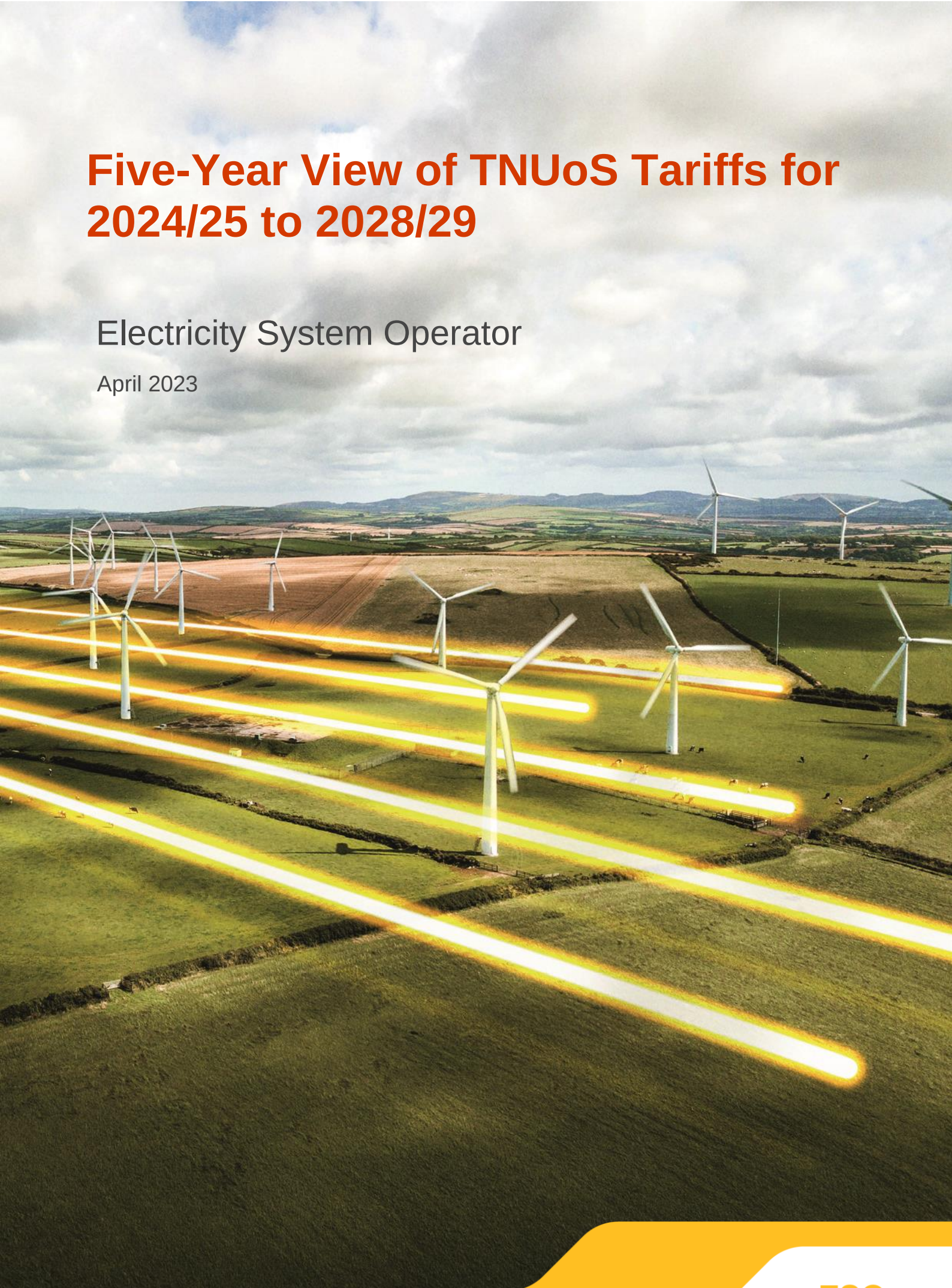
Five-Year View of TNUoS Tariffs for 2024/25 to 2028/29

Electricity System Operator

April 2023



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Executive summary

Transmission Network Use of System (TNUoS) charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the five-year view on future TNUoS Tariffs for 2024/25 - 2028/29.

Under the National Grid Electricity System Operator (ESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish a five-year view of future Transmission Network Use of System (TNUoS) tariffs annually on our website[1].

This report provides the forecast for the period of 2024/25 to 2028/29 and also includes the initial quarterly forecast of TNUoS tariffs for year 2024/25.

We fully appreciate that there are uncertainties with several ongoing charging methodology changes. We therefore have also included sensitivity analysis for a number of scenarios to help the industry to understand the potential implications of change, where possible.

CMP317/327 Judicial Review outcome

Commission Regulation (EU) No. 838/2010 (which is retained EU law) sets out that the annual average transmission charges paid by producers in Great Britain must fall within €0-2.50/MWh.

There have been a number of code modifications to update the CUSC in relation to this regulation and specifically there have been legal challenges resulting from Ofgem's decision to approve CUSC Modification Proposal CMP317/327.

On 21st April, Ofgem published an open letter in respect of CMP317/327[2]. In the short term, Ofgem do not expect any change to the ESO's processes or forecasts; however, ESO is expected to raise a CUSC modification proposal to align CUSC treatment of large embedded generation with the Limiting Regulation.

Total revenues to be recovered

The total TNUoS revenue is forecast at £4.58bn for FY24/25, (an increase of £159m from 2023/24). This is set to increase to £5.31bn in 2028/29. OFTO revenue is forecast to increase steadily in the next five years whilst onshore TOs revenues also increase (by a comparatively much smaller amount) under their RIIO-2 business plan. The 2024/25 revenue forecast will be updated through the year and finalised by January Final Tariffs, based on onshore and offshore TOs' submissions and other relevant information.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.01bn for 2024/25 (an increase of £65.3m since the 2023/24 Final Tariffs). It is forecast to grow to £1.36bn by 2028/29, mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base for 2024/25 has been forecast to be to 78GW based on our best view, an increase of 2.22GW from 2023/24. This view will be further refined throughout the year. The charging base is forecast to reach 106.9GW by 2028/29.

The average generation tariff for 2024/25 is £12.94/kW, an increase of £0.48/kW from the 2023/24 Final tariffs. It is expected to fluctuate with a high of £13.12/kW in 2025/26 and a low of £11.30/kW in 2026/27. The fluctuation in the average tariff is due to the change in the overall revenue to be recovered year on year vs the proportional year on year increase in the generation charging base – in 26/27 we see that the generation charging base rises at a faster rate

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

[2] Further decision in respect of CMPs 317 and 327 | Ofgem

than the generation revenue, causing a reduction in the average tariff.

Demand tariffs

Revenue to be collected through demand is forecast to be £3,566m for 2024/25, a £94.17m increase since the 2023/24 charging year. Demand revenue will increase year-on-year. By 2028/29 demand revenue will reach £3,955m. The main driver for this trend is the change in proportion in revenue to be recovered through demand versus generation and the overall increase in total revenue.

The impact on the end consumer is forecast to be £46.60 for FY24/25, an increase of £1.45 from the 2023/24 charging year. This is due to the increase in the demand revenue, driven by an overall increase in revenue. This is 4.03% of the average annual electricity consumer bill. The TNUoS charge impact is expected to increase by £6.34 to £51.49 by 2028/29 (4.45% of average annual electricity bill).

In 2024/25 it is forecast that £19.93m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £0.51m since 2023/24 charging year. This is due to an increase in the forecast charging base for Embedded Export and an increase in the average locational tariffs. The EET fluctuates marginally year on year reaching £19.54m in 2028/29. The average EET is forecast at £2.80/kW, which is an increase of £0.26/kW 2023/24 charging year. The average EET fluctuates year on year in-line with the change in Embedded Export volumes with a low of £2.14/kW in 2027/28.

The average gross HH demand tariff for 2024/25 is to be £6.38/kW, an increase of £0.79/kW and is set to decrease year on year reaching £4.65/kW in 2028/29. The average NHH demand tariff is forecast to be 0.30p/kWh in 2024/25, an increase of 0.04p/kWh since 2023/24 charging year and is set to decrease year on year to 0.21p/kWh by 2028/29.

Next TNUoS tariff publication

The timetable of TNUoS tariffs forecasts for 2024/25 is available on our website[3].

Our next TNUoS tariff publication will be the quarterly updated forecast of 2024/25 tariffs, which will be published in July 2023.

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

Feedback

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

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

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

Charging Methodology Changes

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This Report

This report contains the five-year view on TNUoS tariffs for the charging years 2024/25 – 2028/29, and the initial quarterly forecast of TNUoS for the charging year 2024/25.

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

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

This section summarises any key changes to the methodology.

Charging methodology changes

There are a number of 'in-flight' proposals to change the charging methodologies, which may impact TNUoS tariffs and charges. These are summarised in the CUSC modifications Table 27.

Regulatory Uncertainty

There have been legal challenges resulting from Ofgem's decision to approve CUSC Modification Proposal CMP317/327 (in relation to the Limiting Regulation of average generation charge within the range of €0-2.50/MWh).

On 21st April, Ofgem published an open letter following their further decision in respect of CMP317/327[4]. In the short term, Ofgem do not expect any change to ESO's processes or forecasts. In future, the ESO is expected to raise a CUSC modification proposal to align CUSC treatment of large embedded generation with the Limiting Regulation, we expect the tariff impact of this to be small.

TNUoS Task Force and electricity network charging

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

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

Ofgem has recently published an open letter providing an update on our prioritisation of activities on electricity network charging and connections[5]. In this open letter, Ofgem confirmed that the TNUoS Taskforce will continue to focus on addressing concerns regarding the stability and predictability of TNUoS charges, while longer-term reform (late 2020s into 2030s) is led by their Strategic Transmission Charging Reform programme, exploring the role of TNUoS in the context of different options for wholesale market design under consideration by REMA (review of electricity market arrangements).

[4] Further decision in respect of CMPs 317 and 327 | Ofgem

[5] https://www.ofgem.gov.uk/publications/open-letter-regarding-prioritisation-electricity-network-charging-and-connections-activity

Price Control Impact on Charging Parameters

In accordance with the CUSC, at the start of each price control, various elements of the TNUoS charging methodology must be revised and updated. This forecast covers the final two years of RIIO-2 and the first three years of the following price control, which will commence in 2026-27. Input data for the recalculation of parameters is required from a number of sources, including the TO's and the Ofgem price control determinations, and will become available at different stages over the course of 2025-26. In this report, our assumptions are in line with the current RIIO-2 parameters, with inflation applied where applicable.

Generation tariffs

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

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1. Generation tariffs summary

This section summarises our view of generation tariffs from 2024/25 to 2028/29 and how these tariffs were calculated.

Table 1 Changes to Average Generation Tariffs

Generation Tariffs (£/kW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Adjustment Tariff	- 0.928179	- 1.296387	- 2.167565	- 3.296961	- 5.281116	- 6.205011
Average Generation Tariff*	12.454583	12.937121	13.121493	11.303263	12.127407	12.721659

*N.B. These generation average tariffs include local tariffs

The average generation tariff is calculated by dividing the total revenue payable by generation over the generation charging base in GW. These average tariffs include revenues from local tariffs.

The generation adjustment is used to ensure generation tariffs are compliant with Limiting Regulation, which requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. The adjustment tariff is currently negative to ensure Generation Tariffs are compliant with the legislation. The implementation of CMP317/327, followed by the implementation of CMP391, means that charges for the "Connection Exclusion" (i.e. assets built for generation connection) are not included in the €2.50/MWh cap. In addition, TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap.

Over the next five years, it is expected that the average generation tariff will increase from £12.94/kW in 2024/25 to £13.12/kW in 2025/26 before dropping down to £11.30/kW in 2026/27 and then increasing each year to £12.72/kW by 2028/29. This change is driven by the quantity of overall revenue that is to be recovered by generation compared to the quantity of chargeable TEC. The adjustment tariff is expected to decrease year-on-year, increasing in magnitude, to become more negative; changing from -£1.296/kW in 2024/25 to -£6.205/kW by 2028/29. This is due to the revenue which is expected to be collected from wider 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.

2. Generation wider tariffs

The following section summarises the five-year view of wider generation tariffs from 2024/25 to 2028/29. A brief description of generation wider tariff structure can be found in Appendix A.

The wider tariffs are calculated depending on the generator type and made of four components, two of the components (Year Round Shared Element and Year Round Not Shared Element) are multiplied by the generator's specific Annual Load Factor (ALF). The ALF is explained in Appendix D.

The classifications of generator type are listed below:

Conventional Carbon	Conventional Low Carbon	Intermittent
Biomass	Nuclear	Offshore wind
CCGT/CHP	Hydro	Onshore wind
Coal		Solar PV
OCGT/Oil		Tidal
Pumped storage		
Battery storage		
Reactive Compensation		

Each forecast, we publish example tariffs for a generator of each technology type using an example ALF. The example ALFs we have used in this forecast are:

Conventional Carbon – 40%

Conventional Low Carbon – 75%

Intermittent – 45%

The ALFs used in these examples are for illustration only. Tariffs for individual generators are calculated using their own ALFs where we have 3 or more years of data or the generic ALFs if not.

Table 2 Generation wider tariffs in 2024/25

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	2.747082	27.563546	15.142500	-1.296387	18.533113	37.265855	26.249709
2	East Aberdeenshire	4.222448	16.532621	15.142500	-1.296387	15.596109	30.468027	21.285792
3	Western Highlands	2.891893	25.258818	14.295580	-1.296387	17.417265	34.835200	24.365661
4	Skye and Lochalsh	2.830750	25.258818	21.085378	-1.296387	20.072041	41.563855	31.155459
5	Eastern Grampian and Tayside	5.038218	19.719870	11.393242	-1.296387	16.187076	29.924976	18.970797
6	Central Grampian	4.600528	20.424859	12.101943	-1.296387	16.314862	30.724728	19.996743
7	Argyll	2.944939	18.185058	18.326386	-1.296387	16.253130	33.613732	25.213275
8	The Trossachs	3.964083	18.185058	9.808291	-1.296387	13.865036	26.114781	16.695180
9	Stirlingshire and Fife	2.888834	17.415838	9.218242	-1.296387	12.246079	23.872568	15.758982
10	South West Scotlands	1.674892	17.246070	9.165719	-1.296387	10.943221	22.478777	15.630064
11	Lothian and Borders	2.520747	17.246070	3.744124	-1.296387	9.620438	17.903037	10.208469
12	Solway and Cheviot	1.700315	11.584366	5.376188	-1.296387	7.188150	14.468391	9.292766
13	North East England	3.017042	8.778373	3.406554	-1.296387	6.594626	11.710989	6.060435
14	North Lancashire and The Lakes	1.490227	8.778373	0.679153	-1.296387	3.976850	7.456773	3.333034
15	South Lancashire, Yorkshire and Humber	3.949460	3.785144	0.254471	-1.296387	4.268919	5.746402	0.661399
16	North Midlands and North Wales	2.829383	2.408294	-	-1.296387	2.496314	3.339217	-0.212655
17	South Lincolnshire and North Norfolk	2.065945	4.158987	-	-1.296387	2.433153	3.888798	0.575157
18	Mid Wales and The Midlands	1.558632	3.288633	-	-1.296387	1.577698	2.728720	0.183498
19	Anglesey and Snowdon	4.843842	2.395815	-	-1.296387	4.505781	5.344316	-0.218270
20	Pembrokeshire	7.157197	-8.809498	-	-1.296387	2.337011	-0.746314	-5.260661
21	South Wales & Gloucester	2.350580	-8.848554	-	-1.296387	-2.485229	-5.582223	-5.278236
22	Cotswold	1.515721	4.268690	-11.755566	-1.296387	-2.775416	-8.334715	-11.131043
23	Central London	-2.520375	4.268690	-0.518177	-1.296387	-2.316557	-1.133422	0.106347
24	Essex and Kent	-2.074848	4.268690	-	-1.296387	-1.663759	-0.169717	0.624524
25	Oxfordshire, Surrey and Sussex	-0.529398	-3.069692	-	-1.296387	-3.053662	-4.128054	-2.677748
26	Somerset and Wessex	-4.068236	-4.787749	-	-1.296387	-7.279723	-8.955435	-3.450874
27	West Devon and Cornwall	-4.920292	-11.426364	-	-1.296387	-10.787225	-14.786452	-6.438251

Table 3 Generation wider tariffs in 2025/26

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	3.358323	26.137080	17.049837	- 2.167565	18.465525	37.843405	26.643958
2	East Aberdeenshire	4.134833	16.919035	17.049837	- 2.167565	15.554817	31.706381	22.495838
3	Western Highlands	3.743084	24.124298	15.987297	- 2.167565	17.620157	35.656040	24.675666
4	Skye and Lochalsh	3.647928	24.124298	22.944681	- 2.167565	20.307955	42.518268	31.633050
5	Eastern Grampian and Tayside	4.542402	19.852310	13.063494	- 2.167565	15.541159	30.327564	19.829469
6	Central Grampian	4.450955	20.340082	13.632086	- 2.167565	15.872257	31.170538	20.617558
7	Argyll	2.894799	18.328032	21.115138	- 2.167565	16.504502	35.588396	27.195187
8	The Trossachs	3.979062	18.328032	11.248876	- 2.167565	13.642260	26.806397	17.328925
9	Stirlingshire and Fife	2.872258	17.655062	10.639094	- 2.167565	12.022355	24.585084	16.416307
10	South West Scotlands	1.627096	17.561525	10.601848	- 2.167565	10.724880	23.232523	16.336969
11	Lothian and Borders	2.508802	17.561525	4.642979	- 2.167565	9.223039	18.155360	10.378100
12	Solway and Cheviot	1.599292	12.316967	6.209355	- 2.167565	6.842256	14.878807	9.584425
13	North East England	3.130594	9.473956	3.740173	- 2.167565	6.248681	11.808669	5.835888
14	North Lancashire and The Lakes	1.351578	9.473956	1.521954	- 2.167565	3.582377	7.811434	3.617669
15	South Lancashire, Yorkshire and Humber	3.915224	4.505088	0.273966	- 2.167565	3.659281	5.400441	0.133691
16	North Midlands and North Wales	2.691995	3.263382	-	- 2.167565	1.829783	2.971967	- 0.699043
17	South Lincolnshire and North Norfolk	2.355352	4.335824	-	- 2.167565	1.922117	3.439655	- 0.216444
18	Mid Wales and The Midlands	0.777130	3.877006	-	- 2.167565	0.160367	1.517320	- 0.422912
19	Anglesey and Snowdon	5.173464	3.065727	-	- 2.167565	4.232190	5.305194	- 0.787988
20	Pembrokeshire	7.415670	- 8.584535	-	- 2.167565	1.814291	- 1.190296	- 6.030606
21	South Wales & Gloucester	2.349244	- 8.341082	-	- 2.167565	- 3.154754	- 6.074133	- 5.921052
22	Cotswold	1.609040	4.084298	- 11.457343	- 2.167565	- 3.507743	- 8.952645	- 11.786974
23	Central London	- 1.891278	4.084298	- 0.778853	- 2.167565	- 2.736665	- 1.774473	- 1.108484
24	Essex and Kent	- 1.275559	4.084298	-	- 2.167565	- 1.809405	- 0.379901	- 0.329631
25	Oxfordshire, Surrey and Sussex	- 0.305601	- 3.033953	-	- 2.167565	- 3.686747	- 4.748631	- 3.532844
26	Somerset and Wessex	- 3.919880	- 4.593112	-	- 2.167565	- 7.924690	- 9.532279	- 4.234465
27	West Devon and Cornwall	- 4.844497	- 11.276492	-	- 2.167565	- 11.522659	- 15.469431	- 7.241986

Table 4 Generation wider tariffs in 2026/27

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	3.250414	25.762562	18.989970	-3.296961	17.854466	38.265345	27.286162
2	East Aberdeenshire	3.948595	16.807061	18.989970	-3.296961	14.970446	32.246900	23.256186
3	Western Highlands	4.044211	24.162660	17.816292	-3.296961	17.538831	36.685537	25.392528
4	Skye and Lochalsh	3.942673	24.162660	27.070675	-3.296961	21.139046	45.838382	34.646911
5	Eastern Grampian and Tayside	5.136791	20.754180	14.779054	-3.296961	16.053124	32.184519	20.821474
6	Central Grampian	4.921889	20.323618	14.175602	-3.296961	15.424616	31.043244	20.024269
7	Argyll	3.115863	18.771352	24.400050	-3.296961	17.087463	38.297466	29.550197
8	The Trossachs	4.183184	18.771352	11.973229	-3.296961	13.184055	26.937966	17.123376
9	Stirlingshire and Fife	2.894715	18.248295	11.370262	-3.296961	11.445177	24.654237	16.285034
10	South West Scotlands	1.796113	18.129054	11.307967	-3.296961	10.273960	23.403910	16.169080
11	Lothian and Borders	2.638914	18.129054	4.894002	-3.296961	8.551175	17.832746	9.755115
12	Solway and Cheviot	1.764902	13.235118	7.102760	-3.296961	6.603092	15.497040	9.761602
13	North East England	3.161315	9.399114	3.535317	-3.296961	5.038126	10.449007	4.467957
14	North Lancashire and The Lakes	1.495686	9.399114	2.379418	-3.296961	2.910138	7.627479	3.312058
15	South Lancashire, Yorkshire and Humber	4.078555	5.358245	0.154608	-3.296961	2.986735	4.954886	-0.731143
16	North Midlands and North Wales	2.453793	4.807992	0.011009	-3.296961	1.084432	2.773835	-1.122356
17	South Lincolnshire and North Norfolk	1.449274	3.573657	-0.001228	-3.296961	-0.418715	0.831328	-1.690043
18	Mid Wales and The Midlands	0.209957	3.546891	-0.001228	-3.296961	-1.668739	-0.428064	-1.702088
19	Anglesey and Snowdon	2.641019	6.469753	0.011009	-3.296961	1.936363	4.207382	-0.374563
20	Pembrokeshire	8.989864	-6.617780	-	-3.296961	3.045791	0.729568	-6.274962
21	South Wales & Gloucester	3.927075	-7.067475	-	-3.296961	-2.196876	-4.670492	-6.477325
22	Cotswold	2.896865	3.624442	-10.873311	-3.296961	-3.299644	-8.555076	-12.539273
23	Central London	-2.898475	3.624442	-0.765375	-3.296961	-5.051809	-4.242480	-2.431337
24	Essex and Kent	-1.970693	3.624442	-	-3.296961	-3.817877	-2.549323	-1.665962
25	Oxfordshire, Surrey and Sussex	-0.613257	-3.551319	-	-3.296961	-5.330746	-6.573707	-4.895055
26	Somerset and Wessex	-0.838621	-3.712029	-	-3.296961	-5.620394	-6.919604	-4.967374
27	West Devon and Cornwall	0.064405	-6.884653	-	-3.296961	-5.986417	-8.396046	-6.395055

