Public

Issue	Revision
7.4	0

The Statement of Use of System Charges
Effective from 1 April 2025

Based Upon:

The Statement of the Connection Charging Methodology

and

The Statement of the Use of System Charging Methodology

contained within

Section 14 Parts I and II respectively

of the Connection and Use of System Code

NESO
National Energy System Operator

Contents

Introduction

This charging statement is published annually in accordance with the National Energy System Operator's (NESO) Electricity System Operator Licence.

This document sets out the annual Transmission Network Use of System (TNUoS) tariffs and charges for 2025/26 and the parameters used to calculate these. This document also includes the Application Fees charged by NESO in relation to applications for connection, use of system and engineering works.

You can find further information on the methodology we use and principles which we derive the TNUoS and Connection charges in Section 14 of the Connection and Use of System Code (CUSC) – the **Statement of the Use of System Charging Methodology.** The CUSC is available on our website at:

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

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Schedule 1 - Transmission Network Use of System Charge (TNUoS)

1. Basis of 2025/26 Transmission Network Use of System Charges

The Transmission Network Use of System Charges for 2025/26 published in this document have been calculated using the methodology described in the Statement of Use of System Charging Methodology. The Onshore generation and demand tariff calculations utilises a Direct Current Load Flow (DCLF) Investment Cost Related Pricing (ICRP) transport and tariff model. Offshore Local Tariffs are calculated at the time of asset transfer and are increased by indexation each year. Offshore Local Tariffs, Onshore Local Substation Tariffs and several of the parameters used in tariff setting are also recalculated at the start of each price control.

Four TNUoS charging methodology changes have been approved by Ofgem, each with the implementation date of 1 April 2025, and have therefore been implemented in the 2025/26 tariffs, where applicable[1]. These are:

- CMP392: ‘Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation’
- CMP411: ‘Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies’
- CMP424: ‘Amendments to Scaling Factors used for Year-Round TNUoS Charges’
- CMP430: ‘Adjustments to TNUoS Charging from 2025 to support the Market Wide Half Hourly Settlement (MHHS) Programme’

If you would like further details on how the TNUoS tariffs have been calculated, changes that have been implemented and the parameters used to set tariffs, you can find it in our 2025/26 Final TNUoS report. The latest and historical tariff reports can be found here (click on the tab labelled “TNUoS tariffs and notification of changes”):

neso.energy/industry-information/charging/tnuos-charges

[1] Please note that CMP392 & CMP430 do not affect the calculation of TNUoS tariffs and the methodology introduced by CMP411 is only effective in the event that Ofgem determines that an offshore project includes Anticipatory Investment and consequently does not affect the calculation of 2025/26 TNUoS tariffs.

The following tables provide a summary of some of the parameters utilised to calculate tariffs.

Table 1.1: TNUoS Calculation Parameters

Parameter	Value/Basis
Transport model network, nodal generation & nodal demand data	Based upon various data sources as defined in Section 14 of the Connection and Use of System Code (CUSC)
Expansion constant	18.411714
Annuity factor	4.2%
Overhead factor	1.5%
Locational onshore security factor	1.76
Offshore civil engineering discount	0.729447

Table 1.2: Onshore Wider Cable and Overhead Line (OHL) Expansion Factors

TO Region	Cable Expansion Factor			OHL Expansion Factor		
	400kV	275kV	132kV	400kV	275kV	132kV
Scottish Hydro Electric Transmission plc	10.20	11.45	20.77	1.00	1.20	2.59
SP Transmission plc	10.20	11.45	22.58	1.00	1.20	2.87
National Grid Electricity Transmission plc	10.20	11.45	22.58	1.00	1.20	2.87

Table 1.3 Onshore Local Expansion Factors (All TO Regions)

2dp	400kV	275kV	132kV			
			Single Circuit <200MVA	Double Circuit <200MVA	Single Circuit ≥200MVA	Double Circuit ≥200MVA
Cable Expansion Factor	10.20	11.45	22.58	22.58	22.58	22.58
OHL Expansion Factor	1.00	1.20	10.33	8.38	5.91	3.95

Table 1.4 Offshore Local Expansion Factors

Power Station	Local Expansion Factor (to 2 d.p.)
Barrow	85.44
Beatrice	7.72
Burbo Bank	27.15
Dudgeon	21.04
East Anglia 1	23.64
Galloper	19.67
Greater Gabbard	50.61, 48.3
Gunfleet	96.98
Gwynt Y Mor	46.36
Hornsea 1A	21.00
Hornsea 1B	20.10
Hornsea 1C	18.38
Hornsea 2A	4.78
Hornsea 2B	4.78
Hornsea 2C	4.78
Humber Gateway	44.31
Lincs	75.52
London Array	52.89
Moray East	13.74
Ormonde	82.20
Race Bank	11.22
Rampion	33.60
Robin Rigg	336.80
Robin Rigg West	336.80
Sheringham Shoal	48.85
Thanet	81.24
Triton Knoll	17.37
Walney 1	71.22
Walney 2	63.92
Walney 3	17.69
Walney 4	21.25
West of Duddon Sands	66.60
Westermost Rough	87.12

Please note Greater Gabbard has a Local Expansion Factor for each offshore platform due to varying circuit ratings. Further Offshore Local Expansion Factors applicable to generation connecting to offshore transmission infrastructure during 2025/26 will be published in future revisions of this statement following the completion of asset transfer.

These scaling factors and generation plant types are set out in the latest Security and Quality of Supply Standard (SQSS) and are used to calculate TNUoS tariffs. Please note that following the approval of CMP424: ‘Amendments to Scaling Factors used for Year Round TNUoS Charges’, there is now a lower limit on the variable generation scaling factors used for the purpose of the Year Round background tariff calculation.

Table 1.5 Generation scaling factors for the purpose of tariff calculation

Generation Plant Type	Peak Security Background	Year-Round Background
Intermittent	Fixed (0%)	Fixed (70%)
Nuclear & CCS	Variable	Fixed (85%)
Interconnectors	Fixed (0%)	Fixed (100%)
Hydro	Variable	Variable (>10%)
Electricity Storage (including Pumped Storage)	Variable	Fixed (50%)
Peaking	Variable	Fixed (0%)
Other (Conventional)	Variable	Variable (>10%)

These categories are used to calculate the Not Shared Year-Round and Shared Year-Round tariffs. The categorisation is based on generators’ impact on the transmission network, and do not reflect carbon intensity or energy policies. “Carbon” means “flexible generators” and “Low Carbon” means “inflexible generators”.

Table 1.6 Categorisation of Low Carbon and Carbon generation

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (excl. Pumped Storage)
Biomass	Nuclear
Oil	Marine
Electricity Storage (inc. Pumped Storage)	Solar
Interconnectors	Tidal

The categorisation will be updated from time to time, to include new technologies.

2. Schedule of Transmission Network Use of System Wider Zonal Generation Charges (£/kW) in 2025/26

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.

Charges for the "Connection Exclusion" (i.e. assets built for generation connection) are not included in the €0-2.50/MWh range, whereas TNUoS local charges associated with pre-existing assets are included in the €0-2.50/MWh range.

The following table provides the Wider Zonal Generation TNUoS tariffs applicable from 1 April 2025.

Table 1.7 Wider Zonal Generation TNUoS Tariffs

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

The System Peak, Shared Year-Round and Not Shared Year-Round tariffs are locational elements that reflect the cost of providing incremental capacity to generation on an area of the main integrated onshore transmission system. The non-locational adjustment ensures that the appropriate amount of transmission revenue is recovered from generators within the generation cap of €0-2.50/MWh.

For conventional low-carbon generation technologies, the wider zonal generation tariff is the sum of the Peak Tariff, the Shared Year-Round Tariff scaled by the generator's Annual Load Factor, the Not Shared Year-Round Tariff and the Adjustment Tariff.

For conventional carbon generation technology, the wider zonal generation tariff is the sum of the Peak Tariff and the Adjustment Tariff, and the Shared Year-Round Tariff and Not Shared Year-Round Tariff scaled by the generator's Annual Load Factor (ALF).

For intermittent generation technologies, the wider zonal generation tariff is the sum of the Shared Year-Round Tariff scaled by the generator's Annual Load Factor, the Not Shared Year-Round Tariff and the Adjustment Tariff.

