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Final TNUoS Tariffs for 2025/26

National Energy System Operator

NESO
National Energy
System Operator

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Executive Summary

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 2025/26.

Under the National Energy System Operator's (NESO) Electricity System Operator Licence condition E10 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish the Final Transmission Network Use of System (TNUoS) tariffs for year 2025/26 on our website[1].

These tariffs will take effect from 1 April 2025, they have no impact on charging year 2024/25.

Total revenues to be recovered

The total TNUoS revenue to be collected is £5.1bn for 2025/26, (a decrease of £416.39m from the Draft Forecast and an £898.47m increase since 24/25 tariffs were set). The decrease between draft and final is mainly due to revisions to Onshore Transmission Owner (ONTO) Allowed Revenue that was submitted in January 2025. These are the final submissions, resulting in changes for NGET (-£197.37m), SPT (+£14.27m) and SHET (-£133.74m). Other pass-through items have decreased by £104.89m. Revisions to Offshore Transmission Owner (OFTO) revenue inflation and forecast OFTO Asset Transfer Dates and Interconnector contributions have seen an aggregated increase of £5.34m.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.13bn for 2025/26, a decrease of £33.4m since the Draft Forecast. This is mainly driven by the decrease in revenue from offshore local tariffs.

The generation charging base has been updated to 88.7 GW based on our best view on generation projects for 2025/26. This is a decrease of 6 GW since the Draft Forecast. The average generation tariff is £12.73/kW, an increase of £0.45/kW due to the decrease in the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £3.96bn for 2025/26, a £383m decrease since the Draft Forecast. The decrease in demand revenue is the result of the decrease in TNUoS revenue mainly driven by the decrease in onshore TOs revenue.

The TNUoS cost for the average domestic household is forecast to be £51.30 for 2025/26 (5.8% of the average annual electricity consumer bill), a decrease of £4.98 since the 2025/26 Draft Forecast. This is an increase of £11.52 since 2024/25

[1] neso.energy/industry-information/charging/tnuos-charges

due to the increase in TNUoS revenue to be collected.

In 2025/26, it is forecast that £22.88m would be payable to embedded generators (<100 MW) through the Embedded Export Tariff (EET), a decrease of £1.4m since the Draft Forecast. This is due to both the average tariff and forecast export volume decreasing. The average EET is finalised at £3.08/kW, which is a decrease of £0.02/kW since the Draft Forecast.

The average gross HH demand tariff for 2025/26 is £8.49/kW, an increase of £0.68/kW compared to the Draft Forecast and the average NHH demand tariff forecast is forecast to be 0.38p/kWh, an increase of 0.005p/kWh since the Draft Forecast.

Next TNUoS tariff publication

The timetable of TNUoS tariff forecasts for 2026/27 is available on our website[2].

Our next TNUoS tariff publication will be our initial forecast of 2026/27 tariffs, which will be published in April 2025.

Feedback

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

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

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

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

Our contact details:

Email: TNUoS.Queries@nationalenergyso.com

[2] neso.energy/document/353071/download

Charging Methodology Changes

This Report

This report contains the Final TNUoS tariffs for the charging year 2025/26.

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 2025 in the Final Tariffs for 2025/26.

This section summarises any key changes to the methodology.

Charging Methodology Changes

No changes have been approved to the charging methodology since we published the Draft Tariffs for 2025/26 and consequently no additional changes have been incorporated in these Final Tariffs for 2025/26.

Four CUSC modifications proposals have been approved by Ofgem through the year which were incorporated in our previous quarterly forecasts for 2025/26 tariffs, where required. These are:

- **CMP392**: 'Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation' which introduced additional reporting to aid in the understanding of the calculation of the Connection Exclusion. This modification does not impact on the calculation of the tariffs themselves and therefore has no impact on the Final Tariffs.
- **CMP411**: 'Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies' which introduces a methodology for the recovery of AI costs via the AI Cost Gap Tariff, which would be applicable to the relevant offshore generator(s). CMP411 has no impact on the Final Tariffs since the methodology is only used in the event that Ofgem determine that an offshore project includes Anticipatory Investment.
- **CMP424**: 'Amendments to Scaling Factors used for Year-Round TNUoS Charges' which introduces a mechanism which sets a lower limit on the variable generation scaling factors used for the purpose of the Year-Round background tariff calculation within the Transport model.
- **CMP430**: 'Adjustments to TNUoS Charging from 2025 to support the Market Wide Half Hourly Settlement (MHHS) Programme' which aims to rectify defects relating to demand locational Transmission Network Use of System (TNUoS) charging and does not impact the calculation of the tariffs.

Approved CUSC methodology changes that affect 2025/26 tariffs are summarised in the CUSC modifications Table 24.

TNUoS Task Force and electricity network charging

In May 2022, Ofgem published an open letter[3] outlining their thinking on the scope of the work to be undertaken by a Task Force and asked NESO 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.

Task Force Workstream analysis and defect identification has resulted in a number of proposed CUSC changes which continue to go through the usual CUSC modification process. Further detail regarding the priority areas and Task Force meeting materials can be located on the NESO website[4].

Please note that this ongoing work has no impact on the Final Tariffs for 2025/26.

[3] ofgem.gov.uk/publications/tnuos-task-forces
[4] neso.energy/industry-information/charging/charging-futures/task-forces

Generation Tariffs

Generation Wider Tariffs

Onshore Local Substation Tariffs

Onshore Local Circuit Tariffs

Offshore Local Tariffs

Generation Tariffs Summary

This section summarises our view of generation tariffs for 2025/26 and how these tariffs were calculated.

Table 1 Summary of Generation Tariffs

Generation Tariffs (£/kW)	2025/26 Draft	2025/26 Final	Change since last forecast
Adjustment	- 1.558845	- 1.753040	- 0.194194
Average Generation Tariff*	12.272536	12.726944	0.454408

*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 the 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. Charges for the "Connection Exclusion" (meaning assets built for generation connection) are not included in the €2.50/MWh cap, whereas TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap, henceforth known as the "gen cap".

Average generation tariffs have increased by £0.45/kW, due to the 6 GW decrease in the generation charging base, compared to the Draft Forecast. The generation adjustment has decreased by £0.19/kW, increasing in magnitude, to become more negative; this is because the revenue which can be collected from generator tariffs has decreased and therefore more of an adjustment is required to ensure charges are within the gen cap, since the expected charging base has also decreased it means the adjustment tariff has increased in magnitude.

Generation Wider Tariffs

The following section summarises the wider generation tariffs for 2025/26. 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:

- the Peak tariff (not applicable to intermittent generators);
- the Year Round Shared tariff (applicable to all generators and multiplied by the generator's specific Annual Load Factor (ALF));

- the Year Round Not Shared tariff (applicable to all generators, multiplied by the generator's specific Annual Load Factor (ALF) for Conventional Carbon generators only);
- the Adjustment tariff (applicable to all generators).

Annual Load Factors are 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 their own data combined with the generic ALFs if we don't.

Table 2 Generation Wider Tariffs

Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
	Generation Tariffs					Example tariffs for a generator of each technology type		
1	North Scotland	2.288151	23.984031	17.659859	- 1.753040	17.192667	36.182993	26.699633
2	East Aberdeenshire	2.910959	15.929791	17.659859	- 1.753040	14.593779	30.765121	23.075225
3	Western Highlands	2.396306	22.514052	16.552739	- 1.753040	16.269982	34.081544	24.931022
4	Skye and Lochalsh	- 6.611418	22.514052	16.181290	- 1.753040	7.113679	24.702371	24.559573
5	Eastern Grampian and Tayside	1.803437	18.746946	13.138581	- 1.753040	12.804608	27.249188	19.821667
6	Central Grampian	4.064652	18.544109	12.944675	- 1.753040	14.907126	29.164369	19.536484
7	Argyll	3.583309	16.940216	21.391974	- 1.753040	17.163145	35.927405	27.262031
8	The Trossachs	2.823609	16.940216	11.388546	- 1.753040	12.402074	25.164277	17.258603
9	Stirlingshire and Fife	1.542154	16.426609	11.072204	- 1.753040	10.788639	23.181275	16.711138
10	South West Scotlands	1.861108	15.567886	10.682177	- 1.753040	10.608093	22.466160	15.934686
11	Lothian and Borders	1.283110	15.567886	5.112375	- 1.753040	7.802174	16.318360	10.364884
12	Solway and Cheviot	0.765542	11.225338	7.099740	- 1.753040	6.342533	14.531246	10.398102
13	North East England	1.971469	7.783992	3.998834	- 1.753040	4.931559	10.055257	5.748590
14	North Lancashire and The Lakes	0.913770	7.783992	1.331831	- 1.753040	2.807059	6.330555	3.081587
15	South Lancashire, Yorkshire and Humber	2.536147	3.971199	0.720953	- 1.753040	2.659968	4.482459	0.754953
16	North Midlands and North Wales	1.824078	1.556608	0.005437	- 1.753040	0.695856	1.243931	- 1.047129
17	South Lincolnshire and North Norfolk	0.201803	2.722942	0.005437	- 1.753040	- 0.459885	0.496407	- 0.522279
18	Mid Wales and The Midlands	0.235364	2.721706	0.005437	- 1.753040	- 0.426819	0.529041	- 0.522835
19	Anglesey and Snowdon	5.688998	0.767063	0.005437	- 1.753040	4.244958	4.516692	- 1.402425
20	Pembrokeshire	7.753209	- 9.929935	-	- 1.753040	2.028195	- 1.447282	- 6.221511
21	South Wales & Gloucester	3.082694	- 10.828978	-	- 1.753040	- 3.001937	- 6.792080	- 6.626080
22	Cotswold	2.809476	1.794081	- 10.184174	- 1.753040	- 2.299601	- 7.782177	- 11.129878
23	Central London	- 2.912018	1.794081	- 6.016002	- 1.753040	- 6.353826	- 9.335499	- 6.961706
24	Essex and Kent	- 1.599071	1.794081	-	- 1.753040	- 2.634479	- 2.006550	- 0.945704
25	Oxfordshire, Surrey and Sussex	- 0.018492	- 4.392691	-	- 1.753040	- 3.528608	- 5.066050	- 3.729751
26	Somerset and Wessex	- 0.549731	- 6.379161	-	- 1.753040	- 4.854435	- 7.087142	- 4.623662
27	West Devon and Cornwall	0.191883	- 12.517022	-	- 1.753040	- 6.567966	- 10.948924	- 7.385700

