TNUoS 2021/22 Draft Tariffs Webinar

NGESO Revenue Team

December 2020

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NGESO Revenue Team
- TNUoS Tariff Forecasting & Setting

Rebecca Yang

Forecasting, setting and billing TNUoS to recover around ~£3bn of revenue per year from generators and suppliers

Sarah Chleboun

(On Maternity Leave)

Jo Zhou

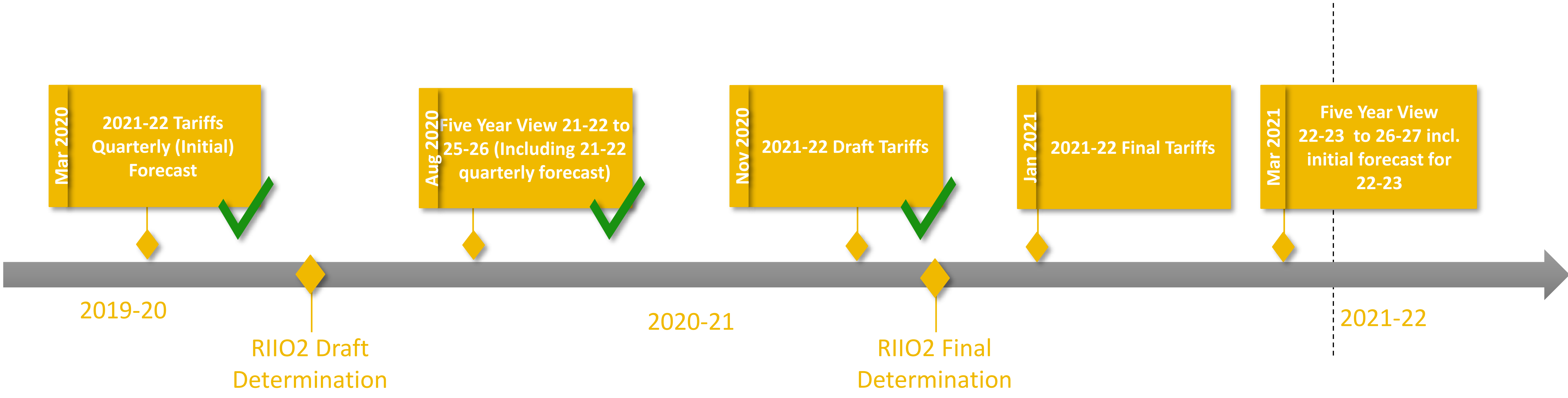
- Revenue
- Onshore Local Circuits
- Annual Load Factors (ALFs)

Alice McCormick

- Generation
- Local substation
- Offshore

Matt Wootton

- Demand
- EET
- RIIO2 Parameters



- We have published three forecasts for the TNUoS tariffs for 2021/22.
- The draft tariffs have incorporated CMP324/325 (generation rezoning)
- The final tariffs will be published by 31st January 2021 and take effect from 1st April 2021.
- Final tariffs for 2021/22 will incorporate
  - RIIO-2 Final Determinations
  - CMP 317/327 (Transmission Generation Residual)
  - CMP 353 (Expansion Constant & Factor)
  - CMP344 (Revenue adjustment) if decision confirmed
  - Consultation outcome for locational security factor

TNUoS Forecast Challenges

It has been very challenging to produce the draft tariffs for 21/22. This is mainly driven by a number of significant uncertainties with the charging framework. Whenever we can, we have provided sensitivity analysis to help the industry understand the implications.

Regulatory Changes

- Transmission Generation Residual (**TGR**) by April 2021 - Ofgem decision pending
- **CMP 344** TO revenue adjustment

Information Provision

- Delay in receiving 3rd party information
- Significant increase in onshore TOs revenue forecast (~**£362m**)

COVID19

- COVID19 has introduced increased uncertainty in demand forecast

RIIO2 Reset

A number of key charging parameters to be re-set for RIIO2:

- CMP324/325 Generation re-zoning – Ofgem decision confirmed
- CMP353 expansion constant/factors – Ofgem decision confirmed
- **Locational security factor** – ongoing industry consultation

Our Approach and Key Messages

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Input changes in this tariff publication

No new data since last forecast | Updated | Updated and locked down

		March	Five-year forecast	August	DRAFT Nov	FINAL Jan
Methodology		Open to industry governance				
Locational	DNO/DCC demand data	Demand forecast provided by DNOs/DCCs in 2019 (for charging years 2021/22 – 2025/26)			DNOs/DCCs update by week24	As per Draft Tariffs
	Contracted TEC	Latest TEC	Latest TEC	Latest TEC	TEC Register frozen at 31 October	As per Draft Tariffs
	Network model	As modelled in ETYS 2019 for charging years 2021/22 – 2025/26)			Updated with ETYS 2020	As per Draft Tariffs
Residual	Allowed revenue	Initial revenue forecast	Update financial parameters	Update financial parameters	Latest TO forecasts	Final TO revenue submissions
	Demand charging bases	Revised forecast	Revised forecast	Revised forecast	Revised forecast	Final forecast
	Generation charging base	ESO best view	ESO best view	ESO best view	ESO best view	ESO final best view
	Generation ALFs	As in 2019 ALF report			As in 2020 ALF report	As per Final ALF for 21/22
	Generation revenue	Forecast	Forecast	Fixed gen rev £m (CMP317/327)	As per August*	As per August*

Our Approach

We provide detailed analysis for the base case with a number of assumptions. The sensitivities provide an overview of the implications of the ongoing changes in charging mechanism should / when these are agreed.

