Version 2.0

Final TNUoS Tariffs for 2024/25

Electricity System Operator

January 2024

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 Final 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 the Final Transmission Network Use of System (TNUoS) tariffs for year 2024/25 on our website[1].

These tariffs will take effect from 1st April 2024, they have no impact on charging year 2023/24.

Total revenues to be recovered

The total TNUoS revenue is forecast at £4.19bn for 2024/25. This is a decrease of £225.5m from 2023/24, however an increase of £174.8m since Draft forecast. This increase since Draft is due to January submissions of Allowed Revenue from the onshore TOs (+£218.6m), revisions to OFTO allowed revenue (+£9.9m), interconnector revenue contributions (-£76.5m), and other pass-through costs (+£22.7m).

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.06bn for 2024/25, an increase of £7.4m since the Draft forecast. This is mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base has been updated to 82.94GW based on our best view on generation projects for 2024/25. This is a decrease of 2.3GW since the Draft forecast. The average generation tariff is £12.76/kW, an increase of £0.43/kW due to the increase in revenue to be collected from generation and the decrease to the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £3,130m for 2024/25, a £167.4m increase since the Draft tariffs. This is driven by the increase of total TNUoS revenue of £174.8m.

Of this total, £3,037m is forecast to be collected via the Transmission Demand Residual an increase of (£167.3m) compared to our Draft forecast.

The impact on the end consumer is forecast to be £39.79 for FY24/25 (3.6% of the average annual electricity consumer bill), an increase of £2.05 from the 2024/25 Draft forecast. This is due to the increase of the domestic transmission demand residual charge since the Draft forecast. The 2024/25 impact on the end consumer is a £5.36 decrease since the 2023/24 value.

In 2024/25 it is forecast that £19.24m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), a decrease of £0.05m since the Draft forecast. This is due to the increase in the forecast charging base for Embedded Export and a decrease in the average locational tariffs. The average EET is forecast at £2.63/kW, which is an increase of £0.05/kW versus Draft forecast.

The average gross HH demand tariff for 2024/25 is to be £6.50/kW, a decrease of £0.01/kW compared to Draft forecast and the average NHH demand tariff forecast is at 0.31p/kWh, a decrease of 0.02p/kWh since Draft forecast.

Next TNUoS tariff publication

The timetable of TNUoS tariffs forecasts for 2025/26 is available on our website[2].

Our next TNUoS tariff publication will be our initial forecast of 2025/26 tariffs and the 5 Year View of TNUoS tariffs, which will be published in April 2024.

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

[2] https://www.nationalgrideso.com/document/301571/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 Final TNUoS tariffs for the charging year 2024/25.

The TNUoS tariff setting methodology defined in the CUSC is subject to open governance. We are obliged to comply with the latest approved CUSC changes applicable from 1st April 2024 in the Final Tariffs for 2024/25.

This section summarises any key changes to the methodology.

Charging methodology changes

We have incorporated CMP379: 'Determining TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)' which has been directed for operation with an implementation date of 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. In accordance with the CUSC methodology, we have created site specific tariffs for transmission connected users that are already connected to or are due to be connected to National Electricity Transmission System to multiple DNO areas in 2024/25.

Approved CUSC methodology changes that affect 2024/25 tariffs 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.

No changes proposed to be taken forward by the Task Force are being implemented in the 2024/25 tariffs.

[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

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1. Generation tariffs summary

This section summarises our view of generation tariffs for 2024/25 and how these tariffs were calculated.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2024/25 Draft	2024/25 Final	Change since last forecast
Adjustment	- 1.717191	- 1.529118	0.188073
Average Generation Tariff*	12.325803	12.755275	0.429472

*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 £0.43/kW, due to an increase of £7.4m in the revenue to be collected from generation and the 2.3GW decrease in the generation charging base, compared to the Draft forecast. The generation adjustment has increased by £0.19/kW, decreasing in magnitude, to become less negative; this is because the charging base has decreased since the Draft forecast and therefore less revenue is expected to be collected via the wider tariff components, 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%	Conventional Low Carbon 75%	Intermittent 45%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	2.996130	20.547337	18.248646	-1.529118	16.985405	35.126161	25.965830
2	East Aberdeenshire	4.134330	11.778569	18.248646	-1.529118	14.616098	29.687785	22.019884
3	Western Highlands	3.230485	20.305204	18.076420	-1.529118	17.054017	35.006690	25.684644
4	Skye and Lochalsh	-1.989329	20.305204	19.870000	-1.529118	12.551635	31.580456	27.478224
5	Eastern Grampian and Tayside	5.853910	15.742151	14.103528	-1.529118	16.263064	30.234933	19.658378
6	Central Grampian	4.942105	15.970825	14.409646	-1.529118	15.565175	29.800752	20.067399
7	Argyll	3.157627	14.100590	20.444992	-1.529118	15.446742	32.648944	25.261140
8	The Trossachs	3.944171	14.100590	11.871885	-1.529118	12.804043	24.862381	16.688033
9	Stirlingshire and Fife	2.474974	13.819136	11.646784	-1.529118	11.132224	22.956992	16.336277
10	South West Scotlands	2.707958	13.364269	11.382199	-1.529118	11.077427	22.584241	15.867002
11	Lothian and Borders	2.408183	13.364269	5.302762	-1.529118	8.345877	16.205029	9.787565
12	Solway and Cheviot	1.636696	8.689987	6.607014	-1.529118	6.226378	13.232082	8.988390
13	North East England	3.319860	6.079623	3.852638	-1.529118	5.763646	10.203097	5.059350
14	North Lancashire and The Lakes	1.255369	6.079623	1.383497	-1.529118	2.711499	5.669465	2.590209
15	South Lancashire, Yorkshire and Humber	4.196041	2.039167	0.341717	-1.529118	3.619277	4.538015	-0.269776
16	North Midlands and North Wales	2.996034	0.468681	-	-1.529118	1.654388	1.818427	-1.318212
17	South Lincolnshire and North Norfolk	1.263625	2.464145	-	-1.529118	0.720165	1.582616	-0.420253
18	Mid Wales and The Midlands	1.291875	4.206973	-	-1.529118	1.445546	2.917987	0.364020
19	Anglesey and Snowdon	4.761625	0.614076	-	-1.529118	3.478137	3.693064	-1.252784
20	Pembrokeshire	8.245736	-8.308040	-	-1.529118	3.393402	0.485588	-5.267736
21	South Wales & Gloucester	3.945510	-8.526868	-	-1.529118	-0.994355	-3.978759	-5.366209
22	Cotswold	3.461436	4.275752	-10.960559	-1.529118	-0.741605	-5.821427	-10.565589
23	Central London	-3.403205	4.275752	-3.548596	-1.529118	-4.641461	-5.274105	-3.153626
24	Essex and Kent	-3.148861	4.275752	-	-1.529118	-2.967678	-1.471165	0.394970
25	Oxfordshire, Surrey and Sussex	-0.703694	-2.203398	-	-1.529118	-3.114171	-3.885361	-2.520647
26	Somerset and Wessex	-1.116080	-4.720325	-	-1.529118	-4.533328	-6.185442	-3.653264
27	West Devon and Cornwall	-0.429420	-9.779349	-	-1.529118	-5.870278	-9.293050	-5.929825