The 40%, 75% and 45% ALFs used in this table for the Conventional Carbon, Conventional Low Carbon and Intermittent example tariffs are for illustration only. Tariffs for individual generators are calculated using their own ALF.

Wider generation charges are charged based on which zone the transmission substation is in that the generator connects to.

3. Schedule of Annual Load Factors for 2025/26

The below tables show the final Annual Load Factors (ALFs) to be used in the calculation of generator TNUoS tariffs for 2025/26, effective from 1 April 2025.The ALFs are based on generation data for the last five years from 2019/20 until 2023/24. Where historic data is not available for a new or mothballed station, we use a generic ALF corresponding to the station's generation technology type.

Table 1.8 Annual Load Factors

Power Station	Technology	Specific ALF
ABERDEEN	Offshore_Wind	40.2451%
ACHRUACH	Onshore_Wind	35.8342%
AFTON	Onshore_Wind	38.4176%
AIKENGALL II	Onshore_Wind	36.1285%
AN SUIDHE	Onshore_Wind	37.0169%
ARECLEOCH	Onshore_Wind	24.5527%
BAD A CHEO	Onshore_Wind	39.5007%
BARROW	Offshore_Wind	36.1543%
BEATRICE	Offshore_Wind	47.3156%
BEAULY CASCADE	Hydro	33.7245%
BEECHGREEN ENERGYFARM	Solar	10.8336%
BEINNEUN	Onshore_Wind	35.3579%
BHLARAIDH	Onshore_Wind	34.0967%
BLACKLAW	Onshore_Wind	22.3611%
BLACKCRAIG WINDFARM	Onshore_Wind	44.3226%
BLACKLAW EXTENSION	Onshore_Wind	28.1226%
BRIMSDOWN	CCGT_CHP	54.3014%

Power Station	Technology	Specific ALF
BURBO BANK EXT	Offshore_Wind	43.5333%
BUSTLEHOLME	Battery	3.4148%
CAPENHURST	Battery	3.9951%
CARRAIG GHEAL	Onshore_Wind	44.3550%
CARRINGTON	CCGT_CHP	49.2223%
CLUNIE	Hydro	38.7425%
CLYDE (NORTH)	Onshore_Wind	37.3338%
CLYDE (SOUTH)	Onshore_Wind	32.2006%
CONNAHS QUAY	CCGT_CHP	18.3882%
CONON CASCADE	Hydro	51.7799%
CORBY	CCGT_CHP	0.4779%
CORRIEGARTH	Onshore_Wind	45.7447%
CORRIEMOILLIE	Onshore_Wind	30.9054%
CORYTON	CCGT_CHP	22.2077%
COTTAM DEVELOPMENT CENTRE	CCGT_CHP	57.1270%
COUR	Onshore_Wind	50.2983%
COVENTRY	Battery	4.4000%
COWES	Gas_Oil	0.1167%
COWLEY	Battery	2.8499%
CREAG RIABHACH WIND FARM	Onshore_Wind	36.4072%
CROSSDYKES	Onshore_Wind	35.3197%
CRUACHAN	Pumped_Storage	9.8602%
CRYSTAL RIG II	Onshore_Wind	44.8271%
CRYSTAL RIG III	Onshore_Wind	49.8861%
CUMBERHEAD WIND FARM	Onshore_Wind	30.9009%
DALQUHANDY WIND FARM	Onshore_Wind	35.7876%
DAMHEAD CREEK	CCGT_CHP	28.2609%
DERSALLOCH	Onshore_Wind	33.1083%
DIDCOT B	CCGT_CHP	49.0180%
DIDCOT GTS	Gas_Oil	0.1133%
DINORWIG	Pumped_Storage	8.2770%
DOGGER BANK PROJECT A	Offshore_Wind	34.8302%
DORENELL	Onshore_Wind	46.3320%
DOUGLAS WEST	Onshore_Wind	41.2485%
DRAX	Coal	42.9953%
DUDGEON	Offshore_Wind	49.5318%
DUNGENESS B	Nuclear	0.0000%
DUNLAW EXTENSION	Onshore_Wind	25.4981%
DUNMAGLASS	Onshore_Wind	43.2333%
EAST ANGLIA 1	Offshore_Wind	51.7222%
EDINBANE WIND	Onshore_Wind	30.8511%
ERROCHTY	Hydro	24.6355%
EWE HILL	Onshore_Wind	30.7996%
FALLAGO	Onshore_Wind	46.1398%
FARR WINDFARM	Onshore_Wind	39.6324%
FASNAKYLE G1 & G3	Hydro	47.0624%
FAWLEY CHP	CCGT_CHP	66.5955%
FFESTINIOG	Pumped_Storage	4.3851%
FINLARIG	Hydro	62.1034%
FOYERS	Pumped_Storage	15.4573%
FREASDAIL	Onshore_Wind	39.4536%
GALAWHISTLE	Onshore_Wind	40.7644%
GALLOPER	Offshore_Wind	52.5883%
GARRY CASCADE	Hydro	55.2644%
GLANDFORD BRIGG	CCGT_CHP	0.0411%
GLEN APP	Onshore_Wind	20.7739%

Public

Power Station	Technology	Specific ALF
GLEN KYLLACHY WIND FARM	Onshore_Wind	36.9564%
GLENDOE	Hydro	33.8377%
GLENMORISTON	Hydro	14.2709%
GORDONBUSH	Onshore_Wind	39.1189%
GRAIN	CCGT_CHP	45.8930%
GRANGEMOUTH	CCGT_CHP	49.9340%
GREAT YARMOUTH	CCGT_CHP	43.6912%
GREATER GABBARD	Offshore_Wind	43.4002%
GRIFFIN WIND	Onshore_Wind	24.0532%
GUNFLEET SANDS I	Offshore_Wind	41.8209%
GUNFLEET SANDS II	Offshore_Wind	41.1097%
GWYNT Y MOR	Offshore_Wind	38.7443%
HADYARD HILL	Onshore_Wind	30.3153%
HALSARY WIND FARM	Onshore_Wind	48.9611%
HARESTANES	Onshore_Wind	26.8445%
HARTING RIG WIND FARM	Onshore_Wind	31.0916%
HARTLEPOOL	Nuclear	70.6726%
HEYSHAM	Nuclear	68.7452%
HINKLEY POINT B	Nuclear	35.6737%
HORNSEA 1A	Offshore_Wind	50.6026%
HORNSEA 1B	Offshore_Wind	51.4636%
HORNSEA 1C	Offshore_Wind	50.9696%
HORNSEA 2A	Offshore_Wind	31.4270%
HORNSEA 2B	Offshore_Wind	35.2416%
HORNSEA 2C	Offshore_Wind	42.4739%
HUMBER GATEWAY	Offshore_Wind	46.0448%
IMMINGHAM	CCGT_CHP	53.9603%
INDIAN QUEENS	Gas_Oil	0.2408%
IRON ACTON	Solar	11.3316%
J G PEARS	CCGT_CHP	42.0329%
KEADBY	CCGT_CHP	25.2871%
KEADBY II CCGT POWER STATION	CCGT_CHP	30.1938%
KEITH HILL	Onshore_Wind	21.5750%
KEMSLEY	Battery	3.5815%
KENNOXHEAD WIND FARM EXTENSION	Onshore_Wind	31.3567%
KILBRAUR	Onshore_Wind	42.0001%
KILGALLIOCH	Onshore_Wind	40.3494%
KILLIN CASCADE	Hydro	40.5347%
KILLINGHOLME (POWERGEN)	Gas_Oil	1.3869%
KINGS LYNN A	CCGT_CHP	44.2096%
KYPE MUIR	Onshore_Wind	34.2223%
LANGAGE	CCGT_CHP	30.5705%
LINCS WIND FARM	Offshore_Wind	46.3570%
LITTLE BARFORD	CCGT_CHP	38.1756%
LOCHLUICHART	Onshore_Wind	29.9452%
LONDON ARRAY	Offshore_Wind	44.9231%
LYNEMOUTH	Biomass	71.7698%
MARCHWOOD	CCGT_CHP	60.7771%
MARK HILL	Onshore_Wind	26.9028%
MEDWAY	CCGT_CHP	22.2220%
MIDDLE MUIR	Onshore_Wind	33.2885%
MILLENNIUM	Onshore_Wind	42.7235%
MINNYGAP	Onshore_Wind	31.5863%
MORAY EAST POWER STATIONS	Offshore_Wind	37.6653%
NANT	Hydro	33.6806%
NURSLING TERTIARY	Battery	1.3209%

