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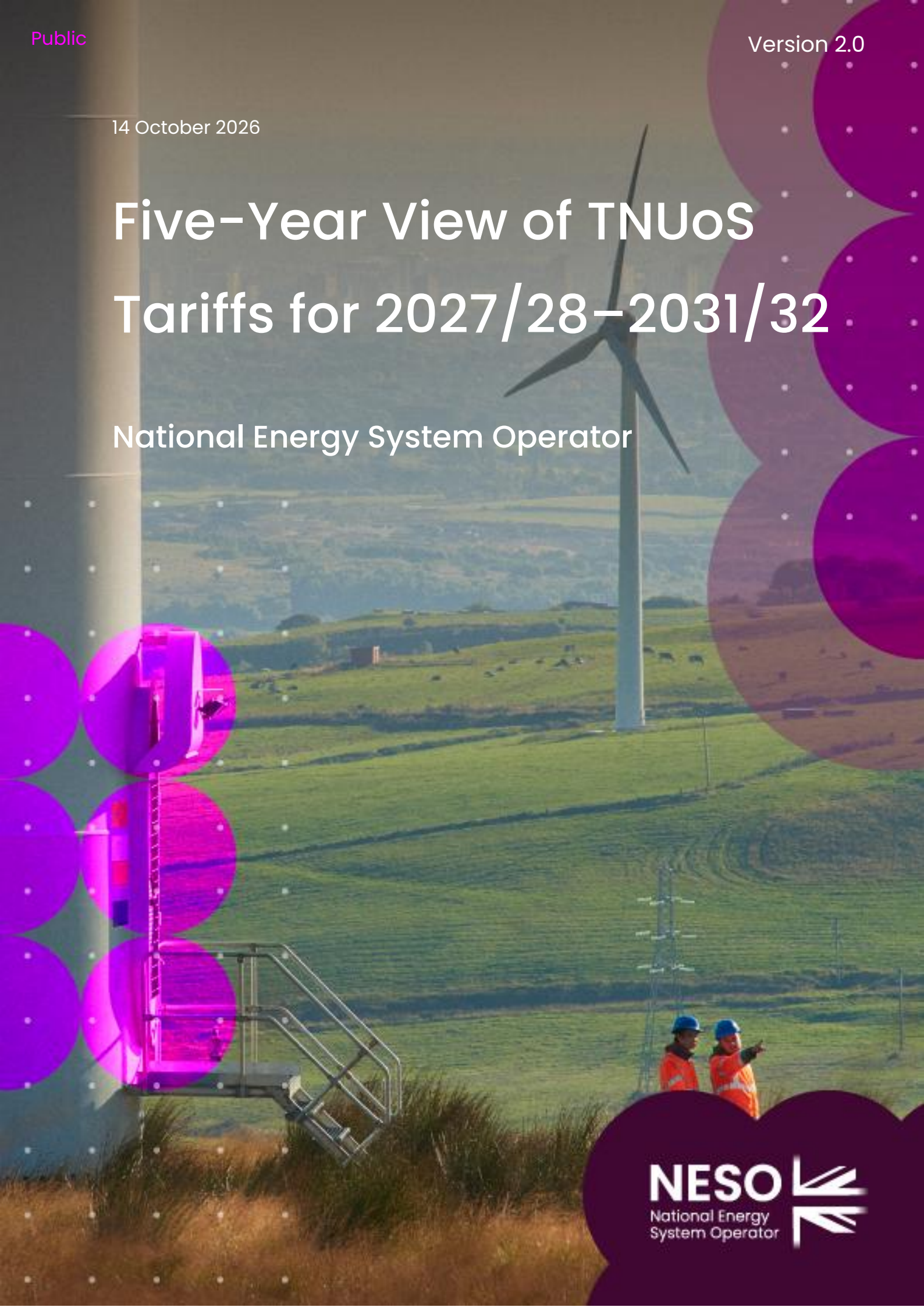
Five-Year View of TNUoS Tariffs for 2027/28–2031/32

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 Five-Year View of TNUoS Tariffs for 2027/28-2031/32.

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 this five-year view of future Transmission Network Use of System (TNUoS) tariffs on our website[1].

This report provides a forecast for the period of 2027/28 to 2031/32; they have no impact on charging year 2026/27.

Total revenues to be recovered

The total TNUoS revenue to be collected in 2027/28 is forecast to be £9.5bn (an increase of £0.4bn from the 2027/28 Initial Tariffs). This is set to increase to £13.8bn in 2031/32. Forecast revenues have been based on latest Transmission Owner data as provided in January 2026, together with updated forecasts of other pass-through items. We have also modelled the impact of three additional revenue scenarios; allowed revenues based on the February 2026 Price Control Financial Model and high and low cases which are set at 10% above and below the base case.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.36bn for 2027/28 (a decrease of £22m since the Initial Tariffs). It is forecast to grow to £1.96bn by 2031/32, mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base for 2027/28 has been forecast to be 110.7GW based on our best view, a decrease of 11.1GW since Initial Tariffs. This view will be further refined throughout the year. The charging base is forecast to reach 158.4GW by 2031/32.

The average generation tariff for 2027/28 is £12.32/kW, an increase of £0.95/kW since the Initial Tariffs. It is expected to fluctuate before reaching £12.35/kW in 2031/32. The fluctuation in the average tariff is caused by the generation revenue to be collected and the generation charging base increasing at different rates across the five years.

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

Demand tariffs

Revenue to be recovered through demand residual charges is forecast to be £7.97bn in 2027/28, rising to £11.66bn by 2031/32. The increase in demand revenue is the result of the increase in TNUoS revenue.

The TNUoS cost for the average domestic household is forecast to be £103.24 for 2027/28 which forms 12% of the average annual electricity consumer bill. This is £20.00 higher than the Final 2026/27 Tariffs, when TNUoS represented 8.8% of the total bill, and £6.39 higher than our Initial Tariffs for 2027/28.

In 2027/28, it is forecast that £32.08m would be payable to embedded generators (<100 MW) through the Embedded Export Tariff (EET), This is forecast to increase to £41.01m in 2031/32.

The average HH gross tariff is forecast to be £3.29/kW in 2027/28, increasing to £4.05/kW in 2031/32.

Next TNUoS tariff publication

The timetable of TNUoS tariff forecasts for 2027/28 is available on our website[2].

Our next TNUoS tariff publication will be the Draft forecast of 2027/28 tariffs, which will be published in November 2026.

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@neso.energy

[2] neso.energy/document/376486/download

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Charging Methodology Changes

This Report

This report contains the Five-Year View of TNUoS tariffs for the charging years 2027/28–2031/32.

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

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 Initial Tariffs for 2027/28 and consequently no additional changes have been incorporated in this forecast.

There are a number of 'in-flight' proposals to change the charging methodologies, which may impact TNUoS tariffs and charges. These are summarised in the CUSC modifications Table 30.

Reformed National Pricing and electricity network charging (RNP)

In July 2025, the government concluded the Review of Electricity Market Arrangements (REMA) and launched the Reformed National Pricing (RNP) Programme[3]. A central part of this programme is the reform of locational charges for new assets, to guide investment to locations consistent with the Strategic Spatial Energy Plan (SSEP).

Please note that this ongoing work has not been included in this forecast.

Details of any CUSC modifications that may impact 2027/28 tariffs onwards can be found in Appendix B.

Price Control Impact on Charging Parameters

In accordance with the CUSC, several parameters which affect TNUoS tariffs must be recalculated and reset in preparation for a new price control. This forecast covers the remaining years of RIIO-ET3 and the first year of the following price control, which will commence in April 2031. Input data for the recalculation of parameters is required from a number of sources, including the TOs and the Ofgem price control determinations, and will not become available until 2030/31. In this report, our assumptions are in line with the current RIIO-ET3 parameters, with inflation applied where applicable.

[3] ofgem.gov.uk/sites/default/files/2025-07/open-letter-reforming-network-charging-signals.pdf

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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 from 2027/28 to 2031/32 and how these tariffs were calculated.

Table 1 Summary of Generation Tariffs

Generation Tariffs (£/kW)	Initial Tariffs 2027/28	2027/28	2028/29	2029/30	2030/31	2031/32
Adjustment Tariff	- 2.114050	- 2.167730	- 2.477199	- 2.276787	- 4.685346	- 5.387665
Average Generation Tariff*	11.37618	12.321872	11.953440	11.999528	11.952995	12.346955

*Please note that the average generation 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".

Over the next five years, it is expected that the average generation tariff will fluctuate, year on year, starting from £12.32/kW in 2027/28 and ending with £12.35/kW in 2031/32. This fluctuation is due to the generation revenue to be collected and the expected increase in generation charging base increasing at different rates across the years. The adjustment tariff fluctuates a little but is largely expected to decrease year-on-year, increasing in magnitude, to become more negative; it is expected to change from -£2.167730/kW in 2027/28 to -£5.387665/kW in 2031/32. This is due to the revenue which is expected to be collected from generation locational tariffs increasing, meaning there is more of a requirement to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

Generation Wider Tariffs

The following section summarises the five-year view of wider generation tariffs from 2027/28 to 2031/32. 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 comprise 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		

In 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 in 2027/28

Generation Tariffs						Example tariffs for a generator of each technology type		
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)
1	North Scotland	3.527130	31.810584	15.608389	-2.167730	20.326989	40.825727	27.755422
2	East Aberdeenshire	4.687225	18.756924	15.608389	-2.167730	16.265620	32.195577	21.881275
3	Western Highlands	3.632514	29.411091	13.940512	-2.167730	18.805425	37.463614	25.007773
4	Skye and Lochalsh	3.634575	29.411091	22.072977	-2.167730	22.060472	45.598140	33.140238
5	Eastern Grampian and Tayside	5.754288	25.018614	10.229233	-2.167730	17.685697	32.579752	19.319879
6	Central Grampian	5.374305	27.524225	13.530761	-2.167730	19.628569	37.380505	23.748932
7	Argyll	4.590181	23.482221	14.604205	-2.167730	17.657021	34.638322	23.003474
8	The Trossachs	4.691683	23.482221	8.134016	-2.167730	15.170448	28.269635	16.533285
9	Stirlingshire and Fife	3.097875	22.575337	7.404163	-2.167730	12.921945	25.265811	15.395335
10	South West Scotlands	3.495608	21.717086	6.915693	-2.167730	12.780990	24.531386	14.520652
11	Lothian and Borders	3.127161	21.717086	0.417996	-2.167730	9.813464	17.665242	8.022955
12	Solway and Cheviot	2.328960	13.989848	4.481851	-2.167730	7.549910	15.135467	8.609553
13	North East England	4.191375	8.596380	2.628902	-2.167730	6.513758	11.099832	4.329543
14	North Lancashire and The Lakes	2.531704	8.596380	1.586944	-2.167730	4.437304	8.398203	3.287585
15	South Lancashire, Yorkshire and Humber	4.715033	2.528115	0.133492	-2.167730	3.611946	4.576881	-0.896586
16	North Midlands and North Wales	3.155808	0.571953	-	-2.167730	1.216859	1.417043	-1.910351
17	South Lincolnshire and North Norfolk	-0.280322	3.379947	-	-2.167730	-1.096073	0.086908	-0.646754
18	Mid Wales and The Midlands	-0.207317	3.244837	-	-2.167730	-1.077112	0.058581	-0.707553
19	Anglesey and Snowdon	5.286347	-1.130833	-	-2.167730	2.666284	2.270492	-2.676605
20	Pembrokeshire	8.303171	-10.536560	-	-2.167730	1.920817	-1.766979	-6.909182
21	South Wales & Gloucester	2.286209	-11.749656	-	-2.167730	-4.581383	-8.693763	-7.455075
22	Cotswold	0.068862	4.447490	-15.204072	-2.167730	-6.401501	-13.967323	-15.370432
23	Central London	-3.797988	4.447490	-5.864911	-2.167730	-6.532686	-8.495012	-6.031271
24	Essex and Kent	-3.035553	4.447490	-	-2.167730	-3.424287	-1.867666	-0.166360
25	Oxfordshire, Surrey and Sussex	-1.153433	-3.489340	-	-2.167730	-4.716899	-5.938168	-3.737933
26	Somerset and Wessex	-3.994039	-4.288012	-	-2.167730	-7.876974	-9.377778	-4.097335
27	West Devon and Cornwall	-4.888140	-15.716939	-	-2.167730	-13.342646	-18.843574	-9.240353

Table 3 Generation Wider Tariffs in 2028/29

Generation Tariffs						Example tariffs for a generator of each technology type		
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)
1	North Scotland	2.825255	27.983791	25.547194	-2.477199	21.760450	46.883093	35.662701
2	East Aberdeenshire	1.801802	24.228035	11.330327	-2.477199	13.547948	28.825956	19.755744
3	Western Highlands	4.203752	24.021152	18.269057	-2.477199	18.642637	38.011474	26.601376
4	Skye and Lochalsh	4.166649	24.021152	26.581159	-2.477199	21.930374	46.286473	34.913478
5	Eastern Grampian and Tayside	5.468003	21.497969	12.971686	-2.477199	16.778666	32.085967	20.168573
6	Central Grampian	5.132923	22.072724	14.687481	-2.477199	17.359806	33.897748	22.143008
7	Argyll	5.970411	19.841932	21.486714	-2.477199	20.024670	39.861375	27.938384
8	The Trossachs	4.998159	19.841932	7.959468	-2.477199	13.641520	25.361877	14.411138
9	Stirlingshire and Fife	2.442937	19.975128	8.163206	-2.477199	11.221072	23.110290	14.674815
10	South West Scotlands	2.534899	20.756970	8.754509	-2.477199	11.862292	24.379937	15.617947
11	Lothian and Borders	2.666912	20.756970	2.099344	-2.477199	9.332239	17.856785	8.962782
12	Solway and Cheviot	1.992870	12.743671	5.359201	-2.477199	6.756820	14.432625	8.616654
13	North East England	3.918133	8.407094	3.265237	-2.477199	6.109866	11.011492	4.571230
14	North Lancashire and The Lakes	1.527573	8.407094	1.059022	-2.477199	2.836820	6.414717	2.365015
15	South Lancashire, Yorkshire and Humber	4.414957	2.758946	0.284888	-2.477199	3.155292	4.291856	-0.950785
16	North Midlands and North Wales	2.804639	0.417977	-	-2.477199	0.494631	0.640923	-2.289109
17	South Lincolnshire and North Norfolk	-0.340587	4.246768	-	-2.477199	-1.119079	0.367290	-0.566153
18	Mid Wales and The Midlands	0.088414	3.104467	-	-2.477199	-1.146998	-0.060435	-1.080189
19	Anglesey and Snowdon	5.040647	-1.182405	-	-2.477199	2.090486	1.676644	-3.009281
20	Pembrokeshire	8.357893	-10.598443	-	-2.477199	1.641317	-2.068138	-7.246498
21	South Wales & Gloucester	2.675239	-12.076928	-	-2.477199	-4.632731	-8.859656	-7.911817
22	Cotswold	0.096578	3.898851	-14.985276	-2.477199	-6.815191	-14.441759	-15.707992
23	Central London	-2.785442	3.898851	-5.867397	-2.477199	-6.050059	-8.205900	-6.590113
24	Essex and Kent	-1.997076	3.898851	-	-2.477199	-2.914735	-1.550137	-0.722716
25	Oxfordshire, Surrey and Sussex	-0.500371	-4.149626	-	-2.477199	-4.637420	-6.089790	-4.344531
26	Somerset and Wessex	-3.941365	-5.240688	-	-2.477199	-8.514839	-10.349080	-4.835509
27	West Devon and Cornwall	-5.398221	-16.301159	-	-2.477199	-14.395884	-20.101289	-9.812721