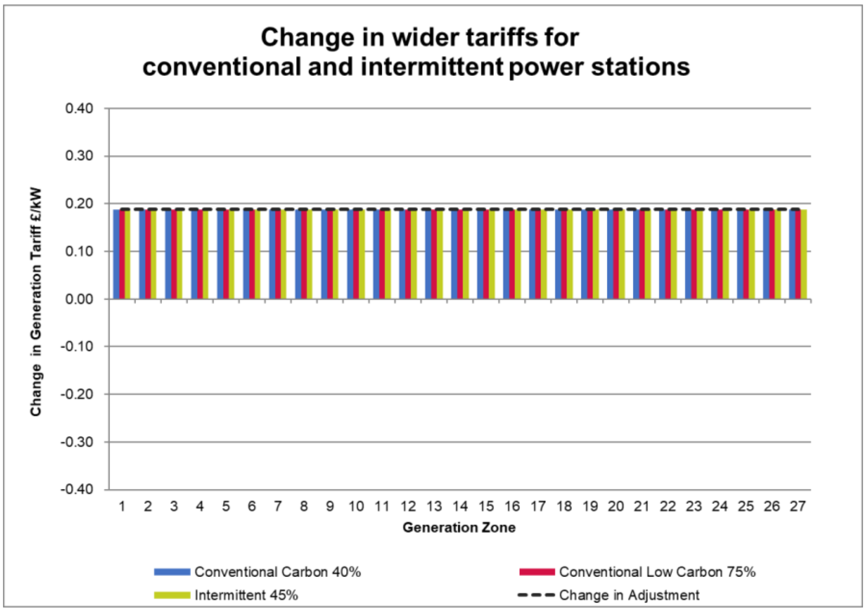
3. Changes to wider tariffs since the Draft Forecast

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

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			
Zone	Zone Name	2024/25 Draft	2024/25 Final	Change	2024/25 Draft	2024/25 Final	Change	2024/25 Draft	2024/25 Final	Change	Change in Adjustment
1	North Scotland	16.797332	16.985405	0.188073	34.938088	35.126161	0.188073	25.777757	25.965830	0.188073	0.188073
2	East Aberdeenshire	14.428025	14.616098	0.188073	29.499712	29.687785	0.188073	21.831811	22.019884	0.188073	0.188073
3	Western Highlands	16.865943	17.054017	0.188073	34.818616	35.006690	0.188074	25.496570	25.684644	0.188073	0.188073
4	Skye and Lochalsh	12.363561	12.551635	0.188073	31.392382	31.580456	0.188074	27.290150	27.478224	0.188073	0.188073
5	Eastern Grampian and Tayside	16.074990	16.263064	0.188073	30.046860	30.234933	0.188074	19.470305	19.658378	0.188073	0.188073
6	Central Grampian	15.377101	15.565175	0.188074	29.612678	29.800752	0.188074	19.879326	20.067399	0.188073	0.188073
7	Argyll	15.258669	15.446742	0.188073	32.460871	32.648944	0.188073	25.073067	25.261140	0.188073	0.188073
8	The Trossachs	12.615970	12.804043	0.188073	24.674308	24.862381	0.188073	16.499960	16.688033	0.188073	0.188073
9	Stirlingshire and Fife	10.944151	11.132224	0.188073	22.768919	22.956992	0.188073	16.148204	16.336277	0.188073	0.188073
10	South West Scotlands	10.889354	11.077427	0.188073	22.396167	22.584241	0.188074	15.678929	15.867002	0.188073	0.188073
11	Lothian and Borders	8.157804	8.345877	0.188073	16.016955	16.205029	0.188074	9.599492	9.787565	0.188073	0.188073
12	Solway and Cheviot	6.038305	6.226378	0.188073	13.044009	13.232082	0.188074	8.800317	8.988390	0.188073	0.188073
13	North East England	5.575573	5.763646	0.188073	10.015024	10.203097	0.188073	4.871277	5.059350	0.188073	0.188073
14	North Lancashire and The Lakes	2.523426	2.711499	0.188073	5.481392	5.669465	0.188073	2.402136	2.590209	0.188073	0.188073
15	South Lancashire, Yorkshire and Humber	3.431202	3.619277	0.188074	4.349941	4.538015	0.188075	- 0.457849	- 0.269776	0.188073	0.188073
16	North Midlands and North Wales	1.466315	1.654388	0.188073	1.630353	1.818427	0.188074	- 1.506285	- 1.318212	0.188073	0.188073
17	South Lincolnshire and North Norfolk	0.532092	0.720165	0.188073	1.394543	1.582616	0.188073	- 0.608326	- 0.420253	0.188073	0.188073
18	Mid Wales and The Midlands	1.257473	1.445546	0.188073	2.729913	2.917987	0.188074	0.175946	0.364020	0.188073	0.188073
19	Anglesey and Snowdon	3.290064	3.478137	0.188073	3.504990	3.693064	0.188074	- 1.440857	- 1.252784	0.188073	0.188073
20	Pembrokeshire	3.205329	3.393402	0.188073	0.297515	0.485588	0.188073	- 5.455809	- 5.267736	0.188073	0.188073
21	South Wales & Gloucester	- 1.182429	- 0.994355	0.188073	- 4.166833	- 3.978759	0.188074	- 5.554282	- 5.366209	0.188073	0.188073
22	Cotswold	- 0.929678	- 0.741605	0.188073	- 6.009501	- 5.821427	0.188074	- 10.753662	- 10.565589	0.188073	0.188073
23	Central London	- 4.829534	- 4.641461	0.188073	- 5.462179	- 5.274105	0.188074	- 3.341699	- 3.153626	0.188073	0.188073
24	Essex and Kent	- 3.155752	- 2.967678	0.188073	- 1.659239	- 1.471165	0.188074	0.206897	0.394970	0.188073	0.188073
25	Oxfordshire, Surrey and Sussex	- 3.302244	- 3.114171	0.188073	- 4.073434	- 3.885361	0.188073	- 2.708720	- 2.520647	0.188073	0.188073
26	Somerset and Wessex	- 4.721401	- 4.533328	0.188073	- 6.373516	- 6.185442	0.188074	- 3.841338	- 3.653264	0.188073	0.188073
27	West Devon and Cornwall	- 6.058352	- 5.870278	0.188074	- 9.481125	- 9.293050	0.188075	- 6.117899	- 5.929825	0.188073	0.188073

Figure 1 Variation in generation wider zonal tariffs



Locational changes

The generation tariffs have increased by at least £0.188073/kW in every zone, due to the increase in the adjustment tariff (which has decreased in magnitude to become less negative). There is a small variation in tariffs for a number of zones since the Draft tariffs, which has been caused by an update to nodal demand at nodes that were affected by the implementation of CMP379, this has increased the Peak security tariff by £0.000001/kW in zones 6, 15 and 27 and increased the Year Round Shared tariff by £0.000001/kW in 16 zones across Great Britain. There has been no change to the Year Round Not Shared tariff since the Draft tariffs.

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 £0.19/kW since the Draft forecast, decreasing in magnitude, to become less negative. This is due to a reduction in the revenue to be collected by the wider tariff, caused by the decrease in the charging base, meaning that 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 was finalised within the Draft forecast, and therefore onshore local substation tariffs have not changed.

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.

The 2024/25 onshore local circuit tariffs have been finalised and remain unchanged since the Draft tariffs; however, the tariffs for Arecleoch Extension, Chirmorie and Stranoch have been removed as they have no contracted TEC within 2024/25 and therefore should not have had tariffs published in November. The final 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	Dunhill	1.741283	Lochay	0.369679
Aberdeen Bay	3.253177	Dunlaw Extension	1.696117	Luichart	0.684968
Achruach	- 3.012829	Dunmaglass	1.056667	Marchwood	- 0.287364
Aigas	0.821868	Edinbane	8.315968	Mark Hill	1.072131
An Suidhe	- 1.120900	Enoch Hill	1.615924	Middle Muir	2.772594
Arecleoch	2.920527	Ewe Hill	1.692310	Middleton	0.174111
Ayrshire Grid Collector	0.164288	Fallago	- 0.070945	Millennium South	0.528866
Beinneun Wind Farm	1.640514	Farr	4.226137	Millennium Wind	1.906385
Benbrack	0.885177	Fernoch	5.208303	Mossford	3.639452
Bhlaraidh Wind Farm	0.740386	Ffestiniogg	0.264173	Nant	- 1.511005
Black Hill	1.865660	Fife Grid Services	0.184443	Necton	0.531832
Black Law	2.033236	Finlarig	0.369679	Rhigos	0.128077
BlackCraig Wind Farm	6.306177	Foyers	0.339651	Rocksavage	- 0.017841
BlackLaw Extension	4.422820	Galawhistle	1.269233	Saltend	- 0.018858
Broken Cross	1.292604	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	Strathbrora	- 0.207902
Creag Riabhach	4.066472	Harestanes	2.772594	Strathy Wind	1.942483
Cruachan	2.164215	Hartlepool	0.036918	Stronelairg	1.299770
Culligran	2.101062	Invergarry	0.369679	Wester Dod	0.423078
Cumberhead Collector	0.846155	Kennoxhead	4.943037	Whitelee	0.128656
Cumberhead West	4.484188	Kergord	59.436040	Whitelee Extension	0.364524
Deanie	3.451745	Kilgallioch	1.286557		
Dersalloch	2.724961	Kilmorack	0.150076		
Dinorwig	2.865274	Kype Muir	1.798080		
Dorenell	2.487547	Langage	- 0.390760		
Douglas North	0.739359	Limekilns	2.155514		

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way they are modelled in the Transport and Tariff model. This table shows the circuits which have been amended in the model, to account for the one-off charges that have already been applied to generators. For more information, please see CUSC sections 2, paragraph 14.4 and 14.15.15.

