12.594908	-10.753662	1.841246	0.489746
23	Central London	-4.285530	-4.829534	-0.544004	-4.434183	-5.462179	-1.027996	-3.199617	-3.341699	-0.142082	0.489746
24	Essex and Kent	-2.710055	-3.155752	-0.445696	-0.754625	-1.659239	-0.904614	0.307188	0.206897	-0.100291	0.489746
25	Oxfordshire, Surrey and Sussex	-3.320583	-3.302244	0.018339	-3.715702	-4.073434	-0.357732	-2.714947	-2.708720	0.006226	0.489746
26	Somerset and Wessex	-7.582348	-4.721401	2.860947	-9.111062	-6.373516	2.737546	-4.172426	-3.841338	0.331088	0.489746
27	West Devon and Cornwall	-10.709411	-6.058352	4.651059	-14.480539	-9.481125	4.999415	-7.055530	-6.117899	0.937631	0.489746

Figure 1 Variation in generation wider zonal tariffs



Locational changes

Locational tariffs have been impacted by the update of various locational inputs, including the nodal generation and demand and the network model used to model flows. This means that there have been changes in the overall tariffs across each generation zone. In particular, the change in flows has resulted in a large decrease in zone 4, which is often sensitive to small changes in flows due to local generation and demand being nearly matching, and the long radial circuits. Overall, the North-South tariff divide has decreased.

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 increased by £0.49/kW since the July forecast, decreasing in magnitude, to become less negative. This is mainly due to changes to locational tariffs which results in less wider revenue expected to be collected from generators. These changes cause the adjustment to go less negative as there is less 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 finalised, and therefore onshore local substation tariffs are finalised for charging year 2024/25.

Table 4 Local substation tariffs

2024/25 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.174450	0.087229	0.060166
<1320 MW	Redundancy	0.367586	0.186703	0.132570
>=1320 MW	No redundancy	-	0.256277	0.182462
>=1320 MW	Redundancy	-	0.385653	0.277379

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 finalised. 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	1.663557	Dorenell	2.487547	Langage	-0.390760
Aberdeen Bay	3.253177	Douglas North	0.739359	Limekilns	2.155514
Achruach	-3.012829	Dunhill	1.741283	Lochay	0.369679
Aigas	0.821868	Dunlaw Extension	1.696117	Luichart	0.684968
An Suidhe	-1.120900	Dunmaglass	1.056667	Marchwood	-0.287364
Arecleoch	2.920527	Edinbane	8.315968	Mark Hill	1.072131
Arecleoch extension	2.475745	Enoch Hill	1.615924	Middle Muir	2.772594
Ayrshire grid collector	0.164288	Ewe Hill	1.692310	Middleton	0.174111
Beinneun Wind Farm	1.640514	Fallago	-0.070945	Millennium South	0.528866
Benbrack	0.885177	Farr	4.226137	Millennium Wind	1.906385
Bhlaraidh Wind Farm	0.740386	Fernoch	5.208303	Mossford	3.639452
Black Hill	1.865660	Ffestiniogg	0.264173	Nant	-1.511005
Black Law	2.033236	Fife Grid Services	0.184443	Necton	0.531832
BlackCraig Wind Farm	6.306177	Finlarig	0.369679	Rhigos	0.128077
BlackLaw Extension	4.422820	Foyers	0.339651	Rocksavage	-0.017841
Broken Cross	1.292604	Galawhistle	1.269233	Saltend	-0.018858
Chirmorie	0.653898	Glen Kyllachy	0.554519	Sandy Knowe	3.911476
Clyde (North)	0.128656	Glendoe	2.229843	Sanquhar II	8.407555
Clyde (South)	0.150098	Glenglass	5.563530	Shepherds rig	0.094278
Corriegarth	2.957434	Gordonbush	-0.091222	South Humber Bank	-0.215606
Corriemoillie	1.928831	Griffin Wind	11.520518	Spalding	0.324630
Coryton	0.053484	Hadyard Hill	3.327113	Stranoch	-0.492108
Creag Riabhach	4.066472	Harestanes	2.772594	Strathbrora	-0.207902
Cruachan	2.164215	Hartlepool	0.036918	Strathy Wind	1.942483
Culligran	2.101062	Invergarry	0.369679	Stronelairg	1.299770
Cumberhead Collector	0.846155	Kennoxhead	4.943037	Wester Dod	0.423078
Cumberhead West	4.484188	Kergord	59.436040	Whitelee	0.128656
Deanie	3.451745	Kilgallioch	1.286557	Whitelee Extension	0.364524
Dersalloch	2.724961	Kilmorack	0.150076		
Dinorwig	2.865274	Kype Muir	1.798080		

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 132kV	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 July, 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 July Tariff Component (£/kW)			2024/25 November Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.247564	59.420300	1.475487	11.260530	59.488802	1.477188	0.012966	0.068502	0.001701
Beatrice	9.099927	24.950455	-	9.143187	25.069066	-	0.043260	0.118611	-
Burbo Bank	14.134257	27.317187	-	14.201448	27.447048	-	0.067191	0.129861	-
Dudgeon	20.673584	32.437170	-	20.771862	32.591371	-	0.098278	0.154201	-
East Anglia 1	12.237831	51.646896	-	12.296008	51.892416	-	0.058177	0.245520	-
Galloper	21.162209	33.470209	-	21.262810	33.629321	-	0.100601	0.159112	-
Greater Gabbard	20.956342	48.495084	-	20.980502	48.550991	-	0.024160	0.055907	-
Gunfleet	24.477090	22.572268	4.218886	24.505308	22.598290	4.223750	0.028218	0.026022	0.004864
Gwynt y mor	26.542414	26.242009	-	26.668592	26.366759	-	0.126178	0.124750	-
Hornsea 1A	9.447158	33.425519	-	9.492068	33.584419	-	0.044910	0.158900	-
Hornsea 1B	9.447158	33.425519	-	9.492068	33.584419	-	0.044910	0.158900	-
Hornsea 1C	9.447158	33.425519	-	9.492068	33.584419	-	0.044910	0.158900	-
Hornsea 2A				10.866250	36.707817	-	10.866250	36.707817	-
Hornsea 2B				10.866250	36.707817	-	10.866250	36.707817	-
Hornsea 2C				10.866250	36.707817	-	10.866250	36.707817	-
Humber Gateway	15.620359	35.838476	-	15.694615	36.008846	-	0.074256	0.170370	-
Lincs	21.684789	85.278858	-	21.787874	85.684260	-	0.103085	0.405402	-
London Array	14.715761	50.454704	-	14.785717	50.694557	-	0.069956	0.239853	-
Ormonde	34.581376	64.640088	0.515127	34.621243	64.714608	0.515721	0.039867	0.074520	0.000594
Race Bank	12.519354	34.771995	-	12.578868	34.937295	-	0.059514	0.165300	-
Rampion	10.227106	26.753675	-	10.275724	26.880857	-	0.048618	0.127182	-
Robin Rigg	- 0.759017	43.083399	13.803647	- 0.759892	43.133068	13.819561	- 0.000875	0.049669	0.015914
Robin Rigg West	- 0.759017	43.083399	13.803647	- 0.759892	43.133068	13.819561	- 0.000875	0.049669	0.015914
Sheringham Shoal	32.353563	38.104636	0.828283	32.390862	38.148565	0.829238	0.037299	0.043929	0.000955
Thanet	24.706011	46.286767	1.114286	24.734493	46.340129	1.115570	0.028482	0.053362	0.001284
Walney 1	29.867857	59.713440	-	29.902290	59.782280	-	0.034433	0.068840	-
Walney 2	27.787660	56.550657	-	27.819695	56.615851	-	0.032035	0.065194	-
Walney 3	12.859949	26.053487	-	12.921083	26.177340	-	0.061134	0.123853	-
Walney 4	12.859949	26.053487	-	12.921083	26.177340	-	0.061134	0.123853	-
West of Duddon Sands	11.500962	57.330789	-	11.555635	57.603329	-	0.054673	0.272540	-
Westermost Rough	23.385279	39.798773	-	23.496449	39.987970	-	0.111170	0.189197	-