Power Station	Technology	Specific ALF
ORMONDE	Offshore_Wind	33.6022%
PEMBROKE	CCGT_CHP	67.2627%
PEN Y CYMOEDD	Onshore_Wind	35.9751%
PETERBOROUGH	CCGT_CHP	0.7084%
PETERHEAD	CCGT_CHP	41.0056%
POGBIE	Onshore_Wind	29.6459%
RACE BANK	Offshore_Wind	46.9881%
RAMPION	Offshore_Wind	44.2126%
RATCLIFFE-ON-SOAR	Coal	15.1219%
RICHBOROUGH 1	Battery	3.8713%
RICHBOROUGH 2	Battery	3.6143%
ROBIN RIGG EAST	Offshore_Wind	39.1360%
ROBIN RIGG WEST	Offshore_Wind	40.4771%
ROCKSAVAGE	CCGT_CHP	25.2924%
RYE HOUSE	CCGT_CHP	8.1644%
SALTEND	CCGT_CHP	65.6219%
SANDY KNOWE WIND FARM	Onshore_Wind	32.2335%
SANQUHAR	Onshore_Wind	53.1150%
SEABANK	CCGT_CHP	30.9786%
SEAGREEN 1	Offshore_Wind	34.9834%
SELLAFIELD	CCGT_CHP	1.2841%
SEVERN POWER	CCGT_CHP	3.7888%
SHERINGHAM SHOAL	Offshore_Wind	42.4923%
SHOREHAM	CCGT_CHP	36.8146%
SIZEWELL B	Nuclear	81.3608%
SLOY G2 & G3	Hydro	13.8799%
SOUTH HUMBER BANK	CCGT_CHP	43.3955%
SOUTH KYLE WIND FARM	Onshore_Wind	25.1865%
SPALDING	CCGT_CHP	47.1271%
SPALDING ENERGY EXPANSION	Gas_Oil	2.8347%
STAYTHORPE	CCGT_CHP	52.7299%
STRATHY NORTH & SOUTH	Onshore_Wind	35.5870%
STRONELAIRG	Onshore_Wind	40.3168%
SUTTON BRIDGE	CCGT_CHP	2.0086%
TAYLORS LANE	Gas_Oil	0.2587%
TEES RENEWABLE	Biomass	14.2040%
THANET	Offshore_Wind	38.5936%
TODDLEBURN	Onshore_Wind	32.5529%
TORNESS	Nuclear	77.6656%
TRALORG	Onshore_Wind	69.2185%
TRITON KNOLL OFFSHORE WIND FARM	Offshore_Wind	49.8218%
TWENTYSHILLING WIND FARM	Onshore_Wind	38.0319%
WALNEY 4	Offshore_Wind	49.7144%
WALNEY I	Offshore_Wind	41.9193%
WALNEY II	Offshore_Wind	48.2225%
WALNEY III	Offshore_Wind	49.6777%
WEST BURTON B	CCGT_CHP	51.2284%
WEST OF DUDDON SANDS	Offshore_Wind	49.5584%
WESTERMOST ROUGH	Offshore_Wind	50.4391%
WHITELEE	Onshore_Wind	27.8611%
WHITELEE EXTENSION	Onshore_Wind	25.1574%
WHITESIDE HILL	Onshore_Wind	55.9497%
WILTON	CCGT_CHP	19.5219%
WINDY RIG WIND FARM	Onshore_Wind	42.1530%
WINDY STANDARD II	Onshore_Wind	49.1544%
WISHAW ENERGY STORAGE FACILITY	Battery	4.4086%

Table 1.9 Generic Annual Load Factors

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

These Generic ALFs are calculated in accordance with CUSC 14.15.111.

Includes OCGTs (Open Cycle Gas Turbine generating plant).

* Due to no metered data being available the Generic ALF values for Wave, Tidal and Solar technologies are taken from the Department of Energy Security & Net Zero publication: gov.uk/government/publications/renewables-obligation-level-calculations-2025-to-2026/calculating-the-level-of-the-renewables-obligation-for-2025-to-2026

4. Schedule of Transmission Network Use of System Local Substation Generation Charges (£/kW) in 2025/26

The following table provides the Local Substation Generation TNUoS tariffs applicable to all generation directly connected to the onshore GB Transmission Network from 1 April 2025

Table 1.10 Onshore Local Substation Tariffs (£/kW)

Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.179523	0.089766	0.061916
<1320 MW	Redundancy	0.378275	0.192132	0.136425
≥1320 MW	No redundancy	-	0.263729	0.187768
≥1320 MW	Redundancy	-	0.396867	0.285445

The above tariffs reflect the cost of the transmission substation equipment provided to facilitate generation connecting to an onshore substation.

The following table provides the Local Substation Generation TNUoS tariffs applicable to generation connecting to offshore transmission infrastructure from 1 April 2025.

Table 1.11 Offshore Local Substation Tariffs (£/kW)

Offshore Generator	Local Substation (£/kW)	Offshore Generator	Local Substation (£/kW)
Barrow	11.656304	London Array	15.184275
Beatrice	9.389647	Moray East	11.318789
Burbo Bank Extension	14.584257	Ormonde	35.838076
Dudgeon	21.331780	Race Bank	12.917939
East Anglia 1	12.627454	Rampion	10.552712
Galloper	21.835962	Robin Rigg	-0.7866000
Greater Gabbard	21.715879	Robin Rigg West	-0.7866000
Gunfleet	25.366596	Sheringham Shoal	33.529303
Gwynt y mor	27.387460	Thanet	25.603836
Hornsea 1A	9.747932	Triton Knoll	10.636370
Hornsea 1B	9.747932	Walney 1	30.953266
Hornsea 1C	9.747932	Walney 2	28.797474
Hornsea 2A	11.047354	Walney 3	13.269379
Hornsea 2B	11.047354	Walney 4	13.269379
Hornsea 2C	11.047354	West of Duddon Sands	11.867124
Humber Gateway	16.117673	Westermost Rough	24.129810
Lincs	22.375180		

Further local substation tariffs applicable to generation connecting to offshore transmission infrastructure during 2025/26 will be published in future revisions of this statement following the completion of asset transfer.

5. Schedule of Transmission Network Use of System Local Circuit Charges (£/kW) in 2025/26

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

Table 1.12 Onshore Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.711931	Douglas North	0.760858	Langage	-0.403347
Aberdeen Bay	3.347776	Dunhill	1.791917	Limekilns	2.411223
Achruach	-1.635430	Dunlaw Extension	0.535619	Lochay	0.380429
Aigas	0.879048	Dunmaglass	1.087393	Luichart	0.705380
An Suidhe	-1.050313	Edinbane	8.557476	Marchwood	-0.295137
Arecleoch	3.005452	Enoch Hill	0.760858	Mark Hill	1.103307
Ayrshire Grid Collector	0.169065	Ewe Hill	1.741520	Middle Muir	2.640178
Beinneun Wind Farm	1.687266	Fallago	-0.077458	Middleton	0.179398
Benbrack	0.910916	Farr	4.349028	Millennium Wind	1.994149
Bhlaraidh Wind Farm	0.761915	Faw Side	10.150431	Mossford	1.985413
Black Hill	1.919911	Fernoch	5.359798	Nant	-1.555071
Blacklaw	2.092360	Ffestiniog	0.271855	Necton	1.357057
Blackcraig Wind Farm	6.924933	Fife Grid Services	0.189806	Rhigos	0.510601
Blacklaw Extension	4.551430	Finlarig	0.380429	Rocksavage	0.018419
Broken Cross	1.330269	Foyers	0.349528	Saltend	-0.019375
Clyde (North)	0.132397	Galawhistle	1.306140	Sandy Knowe	5.260736
Clyde (South)	0.154463	Glen Kyllachy	1.247184	Sanquhar II	8.652036
Coalburn BESS	0.469624	Glendoe	2.494369	Scoop Hill	0.539490
Corriegarth	3.043433	Glenglass	5.725310	Shepherds Rig	0.093224
Corriemoillie	1.985413	Gordonbush	0.035220	South Humber Bank	-0.221900
Coryton	0.050973	Griffin Wind	12.154789	Spalding	0.338949
Creag Riabhach	4.184720	Hadyard Hill	3.423862	St Fergus Mobil	1.275310
Cruachan	2.215016	Harestanes	2.853218	Stranoch	3.761346
Culligran	2.162159	Hartlepool	0.228102	Strathbrora	-0.094295
Cumberhead Collector	0.870760	Invergarry	0.380429	Strathy Wind	2.134840
Cumberhead West	4.614582	Kergord	61.164365	Stronelairg	1.341262
Deanie	3.552118	Kilgallioch	1.323968	Wester Dod	0.435324
Dersalloch	2.804200	Kilmarnock BESS	0.488409	Whitelee	0.132397
Dinorwig	3.127755	Kilmorack	0.154440	Whitelee Extension	0.375124
Dorenell	3.001461	Kype Muir	1.850365		