Table 5 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	2.545798	31.856028	26.951749	- 5.281116	20.787793	48.108452	36.005846
2	East Aberdeenshire	7.644601	19.007046	26.951749	- 5.281116	20.747003	43.570519	30.223804
3	Western Highlands	2.692881	29.262326	24.224536	- 5.281116	18.806510	43.583046	32.111467
4	Skye and Lochalsh	2.612158	29.262326	33.710334	- 5.281116	22.520106	52.988121	41.597265
5	Eastern Grampian and Tayside	4.218140	25.994436	20.273804	- 5.281116	17.444320	38.706655	26.690184
6	Central Grampian	4.127318	25.486436	19.400347	- 5.281116	16.800915	37.361376	25.588127
7	Argyll	2.346169	24.060391	27.013450	- 5.281116	17.494589	42.123796	32.559510
8	The Trossachs	3.447383	24.060391	16.923773	- 5.281116	14.559933	33.135333	22.469833
9	Stirlingshire and Fife	2.193669	23.651778	16.354944	- 5.281116	12.915242	31.006331	21.717128
10	South West Scotlands	1.188520	23.145583	16.011625	- 5.281116	11.570287	29.278216	21.146021
11	Lothian and Borders	1.975065	23.145583	11.624816	- 5.281116	10.602109	25.677952	16.759212
12	Solway and Cheviot	0.902438	16.893782	10.140379	- 5.281116	6.434986	18.432038	12.461465
13	North East England	2.964584	10.500729	2.275605	- 5.281116	2.794002	7.834620	1.719817
14	North Lancashire and The Lakes	0.343824	10.500729	3.550612	- 5.281116	0.683244	6.488867	2.994824
15	South Lancashire, Yorkshire and Humber	3.621371	6.048594	0.070643	- 5.281116	0.787950	2.947344	- 2.488606
16	North Midlands and North Wales	1.755728	5.895984	0.032352	- 5.281116	- 1.154054	0.928952	- 2.595571
17	South Lincolnshire and North Norfolk	1.179871	3.880628	0.008323	- 5.281116	- 2.545665	- 1.182451	- 3.526510
18	Mid Wales and The Midlands	0.036921	3.679277	0.008323	- 5.281116	- 3.769155	- 2.476414	- 3.617118
19	Anglesey and Snowdon	3.072638	6.643352	0.032352	- 5.281116	0.461804	2.806388	- 2.259256
20	Pembrokeshire	8.719236	- 5.359624	-	- 5.281116	1.294270	- 0.581598	- 7.692947
21	South Wales & Gloucester	3.626455	- 5.913676	-	- 5.281116	- 4.020131	- 6.089918	- 7.942270
22	Cotswold	3.726728	3.206296	- 9.962900	- 5.281116	- 4.257030	- 9.112566	- 13.801183
23	Central London	- 2.697053	3.206296	- 0.682973	- 5.281116	- 6.968840	- 6.256420	- 4.521256
24	Essex and Kent	- 2.036018	3.206296	-	- 5.281116	- 6.034616	- 4.912412	- 3.838283
25	Oxfordshire, Surrey and Sussex	- 0.206296	- 3.860798	-	- 5.281116	- 7.031731	- 8.383011	- 7.018475
26	Somerset and Wessex	3.227765	- 5.921913	-	- 5.281116	- 4.422116	- 6.494786	- 7.945977
27	West Devon and Cornwall	3.587334	- 9.658094	-	- 5.281116	- 5.557020	- 8.937353	- 9.627258

Table 6 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	2.679675	24.644973	35.826851	-6.205011	20.663394	50.785245	40.712078
2	East Aberdeenshire	0.814596	24.644808	27.519831	-6.205011	15.475441	40.613022	32.404984
3	Western Highlands	3.497142	23.500802	30.917813	-6.205011	19.059577	45.835546	35.288163
4	Skye and Lochalsh	3.384910	23.500802	40.489507	-6.205011	22.776023	55.295008	44.859857
5	Eastern Grampian and Tayside	2.769754	22.281630	25.058021	-6.205011	15.500603	38.333987	28.879744
6	Central Grampian	4.084882	22.014115	23.585058	-6.205011	16.119540	37.975515	27.286399
7	Argyll	2.379080	21.443765	32.698963	-6.205011	17.831160	44.955856	36.143646
8	The Trossachs	3.529269	21.443765	20.420804	-6.205011	14.070086	33.827886	23.865487
9	Stirlingshire and Fife	2.473005	21.319275	19.986711	-6.205011	12.790388	32.244161	23.375374
10	South West Scotlands	1.217347	20.824840	19.344627	-6.205011	11.080123	29.975593	22.510794
11	Lothian and Borders	1.984951	20.824840	14.717410	-6.205011	9.996840	26.115980	17.883577
12	Solway and Cheviot	0.870126	15.497280	12.147146	-6.205011	5.722885	18.435221	12.915911
13	North East England	2.808988	10.130570	3.116584	-6.205011	1.902839	7.318489	1.470330
14	North Lancashire and The Lakes	0.328545	10.130570	4.345737	-6.205011	-0.085943	6.067199	2.699483
15	South Lancashire, Yorkshire and Humber	3.408700	6.145974	0.317302	-6.205011	-0.211001	2.130472	-3.122021
16	North Midlands and North Wales	1.869654	5.484929	0.094543	-6.205011	-2.103568	-0.127117	-3.642250
17	South Lincolnshire and North Norfolk	0.769474	4.089726	0.014209	-6.205011	-3.793963	-2.354034	-4.350425
18	Mid Wales and The Midlands	-0.312395	3.798861	0.007047	-6.205011	-4.995043	-3.661213	-4.488477
19	Anglesey and Snowdon	4.325029	5.939736	0.094543	-6.205011	0.533730	2.669363	-3.437587
20	Pembrokeshire	9.168668	-5.160613	-	-6.205011	0.899412	-0.906803	-8.527287
21	South Wales & Gloucester	3.811756	-5.895185	-	-6.205011	-4.751329	-6.814644	-8.857844
22	Cotswold	4.077810	3.689315	-10.745285	-6.205011	-4.949589	-10.105500	-15.290104
23	Central London	-3.088279	3.689315	-1.096974	-6.205011	-8.256354	-7.623278	-5.641793
24	Essex and Kent	-2.650333	3.689315	-	-6.205011	-7.379618	-6.088358	-4.544819
25	Oxfordshire, Surrey and Sussex	0.009779	-3.442129	-	-6.205011	-7.572084	-8.776829	-7.753969
26	Somerset and Wessex	4.146864	-5.333011	-	-6.205011	-4.191351	-6.057905	-8.604866
27	West Devon and Cornwall	4.634848	-9.110767	-	-6.205011	-5.214470	-8.403238	-10.304856

3. Changes to wider tariffs over the five-year period

The following section provides details of the wider generation tariffs for 2024/25 to 2028/29 and explains how these could change over the next five years. We have compared the example tariffs based on a Conventional Carbon generator with an ALF of 40%, a Conventional Low Carbon generator with an ALF of 75%, and an Intermittent generator with an ALF of 45% for illustration purposes only.

Table 7 Comparison of Conventional Carbon (40%) tariffs

Zone	Zone Name	Example Wider Generation Tariffs (£/kW) Conventional Carbon 40%					
		2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
1	North Scotland	16.647142	18.533113	18.465525	17.854466	20.787793	20.663394
2	East Aberdeenshire	13.708389	15.596109	15.554817	14.970446	20.747003	15.475441
3	Western Highlands	15.854361	17.417265	17.620157	17.538831	18.806510	19.059577
4	Skye and Lochalsh	18.395791	20.072041	20.307955	21.139046	22.520106	22.776023
5	Eastern Grampian and Tayside	13.839660	16.187076	15.541159	16.053124	17.444320	15.500603
6	Central Grampian	13.817678	16.314862	15.872257	15.424616	16.800915	16.119540
7	Argyll	15.060368	16.253130	16.504502	17.087463	17.494589	17.831160
8	The Trossachs	11.587184	13.865036	13.642260	13.184055	14.559933	14.070086
9	Stirlingshire and Fife	10.261207	12.246079	12.022355	11.445177	12.915242	12.790388
10	South West Scotlands	8.758879	10.943221	10.724880	10.273960	11.570287	11.080123
11	Lothian and Borders	10.042561	9.620438	9.223039	8.551175	10.602109	9.996840
12	Solway and Cheviot	5.916095	7.188150	6.842256	6.603092	6.434986	5.722885
13	North East England	6.887900	6.594626	6.248681	5.038126	2.794002	1.902839
14	North Lancashire and The Lakes	2.800682	3.976850	3.582377	2.910138	0.683244	- 0.085943
15	South Lancashire, Yorkshire and Humber	4.541608	4.268919	3.659281	2.986735	0.787950	- 0.211001
16	North Midlands and North Wales	2.317316	2.496314	1.829783	1.084432	- 1.154054	- 2.103568
17	South Lincolnshire and North Norfolk	2.179598	2.433153	1.922117	- 0.418715	- 2.545665	- 3.793963
18	Mid Wales and The Midlands	1.228474	1.577698	0.160367	- 1.668739	- 3.769155	- 4.995043
19	Anglesey and Snowdon	3.620493	4.505781	4.232190	1.936363	0.461804	0.533730
20	Pembrokeshire	2.321303	2.337011	1.814291	3.045791	1.294270	0.899412
21	South Wales & Gloucester	- 2.577226	- 2.485229	- 3.154754	- 2.196876	- 4.020131	- 4.751329
22	Cotswold	- 2.749320	- 2.775416	- 3.507743	- 3.299644	- 4.257030	- 4.949589
23	Central London	- 4.286024	- 2.316557	- 2.736665	- 5.051809	- 6.968840	- 8.256354
24	Essex and Kent	- 2.011367	- 1.663759	- 1.809405	- 3.817877	- 6.034616	- 7.379618
25	Oxfordshire, Surrey and Sussex	- 2.025978	- 3.053662	- 3.686747	- 5.330746	- 7.031731	- 7.572084
26	Somerset and Wessex	- 2.758907	- 7.279723	- 7.924690	- 5.620394	- 4.422116	- 4.191351
27	West Devon and Cornwall	- 5.118477	- 10.787225	- 11.522659	- 5.986417	- 5.557020	- 5.214470

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

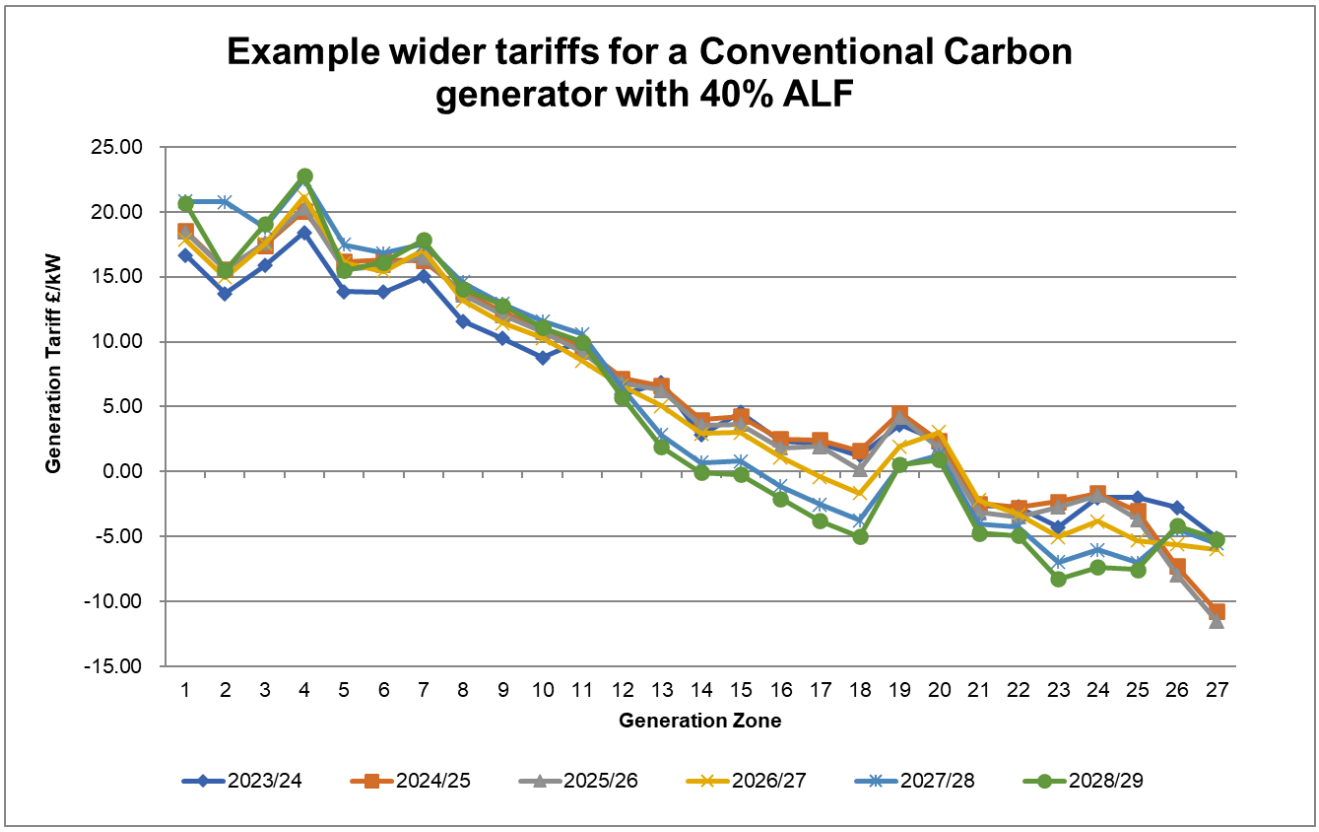


Table 8 Comparison of Conventional Low Carbon (75%) tariffs

Zone	Zone Name	Example Wider Generation Tariffs (£/kW) Conventional Low Carbon 75%					
		2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
1	North Scotland	34.095576	37.265855	37.843405	38.265345	48.108452	50.785245
2	East Aberdeenshire	28.049539	30.468027	31.706381	32.246900	43.570519	40.613022
3	Western Highlands	32.339226	34.835200	35.656040	36.685537	43.583046	45.835546
4	Skye and Lochalsh	38.818360	41.563855	42.518268	45.838382	52.988121	55.295008
5	Eastern Grampian and Tayside	27.106797	29.924976	30.327564	32.184519	38.706655	38.333987
6	Central Grampian	27.497103	30.724728	31.170538	31.043244	37.361376	37.975515
7	Argyll	32.093261	33.613732	35.588396	38.297466	42.123796	44.955856
8	The Trossachs	23.259818	26.114781	26.806397	26.937966	33.135333	33.827886
9	Stirlingshire and Fife	21.220886	23.872568	24.585084	24.654237	31.006331	32.244161
10	South West Scotlands	19.976710	22.478777	23.232523	23.403910	29.278216	29.975593
11	Lothian and Borders	18.333531	17.903037	18.155360	17.832746	25.677952	26.115980
12	Solway and Cheviot	12.639671	14.468391	14.878807	15.497040	18.432038	18.435221
13	North East England	11.470055	11.710989	11.808669	10.449007	7.834620	7.318489
14	North Lancashire and The Lakes	5.638146	7.456773	7.811434	7.627479	6.488867	6.067199
15	South Lancashire, Yorkshire and Humber	5.423504	5.746402	5.400441	4.954886	2.947344	2.130472
16	North Midlands and North Wales	2.553257	3.339217	2.971967	2.773835	0.928952	- 0.127117
17	South Lincolnshire and North Norfolk	3.206151	3.888798	3.439655	0.831328	- 1.182451	- 2.354034
18	Mid Wales and The Midlands	2.236666	2.728720	1.517320	- 0.428064	- 2.476414	- 3.661213
19	Anglesey and Snowdon	3.883449	5.344316	5.305194	4.207382	2.806388	2.669363
20	Pembrokeshire	- 0.765236	- 0.746314	- 1.190296	0.729568	- 0.581598	- 0.906803
21	South Wales & Gloucester	- 5.622423	- 5.582223	- 6.074133	- 4.670492	- 6.089918	- 6.814644
22	Cotswold	- 8.300711	- 8.334715	- 8.952645	- 8.555076	- 9.112566	- 10.105500
23	Central London	- 5.130889	- 1.133422	- 1.774473	- 4.242480	- 6.256420	- 7.623278
24	Essex and Kent	- 0.495207	- 0.169717	- 0.379901	- 2.549323	- 4.912412	- 6.088358
25	Oxfordshire, Surrey and Sussex	- 2.677313	- 4.128054	- 4.748631	- 6.573707	- 8.383011	- 8.776829
26	Somerset and Wessex	- 3.672403	- 8.955435	- 9.532279	- 6.919604	- 6.494786	- 6.057905
27	West Devon and Cornwall	- 7.720830	- 14.786452	- 15.469431	- 8.396046	- 8.937353	- 8.403238