Table 6 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Bhlaraidh 132kV	Glenmoriston 132kV	7.4km Cable	7.4km OHL	Bhlaraidh
Enoch Hill 132kV	New Cumnock 132kV	4.4km Cable	4.4km OHL	Enoch Hill
Glen Glass 132kV	Sandy Knowe132kV	4km Cable	4km OHL	Sandy Knowe
Coalburn 132kV	Cumberhead Collector 132kV	8.01km Cable	8.01km OHL	Dalquhandy
Cumberhead Collector 132k\	Galawhistle 132kV	3.69km Cable	3.69km OHL	Galawhistle
Coalburn 132kV	Kype Muir 132kV	17km Cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km Cable	13km OHL	Middle Muir
Crystal Rig 132kV	Wester Dod 132kV	3.9km Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km Cable	9.5km of OHL	Aberdeen Bay
East Kilbride South 275kV	Whitelee 275kV	6km Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Melgarve 132kV	Stronelairg 132kV	10km Cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km Cable	15.33km OHL	Harestanes
Arecleoch 132kV	Arecleoch Tee 132kV	2.5km Cable	2.5km OHL	Arecleoch
Wishaw 132kV	Blacklaw 132kV	11.46km Cable	11.46km of OHL	Blacklaw

Offshore local tariffs for generation

6. Offshore local generation tariffs

The offshore local 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 November, 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 Draft Tariff Component (£/kW)			2024/25 Final Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.260530	59.488802	1.477188	11.252890	59.448440	1.476186	- 0.007640	- 0.040362	- 0.001002
Beatrice	9.143187	25.069066	-	9.143187	25.069066	-	-	-	-
Burbo Bank	14.201448	27.447048	-	14.201448	27.447048	-	-	-	-
Dudgeon	20.771862	32.591371	-	20.771862	32.591371	-	-	-	-
East Anglia 1	12.296008	51.892416	-	12.296008	51.892416	-	-	-	-
Galloper	21.262810	33.629321	-	21.262810	33.629321	-	-	-	-
Greater Gabbard	20.980502	48.550991	-	20.966472	48.518525	-	- 0.014030	- 0.032466	-
Gunfleet	24.505308	22.598290	4.223750	24.488681	22.582957	4.220884	- 0.016627	- 0.015333	- 0.002866
Gwynt y mor	26.668592	26.366759	-	26.668592	26.366759	-	-	-	-
Hornsea 1A	9.492068	33.584419	-	9.492068	33.584419	-	-	-	-
Hornsea 1B	9.492068	33.584419	-	9.492068	33.584419	-	-	-	-
Hornsea 1C	9.492068	33.584419	-	9.492068	33.584419	-	-	-	-
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	15.694615	36.008846	-	15.694615	36.008846	-	-	-	-
Lincs	21.787874	85.684260	-	21.787874	85.684260	-	-	-	-
London Array	14.785717	50.694557	-	14.785717	50.694557	-	-	-	-
Ormonde	34.621243	64.714608	0.515721	34.597753	64.670699	0.515371	- 0.023490	- 0.043909	- 0.000350
Race Bank	12.578868	34.937295	-	12.578868	34.937295	-	-	-	-
Rampion	10.275724	26.880857	-	10.275724	26.880857	-	-	-	-
Robin Rigg	- 0.759892	43.133068	13.819561	- 0.759377	43.103802	13.810184	0.000515	- 0.029266	- 0.009377
Robin Rigg West	- 0.759892	43.133068	13.819561	- 0.759377	43.103802	13.810184	0.000515	- 0.029266	- 0.009377
Sheringham Shoal	32.390862	38.148565	0.829238	32.368885	38.122682	0.828675	- 0.021977	- 0.025883	- 0.000563
Thanet	24.734493	46.340129	1.115570	24.717711	46.308687	1.114813	- 0.016782	- 0.031442	- 0.000757
Walney 1	29.902290	59.782280	-	29.882002	59.741719	-	- 0.020288	- 0.040561	-
Walney 2	27.819695	56.615851	-	27.800820	56.577438	-	- 0.018875	- 0.038413	-
Walney 3	12.921083	26.177340	-	12.921083	26.177340	-	-	-	-
Walney 4	12.921083	26.177340	-	12.921083	26.177340	-	-	-	-
West of Duddon Sands	11.555635	57.603329	-	11.555635	57.603329	-	-	-	-
Westermost Rough	23.496449	39.987970	-	23.496449	39.987970	-	-	-	-

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 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 Draft	2024/25 Final	Change
Average (£/site/annum)	89.159371	94.520751	5.361380
Unmetered (p/kWh/annum)	1.1231125	1.1885712	0.0654586
Demand Residual (£m)	2,869.8	3,037.0	167.3

HH Tariffs (Locational)	2024/25 Draft	2024/25 Final	Change
Average Tariff (£/kW)	6.513260	6.501527	- 0.011734

EET	2024/25 Draft	2024/25 Final	Change
Average Tariff (£/kW)	2.577941	2.631433	0.053491
AGIC (£/kW)	2.712754	2.712754	-
Embedded Export Volume (GW)	7.481415	7.310599	- 0.170816
Total Credit (£m)	19.286646	19.237348	- 0.049298

NHH Tariffs (locational)	2024/25 Draft	2024/25 Final	Change
Average (p/kWh)	0.325016	0.307466	- 0.017550

Since the publication of the Draft tariffs, both the average HH & NHH demand tariffs have seen an overall increase. The main driver being the increase in the total amount of revenue to be recovered through TNUoS residual element of demand tariffs. Overall total Demand residual revenue has increased by £167.3m since the Draft tariffs.

The average HH gross tariff is set at £6.50/kW, a reduction of £0.01/kW compared to draft. The average NHH tariff is forecast at 0.31p/kWh, a reduction of 0.02p/kWh.

The Embedded Export Volume for the Final tariffs is 7.31GW, a decrease of 0.17GW compared to the Draft forecast. The total credit paid out to embedded generators (<100MW) is currently forecast at £19.24m, a reduction of £0.05m. This is driven by a reduction in export volumes for the Zones whose tariffs are not floored. The average Embedded Export Tariff (EET) is now forecast at £2.63/kW an increase of £0.05/kW compared to the Draft 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	-	-	2.565717
8	Midlands	2.373139	0.312657	5.085893
9	Eastern	0.825367	0.113949	3.538121
10	South Wales	4.503509	0.533793	7.216263
11	South East	3.859199	0.538522	6.571953
12	London	5.732674	0.644217	8.445428
13	Southern	6.869732	0.903934	9.582486
14	South Western	8.198917	1.129620	10.911671

8. Demand Residual Tariffs

Since Draft Tariffs we have updated the distribution connected site count forecast to take account of the latest trends in actual site counts which are now being provided by Licenced Distribution System Operators on a monthly basis as the forecast for the demand residual charging base. 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]. The residual band thresholds will remain the same for the duration of the RIIO-2 price control period.