The following table provides the Local Circuit Generation TNUoS tariffs applicable to generation connecting to offshore transmission infrastructure from 1 April 2025

Table 1.13 Offshore Local Circuit Tariffs

Offshore Generator	Local Circuit (£/kW)	Offshore Generator	Local Circuit (£/kW)
Barrow	61.579655	London Array	52.061059
Beatrice	25.744817	Moray East	28.352051
Burbo Bank Extension	28.1869	Ormonde	66.989132
Dudgeon	33.469891	Race Bank	35.879051

East Anglia 1	53.291208	Rampion	27.605447
Galloper	34.535819	Robin Rigg	44.649066
Greater Gabbard	50.252729	Robin Rigg West	44.649066
Gunfleet	23.392552	Sheringham Shoal	39.489373
Gwynt y mor	27.077491	Thanet	47.968845
Hornsea 1A	34.489707	Triton Knoll	31.688721
Hornsea 1B	34.489707	Walney 1	61.883448
Hornsea 1C	34.489707	Walney 2	58.605728
Hornsea 2A	37.319614	Walney 3	26.882966
Hornsea 2B	37.319614	Walney 4	26.882966
Hornsea 2C	37.319614	West of Duddon Sands	59.156062
Humber Gateway	36.979486	Westermost Rough	41.065869
Lincs	87.99393		

Further local circuit tariffs applicable to generation connecting to offshore transmission infrastructure during 2025/26 will be published in future revisions of this statement following the completion of asset transfer.

6. Transmission Network Use of System STTEC and LDTEC Charges in 2025/26

Short-Term Transmission Entry Capacity (STTEC) can be arranged in 4, 5 or 6 week blocks, with the tariff for the applicable duration applying. The STTEC tariff is calculated in accordance with CUSC paragraph 14.16.3 as follows:

$$\text{STTEC Tariff (in £/kW)} = \frac{\text{FT x 0.9 x STTEC Period (in days)}}{120}$$

Where FT = Final annual TNUoS Tariff (wider + local circuit + local substation tariffs) for the generator (in £/kW)

The Limited Duration Transmission Entry Capacity (LDTEC) tariff is applied at two rates during the year. The higher LDTEC rate applies to the first 17 weeks of access within a charging year (whether consecutive or not), and the lower LDTEC rate applies to any subsequent access within the year. The LDTEC tariff is calculated in accordance with CUSC paragraph 14.16.6 as follows:

$$\text{Initial 17 weeks (higher rate): LDTEC Tariff (in £/kW/week)} = \frac{\text{FT x 0.9 x 7}}{120}$$

$$\text{Remaining weeks (lower rate): LDTEC Tariff (in £/kW/week)} = \frac{\text{FT x 0.1075 x 7}}{(316 - 120)}$$

Where FT = Final annual TNUoS Tariff (wider + local circuit + local substation tariffs) for the generator (in £/kW)

If you would like us to calculate an STTEC Tariff or LDTEC Tariff for you, please contact us at: TNUoS.Queries@nationalenergyso.com

To make an application for STTEC or LDTEC, please complete CUSC Exhibit P (for STTEC) or Exhibit S (for LDTEC) and submit your application to: transmissionconnections@nationalenergyso.com

7. Schedule of Pre-Asset Transfer Related Embedded Transmission Use of System Charges in 2025/26

The following table provides the Pre-Asset Transfer Related Embedded Transmission Use of System (ETUoS) tariffs applicable to embedded transmission connected offshore generation from 1 April 2025. The relating charge is used to recover the element of the Offshore Transmission Operator's Revenue that relates to distribution charges paid in the development of the offshore transmission network.

Table 1.15 Pre-Asset Transfer ETUoS Tariff (£/kW)

Offshore Generator	$ETUoS_{OFTO}$
Barrow	1.529107
Gunfleet	4.372202
Ormonde	0.533847
Robin Rigg	14.305277
Robin Rigg West	14.305277
Sheringham Shoal	0.858383
Thanet	1.154779

Please note that in addition to the charges listed above, any enduring distribution charges made to NESO will be passed through to the relating generator in the form of an $ETUoS_{DNO}$ charge.

Further Pre-Asset Transfer Related $ETUoS_{OFTO}$ tariffs applicable to generation connecting to offshore transmission infrastructure during 2025/26 will be published in future revisions of this statement following the completion of asset transfer.

8. Schedule of Transmission Network Use of System Half hourly (HH) Demand Tariffs (£/kW) and Non half Hourly (NHH) Demand Tariffs (p/kWh) for 2025/26

There are two types of demand, Half-Hourly metered (HH) and Non-Half-Hourly metered (NHH). The following table provides the Zonal Demand tariffs for Half Hourly metered demand, Energy Consumption TNUoS tariffs for non-Half-Hourly metered demand and the tariffs for Embedded Export (EET) which are applicable from 1 April 2025.

Table 1.16 Zonal Demand and Energy Consumption TNUoS Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	2.483002
8	Midlands	2.990958	0.386732	5.782595
9	Eastern	1.110745	0.152494	3.902382
10	South Wales	6.885043	0.807732	9.676680
11	South East	5.568235	0.774324	8.359872
12	London	7.405345	0.813457	10.196982
13	Southern	7.570174	0.986192	10.361811
14	South Western	10.123037	1.377268	12.914674

A demand User's zone will be determined by the GSP Group to which the User is deemed to be connected.

The Demand Tariff is applied to the demand User's average half-hourly metered demand over the three Triad periods, as described in the Statement of Use of Charging Methodology.

Demand Tariffs are a combination of a locational element that reflects the cost of providing incremental capacity to demand on an area of the main integrated onshore transmission system, and a non-locational residual element will now be charged in the form of a set of daily charges per site across the banding categories and thresholds. This ensures that the appropriate amount of transmission revenue is recovered from demand Users.

In the case of parties liable for both generation and demand charges, the demand tariff zone applicable in respect of that party's demand will be that in which the Transmission Licensee's substation to which the party is connected is geographically located. For example, if a power station were connected at a Transmission Licensee's substation that is geographically located within demand zone 1, it would pay the zone 1 demand tariff.

The NHH demand tariff is based on the annual energy consumption during the period 16:00 hrs to 19:00 hrs (i.e. settlement periods 33 to 38 inclusive) over the relevant charging year.