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 non-locational set of daily charge per site across the banding categories and thresholds.

Table 8 Summary of demand tariffs

Non-locational Banded Tariffs	2024/25 July	2024/25 November	Change
Average (£/site/annum)	108.871088	89.159371	- 19.711717
Unmetered (p/kWh/annum)	1.2837767	1.1231125	- 0.1606642
Demand Residual (£m)	3,484.7	2,869.8	- 614.9

HH Tariffs (Locational)	2024/25 July	2024/25 November	Change
Average Tariff (£/kW)	5.689196	6.513260	0.824065

EET	2024/25 July	2024/25 November	Change
Average Tariff (£/kW)	2.458701	2.577941	0.119240
AGIC (£/kW)	2.702342	2.712754	0.010412
Embedded Export Volume (GW)	6.857899	7.481415	0.623516
Total Credit (£m)	16.861525	19.286646	2.425121

NHH Tariffs (locational)	2024/25 July	2024/25 November	Change
Average (p/kWh)	0.280371	0.325016	0.044645

Since the publication of the July forecast, both the average HH & NHH demand tariffs have seen an increase. The main driver being the increase in the total amount of revenue to be recovered through TNUoS locational element of demand tariffs and updates to nodal demand. Overall total Demand revenue has reduced since the July forecast by £607m.

The average HH gross tariff is set at £6.51/kW, an increase of £0.82/kW compared to July forecast. The average NHH tariff is forecast at 0.33p/kWh, an increase of 0.04p/kWh.

Embedded Export Volume for the draft forecast is 7.48GW an increase of 0.62GW compared to July forecast. The total credit paid out to embedded generators (<100MW) is currently forecast at £19.29m, an increase of £2.43m. This is driven by an increase in export volumes for the Zones whose tariffs are not floored. The average EET is now forecast at £2.58/kW an increase of £0.12/kW compared to the July 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	-	-	2.565718
8	Midlands	2.373140	0.331477	5.085894
9	Eastern	0.827333	0.121828	3.540087
10	South Wales	4.503510	0.561335	7.216264
11	South East	3.859199	0.572982	6.571953
12	London	5.734465	0.687413	8.447219
13	Southern	6.869733	0.964020	9.582487
14	South Western	8.198917	1.185452	10.911671

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 of the published tables excel spreadsheet[4].

Table 10 shows the forecast demand residual tariffs by band. These tariffs will apply to HH and NHH demand as well the locational HH and NHH tariffs (where applicable).

[4] Please see the Numerical data section of ‘Tools and Supporting Information’ for the link to the published tables excel spreadsheet.

Table 10 Non-Locational demand residual banded charges

Band		2024/25 July	2024/25 November	Change
Domestic	Tariff - £/Site/Day	0.123070	0.098727	-0.024343
LV_NoMIC_1		0.062848	0.065351	0.002503
LV_NoMIC_2		0.286013	0.231905	-0.054108
LV_NoMIC_3		0.682049	0.540823	-0.141226
LV_NoMIC_4		2.117729	1.693296	-0.424433
LV1		3.421300	2.938703	-0.482597
LV2		6.281411	5.059902	-1.221509
LV3		10.223005	8.266652	-1.956353
LV4		23.028571	19.174832	-3.853739
HV1		17.819143	14.844464	-2.974679
HV2		57.357083	45.903309	-11.453774
HV3		112.618479	90.769885	-21.848594
HV4		285.827674	231.419602	-54.408072
EHV1		134.873289	106.284923	-28.588366
EHV2		663.159738	572.422573	-90.737165
EHV3		1337.142725	1157.404151	-179.738574
EHV4		3641.431558	3151.067193	-490.364365
T-Demand1		503.117244	375.204547	-127.912697
T-Demand2		1851.779425	1522.758894	-329.020531
T-Demand3		4572.834315	3547.882635	-1024.951680
T-Demand4		10332.780846	11299.546455	966.765609
Unmetered demand			**p/kWh**	
Unmetered		1.283777	1.123113	-0.160664
Demand Residual (£m)		**3484.66**	**2869.77**	**-614.89**

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 and site counts used in the calculation of the above tariffs are based on the out-turn data from 2022/23 provided by the DNO/IDNO's latest submission in October/November 2023. These updated values will remain the same in the Final tariffs for 2024/25. 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 in the final row of Table 10.

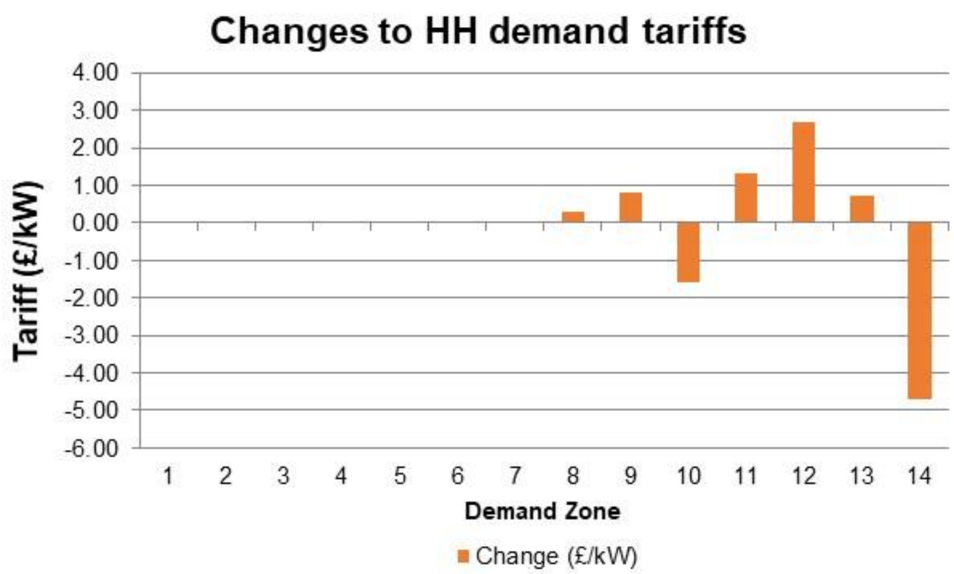
9. Half-Hourly demand tariffs

Table 11 shows the Draft gross HH demand tariffs for 2024/25 compared to the July forecast.

