TNUoS Briefing

Differential impact of onshore Transmission Network Use of System (TNUoS) charges on the economics of offshore wind projects around the GB coastline.

Client: Crown Estate Scotland

Reference: 4892_001_001A

ITPEnergised - TNUoS

- *Purpose-built in-house TNUoS model – forecasts to 2050 and bespoke modelling to reflect discrete sensitivities*
- *Policy & regulatory division supporting TNUoS interrogation & interpretation, development and governance of the methodology*
- *Engineering division supporting DC load flow modelling, model expansion and boundary flow analysis*

The Brief

ITPEnergised was commissioned by the Scottish Offshore Wind Energy Council Developers Group to develop a short report on the differential impact of onshore Transmission Network Use of System (TNUoS) charges on the economics of offshore wind projects around the GB coastline.

The following slides explain how TNUoS works, the latest forecasts for charges in different parts of GB in financial year 2026/27, and the impacts that will have on offshore wind developments in different parts of the country.

ITPEnergised TNUoS estimates are based on National Grid Electricity System Operator (NGESO) five year forecasts published in May 2021.

Intermittent tariffs for offshore generators assume a 51% load factor consistent with BEIS electricity generation costs

Investment in transmission

Transmission licensees plan, finance, build and maintain the transmission grid. Their investment is repaid by those that use the transmission system – demand and generation users – through Transmission Network Use of System (TNUoS) charges.

The total revenues that the licensees are allowed to recover via TNUoS are set by Ofgem during the price control process. For the year 2021/22 these stand at £2,843M. NGESO's 5 year forecasts estimate these revenues to remain fairly stable, increasing at a rate of 6% per annum.

This total revenue 'pot' is allocated to different users by a two-step process:-

(1) Deriving locational prices via a model of the load flow on the network

(2) re-balancing charges by a uniform +ve or –ve amount (the generation tariff adjustment) so that TNUoS collects the target revenue set out above.

This two step process is, in simple terms, what constitutes the **TNUoS model**.

'Flow' can be negative in the model, which carries through to negative tariffs. The rebalancing step (2) can also drive negative tariffs where NGESO needs to offset what would otherwise be over-recovery of revenue.

Elements of TNUoS – offshore generators

WIDER TARIFFS

Pays for the Main Interconnected System (MITS), varies by zone

LOCAL CIRCUIT & SUBSTATION TARIFF

Pays for connection to MITS, specific to the project

Wider tariffs = subject of this report. They are source of regional differentials, and are outside a project's control