Table 4 Generation Wider Tariffs in 2029/30

Generation Tariffs						Example tariffs for a generator of each technology type		
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)
1	North Scotland	3.921070	34.294109	18.962694	-2.276787	22.947004	46.327559	32.118256
2	East Aberdeenshire	1.848859	30.772229	5.632400	-2.276787	14.133924	28.283644	17.203116
3	Western Highlands	6.255400	29.319272	12.357811	-2.276787	20.649446	38.325878	23.274696
4	Skye and Lochalsh	6.303211	29.319272	21.249598	-2.276787	24.253972	47.265476	32.166483
5	Eastern Grampian and Tayside	6.995542	25.061662	9.813128	-2.276787	18.668671	33.328130	18.814089
6	Central Grampian	6.598028	26.391571	11.063822	-2.276787	19.303398	35.178741	20.663242
7	Argyll	7.196054	21.580412	17.358826	-2.276787	20.494962	38.463402	24.793224
8	The Trossachs	6.136329	21.579644	6.481325	-2.276787	15.083930	26.525600	13.915378
9	Stirlingshire and Fife	3.101244	21.638112	6.519810	-2.276787	12.087626	23.572851	13.980173
10	South West Scotlands	3.434866	23.201501	7.024337	-2.276787	13.248414	25.583542	15.188225
11	Lothian and Borders	3.225227	23.201501	-0.190829	-2.276787	10.152709	18.158737	7.973059
12	Solway and Cheviot	2.468986	14.119260	4.227906	-2.276787	7.531065	15.009550	8.304786
13	North East England	4.102787	8.939192	2.367213	-2.276787	6.348562	10.897607	4.113062
14	North Lancashire and The Lakes	2.055062	8.939192	0.261894	-2.276787	3.458709	6.744563	2.007743
15	South Lancashire, Yorkshire and Humber	4.752315	3.150782	0.212883	-2.276787	3.820994	5.051498	-0.646052
16	North Midlands and North Wales	2.823518	0.690351	-0.012595	-2.276787	0.817833	1.051899	-1.978724
17	South Lincolnshire and North Norfolk	-0.770373	4.773587	-0.012595	-2.276787	-1.142763	0.520435	-0.141268
18	Mid Wales and The Midlands	-0.096142	3.108290	-0.012595	-2.276787	-1.134651	-0.054307	-0.890652
19	Anglesey and Snowdon	5.636920	-1.517266	-0.012595	-2.276787	2.748189	2.209589	-2.972152
20	Pembrokeshire	8.363011	-10.735798	-	-2.276787	1.791905	-1.965625	-7.107896
21	South Wales & Gloucester	2.553835	-11.905816	-	-2.276787	-4.485278	-8.652314	-7.634404
22	Cotswold	-0.154331	3.823918	-14.923772	-2.276787	-6.871060	-14.486952	-15.479796
23	Central London	-3.070995	3.823918	-5.522440	-2.276787	-6.027191	-8.002284	-6.078464
24	Essex and Kent	-2.027099	3.823918	-	-2.276787	-2.774319	-1.435948	-0.556024
25	Oxfordshire, Surrey and Sussex	-0.523294	-4.410387	-	-2.276787	-4.564236	-6.107871	-4.261461
26	Somerset and Wessex	-4.953005	-6.326240	-	-2.276787	-9.760288	-11.974472	-5.123595
27	West Devon and Cornwall	-6.190053	-17.277420	-	-2.276787	-15.377808	-21.424905	-10.051626

Table 5 Generation Wider Tariffs in 2030/31

Generation Tariffs						Example tariffs for a generator of each technology type		
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)
1	North Scotland	5.136835	44.224644	33.958698	-4.685346	31.724826	67.578670	49.174442
2	East Aberdeenshire	3.817805	38.227614	11.259693	-4.685346	18.927382	39.062863	23.776773
3	Western Highlands	4.557401	38.297059	23.580985	-4.685346	24.623273	52.175834	36.129316
4	Skye and Lochalsh	4.498320	38.297059	38.636067	-4.685346	30.586224	67.171835	51.184398
5	Eastern Grampian and Tayside	10.742507	31.878386	18.063810	-4.685346	26.034039	48.029761	27.723738
6	Central Grampian	8.685040	31.598010	17.727606	-4.685346	23.729940	45.425808	27.261365
7	Argyll	8.673036	27.132408	22.721927	-4.685346	23.929424	47.058923	30.246165
8	The Trossachs	7.641353	27.131674	12.320677	-4.685346	18.736947	35.625440	19.844584
9	Stirlingshire and Fife	3.920485	27.332136	12.494038	-4.685346	15.165609	32.228279	20.108153
10	South West Scotlands	4.113026	26.647213	12.219351	-4.685346	14.974306	31.632441	19.525251
11	Lothian and Borders	3.960901	26.647213	7.398639	-4.685346	12.893896	26.659604	14.704539
12	Solway and Cheviot	3.151692	16.974616	8.202287	-4.685346	8.537107	19.399595	11.155518
13	North East England	4.483910	7.277061	3.530016	-4.685346	4.121395	8.786376	2.119347
14	North Lancashire and The Lakes	2.756646	7.277061	2.396086	-4.685346	1.940559	5.925182	0.985417
15	South Lancashire, Yorkshire and Humber	5.325110	0.955939	0.438245	-4.685346	1.197438	1.794963	-3.816928
16	North Midlands and North Wales	4.011548	-1.092510	-0.071075	-4.685346	-1.139232	-1.564256	-5.248051
17	South Lincolnshire and North Norfolk	0.864197	5.491132	0.213033	-4.685346	-1.539483	0.510233	-2.001304
18	Mid Wales and The Midlands	-0.316772	4.072861	0.127267	-4.685346	-3.322067	-1.820205	-2.725292
19	Anglesey and Snowdon	6.689936	-2.596985	-0.071075	-4.685346	0.937366	-0.014224	-5.925064
20	Pembrokeshire	8.240046	-12.426966	-	-4.685346	-1.416086	-5.765525	-10.277481
21	South Wales & Gloucester	2.240605	-13.221180	-	-4.685346	-7.733213	-12.360626	-10.634877
22	Cotswold	-0.584323	3.164483	-15.769175	-4.685346	-10.311546	-18.665482	-19.030504
23	Central London	-3.875039	3.164483	-5.297351	-4.685346	-9.413532	-11.484374	-8.558680
24	Essex and Kent	-3.276495	3.164483	-	-4.685346	-6.696048	-5.588479	-3.261329
25	Oxfordshire, Surrey and Sussex	-0.389738	-5.254245	-	-4.685346	-7.176782	-9.015768	-7.049756
26	Somerset and Wessex	-5.935462	-7.671884	-	-4.685346	-13.689562	-16.374721	-8.137694
27	West Devon and Cornwall	-6.937479	-18.819136	-	-4.685346	-19.150479	-25.737177	-13.153957

Table 6 Generation Wider Tariffs in 2031/32

Generation Tariffs						Example tariffs for a generator of each technology type		
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)
1	North Scotland	4.864517	37.155620	39.576697	- 5.387665	30.169779	66.920264	50.909061
2	East Aberdeenshire	3.843284	31.169314	16.918282	- 5.387665	17.690657	38.750887	25.556808
3	Western Highlands	4.178815	32.784402	27.389537	- 5.387665	22.860726	50.768989	36.754853
4	Skye and Lochalsh	4.122094	32.784402	42.717440	- 5.387665	28.935166	66.040171	52.082756
5	Eastern Grampian and Tayside	10.516391	27.819396	20.150801	- 5.387665	24.316805	46.144074	27.281864
6	Central Grampian	8.805685	27.275566	19.173262	- 5.387665	21.997551	43.047957	26.059602
7	Argyll	8.976401	23.739855	23.292069	- 5.387665	22.401506	44.685696	28.587339
8	The Trossachs	7.912567	23.739112	12.764748	- 5.387665	17.126446	33.093984	18.059683
9	Stirlingshire and Fife	4.130881	24.246809	13.438998	- 5.387665	13.817539	30.367321	18.962397
10	South West Scotlands	4.121270	22.353801	12.068229	- 5.387665	12.502417	27.567185	16.739774
11	Lothian and Borders	4.007696	22.353801	9.748936	- 5.387665	11.461126	25.134318	14.420481
12	Solway and Cheviot	3.341370	16.967727	9.191647	- 5.387665	8.417455	19.871147	11.439459
13	North East England	5.043020	8.177110	2.285459	- 5.387665	3.840383	8.073647	0.577494
14	North Lancashire and The Lakes	2.626952	8.177110	4.061800	- 5.387665	2.134851	7.433920	2.353835
15	South Lancashire, Yorkshire and Humber	5.785649	0.748308	0.489874	- 5.387665	0.893257	1.449089	- 4.561052
16	North Midlands and North Wales	4.347589	- 1.163920	- 0.032158	- 5.387665	- 1.518507	- 1.945174	- 5.943587
17	South Lincolnshire and North Norfolk	1.263179	4.807019	0.316441	- 5.387665	- 2.075102	- 0.202781	- 2.908065
18	Mid Wales and The Midlands	- 0.450848	4.201957	0.258033	- 5.387665	- 4.054517	- 2.429012	- 3.238751
19	Anglesey and Snowdon	6.197030	- 1.932711	- 0.032158	- 5.387665	0.023417	- 0.672326	- 6.289543
20	Pembrokeshire	7.792165	- 12.256255	-	- 5.387665	- 2.498002	- 6.787691	- 10.902980
21	South Wales & Gloucester	2.132577	- 13.326134	-	- 5.387665	- 8.585542	- 13.249689	- 11.384425
22	Cotswold	- 0.867612	3.087495	- 15.964798	- 5.387665	- 11.406198	- 19.904454	- 19.963090
23	Central London	- 3.507315	3.087495	- 5.047021	- 5.387665	- 9.678790	- 11.626380	- 9.045313
24	Essex and Kent	- 3.266077	3.087495	0.051271	- 5.387665	- 7.398236	- 6.286850	- 3.947021
25	Oxfordshire, Surrey and Sussex	- 1.387715	- 5.242324	-	- 5.387665	- 8.872310	- 10.707123	- 7.746711
26	Somerset and Wessex	- 5.746048	- 8.351561	-	- 5.387665	- 14.474337	- 17.397384	- 9.145867
27	West Devon and Cornwall	- 6.529471	- 19.982878	-	- 5.387665	- 19.910287	- 26.904295	- 14.379960

Changes to Wider Tariffs over the five-year period

The following section provides details of the wider generation tariffs for 2027/28 to 2031/32 and explains how these could change over the next five years. 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 7 Comparison of Conventional Carbon (40%) tariffs

		Example Wider Generation Tariffs (£/kW)					
		Conventional Carbon 40%					
Zone	Zone Name	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
1	North Scotland	20.759434	20.326989	21.760450	22.947004	31.724826	30.169779
2	East Aberdeenshire	17.756339	16.265620	13.547948	14.133924	18.927382	17.690657
3	Western Highlands	18.618857	18.805425	18.642637	20.649446	24.623273	22.860726
4	Skye and Lochalsh	21.660330	22.060472	21.930374	24.253972	30.586224	28.935166
5	Eastern Grampian and Tayside	18.801047	17.685697	16.778666	18.668671	26.034039	24.316805
6	Central Grampian	18.224566	19.628569	17.359806	19.303398	23.729940	21.997551
7	Argyll	20.935003	17.657021	20.024670	20.494962	23.929424	22.401506
8	The Trossachs	15.020424	15.170448	13.641520	15.083930	18.736947	17.126446
9	Stirlingshire and Fife	13.238383	12.921945	11.221072	12.087626	15.165609	13.817539
10	South West Scotlands	13.484867	12.780990	11.862292	13.248414	14.974306	12.502417
11	Lothian and Borders	10.247806	9.813464	9.332239	10.152709	12.893896	11.461126
12	Solway and Cheviot	7.698797	7.549910	6.756820	7.531065	8.537107	8.417455
13	North East England	6.691874	6.513758	6.109866	6.348562	4.121395	3.840383
14	North Lancashire and The Lakes	3.009505	4.437304	2.836820	3.458709	1.940559	2.134851
15	South Lancashire, Yorkshire and Humber	3.764821	3.611946	3.155292	3.820994	1.197438	0.893257
16	North Midlands and North Wales	1.532294	1.216859	0.494631	0.817833	- 1.139232	- 1.518507
17	South Lincolnshire and North Norfolk	- 1.554787	- 1.096073	- 1.119079	- 1.142763	- 1.539483	- 2.075102
18	Mid Wales and The Midlands	- 0.610233	- 1.077112	- 1.146998	- 1.134651	- 3.322067	- 4.054517
19	Anglesey and Snowdon	3.032391	2.666284	2.090486	2.748189	0.937366	0.023417
20	Pembrokeshire	1.904019	1.920817	1.641317	1.791905	- 1.416086	- 2.498002
21	South Wales & Gloucester	- 3.634813	- 4.581383	- 4.632731	- 4.485278	- 7.733213	- 8.585542
22	Cotswold	- 5.623340	- 6.401501	- 6.815191	- 6.871060	- 10.311546	- 11.406198
23	Central London	- 7.688756	- 6.532686	- 6.050059	- 6.027191	- 9.413532	- 9.678790
24	Essex and Kent	- 4.428212	- 3.424287	- 2.914735	- 2.774319	- 6.696048	- 7.398236
25	Oxfordshire, Surrey and Sussex	- 4.424605	- 4.716899	- 4.637420	- 4.564236	- 7.176782	- 8.872310
26	Somerset and Wessex	- 7.995342	- 7.876974	- 8.514839	- 9.760288	- 13.689562	- 14.474337
27	West Devon and Cornwall	- 12.373630	- 13.342646	- 14.395884	- 15.377808	- 19.150479	- 19.910287

Figure 1 Example Wider tariffs for a Conventional Carbon generator with an ALF of 40%