Table 11 Half-Hourly demand tariffs

Zone	Zone Name	2024/25 July (£/kW)	2024/25 November (£/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	2.090372	2.373140	0.282768
9	Eastern	-	0.827333	0.827333
10	South Wales	6.075306	4.503510	- 1.571796
11	South East	2.520346	3.859199	1.338853
12	London	3.028687	5.734465	2.705778
13	Southern	6.127129	6.869733	0.742604
14	South Western	12.883741	8.198917	- 4.684824

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the fluctuations in tariffs for zones 8 through to 14 tariffs are due to a combination of an increase in the forecast Expansion Constant (EC) an increase of £0.07 £/MWkm since July tariffs and changes in the charging base (changes in forecast Gross and HH demand across zones) have also had an impact on locational tariffs which make up the HH tariff.

The forecast level of gross HH chargeable demand has reduced by 0.73GW in comparison with the July tariffs and is currently forecast at 17.19GW.

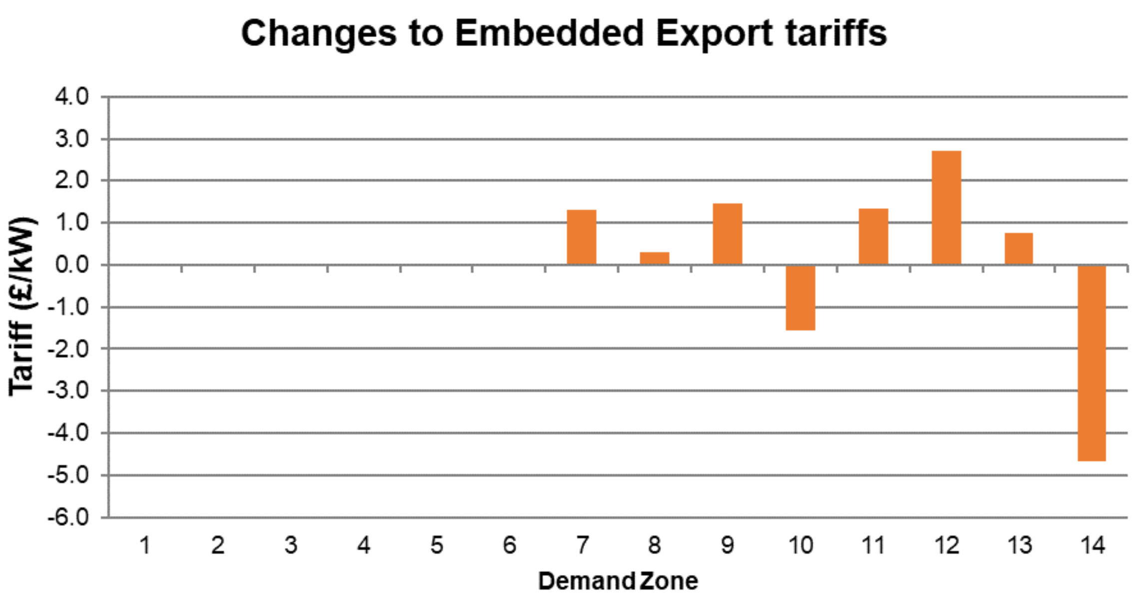
10. Embedded Export Tariffs (EET)

The next table shows the difference in Embedded Export Tariffs between the July and Draft forecast.

Table 12 Embedded Export Tariffs

Zone	Zone Name	2024/25 July (£/kW)	2024/25 November (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	1.272676	2.565718	1.293042
8	Midlands	4.792714	5.085894	0.293180
9	Eastern	2.077003	3.540087	1.463084
10	South Wales	8.777648	7.216264	- 1.561384
11	South East	5.222688	6.571953	1.349265
12	London	5.731029	8.447219	2.716190
13	Southern	8.829471	9.582487	0.753016
14	South Western	15.586083	10.911671	- 4.674412

Figure 3 Embedded export tariff changes



In this forecast, there has been an increase to the average EET tariff of 0.12/kW versus the July forecast. This is primarily due to a change in locational demand and a change in forecast Embedded Export Volumes. The changes in locational demand tariffs and the corresponding impact of the update to Week 24 demand data can be seen in Table 25. The Embedded Export Volume has increased from 0.62GW to 7.48GW since the July forecast. There has been a slight increase to the avoided GSP Infrastructure Costs (AGIC) of £0.01/kW to £2.71/kW due to an increase in inflation for 2024/25. The overall impact of these changes has increased the average EET by £0.12/kW to £2.58/kW.

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 residual tariffs.

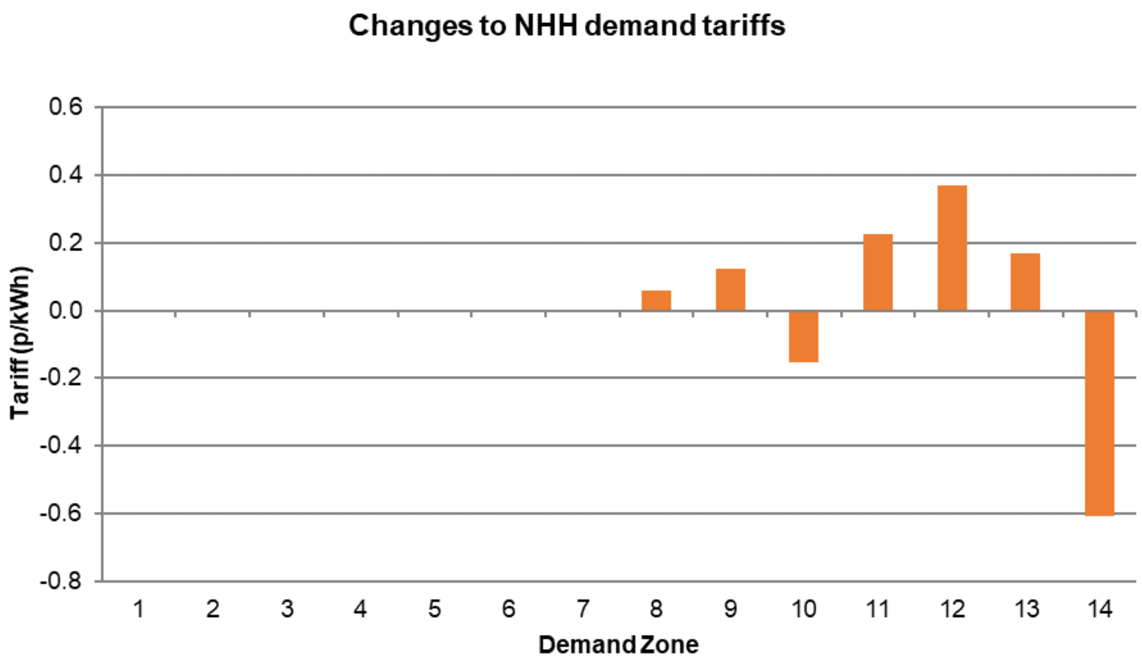
11. Non-Half-Hourly demand tariffs

Table 13 and Figure 4 show the difference between the 2024/25 July forecast compared to the Draft forecast.