Table 10 shows the forecast demand residual tariffs by band. These tariffs will apply to final demand sites as well as the locational HH and NHH tariffs.

[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 charges

Band		2024/25 Draft	2024/25 Final	Change
Domestic	Tariff - £/Site/Day	0.098727	0.104586	0.005859
LV_NoMIC_1		0.065351	0.069796	0.004445
LV_NoMIC_2		0.231905	0.253213	0.021308
LV_NoMIC_3		0.540823	0.584795	0.043972
LV_NoMIC_4		1.693296	1.741054	0.047758
LV1		2.938703	3.129643	0.190940
LV2		5.059902	5.323905	0.264003
LV3		8.266652	8.488176	0.221524
LV4		19.174832	19.793806	0.618974
HV1		14.844464	16.455194	1.610730
HV2		45.903309	49.655569	3.752260
HV3		90.769885	95.286086	4.516201
HV4		231.419602	243.634626	12.215024
EHV1		106.284923	132.851337	26.566414
EHV2		572.422573	668.538064	96.115491
EHV3		1157.404151	1255.850294	98.446143
EHV4		3151.067193	3520.063002	368.995809
T-Demand1		375.204547	397.072685	21.868138
T-Demand2		1522.758894	1611.510222	88.751328
T-Demand3		3547.882635	3754.664746	206.782111
T-Demand4		11299.546455	11958.120683	658.574228
Unmetered demand		**p/kWh**		
Unmetered		1.123113	1.188571	0.065459
Demand Residual (£m)		**2869.77**	**3037.03**	**167.26**

On average, Transmission Demand Residual tariffs have increased by 6% since our Draft forecast in line with the increase in the demand revenue to be collected. Deviations away from this are due to updated site count forecast which now uses the latest actual data on sites being billed.

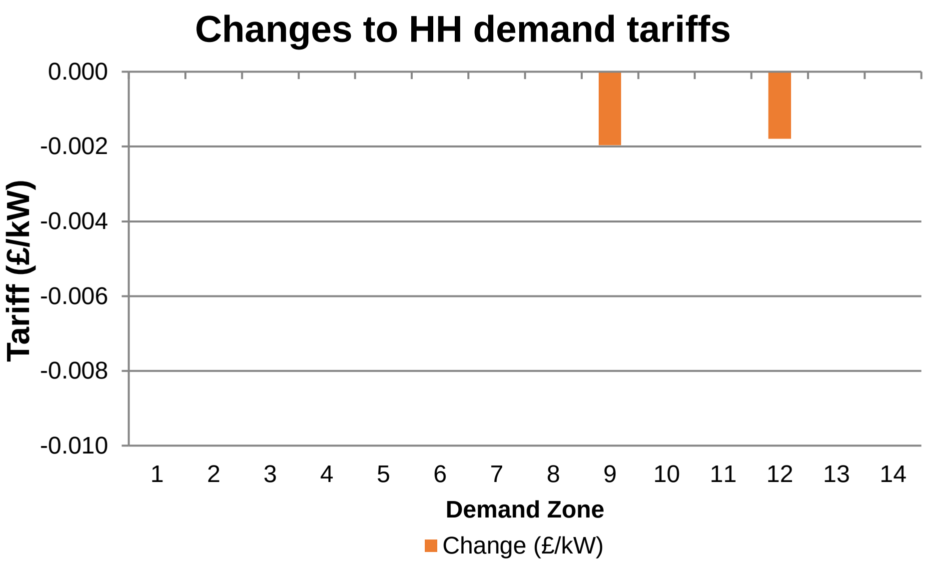
9. Half-Hourly demand tariffs

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

Table 11 Half-Hourly demand tariffs

Zone	Zone Name	2024/25 Draft (£/kW)	2024/25 Final (£/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	2.373140	2.373139	- 0.000001
9	Eastern	0.827333	0.825367	- 0.001966
10	South Wales	4.503510	4.503509	- 0.000001
11	South East	3.859199	3.859199	-
12	London	5.734465	5.732674	- 0.001791
13	Southern	6.869733	6.869732	- 0.000001
14	South Western	8.198917	8.198917	-

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the fluctuations in tariffs for zones 8 through to 13 tariffs are due to changes in the charging base (changes in forecast Gross and HH demand across zones) which have had an impact on locational tariffs which make up the HH tariff.

The forecast level of gross HH chargeable demand has increased by 0.05GW in comparison with the Draft tariffs and is currently forecast at 17.24GW.

Half-Hourly Demand Tariffs for Transmission Connected Users with Multiple DNO's

CMP379 has been directed for implementation on 1st April 2024, this means that where a transmission site has a local GSP which connects to and feeds multiple DNO networks, Demand Tariffs will now be derived from the average zonal tariffs from the relevant DNO zones. We have created site specific tariffs for transmission connected users that are already connected to, or are due to be connected to, the National Electricity Transmission System at the boundaries of multiple DNO areas in 2024/25.

Table 11a Half-Hourly Demand tariffs for Transmission Connected users with multiple DNO's

		Demand Zone		T-connected Site		
Site Code	Site Name	DNO 1	DNO 2	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	T-Connected Tariff Floored (£/kW)
MELK	MELKSHAM	13	14	1.027732	6.506593	7.534325
BARK	BARKING	9	12	2.871629	0.409270	3.280899

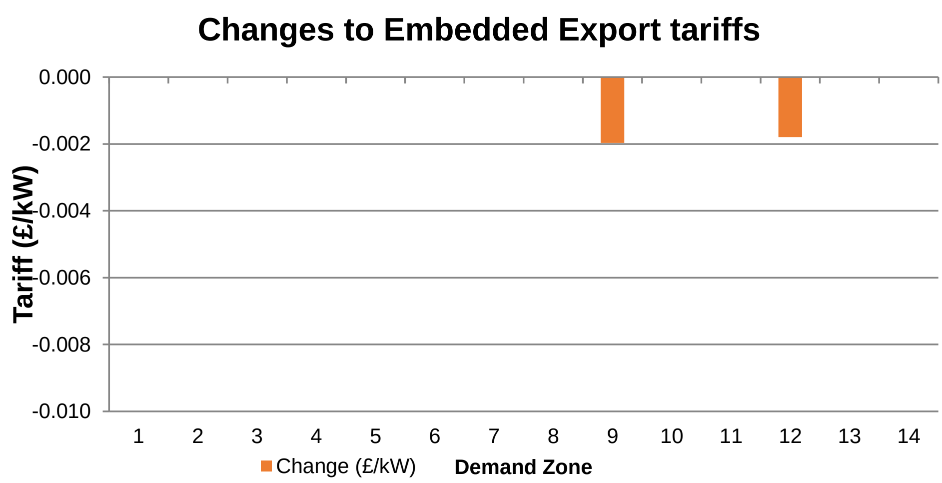
10. Embedded Export Tariffs (EET)

The next table shows the difference in Embedded Export Tariffs since the Draft forecast.

Table 12 Embedded Export Tariffs

Zone	Zone Name	2024/25 Draft (£/kW)	2024/25 Final (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	2.565718	2.565717	- 0.000001
8	Midlands	5.085894	5.085893	- 0.000001
9	Eastern	3.540087	3.538121	- 0.001966
10	South Wales	7.216264	7.216263	- 0.000001
11	South East	6.571953	6.571953	-
12	London	8.447219	8.445428	- 0.001791
13	Southern	9.582487	9.582486	- 0.000001
14	South Western	10.911671	10.911671	-

Figure 3 Embedded export tariff changes



In this forecast, there has been an increase to the average EET of 0.05/kW versus the Draft 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 decreased by 0.17GW to 7.31GW since the Draft forecast.

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.