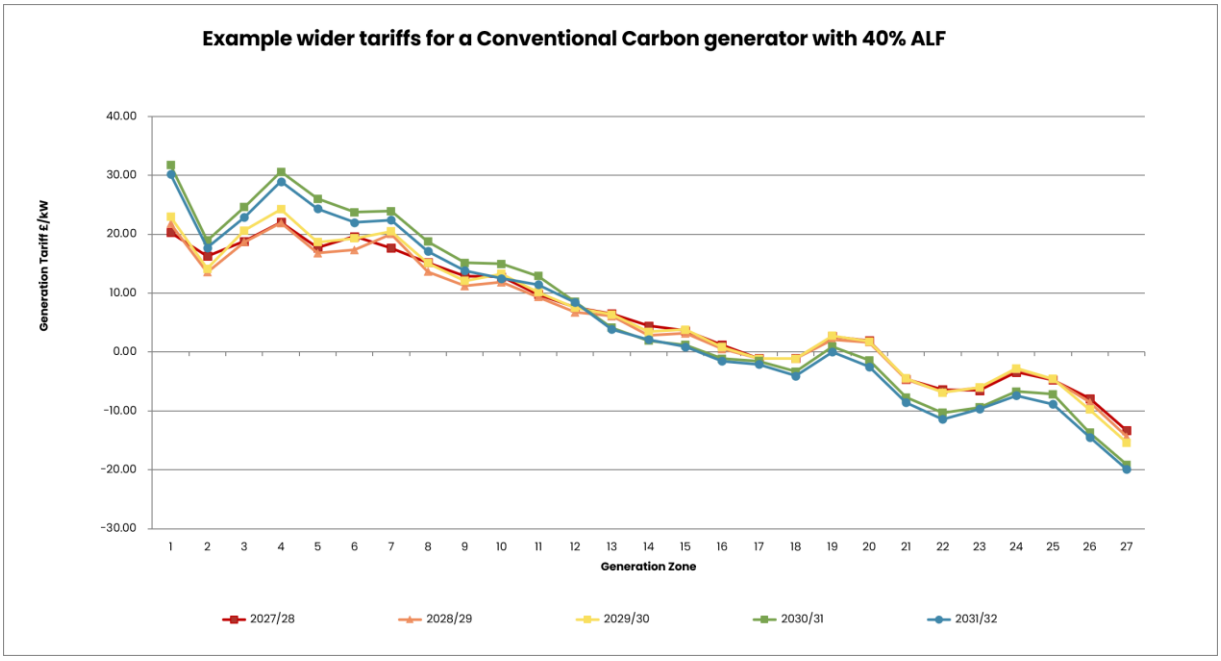


Table 8 Comparison of Conventional Low Carbon (75%) tariffs

		Example Wider Generation Tariffs (£/kW)					
		Conventional Low Carbon 75%					
Zone	Zone Name	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
1	North Scotland	41.485944	40.825727	46.883093	46.327559	67.578670	66.920264
2	East Aberdeenshire	34.007222	32.195577	28.825956	28.283644	39.062863	38.750887
3	Western Highlands	37.506714	37.463614	38.011474	38.325878	52.175834	50.768989
4	Skye and Lochalsh	45.161701	45.598140	46.286473	47.265476	67.171835	66.040171
5	Eastern Grampian and Tayside	33.670035	32.579752	32.085967	33.328130	48.029761	46.144074
6	Central Grampian	32.992591	37.380505	33.897748	35.178741	45.425808	43.047957
7	Argyll	39.580983	34.638322	39.861375	38.463402	47.058923	44.685696
8	The Trossachs	27.834981	28.269635	25.361877	26.525600	35.625440	33.093984
9	Stirlingshire and Fife	25.145954	25.265811	23.110290	23.572851	32.228279	30.367321
10	South West Scotlands	25.685031	24.531386	24.379937	25.583542	31.632441	27.567185
11	Lothian and Borders	17.340144	17.665242	17.856785	18.158737	26.659604	25.134318
12	Solway and Cheviot	14.359209	15.135467	14.432625	15.009550	19.399595	19.871147
13	North East England	10.827390	11.099832	11.011492	10.897607	8.786376	8.073647
14	North Lancashire and The Lakes	4.909589	8.398203	6.414717	6.744563	5.925182	7.433920
15	South Lancashire, Yorkshire and Humber	4.484060	4.576881	4.291856	5.051498	1.794963	1.449089
16	North Midlands and North Wales	1.688825	1.417043	0.640923	1.051899	- 1.564256	- 1.945174
17	South Lincolnshire and North Norfolk	- 0.647114	0.086908	0.367290	0.520435	0.510233	- 0.202781
18	Mid Wales and The Midlands	0.612195	0.058581	- 0.060435	- 0.054307	- 1.820205	- 2.429012
19	Anglesey and Snowdon	3.078617	2.270492	1.676644	2.209589	- 0.014224	- 0.672326
20	Pembrokeshire	- 1.272350	- 1.766979	- 2.068138	- 1.965625	- 5.765525	- 6.787691
21	South Wales & Gloucester	- 7.184444	- 8.693763	- 8.859656	- 8.652314	- 12.360626	- 13.249689
22	Cotswold	- 12.392559	- 13.967323	- 14.441759	- 14.486952	- 18.665482	- 19.904454
23	Central London	- 10.167750	- 8.495012	- 8.205900	- 8.002284	- 11.484374	- 11.626380
24	Essex and Kent	- 3.016287	- 1.867666	- 1.550137	- 1.435948	- 5.588479	- 6.286850
25	Oxfordshire, Surrey and Sussex	- 5.423044	- 5.938168	- 6.089790	- 6.107871	- 9.015768	- 10.707123
26	Somerset and Wessex	- 9.842151	- 9.377778	- 10.349080	- 11.974472	- 16.374721	- 17.397384
27	West Devon and Cornwall	- 17.476641	- 18.843574	- 20.101289	- 21.424905	- 25.737177	- 26.904295

Figure 2 Example Wider tariffs for a Conventional Low Carbon generator with an ALF of 75%

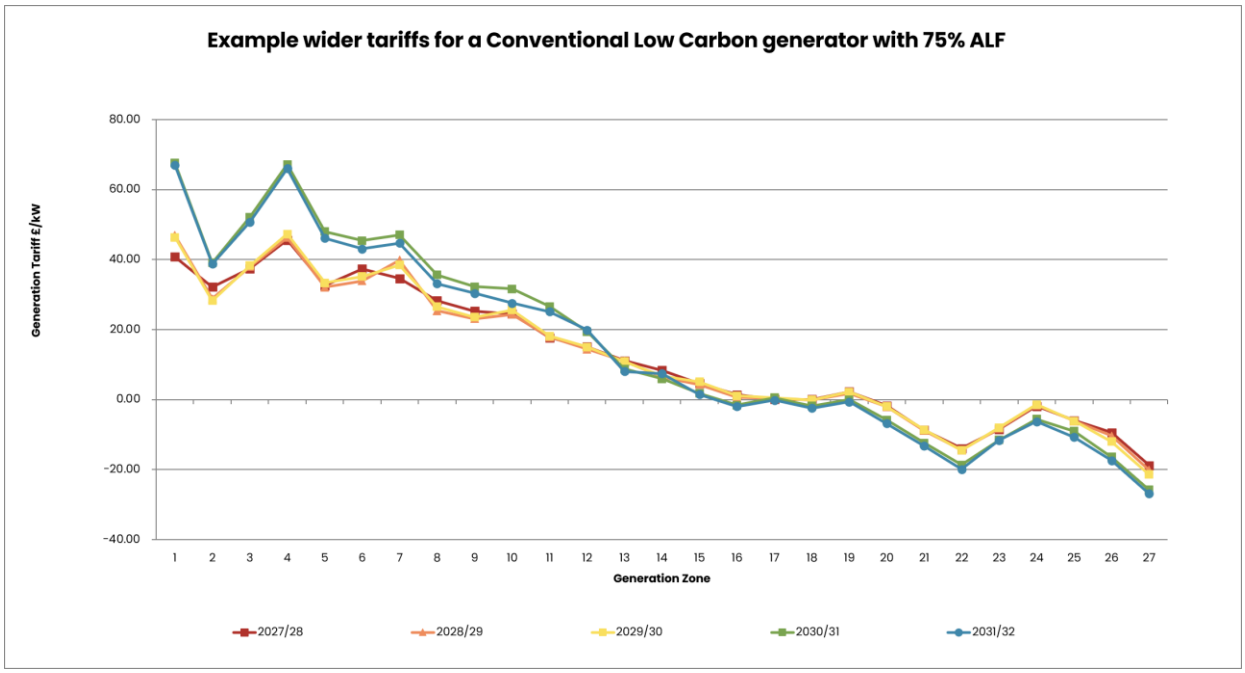
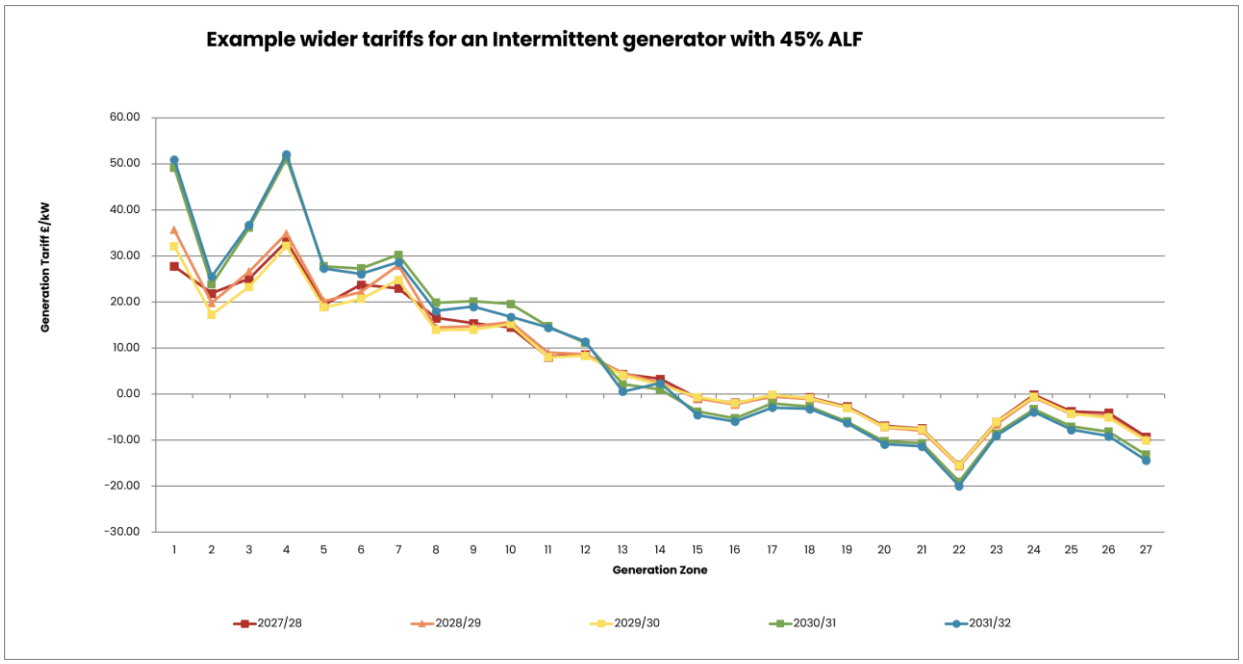


Table 9 Comparison of Intermittent (45%) tariffs

		Example Wider Generation Tariffs (£/kW)					
		Intermittent 45%					
Zone	Zone Name	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
1	North Scotland	27.938974	27.755422	35.662701	32.118256	49.174442	50.909061
2	East Aberdeenshire	22.184596	21.881275	19.755744	17.203116	23.776773	25.556808
3	Western Highlands	25.194429	25.007773	26.601376	23.274696	36.129316	36.754853
4	Skye and Lochalsh	32.883619	33.140238	34.913478	32.166483	51.184398	52.082756
5	Eastern Grampian and Tayside	19.105724	19.319879	20.168573	18.814089	27.723738	27.281864
6	Central Grampian	18.949352	23.748932	22.143008	20.663242	27.261365	26.059602
7	Argyll	25.640993	23.003474	27.938384	24.793224	30.246165	28.587339
8	The Trossachs	15.921955	16.533285	14.411138	13.915378	19.844584	18.059683
9	Stirlingshire and Fife	14.547288	15.395335	14.674815	13.980173	20.108153	18.962397
10	South West Scotlands	14.972606	14.520652	15.617947	15.188225	19.525251	16.739774
11	Lothian and Borders	6.459562	8.022955	8.962782	7.973059	14.704539	14.420481
12	Solway and Cheviot	7.255654	8.609553	8.616654	8.304786	11.155518	11.439459
13	North East England	3.696265	4.329543	4.571230	4.113062	2.119347	0.577494
14	North Lancashire and The Lakes	- 0.029456	3.287585	2.365015	2.007743	0.985417	2.353835
15	South Lancashire, Yorkshire and Humber	- 1.178682	- 0.896586	- 0.950785	- 0.646052	- 3.816928	- 4.561052
16	North Midlands and North Wales	- 1.912796	- 1.910351	- 2.289109	- 1.978724	- 5.248051	- 5.943587
17	South Lincolnshire and North Norfolk	- 0.947042	- 0.646754	- 0.566153	- 0.141268	- 2.001304	- 2.908065
18	Mid Wales and The Midlands	- 0.542358	- 0.707553	- 1.080189	- 0.890652	- 2.725292	- 3.238751
19	Anglesey and Snowdon	- 2.054617	- 2.676605	- 3.009281	- 2.972152	- 5.925064	- 6.289543
20	Pembrokeshire	- 6.197952	- 6.909182	- 7.246498	- 7.107896	- 10.277481	- 10.902980
21	South Wales & Gloucester	- 6.677862	- 7.455075	- 7.911817	- 7.634404	- 10.634877	- 11.384425
22	Cotswold	- 13.933958	- 15.370432	- 15.707992	- 15.479796	- 19.030504	- 19.963090
23	Central London	- 6.783584	- 6.031271	- 6.590113	- 6.078464	- 8.558680	- 9.045313
24	Essex and Kent	- 0.298718	- 0.166360	- 0.722716	- 0.556024	- 3.261329	- 3.947021
25	Oxfordshire, Surrey and Sussex	- 3.397756	- 3.737933	- 4.344531	- 4.261461	- 7.049756	- 7.746711
26	Somerset and Wessex	- 4.488518	- 4.097335	- 4.835509	- 5.123595	- 8.137694	- 9.145867
27	West Devon and Cornwall	- 8.675064	- 9.240353	- 9.812721	- 10.051626	- 13.153957	- 14.379960

Figure 3 Example Wider tariffs for an Intermittent generator with an ALF of 45%



Locational Changes

Locational tariffs are generally expected to become slightly more polarised over the next 5 years, mainly driven by the north-south flows in the best view scenarios. The best view has been aligned to the relevant years of the 10-Year Forecast produced by Future Energy Scenarios (FES).

From 2030/31, the impact of two new HVDC links (Eastern Green Links 1 and 2) can be seen, particularly in Scottish zones where a significant increase can be seen from the previous years.

To view the changes in generation in each zone, please see Table A in the accompanying tables spreadsheet published on our website neso.energy and Table 37.

It is worth noting that the ongoing review of the Expansion Constant and Factors calculation through CMP315/375 and the resulting decision could impact locational charges. For further information on Modification CMP315/375, please refer to the workgroup notes[4].

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 is forecast to fluctuate a little but overall, it is expected to decrease from -£2.167730/kW in 2027/28 to -£5.387665/kW in 2031/32, increasing in magnitude, to become more negative due to the increase in revenue to be collected via the generation charges. For a full breakdown of the generation revenues, please see Table 29.

[4] neso.energy/industry-information/codes/cusc/modifications/cmp375-enduring-expansion-constant-expansion-factor-review

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.

For this five-year view, we have assumed that the onshore local substation tariffs which were set for the RIIO-ET3 period continue to be inflated in line with CPIH.

Tariffs for subsequent years will then continue to be inflated in line with CPIH.