Table 13 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2024/25 July (p/kWh)	2024/25 November (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	0.270342	0.331477	0.061135
9	Eastern	-	0.121828	0.121828
10	South Wales	0.713381	0.561335	- 0.152046
11	South East	0.345266	0.572982	0.227716
12	London	0.318591	0.687413	0.368822
13	Southern	0.794154	0.964020	0.169866
14	South Western	1.793581	1.185452	- 0.608129

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2024/25 Draft forecast is set at 0.33p/kWh, a 0.04p/kWh increase compared to July forecast. The fluctuations in NHH tariffs since July forecast are driven by the changes to the Demand Charging Base (reduction of 1.3TWh) and zonal NHH demand revenue recovery (increase of £6m since July forecast).

Overview of data inputs

ESO

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

12. Inputs affecting the locational element of tariffs

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

- Contracted position of generation;
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor;
- Expansion constant

Contracted, 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.[5] The contracted TEC volumes are based on the 31st October 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 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. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2024.

Table 14 Contracted, Modelled & Chargeable TEC

	2024/25 Tariffs			
Generation (GW)	Initial	July	Draft	Final
Contracted TEC	104.55	102.94	101.10	
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	85.23	

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 as stated in the interconnector register as of 31st October 2023.

[5] 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
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	1,988	0
IFA2 Interconnector	Chilling 400kV Substation	France	26	0	1,100	0
Lion (EuroLink)	Friston 400kV Substation	Netherlands	18	0	1,600	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	500	0
Nemo Link	Richborough 400kV Substation	Belgium	24	0	1,020	0
NS Link	Blyth GSP	Norway	13	0	1,400	0
Viking Link	Bicker Fen 400kV Substation	Denmark	17	4	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 £17.891453/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 (or at asset transfer, if later), 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 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 finalised by January Final Tariffs based on Onshore and Offshore TOs' final 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	1,840.8	-
Scottish Power Transmission	500.9	503.6	452.4	-
SHE Transmission	979.8	984.9	736.8	-
Total TO Income from TNUoS	**3,703.8**	**3,723.8**	**3,030.1**	**-**
Other Income from TNUoS				
Other Pass-through from TNUoS	107.3	96.7	113.8	-
Offshore (plus interconnector contribution / allowance)	764.8	785.9	869.9	-
Total Other Income from TNUoS	**872.1**	**882.5**	**983.6**	**-**
Total to Collect from TNUoS	**4,575.9**	**4,606.3**	**4,013.7**	**-**

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.

In line with the Limiting Regulation, the average TNUoS generation charge, excluding local charges associated with Physical Assets Required for Connection (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.

The majority of TNUoS local charges (including onshore and offshore local charges) fall into the definition of Charges for PARC, however, a small part of the TNUoS onshore local charges (about £7.9m in this forecast) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is a change of +£0.4m of local charges associated with pre-existing assets since the July forecast, due to progress made to update the pre-existing asset database, and inflation on the expansion constant.

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	2.50	
y	Error Margin	23.6%	31.4%	31.4%	
ER	Exchange Rate (€/£)	1.12	1.12	1.12	
MAR	Total Revenue (£m)	4,575.9	4,606.3	4,013.7	
GO	Generation Output (TWh)	189.9	204.0	204.0	
G	% of revenue from generation	22.06%	22.49%	26.18%	
D	% of revenue from demand	77.94%	77.51%	73.82%	
G.R	Revenue recovered from generation (£m)	1,009.3	1,035.8	1,050.6	
D.R	Revenue recovered from demand (£m)	3,566.6	3,570.5	2,963.1	
Breakdown of generation revenue					
	Revenue from the Peak element	103.0	111.1	115.2	
	Revenue from the Year Round Shared element	187.0	180.0	141.9	
	Revenue from the Year Round Not Shared element	132.6	201.4	194.5	
	Revenue from Onshore Local Circuit tariffs	19.6	45.0	46.5	
	Revenue from Onshore Local Substation tariffs	12.0	12.5	13.1	
	Revenue from Offshore Local tariffs	656.1	672.8	685.7	
	Revenue from the adjustment element	-101.1	-186.9	-146.4	
G.MAR	Total Revenue recovered from generation (£m)	1,009.3	1,035.8	1,050.6	
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	7.5	7.9	

The “gen cap”

Paragraph 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[6] 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).

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/£.

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

Generation Output

The forecast output of generation is 204TWh and was updated in our July forecast. 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 was updated and finalised in the July 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	13531
Glen App Windfarm	1.848396	
Beinneun Wind Farm	0.057785	
Afton Wind Farm	0.000000	
Benbrack wind farm	0.423078	
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	
Edinbane Windfarm	0.000000	
Ewe Hill	0.000000	
Fallago Rig Wind Farm	0.000000	
Carraig Gheal Wind Farm	5.208067	
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	0.242076	
Aikengall II Windfarm	0.000000	
Whitelee Extension	0.000000	
Bhlaraidh Wind Farm	0.000000	
Dorenell Windfarm	1.243773	
Harting Rig Wind Farm	0.000000	
Middle Muir Wind Farm	0.000000	
Aberdeen Offshore Wind Farm	0.000000	
Glen Kyllachy Wind Farm	0.554519	
Enoch Hill	0.000000	
Galawhistle Wind Farm	0.000000	
Kennoxhead Wind Farm	0.000000	
Broken Cross Windfarm	1.292604	
Hunterston Energy Storage Facility	0.000000	
Kincardine Battery Storage Facility	0.000000	
Limekiln	0.000000	
Cumberhead West Wind Farm	0.000000	
Shepherds Rig Wind Farm	-0.092410	
Viking Wind Farm	0.000000	
Arecleoch Windfarm Extension	0.393662	
Sanquhar Wind Farm	1.562191	
Crossdykes	0.000000	
Aikengall IIa Wind Farm	0.000000	
Kype Muir	0.000000	
Kennoxhead Wind Farm Extension	0.000000	
Cumberhead	0.000000	
Chirmorie Wind Farm	-0.473685	
Sandy Knowe Wind Farm	2.544866	
Douglas West	0.000000	
Dalquhandy Wind Farm	0.000000	
Stranoch Wind Farm	-0.473685	
Twentyshilling Wind Farm	1.562191	
Douglas West Extension	0.000000	
Whiteside Hill Wind Farm	1.562191	
Windy Rig Wind Farm	0.000000	
Windy Standard II (Brockloch Rig) Wind Farm	0.000000	
Pencloe Windfarm	0.000000	
Glenmuckloch Wind Farm	1.562191	
Sanquhar II Wind Farm	1.562191	

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	0.174450	37.2
Toddleburn Wind Farm	0.174450	

20. Charging bases for 2024/25

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 85.23GW, which is an increase of 0.5GW since the July forecast. It is based on our internal view of what generation we expect to connect next financial year.