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

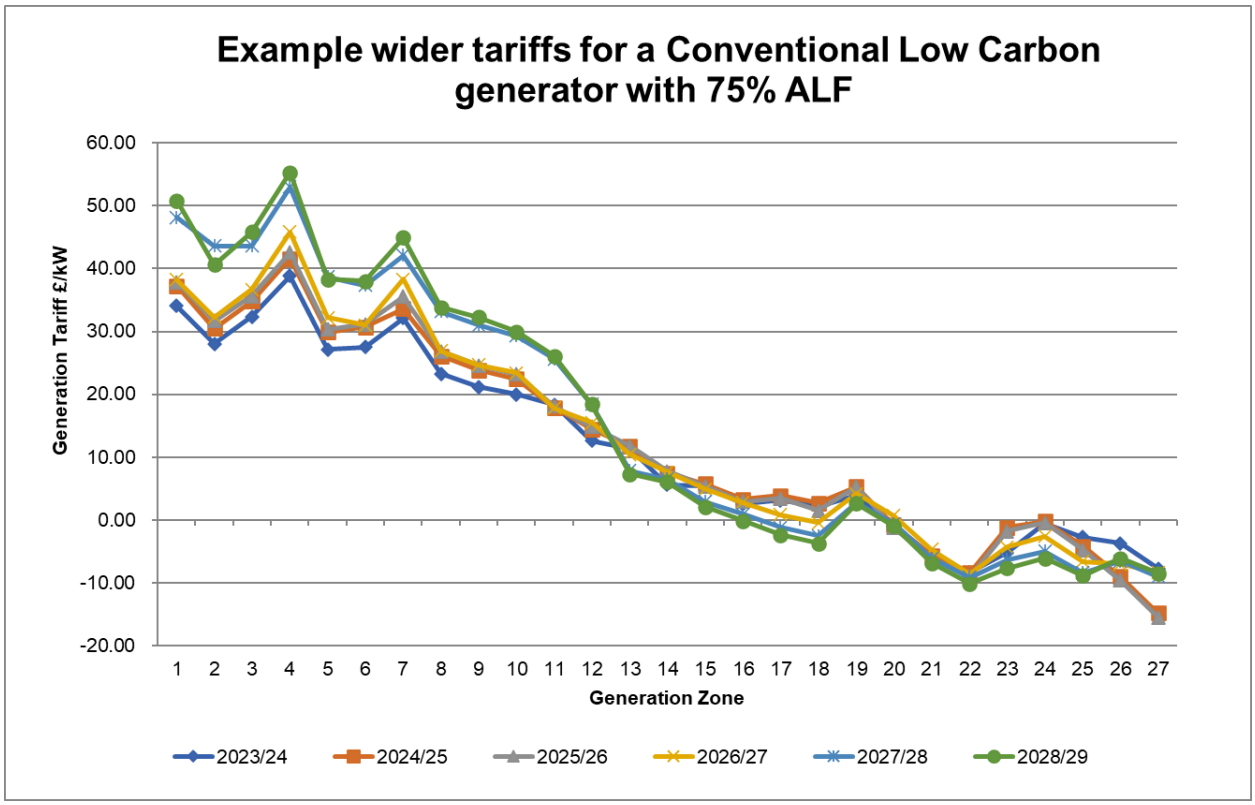
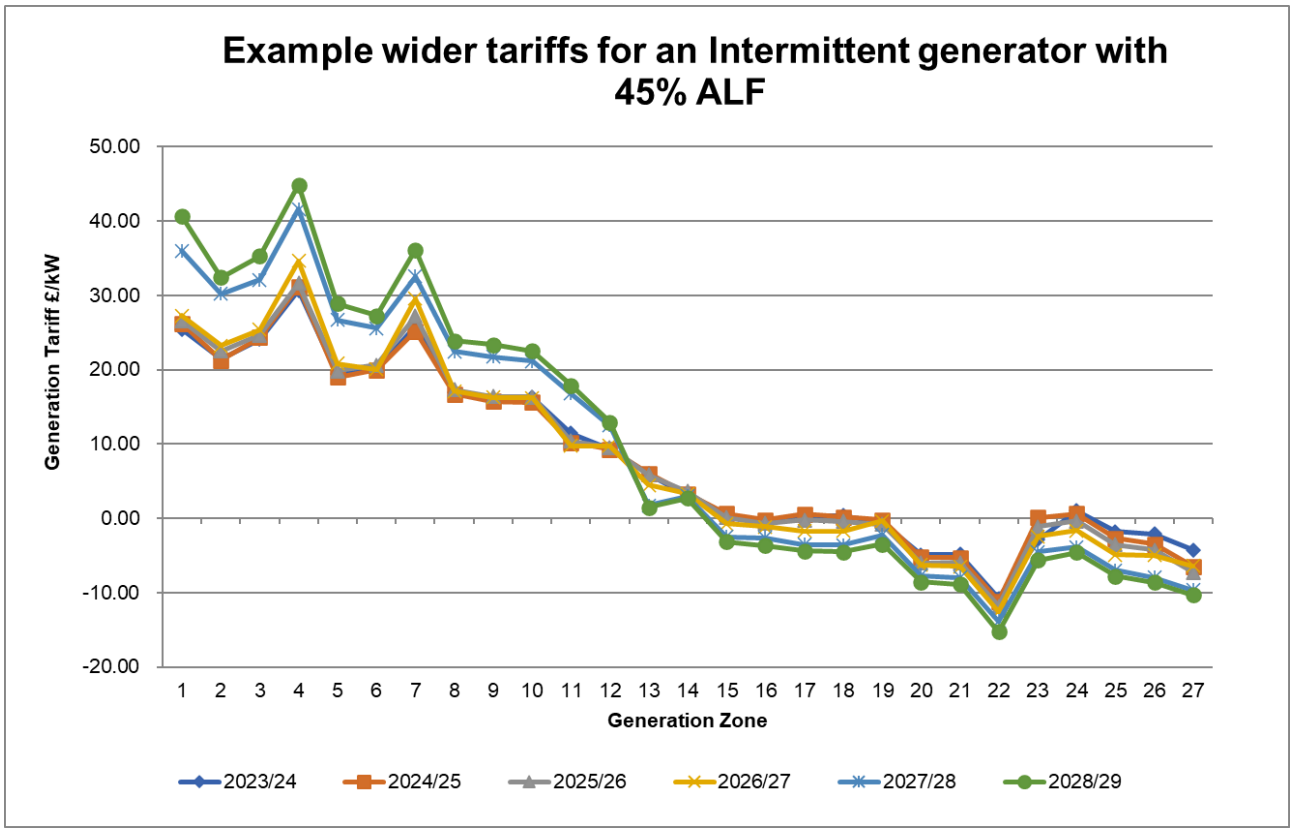


Table 9 Comparison of Intermittent (45%) tariffs

Zone	Zone Name	Example Wider Generation Tariffs (£/kW) Intermittent 45%					
		2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
1	North Scotland	25.445086	26.249709	26.643958	27.286162	36.005846	40.712078
2	East Aberdeenshire	21.450006	21.285792	22.495838	23.256186	30.223804	32.404984
3	Western Highlands	24.080784	24.365661	24.675666	25.392528	32.111467	35.288163
4	Skye and Lochalsh	30.643624	31.155459	31.633050	34.646911	41.597265	44.859857
5	Eastern Grampian and Tayside	19.406001	18.970797	19.829469	20.821474	26.690184	28.879744
6	Central Grampian	20.032348	19.996743	20.617558	20.024269	25.588127	27.286399
7	Argyll	25.913829	25.213275	27.195187	29.550197	32.559510	36.143646
8	The Trossachs	16.980064	16.695180	17.328925	17.123376	22.469833	23.865487
9	Stirlingshire and Fife	15.914669	15.758982	16.416307	16.285034	21.717128	23.375374
10	South West Scotlands	16.298142	15.630064	16.336969	16.169080	21.146021	22.510794
11	Lothian and Borders	11.420040	10.208469	10.378100	9.755115	16.759212	17.883577
12	Solway and Cheviot	9.305625	9.292766	9.584425	9.761602	12.461465	12.915911
13	North East England	5.965776	6.060435	5.835888	4.467957	1.719817	1.470330
14	North Lancashire and The Lakes	3.057959	3.333034	3.617669	3.312058	2.994824	2.699483
15	South Lancashire, Yorkshire and Humber	0.272454	0.661399	0.133691	- 0.731143	- 2.488606	- 3.122021
16	North Midlands and North Wales	- 0.624825	- 0.212655	- 0.699043	- 1.122356	- 2.595571	- 3.642250
17	South Lincolnshire and North Norfolk	0.391675	0.575157	- 0.216444	- 1.690043	- 3.526510	- 4.350425
18	Mid Wales and The Midlands	0.368067	0.183498	- 0.422912	- 1.702088	- 3.617118	- 4.488477
19	Anglesey and Snowdon	- 0.590093	- 0.218270	- 0.787988	- 0.374563	- 2.259256	- 3.437587
20	Pembrokeshire	- 4.896587	- 5.260661	- 6.030606	- 6.274962	- 7.692947	- 8.527287
21	South Wales & Gloucester	- 4.843431	- 5.278236	- 5.921052	- 6.477325	- 7.942270	- 8.857844
22	Cotswold	- 10.758082	- 11.131043	- 11.786974	- 12.539273	- 13.801183	- 15.290104
23	Central London	- 2.913872	0.106347	- 1.108484	- 2.431337	- 4.521256	- 5.641793
24	Essex and Kent	1.021170	0.624524	- 0.329631	- 1.665962	- 3.838283	- 4.544819
25	Oxfordshire, Surrey and Sussex	- 1.765610	- 2.677748	- 3.532844	- 4.895055	- 7.018475	- 7.753969
26	Somerset and Wessex	- 2.102673	- 3.450874	- 4.234465	- 4.967374	- 7.945977	- 8.604866
27	West Devon and Cornwall	- 4.274061	- 6.438251	- 7.241986	- 6.395055	- 9.627258	- 10.304856

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



Locational changes

Locational tariffs are generally expected to become 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 a 5-year generation forecast central case produced by Future Energy Scenarios (FES).

In 2027/28 the impact of a new HVDC link (Torness to Hawthorn Pit) can be seen, particularly in Scottish zones where a significant increase can be seen from the previous years.

Zone 4 (Skye) and Zone 7 (Argyll) see more variation, particularly for Conventional Low Carbon and Intermittent generators, in each year due to those zones being sensitive to generation/demand changes, due to the relatively long radial circuits.

To view the changes in generation in each zone, please see Table A in the accompanying tables spreadsheet published on our website here and Table 34 on page 73.

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 CMP317/275 please refer to the workgroup notes[6].

Adjustment tariff changes

The adjustment tariff is currently forecast to be negative across the next five years due to the wider tariffs causing the average generation charge to breach the cap.

[6] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp375-enduring

The adjustment tariff is forecast to decrease from -£1.296/kW in 2024/25 to -£6.205/kW in 2028/29, increasing in magnitude, to become more negative. due to the increase in revenue to be collected via the wider locational charges. For a full breakdown of the generation revenues, please see Table 26.

Onshore local tariffs for generation

4. Onshore local substation tariffs

Onshore local substation tariffs reflect the cost of the first transmission infrastructure 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 prior to the RIIO-2 period continue to be inflated in line with CPIH.

Table 10 Local substation tariffs

2024/25 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.172296	0.086151	0.059423
<1320 MW	Redundancy	0.363046	0.184396	0.130933
≥1320 MW	No redundancy	-	0.253111	0.180208
≥1320 MW	Redundancy	-	0.380890	0.273953

5. Onshore local circuit tariffs

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

The 2024/25 onshore local circuit tariffs will be refined in the next quarterly forecast. Table 11 shows the five year view of onshore local circuit tariffs.

Table 11 Onshore local circuit tariffs

Connection Point	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	2028/29 (£/kW)	Connection Point	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	2028/29 (£/kW)	Connection Point	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	2028/29 (£/kW)
Aberarder	0.912782	0.933776	0.958055	0.982006	1.006556	Douglas North	0.730226	0.747021	0.766444	0.785605	0.805245	Lairg			0.175431	0.179816	0.184312
Aberdeen Bay	3.212994	3.286893	3.372352	3.456661	3.543078	Dunmaglass	1.043615	1.067618	1.095376	1.122760	1.150829	Langage	-0.394365	-0.403584	-0.413885	-0.423856	-0.434058
Achruach	-2.977959	-3.045935	-3.123723	-3.204249	-3.283797	Dunhill	1.719774	1.759329	1.540928	1.855151	1.901317	lethans				5.400275	5.535161
Aigas	0.811716	0.830386	0.851976	0.873275	0.895107	Dunlaw Extension	1.681385	1.844704	1.894490	1.912059	1.961015	Limekilns	2.128889	2.252952	2.311529	2.369317	2.428550
An Suidhe	-1.109392	-1.134394	-1.162487	-1.193979	-1.223268	Edinbane	8.216302	8.405215	8.627177	8.847741	9.068708	Lochay	0.365113	0.373511	0.383222	0.392802	0.402622
Arecleoch	2.884453	2.950795	3.027516	3.103204	3.180784	elchies				2.697244	2.764675	Lorg			3.798505	2.453206	2.073506
Arecleoch extension	3.077724	2.784713	2.857116	2.928544	3.001757	energy isles wind fa				73.481598	78.158548	Luichart	0.679226	0.696371	0.714143	0.731824	0.749894
ayrshire grid collector	0.162258	0.184434	0.189229	0.193960	0.198809	Enoch Hill	1.595964	1.632671	1.675120	1.716998	1.759923	Marchwood	0.449333	0.459518	-0.297946	0.305414	-0.313056
beaw field				70.838909	75.045034	euchanhead			4.469143	3.238810	2.878751	Mark Hill	1.058888	1.083242	1.111406	1.139192	1.167671
Beinneun Wind Farm	1.618915	1.656133	1.699183	1.741652	1.785200	Ewe Hill	1.671407	1.709849	1.754305	1.798163	1.843117	melvich				2.516666	2.492384
Benbrack	0.852148	0.440785	0.328475	0.480722	0.492637	Fallago	-0.069247	-0.068157	-0.068858	-0.025149	-0.024706	Middle Muir	2.738347	2.801329	2.874164	2.946018	3.019668
Bhlaraidh Wind Farm	0.731240	0.748059	0.767509	0.786696	0.806364	Farr	4.173935	4.269936	4.380954	4.490478	4.602740	Middleton	0.180097	0.187879	0.008931	0.003638	0.006941
Black Hill	1.842615	1.884996	1.669862	1.987308	2.036777	Faw Side		5.939594	6.193775	6.700707	6.868949	Millennium South	0.522985	0.534965	0.549132	0.563258	0.577282
Black Law	2.008121	2.054308	2.107720	2.160413	2.214423	Fernoch	5.144497	5.262808	5.399633	5.534616	5.672970	Millennium Wind	1.881502	1.924760	1.974794	2.024153	2.074764
BlackCraig Wind Farm	6.599651	3.565655	2.070427	2.313788	2.371512	Ffestiniogg	0.260910	0.266911	0.273851	0.280697	0.287714	Mossford	3.597217	3.681475	3.776861	3.871109	3.967661
BlackLaw Extension	4.368189	4.468657	4.584842	4.699463	4.816950	Fife Grid Services	0.182165	0.207060	0.212444	0.217755	0.223199	mossy hill				60.751311	63.086212
Blarghour			1.955006	1.938911	1.944133	Finlarig	0.365113	0.373511	0.383222	0.392802	0.402622	Nant	2.953831	3.021756	3.100314	3.177813	3.257247
Branxton			0.467292			Foyers	0.335456	0.343171	0.352094	0.360896	0.369918	Necton	-0.516923	-0.524959	-0.537172	-0.549570	-0.562132
Broken Cross	1.197763	1.225273	1.257107	1.288510	1.320690	Friston		0.565665	0.583635			north lowther energy initiati			1.535017	1.573392	1.612727
carrick			0.555703	0.569596	0.583836	Galawhistle	1.253555	1.282387	1.315729	1.348622	1.382338	old forest of ae				-2.478245	1.503997
Chirmorie	2.649616	2.521298	2.586852	2.651523	2.717811	Gills Bay		1.646230	1.689031	1.731257	1.774539	overhill				1.287749	1.319942
Clash Gour		0.120827	-0.136679	0.141733	1.886661	Glen Kyllachy	0.547669	0.560266	0.574833	0.589204	0.603934	quantans hill				1.104584	0.345584
Clauchrie		1.632671	1.675120	1.716998	1.759923	Glen Ullinish			0.192627	-	-	Rawhills			0.851530	0.775838	0.795234
Cloiche			1.918142	1.966096	2.015248	Glendoe	2.202299	2.252952	2.311529	2.369317	2.428550	Rhigos	0.124975	0.127945	0.131236	0.134455	0.540439
Clyde (North)	0.127067	0.129989	0.133369	0.136703	0.140121	Glenglass	5.494809	5.621190	5.503197	5.916476	6.064175	Rocksavage	0.017623	0.018030	-0.018500	-0.018964	-0.019440
Clyde (South)	0.148244	0.151654	-	0.159487	0.163474	glenmuckloch hydro			3.859394	4.112526	4.215219	ryhall				-0.499852	-0.509217
Coalburn BESS		0.495581	0.414364	0.220542	0.226150	glenshimmeroch				0.035076	-0.040160	Saltend	-0.018618	0.019047	-0.019543	-0.020031	-0.020533
Coire Glas				0.754792	0.773662	Gordonbush	0.051673	0.097129	0.061191	0.085004	0.079295	Sandy Knowe	3.863161	3.952014	3.904685	4.158949	4.262802
Connagill			0.627161	0.660701	0.670972	Greenburn	1.460452	1.494042	1.532887	1.571210	1.610490	Sanquhar II	8.303705	8.494690	8.451408	8.938393	9.161640
Corriegarth	2.920904	2.988085	3.065775	3.142419	3.220980	Griffin Wind	11.377057	11.637852	5.626921	5.766647	1.057102	Scoop Hill			0.529678	0.257867	0.264314	0.270922
Corriemoillie	1.907726	1.953125	2.003573	2.053490	2.104602	Hadyard Hill	3.286017	3.361595	3.448997	3.535221	3.623602	Shepherds rig	0.723970	0.750030	2.893675	1.525755	1.122870
Coryton	0.044255	0.046230	0.047555	0.048714	0.050033	Harestanes	2.738347	2.801329	2.874164	2.946018	3.019668	South Humber Bank	-0.212817	-0.217681	-0.223323	-0.228923	-0.234650
costa head			2.273004	2.369317	6.253464	Hartlepool	0.039754	0.042642	0.045040	0.210222	-0.000681	Spalding	0.320310	0.330783	0.340523	0.349697	0.359259
Craig Watch Wind Farm				0.157121	0.201311	Heathland			3.680354	3.768070	3.862272	stornoway wind				67.977990	69.676396
CREAG RIABHACH	4.016243	4.108616	4.215440	4.320826	4.428847	hesta head			8.181459	8.222575	8.428139	Stronach	3.671932	3.641830	3.736517	3.829930	3.925679
Cruachan	2.137846	2.187120	2.244046	2.300345	2.357918	hopsrig collector			2.903971	2.976570	3.050984	Strathbrora	-0.074023	-0.034694	-0.070464	-0.051627	-0.060171
culham jet				-0.037725	-0.038852	Invergarry	0.365113	0.373511	0.383222	0.392802	0.402622	Strathy		2.113293	2.135517	2.206766	2.255688
Culligran	2.075110	2.122837	2.178031	2.232482	2.288294	Kennoxhead	4.881980	4.994266	5.124117	5.252220	5.383525	Strathy Wind	2.031398	2.113293	2.135517	2.206766	2.255688
Cumberhead Collector	0.835703	0.854925	0.877153	0.899081	0.921558	Kergord	55.350509	55.090138	56.774147	57.036448	59.278477	Strathy Wood		3.174840	3.257386	3.338820	3.422291
Cumberhead West	4.428799	4.489845	4.606581	4.721745	4.839789	Kilgallioch	1.270665	1.299891	1.333688	1.367030	1.401206	Stronelairg	1.287715	1.320099	1.354705	1.123852	1.151948
daer				4.116944	4.287733	Kilmarnock BESS		0.479527	0.567686	0.581879	0.596426	teindland wind farm				2.946018	3.019668
Deanie	3.409109	3.487519	3.578194	3.667649	3.759340	Kilmorack	0.148222	0.151631	0.155574	0.159463	0.163450	troston			1.147530	1.017082	0.966396
Dersalloch	2.691303	2.753202	2.824786	2.895405	2.967791	Kings Lynn		-0.457298	-0.467752	-0.478414	-0.489197	Wester Dod	0.417852	0.427462	0.438576	0.449541	0.460779
Dinorwig	2.829882	2.894969	2.970238	3.044494	3.120607	kirkton				1.253030	1.278109	Whitelee	0.127067	0.129989	0.133369	0.136703	0.140121
Dorenell	2.456821	2.513328	2.578674	2.643141	2.709219	Kype Muir	1.775870	1.816715	1.863949	1.910548	1.958312	Whitelee Extension	0.360022	0.368302	0.377878	0.387325	0.397008

* Available in excel format on the website here

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

Offshore local tariffs for generation

6. Offshore local generation tariffs

The local offshore tariffs (substation, circuit and Embedded Transmission Use of System) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of a price control or on transfer to the offshore transmission owner (OFTO). The tariffs are subsequently indexed each year, in line with the revenue of the associated Offshore Transmission Owner. Since January, the forecast has been updated with the latest inflation indices.

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

Table 13 Offshore local tariffs 2024/25

Offshore Generator	2023/24 Final Tariff Component (£/kW)			2024/25 April Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	10.258673	54.196042	1.345762	11.134985	58.825554	1.460719	0.876312	4.629512	0.114957
Beatrice	8.398974	23.028560	-	9.010706	24.705826	-	0.611732	1.677266	-
Burbo Bank	13.045517	25.212986	-	13.995676	27.049353	-	0.950159	1.836367	-
Dudgeon	19.081129	29.938585	-	20.470887	32.119137	-	1.389758	2.180552	-
East Anglia 1				12.117844	51.140519	-	12.117844	51.140519	-
Galloper	19.532116	30.892051	-	20.954722	33.142047	-	1.422606	2.249996	-
Greater Gabbard	19.114039	44.231809	-	20.746588	48.009690	-	1.632549	3.777881	-
Gunfleet	22.325054	20.587704	3.847960	24.232095	22.346339	4.176659	1.907041	1.758635	0.328699
Gwynt y mor	24.497892	24.220627	-	26.282176	25.984717	-	1.784284	1.764090	-
Hornsea 1A	8.719458	30.850803	-	9.354532	33.097796	-	0.635074	2.246993	-
Hornsea 1B	8.719458	30.850803	-	9.354532	33.097796	-	0.635074	2.246993	-
Hornsea 1C	8.719458	30.850803	-	9.354532	33.097796	-	0.635074	2.246993	-
Humber Gateway	14.417146	33.077894	-	15.467207	35.487094	-	1.050061	2.409200	-
Lincs	20.014443	78.709959	-	21.472178	84.442733	-	1.457735	5.732774	-
London Array	13.582228	46.568255	-	14.571479	49.960015	-	0.989251	3.391760	-
Ormonde	31.540966	58.956904	0.469837	34.235246	63.993096	0.509971	2.694280	5.036192	0.040134
Race Bank	11.555007	32.093562	-	12.396606	34.431070	-	0.841599	2.337508	-
Rampion	9.439328	24.692880	-	10.126833	26.491366	-	0.687505	1.798486	-
Robin Rigg	- 0.692284	39.295488	12.590025	- 0.751420	42.652171	13.665484	- 0.059136	3.356683	1.075459
Robin Rigg West	- 0.692284	39.295488	12.590025	- 0.751420	42.652171	13.665484	- 0.059136	3.356683	1.075459
Sheringham Shoal	29.509024	34.754460	0.755460	32.029732	37.723242	0.819992	2.520708	2.968782	0.064532
Thanet	22.533848	42.217215	1.016317	24.458725	45.823477	1.103133	1.924877	3.606262	0.086816
Walney 1	27.241862	54.463409	-	29.568906	59.115760	-	2.327044	4.652351	-
Walney 2	25.344557	51.578699	-	27.509530	55.984634	-	2.164973	4.405935	-
Walney 3	11.869367	24.046627	-	12.733863	25.798043	-	0.864496	1.751416	-
Walney 4	11.869367	24.046627	-	12.733863	25.798043	-	0.864496	1.751416	-
West of Duddon Sands	10.615060	52.914686	-	11.388199	56.768683	-	0.773139	3.853997	-
Westermost Rough	21.583947	36.733135	-	23.155996	39.408562	-	1.572049	2.675427	-

Please see the tables file for a full breakdown of offshore local tariffs for each of the five years.