Table 10 Onshore Local Substation Tariffs

2027/28 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.418770	0.173034	0.126126
<1320 MW	Redundancy	0.884738	0.383696	0.267439
≥1320 MW	No redundancy	-	0.526380	0.367091
≥1320 MW	Redundancy	-	0.805020	0.550066

Onshore Local Circuit Tariffs

Where a transmission-connected generator is not directly connected to the Main Interconnected Transmission System (MITS), the onshore local circuit tariffs reflect the cost and flows on circuits between its connection and the MITS. Local circuit tariffs can change as a result of system power flows and inflation.

In this forecast, the onshore local circuit tariffs have been updated, with some local substations expected to become MITS nodes during the five years. The tariffs will be further refined in subsequent quarterly publications. Table 11 shows an extract of the forecast onshore local circuit tariffs for 2027/28 to 2031/32.

Table 11 Onshore Local Circuit Tariffs

Connection Point	2027/28 (£/kW)	2028/29 (£/kW)	2029/30 (£/kW)	2030/31 (£/kW)	2031/32 (£/kW)
Breakish Windfarm			3.717608	3.792582	3.868436
Aberarder	1.873836	1.914541	1.952495	1.991872	2.031710
Aberdeen Bay	1.985465	2.028595	2.068811	2.110533	2.152745
Achany Extension	3.933867	4.019321	4.099002	4.181667	4.265303
Achruach	0.479663	0.244810	0.249659	0.254692	0.259783
Aigas	0.845789	1.444443	1.473078	1.502786	1.532843

For the complete table, please see Table 11 in the published tables file at https://www.neso.energy/document/388501/download

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 12 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Bhlaraidh 132kV	Glenmoriston 132kV	7.8km Cable	7.8km 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	7km Cable	7km OHL	Dalquhandy
Cumberhead Collector 132kV	Galawhistle 132kV	2.6km Cable	2.6km OHL	Galawhistle
Coalburn 132kV	Kype Muir 132kV	17km Cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	14km Cable	14km OHL	Middle Muir
Crystal Rig 132kV	Wester Dod 132kV	3.99km Cable	3.99km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	7.8km Cable	7.8km 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	1.7km Cable	1.7km OHL	Arecleoch
Wishaw 132kV	Blacklaw 132kV	6.13km Cable	6.13km of OHL	Blacklaw
Red John 275kV	Knocknagael 275kV	9km Cable	9km OHL	Loch na Cathrach
Overhill 132kV	New Cumnock 132kV	3km Cable	3km OHL	Overhill

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 then indexed annually in line with the associated OFTO's revenue.

Since April, the forecast has been updated with the latest inflation indices.

Offshore local generation tariffs associated with projects due to transfer in 2026/27 onwards will be confirmed once asset transfer has taken place and tariffs have been set.

Table 13 Offshore local tariffs 2027/28

Offshore Generator	2027/28 April Initial Tariff Component (£/kW)			2027/28 October Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	12.062854	63.739333	1.582735	12.225632	64.599445	1.604093	0.162778	0.860112	0.021358
Beatrice	10.522284	28.674626	-	10.750613	29.296852	-	0.228329	0.622226	-
Burbo Bank Extension	15.346714	29.631821	-	15.679730	30.274818	-	0.333016	0.642997	-
Dudgeon	22.430762	35.171453	-	22.917499	35.934658	-	0.486737	0.763205	-
East Anglia 1	14.039789	59.193999	-	14.344446	60.478482	-	0.304657	1.284483	-
Galloper	23.118374	36.458268	-	23.620032	37.249395	-	0.501658	0.791127	-
Greater Gabbard	22.295296	51.618365	-	22.596153	52.314914	-	0.300857	0.696549	-
Gunfleet Sands I	26.320976	24.272880	4.536741	26.676157	24.600423	4.597960	0.355181	0.327543	0.061219
Gunfleet Sands II	26.320976	24.272880	4.536741	26.676157	24.600423	4.597960	0.355181	0.327543	0.061219
Gwynt y mor	34.395726	33.837337	-	35.142097	34.571592	-	0.746371	0.734255	-
Hornsea 1A	12.586286	39.356032	-	12.859403	40.210039	-	0.273117	0.854007	-
Hornsea 1B	12.586286	39.356032	-	12.859403	40.210039	-	0.273117	0.854007	-
Hornsea 1C	12.586286	39.356032	-	12.859403	40.210039	-	0.273117	0.854007	-
Hornsea 2A	11.793728	39.977571	-	11.958123	40.534825	-	0.164395	0.557254	-
Hornsea 2B	11.793728	39.977571	-	11.958123	40.534825	-	0.164395	0.557254	-
Hornsea 2C	11.793728	39.977571	-	11.958123	40.534825	-	0.164395	0.557254	-
Humber Gateway	19.694802	44.860236	-	20.122170	45.833683	-	0.427368	0.973447	-
Lincs	23.260827	88.349420	-	23.765576	90.266562	-	0.504749	1.917142	-
London Array	15.331778	52.625057	-	15.664470	53.766997	-	0.332692	1.141940	-
Moray East	12.718157	31.845369	-	12.994135	32.536398	-	0.275978	0.691029	-
Ormonde	37.541339	69.158233	0.551134	38.047929	70.091468	0.558571	0.506590	0.933235	0.007437
Race Bank	13.866849	38.430020	-	14.167753	39.263934	-	0.300904	0.833914	-
Rampion	12.061612	31.343156	-	12.323344	32.023288	-	0.261732	0.680132	-
Robin Rigg	- 0.816440	45.788984	14.670499	- 0.827457	46.406870	14.868465	- 0.011017	0.617886	0.197966
Robin Rigg West	- 0.816440	45.788984	14.670499	- 0.827457	46.406870	14.868465	- 0.011017	0.617886	0.197966
Seagreen 1	12.042178	21.843482	-	12.210036	22.147962	-	0.167858	0.304480	-
Sheringham Shoal	35.437001	41.719013	0.906849	35.915196	42.281978	0.919086	0.478195	0.562965	0.012237
Thanet	27.180579	50.889065	1.225079	27.547360	51.575773	1.241610	0.366781	0.686708	0.016531
Triton Knoll	11.790577	35.144001	-	12.046427	35.906610	-	0.255850	0.762609	-
Walney 1	32.185582	64.344280	-	32.619901	65.212555	-	0.434319	0.868275	-
Walney 2	33.174400	67.335483	-	33.622063	68.244122	-	0.447663	0.908639	-
Walney 3	14.423980	29.139914	-	14.736974	29.772237	-	0.312994	0.632323	-
Walney 4	14.423980	29.139914	-	14.736974	29.772237	-	0.312994	0.632323	-
West of Duddon Sands	12.408059	61.804099	-	12.677308	63.145219	-	0.269249	1.341120	-
Westermost Rough	25.257261	42.966083	-	25.805332	43.898427	-	0.548071	0.932344	-

Public

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 standing charges applicable to both HH and NHH final demand 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 14 Summary of Demand Tariffs

Non-locational Residual Tariffs	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
Unmetered (p/kWh)	3.07	3.22	3.72	4.10	4.26	4.29
Demand Residual (£m)	7,585	7,973	9,372	10,580	11,276	11,662
HH Tariffs (Locational)	**2027/28 April Initial**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
Average Tariff (£/kW)	3.48	3.29	3.19	3.33	4.08	4.05
EET	**2027/28 April Initial**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
Average Tariff (£/kW)	3.37	4.30	4.30	4.53	5.17	5.21
AGIC (£/kW)	3.20	3.24	3.31	3.38	3.44	3.51
Embedded Export Volume (GW)	7.65	7.45	7.52	7.42	7.64	7.87
Total Credit (£m)	25.74	32.08	32.31	33.63	39.48	41.01
NHH Tariffs (locational)	**2027/28 April Initial**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
Average (p/kWh)	0.48	0.46	0.45	0.46	0.58	0.58

Revenue to be recovered through the demand residual is forecast to be £7.97bn in 2027/28 £388m higher than our initial tariffs in April, rising to £11.66bn by 2031/32.

The average HH & NHH demand tariffs are forecast to decrease in 2028/29 and start increasing again from 2029/30.

The average HH gross tariff is forecast to be £3.29/kW in 2027/28, a decrease of £0.19/kW compared to our initial tariffs. The average NHH tariff is forecast to be 0.46 p/kWh, a decrease of 0.02 p/kWh since April.

The total credit paid out to embedded generators (<100 MW) in 2027/28 is currently forecast to be £32m, an increase of £6.34m since the initial tariffs in April. The average Embedded Export Tariff (EET) is now forecast to be £4.30/kW, an increase of £0.94/kW compared to the initial tariffs.

Demand Residual Tariffs

The Site count forecast for 2027 is based upon the latest actual site counts. Changes in future years are in line with observed trends.

The consumption data used to allocate the proportion of residual revenue to each charging band is the expected RIIO-ET3 band consumption for the previous October to September in line with the average of the future energy scenarios demand expectations.

A breakdown of the banding thresholds, consumptions, consumption proportions and site counts for the demand residual standing 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-ET3 price control period. No forecast of revised band thresholds for 2031/32 has been made and is assumed to be consistent with RIIO-ET3.

The table below shows the forecast demand residual tariffs by band. These tariffs will apply to final demand sites in addition the HH or NHH locational charges.

Table 15 Non-Locational demand residual charges

Band		2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
Domestic	Tariff - £/Site/Day	0.257643	0.275932	0.319460	0.356025	0.376877	0.387433
LV_NoMIC_1		0.263362	0.308639	0.365069	0.412182	0.437612	0.448506
LV_NoMIC_2		0.729530	0.749268	0.886260	1.000635	1.062370	1.088815
LV_NoMIC_3		1.587827	1.533665	1.829125	2.080506	2.223322	2.291588
LV_NoMIC_4		4.379177	4.623741	5.469116	6.174924	6.555891	6.719087
LV1		7.139101	6.793444	7.970064	8.933446	9.424457	9.606534
LV2		14.176046	15.107212	17.723771	19.866134	20.958041	21.362943
LV3		17.709681	17.467824	20.493239	22.970361	24.232887	24.701058
LV4		47.016191	52.487322	61.578089	69.021349	72.814987	74.221745
HV1		39.412715	35.975413	42.552925	48.044531	51.008675	52.278436
HV2		145.020615	167.707832	199.193690	225.729772	240.429513	247.095775
HV3		229.525103	230.002080	272.590242	308.307974	327.830799	336.432715
HV4		654.727845	791.186897	938.491771	1,062.273453	1,130.293674	1,160.615350
EHV1		402.855098	438.791353	523.282845	595.128494	635.880430	655.275009
EHV2		1,427.699181	1,417.139634	1,676.240312	1,892.565088	2,009.328313	2,059.346621
EHV3		3,110.690173	3,114.389220	3,698.908205	4,191.482421	4,464.263398	4,587.889797
EHV4		7,053.881657	7,601.374271	9,028.025615	10,230.264871	10,896.048801	11,197.787107
T-Demand1		1,675.061745	1,882.724059	2,334.888356	2,861.329440	3,295.351396	3,676.978831
T-Demand2		3,619.000184	4,181.892288	5,192.424008	6,202.776004	7,009.349907	7,852.346799
T-Demand3		9,366.458461	8,986.377527	10,810.987265	12,151.709350	13,779.291381	15,954.615114
T-Demand4		25,716.522168	26,610.783952	24,621.839443	25,808.148507	30,254.736139	26,364.088267
Unmetered demand		**p/kWh**			**p/kWh**		
Unmetered		3.068032	3.219364	3.715229	4.103744	4.262461	4.285558
Demand Residual (£m)		**7584.792992**	**7,972.64**	**9,371.59**	**10,580.00**	**11,276.27**	**11,662.24**

For 2027/28 on average, Transmission Demand Residual tariffs are forecast to be 5% higher than our initial tariffs, driven by the increase in revenue to be collected.

[5] Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.

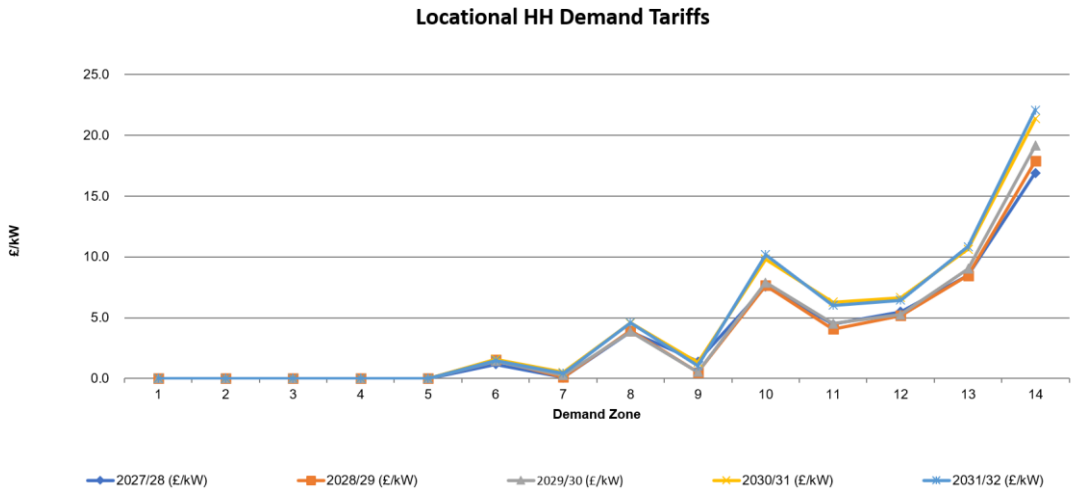
Half-Hourly Demand Tariffs

Table 16 shows the forecast gross HH demand tariffs for the next 5 years

Table 16 Half-Hourly Demand Tariffs

Zone	Zone Name	2027/28 April Initial	2027/28 (£/kW)	2028/29 (£/kW)	2029/30 (£/kW)	2030/31 (£/kW)	2031/32 (£/kW)
1	Northern Scotland	-	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-	-
3	Northern	-	-	-	-	-	-
4	North West	-	-	-	-	-	-
5	Yorkshire	-	-	-	-	-	-
6	N Wales & Mersey	-	1.172013	1.553106	1.432207	1.581640	1.500501
7	East Midlands	0.230675	0.101222	0.110232	0.263839	0.506380	0.439005
8	Midlands	3.555364	3.866779	3.929884	3.860059	4.582768	4.598810
9	Eastern	1.317511	1.411571	0.508442	0.542197	1.341784	1.034897
10	South Wales	6.557388	7.571454	7.639431	7.892108	9.803642	10.180975
11	South East	5.871060	4.464584	4.082415	4.515338	6.275763	6.019030
12	London	7.986827	5.490841	5.165429	5.259470	6.664134	6.453455
13	Southern	8.405911	8.480694	8.475011	9.025254	10.628313	10.841189
14	South Western	15.404273	16.912246	17.883577	19.145394	21.363184	22.061824

Figure 4 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, there are changes in tariffs for zones 6 through to 14 with a general trend of increasing across the 5-year time horizon, with zone 6 now forecast to be non-zero from 2027/28. These are due to changes in the network along with Nodal demand and generation forecasts. The larger increases in zones 10 to 14 in the latter years are due to increases in the peak demand seen in the nodal week 24 demand forecasts. Zones 1 through 5 are forecast to be subject to the zero floor on demand tariffs.