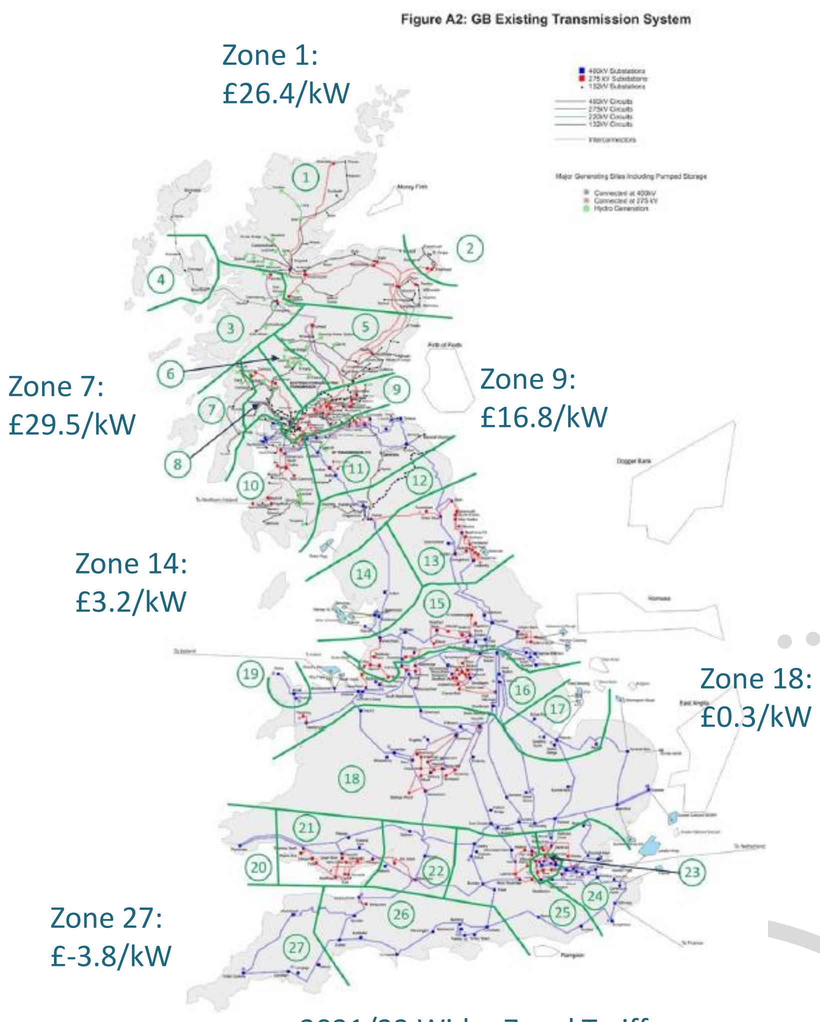
Wider TNUoS zones

The load flow model generates a price for every one of the current 175 generation nodes on the system.

These nodes are grouped into zones.

Generators pay a zonal charge, which is the weighted average of the nodal prices.

Currently the GB system is split into 27 generation zones, starting with Zone 1 in the far north of Scotland and finishing with Zone 27 in Cornwall.



2021/22 Wider Zonal Tariffs
(NGESO published at 40% ALF)

Trends in wider tariffs

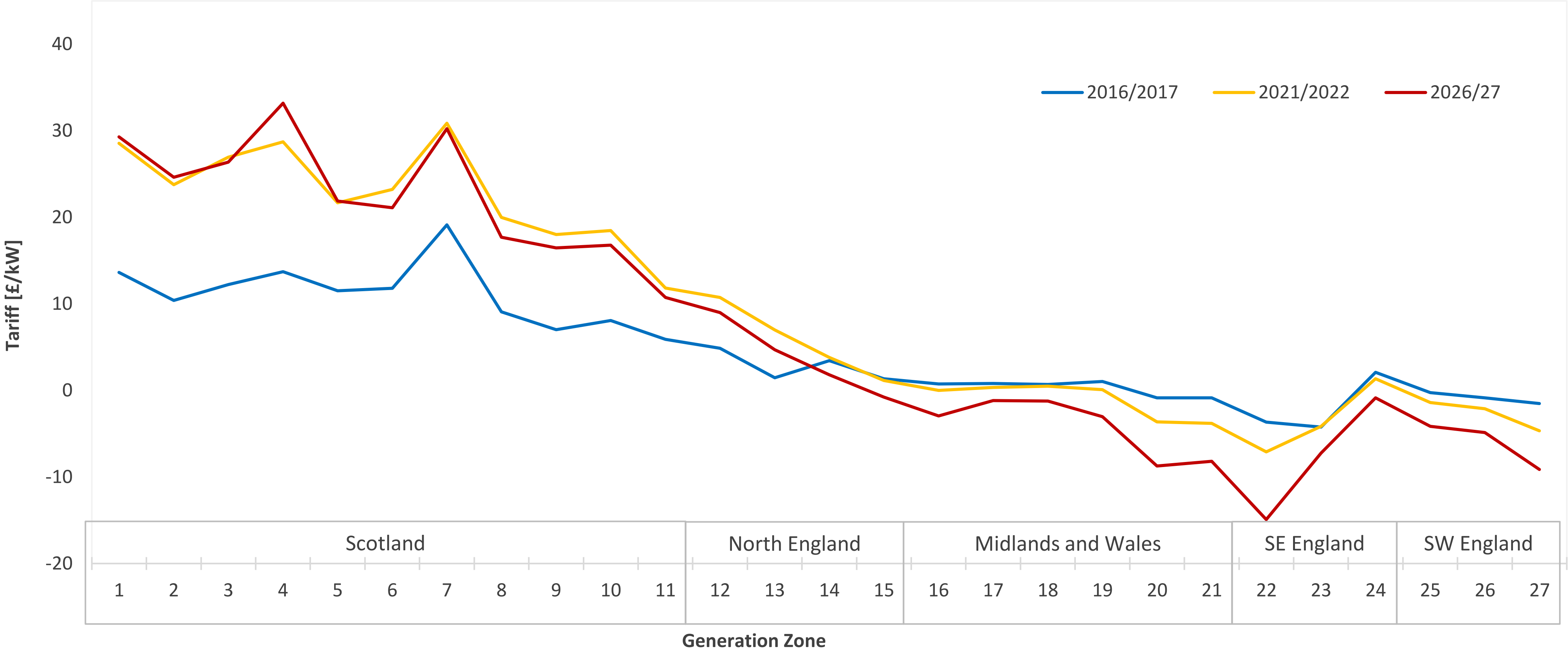
Based on 51% load factor for offshore wind farms, the following slide shows wider tariffs for all 27 zones:

(1) 2016/17 – the year 'Project TransmiT' changes to the methodology were implemented (see annex – introduced different tariffs for intermittent and conventional generation)

(2) 2021/22 - current financial year

(3) 2026/27 - the latest date for which National Grid ESO forecasts is available from their 5 Year Forecast

Wider Zonal Tariffs 2016/17, 2021/22, 2026/27



Commentary

Differential

- It can be seen that the charges are highest in northern parts of Scotland, and negative in a number of zones in the south of GB, meaning generators are paid to connect to the network.

Trends in the differential

- Charges in a number of northern zones will more than double between 2016/17 and 2026/27, without even taking account of changes in the methodology which are expected to further exacerbate this trend (see slides 19 & 20 – these show the possible impact of updating the expansion constant, the assumption on the unit cost of transmission. This was due to change in 2021/22 but has been delayed through modification CMP353. CMP315 & CMP375 have been raised to better understand the issues).
- The difference in charges between the highest and lowest tariff zones is projected to double from 2016/17 to 2026/27**.**
- The differential between the highest and lowers zones is projected to reach around £48 in 2026/27, compared to £23 in 2016/17. (£42 in 2026/27, compared to £21 in 2016/17 excluding landlocked generation zones 6, 8, 22 & 23)

Volatility

- Charges are becoming increasingly volatile and difficult to predict, something which lead National Grid itself to propose greater averaging of charges into 14 zones (rejected by Ofgem).
- TNUoS tariffs are recalculated annually. TNUoS, by design, responds to changes in generation, demand and infrastructure renewal and expansion. This means that as soon as a generator makes a locational decision, the locational ‘signal’ changes.
- On top of this is constant change through open governance of the TNUoS methodology.

Impact of TNUoS on Levelised Cost of Energy

In order to demonstrate the impacts of wider zonal tariffs on project economics, ITPEnergised was asked to set out the following figures for a notional 1GW offshore wind project in each of the 27 TNUoS charging zones across GB in 2026/27, again assuming a 51 per cent load factor:

- Costs per kW of each unit of capacity connected to the transmission network
- The annual total cost to the project as a result of the wider zonal tariff
- The impact of wider zonal tariffs on the Levelised Cost of Energy, calculated by dividing the annual charge by the average annual output of the wind farm

The results are set out in the following slide.

Impact on Levelised Cost of Energy, forecast 2026/27 tariffs

Zone	Intermittent tariff (£/kW)	Annual cost per notional 1GW project (£)	Annual cost per MWh of output (£/MWh)
1	29.28	29,284,146	6.55
2	24.63	24,627,527	5.51
3	26.37	26,365,805	5.90
4	33.18	33,176,802	7.43
5	21.87	21,871,327	4.90
6	21.10	21,104,836	4.72
7	30.22	30,221,765	6.76
8	17.70	17,702,315	3.96
9	16.48	16,476,144	3.69
10	16.77	16,769,504	3.75
11	10.73	10,731,694	2.40
12	8.98	8,982,222	2.01
13	4.70	4,702,554	1.05
14	1.80	1,798,079	0.40
15	-0.76	-760,377	-0.17
16	-2.95	-2,953,242	-0.66
17	-1.17	-1,165,657	-0.26
18	-1.24	-1,243,945	-0.28
19	-3.04	-3,040,142	-0.68
20	-8.72	-8,718,620	-1.95
21	-8.20	-8,199,984	-1.84
22	-14.92	-14,920,642	-3.34
23	-7.23	-7,229,816	-1.62
24	-0.85	-850,570	-0.19
25	-4.16	-4,164,722	-0.93
26	-4.86	-4,861,954	-1.09
27	-9.13	-9,128,613	-2.04

Commentary

Annual Project Costs

- Annual charges for a notional 1GW project range from in excess of £33m to a negative charge of -£9m (excluding Zone 22 which is 'landlocked').
- Presuming a load factor of 51%, the impact of charges on the cost of energy would range from £7.43/MWh to -£2.04/MWh, a difference of £9.47/MWh.