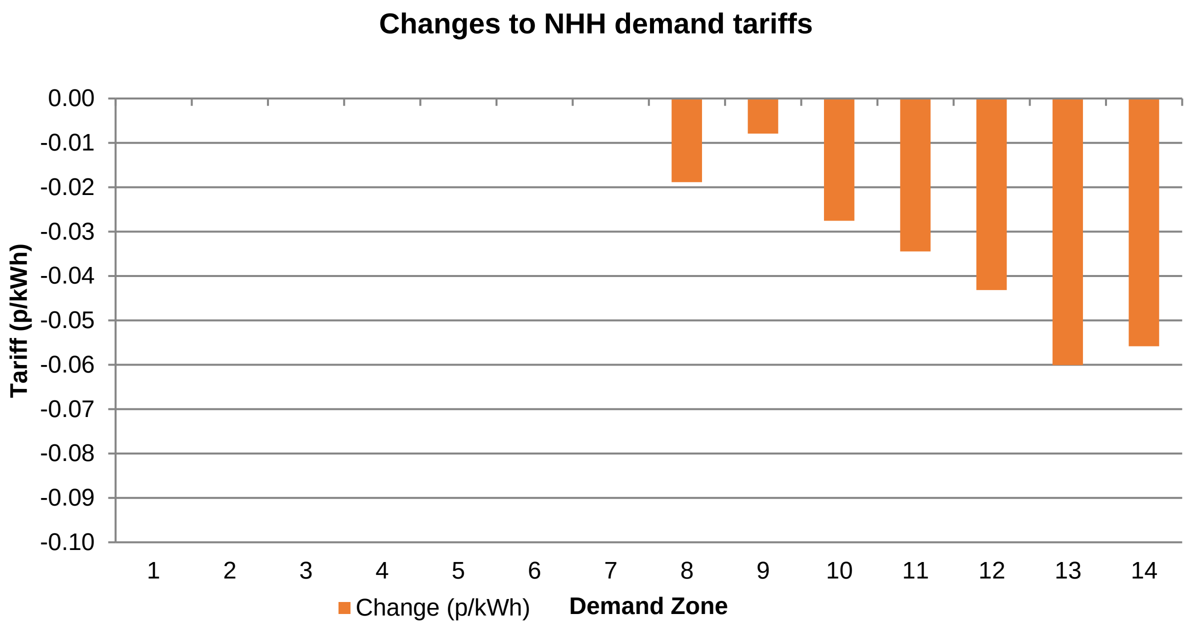
11. Non-Half-Hourly demand tariffs

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

Table 13 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2024/25 Draft (p/kWh)	2024/25 Final (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	0.331477	0.312657	- 0.018820
9	Eastern	0.121828	0.113949	- 0.007879
10	South Wales	0.561335	0.533793	- 0.027542
11	South East	0.572982	0.538522	- 0.034460
12	London	0.687413	0.644217	- 0.043196
13	Southern	0.964020	0.903934	- 0.060086
14	South Western	1.185452	1.129620	- 0.055832

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2024/25 Final tariffs is set at 0.31p/kWh, a 0.02p/kWh reduction compared to Draft forecast. The fluctuations in NHH tariffs since Draft forecast are driven by the changes to the Demand Charging Base (increase of 1.2TWh) and zonal NHH demand revenue recovery (decrease of £0.05m since the Draft forecast).

Overview of data inputs

This section explains the changes to the input data which fed into the Final Tariffs 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 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.

Table 14 Contracted, Modelled & Chargeable TEC

	2024/25 Tariffs			
Generation (GW)	Initial	July	Draft	Final
Contracted TEC	104.55	102.94	101.10	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	82.94

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 throughout 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, National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT), and Scottish Hydro Electric Transmission (SHET), 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 has been 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 (NGET)	2,223.1	2,235.3	1,840.8	2,022.9
Scottish Power Transmission (SPT)	500.9	503.6	452.4	444.7
SHE Transmission (SHET)	979.8	984.9	736.8	781.1
Total TO Income from TNUoS	**3,703.8**	**3,723.8**	**3,030.1**	**3,248.7**
Other Income from TNUoS				
Other Pass-through from TNUoS	107.3	96.7	113.8	59.8
Offshore (plus interconnector contribution / allowance)	764.8	785.9	869.9	880.0
Total Other Income from TNUoS	**872.1**	**882.5**	**983.6**	**939.8**
Total to Collect from TNUoS	**4,575.9**	**4,606.3**	**4,013.7**	**4,188.5**

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 £5.6m in this forecast) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is a change of -£2.3m to local charges associated with pre-existing assets since the Draft forecast, due to progress made to update the pre-existing asset database.

Table 17 Generation and demand revenue proportions

Code	Revenue	2024/25 Tariffs Initial Forecast	July Forecast	November Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50
y	Error Margin	23.6%	31.4%	31.4%	31.4%
ER	Exchange Rate (€/£)	1.12	1.12	1.12	1.12
MAR	Total Revenue (£m)	4,575.9	4,606.3	4,013.7	4,188.5
GO	Generation Output (TWh)	189.9	204.0	204.0	204.0
G	% of revenue from generation	22.06%	22.49%	26.18%	25.26%
D	% of revenue from demand	77.94%	77.51%	73.82%	74.74%
G.R	Revenue recovered from generation (£m)	1,009.3	1,035.8	1,050.6	1,058.0
D.R	Revenue recovered from demand (£m)	3,566.6	3,570.5	2,963.1	3,130.5
Breakdown of generation revenue					
	Revenue from the Peak element	103.0	111.1	115.2	112.6
	Revenue from the Year Round Shared element	187.0	180.0	141.9	137.0
	Revenue from the Year Round Not Shared element	132.6	201.4	194.5	184.7
	Revenue from Onshore Local Circuit tariffs	19.6	45.0	46.5	44.2
	Revenue from Onshore Local Substation tariffs	12.0	12.5	13.1	12.4
	Revenue from Offshore Local tariffs	656.1	672.8	685.7	693.8
	Revenue from the adjustment element	-101.1	-186.9	-146.4	-126.8
G.MAR	Total Revenue recovered from generation (£m)	1,009.3	1,035.8	1,050.6	1,058.0
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	7.5	7.9	5.6

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 €1.117464/£.

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.

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

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, 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.

The 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	14579.49
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	0.000000	
Viking Wind Farm	0.000000	
Arecleoch Windfarm Extension	0.000000	
Sanquhar Wind Farm	3.697870	
Crossdykes	0.000000	
Aikengall IIa Wind Farm	0.000000	
Kype Muir	0.000000	
Kennoxhead Wind Farm Extension	2.033236	
Cumberhead	0.000000	
Chirmorie Wind Farm	0.000000	
Sandy Knowe Wind Farm	2.851442	
Douglas West	0.000000	
Dalquhandy Wind Farm	0.000000	
Stranoch Wind Farm	0.598446	
Twentyshilling Wind Farm	3.697870	
Douglas West Extension	0.000000	
Whiteside Hill Wind Farm	3.697870	
Windy Rig Wind Farm	0.000000	
Windy Standard II (Brockloch Rig) Wind Farm	0.000000	
Pencloe Windfarm	0.000000	
Glenmuckloch Wind Farm	3.427851	
Sanquhar II Wind Farm	5.563530	

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	142.9
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 82.94GW, which is a decrease of 2.3GW since the Draft 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 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 Draft 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	82.94
NHH Demand (4pm-7pm TWh)	24.91	23.05	21.75	22.98
Gross charging				
Total Average Gross Triad (GW)	49.65	47.45	47.02	47.04
HH Demand Average Gross Triad (GW)	18.16	17.93	17.19	17.24
Embedded Generation Export (GW)	7.11	6.86	7.48	7.31

21. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of Final Tariffs, we have used the final 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 locational 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/301561/download

Demand residual charges

Since the implementation of CMP343, the demand residual tariff has been charged separately to the locational tariffs. The revenue to be recovered through the demand residual is now recovered by a set of p/site/day charges on final demand users (both HH and NHH), based on the residual band a site has been allocated to.

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.