Half-Hourly Demand Tariffs for Transmission Connected Users with Multiple DNOs

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 substations at the boundaries of multiple DNO areas.

Table 17 Demand tariffs for Transmission Connected users with multiple DNO's

Site Code	Site Name	Demand Zone			T-Connected Tariff Floored (£/kW)				
		DNO 1	DNO 2	DNO 3	2027/28	2028/29	2029/30	2030/31	2031/32
AMEM	Amersham	9	13		4.946132	4.491726	4.783725	5.985049	5.938043
AXMI	Axminster	13	14		12.696470	13.179294	14.085324	15.995749	16.451507
BARK	Barking	9	12		3.451206	2.836935	2.900833	4.002959	3.744176
BEDD	Beddington	11	12		4.977712	4.623922	4.887404	6.469948	6.236242
BRIM	Brimsdown	9	12		3.451206	2.836935	2.900833	4.002959	3.744176
CARR	Carrington	4	6		0.000000	0.000000	0.000000	0.000000	0.000000
CELL	Cellarhead	6	8		2.519396	2.741495	2.646133	3.082204	3.049656
ECLA	East Claydon	7	13		4.290958	4.292621	4.644546	5.567346	5.640097
GREN	Grendon	9	7		0.756396	0.309337	0.403018	0.924082	0.736951
IROA	Iron Acton	8	10		5.719116	5.784658	5.876084	7.193205	7.389892
KIBY	Kirkby	6	4		0.000000	0.000000	0.000000	0.000000	0.000000
LALE	Laleham	11	13		6.472639	6.278713	6.770296	8.452038	8.430110
LEMR	Lea Marston (was Hams Hall)	7	8		1.984000	2.020058	2.061949	2.544574	2.518908
LITT	Littlebrook	11	12		4.977712	4.623922	4.887404	6.469948	6.236242
MELK	Melksham	13	14		12.696470	13.179294	14.085324	15.995749	16.451507
WALP	Walpole	7	9		0.756396	0.309337	0.403018	0.924082	0.736951
WISD	Willesden	13	12		6.985767	6.820220	7.142362	8.646224	8.647322

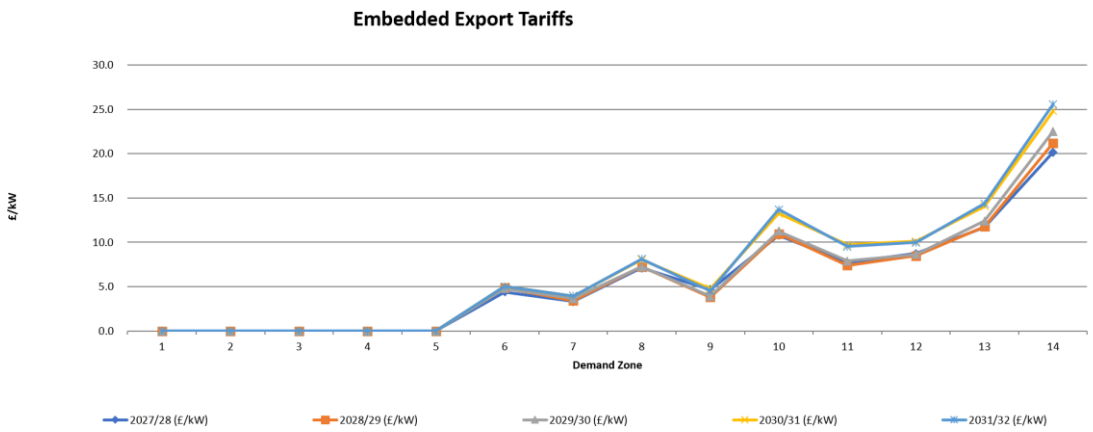
Embedded Export Tariffs (EET)

Table 18 shows the forecast Embedded Export tariffs for the next five years.

Table 18 Embedded Export Tariffs

Zone	Zone Name	2027/28 April Initial	2027/28 (£/kW)	2028/29 (£/kW)	2029/30 (£/kW)	2030/31 (£/kW)	2031/32 (£/kW)
1	Northern Scotland	-	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-	-
3	Northern	-	-	-	-	-	-
4	North West	-	-	-	-	-	-
5	Yorkshire	-	-	-	-	-	-
6	N Wales & Mersey	0.809519	4.412855	4.864348	4.809092	5.026627	5.014390
7	East Midlands	3.435348	3.342064	3.421474	3.640724	3.951367	3.952894
8	Midlands	6.760037	7.107621	7.241126	7.236944	8.027755	8.112699
9	Eastern	4.522184	4.652413	3.819684	3.919082	4.786771	4.548786
10	South Wales	9.762061	10.812296	10.950673	11.268993	13.248629	13.694864
11	South East	9.075733	7.705426	7.393657	7.892223	9.720750	9.532919
12	London	11.191500	8.731683	8.476671	8.636355	10.109121	9.967344
13	Southern	11.610584	11.721536	11.786253	12.402139	14.073300	14.355078
14	South Western	18.608946	20.153088	21.194819	22.522279	24.808171	25.575713
	These tariffs include:						
	AGIC (£/kW)	3.204673	3.240842	3.311242	3.376885	3.444987	3.513889

Figure 5 Embedded export tariff changes



The forecast average EET for 2027/28 is £4.30/kW, an increase to the average EET of £0.94/kW versus the initial tariffs in April. This is forecast to rise to £5.21/kW by 2031/32. This increase is due to the continuing inflation of AGIC and changes in the modelled network

along with Nodal demand and generation forecasts. Zones 1 to 4 are forecast to be subject to the zero floor on EET tariffs.

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 the demand residual tariffs.

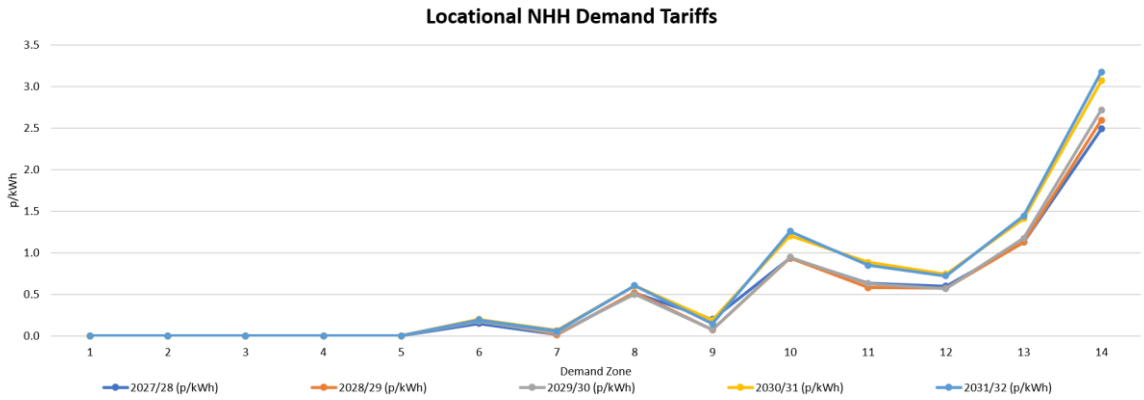
Non-Half-Hourly Demand Tariffs

Table 19 and Figure 6 show the forecast changes in Non-Half-Hourly tariffs.

Table 19 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2027/28 April Initial	2027/28 (p/kWh)	2028/29 (p/kWh)	2029/30 (p/kWh)	2030/31 (p/kWh)	2031/32 (p/kWh)
1	Northern Scotland	-	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-	-
3	Northern	-	-	-	-	-	-
4	North West	-	-	-	-	-	-
5	Yorkshire	-	-	-	-	-	-
6	N Wales & Mersey	-	0.149714	0.196479	0.177991	0.200326	0.190277
7	East Midlands	0.032180	0.013356	0.014549	0.034027	0.066538	0.057787
8	Midlands	0.490768	0.513318	0.520840	0.498767	0.602226	0.605197
9	Eastern	0.193894	0.197863	0.071646	0.074566	0.187171	0.144501
10	South Wales	0.823086	0.933672	0.934312	0.945394	1.203851	1.255923
11	South East	0.864400	0.630078	0.578833	0.625579	0.882297	0.848735
12	London	0.880626	0.596678	0.572313	0.568637	0.741712	0.718733
13	Southern	1.169712	1.126170	1.125410	1.171504	1.407720	1.440550
14	South Western	2.289536	2.489158	2.592684	2.715507	3.068610	3.173258

Figure 6 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2027/28 is 0.46 p/kWh, a 0.02 p/kWh decrease compared to the initial tariffs in April, increasing to 0.58 p/kWh by 2031/32. As mentioned above for the HH and Embedded tariffs, changes in the modelled network along with updated Nodal demand and generation forecasts are driving these increases.

Public

Overview of Data Inputs

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

Inputs affecting the locational element of tariffs

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

- Expected Contracted generation (until October 2026 when it will be based on contracted TEC);
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor
- Expansion constant

Contracted, Modelled and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2027/28 period onwards, which can be found on the TEC register[6]. The contracted TEC volumes are based on the July 2026 TEC register.

Modelled Best View TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the Initial and October forecasts, we forecast our best view of modelled TEC. However, for our November Draft Tariffs and January Final Tariffs we will use the contracted TEC position as published in the TEC register as of 31 October 2026, 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 2027/28 onwards and liable to pay generation TNUoS charges.

Table 20 Contracted, Modelled & Chargeable TEC

Generation (GW)	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
Contracted TEC	138.22	131.78	162.16	199.95	227.53	258.91
Modelled Best View TEC	136.52	122.78	132.32	145.95	161.26	174.91
Chargeable TEC	121.81	110.66	120.20	133.83	146.24	158.40

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

Adjustments for Interconnectors

When modelling flows on the transmission system in order to set locational tariffs, interconnector flows are not included in the Peak model but are included in the Year Round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the calculations of chargeable TEC for either the generation or demand charging bases.

The table below reflects the contracted position of interconnectors for 2027/28 onwards as stated in the interconnector register[7] as of July 2026.

Table 21 Interconnectors

			Generation MW				
Interconnector	Node	Zone	2027/28	2028/29	2029/30	2030/31	2031/32
Alverdiscott	ALVE4A	27	-	-	-	1,800	1,800
Aquind Interconnector	LOVE41	26	-	-	-	2,000	2,000
Auchencrosh	AUCH20	10	500	500	500	500	500
Britned	GRAI41	24	1,200	1,200	1,200	1,200	1,200
Cronos	KEMS41	24	-	-	1,400	1,400	1,400
East - West	CONQ40	16	505	505	505	505	505
ElecLink	SELL4A	24	1,000	1,000	1,000	1,000	1,000
Greenlink	PEMB41	20	504	504	504	504	504
Gridlink	KINO41	24	-	1,500	1,500	1,500	1,500
IFA2 Interconnector	CHIL41	26	1,100	1,100	1,100	1,100	1,100
IFA Interconnector	SELL4A	24	1,988	1,988	1,988	1,988	1,988
MARES	BODE41	16	-	750	750	750	750
Nautilus	LEIS4A	18	-	-	1,500	1,500	1,500
Nemo Link	RICH41	24	1,020	1,020	1,020	1,020	1,020
NeuConnect Interconnector	GRAI41	24	1,400	1,400	1,400	1,400	1,400
NorthConnect	PEHE21	2	-	-	1,400	1,400	1,400
NS Link	BLYT41	13	1,400	1,400	1,400	1,400	1,400
SENECA	LCNA41	15	-	-	-	-	1,200
Tarchon	EACS40	18	-	-	-	1,400	1,400
The Superconnection	CREB41	15	1,000	1,000	1,000	1,000	1,000
Viking Link	BICF41	17	1,500	1,500	1,500	1,500	1,500

Network Model

The network model comprises all onshore transmission substations and circuits. Substations are represented by nodes, and circuits are "links" that connects the nodes to form the onshore transmission network. The network model is based on Electricity Ten Year Statement (ETYS) data, which can be found on NESO's website[8].

In accordance with CUSC 14.15.10, we must use the ETYS network model data including updates up to 31 October 2026. For this publication, the network model is based on the 2025 ETYS data, which was published in Summer 2026.

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

[8] neso.energy/publications/electricity-ten-year-statement-etys

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 2027/28 Expansion Constant is forecast to be £19.751496/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-ET1 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.

Table 22 Expansion Constant

£/MWkm	2027/28	2028/29	2029/30	2030/31	2031/32
Expansion Constant	19.751496	20.180552	20.580620	20.995674	21.415598

Locational Onshore Security Factor

The locational onshore security factor (also called the global security factor), set at 1.75 for the duration of RIIO-ET3, 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.

As the necessary network studies have not yet been undertaken for the next price control, it is currently forecast to remain at 1.75.

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-ET3, 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-ET3 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-ET2 tariff setting.

For this publication, offshore local tariffs are based on the indicative values set for RIIO-ET3 (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 electricity transmission price controls. The current price control, RIIO-ET3 runs from 2026/27 to 2030/31. Forecasts beyond the RIIO-ET3 are based on the revenues for the final price control year, adjusted for inflation.

Since the publication of the Initial TNUoS Tariffs for 2027/28, the onshore transmission owners' January revenue assumptions have been updated to include NESO assumptions for the latest inflation, and a forecast adjustment for under-recovered revenue from the 2026/27 tariffs.

There have also been updates to the other pass-through costs to reflect the latest actual data for 2026/27, and updated forecast assumptions following this.

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

Under the timeline set out in the STC (SO-TO Code), the 2027/28 Draft and Final tariffs will reflect updated revenue forecasts from the TOs.

Table 23 Allowed Revenues

£m Nominal	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
TO Income from TNUoS						
National Grid Electricity Transmission	4,012.2	4,142.9	4,684.2	5,286.3	5,851.8	5,962.1
Scottish Power Transmission	1,468.4	1,512.7	1,511.6	1,638.1	1,731.8	1,758.7
SHE Transmission	2,551.2	2,634.8	3,336.6	3,810.1	3,907.7	4,070.7
Total TO Income from TNUoS	**8,031.8**	**8,290.4**	**9,532.4**	**10,734.4**	**11,491.2**	**11,791.6**
Other Income from TNUoS						
Other Pass-through from TNUoS	92.7	212.6	123.9	117.9	121.4	117.0
Offshore (plus interconnector contribution / allowance)	990.4	967.7	1,283.5	1,473.2	1,591.0	1,893.0
Total Other Income from TNUoS	**1,083.0**	**1,180.3**	**1,407.4**	**1,591.1**	**1,712.4**	**2,010.0**
Total to Collect from TNUoS	**9,114.8**	**9,470.7**	**10,939.8**	**12,325.5**	**13,203.6**	**13,801.6**

Please note these figures are rounded to one decimal place.

For a sensitivity analysis on the impact of revenue on the Transmission Demand Residual (TDR), please refer to Sensitivity Analysis.

Generation / Demand (G/D) Split

The G/D split forecast is shown in Table 24.

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 £9m for 2027/28) are categorised as charges associated with pre-existing assets and are therefore not PARC. The charges associated with pre-existing assets are forecast to be £22m by 2031/32 as more local circuit elements become shared.