ScotWind and Crown Estate Round 4

- The maximum difference between potential ScotWind and Round 4 projects in terms of the impact of transmission charges on LCOE is £8.36/MWh (Zone 4 = £7.43; Zone 25 = -£0.93).

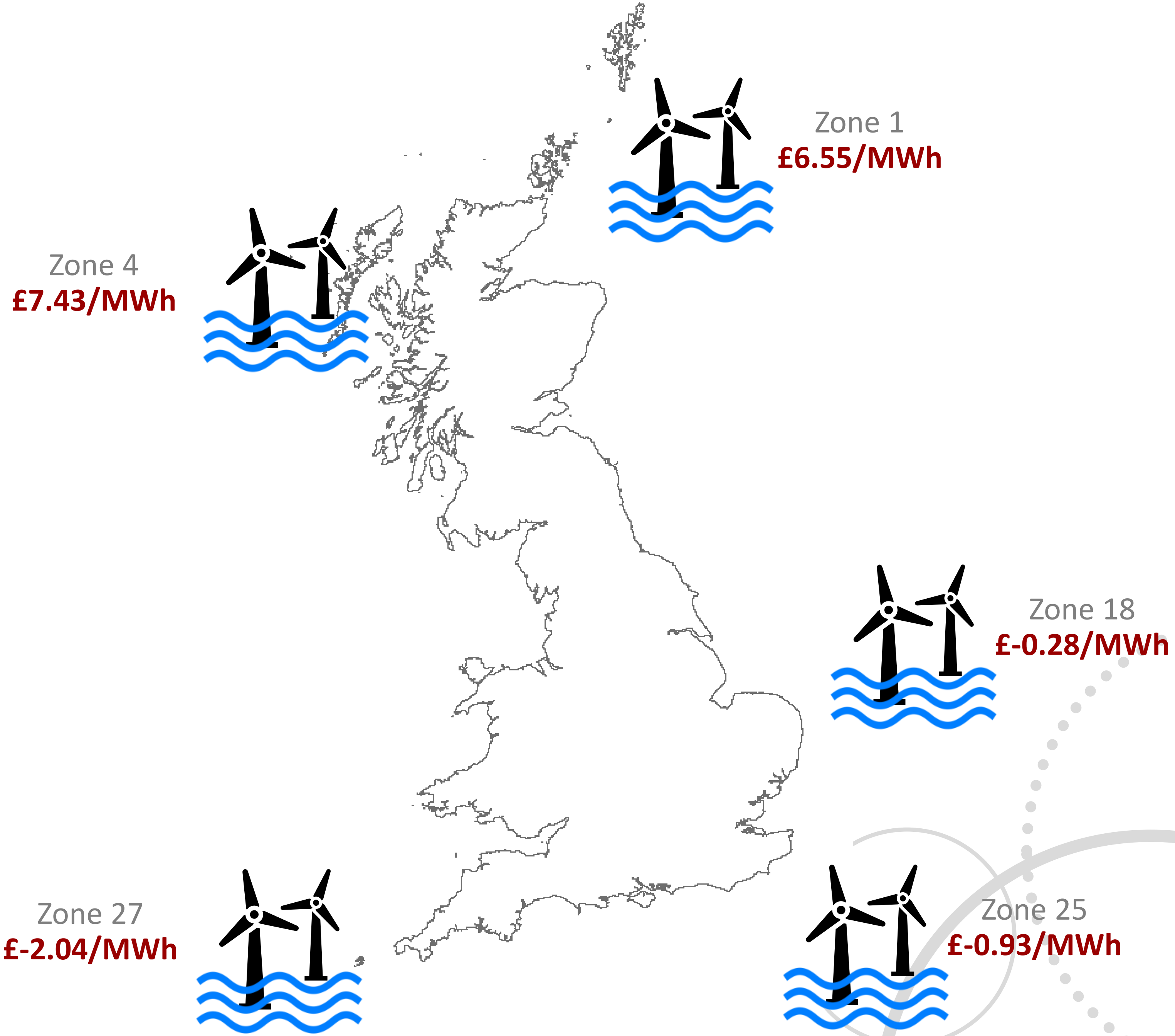
CfD Allocation Round 4

- Similarly, TNUoS charges mean that the LCOE of Scottish projects eligible to bid in CfD Allocation Round 4 are between £0.96 and £8.09 per MWh higher than the projects off the east coast of England.