All consumers continue to be liable for 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. HH and NHH demand locational tariffs are floored at zero, there are 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%	25.26%
D	Proportion of revenue recovered from demand (%)	77.94%	77.51%	73.82%	74.74%
R	Total TNUoS revenue (£m)	4,575.9	4,606.3	4,013.7	4,188.5
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	422.5	492.5	451.5	434.3
O	Revenue recovered from offshore local tariffs (£m)	656.1	672.8	685.7	693.8
L_G	Revenue recovered from onshore local substation tariffs (£m)	12.0	12.5	13.1	12.4
S_G	Revenue recovered from onshore local circuit tariffs (£m)	19.6	45.0	46.5	44.2
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	7.5	7.9	5.6
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	2.5
	Error Margin	23.6%	31.4%	31.4%	31.4%
	Exchange Rate (€/£)	1.12	1.12	1.12	1.12
	Total generation Output (TWh)	189.9	204.0	204.0	204.0
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	324.5	313.0	313.0	313.0
	Adjustment Revenue (£m)	-101.1	-186.9	-146.4	-126.8
BG	Generator charging base (GW)	78.0	84.7	85.2	82.9
AdjTariff	Generator adjusment tariff (£/kW)	-1.30	-2.21	-1.72	-1.53
Gross demand residual					
R_D	Demand residual (£m)	3,470.1	3,484.7	2,869.8	3,037.0
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	115.9	102.0	112.0	112.1
EE	Amount to be paid to Embedded Export Tariffs (£m)	-19.9	-16.9	-19.3	-19.2

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 Final Tariffs on Thursday 8th February. 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/301731/download

This data can also be accessed via our Data Portal:

https://www.nationalgrideso.com/data-portal/transmission-network-use-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

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 investment 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 new 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.

TNUoS tariffs consist of two components: locational based charges that vary by zone, and non-locational or ‘residual’ charges. Residual charges ensure complete revenue recovery for transmission owners (as the Price Control framework). The TNUoS methodology determines the proportion of revenue to be collected from demand and generation users. For generators, the locational and adjustment tariff elements are combined into a single zonal tariff, referred to as the wider zonal generation tariff. Demand charges for both Half Hourly (HH) and Non Half Hourly (NHH) customers are based on location and vary across demand zones. Additionally, with the approval of CMP343 (‘Transmission Demand Residual bandings and allocation’), and implementation from April 2023, a separate daily site charge applies to final demand based on specific usage bands.

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 approved 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.

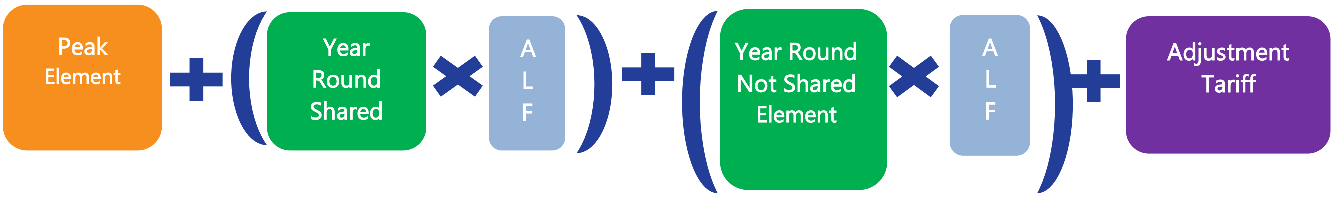
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

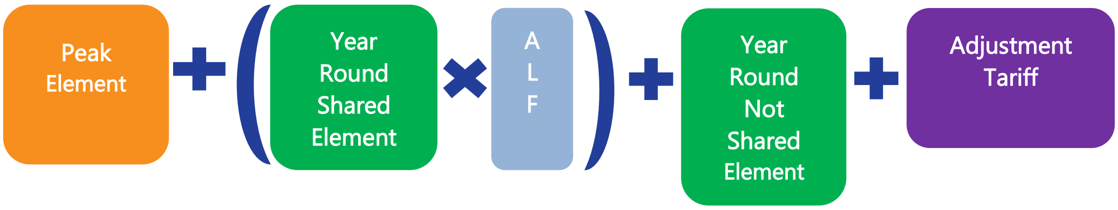
Conventional Carbon Generators

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



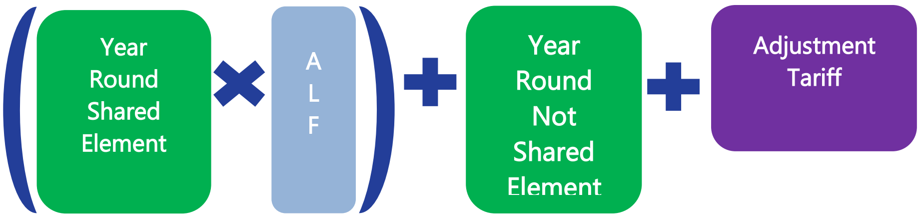
Conventional Low Carbon Generators

(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 an annual liability 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 invoice 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 during 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. CMP379 has been approved. This modification will determine TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)' which has been directed for operation with an implementation date of 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.

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].

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 the demand residual 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.

[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

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

NHH demand tariffs

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

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

Demand residual tariffs

Final demand sites are charged based on the residual band they have been allocated to. 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 were implemented in 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 recently approved modifications which affect 2024/25 TNUoS tariffs are listed below.

Table 23 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	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

Appendix C: Breakdown of locational HH and EE tariffs

ESO

Locational components of demand tariffs

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

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

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

Demand Zone		2024/25 Draft		2024/25 Final		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-1.288362	-31.636748	-1.288362	-31.636748	0.000000	0.000000
2	Southern Scotland	-2.269814	-22.130105	-2.269814	-22.130106	0.000000	0.000000
3	Northern	-3.015987	-8.980381	-3.015987	-8.980381	0.000000	0.000000
4	North West	-0.770094	-4.024376	-0.770094	-4.024376	0.000000	0.000000
5	Yorkshire	-2.010936	-2.179229	-2.010937	-2.179230	0.000000	0.000000
6	N Wales & Mersey	-1.654145	-1.099594	-1.654146	-1.099594	0.000000	0.000000
7	East Midlands	-2.078202	1.931165	-2.078202	1.931165	0.000000	0.000000
8	Midlands	-1.205299	3.578439	-1.205299	3.578438	0.000000	0.000000
9	Eastern	1.149629	-0.322296	1.147096	-0.321729	-0.002532	0.000567
10	South Wales	-4.273545	8.777054	-4.273545	8.777054	0.000000	0.000000
11	South East	3.602929	0.256270	3.602929	0.256270	0.000000	0.000000
12	London	4.593628	1.140837	4.593481	1.139193	-0.000147	-0.001644
13	Southern	2.071641	4.798092	2.071641	4.798092	0.000000	0.000000
14	South Western	-0.016177	8.215094	-0.016177	8.215094	0.000000	0.000000

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

Demand Zone		2024/25 Draft		2024/25 Final		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-32.925110	2.712754	-32.925111	2.712754	-0.000001	0.000000
2	Southern Scotland	-24.399919	2.712754	-24.399919	2.712754	-0.000001	0.000000
3	Northern	-11.996368	2.712754	-11.996369	2.712754	-0.000001	0.000000
4	North West	-4.794470	2.712754	-4.794471	2.712754	-0.000001	0.000000
5	Yorkshire	-4.190166	2.712754	-4.190166	2.712754	-0.000001	0.000000
6	N Wales & Mersey	-2.753739	2.712754	-2.753740	2.712754	-0.000001	0.000000
7	East Midlands	-0.147036	2.712754	-0.147037	2.712754	-0.000001	0.000000
8	Midlands	2.373140	2.712754	2.373139	2.712754	-0.000001	0.000000
9	Eastern	0.827333	2.712754	0.825367	2.712754	-0.001966	0.000000
10	South Wales	4.503510	2.712754	4.503509	2.712754	-0.000001	0.000000
11	South East	3.859199	2.712754	3.859199	2.712754	-0.000001	0.000000
12	London	5.734465	2.712754	5.732674	2.712754	-0.001791	0.000000
13	Southern	6.869733	2.712754	6.869732	2.712754	-0.000001	0.000000
14	South Western	8.198917	2.712754	8.198917	2.712754	-0.000001	0.000000

Appendix D: Annual Load Factors

ALFs

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

For the purposes of this forecast, we have used the final 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 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

ESO

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. No further updates have been made to the contracted generation in the Transport model (affecting locational tariffs) since Draft Tariffs.