Table 24 Generation and demand revenue proportions

Code	Revenue	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50	2.50
y	Error Margin	30.3%	27.8%	27.8%	27.8%	27.8%	27.8%
ER	Exchange Rate (€/£)	1.15	1.15	1.15	1.15	1.15	1.15
MAR	Total Revenue (£m)	9,114.15	9,469.87	10,938.94	12,324.63	13,202.78	13,800.74
GO	Generation Output (TWh)	214.00	204.64	213.74	217.93	235.80	249.18
G	% of revenue from generation	15.2%	14.4%	13.1%	13.0%	13.2%	14.17%
D	% of revenue from demand	84.80%	85.60%	86.87%	86.97%	86.76%	85.83%
G.R	Revenue recovered from generation (£m)	1,385.70	1,363.54	1,436.81	1,605.92	1,748.04	1,955.73
D.R	Revenue recovered from demand (£m)	7,728.45	8,106.33	9,502.13	10,718.71	11,454.75	11,845.02
Breakdown of generation revenue							
	Revenue from the Peak element	164.68	150.17	143.79	161.66	172.48	172.41
	Revenue from the Year Round Shared element	280.22	254.42	253.28	311.36	406.29	389.09
	Revenue from the Year Round Not Shared element	129.93	148.43	225.55	167.01	453.95	662.30
	Revenue from Onshore Local Circuit tariffs	56.04	57.36	33.79	30.48	51.79	51.25
	Revenue from Onshore Local Substation tariffs	35.88	33.53	37.39	43.02	45.66	48.11
	Revenue from Offshore Local tariffs	976.46	959.51	1,040.77	1,197.08	1,303.06	1,485.95
	Revenue from the adjustment element	-257.51	-239.88	-297.76	-304.71	-685.20	-853.39
G.MAR	Total Revenue recovered from generation (£m)	1,385.70	1,363.54	1,436.81	1,605.92	1,748.04	1,955.73
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	7.97	9.09	11.69	7.82	23.76	21.93

The "gen cap"

Paragraph 14.14.5 (vii) in the CUSC currently limits average annual generation use of system charges to €0-2.50/MWh. The revenue that can be recovered from generation is dependent on the €2.50/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. In this report, the figures were based on OBR's March EFO. This figure is indicative, as per OBR's March EFO, at € 1.146366/£.

Generation Output

The forecast output of generation is 205 TWh in 2027/28 rising to 249 TWh by 2031/32. This figure is from the 10 Year Forecast in the 2025 Future Energy Scenarios.

Error Margin

The error margin for 2027/28 tariffs has been updated and finalised, following publication of the outturn of 2025/26 data. This is derived from historical data in the past five whole years (thus for year 2027/28, we use data from years 2021/22 – 2025/26).

Table 25 Generation revenue error margin calculation

Calculation for 2027/28 - 2031/32			
Data from year:	Revenue inputs		Generation output variance
	Revenue variance	Adjusted variance	
2021/22	4.3%	3.8%	9.5%
2022/23	9.5%	9.0%	13.1%
2023/24	-1.7%	-2.2%	-3.5%
2024/25	0.9%	0.4%	-7.0%
2025/26	-10.6%	-11.1%	-6.3%
Systemic error:	0.5%		
Adjusted error:		11.1%	13.1%
Error margin =			27.8%

Onshore local charges associated with Pre-existing assets

We have published two sets of tariffs relating to pre-existing assets. These are TNUoS local tariffs associated with pre-existing circuits and those for pre-existing substation bays. For the 2027/28 tariff year at the Draft and Final publications we will also include 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 existed prior to the generator applying for connection to the transmission network, and the Onshore 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 26 provides an extract of the onshore local circuit tariff elements associated with pre-existing assets; these values are only used for the purpose of calculating the gen cap.

Table 26 Onshore local circuit tariff elements associated with pre-existing assets

	2027/28	2028/29	2029/30	2030/31	2031/32
Project Name	Pre-existing local circuit tariff (£/kW)	Pre-existing local circuit tariff (£/kW)	Pre-existing local circuit tariff (£/kW)	Pre-existing local circuit tariff (£/kW)	Pre-existing local circuit tariff (£/kW)
Aberarder Wind Farm	£ 0.853556	£ 0.872097	£ 0.889386	£ 0.907322	£ 0.925469
Aberdeen Offshore Wind Farm	£ -	£ -	£ -	£ -	£ -
Achany Extension Wind Farm	£ -	£ -	£ -	£ -	£ -
A'Chruach Wind Farm	£ -	£ -	£ -	£ -	£ -

For the complete table, please see Table 26 in the published tables file at https://www.neso.energy/document/388501/download

Onshore local substation tariffs reflect the cost of accommodating the generator at 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 27 lists out the onshore local substation tariffs associated with pre-existing assets.

Table 27 Onshore local substation tariffs associated with pre-existing assets

	2027/28	2028/29	2029/30	2030/31	2031/32	
Project Name	Pre-existing substation Tariff (£/kW)	Pre-existing substation Tariff (£/kW)	Pre-existing substation Tariff (£/kW)	Pre-existing substation Tariff (£/kW)	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	£ 0.418770	£ 0.427867	£ 0.436349	£ 0.445149	£ 0.445149	37.20
Toddleburn Wind Farm	£ 0.418770	£ 0.427867	£ 0.436349	£ 0.445149	£ 0.445149	

Charging Bases for 2027/28-2031/32

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 2027/28 tariffs is forecast at 110.7 GW, increasing to 158.4 GW in 2031/32. It is based on our internal view of what generation we expect to connect over the next five years; it has also been aligned to the relevant years of the 10 Year Forecast produced by FES.

For the Final 2027/28 Tariffs, in line with the CUSC, we will use the contracted TEC position as of 31 October 2026 to set locational tariffs in the Transport model. Our best view will be used to set the adjustment tariff in the Tariff model.

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated.

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
- 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, before rising again in the latter years of this forecast. Please refer to table TAA in the published tables excel spreadsheet[9] for a detailed breakdown of the changes to the demand charging bases.

Table 28 Charging Bases

Charging Bases	2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
Generation (GW)	121.81	110.66	120.20	133.83	146.24	158.40
NHH Demand (4pm-7pm TWh)	23.06	23.50	24.15	24.97	25.84	26.83
Gross charging						
Total Average Gross Triad (GW)	48.32	48.75	49.33	49.56	51.05	52.58
HH Demand Average Gross Triad (GW	16.63	17.57	17.26	17.08	16.86	17.03
Embedded Generation Export (GW)	7.65	7.45	7.52	7.42	7.64	7.87

Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2026/27 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[10].

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)

[9] Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.

[10] neso.energy/document/376346/download

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

B_G is the generator charging base (GW)

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), charges are based on the voltage and size of the site and 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 have been forecast based on the latest trends in site counts being billed and reflect the updated residual banding thresholds that have applied since April 2026.

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 29 Residual & Adjustment components calculation

Component		2027/28 April Initial	2027/28	2028/29	2029/30	2030/31	2031/32
G	Proportion of revenue recovered from generation (%)	15.20%	14.40%	13.13%	13.03%	13.24%	14.17%
D	Proportion of revenue recovered from demand (%)	84.80%	85.60%	86.87%	86.97%	86.76%	85.83%
R	Total TNUoS revenue (£m)	9,114.15	9,469.87	10,938.94	12,324.63	13,202.78	13,800.74
Generation revenue breakdown (without adjustment)							
ZG	Revenue recovered from the wider locational element of generator tariffs (£m)	574.83	553.01	622.62	640.03	1,032.72	1,223.80
O	Revenue recovered from offshore local tariffs (£m)	976.46	959.51	1,040.77	1,197.08	1,303.06	1,485.95
LG	Revenue recovered from onshore local substation tariffs (£m)	35.88	33.53	37.39	43.02	45.66	48.11
SG	Revenue recovered from onshore local circuit tariffs (£m)	56.04	57.36	33.79	30.48	51.79	51.25
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	7.97	9.09	11.69	7.82	23.76	21.93
Generation adjustment tariff calculation							
	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50	2.50
	Error Margin	0.30	0.28	0.28	0.28	0.28	0.28
	Exchange Rate (€/£)	1.15	1.15	1.15	1.15	1.15	1.15
	Total generation Output (TWh)	214.00	204.64	213.74	217.93	235.80	249.18
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	325.29	322.22	336.55	343.15	371.28	392.34
	Adjustment Revenue (£m)	(257.51)	(239.88)	(297.76)	(304.71)	(685.20)	(853.39)
BG	Generator charging base (GW)	121.81	110.66	120.20	133.83	146.24	158.40
AdjTariff	Generator adjusment tariff (£/kW)	(2.11)	(2.17)	(2.48)	(2.28)	(4.69)	(5.39)
Gross demand residual							
RD	Demand residual (£m)	7,584.79	7,972.6	9,371.6	10,580.0	11,276.3	11,662.2
ZD	Revenue recovered from the locational element of demand tariffs (£m)	169.40	165.77	162.86	172.34	217.96	223.78
EE	Amount to be paid to Embedded Export Tariffs (£m)	-25.74	-32.08	-32.31	-33.63	-39.48	-41.01

Public

Sensitivity Analysis

Purpose

We are conscious that there are uncertainties with the charging methodologies over the next 5 years. To help the industry to understand the potential implications of the ongoing changes, we have undertaken further modelling around potential variables and have included some indicative tariffs / charges.

Following engagement with industry stakeholders, we invited suggestions on the sensitivities that would be most useful to include within the five-year view. In response to the feedback received, the sensitivity analysis considers the impact of changes in allowed revenue on Transmission Demand Residual (TDR) tariffs in 2027/28.

Caveats

The methodology is subject to change due to ongoing CUSC modification proposals. All tariffs in this section are to illustrate mathematically how tariffs may evolve. In presenting sensitivities, it does not infer about our view of the future, likelihoods of certain scenarios or changes to policy.

Whilst every effort is made to ensure the accuracy of the information, it is subject to several estimates and forecasts and may not bear relation to the indicative, or future, tariffs that NESO will publish at a later date.

Impact of varying revenue on TDR

Purpose

We are conscious there are uncertainties over the allowed revenue forecasts over the next five years. To help industry to understand the potential implications of the ongoing changes, we have undertaken further modelling on the impact of additional revenue on the TDR.

Unless stated, these are NESO assumptions based on publicly available information and do not represent the views of the onshore TOs

Revenue sensitivities

For the revenue sensitivity analysis, three scenarios have been created to illustrate the potential impact of changes in the underlying assumptions.

The low case (Revenue Sensitivity 1) assumes revenue is 10% below the January 2026 STCP24-1 submissions from onshore and offshore TOs, and a reduction in other pass-through items.

Table S1 – Revenue Sensitivity 1

£m Nominal	2027/28	2028/29	2029/30	2030/31	2031/32
TO Income from TNUoS					
National Grid Electricity Transmission	3,728.6	4,215.8	4,757.6	5,266.6	5,365.9
Scottish Power Transmission	1,361.4	1,360.4	1,474.3	1,558.6	1,582.8
SHE Transmission	2,371.4	3,002.9	3,429.1	3,516.9	3,663.6
Total TO Income from TNUoS	**7,461.4**	**8,579.1**	**9,661.0**	**10,342.1**	**10,612.4**
Total Other Income from TNUoS	**1,062.3**	**1,266.7**	**1,431.9**	**1,541.2**	**1,809.0**
Total to Collect from TNUoS	**8,523.6**	**9,845.8**	**11,092.9**	**11,883.3**	**12,421.4**

A medium case (Revenue Sensitivity 2) has been developed using the February 2026 PCFM publication, updated for NESOs assumptions on latest inflation and under-collection for the 2026/27 charging year.

Final Determinations for the RIIO-ET3 price control were published in December 2025, with the PCFMs subsequently published by Ofgem on 3 February 2026. The January 2026 submissions reflected the onshore Transmission Owners' latest view of allowed revenue following those determinations. We have continued to use the January 26 submissions, in line with STCP24-1.

For consistency, have maintained the source data for the other onshore transmission owners as our base case. However, we have included the PCFM values as a sensitivity, as shown in Table S2.

Table S2 – Revenue Sensitivity 2

£m Nominal	2027/28	2028/29	2029/30	2030/31	2031/32
TO Income from TNUoS					
National Grid Electricity Transmission	5,321.7	4,825.9	5,535.5	6,215.9	6,844.7
Scottish Power Transmission	1,121.0	1,209.2	1,342.4	1,442.9	1,554.9
SHE Transmission	2,191.5	2,994.8	3,785.1	4,066.6	4,458.6
Total TO Income from TNUoS	**8,634.1**	**9,029.8**	**10,663.0**	**11,725.4**	**12,858.2**
Total Other Income from TNUoS	**1,180.3**	**1,407.4**	**1,591.1**	**1,712.4**	**2,010.0**
Total to Collect from TNUoS	**9,814.4**	**10,437.2**	**12,254.0**	**13,437.8**	**14,868.2**

Revenue Sensitivity 3

The high case sensitivity (Revenue Sensitivity 3) reflects the base case forecast revenue uplifted by 10%.

Table S3 – Revenue Sensitivity 3

£m Nominal	2027/28	2028/29	2029/30	2030/31	2031/32
TO Income from TNUoS					
National Grid Electricity Transmission	4,557.2	5,152.6	5,814.9	6,436.9	6,558.3
Scottish Power Transmission	1,663.9	1,662.7	1,801.9	1,904.9	1,934.6
SHE Transmission	2,898.3	3,670.2	4,191.1	4,298.4	4,477.8
Total TO Income from TNUoS	**9,119.4**	**10,485.6**	**11,807.8**	**12,640.3**	**12,970.7**
Total Other Income from TNUoS	**1,298.3**	**1,548.1**	**1,750.2**	**1,883.7**	**2,211.0**
Total to Collect from TNUoS	**10,417.8**	**12,033.7**	**13,558.0**	**14,524.0**	**15,181.7**

Summary of the revenue sensitivities can be seen in Table S4

Table S4 – Summary of Revenue Sensitivities

Sensitivity Scenario £m	2027/28	2028/29	2029/30	2030/31	2031/32
Sensitivity 1	8,523.6	9,845.8	11,092.9	11,883.3	12,421.4
Base Case	**9,470.7**	**10,939.8**	**12,325.5**	**13,203.6**	**13,801.6**
Sensitivity 2	9,814.4	10,437.2	12,254.0	13,437.8	14,868.2
Sensitivity 3	10,417.8	12,033.7	13,558.0	14,524.0	15,181.7

Impact of varying revenue on the Transmission Demand Residual (TDR)

This analysis is based on the year 2027/28.

The analysis assumes that the increase/decrease in revenue stems from onshore TOs or pass-through costs rather than OFTO revenue. This is because only a relatively small proportion of each OFTO's revenue impacts the revenue to be collected via the demand residual.
The total TDR charge/site is used as the measure because the impact on the individual site types is proportionately the same, with each site increasing/decreasing by the same percentage.
The 2027/28 Transport and Tariff model was run using the revenue scenarios as shown in Table S4.

Table S5 Impact of Additional Revenue on Transmission Demand Residual

	2027/28			
	Sensitivity 1 - 10% Decrease in Allowed Revenue	Base Case	Sensitivity 2 - February 2026 PCFM	Sensitivity 3 - 10% Increase in Allowed Revenues
Revenue (£m)	8,523.63	9,470.70	9,814.43	10,417.77
Generation Share*	20.0%	14.4%	14.2%	13.1%
Demand Share	84.0%	85.6%	85.8%	86.9%
Total TDR charge/site	**-11.9%**	**0%**	**4.3%**	**11.9%**

The average TDR charge increases or decreases in line with the demand share of the revenue. All else remaining unchanged for every additional or reducing £100m the average TDR charge/site will increase or decrease by 1.33% respectively.