Demand Tariffs

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

ESO

7. Demand tariffs summary

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

In this report, we have calculated and forecast demand tariffs for 2024/25 – 2028/29 which includes the implementation of CMP343: 'Transmission Demand Residual bandings and allocation' which took effect from 1st April 2023.

Table 14 Summary of demand tariffs

Non-locational Banded Tariffs	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Average (£/site/annum)		107.454341	108.055308	111.392763	113.838488	120.257821
Unmetered (p/kWh)		1.281006	1.288170	1.327957	1.357114	1.433641
Demand Residual (£m)	2,868	3,470	3,490	3,597	3,676	3,884
HH Tariffs (Locational)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**
Average Tariff (£/kW)	5.589311	6.380539	5.931152	4.918141	4.867896	4.658341
Residual (£/kW)						
EET	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**
Average Tariff (£/kW)	2.546101	2.803593	2.677215	2.321281	2.140200	2.187894
Phased residual (£/kW)	-	-	-	-	-	-
AGIC (£/kW)	2.547308	2.679246	2.740869	2.812132	2.882435	2.954496
Embedded Export Volume (GW)	7.629109	7.109080	7.722083	7.942164	9.083504	8.931698
Total Credit (£m)	19.42	19.93	20.67	18.44	19.44	19.54
NHH Tariffs (locational)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**
Average (p/kWh)	0.267067	0.304654	0.286364	0.230580	0.224899	0.201181

Since the publication of 2023/24 charging year, average HH & NHH demand tariffs have seen a small increase for 2024/25, the main driver being the increase in the total amount of revenue to be recovered through TNUoS locational element of demand tariffs. The current tariffs indicate that the HH/NHH locational tariffs will reduce year on year. HH tariffs will reduce from £6.38kW in 2024/25 to £4.65kW in 2028/29. NHH tariffs will reduce from £0.30p/kWh in 2024/25 to £0.20p/kWh in 2028/29. This is due to locational HH/NHH revenue recovery reducing year on year.

In 2024/25 it is forecast that £19.93m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £0.51m since 2023/24 charging year. This is due to an increase in the forecast charging base for Embedded Export and an increase in the average locational tariffs. The EET fluctuates marginally year on year reaching £19.54m in 2028/29. The average EET is forecast at £2.80/kW, which is an increase of £0.26/kW 2023/24 charging year. The average EET fluctuates year on year in-line with the change in Embedded Export volumes with a low of £2.14/kW in 2028/29.

8. Demand Residual Banding Tariffs

From 2024/25 onwards, we have used the agreed distribution connected bandings and unmetered demand for the demand residual tariffs. As per the CMP343 decision, we have based the banded charges for transmission connect demand on 4 bands whereby the threshold for each band is comparable to the percentiles used in the distribution level bands (LV No MIC to EHV. CMP389 was approved by OFGEM on the 15th of December 2022. The boundary between transmission bands 3 and 4 were revised from 85th to 93rd percentile. It should be noted that CMP389 will not affect the total amount of TNUoS residual revenue collected across the

population of transmission connected sites but will affect the distribution of charges between Users in TDR charging band 3 and band 4.

A breakdown of the banding thresholds, consumptions, consumption proportions and site count for the demand residual banded charges can be seen in Table TB.

Below in Table 15 are the forecast demand residual banded tariffs across each of the banding criteria. These tariffs will apply to HH and NHH demand as well the locational HH and NHH tariffs (where applicable).

Table 15 Non-Locational demand residual banded charges

Band		2024/25	2025/26	2026/27	2027/28	2028/29
Domestic	Tariff - £/Site/Day	0.122804	0.123491	0.127305	0.129745	0.137437
LV_NoMIC_1		0.062712	0.063063	0.065011	0.066257	0.070185
LV_NoMIC_2		0.285396	0.286992	0.295856	0.301526	0.319402
LV_NoMIC_3		0.680577	0.684383	0.705521	0.719041	0.761669
LV_NoMIC_4		2.113158	2.124976	2.190610	2.232590	2.364947
LV1		3.413915	3.433008	3.539042	3.606863	3.820693
LV2		6.267853	6.302908	6.497583	6.622100	7.014685
LV3		10.200939	10.257990	10.574824	10.777476	11.416409
LV4		22.978865	23.107381	23.821088	24.277587	25.716860
HV1		17.780681	17.880125	18.432380	18.785611	19.899299
HV2		57.233281	57.553373	59.330998	60.467996	64.052784
HV3		112.375399	113.003889	116.494188	118.726641	125.765237
HV4		285.210732	286.805849	295.664290	301.330294	319.194375
EHV1		134.582173	135.334860	139.514886	142.188499	150.618009
EHV2		661.728347	665.429240	685.982047	699.127960	740.575098
EHV3		1,334.256581	1,341.718768	1,383.159819	1,409.666197	1,493.236920
EHV4		3,633.571743	3,653.893466	3,766.749595	3,838.934229	4,066.521803
T-Demand1		346.713214	348.652301	359.420964	366.308778	388.025047
T-Demand2		1,431.991398	1,440.000193	1,484.476818	1,512.924798	1,602.617109
T-Demand3		3,990.924147	4,013.244459	4,137.199697	4,216.483504	4,466.453728
T-Demand4		10,429.434588	10,487.763993	10,811.694742	11,018.886172	11,672.130384
Unmetered demand				**p/kWh**		
Unmetered		1.281006	1.288170	1.327957	1.357114	1.433641
Demand Residual (£m)		**3,470.11**	**3,489.52**	**3,597.30**	**3,676.28**	**3,883.59**

The above tariffs are calculated based on the approved published distribution banding thresholds (LV No MIC through to EHV) for RIIO-2 and as per the decision of CMP343, there are 4 transmission connected bands. The thresholds for the T-connected bands are based on average transmission connected consumption data from 2020/21 to 2021/22 and the sites connected over that time. The transmission thresholds were refined for 2023/24 Final tariffs with CMP389 being approved by OFGEM. The consumption, consumption proportions and site counts used in the calculation of the above tariffs and are based on the out-turn data from 2021/22 provided by the DNO/IDNO's latest submission in October/November 2022. We will be provided with the out-turn data for 2022/23 by the DNO/IDNO's in October 2023. The transmission connected out-turn demand data for 2022/23 which the ESO produces will also be made available at the same time. These updated values will be included in the Final tariffs for 2024/25. We currently have no mechanism for forecasting future consumption and site counts across demand residual bands, therefore the only impact on the annual variance in tariffs is the change in the revenue to be recovered through demand residual, which can be seen at the bottom of the above table.

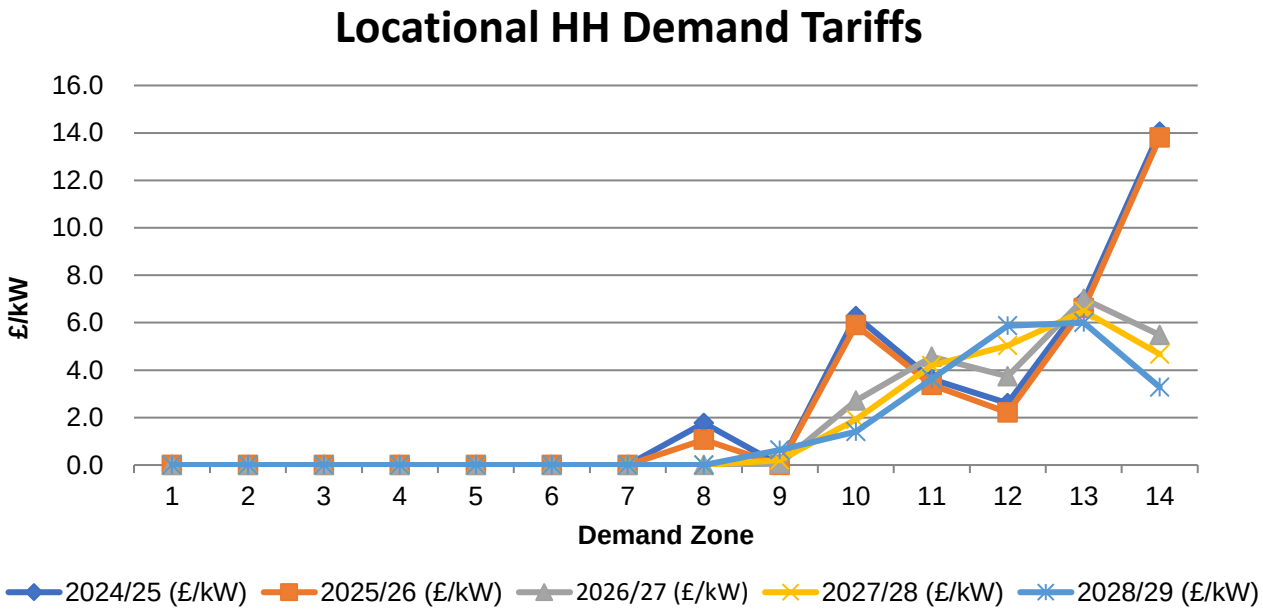
9. Half-Hourly demand tariffs

The table and figure below show the locational HH demand tariffs by demand zone for 2024/25 to 2028/29

Table 16 Half-Hourly demand tariffs

Zone	Zone Name	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	2028/29 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	-	-	-	-	-
8	Midlands	1.763180	1.068878	-	-	-
9	Eastern	-	-	0.052917	0.209739	0.637507
10	South Wales	6.278841	5.896957	2.719665	1.912830	1.401975
11	South East	3.623300	3.375723	4.556362	4.203869	3.629039
12	London	2.609311	2.214430	3.737599	5.037798	5.864258
13	Southern	6.926894	6.619773	7.002205	6.490086	6.000318
14	South Western	14.042811	13.802001	5.484301	4.668582	3.275265

Figure 4 Changes to Locational HH Demand tariffs



The HH tariff (£/kW) will continue to be based on average demand taken over the triad periods but will only be reflective of the zonal locational demand tariffs. As such, the majority of the HH revenue would be collected through the demand residual banded tariffs on a fixed £ per site per day basis.

In 2024/25 the average locational HH tariffs is forecast at £6.38/kW, which will then decrease to £4.65/kW in 2028/29.

As per CMP343 decision tariffs are now floored at £0/kW from 2023/24 onwards with locational tariffs being floored at £0/kW, demand zones 1 to 7 and zone 9 are set to £0/kW for 2024/25 and 2025/26. By 2026/27 zones 1 to 8 will be floored at £0/kW with zone 9 increase back to a positive value. Small fluctuations can be seen in the remaining zones that have not been floored. These fluctuations are within the normal bounds, but due to the removal of the residual element these variations will be more prominent in comparison.

10. Embedded Export Tariffs (EET)

The Embedded Export Tariff is designed to make credit payment to embedded generators (who are not eligible to be charged generation TNUoS tariffs with TEC lower than 100MW) for their metered exports over the triad periods.

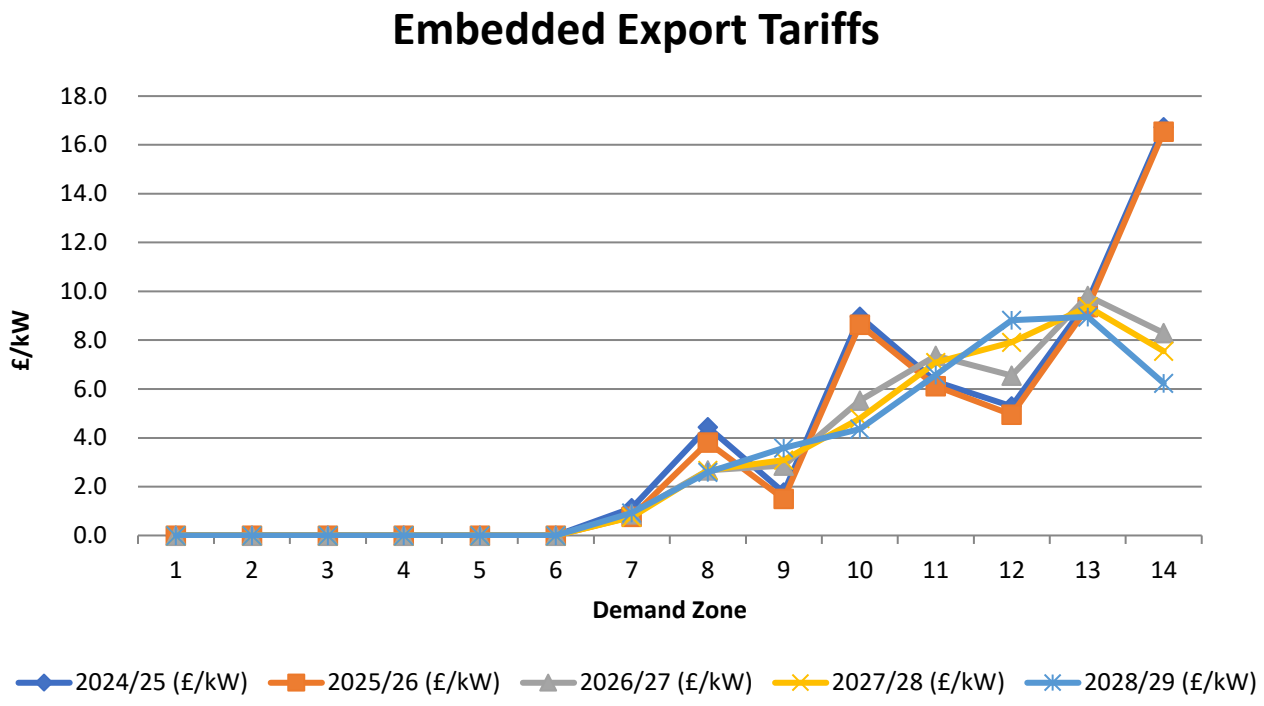
These embedded generators are paid either directly by the ESO or through their supplier when the initial demand reconciliation has been completed in accordance with CUSC (see 14.17.19 onwards). The payment to the EET is recovered through demand revenue, which will affect the price of HH and NHH demand tariffs. There is no direct impact to the EET, through the implementation of the TDR demand residual charging banding methodology.

The table below shows the forecasted Embedded Export Tariffs by zone in the years 2024/25 to 2028/9.

Table 17 Embedded Export Tariffs

Zone	Zone Name	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	2028/29 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	1.116608	0.766376	0.872950	0.752346	0.921762
8	Midlands	4.442426	3.809747	2.667411	2.668943	2.591426
9	Eastern	1.769153	1.507452	2.865049	3.092174	3.592003
10	South Wales	8.958087	8.637826	5.531797	4.795265	4.356471
11	South East	6.302546	6.116592	7.368494	7.086304	6.583535
12	London	5.288557	4.955299	6.549731	7.920233	8.818754
13	Southern	9.606140	9.360642	9.814337	9.372521	8.954814
14	South Western	16.722057	16.542870	8.296433	7.551017	6.229761

Figure 5 Embedded export tariffs changes



In this forecast of the EET, one of the key changes is the continuing inflation of the AGIC. In 2024/25 the AGIC is forecast at £2.67/kW (an increase of £0.13/kW from 2023/24 final tariffs), increasing to £2.95/kW by 2028/29. The fluctuation in the demand locational tariffs over the next 5 years also play their part, as well the changes in the forecast of embedded export. In 2024/25 the average EET is forecast at £2.80/kW, which is an increase of £0.26/kW in comparison to 2023/24 Final tariffs. Over the 5 years the average EET will reduce from £2.80/kW in 2024/25 to £2.19/kW in 2028/29.

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

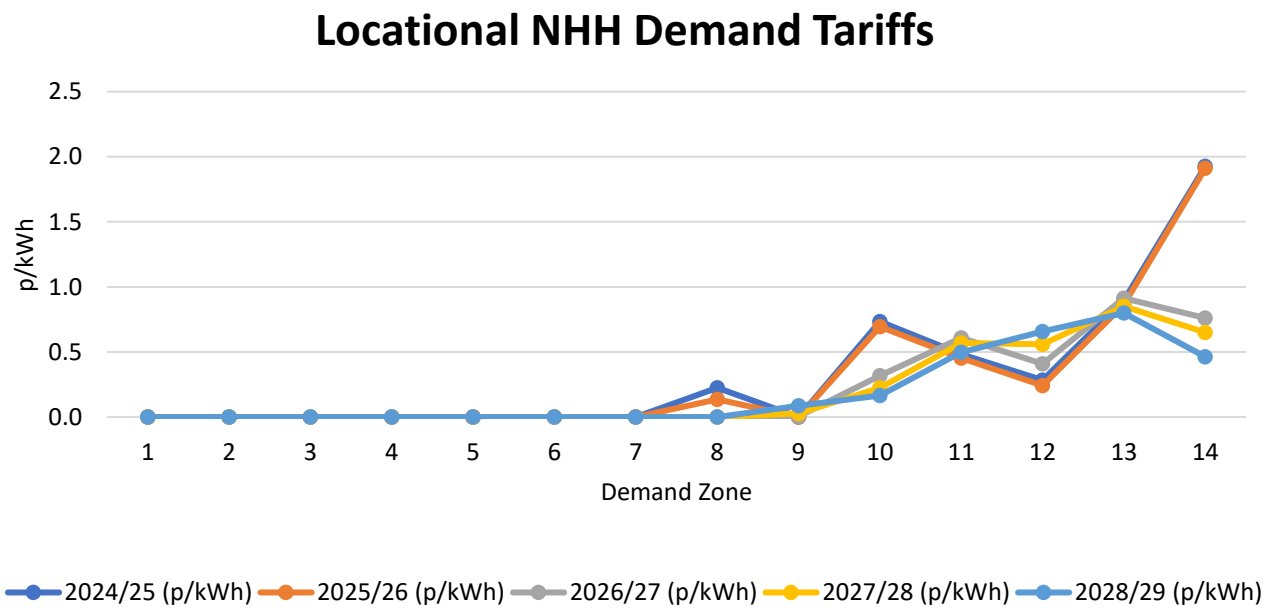
11. Non-Half-Hourly demand tariffs

NHH demand will continue to be subject to a p/kWh charge based on their consumption between 4pm-7pm every day of the year as they are currently. The amount paid will be significantly reduce due to the removal of the demand residual from the tariff calculation. As with locational HH demand tariffs, NHH tariffs will be floored at 0p/kWh which can be seen in Table 18. The additional £ per site per day charge through the banded residual charges will also apply to NHH demand where applicable.

Table 18 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2024/25 (p/kWh)	2025/26 (p/kWh)	2026/27 (p/kWh)	2027/28 (p/kWh)	2028/29 (p/kWh)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	-	-	-	-	-
8	Midlands	0.224463	0.137521	-	-	-
9	Eastern	-	-	0.007201	0.028560	0.087993
10	South Wales	0.733922	0.693944	0.319452	0.225166	0.166640
11	South East	0.484006	0.452938	0.609142	0.568071	0.496822
12	London	0.283072	0.242708	0.410134	0.558288	0.656625
13	Southern	0.896341	0.863105	0.913203	0.851039	0.799172
14	South Western	1.925577	1.910831	0.761119	0.649512	0.462259

Figure 6 Non-Half-Hourly demand tariffs changes



The average NHH tariff forecast for 2024/25 is 0.30p/kWh, a 0.04p/kWh increase compared to 2023/24 final tariffs, due to the change in NHH locational demand revenue recovery. The locational NHH tariff is forecast to reduce year-on-year through from 0.30p/kWh in 2024/25 to 0.22p/kWh in 2028/29.

The changes in locational NHH tariffs will largely be the same as the locational HH tariff and EET. As the main component of these tariffs going forward, will in most part be the impact of the locational Peak and Year-Round elements of demand. The year-on-year changes in charging base for NHH as a whole and the zonal fluctuations (4-7pm consumption) will also cause changes in the NHH tariffs, as will the proportion of NHH charging base versus the HH charging base. For example, an increase in forecast HH peak demand in a zone versus a decrease in NHH 4-7pm consumption in any given year, will increase the proportion of revenue to be recovered through locational HH demand tariff for that zone and reduce the location NHH tariff. This is also true when the scenario is reversed.

Overview of data inputs

This section explains the changes to the input data which fed into this five-year view.

ESO

12. Inputs affecting the locational element of tariffs

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

Contracted position of generation;

Nodal demand;

Local and MITS circuits;

Inflation;

Locational security factor

Expansion constant

Contracted, Modelled and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2024/25 period onwards, which can be found on the TEC register.[7] The contracted TEC volumes are based on the March 2023 TEC register.

Modelled Best View TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the Initial and August 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 TEC register as of 31st October 2023, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 2024/25 onwards and liable to pay generation TNUoS charges. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2024.

Table 19 Contracted, Modelled & Chargeable TEC

Generation (GW)	2024/25	2025/26	2026/27	2027/28	2028/29
Contracted TEC	104.55	129.90	157.47	182.71	203.93
Modelled Best View TEC	89.63	92.13	111.34	115.41	119.05
Chargeable TEC	78.00	80.51	99.21	103.29	106.92

13. Adjustments for interconnectors

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

The table below reflects the contracted position of interconnectors for 2024/25 onwards as stated in the interconnector register as of March 2023.