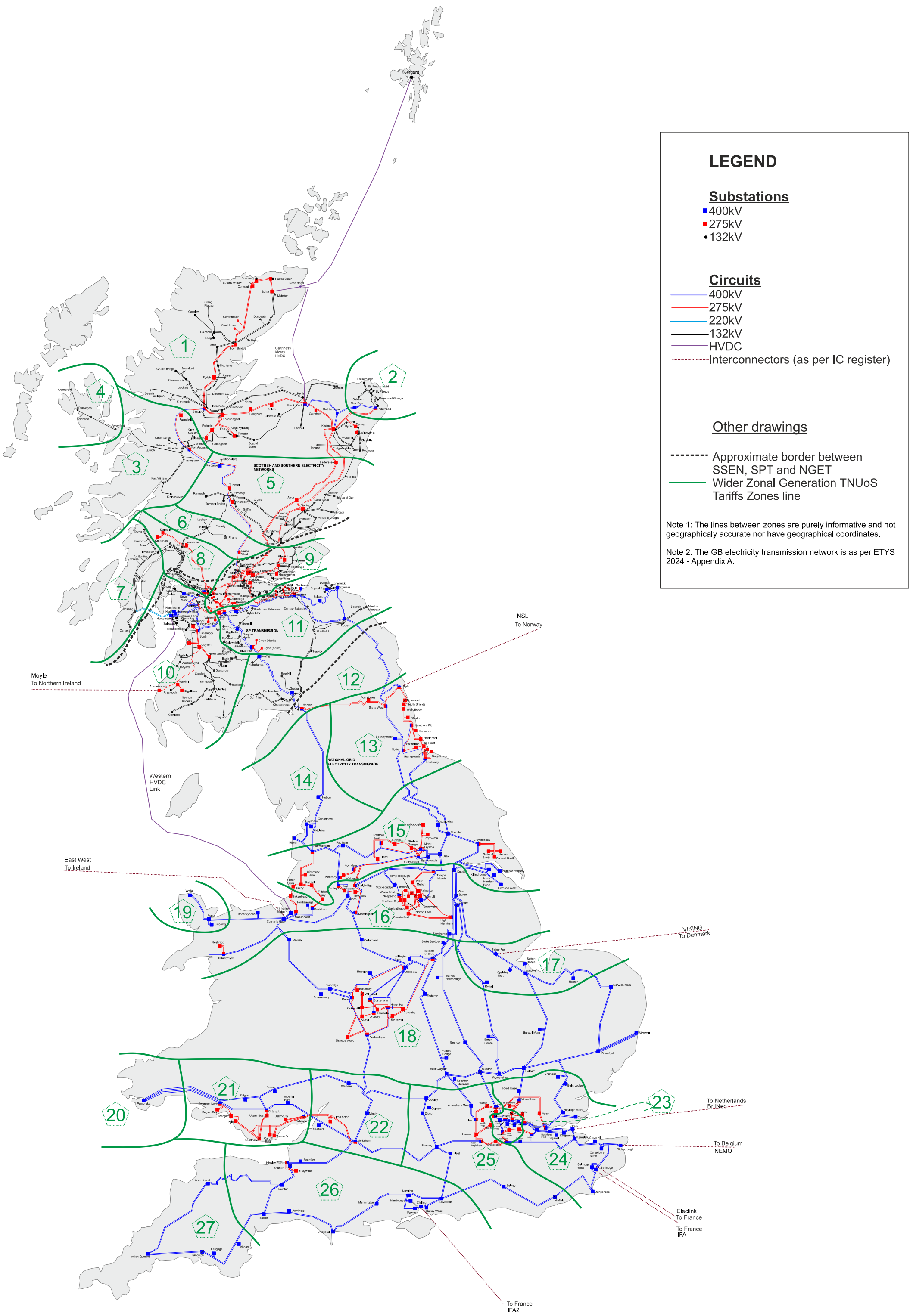
The following table provides the demand residual banded tariffs across each of the banding criteria which are applicable to Final Demand Sites from 1 April 2025. Calculated on a £/Site/Day

Table 1.17 Non-locational demand residual banded charges

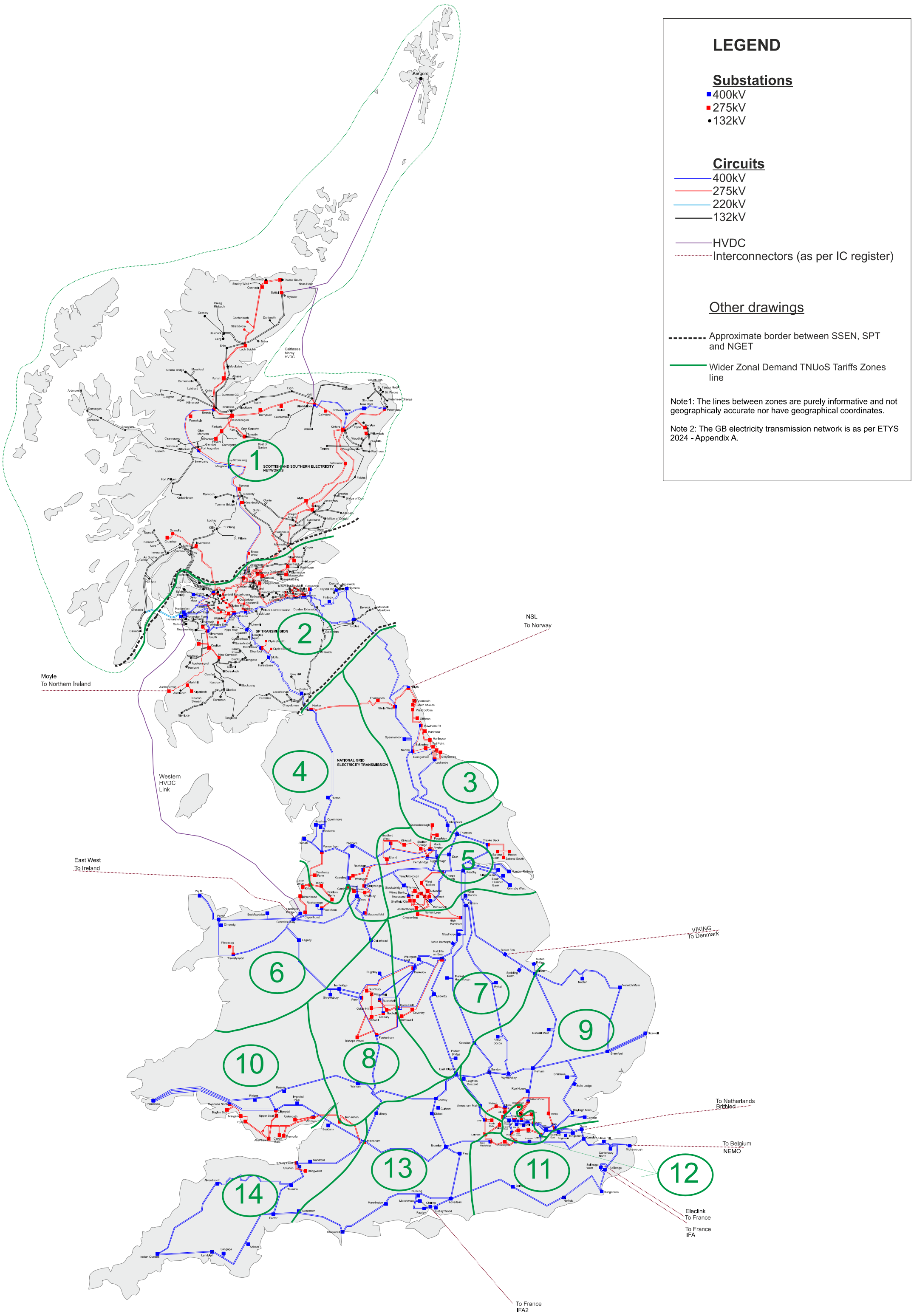
	Band	Percentile	Threshold (kWh/MWh or kVA)		2025/26 Final Tariffs
			Lower (>)	Upper (≤)	
	Metered Demand				**£/Site/Day**
	Domestic				0.135043
kWh	LVN1	≤ 40%	-	≤ 3,571	0.154829
kWh	LVN2	40 - 70%	> 3,571	≤ 12,553	0.366046
kWh	LVN3	70 - 85%	> 12,553	≤ 25,279	0.760709
kWh	LVN4	> 85%	> 25,279	∞	2.068587
kVA	LV1	≤ 40%	-	≤ 80	3.90771
kVA	LV2	40 - 70%	> 80	≤ 150	6.529117
kVA	LV3	70 - 85%	> 150	≤ 231	10.251874
kVA	LV4	> 85%	> 231	∞	22.739548
kVA	HV1	≤ 40%	-	≤ 422	21.830361
kVA	HV2	40 - 70%	> 422	≤ 1,000	62.799637
kVA	HV3	70 - 85%	> 1,000	≤ 1,800	121.79541
kVA	HV4	> 85%	> 1,800	∞	317.59797
kVA	EHV1	≤ 40%	-	≤ 5,000	160.76506
kVA	EHV2	40 - 70%	> 5,000	≤ 12,000	741.78643
kVA	EHV3	70 - 85%	> 12,000	≤ 21,500	1,576.232814
kVA	EHV4	> 85%	> 21,500	∞	3,882.736230
MWh	T-Demand1	≤ 40%	-	≤ 33,548	647.798551
MWh	T-Demand2	40 - 70%	> 33,548	≤ 73,936	2,287.643779
MWh	T-Demand3	70 - 93%	> 73,936	≤ 189,873	5,446.380603
MWh	T-Demand4	> 93%	> 189,873	∞	12,796.715359
	Unmetered Demand				**p/kWh**
	Unmetered				1.571791

9. Zonal Maps Applicable for 2025/26

Generation Use of System Tariff Zones (Geographical map as at 19 August 2025)



Demand Use of System Tariff Zones (Geographical map as at 19 August 2025)



Schedule 2 - Application Fees and Charge-Out Rates

10. Application Fees for Connection and Use of System Agreements

Application fees are payable in respect of applications for new connection agreements, certain use of system agreements and for modifications to existing agreements. The fees are based on reasonable costs incurred by NESO including where appropriate, charges from the Transmission Owners (TO's) in accordance with their charging statements. The application process and options available are detailed in the Statement of the Use of System Charging Methodology which is included in Section 14 of the Connection and Use of System Code (CUSC).