For the Final Tariffs (as per these Draft 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 -September 2023)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

With recent historical trends and forward-looking assumptions (excluding the impact of COVID-19) demand volumes are forecasted to plateau over the next couple of years because of the downturn in the economy. Adjustments have been made in our forecast since the July forecast for 2024/25 based on the latest demand outturn data up to end of September 2023. Please refer to table TAA in the published tables excel spreadsheet[7] for a detailed breakdown of the changes to the demand charging bases.

Table 21 Charging bases

	2024/25 Tariffs			
Charging Bases	Initial	July	Draft	Final
Generation (GW)	78.00	84.69	85.23	
NHH Demand (4pm-7pm TWh)	24.91	23.05	21.75	
Gross charging				
Total Average Gross Triad (GW)	49.65	47.45	47.02	
HH Demand Average Gross Triad (GW)	18.16	17.93	17.19	
Embedded Generation Export (GW)	7.11	6.86	7.48	

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 draft version of the 2024/25 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.[8]

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.

[7] Please see the Numerical data section of 'Tools and Supporting Information' for the link to the published tables excel spreadsheet.
[8] https://www.nationalgrideso.com/document/294546/download

Demand residual banded charges

Since the implementation of CMP343 the demand residual tariff has been excluded from the 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.

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%	26.18%	
D	Proportion of revenue recovered from demand (%)	77.94%	77.51%	73.82%	
R	Total TNUoS revenue (£m)	4,575.9	4,606.3	4,013.7	
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	422.5	492.5	451.5	
O	Revenue recovered from offshore local tariffs (£m)	656.1	672.8	685.7	
L_G	Revenue recovered from onshore local substation tariffs (£m)	12.0	12.5	13.1	
S_G	Revenue recovered from onshore local circuit tariffs (£m)	19.6	45.0	46.5	
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	7.5	7.9	
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	
	Error Margin	23.6%	31.4%	31.4%	
	Exchange Rate (€/£)	1.12	1.12	1.12	
	Total generation Output (TWh)	189.9	204.0	204.0	
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	324.5	313.0	313.0	
	Adjustment Revenue (£m)	-101.1	-186.9	-146.4	
BG	Generator charging base (GW)	78.0	84.7	85.2	
AdjTariff	Generator adjustment tariff (£/kW)	-1.30	-2.21	-1.72	
Gross demand residual					
R_D	Demand residual (£m)	3,470.1	3,484.7	2,869.8	
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	115.9	102.0	112.0	
EE	Amount to be paid to Embedded Export Tariffs (£m)	-19.9	-16.9	-19.3	
B_D	Demand Gross charging base (GW)	49.6	47.4	47.0	

Tools and supporting information

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

Charging webinars

We will be hosting a webinar for the Draft Forecast on Tuesday 12th December. 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/294576/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**.

TNUoS Generation Tariff = Wider Tariff + Local Substation Tariff * + Local Circuit Tariff * + Embedded Network System Charges *

Note: Additional Local Tariffs may be applicable to Offshore generators

*** Local Tariffs**

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

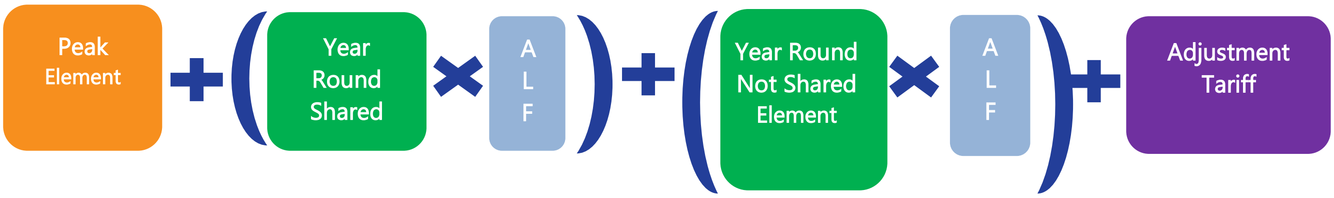
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

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

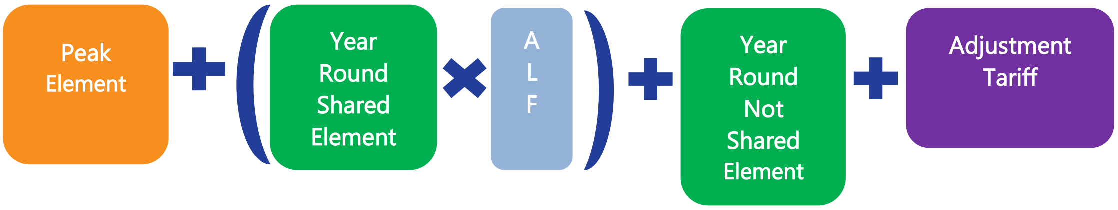
Conventional Carbon Generators

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



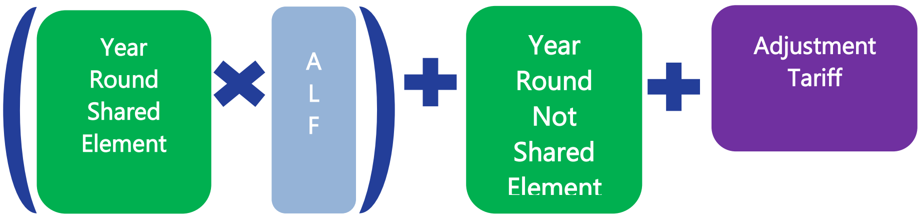
Conventional Low Carbon Generators

(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[9] if they want to export power onto the transmission system from the distribution network using “firm” transmission network capacity. Generators will incur local DUoS[10] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

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

Generation 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 calendar month.

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

[10] 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 final 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.[11] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is 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[12], 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 to avoid 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 submit forecasts for both HH gross demand and embedded export volumes. Customers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon (up to 16 months after the financial year in question).

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

Embedded generators (<100MW CVA registered) will receive payment following the 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.

[11] https://www.nationalgrideso.com/industry-information/charging/triads-data
[12] https://www.nationalgrideso.com/document/130641/download
[13] 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 now make up majority of the TNUoS demand charge in the form of a set of daily charges per site in each of the residual charging bands, this is a non locational charge.