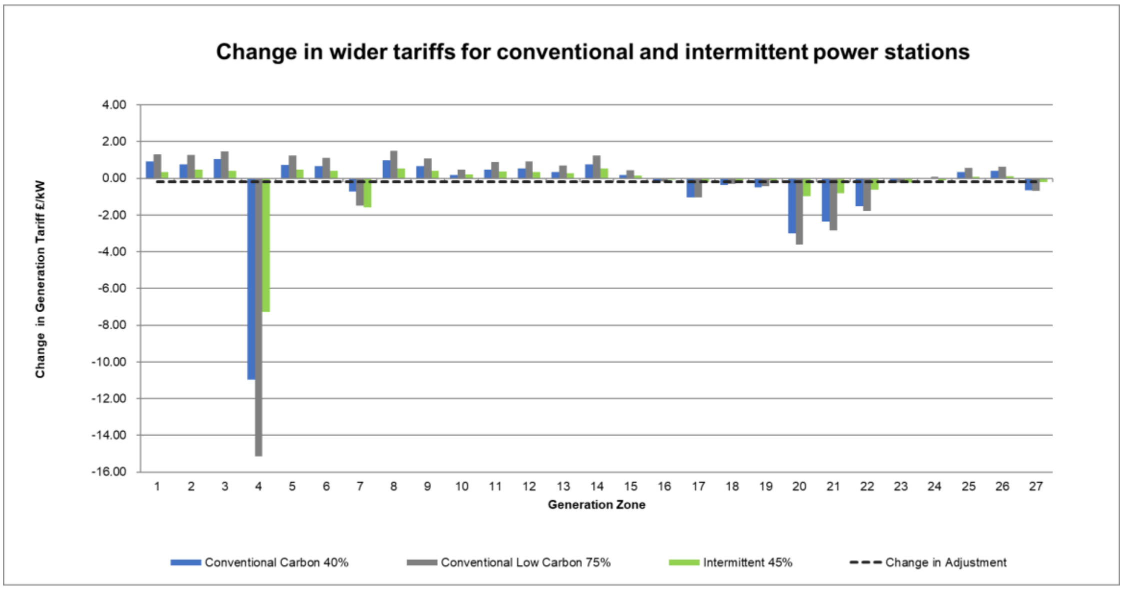
Changes to Wider Tariffs since the Draft Forecast

The following section provides details of the wider generation tariffs for 2025/26 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

Zone	Zone Name	Wider Generation Tariffs (£/kW): Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			
		2025/26 Draft	2025/26 Final	Change	2025/26 Draft	2025/26 Final	Change	2025/26 Draft	2025/26 Final	Change	Change in Adjustment
1	North Scotland	16.261975	17.192667	0.930692	34.864833	36.182993	1.318160	26.364249	26.699633	0.335384	-0.194194
2	East Aberdeenshire	13.828722	14.593779	0.765057	29.507973	30.765121	1.257149	22.605326	23.075225	0.469899	-0.194194
3	Western Highlands	15.234508	16.269982	1.035475	32.612589	34.081544	1.468956	24.526602	24.931022	0.404420	-0.194194
4	Skye and Lochalsh	18.081359	7.113679	-10.967680	39.834991	24.702371	-15.132620	31.819187	24.559573	-7.259614	-0.194194
5	Eastern Grampian and Tayside	12.065475	12.804608	0.739132	26.025222	27.249188	1.223966	19.339320	19.821667	0.482347	-0.194194
6	Central Grampian	14.234662	14.907126	0.672464	28.060491	29.164369	1.103878	19.135458	19.536484	0.401026	-0.194194
7	Argyll	17.889030	17.163145	-0.725885	37.415150	35.927405	-1.487745	28.862301	27.262031	-1.600270	-0.194194
8	The Trossachs	11.428964	12.402074	0.973110	23.672327	25.164277	1.491950	16.724373	17.258603	0.534230	-0.194194
9	Stirlingshire and Fife	10.136129	10.788639	0.652510	22.104983	23.181275	1.076292	16.317103	16.711138	0.394035	-0.194194
10	South West Scotlands	10.441267	10.608093	0.166826	22.002749	22.466160	0.463410	15.724352	15.934686	0.210334	-0.194194
11	Lothian and Borders	7.322199	7.802174	0.479975	15.447005	16.318360	0.871354	9.996558	10.364884	0.368326	-0.194194
12	Solway and Cheviot	5.812396	6.342533	0.530137	13.618280	14.531246	0.912966	10.054469	10.398102	0.343633	-0.194194
13	North East England	4.581658	4.931559	0.349902	9.373591	10.055257	0.681666	5.480129	5.748590	0.268461	-0.194194
14	North Lancashire and The Lakes	2.065052	2.807059	0.742007	5.102615	6.330555	1.227941	2.556178	3.081587	0.525409	-0.194194
15	South Lancashire, Yorkshire and Humber	2.464973	2.659968	0.194995	4.031369	4.482459	0.451091	0.599238	0.754953	0.155715	-0.194194
16	North Midlands and North Wales	0.946763	0.695856	-0.250907	1.406264	1.243931	-0.162333	-0.966722	-1.047129	-0.080407	-0.194194
17	South Lincolnshire and North Norfolk	0.575667	-0.459885	-1.035552	1.550647	0.496407	-1.054240	-0.303863	-0.522279	-0.218416	-0.194194
18	Mid Wales and The Midlands	-0.057268	-0.426819	-0.369551	0.832230	0.529041	-0.303189	-0.413770	-0.522835	-0.109066	-0.194194
19	Anglesey and Snowdon	4.737807	4.244958	-0.492849	4.942701	4.516692	-0.426009	-1.294074	-1.402425	-0.108351	-0.194194
20	Pembrokeshire	5.042135	2.028195	-3.013940	2.168986	-1.447282	-3.616268	-5.252893	-6.221511	-0.968618	-0.194194
21	South Wales & Gloucester	-0.657580	-3.001937	-2.344357	-3.957268	-6.792080	-2.834812	-5.801300	-6.626080	-0.824780	-0.194194
22	Cotswold	-0.762034	-2.299601	-1.537567	-5.997321	-7.782177	-1.784857	-10.501631	-11.129878	-0.628247	-0.194194
23	Central London	-6.133411	-6.353826	-0.220415	-9.095580	-9.335499	-0.239920	-6.713101	-6.961706	-0.248605	-0.194194
24	Essex and Kent	-2.649852	-2.634479	0.015373	-2.079416	-2.006550	0.072865	-0.825427	-0.945704	-0.120277	-0.194194
25	Oxfordshire, Surrey and Sussex	-3.873007	-3.528608	0.344398	-5.624450	-5.066050	0.558399	-3.810700	-3.729751	0.080949	-0.194194
26	Somerset and Wessex	-5.251999	-4.854435	0.397564	-7.728423	-7.087142	0.641281	-4.742818	-4.623662	0.119156	-0.194194
27	West Devon and Cornwall	-5.896682	-6.567966	-0.671284	-10.271909	-10.948924	-0.677015	-7.184137	-7.385700	-0.201563	-0.194194

Figure 1 Variation in generation wider zonal tariffs



Locational Changes

Locational tariffs have been impacted by updates to the nodal demand data and the removal of one project in the nodal generation following the identification of a discrepancy in the TEC (Transmission Entry Capacity) register. This means that there have been variations in the overall tariffs across most generation zones. In particular, the change in flows has resulted in a large decrease in zone 4, which is often sensitive to generation/demand changes, due to the relatively long radial circuits.

Adjustment Tariff Changes

The adjustment tariff is currently negative due to the wider tariffs causing the average generation charge to breach the cap.

The adjustment tariff has decreased by £0.19/kW since the Draft Forecast, increasing in magnitude, to become more negative. This is because the revenue which can be collected from generator tariffs has decreased and therefore more of an adjustment is required to ensure charges are within the gen cap, since the expected charging base has also decreased it means the adjustment tariff has increased in magnitude. For a full breakdown of the generation revenues, please see Table 23.

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 Onshore Local Substation Tariffs

2025/26 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.179523	0.089766	0.061916
<1320 MW	Redundancy	0.378275	0.192132	0.136425
≥1320 MW	No redundancy	-	0.263729	0.187768
≥1320 MW	Redundancy	-	0.396867	0.285445

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 2025/26 onshore local circuit tariffs have been finalised. The updated tariffs are listed below in Table 5. A limited number of onshore local circuit tariffs have changed since Draft Tariffs. These tariffs have changed due to the updates in the wider flows from the final Week 24 demand data. 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	1.711931	Douglas North	0.760858	Langage	-0.403347
Aberdeen Bay	3.347776	Dunhill	1.791917	Limekilns	2.411223
Achruach	-1.635430	Dunlaw Extension	0.535619	Lochay	0.380429
Aigas	0.879048	Dunmaglass	1.087393	Luichart	0.705380
An Suidhe	-1.050313	Edinbane	8.557476	Marchwood	-0.295137
Arecleoch	3.005452	Enoch Hill	0.760858	Mark Hill	1.103307
Ayrshire Grid Collector	0.169065	Ewe Hill	1.741520	Middle Muir	2.640178
Beinneun Wind Farm	1.687266	Fallago	-0.077458	Middleton	0.179398
Benbrack	0.910916	Farr	4.349028	Millennium Wind	1.994149
Bhlaraidh Wind Farm	0.761915	Faw Side	10.150431	Mossford	1.985413
Black Hill	1.919911	Fernoch	5.359798	Nant	-1.555071
Black Law	2.092360	Ffestiniogg	0.271855	Necton	1.357057
BlackCraig Wind Farm	6.924933	Fife Grid Services	0.189806	Rhigos	0.510601
BlackLaw Extension	4.551430	Finlarig	0.380429	Rocksavage	0.018419
Broken Cross	1.330269	Foyers	0.349528	Saltend	-0.019375
Clyde (North)	0.132397	Galawhistle	1.306140	Sandy Knowe	5.260736
Clyde (South)	0.154463	Glen Kyllachy	1.247184	Sanquhar II	8.652036
Coalburn BESS	0.469624	Glendoe	2.494369	Scoop Hill	0.539490
Corriegarth	3.043433	Glenglass	5.725310	Shepherds Rig	0.093224
Corriemoillie	1.985413	Gordonbush	0.035220	South Humber Bank	-0.221900
Coryton	0.050973	Griffin Wind	12.154789	Spalding	0.338949
Creag Riabhach	4.184720	Hadyard Hill	3.423862	St Fergus Mobil	1.275310
Cruachan	2.215016	Harestanes	2.853218	Stranoch	3.761346
Culligran	2.162159	Hartlepool	0.228102	Strathbrora	-0.094295
Cumberhead Collector	0.870760	Invergarry	0.380429	Strathy Wind	2.134840
Cumberhead West	4.614582	Kergord	61.164365	Stronelairg	1.341262
Deanie	3.552118	Kilgallioch	1.323968	Wester Dod	0.435324
Dersalloch	2.804200	Kilmarnock BESS	0.488409	Whitelee	0.132397
Dinorwig	3.127755	Kilmorack	0.154440	Whitelee Extension	0.375124
Dorenell	3.001461	Kype Muir	1.850365		