Table 27 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
There are no contracted generation changes since the Draft Forecast			

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. 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 November forecast, it can be observed that there has been a decrease in pass-through items. This decrease is primarily driven by the interconnector revenue adjustment (-£76.5m, due to early repayment) and Network Innovation Competition Fund (-£4m, following Ofgem indication). These decreases have been offset slight by an increase in Termination Sums (+£16m), License Fee (+£5m) and Adjustment Factor (+£6m).

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	0.69
Network Innovation Competition Fund (NICFt)	3.00	3.00	3.00	-0.89
Strategic Innovation Fund (SIFt)	45.50	45.50	60.83	60.83
The Adjustment Term (ADJt)	0.00	-8.67	-8.67	-2.54
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	764.80	785.85	869.87	880.04
Interconnectors CACM Cost Recovery (ICPt)	-12.88	-12.88	-11.09	-87.79
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	0.00
Termination Sums (TSt)	25.00	25.00	25.00	41.00
NGET revenue pass-through (NGETTOt)	2,223.09	2,235.26	1,840.80	2,022.91
SPT revenue pass-through (TSPt)	500.87	503.60	452.41	444.69
SHET revenue pass-through (TSHt)	979.83	984.94	736.85	781.07
ESO Bad debt (BDt)	3.58	3.12	3.12	3.12
ESO other pass-through items (LFt + ITCt etc)	42.38	38.21	38.21	42.69
ESO legacy adjustment (LARt)	0.00	2.69	2.69	2.69
Total	**4,575.87**	**4,606.32**	**4,013.70**	**4,188.50**

Onshore TOs (NGET, SPT and SHET) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their final revenue breakdown. Since draft, there has been a £218.6m increase in onshore TO revenue, mainly driven by updates to financial parameters (inflation and WACC). However, for SPT, this has been offset by a reduction in forecast business rates liability and totex.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2024/25 is forecast to be £879.8m, an increase of £9.9m since the Draft forecast. Revenues have been adjusted using updated revenue submissions 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.

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	283.31
Inflation		PI_t	352.77	354.65	355.83	366.01
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,840.10	1,840.10	1,726.28	1,788.57
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-258.56	-216.14
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**2,291.27**	**2,303.45**	**1,909.59**	**2,094.53**
SONIA	B1	It-1	4.78%	4.78%	4.78%	4.99%
Allowed Revenue	B2	ARt-1	2,397.06	2,397.06	2,363.45	2,362.37
Recovered Revenue	B4	RRt-1	2,397.06	2,397.06	2,363.45	2,362.37
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**	**0.00**
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00
Legacy MOD	C2	LMODt	-56.66	-56.66	-56.96	-59.41
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00
Legacy TRU term	C4	LTRUt	-11.52	-11.52	-11.83	-12.21
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	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	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	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	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**	**-71.62**
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**	**2,022.91**

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	283.31
Inflation		PI_t	352.77	354.65	355.83	366.01
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	412.42	412.42	390.93	383.48
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-21.01	-30.59
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**513.55**	**516.27**	**469.98**	**464.83**
SONIA	B1	It-1	4.78%	4.78%	4.78%	4.99%
Allowed Revenue	B2	ARt-1	0.00	0.00	543.14	542.79
Recovered Revenue	B4	RRt-1	0.00	0.00	547.70	549.16
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**	**-6.76**
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00
Legacy MOD	C2	LMODt	-12.06	-12.06	-12.13	-12.51
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00
Legacy TRU term	C4	LTRUt	-0.70	-0.70	-0.70	-0.96
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	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	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	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.09	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**	**-13.38**
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**	**444.69**

Table 31 SHET 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	283.31
Inflation		PI_t	352.77	354.65	355.83	366.01
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	772.70	772.70	696.96	706.03
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-145.24	-142.74
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**962.16**	**967.27**	**730.12**	**769.39**
SONIA	B1	It-1	4.78%	4.78%	4.78%	4.99%
Allowed Revenue	B2	ARt-1	859.13	859.13	848.99	849.36
Recovered Revenue	B4	RRt-1	859.13	859.13	859.47	855.93
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**	**-6.98**
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00
Legacy MOD	C2	LMODt	14.50	14.50	14.58	15.29
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00
Legacy TRU term	C4	LTRUt	3.17	3.17	3.26	3.36
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	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	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	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	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**	**18.65**
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**	**781.07**

Table 32 Offshore revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="4">Year</th><th rowspan="2">Notes</th></tr>
<tr><th>Regulatory Year</th><th>2021/22</th><th>2022/23</th><th>2023/24</th><th>2024/25</th></tr>
<tr><td>Barrow</td><td>6.7</td><td>7.0</td><td>7.8</td><td>8.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>8.4</td><td>8.7</td><td>9.7</td><td>10.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>15.3</td><td>15.6</td><td>17.8</td><td>19.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>9.4</td><td>9.8</td><td>10.9</td><td>12.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>15.1</td><td>16.3</td><td>18.3</td><td>20.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>23.4</td><td>24.2</td><td>26.7</td><td>29.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>14.1</td><td>14.7</td><td>16.2</td><td>17.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>32.1</td><td>33.2</td><td>37.0</td><td>38.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>44.7</td><td>46.8</td><td>52.6</td><td>57.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td>20.8</td><td>21.6</td><td>24.0</td><td>26.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>30.0</td><td>32.5</td><td>34.0</td><td>40.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>32.9</td><td>39.8</td><td>37.6</td><td>37.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td>25.3</td><td>25.5</td><td>28.5</td><td>30.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>14.4</td><td>13.3</td><td>15.0</td><td>16.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>14.1</td><td>14.7</td><td>16.5</td><td>18.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Burbo Bank</td><td>14.1</td><td>14.7</td><td>16.4</td><td>17.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Dudgeon</td><td>19.6</td><td>20.8</td><td>22.6</td><td>24.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Race Bank</td><td>27.4</td><td>28.9</td><td>32.5</td><td>35.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Galloper</td><td>17.1</td><td>17.8</td><td>20.1</td><td>21.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 3</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 4</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1A</td><td rowspan="5">137.1</td><td>18.4</td><td>20.6</td><td>22.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1B</td><td>18.4</td><td>20.6</td><td>22.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1C</td><td>18.4</td><td>20.6</td><td>22.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Beatrice</td><td>21.1</td><td>24.4</td><td>25.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Rampion</td><td>15.5</td><td>17.4</td><td>19.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>East Anglia 1</td><td></td><td rowspan="6">68.3</td><td>47.4</td><td>51.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2A</td><td></td><td rowspan="5">138.7</td><td>25.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2B</td><td></td><td>25.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2C</td><td></td><td>25.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Triton Knoll</td><td></td><td>41.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2023/24</td><td></td><td>28.2</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2024/25</td><td></td><td></td><td></td><td>52.6</td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>549.0</td><td>594.3</td><td>765.6</td><td>879.8</td><td></td></tr>
</table>

Notes:

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

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

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

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

Appendix G: Generation zones map

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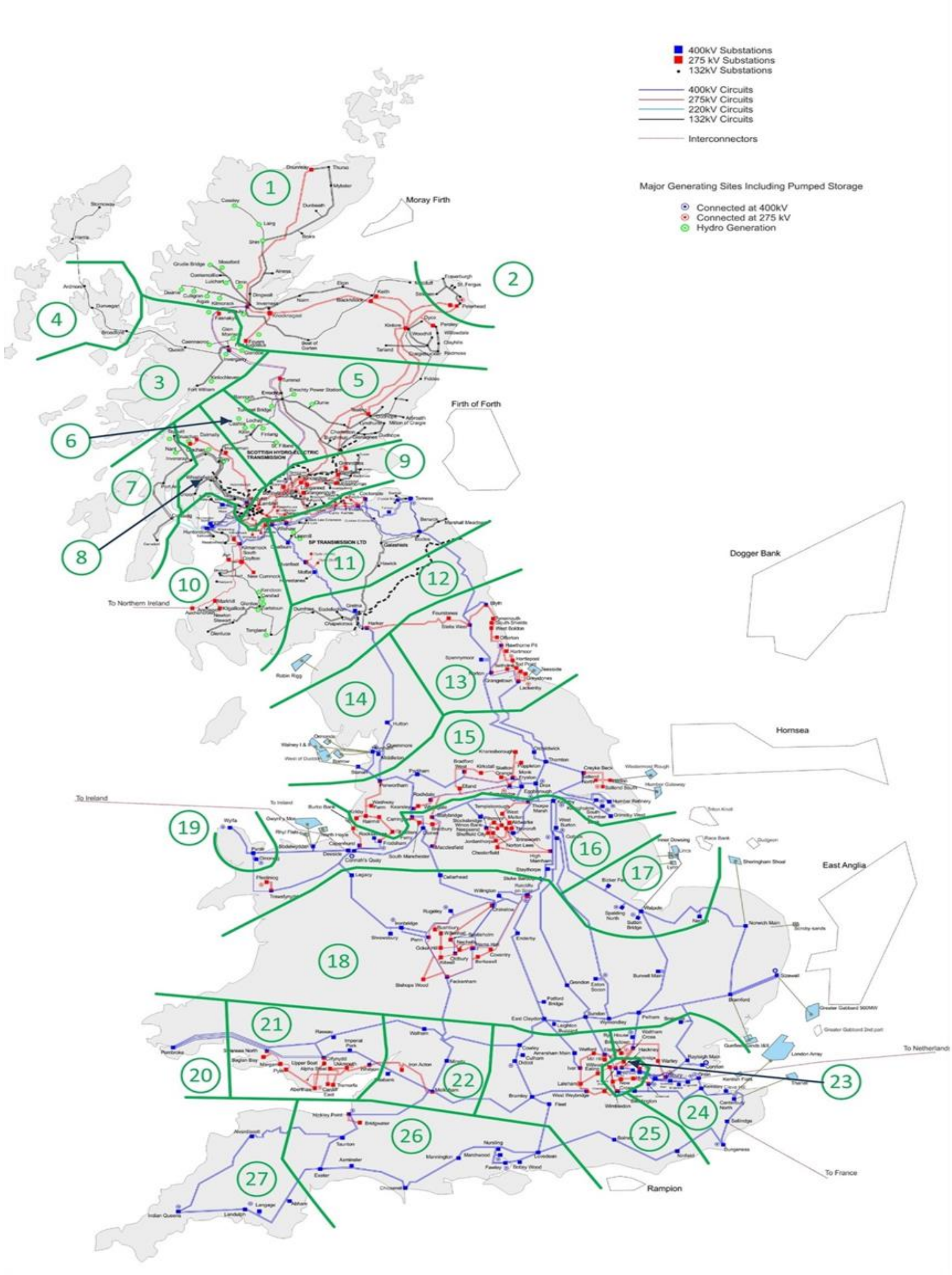
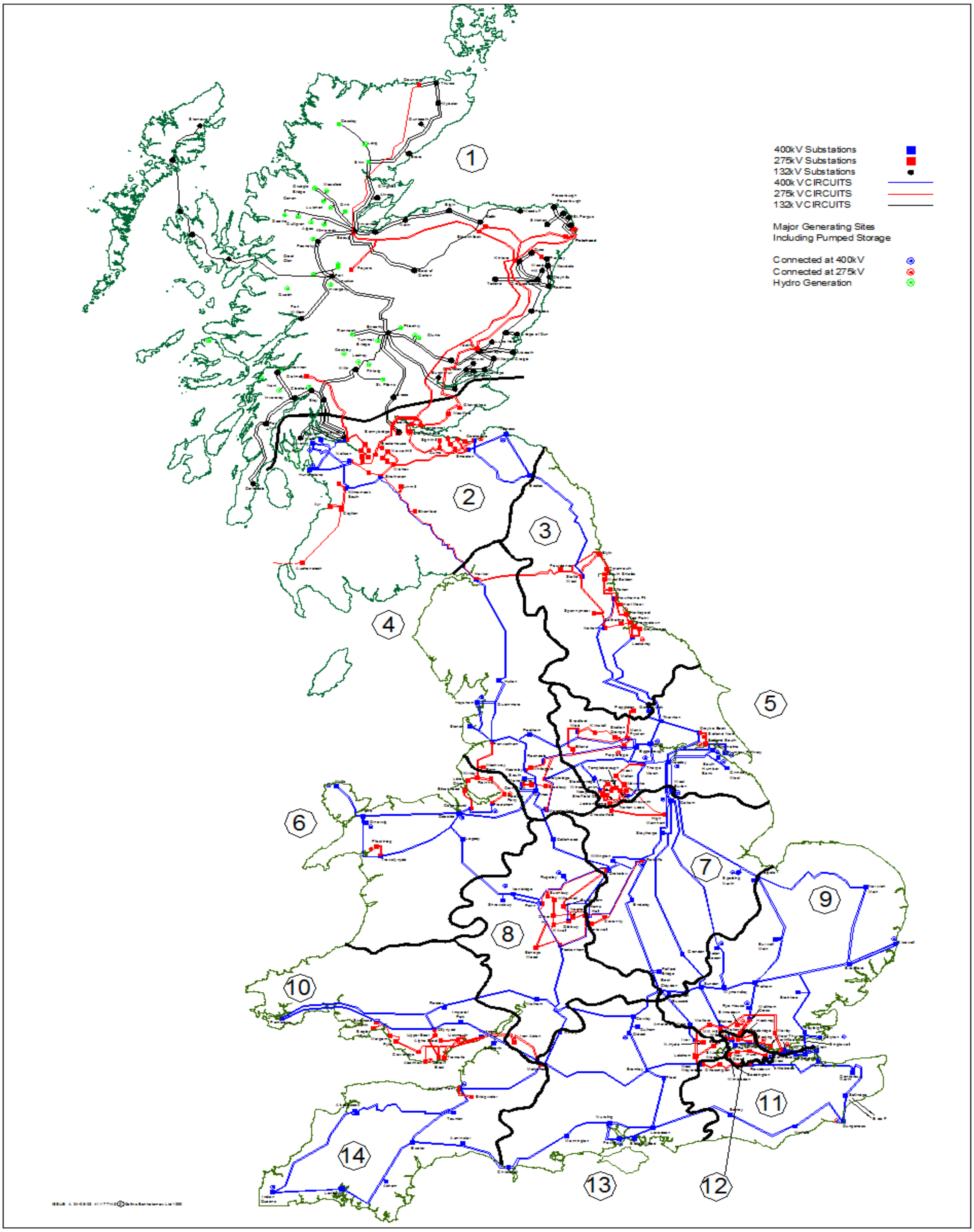
Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to Electricity Ten Year Statement 2023 Appendix A.

Appendix H: Demand zones map


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

Appendix I: Changes to TNUoS parameters

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

2024/25 TNUoS Tariff Forecast					
		April 2023	July 2023	Draft Tariffs November 2023	Final Tariffs January 2024
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
	Inflation	Forecast			Actual
RESIDUAL / ADJUSTMENT	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	From OFTOs & ESO best view
	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
	Demand Charging Bases (including TDR site counts)	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
	Consumption Data (by TDR charging band)	Previous year's data source		DNO/IDNO consumption update received	
	Generation Charging Base	NG best view	NG best view	NG best view	NG final best view
	Generation ALFs	Previous year's data source		Draft ALFs published	Final ALFs published
	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

Document Revision History

Document Revision History

Version Number	Date of Issue	Notes
1.0	31st January 2024	Publication of Final TNUoS Tariffs for 2024/25
2.0	8th February 2024	Correction of typographical errors: • the cited increase to generation tariffs in the *Generation Locational Changes* section; • the exchange rate value cited in the *Generation / Demand (G/D) Split* Section.

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