Appendix B: Changes and proposed changes to the charging methodology

ESO

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
CMP315/375	Expansion Constant & Expansion Factors review	Affect TNUoS locational tariffs for generators and demand users	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
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	
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.	
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	
CMP405	TNUoS Locational Demand Signals for Storage	Separate out the demand Year Round locational signals from Peak Security locational Signals and charge (reward) Storage which imports during times other than Triads	
CMP418	Refine the allocation of Static Var Compensators (SVC) costs at OFTO transfer	Socialise SVC costs through wider TNUoS charges.	
Modifications directed for 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	1st April 2024
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	1st April 2024

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

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 July		2024/25 November		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.582460	-34.697917	-1.288362	-31.636748	1.294097	3.061169
2	Southern Scotland	-2.681924	-22.654641	-2.269814	-22.130105	0.412111	0.524536
3	Northern	-3.371713	-9.833545	-3.015987	-8.980381	0.355726	0.853164
4	North West	-0.985879	-5.234037	-0.770094	-4.024376	0.215784	1.209661
5	Yorkshire	-2.422038	-3.304541	-2.010936	-2.179229	0.411101	1.125312
6	N Wales & Mersey	-1.849476	-2.158502	-1.654145	-1.099594	0.195331	1.058908
7	East Midlands	-2.348905	0.919239	-2.078202	1.931165	0.270703	1.011926
8	Midlands	-1.158415	3.248787	-1.205299	3.578439	-0.046884	0.329651
9	Eastern	0.836906	-1.462245	1.149629	-0.322296	0.312723	1.139949
10	South Wales	-2.622397	8.697703	-4.273545	8.777054	-1.651148	0.079352
11	South East	3.450012	-0.929665	3.602929	0.256270	0.152918	1.185935
12	London	3.759636	-0.730949	4.593628	1.140837	0.833992	1.871786
13	Southern	2.069160	4.057969	2.071641	4.798092	0.002481	0.740123
14	South Western	3.512459	9.371282	-0.016177	8.215094	-3.528635	-1.156189

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

Demand Zone		2024/25 July		2024/25 November		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-37.280376	2.702342	-32.925110	2.712754	4.355266	0.010412
2	Southern Scotland	-25.336565	2.702342	-24.399919	2.712754	0.936647	0.010412
3	Northern	-13.205259	2.702342	-11.996368	2.712754	1.208891	0.010412
4	North West	-6.219916	2.702342	-4.794470	2.712754	1.425446	0.010412
5	Yorkshire	-5.726579	2.702342	-4.190166	2.712754	1.536413	0.010412
6	N Wales & Mersey	-4.007978	2.702342	-2.753739	2.712754	1.254239	0.010412
7	East Midlands	-1.429666	2.702342	-0.147036	2.712754	1.282630	0.010412
8	Midlands	2.090372	2.702342	2.373140	2.712754	0.282768	0.010412
9	Eastern	-0.625339	2.702342	0.827333	2.712754	1.452672	0.010412
10	South Wales	6.075306	2.702342	4.503510	2.712754	-1.571797	0.010412
11	South East	2.520346	2.702342	3.859199	2.712754	1.338853	0.010412
12	London	3.028687	2.702342	5.734465	2.712754	2.705778	0.010412
13	Southern	6.127129	2.702342	6.869733	2.712754	0.742604	0.010412
14	South Western	12.883741	2.702342	8.198917	2.712754	-4.684824	0.010412

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 draft version of the 2024/25 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2018/19 to 2022/23. Generators which commissioned after 1 April 2020 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 2024/25 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 have been updated with the recently released Draft ALFs. These are available for industry consultation until Thursday 21st December, after which they will become final. It is feasible that the ALFs may therefore change ahead of the January Final tariffs following this consultation period. The specific and generic 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	1.6301%
Biomass	45.5650%
CCGT_CHP	49.4274%
Coal	16.3291%
Gas_Oil	0.4504%
Hydro	40.4462%
Nuclear	61.9265%
Offshore_Wind	46.7794%
Onshore_Wind	38.6821%
Pumped_Storage	8.3570%
Reactive_Compensation	0.0000%
Solar	10.9000%
Tidal	12.6000%
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 is now fixed using the TEC register as of 31 October 2023, as required by CUSC 14.15.6 and no further changes to Contracted TEC will be made.

Table 27 shows the contracted generation changes notified since the July forecast using data from the October 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
Arecleoch Windfarm Extension	-72.8	AREX10	10
BOOM Power Llanbabo Generation	-300	WYLF40	19
Bramford (Tertiary)	7.1	BRFO40	18
Bramley BESS	-50	BRLE40	25
Bustleholme	49.9	BUST20	18
Carrington	50	CARR20	16
Chapel Farm Battery Storage Project	49.5	SUND40	18
Chirmorie Wind Farm	-80	CHMO10	10
Coventry	49.9	COVE20	18
Cowley (Tertiary)	50	COWL40	25
Coylton 275kV Greener Grid Park	-49.9	COYL20	10
IFA Interconnector	-12	SELL40	24
Immingham	50	HUMR40	15
Indian Queens Energy	-50	INDQ40	27
Indian Queens PP	-2.4	INDQ40	27
Iron Acton	-21	IROA10	22
Isenau Eight	249	HAWP20	13
Kirkby	-50	KIBY20	15
Landulph	49.9	LAND4A	27
Llanwern Phase 1	-95	WHSO20	21
Melksham (Tertiary)	49.9	MELK40_SEP	22
Neilston 132kV Greener Grid Park	0	NEIL10	10
NeuConnect Interconnector	-1400	GRAI40	24
Norwich PP	7	NORM40	18
Powersite @ Drakelow	380	DRAK40	18
Seagreen 1A Offshore Wind Farm	-500	COCK20	11
Stranoch Wind Farm	-102	STOC10	10
Alverdiscott PP	-50	ALVE4A	27
Taunton	-49.9	TAUN4A	26

Appendix F: Transmission company revenues

ESO

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have updated us with their revenue forecast for year 2024/25, and the revenue forecasts will be updated again in January 2024. In addition, there are some pass-through items that are to be collected by ESO via TNUoS charges, including the Strategic Innovation Fund (SIF) and contributions made from interconnectors.

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 places 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 July forecast, it can be observed that there have been significant changes (see table 28) with the most notable variations being seen with a decrease in TO Revenue. The total TNUoS revenue is forecast at £4.01bn for FY24/25, (a decrease of £593m from the July forecast). This decrease is mainly due to the October submissions of Allowed Revenue from the TOs which are the first full submissions since January 2023 and will therefore have significantly newer data supporting them. As such the Allowed Revenue has changed for NGET (-£394.5m), SPT (-£51.2m) and SHET (-£248.1m).

Other changes seen are reviews of the Adjustment Term and pass-through items as actual data replaces forecast data (£17.1m) and revisions to OFTO allowed revenue plus interconnector contributions (£84m).

Table 28 ESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through			
	Initial Forecast	July Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.70	0.69	0.69	
Network Innovation Competition Fund (NICFt)	3.00	3.00	3.00	
Strategic Innovation Fund (SIFt)	45.50	45.50	60.83	
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	869.87	
Interconnectors CACM Cost Recovery (ICPt)	-12.88	-12.88	-11.09	
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	
Termination Sums (TSt)	25.00	25.00	25.00	
NGET revenue pass-through (NGETTOt)	2,223.09	2,235.26	1,840.80	
SPT revenue pass-through (TSPt)	500.87	503.60	452.41	
SHETL revenue pass-through (TSHt)	979.83	984.94	736.85	
ESO Bad debt (BDt)	3.58	3.12	3.12	
ESO other pass-through items (LFt + ITCt etc)	42.38	38.21	38.21	
ESO legacy adjustment (LARt)	0.00	2.69	2.69	
Total	**4,575.87**	**4,606.32**	**4,013.70**	

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their revenue breakdown and will next update them in January 2024.The current forecasts include updates in correction term and adjustment data, and refreshed forecasts of inflation. The data is liable to change as inflation parameters are updated. The allowed revenue figures will be finalised in the January 2024 submission by TOs and will incorporate any potential upward and downward changes.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2024/25 is forecast to be £869.9m, an increase of £8.9m since the July forecast. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to the latest RPI and CPI data (as part of the calculation of each OFTO's 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.