Public

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 Five-year view on Wednesday 14 October. 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/388501/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@neso.energy

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.

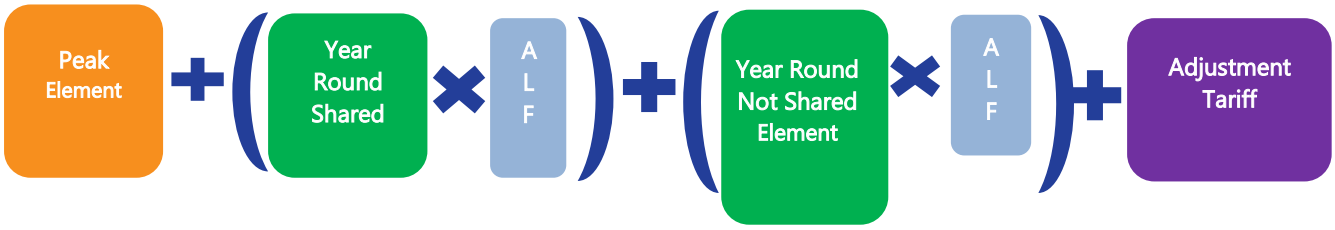
† Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

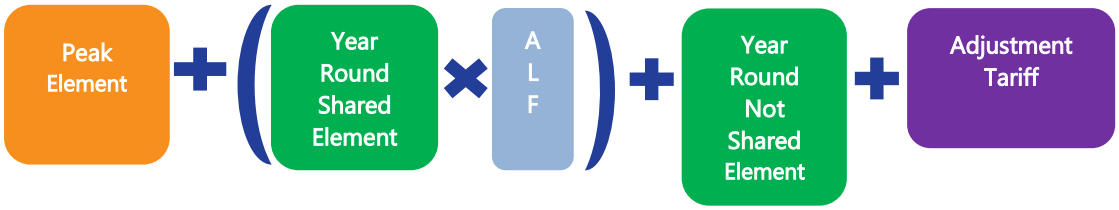
Conventional Carbon Generators

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



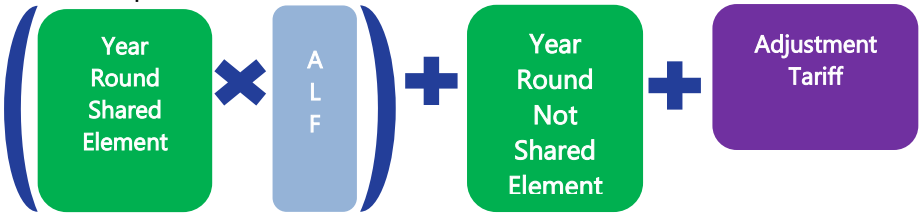
Conventional Low Carbon Generators

(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[11] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[12] 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:

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

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

[12] 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[13]. 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[14].

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).

[13] neso.energy/industry-information/charging/tnuos-charges#Triads-data
[14] 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[15].

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 4pm–7pm 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 standing 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.

[15] 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 that could affect the TNUoS tariff calculation methodology for 2027/28 – 2031/32. Each modification requires approval from Ofgem, and if any Workgroup Alternative CUSC Modifications (WACMs) are proposed, Ofgem will determine which, if any, are approved.

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 modifications already in progress which could affect future tariffs are listed below:

Table 30 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change
CMP288	Explicit charging arrangements for customer delays and backfeeds	Potential impact on non-locational tariffs only
CMP315/375	Expansion Constant & Expansion Factor Review	Affects TNUoS locational tariffs for generators and demand users
CMP316/397	TNUoS Arrangements for Co-located Generation Sites	Affects TNUoS locational tariffs
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs. Status: Ofgem rejected the proposal, and the proposer has appealed the decision to the Competition and Markets Authority (CMA). The modification is currently at CMA appeal.
CMP405	TNUoS Locational Demand Signals for Storage	Change demand locational tariffs so they are not floored at zero

CMP419	Generation Zoning Methodology Review	Seeks to review the existing generation zoning methodology to incorporate offshore assets connected as part of the Holistic Network Design (HND) to enable the wider tariff to be applied to offshore generators
CMP423	Generated Weighted Reference Node	Seeks to change the way the Tariff and Transport model calculates tariffs. There would be no change to the structure of the tariffs, or any other aspect of charging
CMP426	TNUoS charges for transmission circuits identified for the HND to add capacity across boundaries	Considers the cost recovery for circuits classified as boundary reinforcement within the Holistic Network Design (HND), ensuring their purpose and function are considered when setting the TNUoS tariff and identifying the users the costs are recovered from.
CMP433	Optimised Transmission Investment Cost model	Seeks to replace the Transport component of the Transport and Tariff (T&T) model with an economic market model
CMP440	Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor	Seeks to reintroduce negative locational tariffs for demand
CMP442	Introducing the option to fix Generator TNUoS charges	Seeks to give Generators the opportunity to fix their wider TNUoS charges against the forecast tariffs provided by NESO.
CMP445	Pro-rating first year TNUoS for Generators	Seeks to ensure that Generators only pay TNUoS on a pro-rated basis from their Charging Date, during the first year of connection.

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 (shown in Table 18) is then also added, and the resulting tariff is floored at zero to avoid negative tariffs (charges).

Table 31 Locational elements of the HH demand tariff for 2027/28

Demand Zone		2027/28		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.216683	-37.851191	0.000000
2	Southern Scotland	-2.805350	-25.539761	0.000000
3	Northern	-3.963382	-10.080090	0.000000
4	North West	-1.674371	-4.691478	0.000000
5	Yorkshire	-3.626729	-2.744323	0.000000
6	N Wales & Mersey	-1.898491	3.070505	1.172013
7	East Midlands	-1.641464	1.742685	0.101222
8	Midlands	-1.193934	5.060713	3.866779
9	Eastern	2.156208	-0.744637	1.411571
10	South Wales	-3.548514	11.119967	7.571454
11	South East	3.932979	0.531604	4.464584
12	London	3.933948	1.556893	5.490841
13	Southern	2.989707	5.490987	8.480694
14	South Western	3.466704	13.445542	16.912246

Table 32 Locational elements of the HH demand tariff for 2028/29

Demand Zone		2028/29		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-1.635675	-36.191522	0.000000
2	Southern Scotland	-2.303910	-25.183921	0.000000
3	Northern	-3.577500	-10.752885	0.000000
4	North West	-1.094627	-4.161886	0.000000
5	Yorkshire	-3.114739	-3.117645	0.000000
6	N Wales & Mersey	-1.387108	2.940215	1.553106
7	East Midlands	-1.276802	1.387033	0.110232
8	Midlands	-0.794674	4.724558	3.929884
9	Eastern	1.562360	-1.053918	0.508442
10	South Wales	-3.699111	11.338541	7.639431
11	South East	3.046884	1.035531	4.082415
12	London	2.737374	2.428055	5.165429
13	Southern	2.423652	6.051358	8.475011
14	South Western	3.855806	14.027771	17.883577

Table 33 Locational elements of the HH demand tariff for 2029/30

Demand Zone		2029/30		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.437656	-36.551058	0.000000
2	Southern Scotland	-3.012806	-25.543614	0.000000
3	Northern	-3.993215	-10.473297	0.000000
4	North West	-1.569681	-3.723346	0.000000
5	Yorkshire	-3.535002	-2.689688	0.000000
6	N Wales & Mersey	-1.813682	3.245889	1.432207
7	East Midlands	-0.992652	1.256491	0.263839
8	Midlands	-0.841758	4.701817	3.860059
9	Eastern	1.827313	-1.285116	0.542197
10	South Wales	-3.602521	11.494629	7.892108
11	South East	3.373569	1.141769	4.515338
12	London	3.147527	2.111943	5.259470
13	Southern	2.808214	6.217040	9.025254
14	South Western	4.505668	14.639726	19.145394

Table 34 Locational elements of the HH demand tariff for 2030/31

Demand Zone		2030/31		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-3.507170	-51.646453	0.000000
2	Southern Scotland	-3.818952	-36.387458	0.000000
3	Northern	-4.282843	-9.712300	0.000000
4	North West	-2.787397	-2.586222	0.000000
5	Yorkshire	-3.886968	-0.517831	0.000000
6	N Wales & Mersey	-3.476161	5.057801	1.581640
7	East Midlands	-1.403126	1.909506	0.506380
8	Midlands	-1.098984	5.681752	4.582768
9	Eastern	2.979864	-1.638080	1.341784
10	South Wales	-3.315449	13.119090	9.803642
11	South East	4.556031	1.719732	6.275763
12	London	4.088718	2.575416	6.664134
13	Southern	3.510612	7.117701	10.628313
14	South Western	5.149982	16.213203	21.363184

Table 35 Locational elements of the HH demand tariff for 2031/32

Demand Zone		2031/32		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-3.585813	-50.430027	0.000000
2	Southern Scotland	-4.315668	-33.999047	0.000000
3	Northern	-4.783072	-9.569980	0.000000
4	North West	-2.156265	-3.908729	0.000000
5	Yorkshire	-4.436516	-0.196892	0.000000
6	N Wales & Mersey	-2.925791	4.426292	1.500501
7	East Midlands	-1.544555	1.983561	0.439005
8	Midlands	-0.573733	5.172543	4.598810
9	Eastern	2.901729	-1.866832	1.034897
10	South Wales	-3.149417	13.330391	10.180975
11	South East	4.322505	1.696525	6.019030
12	London	4.038715	2.414740	6.453455
13	Southern	3.461013	7.380176	10.841189
14	South Western	5.027208	17.034616	22.061824

Appendix D: Annual Load Factors

ALFs

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

For the purposes of this forecast, we have used the final version of the 2026/27 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2020/21 to 2024/25. Generators which commissioned after 1 April 2022 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 2026/27 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 2027/28 TNUoS Tariffs will be updated by our Draft Tariffs publication in November 2026. The specific and generic ALFs that will apply to the 2026/27 TNUoS Tariffs have been published in the following places:

- Final Annual Load Factors for 2026/27 TNUoS Tariffs: neso.energy/document/376346/download
- Specific ALFs in excel format: neso.energy/document/376351/download

Generic ALFs

Table 36 Generic ALFs

Technology	Generic ALF
Battery	8.0542%
Biomass	40.0724%
CCGT_CHP	41.5400%
Coal	7.5610%
Gas_Oil	6.9166%
Hydro	37.1713%
Nuclear	60.9910%
Offshore_Wind	47.1080%
Onshore_Wind	39.6831%
Pumped_Storage	10.9859%
Reactive_Compensation	0.0000%
Solar	16.8358%
Tidal	14.1000%
Wave	2.9000%

Please note: ALF figures for Wave and Tidal 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) for 2027/28 tariffs will be fixed using the TEC register as of 31 October 2026, as required by the CUSC 14.15.6 and no further changes to Contracted TEC will be made after that point.

For the complete breakdown of Contracted TEC per generator for each year, please see *Table A*: *Contracted TEC by Generator* in the Tables spreadsheet, published on our website[16].

The table below shows the contracted generation, by zone, using data from the July 2026 TEC register. Please note that stations with Bilateral Embedded Generator Agreements for less than 100 MW TEC are not chargeable and are not included in this table.

Table 37 Contracted TEC by generation zone

Zone	Zone Name	2027/28 (MW)	2028/29 (MW)	2029/30 (MW)	2030/31 (MW)	2031/32 (MW)
1	North Scotland	4,775	6,041	7,977	12,431	14,366
2	East Aberdeenshire	2,185	2,485	4,285	4,885	4,885
3	Western Highlands	488	488	1,959	1,959	1,959
4	Skye and Lochalsh	331	331	381	381	381
5	Eastern Grampian and Tayside	1,828	2,152	2,602	2,852	2,852
6	Central Grampian	68	68	68	68	251
7	Argyll	216	216	552	702	807
8	The Trossachs	960	960	960	1,560	1,760
9	Stirlingshire and Fife	620	1,918	3,560	4,160	5,685
10	South West Scotland	6,306	7,280	9,612	10,378	10,549
11	Lothian and Borders	8,116	11,454	14,938	15,285	17,880
12	Solway and Cheviot	1,198	1,694	1,836	1,836	2,586
13	North East England	7,227	7,227	9,084	9,084	11,039
14	North Lancashire and The Lakes	4,364	4,764	4,764	4,764	4,764
15	South Lancashire, Yorkshire and Humber	19,565	22,043	26,796	29,356	36,106
16	North Midlands and North Wales	15,270	19,060	24,657	26,526	27,618
17	South Lincolnshire and North Norfolk	8,161	9,881	10,881	13,858	16,638
18	Mid Wales and The Midlands	13,791	18,526	24,894	29,743	35,824
19	Anglesey and Snowdon	1,951	2,271	2,671	2,671	2,751
20	Pembrokeshire	3,053	3,568	3,568	3,568	3,868
21	South Wales & Gloucester	2,542	4,887	5,798	5,986	5,986
22	Cotswold	1,796	2,008	2,008	2,508	2,508
23	Central London	140	140	140	140	140
24	Essex and Kent	16,628	19,957	22,713	23,728	26,361
25	Oxfordshire, Surrey and Sussex	6,152	6,209	6,409	6,747	7,447
26	Somerset and Wessex	2,810	4,987	5,293	9,010	9,010
27	West Devon and Cornwall	1,237	1,545	1,545	3,345	4,894

[16] neso.energy/document/388501/download

Appendix F: Transmission Company Revenues

Transmission Owner revenue forecasts

The revenue forecast for onshore TO revenue is based on their January 2026 submissions. Updates have been made by NESO, to include the latest inflation, and the impact of the forecast under-recovery for 2026/27 tariffs. Offshore TO revenue has been based on data submissions received from Offshore TOs in January 2026. 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 transmission 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 TOs (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 38) shows details of the pass-through TNUoS revenue items under NESO's licence conditions.

Compared to the 2027/28 Initial Tariffs, there has been an increase in ONTO allowed revenues, adjustment term and other pass-through items. This has been offset by a slight decrease to the OFTO allowed revenues.

Table 38 NESO revenue breakdown

Term	NESO TNUoS Other Pass-Through				
	2027/28	2028/29	2029/30	2030/31	2031/32
Embedded Offshore Pass-Through (OFETt)	0.83	0.83	0.83	0.83	0.83
Network Innovation Competition Fund (NICFt)	0.00	0.00	0.00	0.00	0.00
Strategic Innovation Fund (SIFt)	43.99	24.50	15.63	13.79	6.13
The Adjustment Term (ADJt)	69.74	0.00	0.00	0.00	0.00
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	1,017.14	1,322.43	1,522.16	1,652.93	1,892.97
Interconnectors CACM Cost Recovery (ICPt)	-49.47	-38.90	-48.98	-61.93	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	0.00	0.00
Termination Sums (TSt)	0.00	0.00	0.00	0.00	0.00
NGET revenue pass-through (NGETTOt)*	4,142.90	4,684.21	5,286.25	5,851.77	5,962.12
SPT revenue pass-through (TSPt)	1,512.67	1,511.57	1,638.09	1,731.75	1,758.71
SHETL revenue pass-through (TSHt)	2,634.84	3,336.59	3,810.07	3,907.67	4,070.72
NESO Bad debt (BDt)	0.00	0.00	0.00	0.00	0.00
NESO other pass-through items (LFt + ITCt etc)	98.07	98.54	101.41	106.81	110.09
NESO legacy adjustment (LARt)	0.00	0.00	0.00	0.00	0.00
Total	**9,470.70**	**10,939.77**	**12,325.46**	**13,203.61**	**13,801.57**

Onshore TOs (NGET, SPT and SHET) revenue forecast

The five-year forecast of onshore TO revenues is based on the revenue submissions provided in January 2026, in accordance with STCP24-1. This forecast has been updated to reflect NESO's assumption for latest inflation outturn and forecasts, together with an estimate of under-recovery for the 2026/27 charging year.