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

Table 20 Interconnectors

			Generation MW				
Interconnector	Node	Zone	2024/25	2025/26	2026/27	2027/28	2028/29
Aminth	NORM40	18.00	0	0	0	0	1,400
Aquind Interconnector	LOVE40	25.00	0	2,000	2,000	2,000	2,000
Auchencrosh (interconnector CCT)	AUCH20	10.00	500	500	500	500	500
Britned	GRAI40	24.00	1,200	1,200	1,200	1,200	1,200
Continental Link	BLYT4A	13.00	0	0	0	1,800	1,800
Cronos	KEMS40	24.00	0	1,400	1,400	1,400	1,400
East West Interconnector	CONQ40	16.00	505	505	505	505	505
ElecLink	SELL40	24.00	1,000	1,000	1,000	1,000	1,000
EuroLink	LEIS4A	18.00	1,600	1,600	1,600	1,600	1,600
FAB Link Interconnector	EXET40	26.00	0	1,400	1,400	1,400	1,400
Greenlink	PEMB40	20.00	504	504	504	504	504
Gridlink Interconnector	KINO40	24.00	1,500	1,500	1,500	1,500	1,500
IFA Interconnector	SELL40	24.00	2,000	2,000	2,000	2,000	2,000
IFA2 Interconnector	CHIL40	26.00	1,100	1,100	1,100	1,100	1,100
Kulizumboo Interconnector	CANT40	24.00	0	0	0	700	700
MARES	BODE40	16.00	0	750	750	750	750
Nautilus	LEIS40	18.00	0	0	0	1,500	1,500
Nemo Link	RICH40	24.00	1,020	1,020	1,020	1,020	1,020
NeuConnect Interconnector	GRAI40	24.00	1,400	1,400	1,400	1,400	1,400
NorthConnect	PEHE20	2.00	0	0	0	1,400	1,400
NS Link	BLYT4A	13.00	1,400	1,400	1,400	1,400	1,400
The Superconnection	CREB40	15.00	0	0	0	1,000	1,000
Viking Link Denmark Interconnector	BICF4A	17.00	1,500	1,500	1,500	1,500	1,500

14. Expansion Constant

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. The 2024/25 Expansion Constant is forecast to be £17.670457/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-T1 value set back in 2013/14, and will continue to increase in-line with inflation. A review of the EC methodology and the expansion factors is ongoing with the industry (CMP315/375), any impact will be included in our forecast publications if the modification is approved.

Table 21 Expansion Constant for 2024/25 to 2028/29

£/MWkm	2024/25	2025/26	2026/27	2027/28	2028/29
Expansion Constant	17.670457	18.076877	18.546876	19.010548	19.485812

15. Locational onshore security factor

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

16. Onshore substation tariffs

Local onshore substation tariffs are reviewed and updated at each price control as part of the TNUoS tariff parameter refresh. Once set for the first year of that price control, the tariffs are then indexed by the average May to October CPIH (actuals and forecast), as per the CUSC requirements, for the subsequent years within that price control period.

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

17. Offshore local tariffs

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

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

18. Allowed revenues

The majority of the TNUoS charges look to recover the allowed revenue for the onshore and offshore TOs in Great Britain. It also recovers some other revenue for example, Strategic Innovation Fund and interconnector revenue recovery or redistribution.

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

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

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

Table 22 Allowed revenues

£m Nominal	2024/25	2025/26	2026/27	2027/28	2028/29
TO Income from TNUoS					
National Grid Electricity Transmission	2,223.1	2,254.1	2,358.6	2,405.8	2,453.9
Scottish Power Transmission	500.9	517.1	533.2	543.7	554.6
SHE Transmission	979.8	985.3	989.8	1,009.6	1,029.8
Total TO Income from TNUoS	**3,703.8**	**3,756.5**	**3,881.6**	**3,959.1**	**4,038.2**
Other Income from TNUoS					
Other Pass-through from TNUoS	120.2	92.2	92.2	92.2	92.2
Offshore (plus interconnector contribution / allowance)	751.9	786.9	819.3	951.1	1,185.6
Total Other Income from TNUoS	**872.1**	**879.0**	**911.5**	**1,043.2**	**1,277.7**
Total to Collect from TNUoS	**4,575.9**	**4,635.5**	**4,793.1**	**5,002.3**	**5,316.0**

Please note these figures are rounded to one decimal place.

19. Generation / Demand (G/D) Split

The G/D split forecast is shown in Table 23.

CMP391 (definition of the term "Charges for Physical Assets Required for Connection") is incorporated in this forecast. Majority of TNUoS local charges (including onshore and offshore local charges) fall into the definition of Charges for Physical Assets Required for Connection (PARC), however, a small part of the TNUoS onshore local charges are categorised as charges associated with pre-existing assets, and are therefore not PARC.

In line with the Limiting Regulation, average TNUoS generation charge (excluding local charges associated with PARC) should be kept within the range of €0 – 2.50/MWh. Local charges associated with pre-existing assets are included when considering the expected average TNUoS generation charges. The 2024/25 figure will be refined in the next quarterly forecast.

Table 23 Generation and demand revenue proportions

Code	Revenue	2024/25	2025/26	2026/27	2027/28	2028/29
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50
y	Error Margin	23.6%	23.6%	23.6%	23.6%	23.6%
ER	Exchange Rate (€/£)	1.12	1.12	1.12	1.12	1.12
MAR	Total Revenue (£m)	4,575.87	4,635.53	4,793.12	5,002.28	5,315.95
GO	Generation Output (TWh)	189.85	188.37	203.69	207.39	207.39
G	% of revenue from generation	22.1%	22.8%	23.4%	25.0%	25.6%
D	% of revenue from demand	77.9%	77.2%	76.6%	75.0%	74.4%
G.R	Revenue recovered from generation (£m)	1,009.27	1,056.53	1,121.56	1,252.76	1,360.37
D.R	Revenue recovered from demand (£m)	3,566.60	3,578.99	3,671.56	3,749.51	3,955.59
Breakdown of generation revenue						
	Revenue from the Peak element	102.97	103.78	126.70	137.87	136.38
	Revenue from the Year Round Shared element	186.95	213.34	290.20	342.70	319.47
	Revenue from the Year Round Not Shared element	132.56	174.73	252.25	413.11	555.66
	Revenue from Onshore Local Circuit tariffs	19.60	48.36	51.68	61.88	66.53
	Revenue from Onshore Local Substation tariffs	12.03	12.43	15.31	17.05	17.90
	Revenue from Offshore Local tariffs	656.13	678.25	712.34	825.45	927.69
	Revenue from the adjustment element	-101.12	-174.50	-327.09	-545.46	-663.43
G.MAR	Total Revenue recovered from generation (£m)	1,009.27	1,056.53	1,121.56	1,252.76	1,360.37
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	3.15	4.63	6.10	6.27	6.40

The "gen cap"

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges to €0 - 2.5/MWh. The revenue that can be recovered from generation is dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin is also applied to reflect revenue and output forecasting accuracy. This revenue limit figure was referred to as the "gen cap" which is part of the UK law (the "Limiting Regulation"). In this report, the term "gen cap" is used to refer to the "upper limit of the Limiting Regulation" in the CUSC.

TNUoS generation residual (TGR) change

CUSC modification proposals CMP317/327 were approved in December 2020 and were included in the 2021/22 final tariffs. For the purpose of maintaining compliance with the Limiting Regulation (the [0 ~ €2.50]/MWh range), an adjustment tariff (in £/kW) is introduced to bring generation charge into the range, and this is known as the TGR.

Exchange Rate

The exchange rate for gen cap calculation is based on the latest Economic and Fiscal Outlook (EFO), published by the Office of Budgetary Responsibility (OBR), and published prior to 31st October. In this report, the figures were based on OBR's March EFO.

Generation Output

The forecast output of generation is the average of the four scenarios (plus the central case) in the 2022 Future Energy Scenarios. For 2024/25 tariffs, this figure will be updated in the next quarterly forecast, to be published by July.

Error Margin

The error margin for 2024/25 tariffs will be updated and finalised in the next quarterly forecast, following publication of the outturn of 2022/23 data. In this report, the error margin is the same as we used for 2023/24 tariffs, derived from historical data in the past five whole years (thus for year 2023/24, we use data from years 2017/18 – 2021/22).

Table 24 Generation revenue error margin calculation

Calculation for Data from year:	2024/25		
	Revenue inputs		Generation output variance
	Revenue variance	Adjusted variance	
2017/18	-5.2%	2.4%	-1.5%
2018/19	-9.2%	-1.6%	-7.5%
2019/20	-14.6%	-7.1%	-4.1%
2020/21	-13.2%	-5.6%	7.5%
2021/22	4.3%	11.9%	9.5%
Systemic error:	-7.6%		
Adjusted error:		11.9%	9.5%
Error margin =			23.6%

Adjusted variance = the revenue variance - systemic error
Systemic error = the average of all the values in the series
Adjusted error = the maximum of the (absolute) values in the series

Onshore local charges associated with Pre-existing assets

Following implementation of CMP391 (Charges for Physical Assets Required for Connection), we have included local charges associated with pre-existing assets in our TNUoS tariff reports. TNUoS local tariffs associated with pre-existing circuits and pre-existing substation bays are calculated separately.

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

For year 2024/25 tariffs, onshore local tariffs associated with pre-existing assets will be refined and published in the next quarterly forecast.

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

20. Charging bases for 2024/25 to 2028/29

Generation

The forecast generation charging base is less than contracted TEC. It excludes interconnectors, which are not chargeable, and generation that we do not expect to be chargeable during the charging year due to closure, termination or delay in connection. It also includes any generators that we believe may increase their TEC.

We are unable to break down our best view of generation as some of the information used to derive it could be commercially sensitive.

The generation charging base for 2024/25 tariffs is forecast to be 78GW, increasing to 106.9GW in 2028/29 and is based on our internal view of what generation we expect to connect in the next five years. The best view has been aligned to a 5-year generation forecast central case produced by FES.

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated for 2024/25 through to 2028/29.

To forecast chargeable HH and NHH demand and EET volumes, we use a Monte Carlo modelling approach. This incorporates our latest data including:

Historical gross metered demand and embedded export volumes (April 2019 -March 2023)

Weather patterns

Future demand shifts

Expected levels of renewable generation

We assume that with recent historical trends and forward-looking assumptions (excluding the impact of COVID-19) demand volumes will plateau over the next couple of years because of the downturn in the economy. Adjustments have been made in our forecast since Final forecast for 2023/24 based on the latest demand outturn data up to end of March 2023. Please refer to table TAA in the published tables spreadsheet for a detailed breakdown of the changes to the demand charging bases.

Table 25 Charging bases

Charging Bases	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Generation (GW)	75.78	78.00	80.51	99.21	103.29	106.92
NHH Demand (4pm-7pm TWh)	24.23	24.91	25.19	25.56	25.82	26.08
Gross charging						
Total Average Gross Triad (GW)	49.96	49.65	50.60	51.30	51.99	53.37
HH Demand Average Gross Triad (GW)	18.46	18.16	18.48	18.74	18.93	19.54
Embedded Generation Export (GW)	7.63	7.11	7.72	7.94	9.08	8.93

21. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2023/24 ALFs. ALFs are explained in more detail in Appendix D of this report, and the full list of power station ALFs are available on the ESO website.[8]

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

22. Generation adjustment and demand residual

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

Adjustment Tariff = (Total Money collected from generators as determined by G/D split less money recovered through location tariffs) divided by the total chargeable TEC

$$A_G = \frac{G.R - Z_G}{B_G}$$

Where:

A_G is the adjustment tariff (£/kW)

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

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

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

B_G is the generator charging base (GW)

Table 26 shows the calculation of generation adjustment tariffs, and the breakdown of demand revenue by locational and residual.

Demand residual banded charges

Through the approval and decision of CMP343 the demand residual tariff will no longer exist and will not be included in locational tariffs. The revenue to be recovered through the demand residual will now be recovered by a new set of p/site/day charges on final demand users (both HH and NHH), based on site specific banded charges starting in April 2023.

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

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

Table 26 Residual & Adjustment components calculation

Component		2024/25	2025/26	2026/27	2027/28	2028/29
G	Proportion of revenue recovered from generation (%)	22.06%	22.79%	23.40%	25.04%	25.59%
D	Proportion of revenue recovered from demand (%)	77.94%	77.21%	76.60%	74.96%	74.41%
R	Total TNUoS revenue (£m)	4,575.87	4,635.53	4,793.12	5,002.28	5,315.95
Generation revenue breakdown (without adjustment)						
ZG	Revenue recovered from the wider locational element of generator tariffs (£m)	422.5	491.8	669.2	893.7	1,011.5
O	Revenue recovered from offshore local tariffs (£m)	656.1	678.2	712.3	825.5	927.7
LG	Revenue recovered from onshore local substation tariffs (£m)	12.0	12.4	15.3	17.0	17.9
SG	Revenue recovered from onshore local circuit tariffs (£m)	19.6	48.4	51.7	61.9	66.5
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	3.1	4.6	6.1	6.3	6.4
Generation adjustment tariff calculation						
	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50
	Error Margin	23.6%	23.6%	23.6%	23.6%	23.6%
	Exchange Rate (€/£)	1.12	1.12	1.12	1.12	1.12
	Total generation Output (TWh)	189.9	188.4	203.7	207.4	207.4
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	324.50	321.97	348.16	354.48	354.48
	Adjustment Revenue (£m)	-101.1	-174.5	-327.1	-545.5	-663.4
BG	Generator charging base (GW)	78.00	80.51	99.21	103.29	106.92
AdjTariff	Generator adjusment tariff (£/kW)	-1.30	-2.17	-3.30	-5.28	-6.21
Gross demand residual						
RD	Demand residual (£m)	3,470.11	3,489.52	3,597.30	3,676.28	3,883.59
ZD	Revenue recovered from the locational element of demand tariffs (£m)	115.9	109.6	92.2	92.1	91.0
EE	Amount to be paid to Embedded Export Tariffs (£m)	-19.9	-20.7	-18.4	-19.4	-19.5

Sensitivity Analysis

ESO

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.

We asked the industry for suggestions of what sensitivities it would be helpful to see in our five-year view, we welcome the feedback received and as a result the sensitivity analysis that we have undertaken for 2024/25-2028/29 tariffs are:

1. A scenario which tests the impact of additional revenue on TDR
2. Three scenarios which test the impact of delay on construction of a new HVDC bootstrap, deferral of the new HVDC due to slow generation capacity growth, and a second additional HVDC Bootstrap for 2028/29
3. A scenario which tests the Impact of incremental transmission site per band for each forecast year.

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 several 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 the Electricity System Operator will publish at a later date.

23. Impact of additional revenue on TDR

Following analysis of the impact of revenue changes in 2028/29 and 2024/25, it was evident that the impact from an increase or decrease in revenue had the same proportional effect regardless of the year. As such, this sensitivity analysis has only been shown on the year 2024/25 to avoid repetition.

The analysis also assumes 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.

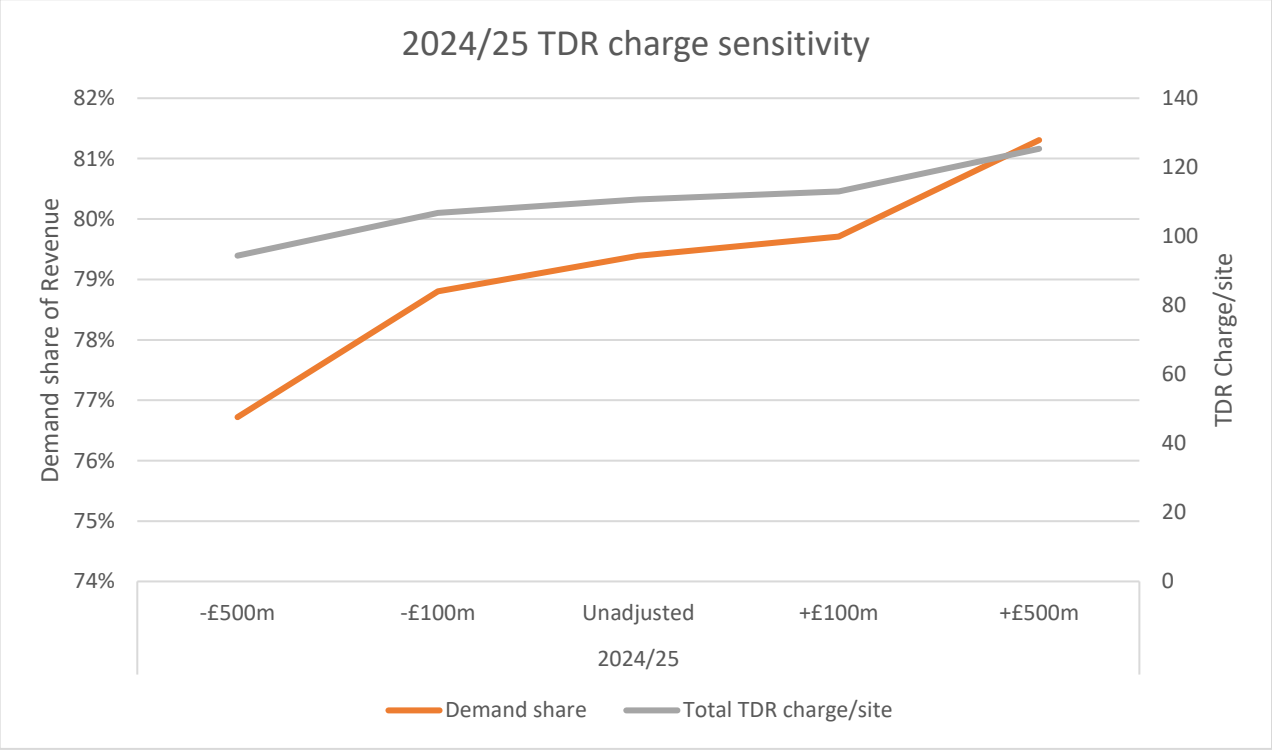
The total TDR charge/site is used as the measure because the impact on the individual site types is proportionately the same (i.e., each site increases/decreases by the same percentage).

The 2024/25 Transport and Tariff model was run five times with a -£500m adjustment, -£100m adjustment, +£100m adjustment, +£500m adjustment and then no adjustment. The results of these runs can be seen in table S1 and figure S1 below.

Table S1 Impact of additional revenue on TDR

	2024/25				
	-£500m	-£100m	Unadjusted	+£100m	+£500m
Revenue (£m)	4,075.17	4,475.17	4,575.17	4,675.17	5,075.17
Generation	7.96%	7.25%	7.09%	6.94%	6.39%
Demand share	76.72%	78.80%	79.26%	79.71%	81.31%
Total TDR charge/site	£94.39	£106.78	£109.75	£112.97	£125.36

Figure S1 Impact of additional revenue on TDR



The average 'total' TDR charge increases or decreases in line with the demand share of the revenue. As a broad rule of thumb, for every additional £100m of revenue, the average TDR charge/site will increase by ~2.8% whilst with every reduction of £100m of revenue, the average TDR charge/site will decrease by ~3%.

24. Impact of HVDC bootstraps and generation growth

HVDC bootstraps are built to increase the capacities of network bottlenecks (referred to as "ETYS boundaries" in the charging methodology). TNUoS tariffs are designed to reflect the locational difference at either side of the associated ETYS boundary, so that generators on the congested side face higher tariffs.

The TNUoS five-year view reflect the latest NOA (Network Options Assessment) report regarding future HVDC projects. In the baseline TNUoS models, a new HVDC (NOA code is E2DC) has been included for years 2027/28 and 2028/29. Using 2028/29 baseline, we have undertaken three sensitivity studies to illustrate possible tariff variations due to uncertainties–

Sensitivity S2 –

The construction of E2DC is delayed due to unexpected factors, and therefore E2DC is not in 2028/29 network.

Sensitivity S3 –

In this scenario, slower growth in generation capacity leads to deferral of E2DC. Therefore in 2028/29 model, total generation capacity north of ETYS boundary B6 (this is the boundary that E2DC is planned to add capacity to) is 2GW less than that in the baseline, and thus the 2GW HVDC link (E2DC) does not have a need case to be built by 2028/29.

Sensitivity S4 –

In this scenario, E2DC is built as per the plan. In addition, another new HVDC (NOA code E4D3, from Peterhead to Drax) is also built by 2028/29.

The following three tables show the illustrative tariffs for different generation technologies, under sensitivities S2 – S4, compared to the baseline.