The application fee is dependent upon size, type and location of the applicant's scheme.

Users can opt for a variable price application and pay an advance of the Engineering Charges based on the fixed prices shown, which will be reconciled once the actual costs have been calculated using the charge out rates contained in Schedule 4.

Alternatively, onshore Users can opt to pay a fixed price application fee in respect of New and Modified Bilateral Agreements. In some circumstances, where a given application is expected to involve significant costs over and above those normally expected (e.g. substantial system studies, special surveys, investigations, or where a Transmission Owner varies the application fee charged to NESO from the standard fee published in their charging statements) to process an offer of terms, NESO reserves the right to remove the option for a fixed price application fee.

There are six zones based on the Boundary of Influence map defined in Schedule 4 of the STC (SO-TO Code). Zone NGET1 maps to where NGET is host and there are no affected TOs, NGET2 maps to where NGET is the host TO and SPT is an affected TO, SPT1 is where SPT is the host TO and NGET is an affected TO, SPT2 maps to where SPT is the host TO and there are no affected TOs, SPT3 maps to where SPT is host TO and SHET is an affected TO and SHET1 is where SHET is the host TO and there are no affected TOs.

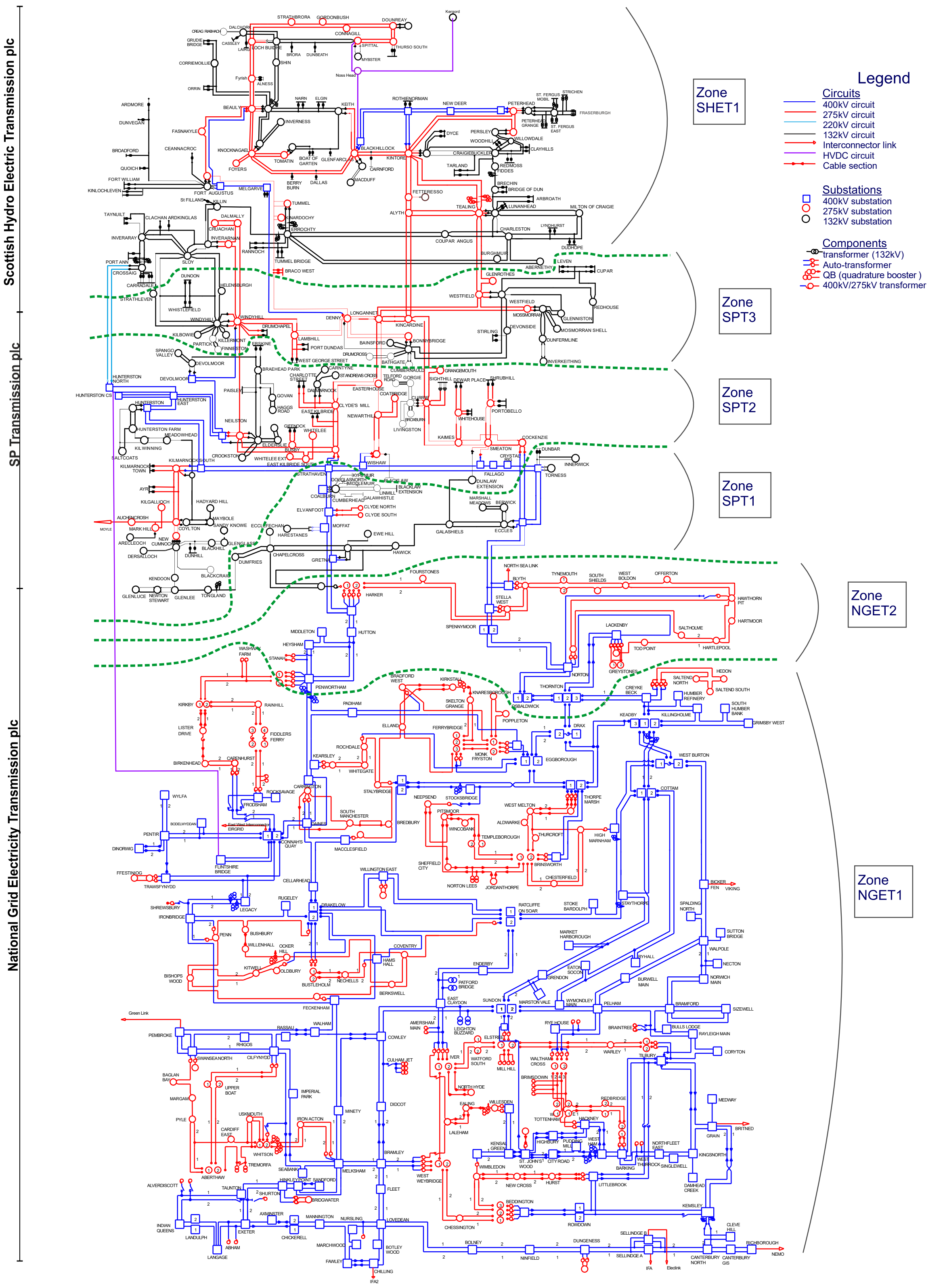
The application fees indicated will be reviewed on an annual basis and reflect any changes to the Boundaries of Influence. It should be noted that the zone to which a particular user is applying is determined by the location of the connection to the National Electricity Transmission System and not by the geographical location of the User's plant and equipment.

All application fees are subject to VAT.

11. Reconciliation and Refunding of Application Fees for Connection and Use of System Agreements

Application Fees will be reconciled and / or refunded in accordance with Section 14 of the Connection and Use of System Code (CUSC).

Application Fees Zonal Map



* ETYS - Electricity Ten Year Statement

12. Application Fees for New Bilateral Agreements and Modifications to existing Bilateral Agreements

Table 2.1 Application Fees

Application Type	Capacity	SHET1	SPT3	SPT2	SPT1	NGET2	NGET 1
		SHET Host SPT affected	SPT Host SHET affected	SPT Host	SPT Host NGET affected	NGET Host SPT affected	NGET Host
New Onshore Application (Entry)	<100MW	£48,100	£56,700	£45,700	£58,850	£41,400	£32,350
	100MW-249MW	£48,100	£56,700	£45,700	£66,600	£56,950	£47,900
	250MW-1800MW	£56,050	£56,700	£45,700	£82,900	£97,500	£80,500
	>1800MW	£91,700	£123,350	£102,350	£165,900	£155,800	£133,150
TEC Change	<100MW	£48,100	£62,200	£45,700	£58,850	£41,400	£32,350
	100MW-249MW	£48,100	£62,200	£45,700	£66,600	£56,950	£47,900
	250MW-1800MW	£56,050	£62,200	£45,700	£82,900	£97,500	£80,500
	>1800MW	£61,700	£118,850	£102,350	£165,900	£155,800	£133,150
New Onshore Supply Point (Exit) or New Onshore Modification Application to Existing Supply Point (Exit)	<=100MW	£53,650	£60,850	£41,050	£56,850	£52,300	£38,700
	>100MW	£68,400	£77,850	£58,050	£78,650	£76,650	£48,300
New Offshore Application (Indicative Fee Only)	-	£112,500	£118,200	£63,200	£96,700	£124,550	£84,900
Statement of Works (Exit)	-	£2,900	£2,900	£1,300	£2,900	£4,450	£3,900
Project Progression (Exit)	-	£20,800	£17,450	£10,150	£19,350	£24,600	£22,350
New Onshore Application BEGA/BELLA	-	£31,150	£31,900	£21,350	£26,050	£19,450	£15,500
Storage	-	£56,050	£58,900	£45,700			
Mod App Admin Change	-	£7,450	£7,450	£2,450	£2,450	£5,750	£4,050
Appendix G		£12,800					

Application Type	Fraction of New Application Fee
Modification Application (Entry, Offshore and Exit)	0.75

If applying for a combination of changes after making an initial application and this is prior to the completion of works associated to the initial application, such as a change to works or completion date that also includes a TEC Change, the Application Fee will be the higher of the TEC Change Fee or Modification Application Fee.