Future Changes

- The differentials above are based on NGESO forecasts for charging year 2026/27. They do not take account of changes in the methodology, which are expected to further exacerbate the trend, and do not capture the volatility in TNUoS charges.

*Difference of up to >**£9.46/MWh** operational cost between north and south zones in 2026/27*



Annex – TNUoS methodology

TNUoS load flow

The Transport Model is comprised of nodes (substations), circuits, generation & demand

Each node can have generation and / or demand

Circuits connect the nodes

Circuits allocated a cost per km

‘flow’ from generation to demand translated to a cost /MW/km

The ‘differential’ between areas of high generation & high demand ‘stretches’ with higher:

- Distance
- Circuit cost
- Flow volume

Network Input Data						Network outputs		Derived outputs	
TO Region	Bus 1	Bus 2	R	X (Peak Security)	X (Year Round)	LineFlow	LineLoss	Cct flow "cost"/MW	Total Cct Flow Cost
NGC	ABHA4A	EXET40	0.10	1.02	1.02	90.90584627	0.082638729	[illegible]	4435.00
NGC	ABHA4A	LAGA40	0.06	0.54	0.54	-173.9058463	0.18145946	[illegible]	4542.00
NGC	ABHA4B	EXET40	0.11	1.03	1.03	90.32682814	0.089748295	[illegible]	4431.00
NGC	ABHA4B	LAGA40	0.06	0.54	0.54	-173.3268281	0.180253136	[illegible]	4527.00
NGC	ABTH20	COWT2A	0.05	0.54	0.54	188.8111277	0.17824821	[illegible]	3014.00
NGC	ABTH20	PYLE20	0.18	1.45	1.45	-14.99314325	0.004046298	[illegible]	636.00
NGC	ABTH20	TREM20	0.23	2.14	2.14	251.5970246	[illegible]	[illegible]	14006.00
NGC	ABTH20	UPPB21	0.12	1.16	1.16	304.5511359	[illegible]	[illegible]	11785.00
NGC	ABTH20	UPPB22	0.12	1.14	1.14	306.5481925	[illegible]	[illegible]	9920.00
NGC	ALDW20	BRIN20	0.14	0.76	0.76	-30.12362997	[illegible]	[illegible]	648.00
NGC	ALDW20	WMEL20	0.04	0.39	0.39	-50.87637003	[illegible]	[illegible]	546.00
NGC	ALVE4A	INDQ40	0.21	1.94	1.94	30.28947926	0.019266504	97.18	2944.00
NGC	ALVE4A	TAUN4A	0.16	1.53	1.53	-114.2894793	0.208993361	73.29	8376.00
NGC	ALVE4B	INDQ40	0.21	1.94	1.94	30.28947926	0.019266504	97.29	2947.00
NGC	ALVE4B	TAUN4B	0.16	1.53	1.53	-114.2894793	0.208993361	73.30	8377.00
NGC	AMEM4A_EPN	AMEM4A_SEP	0.00	0.01	0.01	50	0	0.00	0.00
NGC	AMEM4A_EPN	ECLA40_WPD	0.07	0.70	0.70	-560.0392558	2.195507776	35.31	19775.00
NGC	AMEM4A_EPN	IVER4A	0.04	0.40	0.40	481.0392558	0.925595062	20.26	9746.00