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

Table 6 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Bhlaraidh 132kV	Glenmoriston 132kV	7.4km Cable	7.4km OHL	Bhlaraidh
Enoch Hill 132kV	New Cumnock 132kV	4.4km Cable	4.4km OHL	Enoch Hill
Glen Glass 132kV	Sandy Knowe132kV	4km Cable	4km OHL	Sandy Knowe
Coalburn 132kV	Cumberhead Collector 132kV	8.01km Cable	8.01km OHL	Dalquhandy
Cumberhead Collector 132kV	Galawhistle 132kV	3.69km Cable	3.69km OHL	Galawhistle
Coalburn 132kV	Kype Muir 132kV	17km Cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km Cable	13km OHL	Middle Muir
Crystal Rig 132kV	Wester Dod 132kV	3.9km Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km Cable	9.5km of OHL	Aberdeen Bay
East Kilbride South 275kV	Whitelee 275kV	6km Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Melgarve 132kV	Stronelairg 132kV	10km Cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km Cable	15.33km OHL	Harestanes
Arecleoch 132kV	Arecleoch Tee 132kV	2.5km Cable	2.5km OHL	Arecleoch
Wishaw 132kV	Blacklaw 132kV	11.46km Cable	11.46km of OHL	Blacklaw
Earba PSH 400kV	Dalwhinnie 400kV	15km Cable	15km OHL	Earba PSH
Loch Nan Eun 275kV	Fort Augustus 400kV	6km Cable	6km of OHL	Loch Nan Eun
Red John 275kV	Knocknagael 275kV	9km Cable	9km OHL	Red John
Sheirdrim 132kV	Crossaig 132kV	3km Cable	3km OHL	Sheirdrim

Offshore Local Generation Tariffs

The offshore local tariffs (Substation, Circuit and Embedded Transmission Use of System) reflect the cost of the offshore networks which connect offshore generation to the mainland. 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 2024/25 or 2025/26 will be confirmed once asset transfer has taken place and tariffs have been set.

Table 7 Offshore local tariffs 2025/26

Offshore Generator	2025/26 Draft Tariff Component (£/kW)			2025/26 Final Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.649990	61.546296	1.528279	11.656304	61.579655	1.529107	0.006314	0.033359	0.000828
Beatrice	9.389647	25.744817	-	9.389647	25.744817	-	0.000000	0.000000	-
Burbo Bank Extension	14.584257	28.186900	-	14.584257	28.186900	-	0.000000	0.000000	-
Dudgeon	21.331780	33.469891	-	21.331780	33.469891	-	0.000000	0.000000	-
East Anglia 1	12.627454	53.291208	-	12.627454	53.291208	-	0.000000	0.000000	-
Galloper	21.835962	34.535819	-	21.835962	34.535819	-	0.000000	0.000000	-
Greater Gabbard	21.706351	50.230679	-	21.715879	50.252729	-	0.009528	0.022050	-
Gunfleet	25.352854	23.379880	4.369834	25.366596	23.392552	4.372202	0.013742	0.012672	0.002368
Gwynt y mor	27.387460	27.077491	-	27.387460	27.077491	-	0.000000	0.000000	-
Hornsea 1A	9.747932	34.489707	-	9.747932	34.489707	-	0.000000	0.000000	-
Hornsea 1B	9.747932	34.489707	-	9.747932	34.489707	-	0.000000	0.000000	-
Hornsea 1C	9.747932	34.489707	-	9.747932	34.489707	-	0.000000	0.000000	-
Hornsea 2A	11.047354	37.319614	-	11.047354	37.319614	-	0.000000	0.000000	-
Hornsea 2B	11.047354	37.319614	-	11.047354	37.319614	-	0.000000	0.000000	-
Hornsea 2C	11.047354	37.319614	-	11.047354	37.319614	-	0.000000	0.000000	-
Humber Gateway	16.117673	36.979486	-	16.117673	36.979486	-	0.000000	0.000000	-
Lincs	22.375180	87.993930	-	22.375180	87.993930	-	0.000000	0.000000	-
London Array	15.184275	52.061059	-	15.184275	52.061059	-	0.000000	0.000000	-
Moray East	11.318789	28.352051	-	11.318789	28.352051	-	0.000000	0.000000	-
Ormonde	35.818661	66.952842	0.533558	35.838076	66.989132	0.533847	0.019415	0.036290	0.000289
Race Bank	12.917939	35.879051	-	12.917939	35.879051	-	0.000000	0.000000	-
Rampion	10.552712	27.605447	-	10.552712	27.605447	-	0.000000	0.000000	-
Robin Rigg	-0.7861740	44.624878	14.297527	-0.7866000	44.649066	14.305277	-0.000426	0.024188	0.007750
Robin Rigg West	-0.7861740	44.624878	14.297527	-0.7866000	44.649066	14.305277	-0.000426	0.024188	0.007750
Sheringham Shoal	33.511140	39.467980	0.857918	33.529303	39.489373	0.858383	0.018163	0.021393	0.000465
Thanet	25.589966	47.942859	1.154154	25.603836	47.968845	1.154779	0.013870	0.025986	0.000625
Triton Knoll	10.636370	31.688721	-	10.636370	31.688721	-	0.000000	0.000000	-
Walney 1	30.936498	61.849924	-	30.953266	61.883448	-	0.016768	0.033524	-
Walney 2	28.781873	58.573980	-	28.797474	58.605728	-	0.015601	0.031748	-
Walney 3	13.269379	26.882966	-	13.269379	26.882966	-	0.000000	0.000000	-
Walney 4	13.269379	26.882966	-	13.269379	26.882966	-	0.000000	0.000000	-
West of Duddon Sands	11.867124	59.156062	-	11.867124	59.156062	-	0.000000	0.000000	-
Westermost Rough	24.129810	41.065869	-	24.129810	41.065869	-	0.000000	0.000000	-

Demand Tariffs

Demand Residual Tariffs

Half-Hourly (HH) Tariffs

Non-Half-Hourly (NHH) Tariffs

Embedded Export Tariffs (EET)

Demand Tariffs Summary

There are two types of demand, Half-Hourly (HH) and Non-Half-Hourly (NHH). This 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 charges per site across of the residual charging bands.

Table 8 Summary of Demand Tariffs

Non-locational Banded Tariffs	2025/26 Draft	2025/26 Final	Change
Average (£/site/annum)	130.393037	118.391196	- 12.001842
Unmetered (p/kWh/annum)	1.730788	1.571791	- 0.158996
Demand Residual (£m)	4,224.1	3,836.0	- 388.0

HH Tariffs (Locational)	2025/26 Draft	2025/26 Final	Change
Average Tariff (£/kW)	7.806603	8.485606	0.679003

EET	2025/26 Draft	2025/26 Final	Change
Average Tariff (£/kW)	3.106969	3.084154	- 0.022816
AGIC (£/kW)	2.791637	2.791637	-
Embedded Export Volume (GW)	7.810774	7.417380	- 0.393395
Total Credit (£m)	24.267834	22.876338	- 1.391496

NHH Tariffs (locational)	2025/26 Draft	2025/26 Final	Change
Average (p/kWh)	0.378015	0.383426	0.005410

Since the publication of the Draft Forecast in November, both the average HH & NHH demand tariffs have seen an increase. Driven by increases in demand zone 10 due to increased forecast nodal demand across south Wales. Revenue recovered through the demand residual has decreased by £388m which, when offset by £5m additional locational revenue gives a total Demand revenue decrease since the November Draft Forecast of £383m.

The average HH gross tariff is forecast to be £8.49/kW, an increase of £0.68/kW compared to the November Draft Forecast. The average NHH tariff is forecast to be 0.38 p/kWh, an increase of 0.005 p/kWh compared to the Draft Forecast.

The Embedded Export Volume for the Final Tariffs has decreased since the November forecast by 0.39 GW to 7.42 GW. The total credit paid out to embedded generators (<100 MW) is currently forecast to be £22.88m, a decrease of £1.39m. The average Embedded Export Tariff (EET) is now forecast to be £3.08/kW, a decrease of £0.02/kW compared to the November 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	-	-	2.483002
8	Midlands	2.990958	0.386732	5.782595
9	Eastern	1.110745	0.152494	3.902382
10	South Wales	6.885043	0.807732	9.676680
11	South East	5.568235	0.774324	8.359872
12	London	7.405345	0.813457	10.196982
13	Southern	7.570174	0.986192	10.361811
14	South Western	10.123037	1.377268	12.914674

Demand Residual Tariffs

Since the Draft Forecast, we have updated the site count forecasts for a small number of bands where new information has been received from the Distribution Network Operators (DNO).

The consumption data used to allocate the proportion of residual revenue to each charging band has not changed since our Draft Forecast, and continues to use actual data for October 2023 to September 2024, received from the DNOs.

A breakdown of the banding thresholds, consumptions, consumption proportions and site counts for the demand residual banded charges can be seen in Table TB of the published tables excel spreadsheet[5]. 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 in addition the HH or NHH locational charges.