Table 2.2 Other Application Fees

The following fees are always charged on a fixed fee basis:

<table>
<tr><th>Application Type</th><th>NGET1</th><th>NGET2</th><th>SPT1</th><th>SPT2</th><th>SPT3</th><th>SHET1</th></tr>
<tr><td>Request for STTEC</td><td colspan="6">£10,000</td></tr>
<tr><td>Reactive Only Service Provider</td><td>£12,222</td><td>£12,222</td><td>£39,650</td><td>£39,650</td><td>£39,650</td><td>-</td></tr>
<tr><td>Suppliers and Interconnector Users</td><td colspan="6">£5,000</td></tr>
<tr><td>Novate a bilateral agreement</td><td colspan="6">£3,000</td></tr>
<tr><td>Project Designation – Long Lead Time Project</td><td colspan="6">£3,000</td></tr>
<tr><td>Project Designation – Highly innovative Project</td><td colspan="6">£5,000</td></tr>
<tr><td>Gate 2 to Whole Queue (G2WQ) Advancement*</td><td colspan="2">£13,600</td><td colspan="3">£6,200</td><td>£5,600</td></tr>
</table>

*NESO has introduced a reasonable and proportionate fixed G2WQ Advancement Fee for those projects with existing agreements that are requesting Advancement via the Readiness Declaration in G2WQ. NESO has coordinated with the TOs in relation to this fee, and this fee will only be charged to the projects that pass their initial readiness checks and are strategically aligned, including where it has passed an initial network review that advancement may be possible. The timing of the invoice will be after it is identified that the project is strategically aligned. This means that customers will not be invoiced immediately upon application / submission of the Readiness Declaration. This fee will be levied to each directly connected and Large Embedded Generation project requesting such Advancement. In respect of Small and Medium Embedded Generation projects requesting Advancement via the Host DNO (or Transmission connected iDNO), the relevant Host DNO (or Transmission Connected iDNO) will be invoiced this fee for each Modification Application related to each Grid Supply Point / Bulk Supply Point.

Table 2.3 Limited Duration TEC Request Fees

The following fees are always charged on a fixed fee basis:

<table>
<tr><th></th><th>Duration of LDTEC (t)</th><th>£</th></tr>
<tr><td rowspan="4">Basic request fee for duration t (applicable to all requests for LDTEC Offers)</td><td>t <= 3 months</td><td>£10.000</td></tr>
<tr><td>3 months < t <= 6 months</td><td>£15.000</td></tr>
<tr><td>6 months < t <= 9 months</td><td>£20.000</td></tr>
<tr><td>t > 9 months</td><td>£30.000</td></tr>
<tr><td></td><td>t <= 3 months</td><td>£1.000</td></tr>
</table>

Additional fee for rolling assessment (applicable to a request for an LDTEC Indicative Block Offer)	3 months < t <= 6 months	£1,500
	6 months < t <= 9 months	£2,000
	t > 9 months	£3,000
Additional fee for combined applications (applicable to a combined request for an LDTEC Block Offer and an LDTEC Indicative Block Offer)	t <= 3 months	£5,000
	3 months < t <= 6 months	£7,500
	6 months < t <= 9 months	£10,000
	t > 9 months	£15,000

Table 2.4 Temporary TEC Exchange Rate Request Fees

The following fees are always charged on a fixed fee basis:

Duration of Temporary Exchange period (t)	£
t <= 3 months	£15,000
3 months < t <= 6 months	£25,000
6 months < t <= 9 months	£30,000
t > 9 months	£45,000

13. Examples

1. Entry Application Fee for a New Bilateral Agreement onshore,
   300MW Generator wishing to connect to the transmission system in Zone NGET1.
   Application Fee = £80,500.00

2. Entry Application Fee for a New Bilateral Agreement offshore,
   2000MW Generator wishing to connect to the transmission system in Zone SPT1 for Two Connection Sites.
   Application Fee = 2 * £96,700.00 = £193,400.00

3. Entry Application Fee for a Modification to an existing Bilateral Agreement Offshore,
   2000MW Generator in Zone SPT1 seeking to alter a commissioning date where there are 2 affected transmission interface sites. This would be a Modification.
   Application Fee = 2 * (0.75 * £96,700.00) = £145,050.00

4. Entry Application Fee for a Modification to an existing Bilateral Agreement,
   300MW Generator in Zone NGET2 seeking to alter commissioning date. This would be a Modification.
   Application Fee = 0.75 * £97,500 = £73,125.00

5. Entry Application Fee for an embedded generator (BEGA/ BELLA),
   300MW embedded generator requesting a BEGA in Zone NGET2.
   Application Fee = £19,450.00

6. Entry Application Fee for a TEC Increase 400MW generator in Zone SPT3 wishes to increase TEC by 20MW to 420MW.
   Application Fee = 0.75 * £62,200.00 = £46,650.00

7. Entry Application Fee for a change to completion date,
   500MW generator in Zone NGET2 wishes to change their completion date by moving it back by 12 months.
   Application Fee = 0.75 * £97,500.00 = £73,125.00

8. Entry Application Fee to decrease TEC
   600MW generator in Zone SHET1 wishes to decrease TEC by 100MW to 500MW.
   Application Fee = 0.75* £56,050.00= £42,037.50

Table 2.5 Bilateral Agreement Types

Bilateral Agreement Type	Description
Bilateral Connection Agreement	In respect of Connection Sites of Users.
Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA)	For generators that own or are responsible for embedded exemptible large power stations (another party may be responsible for the output under the CUSC and BSC).
Bilateral Embedded Generation Agreement (BEGA)	For generators and BSC parties with embedded power stations, excluding those which are exempt (unless they otherwise choose to be), who are responsible for the output onto a Distribution System.
Construction Agreement	In respect of parties that are applying for new or modified agreements up until the time of commissioning.

14. Charge-Out Rates for Engineering Charges for Variable Price Applications

Appropriately qualified staff will be appointed to process applications and feasibility studies and carry out work in relation to the development of the National Electricity Transmission System. Travel, subsistence and computing costs will also be charged on an actual basis. It should be noted that these rates only apply to work carried out by the Transmission Licensee’s in relation to licensed transmission activities. Different rates may apply when asked to quote for other work.

Table 2.6 Charge-Out Rates

	£/day			
	NESO	NGET	SPT	SHET
Senior Management; Legal	£1,182	£1,011	£1,110	£1,405
Departmental Management	£984	£921	£950	£953
Senior members of staff (Engineering; Commercial)	£876	£849	£810	£733
Standard (Engineering; Commercial)	£802	£724	£670	£585
Support staff; junior staff	£731	£663	£410	£413

Schedule 3 - Connection Charges

15. Non-Capital Components applicable for Maintenance and Transmission Running Costs in Connection Charges for 2025/26

The following sections set out the components of connection charges and the parameters used to set the charges.

Connection charges are made up of capital and non-capital components. The non-capital component of the connection charge is divided into two parts, as set out below.

Part A: Site Specific Maintenance Charges

Site-specific maintenance charges are calculated each year based on the forecast total site-specific maintenance for GB divided by the total Gross Asset Value (GAV) of the transmission licensees' GB connection assets, to arrive at a percentage of total GAV. For 2025/26 this will be 0.37%

Part B: Transmission Running Costs

The Transmission Running Cost (TRC) factor is calculated at the beginning of each price control to reflect the proportion of the Transmission Running Costs (e.g. rates, operation, indirect overheads) incurred by the transmission licensees that should be attributed to connection assets.