NGC	AMEM4B_EPN	AMEM4B_SEP	0.00	0.01	0.01	50	0	0.00	0.00
NGC	AMEM4B_EPN	ECLA40_WPD	0.07	0.70	0.70	-538.6181473	2.03076656	35.31	19019.00
NGC	AMEM4B_EPN	IVER4B	0.04	0.40	0.40	459.6181473	0.844995365	20.26	9312.00
NGC	AXMI40_SEP	AXMI40_WPD	0.00	0.01	0.01	92	0	0.00	0.00
NGC	AXMI40_SEP	CHIC40	0.04	0.69	0.69	187.7626114	0.141019193	39.50	7417.00
NGC	AXMI40_SEP	EXET40	0.04	0.63	0.63	-386.7626114	0.59834127	36.18	13993.00
NGC	BAGB20	MAGA20	0.04	0.52	0.52	198.0018171	0.156818878	20.86	4131.00
NGC	BAGB20	SWAN2A	0.06	0.75	0.75	218.0602414	0.285301613	38.32	8356.00
NGC	BARK20_EPN	BARK20_LPN	0.00	0.01	0.01	75.47633669	0	0.00	0.00
NGC	BARK20_EPN	REBR20	0.04	0.45	0.45	-125.9458855	0.063449464	13.04	1642.00
NGC	BARK20_LPN	REBR20	0.04	0.44	0.44	-130.5236633	0.068145707	13.00	1697.00
NGC	BARK20_EPN	BARK40	0.03	2.80	2.80	-43.76522558	0.005746185	0.00	0.00
NGC	BARK20_EPN	BARK40	0.03	2.80	2.80	-43.76522558	0.005746185	0.00	0.00
NGC	BARK40	CHUE4A	0.02	0.26	0.26	-415.2233408	0.344820845	13.59	5643.00
NGC	BARK40	CHUE4B	0.02	0.26	0.26	-415.2233408	0.344820845	13.59	5643.00
NGC	BARK40	WHAM40	0.02	0.20	0.20	803.4591375	1.291093171	9.66	7761.00
NGC	BARK40	WHAM40	0.02	0.20	0.20	803.4591375	1.291093171	10.88	8745.00
NGC	BARK40	WTHU4A	0.03	0.32	0.32	-432.0010223	0.55987465	15.87	6856.00
NGC	BARK40	WTHU4B	0.03	0.32	0.32	-432.0010223	0.55987465	15.87	6856.00
NGC	BEDD20_LPN	BEDD20_SPN	0.00	0.01	0.01	449	0	0.00	0.00
NGC	BEDD20_LPN	CHSI20	0.07	0.75	0.75	-22.7193496	0.003613182	22.98	522.00
NGC	BEDD20_LPN	CHSI20	0.07	0.76	0.76	-22.42041079	0.003518724	24.70	554.00
NGC	BEDD20_LPN	WIMB20	0.04	0.38	0.38	4.953869771	9.76725E-05	16.85	83.00
NGC	BEDD20_LPN	WIMB20	0.00	0.00	0.00	483.4926282	0.009560993	21.28	10286.00
NGC	BEDD20_LPN	BEDD4A	0.03	2.68	2.68	-270.4032563	0.219353763	0.00	0.00
NGC	BEDD20_LPN	BEDD4A	0.03	2.68	2.68	-270.4032563	0.219353763	0.00	0.00
NGC	BEDD4A	ROWD4A	0.01	0.14	0.14	-540.8065127	0.292471684	119.17	64447.00
NGC	BEDD20_LPN	BEDD4B	0.03	2.68	2.68	-275.7501125	0.228114374	0.00	0.00
NGC	BEDD20_LPN	BEDD4B	0.03	2.68	2.68	-275.7501125	0.228114374	0.00	0.00
NGC	BEDD4B	ROWD4B	0.01	0.10	0.10	-551.5002249	0.304152498	119.17	65721.00
NGC	BESW20	COVE20	0.09	0.79	0.79	-115.3447113	0.119739622	22.38	2581.00
NGC	BESW20	COVE20	0.09	0.79	0.79	-115.3447113	0.119739622	22.38	2581.00
NGC	BESW20	FECK20	0.14	1.51	1.51	-83.47060248	0.097542781	42.92	3582.00