[5] 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		2025/26 Draft	2025/26 Final	Change
Domestic	Tariff - £/Site/Day	0.148704	0.135043	(0.013661)
LV_NoMIC_1		0.170491	0.154829	(0.015662)
LV_NoMIC_2		0.403074	0.366046	(0.037028)
LV_NoMIC_3		0.844912	0.760709	(0.084203)
LV_NoMIC_4		2.300924	2.068587	(0.232337)
LV1		4.302998	3.907710	(0.395288)
LV2		7.189576	6.529117	(0.660459)
LV3		11.288913	10.251874	(1.037039)
LV4		25.039789	22.739548	(2.300241)
HV1		24.038633	21.830361	(2.208272)
HV2		69.152197	62.799637	(6.352560)
HV3		134.115745	121.795409	(12.320336)
HV4		352.092870	317.597969	(34.494901)
EHV1		177.027409	160.765059	(16.262350)
EHV2		816.822572	741.786430	(75.036142)
EHV3		1,772.543779	1,576.232814	(196.310965)
EHV4		4,172.367764	3,882.736230	(289.631534)
T-Demand1		713.327257	647.798551	(65.528706)
T-Demand2		2,519.052656	2,287.643779	(231.408877)
T-Demand3		5,997.314639	5,446.380603	(550.934036)
T-Demand4		14,091.179805	12,796.715359	(1,294.464446)
Unmetered demand		**p/kWh**	**p/kWh**	
Unmetered		1.730788	1.571791	(0.158996)
Demand Residual (£m)		**4224.09**	**3836.05**	**-388.04**

On average, Transmission Demand Residual tariffs have decreased by 9% since our Draft Forecast, in line with the decrease in the demand revenue to be collected.

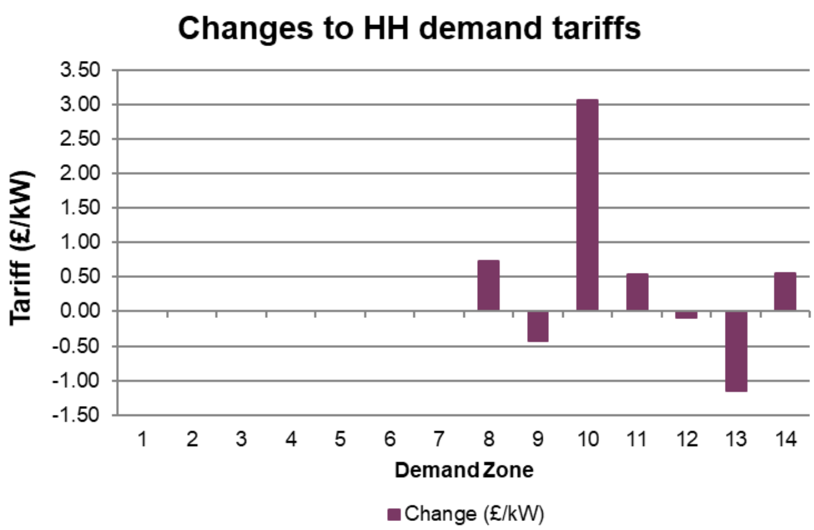
Half-Hourly Demand Tariffs

Table 11 shows the Final gross HH demand tariffs for 2025/26 compared to the Draft Forecast.

Table 11 Half-Hourly Demand Tariffs

Zone	Zone Name	2025/26 Draft (£/kW)	2025/26 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	2.263138	2.990958	0.727820
9	Eastern	1.542340	1.110745	-0.4315950
10	South Wales	3.819751	6.885043	3.065292
11	South East	5.036122	5.568235	0.532113
12	London	7.491102	7.405345	-0.0857570
13	Southern	8.729190	7.570174	-1.1590160
14	South Western	9.567700	10.123037	0.555337

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, there are fluctuations in tariffs for zones 8 through to 14. These are due to finalisation of the Nodal demand forecast. Zones 1 through 7 are subject to the zero floor on demand tariffs.

The forecast level of gross HH chargeable demand has decreased by 1 GW since November and is currently forecast to be 16.9 GW.

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

Where a transmission site has a local GSP which connects to and feeds multiple DNO networks, Demand Tariffs are 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 2025/26.

Table 12 Demand tariffs for Transmission Connected users with multiple DNO's

		Demand Zone			T-connected Site		
Site Code	Site Name	DNO 1	DNO 2	DNO 3	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	T-Connected Tariff Floored (£/kW)
MELK	MELKSHAM	13	14		0.316672	8.529933	8.846605
BARK	BARKING	9	12		2.032994	2.225052	4.258045
WISD	WILLESDEN	9	12	13	1.787590	3.574498	5.362088

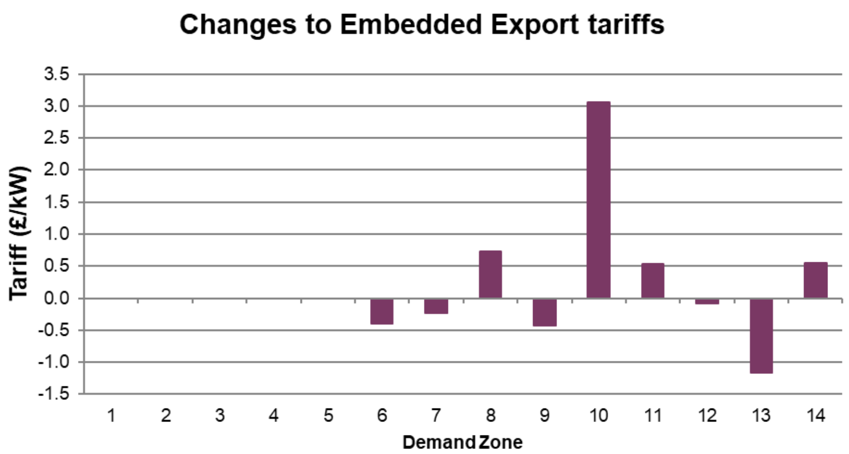
Embedded Export Tariffs (EET)

Table 13 shows the Final Export tariffs for 2025/26 compared to the November Draft Forecast.

Table 13 Embedded Export Tariffs

Zone	Zone Name	2025/26 Draft (£/kW)	2025/26 Final (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.389234	-	-0.3892340
7	East Midlands	2.712561	2.483002	-0.2295590
8	Midlands	5.054775	5.782595	0.727820
9	Eastern	4.333977	3.902382	-0.4315950
10	South Wales	6.611388	9.676680	3.065292
11	South East	7.827759	8.359872	0.532113
12	London	10.282739	10.196982	-0.0857570
13	Southern	11.520827	10.361811	-1.1590160
14	South Western	12.359337	12.914674	0.555337

Figure 3 Embedded export tariff changes



The final average EET is £3.08/kW a decrease to the average EET of £0.02/kW versus the November forecast. This is primarily due to a change modelled network flows driven by nodal demand data. The changes in locational demand tariffs and the corresponding impact can be seen in Table 26. The Embedded Export Volume has decreased since our November forecast to 7.42 GW

The amount of metered embedded generation produced at Triads by suppliers and embedded generators (<100 MW) 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.

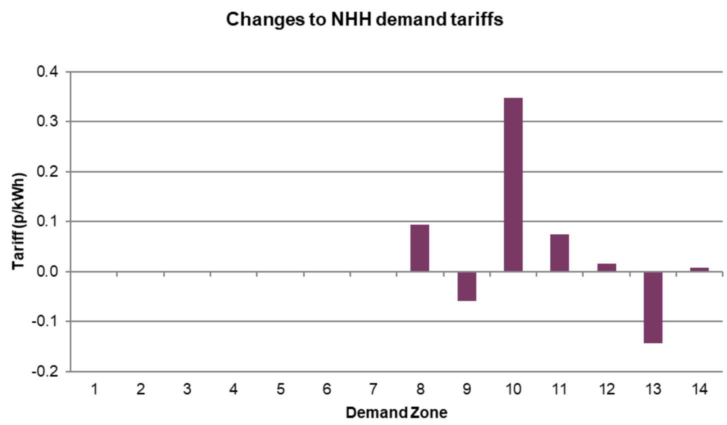
Non-Half-Hourly Demand Tariffs

Table 14 and Figure 4 show the difference in Non-Half-Hourly tariffs between the 2025/26 Final Tariffs and the November Draft Forecast.

Table 14 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2025/26 Draft (p/kWh)	2025/26 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	0.292904	0.386732	0.093828
9	Eastern	0.211744	0.152494	-0.0592500
10	South Wales	0.459966	0.807732	0.347766
11	South East	0.699604	0.774324	0.074720
12	London	0.797542	0.813457	0.015915
13	Southern	1.129760	0.986192	-0.1435680
14	South Western	1.368920	1.377268	0.008348

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2025/26 is 0.38 p/kWh, a 0.005 p/kWh increase compared to the Draft Forecast. As mentioned above for the HH and Embedded tariffs, the locational element of demand charges has caused fluctuations in the NHH zonal tariffs.

The impact of this combined with the 6% increase to the forecast NHH demand is that expected Zonal NHH demand revenue recovery has increased by £6.5m since the Draft Forecast.

Overview of Data Inputs

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

Inputs affecting the locational element of tariffs

The locational elements of generation and demand tariffs are based upon:

- Contracted 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 2025/26 period, which can be found on the TEC register[6]. The contracted TEC volumes are based on the 31 October 2024 TEC register. There has been a small variation in the contracted TEC since the Draft Tariffs following the identification of a discrepancy in the TEC register which has now been corrected to accurately reflect the contract for the affected project.

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 the TEC register as of 31 October 2024, 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 2025/26 and liable to pay generation TNUoS charges.

Table 15 Contracted, Modelled & Chargeable TEC

	2025/26 Tariffs			
Generation (GW)	**Initial**	**July**	**Draft**	**Final**
Contracted TEC	115.47	113.33	112.27	112.18
Modelled Best View TEC	91.86	108.04	*For input to locational tariffs post 31st October please see Contracted TEC*	
Chargeable TEC	83.15	99.22	94.75	88.74

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

[6] See the Registers, Reports and Updates section at neso.energy/industry-information/connections/reports-and-registers

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 2025/26 as stated in the interconnector register[7] as of 31 October 2024.