Table S2 Impact of new HVDC (E2DC) construction delay

Generation Zones		2028/29 Baseline			2028/29 Sensitivity S2 (E2DC construction delay)		
Zone	Zone Name	Baseline Conventional Carbon (40%)	Baseline Conventional Low Carbon (75%)	Baseline Intermittent 45%	E2DC construction delay - Conventional Carbon (40%)	E2DC construction Delay - Conventional Low Carbon (75%)	E2DC Construction Delay -Intermittent 45%
1	North Scotland	20.663394	50.785245	40.712078	18.451577	43.821361	34.839141
2	East Aberdeenshire	15.475441	40.613022	32.404984	13.257586	33.630068	26.510328
3	Western Highlands	19.059577	45.835546	35.288163	16.855739	38.895463	29.440877
4	Skye and Lochalsh	22.776023	55.295008	44.859857	20.572097	48.354842	39.012578
5	Eastern Grampian and Tayside	15.500603	38.333987	28.879744	13.265654	31.343130	23.000496
6	Central Grampian	16.119540	37.975515	27.286399	13.939763	31.226062	21.710741
7	Argyll	17.831160	44.955856	36.143646	16.149923	38.672699	30.514367
8	The Trossachs	14.070086	33.827886	23.865487	11.946839	27.131692	18.284496
9	Stirlingshire and Fife	12.790388	32.244161	23.375374	10.587854	25.309361	17.537549
10	South West Scotlands	11.080123	29.975593	22.510794	9.172171	23.675291	17.199357
11	Lothian and Borders	9.996840	26.115980	17.883577	7.321140	17.849129	10.574139
12	Solway and Cheviot	5.722885	18.435221	12.915911	4.987867	14.595624	9.602817
13	North East England	1.902839	7.318489	1.470330	3.970606	9.841105	3.781762
14	North Lancashire and The Lakes	-0.085943	6.067199	2.699483	0.701538	5.525671	2.037818
15	South Lancashire, Yorkshire and Humber	-0.211001	2.130472	-3.122021	1.809026	4.166004	-1.584383
16	North Midlands and North Wales	-2.103568	-0.127117	-3.642250	-0.600721	1.212072	-2.359956
17	South Lincolnshire and North Norfolk	-3.793963	-2.354034	-4.350425	-1.971372	-0.483814	-2.789247
18	Mid Wales and The Midlands	-4.995043	-3.661213	-4.488477	-3.389633	-1.967897	-2.874891
19	Anglesey and Snowdon	0.533730	2.669363	-3.437587	1.586652	3.460979	-2.280842
20	Pembrokeshire	0.899412	-0.906803	-8.527287	2.329150	0.621509	-6.899041
21	South Wales & Gloucester	-4.751329	-6.814644	-8.857844	-3.320499	-5.282746	-7.226392
22	Cotswold	-4.949589	-10.105500	-15.290104	-3.512763	-8.564694	-13.658302
23	Central London	-8.256354	-7.623278	-5.641793	-6.676827	-5.916467	-3.971150
24	Essex and Kent	-7.379618	-6.088358	-4.544819	-5.796314	-4.392168	-2.898173
25	Oxfordshire, Surrey and Sussex	-7.572084	-8.776829	-7.753969	-6.068017	-7.166854	-6.116294
26	Somerset and Wessex	-4.191351	-6.057905	-8.604866	-2.743925	-4.488186	-6.946125
27	West Devon and Cornwall	-5.214470	-8.403238	-10.304856	-3.582574	-6.762671	-8.792199

Table S3 Impact of HVDC deferral and slower generation capacity growth

Generation Zones		2028/29 Baseline			2028/29 Sensitivity S3 (E2DC need case deferral)		
Zone	Zone Name	Baseline Conventional Carbon (40%)	Baseline Conventional Low Carbon (75%)	Baseline Intermittent 45%	E2DC need case deferral - Conventional Carbon (40%)	E2DC need case deferral - Conventional Low Carbon (75%)	E2DC need case deferral -Intermittent 45%
1	North Scotland	20.663394	50.785245	40.712078	18.756379	44.041136	35.023981
2	East Aberdeenshire	15.475441	40.613022	32.404984	13.579020	33.893244	26.739781
3	Western Highlands	19.059577	45.835546	35.288163	17.164631	39.122981	29.631638
4	Skye and Lochalsh	22.776023	55.295008	44.859857	20.880599	48.581268	39.202170
5	Eastern Grampian and Tayside	15.500603	38.333987	28.879744	13.581476	31.584868	23.203108
6	Central Grampian	16.119540	37.975515	27.286399	14.269385	31.482924	21.915509
7	Argyll	17.831160	44.955856	36.143646	16.484605	38.925256	30.702934
8	The Trossachs	14.070086	33.827886	23.865487	12.292246	27.420726	18.515981
9	Stirlingshire and Fife	12.790388	32.244161	23.375374	10.904902	25.554688	17.744295
10	South West Scotlands	11.080123	29.975593	22.510794	9.524993	23.958802	17.409835
11	Lothian and Borders	9.996840	26.115980	17.883577	7.638610	18.103606	10.795146
12	Solway and Cheviot	5.722885	18.435221	12.915911	5.328950	14.895486	9.856883
13	North East England	1.902839	7.318489	1.470330	4.389323	10.355862	4.249622
14	North Lancashire and The Lakes	-0.085943	6.067199	2.699483	1.026099	5.789804	2.244900
15	South Lancashire, Yorkshire and Humber	-0.211001	2.130472	-3.122021	2.057496	4.410648	-1.262796
16	North Midlands and North Wales	-2.103568	-0.127117	-3.642250	-0.297336	1.309674	-2.321608
17	South Lincolnshire and North Norfolk	-3.793963	-2.354034	-4.350425	-1.644832	-0.152657	-2.472027
18	Mid Wales and The Midlands	-4.995043	-3.661213	-4.488477	-3.037438	-1.624759	-2.574659
19	Anglesey and Snowdon	0.533730	2.669363	-3.437587	2.034741	3.764645	-2.163602
20	Pembrokeshire	0.899412	-0.906803	-8.527287	2.637993	0.876584	-6.653624
21	South Wales & Gloucester	-4.751329	-6.814644	-8.857844	-3.030172	-5.057915	-6.996054
22	Cotswold	-4.949589	-10.105500	-15.290104	-3.164286	-8.288638	-13.493254
23	Central London	-8.256354	-7.623278	-5.641793	-6.611271	-5.738899	-3.498715
24	Essex and Kent	-7.379618	-6.088358	-4.544819	-5.319758	-3.840015	-2.486429
25	Oxfordshire, Surrey and Sussex	-7.572084	-8.776829	-7.753969	-5.836599	-6.942894	-5.811335
26	Somerset and Wessex	-4.191351	-6.057905	-8.604866	-2.450101	-4.236970	-6.686358
27	West Devon and Cornwall	-5.214470	-8.403238	-10.304856	-3.456890	-6.553114	-8.369816

Table S4 Impact of the second new HVDC bootstrap (E4D3)

Generation Zones		2028/29 Baseline (with E2DC)			2028/29 Sensitivity S4 (additional HVDC (E4D3))		
Zone	Zone Name	Baseline Conventional Carbon (40%)	Baseline Conventional Low Carbon (75%)	Baseline Intermittent 45%	Additional HVDC E4D3 - Conventional Carbon (40%)	Additional HVDC E4D3 - Conventional Low Carbon (75%)	Additional HVDC E4D3 - Intermittent 45%
1	North Scotland	18.517701	45.536621	36.186296	22.634724	56.412263	45.748707
2	East Aberdeenshire	14.663715	37.965661	31.407330	16.293747	41.899152	32.128522
3	Western Highlands	16.355444	41.457535	33.266693	20.759847	51.225874	40.380510
4	Skye and Lochalsh	18.852066	48.240500	40.410597	24.505176	60.713975	49.951797
5	Eastern Grampian and Tayside	16.823597	38.967749	28.805760	17.992033	44.449122	33.864239
6	Central Grampian	15.083835	36.974533	28.415423	18.718369	43.532745	31.186331
7	Argyll	16.327940	44.019385	38.327277	20.801208	50.394213	39.252004
8	The Trossachs	11.967982	31.919662	25.427668	15.504845	37.524559	26.629851
9	Stirlingshire and Fife	10.580270	29.475500	23.807940	14.171177	35.966035	26.267368
10	South West Scotlands	11.191255	29.834612	23.422921	11.619811	32.004906	24.084229
11	Lothian and Borders	8.830437	24.996737	19.294493	10.265772	27.500334	18.833341
12	Solway and Cheviot	5.554225	18.240572	14.031597	5.773419	19.423818	13.633443
13	North East England	0.156824	4.914371	1.363769	1.489066	7.379901	1.487459
14	North Lancashire and The Lakes	0.276771	6.555008	3.898253	-0.567593	5.872220	2.402422
15	South Lancashire, Yorkshire and Humber	-1.145964	1.314855	-2.022201	-1.061473	1.245080	-3.910241
16	North Midlands and North Wales	-2.153687	0.380634	-1.914220	-2.742540	-0.712007	-4.303625
17	South Lincolnshire and North Norfolk	-3.962113	-1.959055	-2.631960	-4.605047	-3.208530	-5.140487
18	Mid Wales and The Midlands	-4.346778	-2.985101	-3.491929	-5.759279	-4.451576	-5.256047
19	Anglesey and Snowdon	-0.009483	2.924458	-1.400423	0.002417	2.211648	-4.073871
20	Pembrokeshire	1.835350	-0.162924	-7.900005	0.172848	-1.661229	-9.296523
21	South Wales & Gloucester	-3.261284	-5.313277	-7.969074	-5.483195	-7.573851	-9.626411
22	Cotswold	-4.551550	-8.700773	-12.183991	-5.684987	-10.877351	-16.080009
23	Central London	-7.713681	-10.631876	-10.132277	-9.177513	-8.560533	-6.397770
24	Essex and Kent	-6.133057	-6.296272	-5.540643	-8.209378	-6.929313	-5.292627
25	Oxfordshire, Surrey and Sussex	-8.277200	-10.251277	-7.868895	-8.326829	-9.543190	-8.502318
26	Somerset and Wessex	-7.081882	-9.726294	-8.730754	-4.944127	-6.833535	-9.367663
27	West Devon and Cornwall	-4.500906	-8.020746	-9.856305	-5.966186	-9.178108	-11.068039

The following charts show generation tariffs for conventional carbon (40% ALF), conventional low carbon (75% ALF) and intermittent (45%) respectively, under scenarios S2 – S4, compared to the baseline.

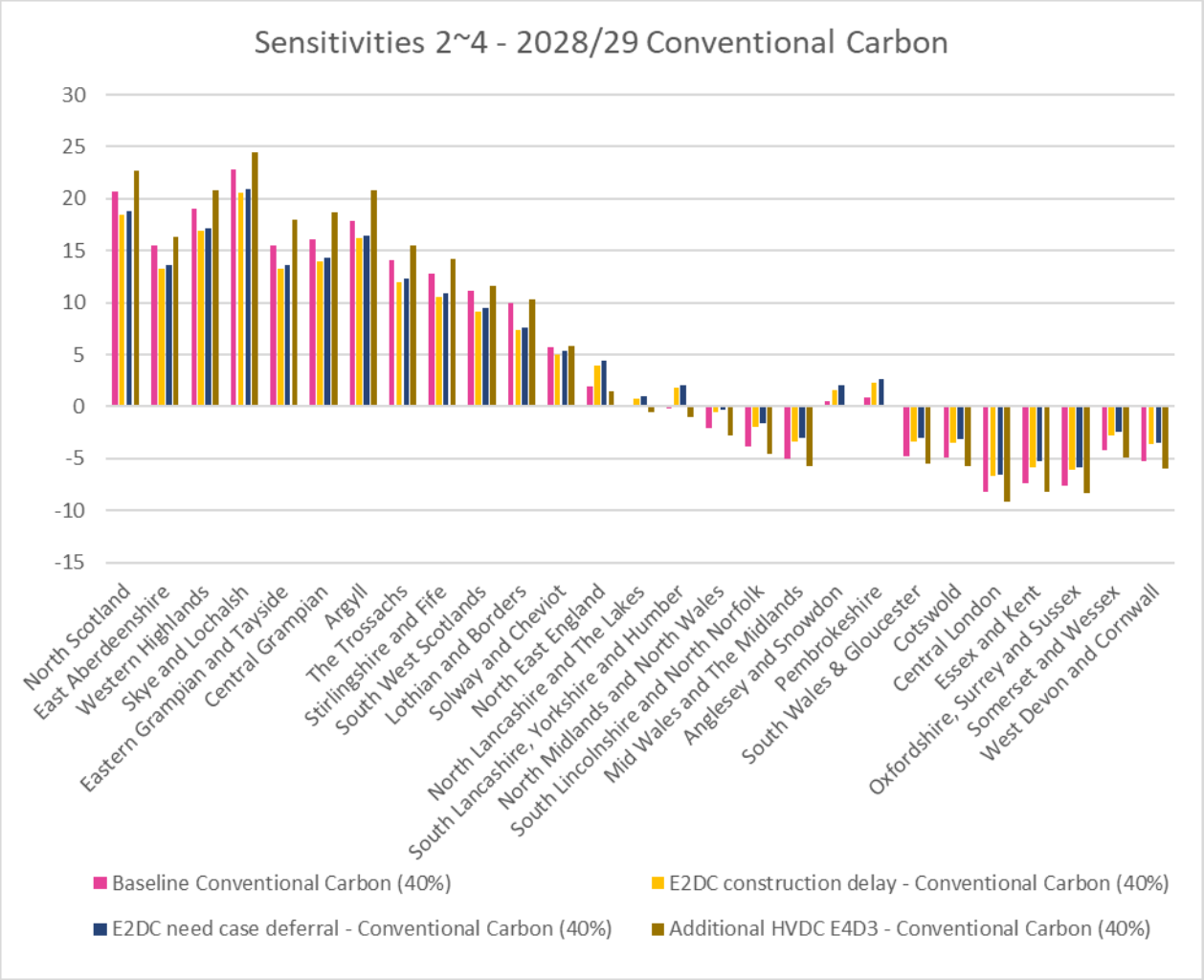


Figure CC Impact of S2 - S4 on conventional carbon generators

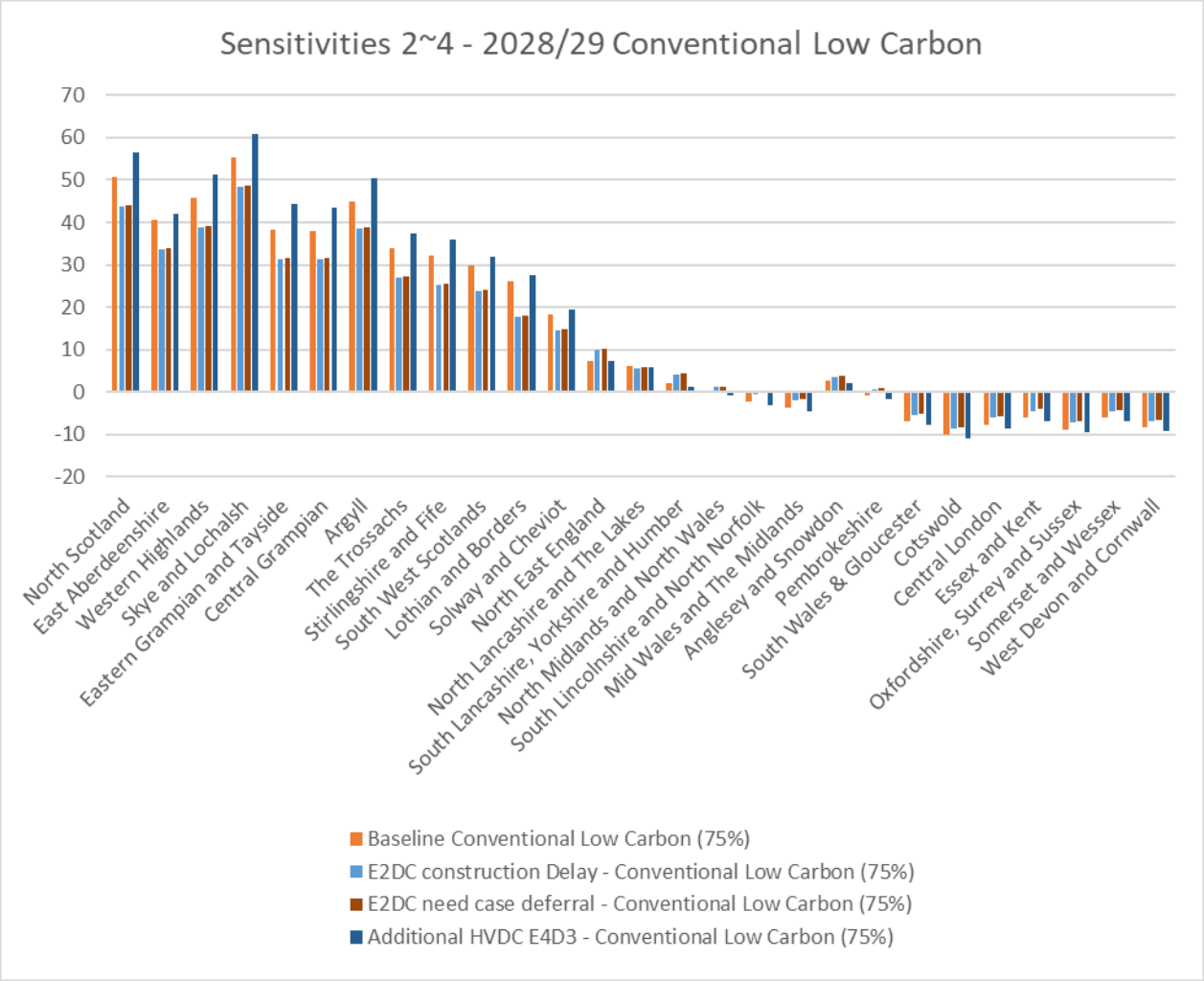


Figure CLC Impact of S2 – S4 on conventional low carbon generators

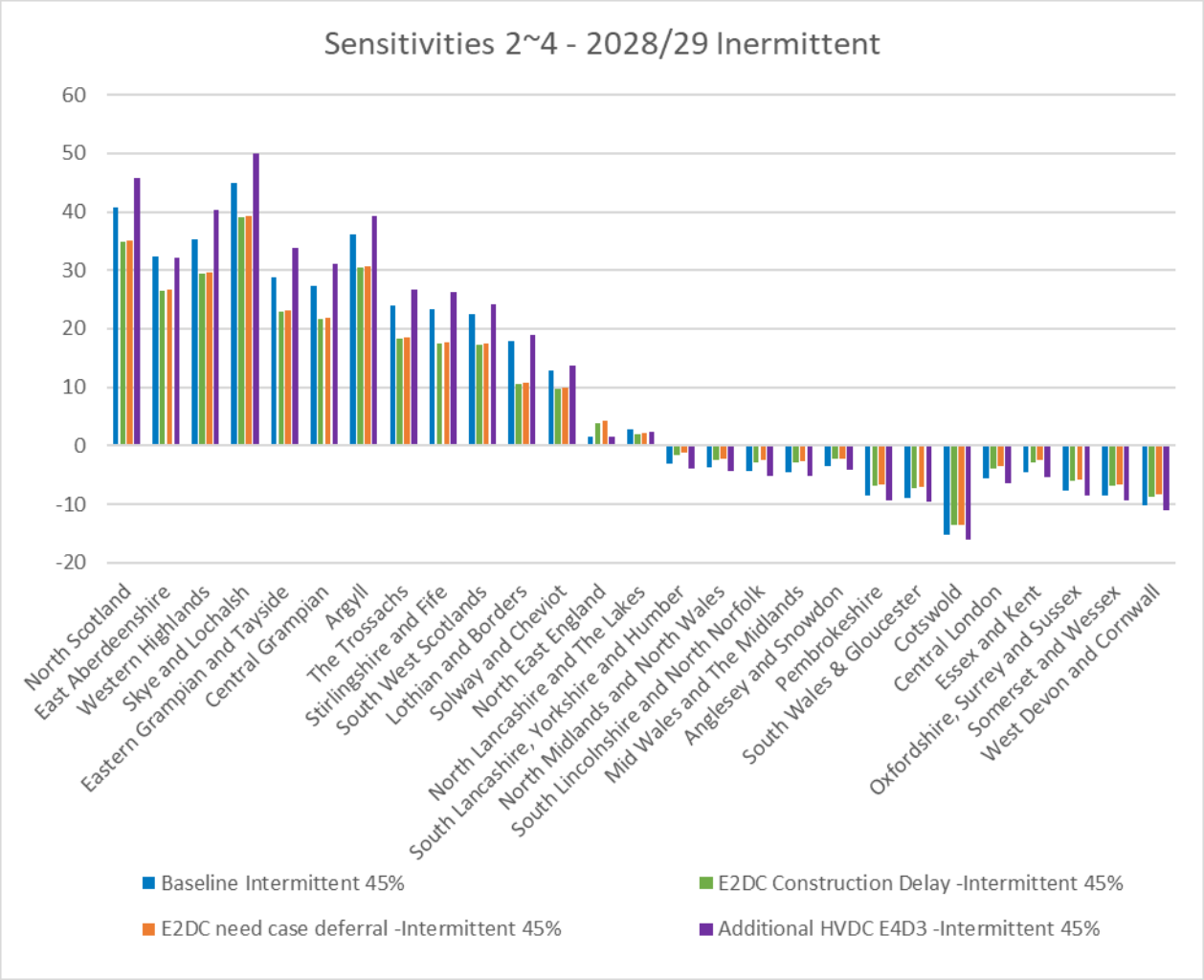


Figure I Impact of S2 – S4 on intermittent generators

Observation

Each of the two HVDC bootstraps increases the tariffs by around £5 ~ 6/kW for intermittent and conventional low carbon generators in Scotland. The impact is less pronounced for other technologies, however the polarisation of locational tariffs is the common theme. Generators in the south see slightly smaller magnitude of tariff change, due to their proximity to the virtual demand centre (the “reference node” in TNUoS methodology).

The difference between S2 and S3 is driven by 2GW of generation capacity. Compared to S2, tariffs under S3 (slower growth in generation capacity) are slightly higher across all 27 generation zones, mainly driven by the increased (less negative) generation adjustment tariffs. The 2GW of generation capacity that is not materialised under S3 (compared to S2), means revenue to be collected from generation locational tariffs is lower under S3. As the 2GW of capacities are in high tariff areas, the reduction in revenue is relatively significant, thus the predominant effect on tariffs is the reduced magnitude of negative adjustment tariff.