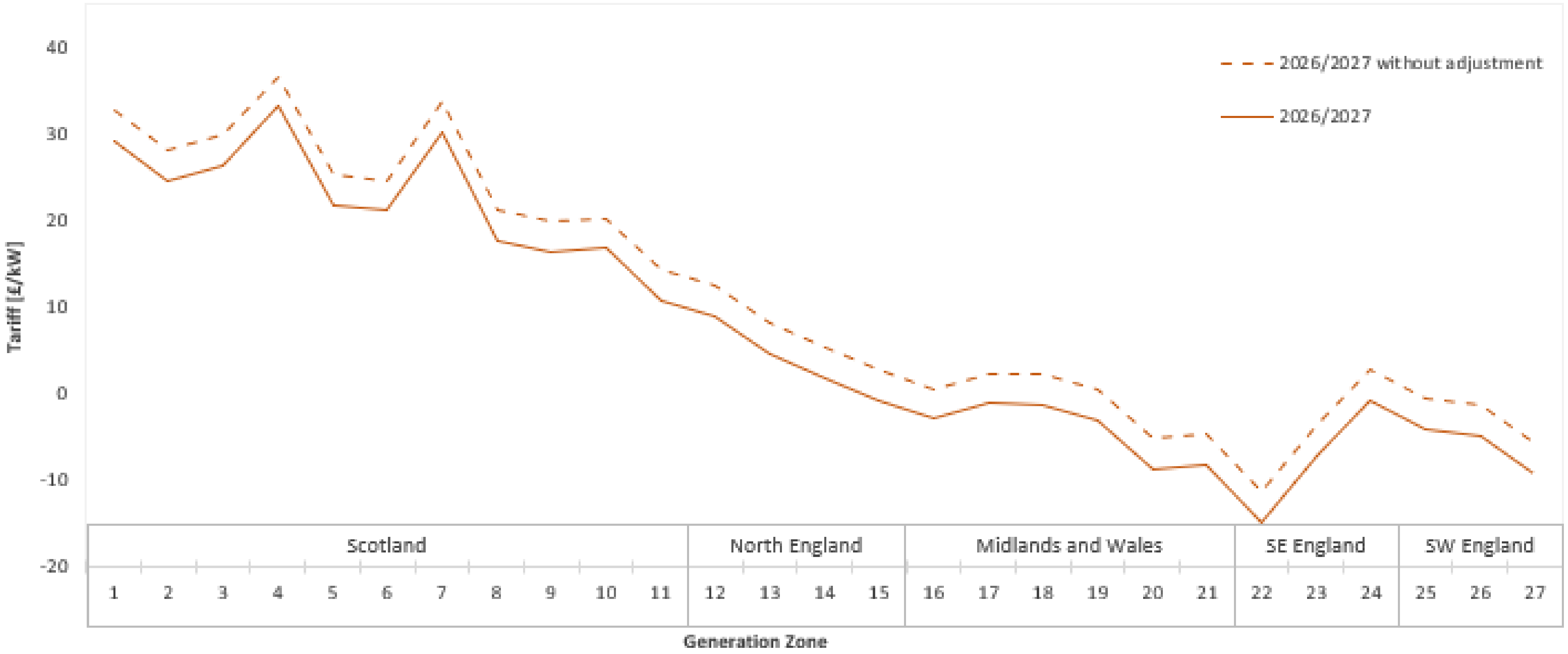
Flow cost

Following slide illustrates impact of the adjustment which moves generation tariffs up or down

Changes in target revenue recovery impact the adjustment

- The adjustment changes all zones by an equal amount to meet target revenue recovery. It changes the price but preserves the differential
- The inclusion or exclusion of certain elements in the calculation of the target revenue has a major impact on the adjustment. From 2021/22 all local charges are excluded, reducing the downwards adjustment necessary to meet target.

Wider Zonal Tariffs 2026/27 – with & without tariff adjustment



Adjustment in 2026/27 £**-3.54**/kW (CMP317 implemented)

TNUoS reflects changes in background conditions, so the more the network changes – the more volatile TNUoS becomes. Responding to net zero, the network will be evolving for the foreseeable future. Furthermore, what seem like minor methodological changes can have a major impact on tariffs. The following slide picks out some key examples.

Evolution of wider TNUoS

vs

Project TransmiT (2016) → Different charges for different types of generators

- Network utilisation is different
- Network investment needs are different

EU cap on <u>average</u> transmission charges paid by generators. Set to ensure that within the EU states internal electricity markets are not affected by variations in charges faced by generators. Cap set at €2.50/MWh.