Table 16 Interconnectors

Interconnector	Node	Interconnected System	Generation MW			
			Generation Zone	Transport Model Peak	Transport Model Year Round	Charging Base
Auchencrosh	Auchencrosh 275kV Substation	Northern Ireland	10	0	500	0
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
IFA Interconnector	Sellindge 400kV Substation	France	24	0	1,988	0
IFA2 Interconnector	Chilling 400kV Substation	France	26	0	1,100	0
LionLink (EuroLink)	Friston 400kV Substation	Netherlands	18	0	1,600	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	0	1,500	0

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 2025/26 Expansion Constant is £18.411714/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-T1 value which was set in 2013/14 and will continue to increase in-line with inflation each year. 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.

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: neso.energy/document/183406/download.

[7] See the Registers, Reports and Updates section at neso.energy/industry-information/connections/reports-and-registers

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.

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.

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). Financial 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).

An overview of revenue to be recovered can be found in Table 18. For more details on the TNUoS revenue breakdown, please refer to Appendix F.

The TOs provide NESO with their revenue forecast under the agreed timeline as specified in the STC (SO-TO Code). The 2025/26 revenue forecast has been based on Onshore and Offshore TOs' final submissions in January 2025.

Table 17 Allowed Revenues

£m Nominal	2025/26 TNUoS Revenue Initial Forecast	July Forecast	November Draft	January Final
ONTO Income from TNUoS				
National Grid Electricity Transmission	2,502.8	2,502.8	2,595.3	2,397.9
Scottish Power Transmission	502.9	502.9	530.5	544.7
SHE Transmission	1,197.3	1,197.3	1,325.4	1,191.6
Total ONTO Income from TNUoS	**4,202.9**	**4,202.9**	**4,451.1**	**4,134.3**
Other Income from TNUoS				
Other Pass-through from TNUoS	131.5	82.8	83.8	(21.1)
Offshore (plus interconnector contribution / allowance)	946.3	982.7	968.5	973.8
Total Other Income from TNUoS	**1,077.8**	**1,065.6**	**1,052.3**	**952.7**
Total to Collect from TNUoS	**5,280.8**	**5,268.5**	**5,503.4**	**5,087.0**

Please note these figures are rounded to one decimal place.

Generation / Demand (G/D) Split

The G/D split forecast is shown in Table 18.

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 (approximately £7.1m) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is an increase of £2.2m to local charges associated with pre-existing assets since the Draft Forecast.

Table 18 Generation and demand revenue proportions

Code	Revenue	2025/26 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	31.4%	29.6%	29.6%	29.6%
ER	Exchange Rate (€/£)	1.16	1.16	1.16	1.18
MAR	Total Revenue (£m)	5,280.8	5,268.5	5,503.4	5,087.0
GO	Generation Output (TWh)	209.1	215.3	215.3	215.3
G	% of revenue from generation	21.38%	22.36%	21.13%	22.20%
D	% of revenue from demand	78.62%	77.64%	78.87%	77.80%
G.R	Revenue recovered from generation (£m)	1,129.1	1,177.9	1,162.8	1,129.3
D.R	Revenue recovered from demand (£m)	4,151.7	4,090.6	4,340.6	3,957.6
Breakdown of generation revenue					
	Revenue from the Peak element	121.1	88.2	94.3	86.6
	Revenue from the Year Round Shared element	140.8	182.6	172.4	181.1
	Revenue from the Year Round Not Shared element	186.7	217.8	202.7	201.0
	Revenue from Onshore Local Circuit tariffs	52.4	48.3	46.6	47.5
	Revenue from Onshore Local Substation tariffs	13.5	15.5	14.4	12.9
	Revenue from Offshore Local tariffs	766.2	796.2	780.0	755.7
	Revenue from the adjustment element	-151.8	-170.7	-147.7	-155.6
G.MAR	Total Revenue recovered from generation (£m)	1,129.1	1,177.9	1,162.8	1,129.3
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	12.3	8.7	4.9	7.1

The "gen cap"

Paragraph 14.14.5 (vii) 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.

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 31 October. The figure has been finalised, as per OBR's October EFO, at €1.183012/£.

Generation Output

The forecast output of generation is 215 TWh and was updated in our July forecast. This figure is the average of the four scenarios (plus the central case) in the 2024 Future Energy Scenarios and the value is finalised for 2025/26 tariffs.

Error Margin

The error margin has been updated and finalised in the July forecast, following publication of the outturn of 2023/24 data. The error margin is derived from historical data in the past five whole years (thus for year 2025/26, we use data from years 2019/20 – 2023/24).

Table 19 Generation revenue error margin calculation

Calculation for	2025/26		
Data from year:	Revenue inputs		Generation output variance
	Revenue variance	Adjusted variance	
2019/20	-14.6%	-11.5%	-4.1%
2020/21	-13.2%	-10.0%	7.5%
2021/22	4.3%	7.4%	9.5%
2022/23	9.5%	12.6%	13.1%
2023/24	-1.7%	1.5%	-3.5%
Systemic error:	-3.1%		
Adjusted error:		12.6%	13.1%
Error margin =			29.6%

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

We have published three sets of tariffs relating to pre-existing. These are TNUoS local tariffs associated with pre-existing circuits and pre-existing substation bays, this year we have also included a breakdown of all local assets and their respective PARC/NONPARC components.

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 20 lists out the onshore local circuit tariff elements associated with pre-existing assets, it is only used for the purpose of calculating the gen cap.

Table 20 Onshore local circuit tariff elements associated with pre-existing assets

Project Name	Pre-existing local circuit tariff (£/kW)	Project Name	Pre-existing local circuit tariff (£/kW)
Aberarder Wind Farm	0.760858	Foyers	0.000000
Aberdeen Offshore Wind Farm	0.000000	Galawhistle Wind Farm	0.000000
A'Chruach Wind Farm	0.000000	Glen App Windfarm	0.000000
Afton Wind Farm	0.000000	Glen Kyllachy Wind Farm	0.000000
Aikengall II Windfarm	0.000000	Glenmuckloch Wind Farm	1.919911
Aikengall IIa Wind Farm	0.000000	Harting Rig Wind Farm	0.000000
Alcemi Coalburn Battery Energy Storage Facility	0.000000	Hartlepool	0.000000
Arecleoch Windfarm Extension	0.000000	Hunterston Energy Storage Facility	0.000000
Beinneun Wind Farm	0.059200	Kennoxhead Wind Farm	2.640178
Benbrack wind farm	0.435380	Kennoxhead Wind Farm Extension	2.640178
Bhlaraidh Wind Farm	0.000000	Kilmarnock BESS	0.000000
Blacklaw	0.000000	Kincardine Battery Storage Facility	0.000000
Blacklaw Extension	0.000000	Kype Muir	0.000000
Broken Cross Windfarm	0.000000	Limekiln	0.000000
Carraig Gheal Wind Farm	5.359595	Lochluichart	0.000000
Chirmorie Wind Farm	0.000000	Marchwood	0.000000
Clyde North	0.000000	Middle Muir Wind Farm	0.000000
Clyde South	0.000000	Pen Y Cymoedd Wind Farm	0.000000
Corriegarth	0.000000	Pencloe Windfarm	0.000000
Coryton ENERGY	0.000000	Rocksavage	0.000000
Crossdykes	0.000000	Saltend	0.000000
Cruachan	0.000000	Sandy Knowe Wind Farm	0.000000
Cumberhead	0.000000	Sanquhar II Wind Farm	5.725310
Cumberhead West Wind Farm	0.000000	Sanquhar Wind Farm	0.895959
Dalquhandy Wind Farm	0.000000	Shepherds Rig Wind Farm	-0.098892
Dersalloch Wind Farm	0.000000	Spalding	0.000000
Dinorwig	0.000000	Stranoch Wind Farm	2.639080
Dorenell Windfarm	0.000000	Stronelairg	0.252812
Douglas West	0.760858	Twentyshilling Wind Farm	0.000000
Douglas West Extension	0.000000	Viking Wind Farm	0.000000
Edinbane Windfarm	0.000000	Whitelee Extension	0.000000
Enoch Hill	0.000000	Whiteside Hill Wind Farm	0.000000
Ewe Hill	0.000000	Windy Rig Wind Farm	0.000000
Fallago Rig Wind Farm	0.000000	Windy Standard II (Brockloch Rig) Wind Farn	0.000000
Ffestiniog	0.000000	Windy Standard III Wind Farm	0.000000

Aggregated pre-existing TEC (MW)	15,068

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 21 lists out the onshore local substation tariffs associated with pre-existing assets.

Table TC in the tables file gives a breakdown of all local assets and their respective PARC/NONPARC components.

Table 21 Onshore local substation tariffs associated with pre-existing assets

Project Name	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	0.179523	37.2
Toddleburn Wind Farm	0.179523	

Charging Bases for 2025/26

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 2025/26 tariffs is forecast at 88.7 GW, which is a decrease of 6 GW 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, in line with the CUSC, we use the contracted TEC position as of 31 October 2024 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 2025/26.

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 2024)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

With recent historical trends and forward-looking assumptions, demand volumes are forecast to plateau over the next couple of years. Adjustments have been made in our forecast since the Draft Forecast for 2025/26 based on the latest demand outturn data up to end of September 2024. Please refer to table TAA in the published tables excel spreadsheet[8] for a detailed breakdown of the changes to the demand charging bases.

Table 22 Charging Bases

	2025/26 Tariffs			
Charging Bases	**Initial**	**July**	**Draft**	**Final**
Generation (GW)	83.15	99.22	94.75	88.74
NHH Demand (4pm-7pm TWh)	23.06	23.29	22.87	24.25
Gross charging				
Total Average Gross Triad (GW)	47.43	47.45	47.49	48.04
HH Demand Average Gross Triad (GW)	17.21	17.70	17.95	16.94
Embedded Generation Export (GW)	7.48	7.48	7.81	7.42

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 2025/26 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 NESO website[9].

[8] Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.
[9] neso.energy/document/352566/download

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.

Demand Residual Charges

The demand residual revenue is recovered by a p/site/day charge on final demand users (both HH and NHH), based on site specific banded charges which came into effect in April 2023.

Each final demand site is allocated to a residual charging band that is based on its capacity or annual energy consumption. The charge is non-locational so all sites within the same band pay the same demand residual tariff regardless of which demand zone they are in.

Site counts across the forecast horizon have been kept static, except for the domestic site count which is forecast to continue to rise.

Demand customers are also 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.