25. Impact of incremental transmission site per band for each forecast year.

This sensitivity looks at the impact of adding an incremental transmission site for each T-connected band for each forecast year. Each forecast year has 1 additional transmission site compared to the previous year. For example, the current forecast year 2024/25 will have 1 additional transmission site per band compared to base case, 2025 will have 2 additional sites per band compared to base case and 2028/29 will have 5 additional sites per band compared against base case. For each incremental site an average consumption per site figure was used for each band.

The greatest impact of adding in additional sites is seen in T-connected band 4. An increase of £67k per site in 2024/25 with 1 additional site added compared to current base case to a maximum increase of £208k Vs base current base case with 5 additional sites in 2028/29.

The greatest benefit in terms of reducing TDR charge per site is seen in T-connected band 3. A reduction of £19.7k in 2024/25 with 1 additional site added compared to current base case to a maximum reduction of £88.5k Vs base current base case with 5 additional sites in 2028/29.

Table S5 Impact of additional T-connected site

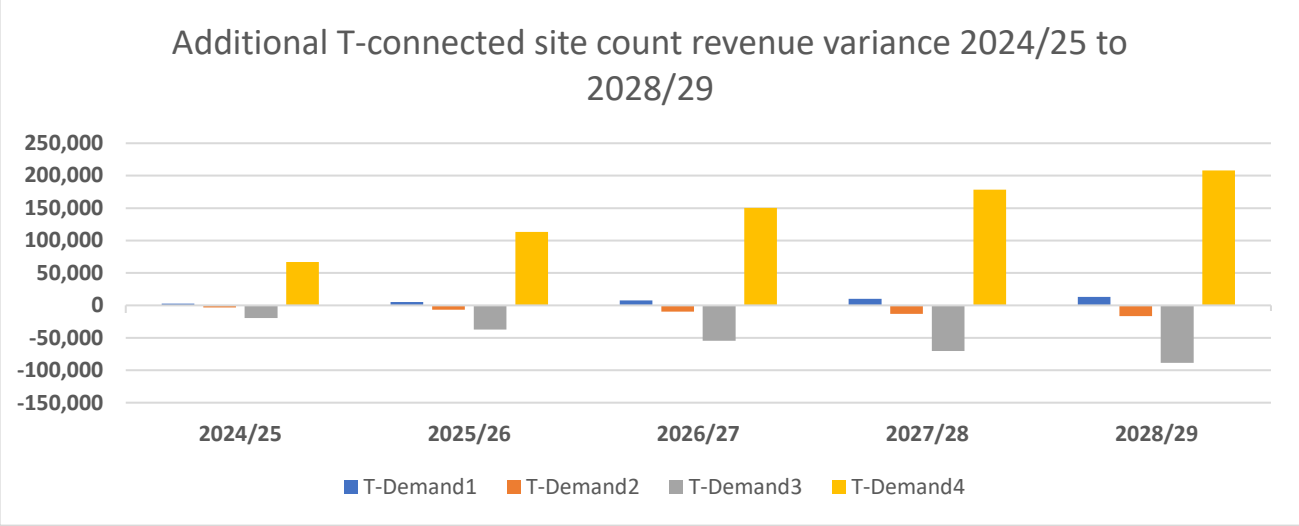
T-connected Site Count	2024/25	2025/26	2026/27	2027/28	2028/29
T-Demand1	30	31	32	33	34
T-Demand2	20	21	22	23	24
T-Demand3	14	15	16	17	18
T-Demand4	6	7	8	9	10
Total transmission sites	70	74	78	82	86

Incremental site (TDR Charge per £/site)	2024/25	2025/26	2026/27	2027/28	2028/29
T-Demand1	129,265	132,518	139,033	144,387	154,793
T-Demand2	519,300	519,055	532,061	540,845	568,464
T-Demand3	1,436,957	1,427,519	1,455,579	1,472,824	1,541,805
T-Demand4	3,873,617	3,941,178	4,096,477	4,211,369	4,468,295

Current 5yv view (TDR Charge per £/site)	2024/25	2025/26	2026/27	2027/28	2028/29
T-Demand1	126,550	127,258	131,189	134,069	141,629
T-Demand2	522,677	525,600	541,834	553,730	584,955
T-Demand3	1,456,687	1,464,834	1,510,078	1,543,233	1,630,256
T-Demand4	3,806,744	3,828,034	3,946,269	4,032,912	4,260,328

Variance (TDR Charge per £/site)	2024/25	2025/26	2026/27	2027/28	2028/29
T-Demand1	2,715	5,260	7,844	10,318	13,164
T-Demand2	-3,377	-6,545	-9,773	-12,885	-16,492
T-Demand3	-19,730	-37,315	-54,499	-70,409	-88,450
T-Demand4	66,873	113,144	150,208	178,457	207,968

Figure S2 Impact of additional T-connected site count TDR charge per site variance 2024/25 to 2028/29.



Tools and supporting information

ESO

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

Charging webinars

We will be hosting a webinar for the Five-Year View on Wednesday 10th May. We will be sending out a communication to those who subscribe to our updates via the ESO website, providing details on the upcoming webinar and how to register. For any questions, please see our contact details below.

Charging model copies available

If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website:

https://www.nationalgrideso.com/document/279556/download

This data can also be accessed via our Data Portal:

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

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

Contact Us

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

Appendix A: Background to TNUoS charging

ESO

Background to TNUoS charging

The ESO sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, ESO determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: Peak Demand and Year Round, where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced. To calculate flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on 'standard' conditions, which means that they reflect the cost of replacing assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" elements are included in the generation and demand tariffs. The demand residual banded charges for demand, and adjustment tariff for generation, is also used to ensure the correct proportion of revenue is collected from demand and generation. The locational and adjustment tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff. Since April 2023, demand has a locational HH and NHH demand tariffs split across demand zones and with approval of CMP343 'demand residual banded charges' the demand residual element is charged across a range of banded annual site charges for HH and NHH demand.

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

Generation charging principles

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

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

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

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

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

Local Tariffs*

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

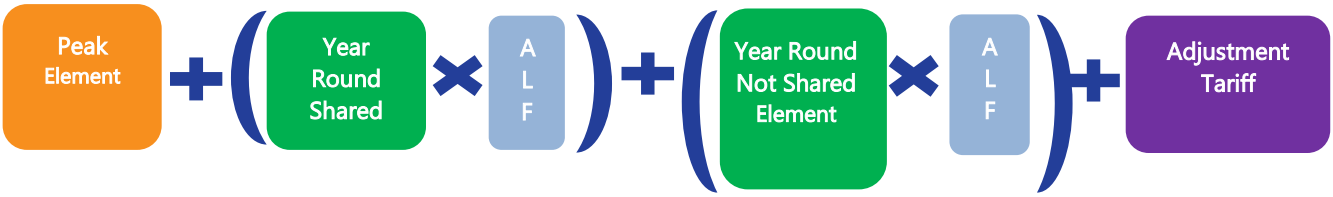
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

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

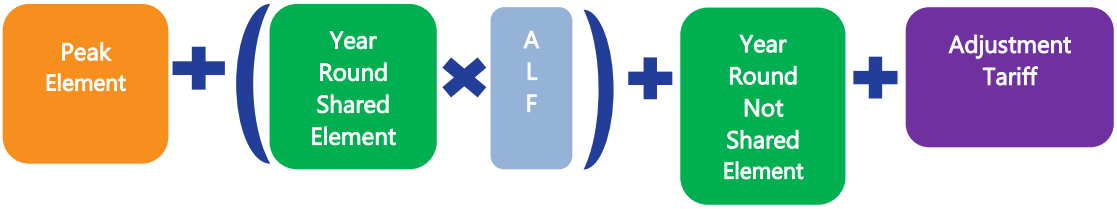
Conventional Carbon Generators

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



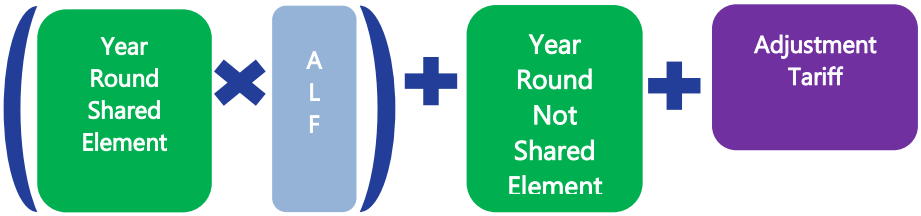
Conventional Low Carbon Generators

(e.g. Hydro, Nuclear)



Intermittent Generators

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



The **Peak** element reflects the cost of using the system at peak times. This is only paid by conventional and peaking generators; intermittent generators do not pay this element.

The **Year Round Shared** and **Year Round Not Shared** elements represent the proportion of transmission network costs shared with other zones, and those specific to each particular zone respectively.

ALFs are calculated annually using data available from the most recent charging year. Any generator with fewer than three years of historical generation data will have any gaps filled using the generic ALF calculated for that generator type.

The **Adjustment Tariff** is a flat rate for all generation zones which adds a non-locational charge (which may be positive or negative) to the Wider TNUoS tariff, to ensure that the correct amount of aggregate revenue is collected from generators as a whole.

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

Local substation tariffs

A generator will have a charge depending on the first onshore substation on the transmission system to which it connects. The cost is based on the voltage of the substation, whether there is a single or double ('redundancy') busbar, and the volume of generation TEC connected at that substation.

Local onshore substation tariffs are set at the start of each TO financial regulatory period and increased by CPIH for each year within the price control period.

Local circuit tariffs

If the first onshore substation which the generator connects to is categorised as a MITS (Main Interconnected Transmission System) node in accordance with CUSC 14.15.33, then there is no Local Circuit charge. Where the first onshore substation is not classified as MITS node, there will be a specific circuit charge for generators connected at that location.

Embedded network system charges

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

Transmission-connected offshore generators connecting to an embedded OFTO may need to pay an Embedded Transmission Use of System charge through TNUoS tariffs to cover DNO charges that form part of the OFTO's tender revenue stream.

Click here to find out more about DNO regions.

Offshore local tariffs

Where an offshore generator's connection assets have been transferred to the ownership of an OFTO (Offshore Transmission Owner), there will be additional **Offshore substation** and **Offshore circuit** tariffs specific to that Offshore Generator.

Billing

TNUoS is charged annually and costs are calculated on the highest level of TEC held by the generator during the year. (A TNUoS charging year runs from 1 April to 31 March). This means that if a generator holds 100MW in TEC from 1 April to 31 January, then 350MW from 1 February to 31 March, the generator will be charged for 350MW of TEC for that charging year.

The calculation for TNUoS generator monthly liability is as follows:

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

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

TNUoS charges are billed on the first of each month, for the month in question.

[9] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: https://www.nationalgrid.com/uk/electricity/connections/applying-connection

[10] Distribution network Use of System charges

Generators with negative TNUoS tariffs

Where a generator's specific tariff is negative, the generator will be paid during the year based on their highest TEC for that year. After the end of the year, there is a reconciliation, when the true amount to be paid to the generator is recalculated.

The value used for this reconciliation is the average output of the individual generator over the three settlement periods of highest output between 1 November and the end of February of the relevant charging year. Each settlement period must be separated by at least ten clear days. Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

For more details, please see CUSC section 14.18.13–17.

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers have two specific tariffs following the implementation of CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff. With the implementation of CMP343, the demand residual element of the demand charges are split out (previously included in the HH and NHH locational charges) and an additional set off banded charges are to apply to HH and NHH demand.

HH gross demand tariffs

HH gross demand tariffs are made up of locational charges which are currently charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.[11] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data are available, via the ESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[12], however this will need to be updated with the introduction of CMP343 and the demand residual banded charges. This guidance will be updated in due course.

Embedded Export Tariffs (EET)

The EET was introduced under CMP264/265 and is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

This tariff contains the locational demand elements and an Avoided GSP Infrastructure Credit. The final zonal EET is floored at £0/kW for the avoidance of negative tariffs and is applied to the metered triad volumes of embedded exports for each demand zone. The money to be paid out through the EET will be recovered through demand tariffs.

Customers must now submit forecasts for both HH gross demand and embedded export volumes. Customers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon (up to 16 months after the financial year in question).

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

Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by the ESO. Payments for embedded exports from SVA registered embedded generators will be paid to their registered supplier.

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

11 https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data
12 https://www.nationalgrideso.com/document/130641/download
13 https://www.nationalgrideso.com/charging/charging-guidance

NHH demand tariffs

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

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

Demand residual banded charges

CMP343 was approved by OFGEM, this related to the Targeted Charging Review Significant Code Review. The new demand residual banded charging methodology has been implemented since April 2023. The demand residual banded charges will now make up majority of the TNUoS demand charge in the form of a set of daily charge per site across the banding categories and thresholds.

Appendix B: Proposed changes to the charging methodology

ESO

Proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2024/25 – 2028/29. Each modification is subject to an approval decision by Ofgem and if any Work Group Alternative CUSC Modifications (WACM) have been raised then Ofgem will decide which, if any, are approved.

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

https://www.nationalgrideso.com/uk/electricity/codes/connection-and-use-system-code?mods

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

Table 27 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP286/287	Improving TNUoS Predictability Through Increased Notice	Increase notice period of tariff setting input data	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
CMP288/289	Explicit charging arrangements for customer delays and backfeeds (CMP288) and consequential change (CMP289)	Potential impact on non-locational tariffs only#	
CMP292	Introducing a Section 8 cut-off date for changes to the Charging Methodologies	Introducing a cut off date for implementation of CUSC changes affecting tariffs	
CMP315/375	Expansion Constant & Expansion Factors review	Affect TNUoS locational tariffs for generators and demand users	
CMP316	TNUoS Arrangements for Co-located Generation Sites	Affect TNUoS locational tariffs	
CMP330/374	Allowing new Transmission Connected parties to build Connection Assets greater than 2km in length	Change CUSC section 14 to enable connection assets greater than 2km in length	
CMP331	Option to replace generic Annual Load Factors (ALFs) with site specific ALFs	Introduce an option for site specific ALFs	
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.	
CMP379	CMP379: Determining TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)	Determine demand zones for transmission-connected demand users at multiple DNO sites	
CMP393	Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage	Change ALF calculation methodology	

CMP405	TNUoS Locational Demand Signals for Storage	Change demand locational tariffs so they are not floored at zero	
CMP411	Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies	Introduce Anticipatory Investment (AI) and a mechanism for the recovery of AI costs within the Section 14 charging methodologies	
CMP413	Rolling 10-year wider TNUoS generation tariffs	Seeks to introduce an obligation on the ESO to publish generation tariffs for a rolling 10-year duration	

Appendix C: Breakdown of locational HH and EE tariffs

ESO

Locational components of demand tariffs

The following tables show the locational components of the HH demand charge (Peak and Year-Round) for each year of the forecast. With the introduction of CMP343 and the removal of the demand residual (demand residual tariff) from HH tariffs, the locational elements combined which make up the HH demand tariff have been floored to £0/kW where only positive tariffs are applied

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

Table 28 Location elements of the HH demand tariff for 2024/25

Demand Zone		2024/25		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.709210	-34.479070	0.000000
2	Southern Scotland	-2.363530	-23.246140	0.000000
3	Northern	-2.724913	-10.441542	0.000000
4	North West	-0.845292	-6.114376	0.000000
5	Yorkshire	-1.747052	-3.913080	0.000000
6	N Wales & Mersey	-1.794419	-3.004907	0.000000
7	East Midlands	-2.268629	0.705991	0.000000
8	Midlands	-1.120264	2.883444	1.763180
9	Eastern	0.268640	-1.178732	0.000000
10	South Wales	-3.014696	9.293537	6.278841
11	South East	3.345551	0.277749	3.623300
12	London	3.230126	-0.620816	2.609311
13	Southern	2.044662	4.882232	6.926894
14	South Western	3.787237	10.255574	14.042811

Table 29 Location elements of the HH demand tariff for 2025/26

Demand Zone		2025/26		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.865752	-35.958148	0.000000
2	Southern Scotland	-2.363123	-24.837521	0.000000
3	Northern	-2.821137	-11.537855	0.000000
4	North West	-0.659832	-7.639216	0.000000
5	Yorkshire	-1.831016	-4.893797	0.000000
6	N Wales & Mersey	-1.718302	-4.575850	0.000000
7	East Midlands	-1.843242	-0.131251	0.000000
8	Midlands	-0.822467	1.891345	1.068878
9	Eastern	-0.299064	-0.934353	0.000000
10	South Wales	-3.190044	9.087001	5.896957
11	South East	2.982128	0.393595	3.375723
12	London	2.682122	-0.467692	2.214430
13	Southern	1.779162	4.840611	6.619773
14	South Western	3.700523	10.101479	13.802001

Table 30 Location elements of the HH demand tariff for 2026/27

Demand Zone		2026/27		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.444560	-37.771821	0.000000
2	Southern Scotland	-2.481344	-26.241606	0.000000
3	Northern	-3.035670	-12.138320	0.000000
4	North West	-0.757638	-8.296366	0.000000
5	Yorkshire	-2.549427	-5.027408	0.000000
6	N Wales & Mersey	-1.078096	-6.023838	0.000000
7	East Midlands	-1.411993	-0.527190	0.000000
8	Midlands	-0.962785	0.818065	0.000000
9	Eastern	0.347330	-0.294413	0.052917
10	South Wales	-4.670493	7.390158	2.719665
11	South East	3.541320	1.015042	4.556362
12	London	3.462181	0.275418	3.737599
13	Southern	1.914167	5.088038	7.002205
14	South Western	-0.426860	5.911161	5.484301

Table 31 Location 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	-1.373233	-48.605771	0.000000
2	Southern Scotland	-1.723326	-36.453925	0.000000
3	Northern	-2.553343	-12.001491	0.000000
4	North West	0.074028	-10.037844	0.000000
5	Yorkshire	-1.918439	-5.605311	0.000000
6	N Wales & Mersey	-0.108724	-7.208109	0.000000
7	East Midlands	-1.216125	-0.913964	0.000000
8	Midlands	-0.451081	0.237588	0.000000
9	Eastern	0.247548	-0.037810	0.209739
10	South Wales	-4.262080	6.174910	1.912830
11	South East	2.860508	1.343361	4.203869
12	London	3.868916	1.168882	5.037798
13	Southern	1.058917	5.431169	6.490086
14	South Western	-3.608875	8.277456	4.668582

Table 32 Location 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	-1.789535	-49.518472	0.000000
2	Southern Scotland	-1.867287	-37.446600	0.000000
3	Northern	-2.390117	-12.438320	0.000000
4	North West	0.183935	-10.003819	0.000000
5	Yorkshire	-1.524725	-6.154877	0.000000
6	N Wales & Mersey	-0.868934	-6.818132	0.000000
7	East Midlands	-1.151300	-0.881434	0.000000
8	Midlands	-0.667625	0.304555	0.000000
9	Eastern	0.793668	-0.156162	0.637507
10	South Wales	-4.807106	6.209081	1.401975
11	South East	2.777315	0.851724	3.629039
12	London	4.643355	1.220903	5.864258
13	Southern	0.866520	5.133798	6.000318
14	South Western	-4.519391	7.794655	3.275265

Appendix D: Annual Load Factors

ESO

ALFs

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

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

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

Generic ALFs

Table 33 Generic ALFs

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

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

These Generic ALFs are calculated in accordance with CUSC 14.15.111.

Appendix E: Contracted generation

ESO

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

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 here , https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-chargesunder 5-Year View Tariff Publications. The data in Table 34 is taken from the TEC register from March 2023. The contracted generation used in the Transport model will be fixed in the November Draft forecast of 2024/25 tariffs, using the TEC register as of 31 October 2023, as stated by the CUSC 14.15.6.

Table 34 Contracted TEC by generation zone

Zone	Zone Name	2024/25 (MW)	2025/26 (MW)	2026/27 (MW)	2027/28 (MW)	2028/29 (MW)
1	North Scotland	3,779	4,501	5,561	7,884	8,488
2	East Aberdeenshire	2,080	2,080	2,080	3,585	3,585
3	Western Highlands	513	513	614	1,226	1,226
4	Skye and Lochalsh	41	41	91	331	331
5	Eastern Grampian and Tayside	1,628	1,628	1,877	1,877	2,223
6	Central Grampian	64	64	64	64	64
7	Argyll	166	216	574	574	724
8	The Trossachs	520	520	520	560	560
9	Stirlingshire and Fife	920	920	1,120	1,620	2,236
10	South West Scotland	3,608	3,692	4,327	4,926	5,292
11	Lothian and Borders	5,218	7,398	10,489	12,928	15,657
12	Solway and Cheviot	501	1,001	1,137	1,440	2,240
13	North East England	5,249	8,034	8,894	11,459	11,459
14	North Lancashire and The Lakes	4,189	4,189	4,389	4,389	4,789
15	South Lancashire, Yorkshire and Humber	14,604	14,837	19,677	22,427	24,577
16	North Midlands and North Wales	11,309	12,159	14,441	17,997	20,483
17	South Lincolnshire and North Norfolk	6,601	9,621	11,901	12,301	12,661
18	Mid Wales and The Midlands	10,633	14,571	19,988	23,229	27,539
19	Anglesey and Snowdon	2,001	2,151	2,511	2,511	3,551
20	Pembrokeshire	2,703	2,703	3,839	3,839	4,486
21	South Wales & Gloucester	1,963	2,612	2,832	2,832	4,964
22	Cotswold	1,411	1,411	1,461	1,461	1,531
23	Central London	240	847	847	854	854
24	Essex and Kent	16,641	20,689	20,942	21,949	22,009
25	Oxfordshire, Surrey and Sussex	2,905	5,164	7,221	7,835	8,035
26	Somerset and Wessex	3,817	7,091	8,831	9,571	11,021
27	West Devon and Cornwall	1,242	1,243	1,243	3,043	3,343

Appendix F: Transmission company revenues

ESO

Transmission Owner revenue forecasts

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

Revenue for offshore networks is included with forecasts by ESO where the Offshore Transmission Owner has yet to be appointed.