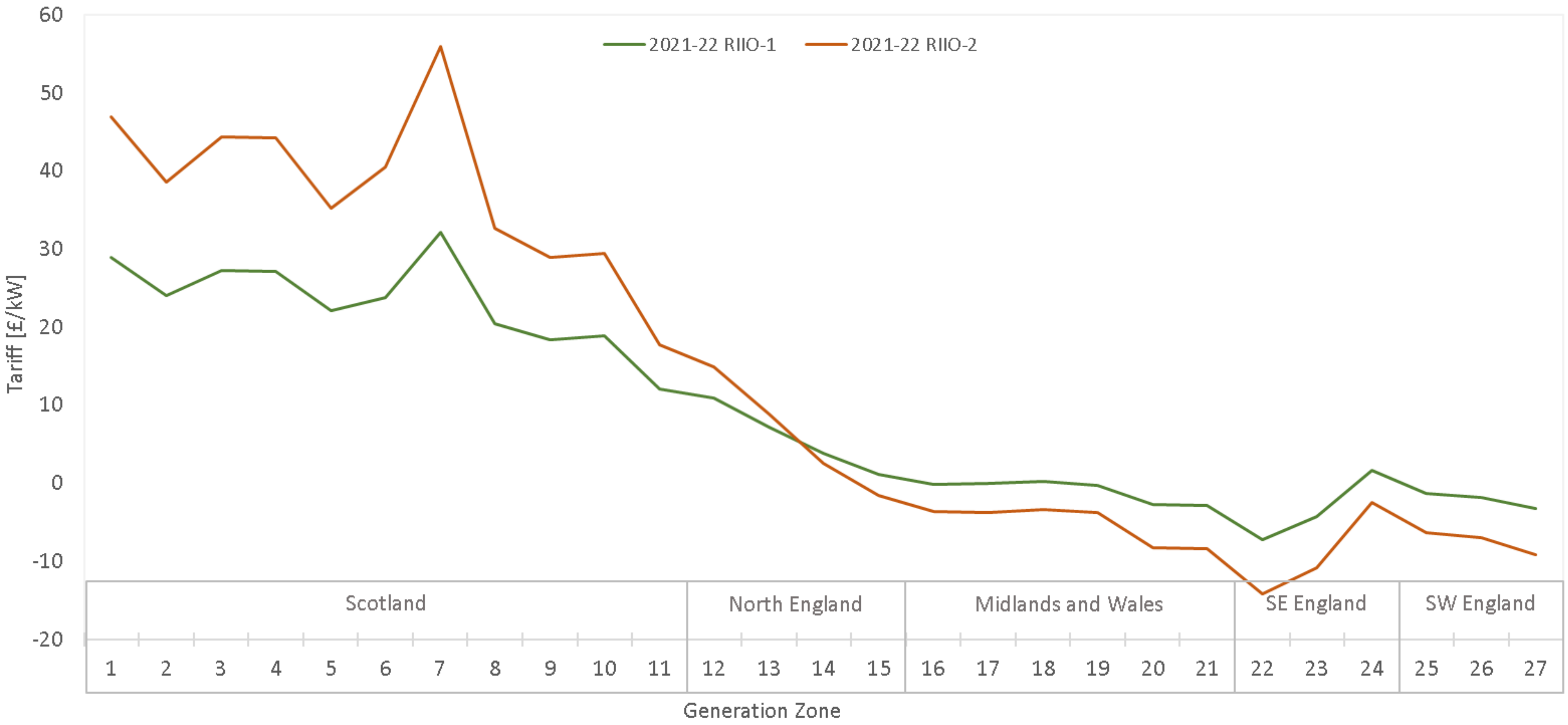
➡ impacts target revenue recovery from generation, and hence the generation tariff adjustment

£££

Expansion constant and expansion factors - Assumptions on the cost of infrastructure revised at the price control (called RIIO) and will likely increase in future years

➡ impacts (stretches) the north-south differential. Example of before and after assumptions given in following slide.

Predicted wider Zonal Tariffs 2021/22 for currently assumed (RIIO-1) and anticipated future (RIIO-2) unit costs of transmission*



*Data taken from modelling for [CMP353](), a CUSC Modification which seeks to delay the introduction of a new expansion constant because the impact is so great.

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