Table 23 Residual & Adjustment components calculation

	Component	2025/26 Tariffs Initial	July	Draft	Final
G	Proportion of revenue recovered from generation (%)	21.38%	22.36%	21.13%	22.20%
D	Proportion of revenue recovered from demand (%)	78.62%	77.64%	78.87%	77.80%
R	Total TNUoS revenue (£m)	5,280.8	5,268.5	5,503.4	5,087.0
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	448.67	488.64	469.43	468.71
O	Revenue recovered from offshore local tariffs (£m)	766.2	796.2	780.0	755.7
L_G	Revenue recovered from onshore local substation tariffs (£m)	13.5	15.5	14.4	12.9
S_G	Revenue recovered from onshore local circuit tariffs (£m)	52.4	48.3	46.6	47.5
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	12.3	8.7	4.9	7.1
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50
	Error Margin	31.4%	29.6%	29.6%	29.6%
	Exchange Rate (€/£)	1.16	1.16	1.16	1.18
	Total generation Output (TWh)	209.11	215.27	215.27	215.27
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	309.19	326.76	326.76	320.37
	Adjustment Revenue (£m)	-151.82	-170.67	-147.69	-155.56
BG	Generator charging base (GW)	83.15	99.22	94.75	88.74
AdjTariff	Generator adjusment tariff (£/kW)	-1.83	-1.72	-1.56	-1.75
Gross demand residual					
R_D	Demand residual (£m)	4,038.8	3,992.7	4,224.1	3,836.0
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	133.60	117.45	140.10	143.78
EE	Amount to be paid to Embedded Export Tariffs (£m)	-21.2	-20.3	-24.3	-22.9
B_D	Demand Gross charging base (GW)	47.4	47.4	47.5	48.0

Tools and supporting information

We would like to ensure that customers understand the current charging arrangements and the reasons why tariffs change. If you have specific queries on this publication, 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 13 February. We will be sending out a communication to those who subscribe to our updates via the NESO 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:

neso.energy/document/353061/download

This data can also be accessed via our Data Portal:

neso.energy/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@nationalenergyso.com

Appendix A: Background to TNUoS charging

Background to TNUoS charging

NESO 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, NESO 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, for example, 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 implementation of Transmission Demand Residual bandings and allocation, 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 ≥ 100 MW) 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**.

Note: Additional Local Tariffs may be applicable to Offshore generators

*** Local Tariffs**

The Wider tariff is set to reflect 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.

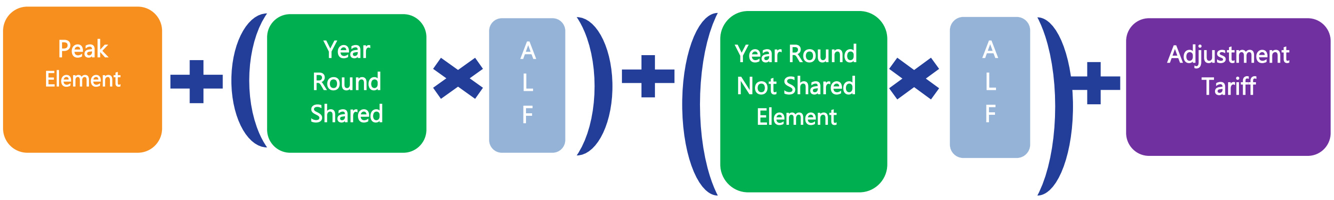
† Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

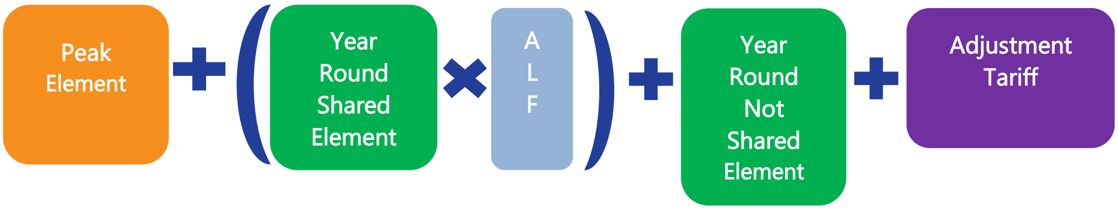
Conventional Carbon Generators

(for example: Biomass, CHP, Coal, Gas, Pumped Storage, Battery)



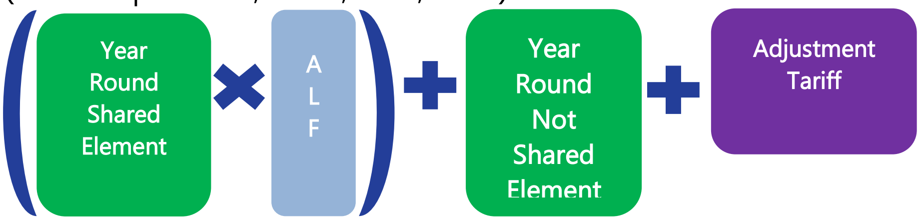
Conventional Low Carbon Generators

(for example: Hydro, Nuclear)



Intermittent Generators

(for example: 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[10] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[11] 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 transmission 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 100 MW in TEC from 1 April to 31 January, then 350 MW from 1 February to 31 March, the generator will be charged for 350 MW of TEC for that charging year.

The calculation for TNUoS generator monthly invoice is as follows:

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

[10] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: neso.energy/industry-information/connections

[11] Distribution network Use of System charges

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

TNUoS charges are billed on the first of each calendar month.

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 applicable tariffs for gross HH demand and embedded export volumes individually rather than being netted. NHH customers have another tariff which is also applied to HH customers in measurement class F and G. Since April 2023, the TNUoS demand residual is charged separately to all final demand. 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[12]. 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 NESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[13].

Embedded Export Tariffs (EET)

The EET 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 (<100 MW CVA registered).

[12] neso.energy/industry-information/charging/tnuos-charges#Triads-data
[13] neso.energy/document/130641/download

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[14].

Embedded generators (<100 MW 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 NESO. Payments for embedded exports from SVA registered embedded generators will be paid to their registered supplier.

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

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.

[14] neso.energy/industry-information/charging/charging-documentation

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which were implemented in the TNUoS tariffs for financial year 2025/26.

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

neso.energy/industry-information/codes/connection-and-use-system-code-cusc/cusc-modifications

A summary of the recently approved modifications which affect 2025/26 TNUoS tariffs are listed below.

Table 24 Summary of concluded CUSC modification proposals

Modification directed for implementation:			
Name	**Title**	**Effect of proposed change**	**Implementation**
CMP392	Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation	Provides stakeholders with legal certainty and transparency of the methodology including the calculation and the output of the calculation	1 April 2025
CMP411	Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies	Introduces Anticipatory Investment (AI) and a mechanism for the recovery of AI costs within the Section 14 charging methodologies	1 April 2025
CMP424	Amendments to Scaling Factors used for Year Round TNUoS charges	Seeks to introduce a mechanism which sets a lower limit on the variable generation scaling factors used for the purpose of Year Round Background tariff calculation	1 April 2025
CMP430	Adjustments to TNUoS Charging from 2025 to support the Market Wide Half Hourly Settlement (MHHS) Programme	Rectifies defects relating to demand locational TNUoS charging that will become apparent during the migration phase of the MHHS Programme	1 April 2025

Appendix C: Breakdown of locational HH and EE tariffs

Locational components of demand tariffs

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

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

Table 25 Location elements of the HH demand tariff for 2025/26

Demand Zone		2025/26 Draft		2025/26 Final		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	- 0.064369	- 33.424399	-0.827604	-33.839448	- 0.763235	- 0.415049
2	Southern Scotland	- 0.814464	- 22.688930	-1.321113	-23.621013	- 0.506650	- 0.932083
3	Northern	- 1.400001	- 10.070967	-1.647426	-11.005420	- 0.247425	- 0.934453
4	North West	- 0.305832	- 5.210810	-0.702065	-5.877306	- 0.396233	- 0.666496
5	Yorkshire	- 0.506379	- 3.353749	-0.790016	-4.258236	- 0.283637	- 0.904487
6	N Wales & Mersey	- 1.524935	- 0.877469	-1.884671	-1.423140	- 0.359736	- 0.545672
7	East Midlands	- 1.379039	1.299963	-1.072230	0.763595	0.306808	- 0.536368
8	Midlands	- 1.365342	3.628480	-1.124923	4.115881	0.240419	0.487401
9	Eastern	0.596787	0.945553	0.606933	0.503811	0.010147	- 0.441742
10	South Wales	- 5.299242	9.118993	-3.661669	10.54671	1.637573	1.427719
11	South East	2.857412	2.178710	2.625117	2.943118	- 0.232295	0.764408
12	London	3.591662	3.899440	3.459054	3.946292	- 0.132609	0.046852
13	Southern	1.696243	7.032946	1.296782	6.273391	- 0.399461	- 0.759555
14	South Western	- 1.142394	10.710094	-0.663438	10.786474	0.478957	0.076380

Table 26 Elements of the Embedded Export Tariff for 2025/26

Demand Zone		2025/26 Draft		2025/26 Final		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	- 33.488768	2.791637	-34.667052	2.791637	- 1.178284	-
2	Southern Scotland	- 23.503394	2.791637	-24.942127	2.791637	- 1.438733	-
3	Northern	- 11.470968	2.791637	-12.652846	2.791637	- 1.181878	-
4	North West	- 5.516642	2.791637	-6.579371	2.791637	- 1.062729	-
5	Yorkshire	- 3.860128	2.791637	-5.048252	2.791637	- 1.188124	-
6	N Wales & Mersey	- 2.402403	2.791637	-3.307812	2.791637	- 0.905408	-
7	East Midlands	- 0.079076	2.791637	-0.308635	2.791637	- 0.229559	-
8	Midlands	2.263138	2.791637	2.990958	2.791637	0.727820	-
9	Eastern	1.542340	2.791637	1.110745	2.791637	- 0.431595	-
10	South Wales	3.819751	2.791637	6.885043	2.791637	3.065291	-
11	South East	5.036122	2.791637	5.568235	2.791637	0.532113	-
12	London	7.491102	2.791637	7.405345	2.791637	- 0.085757	-
13	Southern	8.729190	2.791637	7.570174	2.791637	- 1.159016	-
14	South Western	9.567700	2.791637	10.123037	2.791637	0.555337	-

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 publication, we have used the final version of the 2025/26 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2019/20 to 2023/24. Generators which commissioned after 1 April 2021 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 2025/26 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 2025/26 TNUoS Tariffs have been published in the following places:

- Final Annual Load Factors for 2025/26 TNUoS Tariffs: neso.energy/document/352566/download
- Specific ALFs in excel format: neso.energy/document/352541/download

Generic ALFs

Table 27 Generic ALFs

Technology	Generic ALF
Battery	3.8884%
Biomass	42.9869%
CCGT_CHP	42.3027%
Coal	29.0586%
Gas_Oil	0.8252%
Hydro	39.6894%
Nuclear	55.6863%
Offshore_Wind	48.2176%
Onshore_Wind	41.5111%
Pumped_Storage	9.4949%
Reactive_Compensation	0.0000%
Solar	10.8000%
Tidal	13.2000%
Wave	2.9000%

Please note: ALF figures for Wave, Tidal and Solar technology are generic figures published by DESNZ due to insufficient metered data being available.