In addition, Ofgem has directed that some cost recovery submissions under the Capacity Allocation and Congestion Management (CACM) cost will be recovered via 2024/25 TNUoS revenue, as a one-off adjustment. The total amount of interconnector adjustment will be finalised in January.

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	283.31	
Inflation		PI_t	352.77	354.65	355.83	
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,840.10	1,840.10	1,726.28	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-258.56	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**2,291.27**	**2,303.45**	**1,909.59**	
SONIA	B1	It-1	4.78%	4.78%	4.78%	
Allowed Revenue	B2	ARt-1	2,397.06	2,397.06	2,363.45	
Recovered Revenue	B4	RRt-1	2,397.06	2,397.06	2,363.45	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**	**0.00**	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	-56.66	-56.66	-56.96	
Legacy K correction	C3	LKt	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	-11.52	-11.52	-11.83	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	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	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	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	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**	**-68.79**	
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**	**1,840.80**	

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	283.31	
Inflation		PI_t	352.77	354.65	355.83	
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	412.42	412.42	390.93	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-21.01	
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**513.55**	**516.27**	**469.98**	
SONIA	B1	It-1	4.78%	4.78%	4.78%	
Allowed Revenue	B2	ARt-1	0.00	0.00	543.14	
Recovered Revenue	B4	RRt-1	0.00	0.00	547.70	
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**-4.83**	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	-12.06	-12.06	-12.13	
Legacy K correction	C3	LKt	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	-0.70	-0.70	-0.70	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	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	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	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.09	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**	**-12.74**	
Site Rental Charges				**0.00**		
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**500.87**	**503.60**	**452.41**	

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	283.31	
Inflation		PI_t	352.77	354.65	355.83	
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	772.70	772.70	696.96	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-145.24	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**962.16**	**967.27**	**730.12**	
SONIA	B1	It-1	4.78%	4.78%	4.78%	
Allowed Revenue	B2	ARt-1	859.13	859.13	848.99	
Recovered Revenue	B4	RRt-1	859.13	859.13	859.47	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**	**-11.11**	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	14.50	14.50	14.58	
Legacy K correction	C3	LKt	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	3.17	3.17	3.26	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	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	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	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	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**	**17.84**	
Site Rental Charges				**0.00**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**979.83**	**984.94**	**736.85**	

Table 32 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	Year				
Regulatory Year	2021/22	2022/23	2023/24	2024/25	Notes
Barrow	6.7	7.0	7.8	8.5	Current revenues plus indexation
Gunfleet	8.4	8.7	9.7	10.7	Current revenues plus indexation
Walney 1	15.3	15.6	17.8	19.5	Current revenues plus indexation
Robin Rigg	9.4	9.8	10.9	12.0	Current revenues plus indexation
Walney 2	15.1	16.3	18.3	20.0	Current revenues plus indexation
Sheringham Shoal	23.4	24.2	26.7	29.5	Current revenues plus indexation
Ormonde	14.1	14.7	16.2	17.9	Current revenues plus indexation
Greater Gabbard	32.1	33.2	37.0	40.2	Current revenues plus indexation
London Array	44.7	46.8	52.6	57.1	Current revenues plus indexation
Thanet	20.8	21.6	24.0	26.4	Current revenues plus indexation
Lincs	30.0	32.5	34.0	39.0	Current revenues plus indexation
Gwynt y mor	32.9	39.8	37.6	38.4	Current revenues plus indexation
West of Duddon Sands	25.3	25.5	28.5	30.3	Current revenues plus indexation
Humber Gateway	14.4	13.3	15.0	16.5	Current revenues plus indexation
Westermost Rough	14.1	14.7	16.5	18.0	Current revenues plus indexation
Burbo Bank	14.1	14.7	16.4	17.5	Current revenues plus indexation
Dudgeon	19.6	20.8	22.6	24.9	Current revenues plus indexation
Race Bank	27.4	28.9	32.5	35.0	Current revenues plus indexation
Galloper	17.1	17.8	20.1	21.7	Current revenues plus indexation
Walney 3	13.5	14.1	15.9	17.3	Current revenues plus indexation
Walney 4	13.5	14.1	15.9	17.3	Current revenues plus indexation
Hornsea 1A	137.1	18.4	20.6	22.6	Current revenues plus indexation
Hornsea 1B		18.4	20.6	22.6	Current revenues plus indexation
Hornsea 1C		18.4	20.6	22.6	Current revenues plus indexation
Beatrice		21.1	24.4	25.6	Current revenues plus indexation
Rampion		15.5	17.4	19.6	Current revenues plus indexation
East Anglia 1		68.3	47.4	51.8	Current revenues plus indexation
Hornsea 2A			138.7	25.3	Current revenues plus indexation
Hornsea 2B				25.3	Current revenues plus indexation
Hornsea 2C				25.3	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2023/24				57.1	National Grid Forecast
Forecast to asset transfer to OFTO in 2024/25				54.7	National Grid Forecast
Offshore Transmission Pass-Through (B7)	**549.0**	**594.3**	**765.6**	**869.9**	

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 Revenue.