Notes:

All monies are quoted in millions of pounds, accurate to two decimal place and are in nominal 'money of the day' prices unless stated otherwise.

All reasonable care has been taken in the preparation of these illustrative tables and the data therein. ESO and TOs offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither ESO nor TOs accept or assume responsibility for the use of this information by any person or any person to whom this information is shown or any person to whom this information otherwise becomes available.

ESO TNUoS revenue pass-through items forecasts

From April 2019, a new, legally separate electricity system operator (ESO) was established within National Grid Group, separate from National Grid Electricity Transmission (NGET). As a result, the allowed TNUoS revenue under NGET's licence, is collected by ESO and passed through to NGET, in the same way to the arrangement with Scottish TOs and OFTOs.

In addition, ESO collects the Strategic Innovation Fund (SIF), and passes through the money to network licensees (including TOs, OFTOs and DNOs). There are also a few miscellaneous pass-through items that had been collected by NGET under its licence condition, and this function was also transferred to ESO. The revenue breakdown table below shows details of the pass-through TNUoS revenue items under ESO's licence conditions.

At this point in time, ESO components are not anticipated to vary across the years with the exception of the Network Innovation Competition Fund (NICFt) and the Strategic Innovation Fund (SIFt). NICFt payments are still being made due to the way the funds are administered but are believed to reduce with an eventual end in 2024/25. SIFt payments are expected to continue increasing as more projects begin and reach the next stage of funding (which increases as the project matures). These values will be reviewed again in the July forecast.

Table 35 ESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through				
	2024/25	2025/26	2026/27	2027/28	2028/29
Embedded Offshore Pass-Through (OFETt)	0.70	0.70	0.70	0.70	0.70
Network Innovation Competition Fund (NICFt)	3.00	0.00	0.00	0.00	0.00
Strategic Innovation Fund (SIFt)	45.50	45.50	45.50	45.50	45.50
The Adjustment Term (ADJt)	0.00	0.00	0.00	0.00	0.00
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	764.80	868.18	911.43	1,056.00	1,185.57
Interconnectors CACM Cost Recovery (ICPt)	-12.88	-81.29	-92.08	-104.93	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	0.00	0.00
Termination Sums (TSt)	25.00	0.00	0.00	0.00	0.00
NGET revenue pas-through (NGETTOt)*	2,223.09	2,254.07	2,358.60	2,405.77	2,453.89
SPT revenue pass-through (TSPt)	500.87	517.09	533.22	543.68	554.56
SHETL revenue pass-through (TSHt)	979.83	985.32	989.80	1,009.60	1,029.79
ESO Bad debt (BDt)	3.58	3.58	3.58	3.58	3.58
ESO other pass-through items (LFt + ITCt etc)	42.38	42.38	42.38	42.38	42.38
ESO legacy adjustment (LARt)	0.00	0.00	0.00	0.00	0.00
Total	**4,575.87**	**4,635.53**	**4,793.12**	**5,002.28**	**5,315.95**

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their final revenue breakdown. They include updates in correction term data and refreshed forecasts of interest rates.

All three TOs expect their revenues to increase between 2024/25 to 2028/29. The total TNUoS revenue is forecast at £4.58bn for FY24/25, (an increase of £159m from 2023/24). This is set to increase to £5.31bn in 2028/29.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2024/25 is forecast to be £839.9m, increasing by £291m to £1,185.6m in 2028/29. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to the latest RPI data (as part of the calculation of the inflation term, as defined in the relevant OFTO licence). The 2024/25 forecast includes £163.7m of forecast revenue (19% of total) for OFTOs yet to asset transfer whilst 2028/29 includes £414.6m of revenue (35% of total) for OFTOs yet to asset transfer.

Interconnector adjustment

Since year 2018/19, under CMP283, TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework, and interconnectors' Cap & Floor framework.

In 2022, Ofgem approved an offer from National Grid Ventures (NGV) to make payments of £200 million to consumers over the following two years[14], this was largely comprised of early payments under the cap and floor regulatory regime for electricity interconnectors. This enables interconnectors, under cap & floor arrangements, to make payments of above cap revenues significantly earlier than originally planned, which will offset TNUoS revenue and thus contribute to reducing consumer energy costs. NGV delivered that commitment (comprising payments for IFA, IFA2 and Nemo Link) through payments to consumers via TNUoS in 2023/24.

[14] https://www.nationalgrid.com/ofgem-enables-national-grid-make-early-payment-interconnector-revenues-helping-reduce-household

Table 36 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission				
			2024/25	2025/26	2026/27	2027/28	2028/29
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	283.31	283.31
Inflation		PI_t	352.77	351.18	358.20	365.37	372.68
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,840.10	1,865.44	1,865.44	1,865.44	1,865.44
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.00	0.00	0.00
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**2,291.27**	**2,312.35**	**2,358.60**	**2,405.77**	**2,453.89**
SONIA	B1	It-1	0.05	0.05	0.04	0.04	0.04
Allowed Revenue	B2	ARt-1	2,397.06	2,223.09	2,254.07	2,299.15	2,345.13
Recovered Revenue	B4	RRt-1	2,397.06	2,223.09	2,254.07	2,299.15	2,345.13
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00	0.00
Legacy MOD	C2	LMODt	-56.66	-58.28	0.00	0.00	0.00
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00	0.00
Legacy TRU term	C4	LTRUt	-11.52	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	0.00	0.00
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**-68.18**	**-58.28**	**0.00**	**0.00**	**0.00**
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**2,223.09**	**2,254.07**	**2,358.60**	**2,405.77**	**2,453.89**

Table 37 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission				
			2024/25	2025/26	2026/27	2027/28	2028/29
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	283.31	283.31
Inflation		PI_t	352.77	351.18	353.72	360.65	367.87
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	412.42	427.09	427.09	427.09	427.09
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.00	0.00	0.00
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**513.55**	**529.40**	**533.22**	**543.68**	**554.56**
SONIA	B1	It-1	0.05	0.05	0.04	0.04	0.04
Allowed Revenue	B2	ARt-1	0.00	0.00	0.00	0.00	0.00
Recovered Revenue	B4	RRt-1	0.00	0.00	0.00	0.00	0.00
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00	0.00
Legacy MOD	C2	LMODt	-12.06	-12.41	0.00	0.00	0.00
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00	0.00
Legacy TRU term	C4	LTRUt	-0.70	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.09	0.09	0.00	0.00	0.00
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**-12.67**	**-12.31**	**0.00**	**0.00**	**0.00**
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**500.87**	**517.09**	**533.22**	**543.68**	**554.56**

Table 38 SHETL revenue breakdown

Transmission Revenue Forecast			SHE Transmission				
			2024/25	2025/26	2026/27	2027/28	2028/29
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	283.31	283.31
Inflation		PI_t	352.77	351.18	351.18	351.18	351.18
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	772.70	782.84	798.50	814.47	830.76
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.00	0.00	0.00
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**962.16**	**970.39**	**989.80**	**1,009.60**	**1,029.79**
SONIA	B1	It-1	0.05	0.05	0.04	0.04	0.04
Allowed Revenue	B2	ARt-1	859.13	979.83	985.32	1,122.40	1,235.40
Recovered Revenue	B4	RRt-1	859.13	979.83	985.32	1,122.40	1,235.40
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00	0.00
Legacy MOD	C2	LMODt	14.50	14.92	0.00	0.00	0.00
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00	0.00
Legacy TRU term	C4	LTRUt	3.17	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00	0.00	0.00	0.00
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00	0.00
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	0.00	0.00
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**17.68**	**14.92**	**0.00**	**0.00**	**0.00**
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**979.83**	**985.32**	**989.80**	**1,009.60**	**1,029.79**

Table 39 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	Year						
Regulatory Year	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Notes
Barrow	7.8	8.5	8.7	9.0	9.3	9.7	Current revenues plus indexation
Gunfleet	9.7	10.6	11.0	11.3	11.7	12.1	Current revenues plus indexation
Walney 1	17.8	19.2	19.8	20.5	21.2	21.9	Current revenues plus indexation
Robin Rigg	10.9	11.8	12.3	12.7	13.1	13.5	Current revenues plus indexation
Walney 2	18.3	19.8	20.5	21.2	22.0	22.7	Current revenues plus indexation
Sheringham Shoal	26.7	29.1	30.2	31.2	32.2	33.3	Current revenues plus indexation
Ormonde	16.2	17.8	18.4	19.0	19.6	20.3	Current revenues plus indexation
Greater Gabbard	37.0	39.7	41.3	43.0	43.2	44.0	Current revenues plus indexation
London Array	52.6	55.9	57.7	59.7	61.7	63.8	Current revenues plus indexation
Thanet	24.0	26.0	27.0	27.9	28.3	29.0	Current revenues plus indexation
Lincs	34.0	37.6	38.8	40.2	41.5	42.9	Current revenues plus indexation
Gwynt y mor	37.6	37.6	38.9	40.3	41.7	43.2	Current revenues plus indexation
West of Duddon Sands	28.5	30.7	31.7	32.8	34.0	35.1	Current revenues plus indexation
Humber Gateway	15.0	16.0	16.5	17.1	17.7	18.3	Current revenues plus indexation
Westermost Rough	16.5	17.8	18.4	19.0	19.7	20.3	Current revenues plus indexation
Burbo Bank	16.4	17.6	18.2	18.9	19.5	20.2	Current revenues plus indexation
Dudgeon	22.6	24.4	25.2	26.1	27.0	27.9	Current revenues plus indexation
Race Bank	32.5	35.0	36.1	37.4	38.7	40.1	Current revenues plus indexation
Galloper	20.1	21.6	22.3	23.1	23.9	24.7	Current revenues plus indexation
Walney 3	15.9	17.1	17.6	18.3	18.9	19.5	Current revenues plus indexation
Walney 4	15.9	17.1	17.6	18.3	18.9	19.5	Current revenues plus indexation
Hornsea 1A	20.6	22.3	23.0	23.8	24.7	25.5	Current revenues plus indexation
Hornsea 1B	20.6	22.3	23.0	23.8	24.7	25.5	Current revenues plus indexation
Hornsea 1C	20.6	22.3	23.0	23.8	24.7	25.5	Current revenues plus indexation
Beatrice	24.4	26.6	27.4	28.4	29.3	30.3	Current revenues plus indexation
Rampion	17.4	19.5	20.1	20.8	21.5	22.2	Current revenues plus indexation
East Anglia 1	47.4	52.5	54.2	56.0	57.9	59.8	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2023/24	109.4	144.3	148.6	153.1	157.7	162.4	NGESO Forecast
Forecast to asset transfer to OFTO in 2024/25		19.4	20.4	21.1	21.7	22.3	NGESO Forecast
Forecast to asset transfer to OFTO in 2025/26			0.0	0.0	0.0	0.0	NGESO Forecast
Forecast to asset transfer to OFTO in 2026/27				13.8	29.2	30.1	NGESO Forecast
Forecast to asset transfer to OFTO in 2027/28					100.9	135.1	NGESO Forecast
Forecast to asset transfer to OFTO in 2028/29						64.6	NGESO Forecast
Offshore Transmission Pass-Through (B7)	**736.3**	**839.9**	**868.2**	**911.4**	**1,056.0**	**1,185.6**	

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

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

Appendix G: Generation zones map

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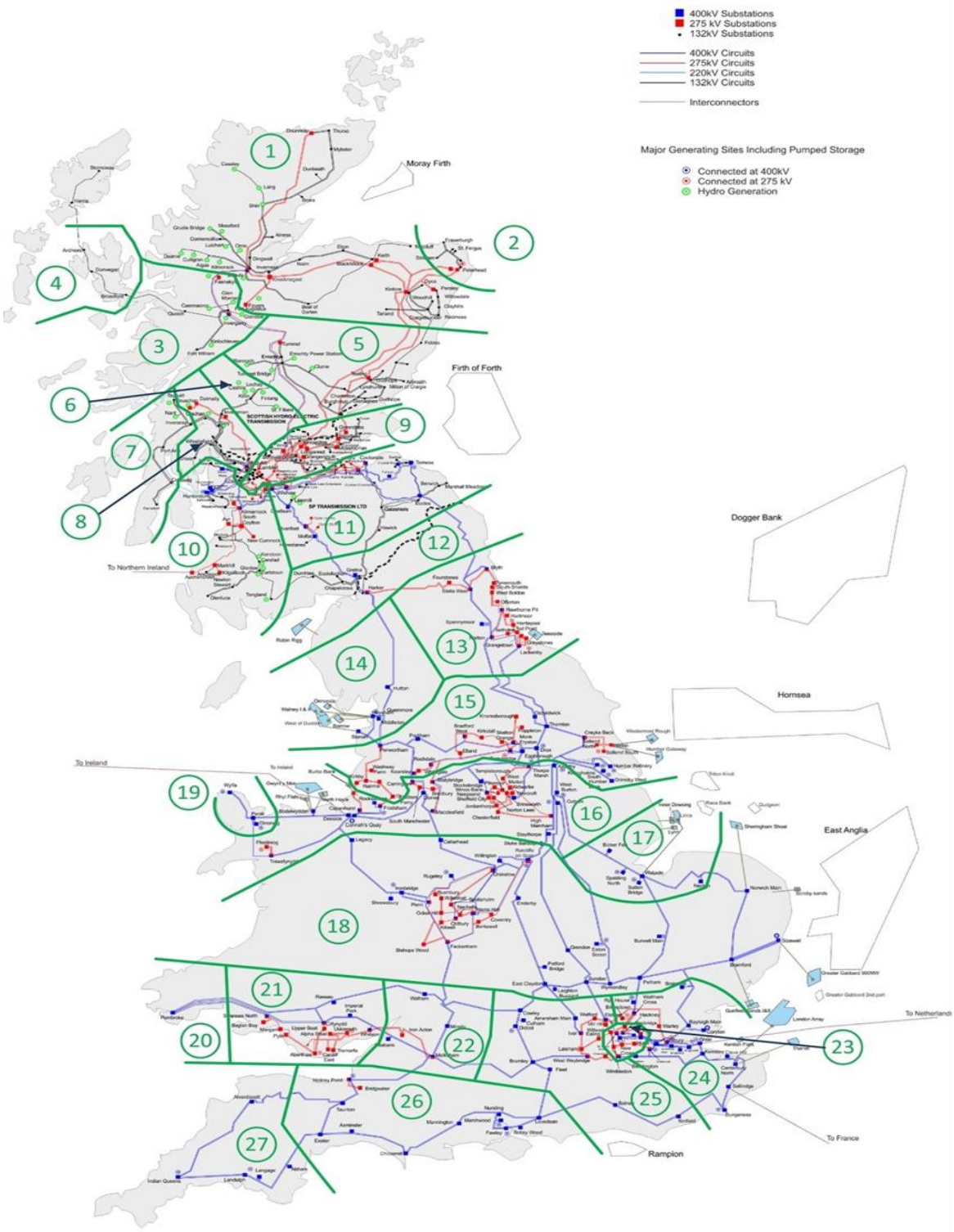
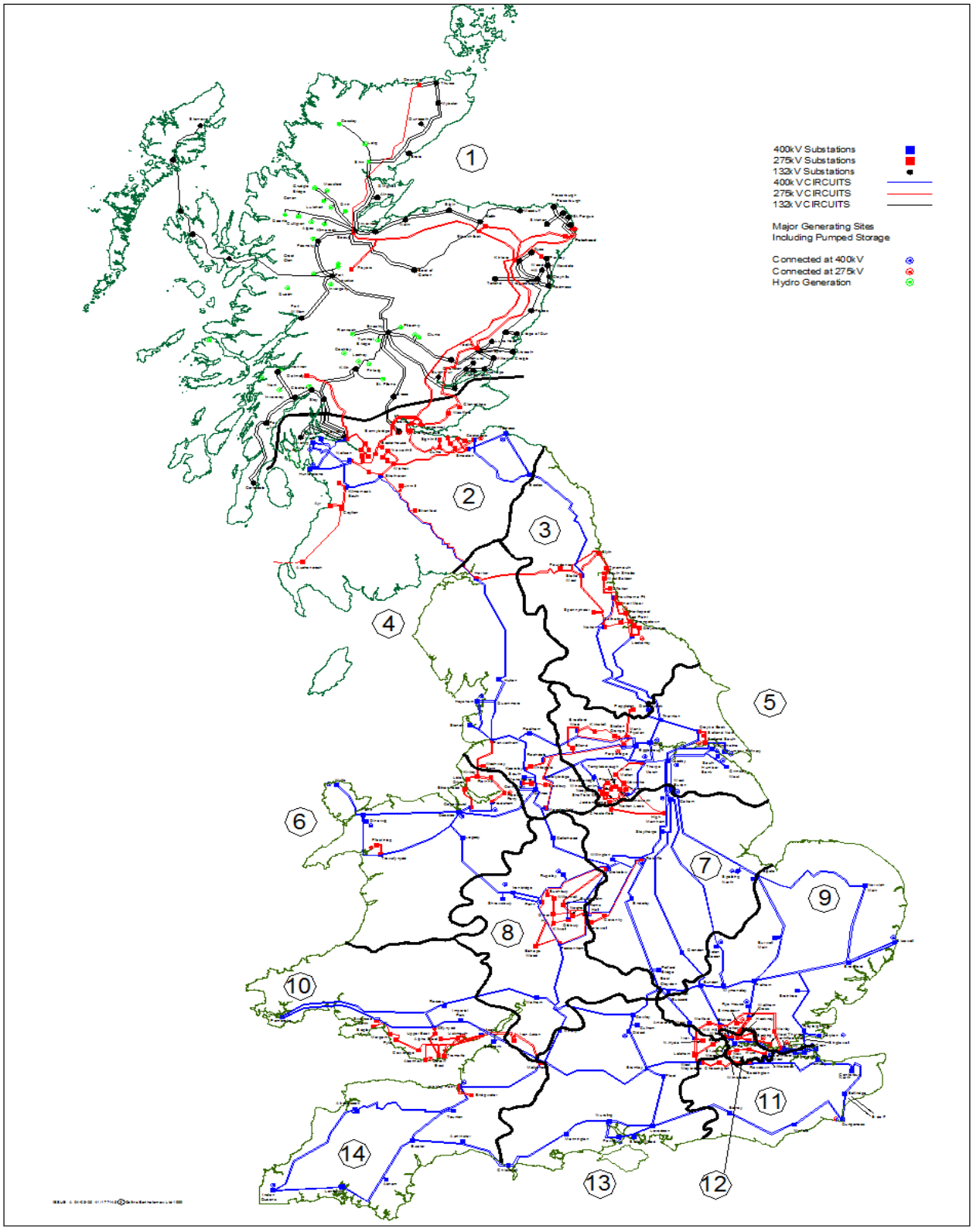
Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to ETYS 2022 Appendix A

Appendix H: Demand zones map

ESO


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
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Appendix I: Changes to TNUoS parameters

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

<table>
<tr><th colspan="6">2024/25 TNUoS Tariff Forecast</th></tr>
<tr><th colspan="2"></th><th>April 2023</th><th>July 2023</th><th>Draft Tariffs November 2023</th><th>Final Tariffs January 2024</th></tr>
<tr><td colspan="2">Methodology</td><td colspan="4">Open to industry governance</td></tr>
<tr><td rowspan="4">LOCATIONAL</td><td>DNO/DCC Demand Data</td><td colspan="2">Initial update using previous year's data source</td><td>Week 24 updated</td><td></td></tr>
<tr><td>Contracted TEC</td><td>Latest TEC Register</td><td>Latest TEC Register</td><td>TEC Register Frozen on 31 October</td><td></td></tr>
<tr><td>Network Model</td><td colspan="2">Initial update using previous year's data source (except local circuit changes which are updated quarterly)</td><td>Latest version based on ETYS</td><td></td></tr>
<tr><td>Inflation</td><td colspan="3">forecast</td><td>Actual</td></tr>
<tr><td rowspan="7">RESIDUAL / ADJUSTMENT</td><td>OFTO Revenue (part of allowed revenue)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>NG best view</td></tr>
<tr><td>Allowed Revenue (non OFTO changes)</td><td>Initial update using previous year's data source</td><td>Update financial parameters</td><td>Latest TO forecasts</td><td>From TOs</td></tr>
<tr><td>Demand Charging Bases</td><td>Initial update using previous year's data source</td><td>Revised forecast</td><td>Revised forecast</td><td>Revised by exception</td></tr>
<tr><td rowspan="2">Banding Data</td><td colspan="2" rowspan="2">Previous year's data source</td><td>DNO/IDNO consumption and site data updated</td><td></td></tr>
<tr><td>Transmission Data updated</td><td>Transmission Data finalised</td></tr>
<tr><td>Generation Charging Base</td><td>NG best view</td><td>NG best view</td><td>NG best view</td><td>NG final best view</td></tr>
<tr><td>Generation ALFs</td><td colspan="2">Previous year's data source</td><td>Draft ALFs published</td><td>Final ALFs published</td></tr>
<tr><td>Generation Revenue (G/D split)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>Generation revenue £m fixed</td></tr>
</table>

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA

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