These Generic ALFs are calculated in accordance with CUSC 14.15.111.

Appendix E: Contracted Generation

The contracted TEC volumes are used to set locational tariffs; however, we also model our best view of contracted TEC which also 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 (affecting locational tariffs) uses the TEC register as of 31 October 2024, as required by the CUSC 14.15.6. One correction has been made to the Contracted TEC since the Draft Forecast, where a conflict was found in the TEC register, this change can be seen in Table 28.

Table 28 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Rowan Wind Energyfarm	-90.8	CRSS10	7

Appendix F: Transmission Company Revenues

Transmission Owner revenue forecasts

The revenue forecast has been based on final data submissions received by Onshore and Offshore TOs in January 2025. In addition, there are some pass-through items that are to be collected by NESO via TNUoS charges, including the Strategic Innovation Fund (SIF) and contributions made from Interconnectors.

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

NESO TNUoS revenue pass-through items forecasts

The allowed TNUoS revenue from the onshore TO's (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) and OFTOs is collected by NESO and passed through to those parties.

NESO also collects the Strategic Innovation Fund (SIF) and passes through the money to network licensees (including ONTOs, OFTOs and DNOs), in addition to a few other pass-through items. The revenue breakdown table below (table 29) shows details of the pass-through TNUoS revenue items under NESO's licence conditions.

Since the Draft Forecast, there has been a decrease in ONTO Allowed Revenues and a small increase of OFTO and Interconnector payments.

Table 29 NESO revenue breakdown

Term	NESO TNUoS Other Pass-Through			
	Initial Forecast	July Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.69	0.67	0.67	0.67
Network Innovation Competition Fund (NICFt)	0.00	0.00	0.00	5.00
Strategic Innovation Fund (SIFt)	85.01	85.01	85.01	53.92
The Adjustment Term (ADJt)	0.00	-40.75	-39.82	-85.10
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	946.31	982.73	968.50	973.84
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00	-43.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	0.00
Termination Sums (TSt)	0.00	0.00	0.00	0.00
NGET revenue pas-through (NGETTOt)*	2,502.79	2,502.79	2,595.27	2,397.89
SPT revenue pass-through (TSPt)	502.87	502.87	530.47	544.74
SHETL revenue pass-through (TSHt)	1,197.29	1,197.29	1,325.36	1,191.62
NESO Bad debt (BDt)	3.12	0.03	0.03	0.03
NESO other pass-through items (LFt + ITCt etc)	42.69	37.88	37.88	47.35
NESO legacy adjustment (LARt)	0.00	0.00	0.00	0.00
Total	**5,280.77**	**5,268.50**	**5,503.36**	**5,086.97**

Onshore TOs (NGET, SPT and SHET) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) provided us with their final revenue breakdown in January 2025 as required by STCP 24-1. Since the Draft Forecast, here has been a £316.84m decrease in the ONTO revenue (NGET, -£197.37m, SPT, +£14.27m and SHET, -£133.74m).

For SPT, revenue increases from Draft to Final are due to increased allowed revenue for 25/26 due to movements in macro-economic inputs (i.e. increase in inflation in OBR November 24 forecast offset by slightly lower Weighted Average Cost of Capital and further increases due to update of forecast recovered revenue for 24/25 from NESO.

Movement in NGET revenue is mainly driven by updated forecasts for re-opener projects, including Accelerated Strategic Transmission Investment (ASTI). These forecasts are updated due to better information maturity, relating to both timing and value of the respective submissions.

Reduction in SHET's revenue is primarily due to the re-profiling of works owing to planning and consenting delays; primarily on ASTI and Large Onshore Transmission Investments (LOTI) projects for which spend will now be expected in the early years of the next ONTO price control as opposed to the final year of the current price control (RIIO-ET2). The indicative submission envisioned greater pace of ASTI & LOTI works for the final year of RIIO-ET2 which drove the higher Allowed Revenue values in the indicative submission. The updated capex figures for Final Tariffs reflect the latest information provided and has been subject to internal due diligence.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2025/26 is forecast to be £1.01bn, an increase of £5.3m 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

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.

Updates to the Interconnector Adjustment forecast were updated based on figures submitted by Interconnectors in January 2025.

Table 30 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	372.27	372.27	368.43	373.07
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	1,952.30	1,952.30	1,987.06	1,928.32
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	38.91	-69.17
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**2,565.33**	**2,565.33**	**2,622.96**	**2,470.08**
SONIA	B1	It-1	0.05	0.05	0.05	0.05
Allowed Revenue	B2	AR_{t-1}	2,022.91	2,022.91	2,001.77	2,001.68
Recovered Revenue	B4	RR_{t-1}	2,022.91	2,022.91	1,969.55	2,010.64
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**34.20**	**-9.51**
Legacy pass-through	C1	LP_t	0.00	0.00	0.00	0.00
Legacy MOD	C2	$LMOD_t$	-62.54	-62.54	-61.90	-62.68
Legacy K correction	C3	LK_t	0.00	0.00	0.00	0.00
Legacy TRU term	C4	$LTRU_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	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	$LSFI_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	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**	**-62.54**	**-62.54**	**-61.90**	**-62.68**
Site Rental Charges			**0.00**	**0.00**	**0.00**	**0.00**
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**2,502.79**	**2,502.79**	**2,595.27**	**2,397.89**

Table 31 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	372.27	372.27	368.43	373.07
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	392.65	392.65	417.84	414.04
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.04	4.65
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**515.94**	**515.94**	**543.41**	**549.87**
SONIA	B1	It-1	0.05	0.05	0.05	0.05
Allowed Revenue	B2	AR_{t-1}	0.00	0.00	449.18	449.14
Recovered Revenue	B4	RR_{t-1}	0.00	0.00	449.18	441.61
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**	**7.98**
Legacy pass-through	C1	LP_t	0.00	0.00	0.00	0.00
Legacy MOD	C2	$LMOD_t$	-13.17	-13.17	-13.04	-13.20
Legacy K correction	C3	LK_t	0.00	0.00	0.00	0.00
Legacy TRU term	C4	$LTRU_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	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	$LSFI_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	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**	**-13.08**	**-13.08**	**-12.94**	**-13.11**
Site Rental Charges			**0.00**	**0.00**	**0.00**	**0.00**
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**502.87**	**502.87**	**530.47**	**544.74**

Table 32 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	372.27	372.27	368.43	373.07
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	898.91	898.91	1,003.52	892.32
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-3.99	-8.00
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**1,181.18**	**1,181.18**	**1,301.03**	**1,167.03**
SONIA	B1	It-1	0.05	0.05	0.05	0.05
Allowed Revenue	B2	AR_{t-1}	781.07	781.07	780.69	780.75
Recovered Revenue	B4	RR_{t-1}	781.07	781.07	772.79	772.79
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**8.38**	**8.44**
Legacy pass-through	C1	LP_t	0.00	0.00	0.00	0.00
Legacy MOD	C2	$LMOD_t$	16.12	16.12	15.95	16.15
Legacy K correction	C3	LK_t	0.00	0.00	0.00	0.00
Legacy TRU term	C4	$LTRU_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	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	$LSFI_t$	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	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**	**16.12**	**16.12**	**15.95**	**16.15**
Site Rental Charges			**0.00**	**0.00**	**0.00**	**0.00**
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**1,197.29**	**1,197.29**	**1,325.36**	**1,191.62**

Table 33 Offshore Revenues

Offshore Transmission Revenue Forecast (£m)	Year					
Regulatory Year	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Notes**
Barrow	6.7	7.0	7.8	8.5	8.8	Current revenues plus indexation
Gunfleet	8.4	8.7	9.7	10.7	11.1	Current revenues plus indexation
Walney 1	15.3	15.6	17.8	19.4	20.3	Current revenues plus indexation
Robin Rigg	9.4	9.8	10.9	12.0	12.4	Current revenues plus indexation
Walney 2	15.1	16.3	18.3	20.0	20.9	Current revenues plus indexation
Sheringham Shoal	23.4	24.2	26.7	29.5	30.0	Current revenues plus indexation
Ormonde	14.1	14.7	16.2	17.9	18.6	Current revenues plus indexation
Greater Gabbard	32.1	33.2	37.0	38.8	41.6	Current revenues plus indexation
London Array	44.7	46.8	52.6	57.3	59.1	Current revenues plus indexation
Thanet	20.8	21.6	24.0	26.3	27.4	Current revenues plus indexation
Lincs	30.0	32.5	34.0	40.9	40.1	Current revenues plus indexation
Gwynt y mor	32.9	39.8	37.6	37.4	78.8	Current revenues plus indexation and IAE
West of Duddon Sands	25.3	25.5	28.5	30.3	32.3	Current revenues plus indexation
Humber Gateway	14.4	13.3	15.0	16.6	17.4	Current revenues plus indexation
Westermost Rough	14.1	14.7	16.5	18.0	18.6	Current revenues plus indexation
Burbo Bank Extension	14.1	14.7	16.4	17.7	18.4	Current revenues plus indexation
Dudgeon	19.6	20.8	22.6	24.9	26.2	Current revenues plus indexation
Race Bank	27.4	28.9	32.5	35.4	36.5	Current revenues plus indexation
Galloper	17.1	17.8	20.1	21.9	22.5	Current revenues plus indexation
Walney 3	13.5	14.1	15.9	17.3	17.8	Current revenues plus indexation
Walney 4	13.5	14.1	15.9	17.3	17.8	Current revenues plus indexation
Hornsea 1A	137.1	18.4	20.6	22.2	22.9	Current revenues plus indexation
Hornsea 1B		18.4	20.6	22.2	22.9	Current revenues plus indexation
Hornsea 1C		18.4	20.6	22.2	22.9	Current revenues plus indexation
Beatrice		21.1	24.4	25.7	26.5	Current revenues plus indexation
Rampion		15.5	17.4	19.7	20.3	Current revenues plus indexation
East Anglia 1		68.3	47.4	51.8	54.8	Current revenues plus indexation
Hornsea 2A			138.7	25.3	27.3	Current revenues plus indexation
Hornsea 2B				25.3	27.3	Current revenues plus indexation
Hornsea 2C				25.3	27.3	Current revenues plus indexation
Triton Knoll				41.3	42.7	Current revenues plus indexation
Moray East				28.2	50.0	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2024/25				52.6	42.3	NESO Forecast
Forecast to asset transfer to OFTO in 2025/26					47.4	NESO Forecast
Offshore Transmission Pass-Through	**549.0**	**594.3**	**765.6**	**879.8**	**1,010.9**	

Notes:

Figures for historic years represent NESO'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.