Appendix G: Generation zones map

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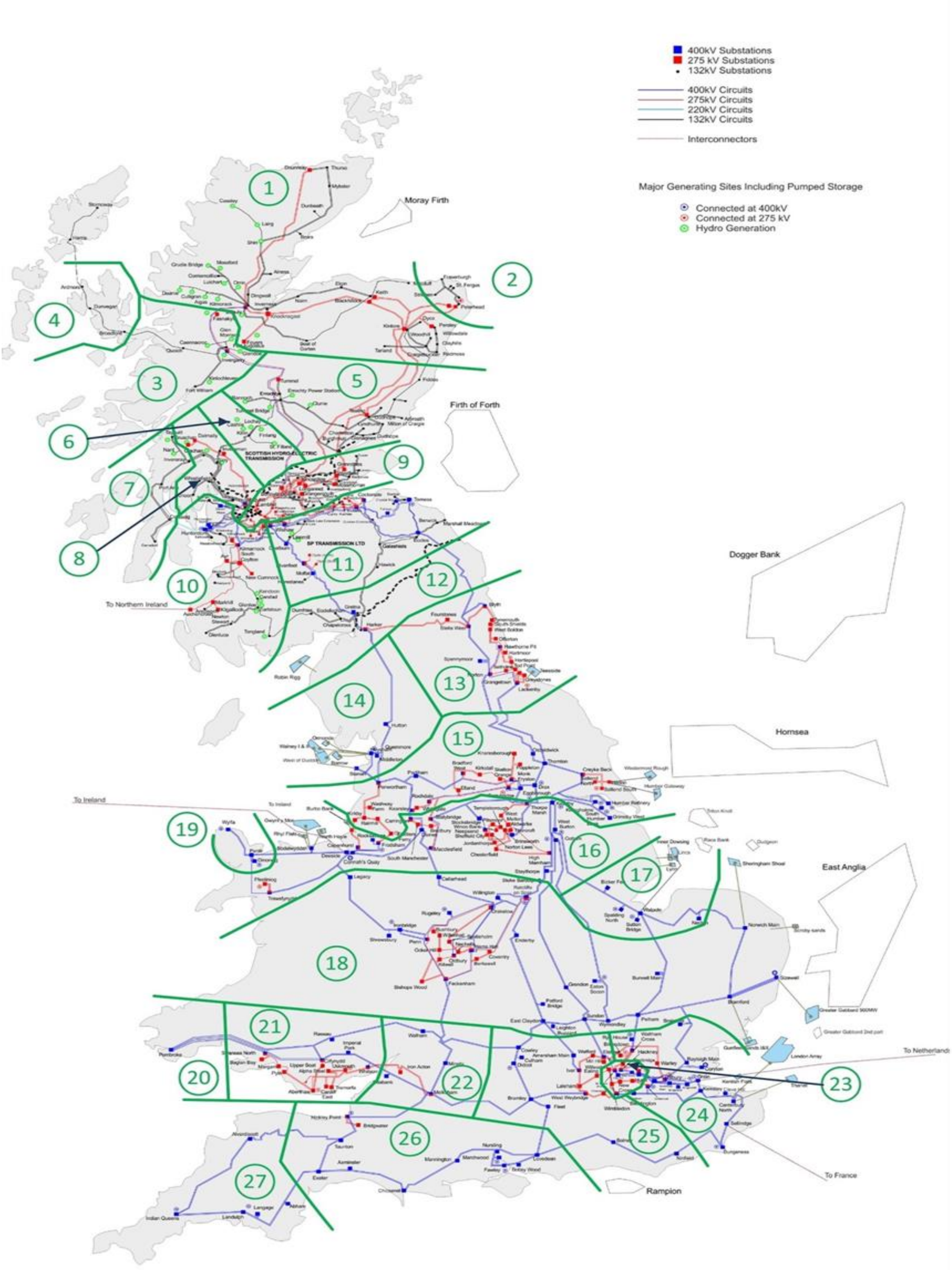
Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to [ETYS 2022 AppA _ diagrams]

Appendix H: Demand zones map

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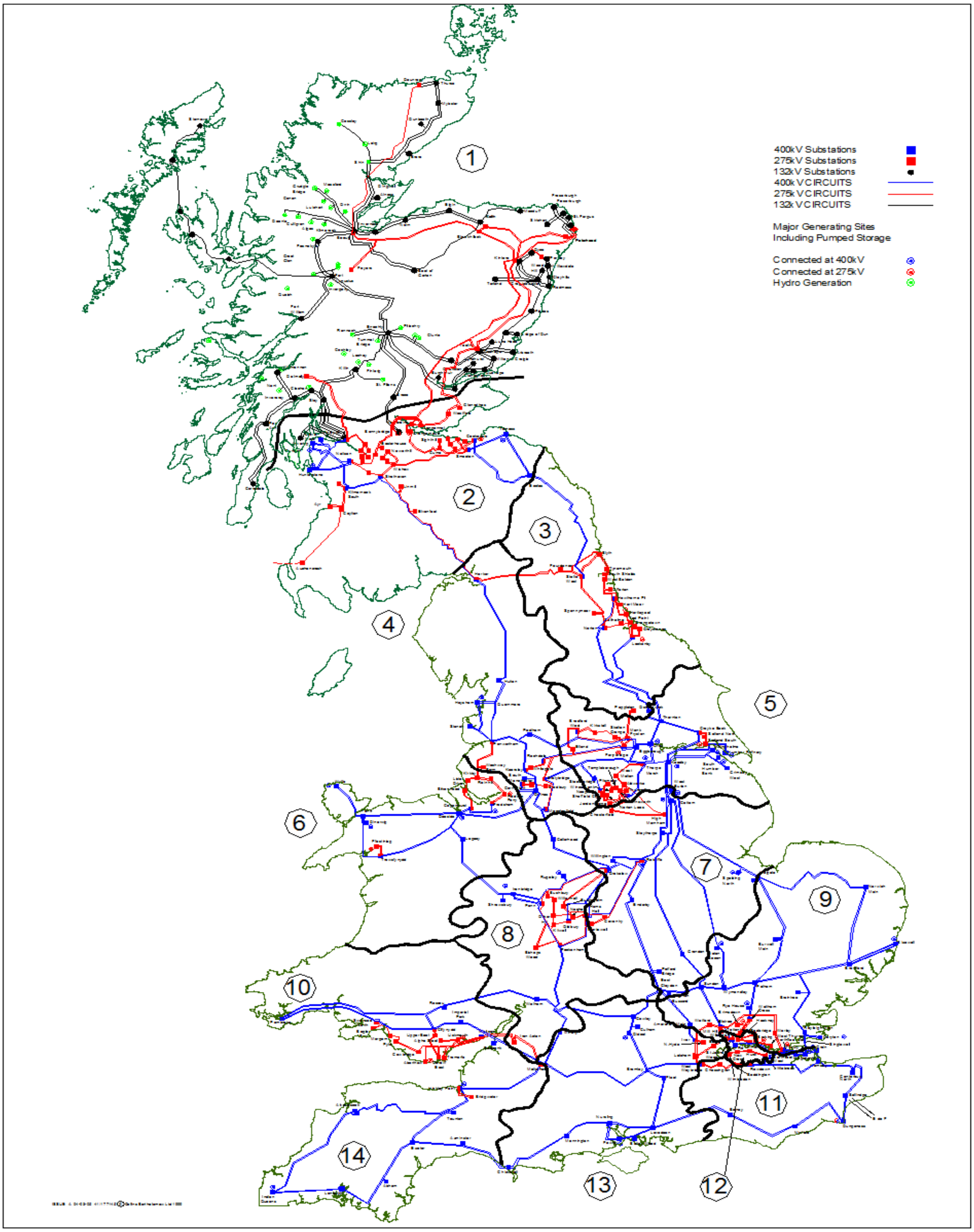
400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
1
2
3
4
5
6
7
8
9
10
11
12
13
14

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	
LOCATIONAL	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
LOCATIONAL	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
LOCATIONAL	Inflation	Forecast			Actual
RESIDUAL / ADJUSTMENT	OFTO Revenue *(part of allowed revenue)*	Forecast	Forecast	Forecast	NG best view
RESIDUAL / ADJUSTMENT	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
RESIDUAL / ADJUSTMENT	Demand Charging Bases	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
RESIDUAL / ADJUSTMENT	Banding Data	Previous year's data source		DNO/IDNO consumption and site data updated	
				Transmission Data updated	Transmission Data finalised
RESIDUAL / ADJUSTMENT	Generation Charging Base	NG best view	NG best view	NG best view	NG final best view
RESIDUAL / ADJUSTMENT	Generation ALFs	Previous year's data source		Draft ALFs published	Final ALFs published
RESIDUAL / ADJUSTMENT	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	30th November 2023	Publication of Draft TNUoS Tariffs for 2024/25
2.0	11th December 2023	SHETL November inflation figure corrected in Table 31. Minor typographical errors corrected within report and tables file.

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