We have also provided a sensitivity analysis on the allowed revenues using these figures within the sensitivity: Impact of varying revenue on TDR.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2027/28 is forecast to be £1.22bn, increasing by £672.5m to £1.89bn in 2031/32. 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). The 2027/28 forecast includes £208.8m of forecast revenue (17% of total) for OFTOs yet to asset transfer, while 2031/32 includes £817.2m of revenue (43% of the total) for OFTOs yet to asset transfer.

Please note that four OFTOs are due to reach the end of their regulatory revenue periods between 2029/30 and 2031/32. For the purposes of this publication, we have assumed that

the regulatory revenue period of each of the affected OFTOs will be extended and that their Base Transmission Revenue will continue at 50% of their original value.

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.

The Interconnector Adjustment forecast is based on figures submitted by Interconnectors in January 2026.

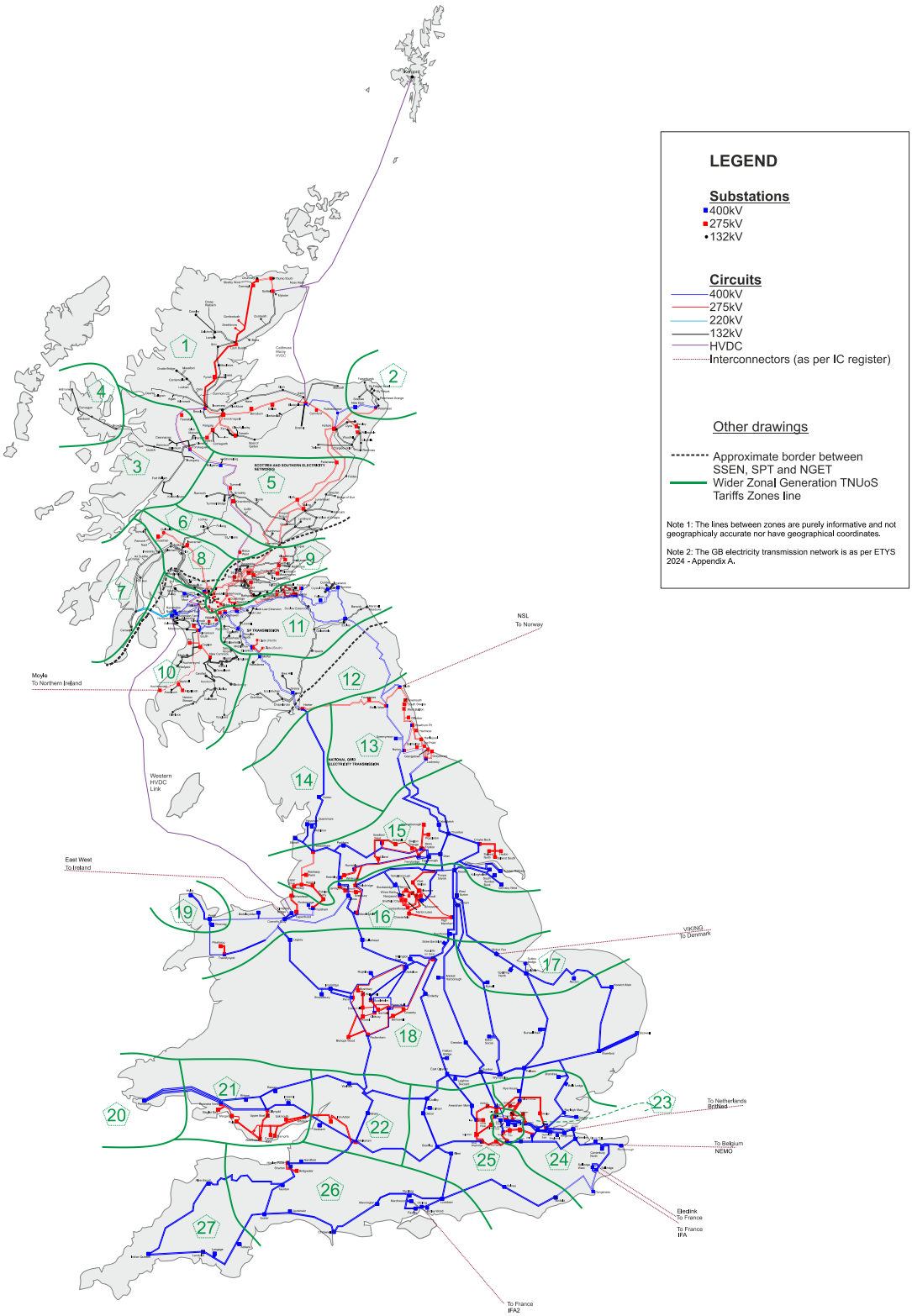
Table 39 Offshore Revenues

Offshore Transmission Revenue Forecast (£m) Regulatory Year	2027/28	2028/29	2029/30	2030/31	2031/32	Notes
Barrow	9.6	9.9	10.0	5.4	5.6	Current revenues plus inflation until Extended Revenue Stream period
Gunfleet	12.0	12.4	12.6	12.9	8.9	Current revenues plus inflation until Extended Revenue Stream period
Walney 1	21.8	22.4	22.8	23.3	19.2	Current revenues plus inflation until Extended Revenue Stream period
Robin Rigg	13.4	13.8	14.1	13.8	7.7	Current revenues plus inflation until Extended Revenue Stream period
Walney 2	22.6	23.2	23.7	24.2	24.7	Current revenues plus indexation
Sheringham Shoal	33.2	34.1	34.9	35.3	36.1	Current revenues plus indexation
Ormonde	20.1	20.7	21.1	21.5	22.0	Current revenues plus indexation
Greater Gabbard	45.5	46.7	47.2	48.7	49.6	Current revenues plus indexation
London Array	64.3	65.6	66.9	68.3	69.8	Current revenues plus indexation
Thanet	29.5	30.2	30.7	31.5	32.1	Current revenues plus indexation
Lincs	43.8	44.7	45.6	46.5	47.5	Current revenues plus indexation
Gwynt y mor	42.6	43.4	44.3	45.2	46.2	Current revenues plus indexation
West of Duddon Sands	35.0	35.7	36.4	37.2	38.0	Current revenues plus indexation
Humber Gateway	18.5	18.9	19.2	19.6	20.0	Current revenues plus indexation
Westermost Rough	20.3	20.7	21.1	21.5	22.0	Current revenues plus indexation
Burbo Bank Extension	20.0	20.5	20.9	21.3	21.8	Current revenues plus indexation
Dudgeon	28.6	29.2	29.8	30.4	31.1	Current revenues plus indexation
Race Bank	39.7	40.6	41.4	42.2	43.2	Current revenues plus indexation
Galloper	24.5	25.0	25.5	26.0	26.6	Current revenues plus indexation
Walney 3	19.4	19.8	20.2	20.6	21.1	Current revenues plus indexation
Walney 4	19.4	19.8	20.2	20.6	21.1	Current revenues plus indexation
Hornsea 1A	25.4	25.9	26.4	26.9	27.5	Current revenues plus indexation
Hornsea 1B	25.4	25.9	26.4	26.9	27.5	Current revenues plus indexation
Hornsea 1C	25.4	25.9	26.4	26.9	27.5	Current revenues plus indexation
Beatrice	32.6	30.9	31.5	32.1	32.8	Current revenues plus indexation
Rampion	22.2	22.7	23.1	23.6	24.1	Current revenues plus indexation
East Anglia 1	59.8	61.0	62.2	63.5	64.9	Current revenues plus indexation
Hornsea 2A	29.2	29.8	30.4	31.0	31.7	Current revenues plus indexation
Hornsea 2B	29.2	29.8	30.4	31.0	31.7	Current revenues plus indexation
Hornsea 2C	29.2	29.8	30.4	31.0	31.7	Current revenues plus indexation
Triton Knoll	47.9	48.9	49.9	50.9	52.0	Current revenues plus indexation
Moray East	54.8	55.9	57.0	58.1	59.4	Current revenues plus indexation
Seagreen 1	46.8	47.7	48.7	49.6	50.6	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2026/27	136.6	139.3	142.1	144.9	147.8	NESO Forecast
Forecast to asset transfer to OFTO in 2027/28	72.2	84.9	86.6	88.4	90.1	NESO Forecast
Forecast to asset transfer to OFTO in 2028/29		66.8	145.0	147.9	150.9	NESO Forecast
Forecast to asset transfer to OFTO in 2029/30			97.1	125.5	128.0	NESO Forecast
Forecast to asset transfer to OFTO in 2030/31				78.4	140.4	NESO Forecast
Forecast to asset transfer to OFTO in 2031/32					159.9	NESO Forecast
Offshore Transmission Pass-Through (B7)	**1,220.4**	**1,322.4**	**1,522.2**	**1,652.9**	**1,893.0**	

Notes:

- 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.
- Network Innovation Competition (NIC) & Strategic Innovation Fund (SIF) payments are not included as they do not form part of OFTO Revenue.
- All monies are nominal 'money of the day' prices unless stated otherwise.
- For four OFTOs, revenues are assumed to reduce to 50% of the original Base Transmission Revenue on entering the Extended Revenue Stream period, with inflation applied.

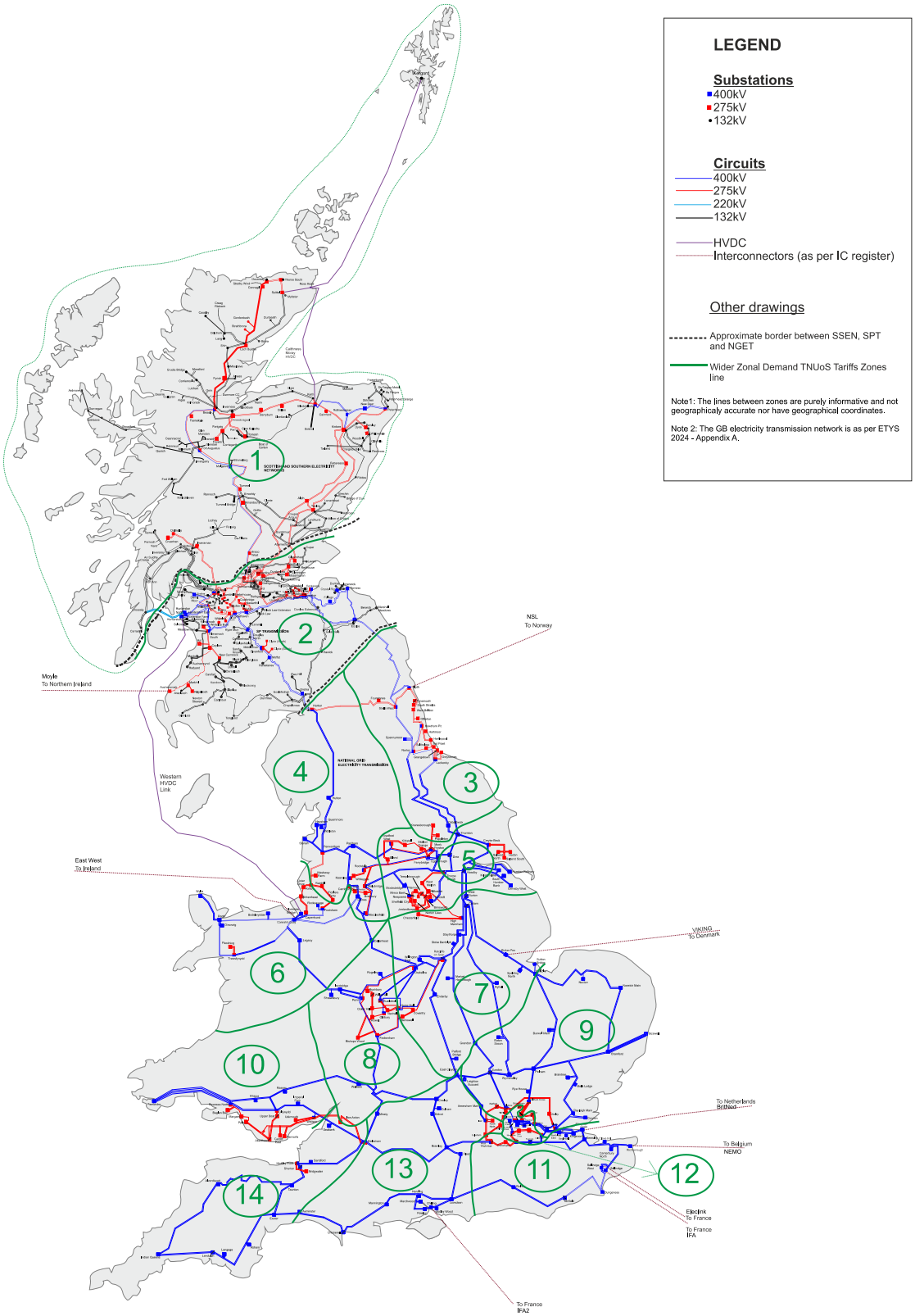
Appendix G: Generation Zones Map



Geographical map as of 1 April 2025

For the most up to date maps, please refer to Electricity Ten Year Statement 2025 Appendix A.

Appendix H: Demand Zones Map



Geographical map as of 1 April 2025

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.

2027/28 TNUoS Tariff Forecast					
		April 2026	**October 2026**	**Draft Tariffs November 2026**	**Final Tariffs January 2027**
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
	Inflation	Forecast			Actual
RESIDUAL/ADJUSTMENT	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	From OFTOs & NESO best view
	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters and other pass-through cost forecasts	Latest ONTO and interconnector revenue submissions, updated financial parameters and other forecasts	Latest ONTO and interconnector revenue submissions, updated financial parameters and other forecasts
	Demand Charging Bases (including TDR site counts)	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
	Consumption Data (by TDR charging band)	Previous year's data source		DNO/IDNO consumption update received	
	Generation Charging Base	NESO best view	NESO best view	NESO best view	NESO final best view
	Generation ALFs	Previous year's data source		Draft ALFs published	Final ALFs published
	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

Public

Document Revision History

Document Revision History

Version Number	Date of Issue	Notes
1.0	9 October 2026	Publication of Five-Year View of TNUoS Tariffs for 2027/28-2031/32
2.0	14 October 2026	Replaced Table 15 to correct transmission connected demand residual tariffs

Public

National Energy System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

TNUoS.Queries@neso.energy

www.neso.energy

NESO
National Energy
System Operator