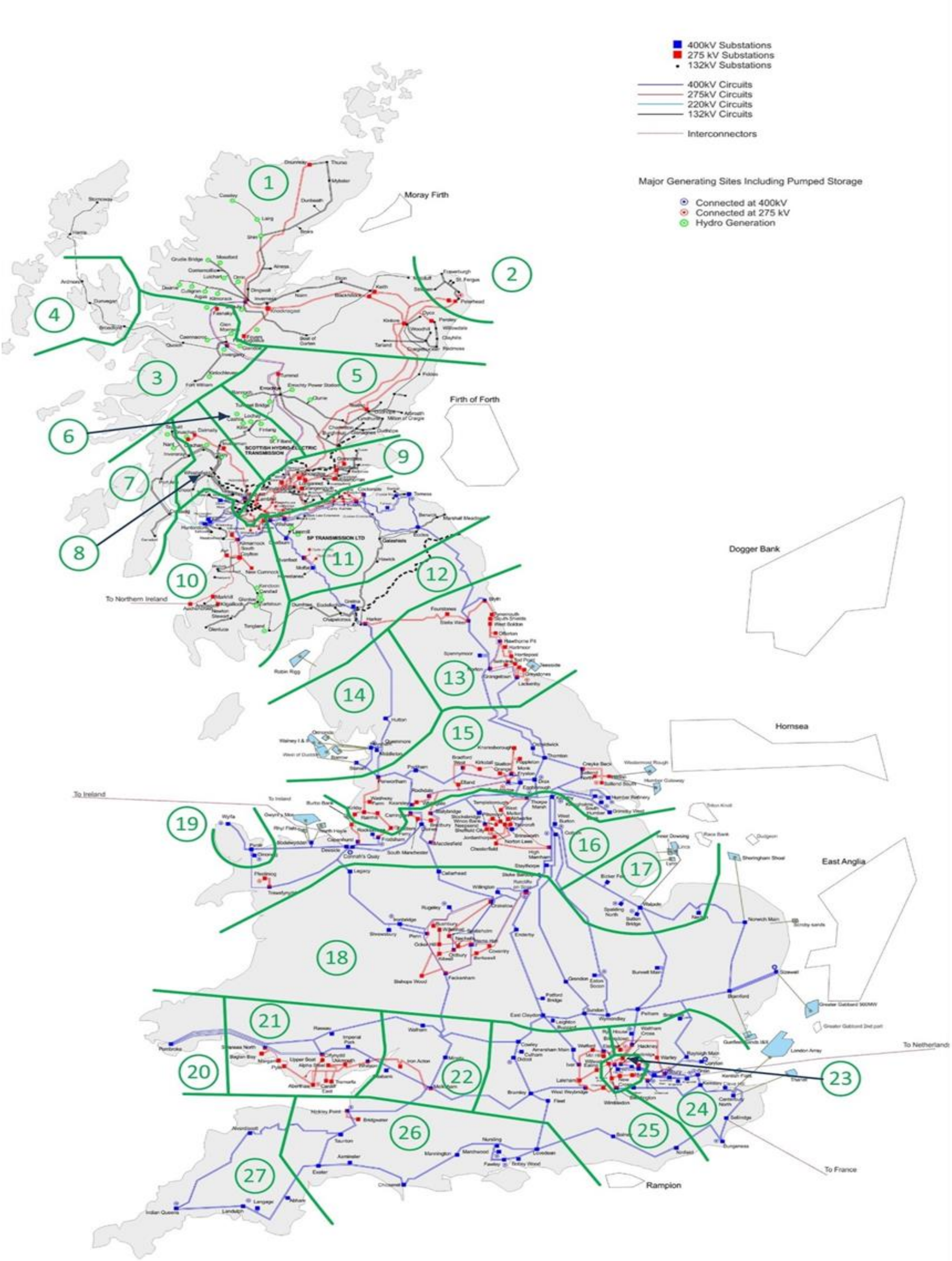
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed.

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

IAE = Income Adjusting Event

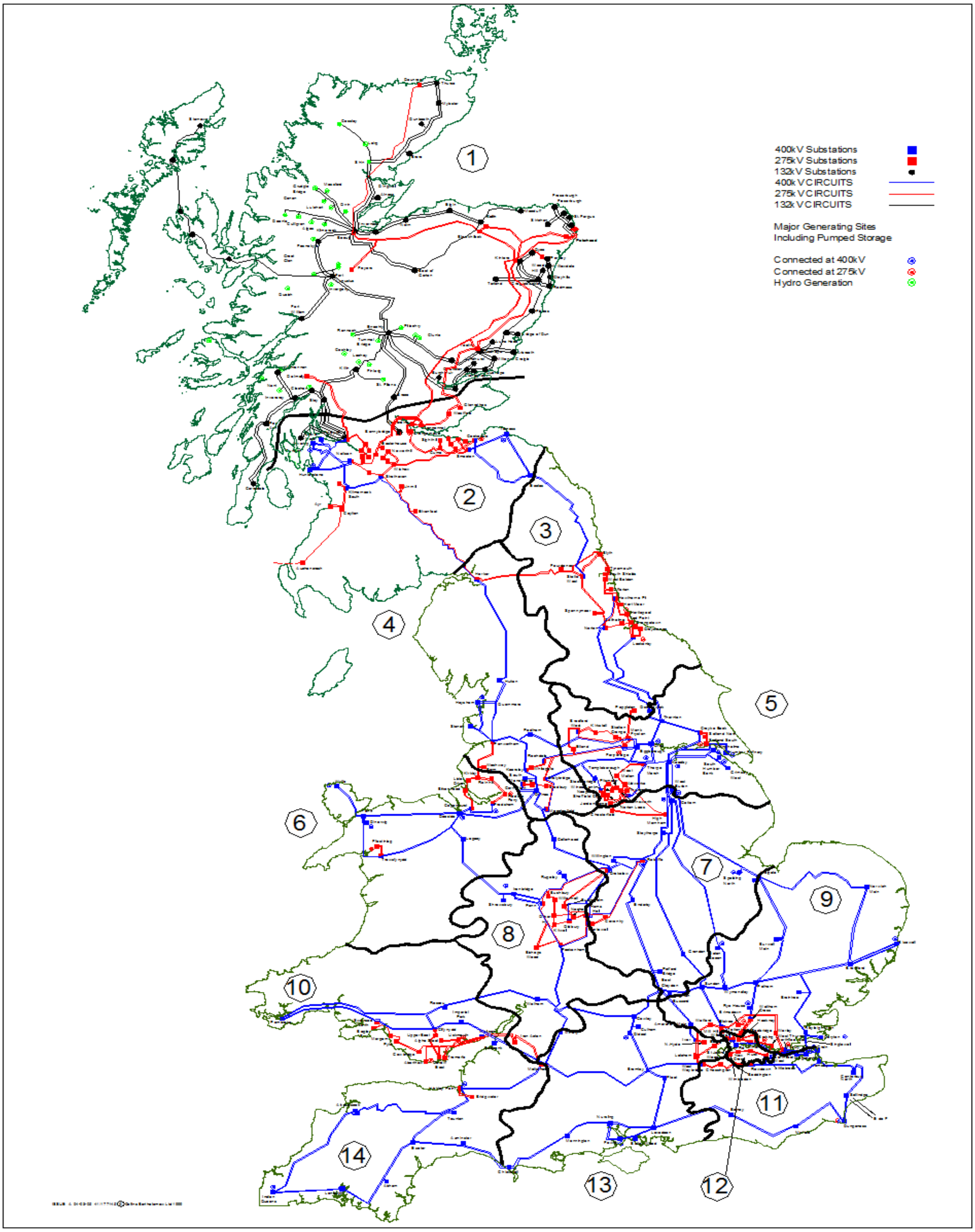
Appendix G: Generation Zones Map

Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to Electricity Ten Year Statement 2024 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.

2025/26 TNUoS Tariff Forecast					
		April 2024	July 2024	Draft Tariffs November 2024	Final Tariffs January 2025
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	Week 24 Finalised
LOCATIONAL	**Contracted TEC**	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
LOCATIONAL	**Network Model**	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
LOCATIONAL	**Inflation**	Forecast			Actual
RESIDUAL / ADJUSTMENT	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	From OFTOs & NESO best view
RESIDUAL / ADJUSTMENT	**Allowed Revenue** *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From ONTOs
RESIDUAL / ADJUSTMENT	**Demand Charging Bases** (including TDR site counts)	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
RESIDUAL / ADJUSTMENT	**Consumption Data** (by TDR charging band)	Previous year's data source		DNO/IDNO consumption update received	
RESIDUAL / ADJUSTMENT	**Generation Charging Base**	NESO best view	NESO best view	NESO best view	NESO final best view
RESIDUAL / ADJUSTMENT	**Generation ALFs**	Previous year's data source		Draft ALFs published	Final ALFs published
RESIDUAL / ADJUSTMENT	**Generation Revenue** (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

Document Revision History

Document Revision History

Version Number	Date of Issue	Notes
1.0	31 January 2025	Publication of Final TNUoS Tariffs for 2025/26

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