The TRC factor is calculated by taking a proportion of the forecast Transmission Running Costs for the transmission licensees (based on operational expenditure figures from the latest price control) that corresponds with the proportion of the transmission licensees' total connection assets as a function of their total business GAV. This cost factor is therefore expressed as a percentage of an asset's GAV and will be fixed for the entirety of the price control period. For 2021/22 to 2025/26 this will be 1.06%.

To illustrate the calculation, the following example uses the average operating expenditure from the published price control and the connection assets of each transmission licensee expressed as a percentage of their total system GAV to arrive at a GB TRC of 1.06%:

Connection assets as a percentage of total system GAV for each TO:

SP Transmission plc	12.90%
Scottish Hydro Electric Transmission plc	8.49%
National Grid Electricity Transmission plc	12.23%

Published current price control average annual operating expenditure (£m):

SP Transmission plc	79.56
Scottish Hydro Electric Transmission plc	108.21
National Grid Electricity Transmission plc	430.14

Total GB Connection GAV = £5.04bn

Gross GB TRC Factor =
(12.23% x £430.14m + 8.49% x £108.21m + 12.9% x £79.56m) / £5.04bn = 1.43%

Net GB TRC Factor = Gross GB TRC Factor – Site Specific Maintenance Factor*
= 1.43% - 0.37% = 1.06%

* Note – the Site-Specific Maintenance Factor used to calculate the TRC Factor is that which applies for the first year of the price control period.

16. Transmission Owner Rate of Return

Rate of return (RoR) is aligned to the pre-tax cost of capital in the price control of the Relevant Transmission Licensee. For 2025/26 this will be as per the table below.

Table 3.1 Rate of Return

Trancsmission Owner	Revaluation Type	Rate of Return
National Grid Electricity Transmission plc	TOPI	4.30%
National Grid Electricity Transmission plc	MEA	5.80%
SP Transmission plc	TOPI	4.30%
Scottish Hydro Electric Transmission plc	TOPI	3.76%

17. Illustrative Connection Asset Charges

An indication of First Year Connection Asset Charges for new connection assets using estimates of Gross Asset Values and examples of connection charges are outlined in Appendix A.

Appendix A: Examples of Connection Charge Calculations

The following examples of connection charge calculations are intended as general illustrations.

Example 1

This example illustrates the method of calculating the first-year connection charge for a given asset value. This method of calculation is applicable to indicative price agreements for new connections, utilising the TOPI method of charging, and assuming:

i) the asset is commissioned on 1 April 2025

ii) there is no inflation from year to year i.e. GAV remains constant

iii) the site-specific maintenance charge component remains constant throughout the 40 years at 0.37% of GAV

iv) the Transmission Running Cost component remains constant throughout the 40 years at 1.06% of GAV

v) the asset is depreciated over 40 years

vi) the rate of return is TO specific and aligned to the pre-tax cost of capital in the price control period for 2021-2025 for the 40-year asset life.

vii) the asset is terminated at the end of its 40-year life

For the purpose of this example, the asset on which charges are based has a Gross Asset Value of £3,000,000 as of the 1 April 2025.

Charge	**Calculation**	
Site Specific Maintenance Charge	3,000,000 x 0.37%	£11,100
(0.37% of GAV)		
Transmission Running Cost	3,000,000 x 1.06%	£31,800
(1.06% of GAV)		
Capital charge	3,000,000 x 2.5%	£75,000
(40-year depreciation 2.5% of GAV)		
Return on mid-year NAV	2,962,500 x 4.00%	£118,500
(4.00% of NAV)		
TOTAL		£236,400

The first-year charge of £236,400.00 would reduce in subsequent years as the NAV of the asset is reduced on a straight-line basis, assuming a zero rate of inflation.

This illustration reflects the annual connection charge over time (assuming no inflation):

Year	Charge
1	£236,400.00
2	£233,400.00
10	£209,400.00
40	£119,400.00

Example 2

The previous example assumes that the asset is commissioned on 1 April 2025. If it is assumed that the asset is commissioned on 1 July 2025, the first-year charge would equal 9/12th of the first-year annual connection charge i.e. £177,300.00

This gives the following annual charges over time:

Year	Charge
1	£177,300.00 connection charge for period July 2025 to March 2026
2	£233,400.00
10	£209,400.00
40	£119,400.00

Example 3

In the case of a firm price agreement, there will be two elements in the connection charge, a finance component and a running cost component. These encompass the four elements set out in the examples above. Using the same assumptions as those in example 1 above, the total annual connection charges will be the same as those presented. These charges will not change because of the adoption of a different charging methodology by NESO, providing that the connection boundary does not change.

Example 4

If a User has chosen a 20-year depreciation period for their Post Vesting connection assets and subsequently remains connected at the site beyond the twentieth year their charges are calculated as follows.

For years 1-20 the charge is as calculated above, except the capital charge will be 5% of GAV

For years 21-40 the NAV will be zero and the asset will be fully depreciated so there will be no rate of return or depreciation element to the charge. They will pay a connection charge based on the following formula:

$$\text{Annual Connection Charge}_n = SSF_n (TOPIGAV_n) + TC_n (GAV_n)$$

One off Charges

To provide or modify a connection, the Transmission Owner may need to carry out works on the transmission system which, although directly attributable to the connection, may not give rise to additional Connection Assets.

Where connection requirements lead to additional capital assets over those normally required, the capital value is paid for as a One-Off Charge. These capital assets require maintenance on a regular basis as is the case with connection assets. This is called “One-Off Assets - Site Specific Annual Maintenance” (OAMF) and “One-Off Assets Running Cost” (OARC). This OAMF and OARC is applicable to NGET Connections Only.

OAMF is a percentage factor applied to the reindexed One-Off capital asset values to recover a reasonable proportion of NGET’s maintenance costs on an annual basis. The current OAMF factor is 0.35%.

OARC is a percentage factor applied to the reindexed One-Off capital asset values to recover a reasonable proportion of NGET’s business running costs. The current OARC factor is 0.92%. This is calculated at the beginning of each price control.

One-Off Asset maintenance charges will be applied annually on a 1/12th monthly basis and applied pro-rata for the first month and first partial year following commissioning. Other payment terms can be agreed.

Example

One-off charge of £100,000 for assets attributable to the connection.

Charge	**Calculation**	
One-Off Assets - Site Specific Annual Maintenance (0.35% of One-off charge)	£100,000 x 0.35%	£350
One-Off Assets Running Cost (0.92% of One-off charge)	£100,000 x 0.92%	£920
Annual Charge		**£1,270**

Appendix B: Index to the Statement of Use of System Charges Revisions

Issue	Description	Modifications
10.1	2014/15 Publication	-
11.0	2015/16 Publication	-
12.0	2016/17 Publication	CMP213 Transmit Application fee tables
13.0	2017/18 Publication	-
14.0	2018/19 Publication	Change introduced by CMP264/265 to demand TNUoS tariffs.
1.0	2019/20 Publication	Document transferred to NGESO Section on Balancing Services removed following changes to incentive mechanism.
2.0	2020/21 Publication	Updated format for application fees with new zones
3.0	2021/22 Publication	Change introduced by the start of RIIO-2 price control parameter reset and several code modifications: Impacting TNUoS tariffs: CMP317/327, CMP324/325, CMP353, CMP355/356, CMP357 Impacting connection charges: CMP306 Application fee review
3.1	2021/22 Publication	Updated to reflect Affected TO Costs for SHET1
3.2	2021/22 Publication	Hornsea 1 Offshore tariffs added Added novation app fee in “Other Application Fees”
4.0	2022/23 Publication	Updated as part of annual review
4.1	2022/23 Publication	Replaced LDTEC/STTEC table with information on how to calculate tariffs.
5.0	2023/24 Publication	Document updated to reflect 2023/24 charges
6.0	2024/25 Publication	Document updated to reflect 2024/25 charges
7.0	2025/26 Publication	Document updated to reflect 2025/26 charges
7.1	2025/26 Publication	Correction to Application Fees in Zones SHET1 and SPT3.
7.2	2025/26 Publication	Application fees updated with fixed fee for G2WQ advancement requests
7.3	2025/26 Publication	TNUoS Zonal Maps updated to make them clearer. No changes made to boundaries
7.4	2025/26 Publication	App Fee Zonal Map updated to make it clearer. No changes made to boundaries