	Base Case	Sensitivities
Generation	▪ Transmission Generation Residual (**TGR**) to exclude asset required for connection ▪ CMP325 **generation re-zoning** applied	• Alternative definition of “assets required for connection” • Include Congestion management cost in EU cap as per findings of CMP317/327
Revenue	▪ Onshore TO revenue – apply TOs latest forecast	• Apply a different annuity factor (as per CMA’s decision on water utilities price control) on TOs base revenue • Implementation of CMP344 to move Income Adjusting Events (IAEs) (£2.8m) from Offshore Local revenue to the demand residual
RIIO Parameters	▪ Apply the inflation uplifted RIIO1 **expansion constant & factor** as per our CMP353 proposal	• Provide the tariffs should the expansion constant & factors be re-set based on TO’s data
	▪ **Locational security factor** – apply 1.8 in line with CUSC reference	• Present the tariffs with 2 and 8 decimal places for locational security factor
	▪ **Local substation tariffs** have been recalculated but would be updated based on Final Determination and RPI changes for Final Tariffs	N/A
	▪ **Offshore local tariffs** have been recalculated with an indicative offshore substation discount applied	N/A
	▪ Avoided GSP Infrastructure Costs (**AGIC**) has been recalculated but would be updated based on Final Determination and RPI updates	N/A

Key findings under base case

Total Revenue

- Based on TOs' data, the total TNUoS revenue for 2021/22 would be £3.4bn (an increase of ~£362m from August forecast). This is based on TO's latest forecast in line with their RIIO2 business plans.

Generation

- Generation revenue is £813m, a decrease of £13m since the August forecast due to the 5GW decrease in the generation charging base. As a result, the average generation tariff increases from £10.74/kW to £11.35/kW.

Demand

- Demand revenue has increased £374m (~14%) to £2,596m since the August forecast; mainly driven by the total revenue increase. As a result, the average HH tariff has increased by £7.64/kW to £52.5/kW and the average NHH tariffs has increased by 0.87p/kWh to 6.56p/kWh.
- Locational demand volumes have decreased since the August forecast by 3.34GW to 46.4GW, due to the 'Week 24' demand forecast update. However a few zones have seen an increase vs the august forecast which created a greater variance in the tariffs for these zones.

Consumer Bill

- Using TO's revenue forecast, TNUoS charge would have an impact of £36.76 on consumer bill, an increase of ~£5 from August forecast. Consumer bill impact is only based on NHH tariffs.

Revenue

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Total Revenuesc

- Total revenue is forecast to be £3,410.2m in 2021/22, an increase by £362m, according to TOs' revenue forecast.
- These figures are highly indicative, and are based largely on TOs' business plans prior to Ofgem's draft determination.
- In this forecast, we have included a sensitivity analysis, using alternative rate of return (and thus annuity factor), to illustrate the possible magnitude of change following Ofgem's draft determinations.
- We have not included Ofgem's final determination in the report or the slides.
- As a high level indication, assuming the demand charging base is 50GW, for each £50m of revenue change, the demand residual tariff will change by £1/kW.

£m Nominal	2021/22 TNUoS Revenue March Forecast	August Forecast	Nov Draft
National Grid Electricity Transmission			
Price controlled revenue	*1,754.9*	*1,753.7*	*1,949.7*
Less income from connections		*29.8*	*29.8*
NGET Income from TNUoS	**1,754.9**	**1,723.9**	**1,919.9**
Scottish Power Transmission			
Price controlled revenue	*389.5*	*384.2*	*410.1*
Less income from connections	*12.7*	*12.7*	*19.5*
SPT Income from TNUoS	**376.7**	**371.5**	**390.6**
SHE Transmission			
Price controlled revenue	*377.5*	*383.4*	*542.6*
Less income from connections	*3.4*	*3.4*	*2.9*
SHE Income from TNUoS	**374.0**	**380.0**	**539.7**
National Grid Electricity System Operator			
Other Pass-through from TNUoS	**17.4**	**17.5**	**14.4**
Offshore (plus interconnector contribution / allowance)	**529.9**	**555.8**	**545.6**
Total to Collect from TNUoS	**3,053.1**	**3,048.6**	**3,410.2**

Breakdown of revenue to be recovered

- Generation revenue decreased slightly, as a result of changes to local charges.
- CMP317/327 seek to remove "assets required for connection" from calculation of "EU gen cap", and to remove generation residual.
- Demand revenue increased significantly, mainly driven by the updated revenue forecast.

	2021/22 Tariffs		
Revenue	**March**	**August**	**Draft**
Total Revenue (£m)	3,053.1	3,048.6	3,410.2
Revenue recovered from generation (£m)	820.6	826.4	813.7
Revenue recovered from NHH users (£m)	1,370.3	1,390.3	1,617.3
Revenue recovered from HH users (£m)	879.4	845.5	994.3
Less revenue paid to EET (£m)	- 17.2	- 13.6	- 15.1
Revenue recovered from demand (£m)	2,232.6	2,222.2	2,596.5

Generation Tariffs

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- For this forecast, as we did for the August forecast, we have modelled the tariffs based on Ofgem's final decision for the Targeted Charging Review (TCR).
- As part of our modelling of the changes to the TGR, we have assumed that local onshore and offshore tariffs are not included in the European €2.50/MWh cap as proposed under CMP317/CMP327.
- Compared to August, the residual has increased by £0.21/kW due to a decrease in the wider tariff revenue driven by locational data input updates.

Table 2

Generation Tariffs (£/kW)	August	2021/22 Draft	Change since last forecast
Residual	-0.232751	-0.027640	0.205111
Average Generation Tariff	10.740461	11.351149	0.610689

* The average generation tariff is calculated by dividing the total revenue payable by generation over the generation charging base in GW.

Generation wider tariffs

The generation TNUoS wider tariffs are made of the four elements below:

Peak Security

Year Round Shared

Generator Residual

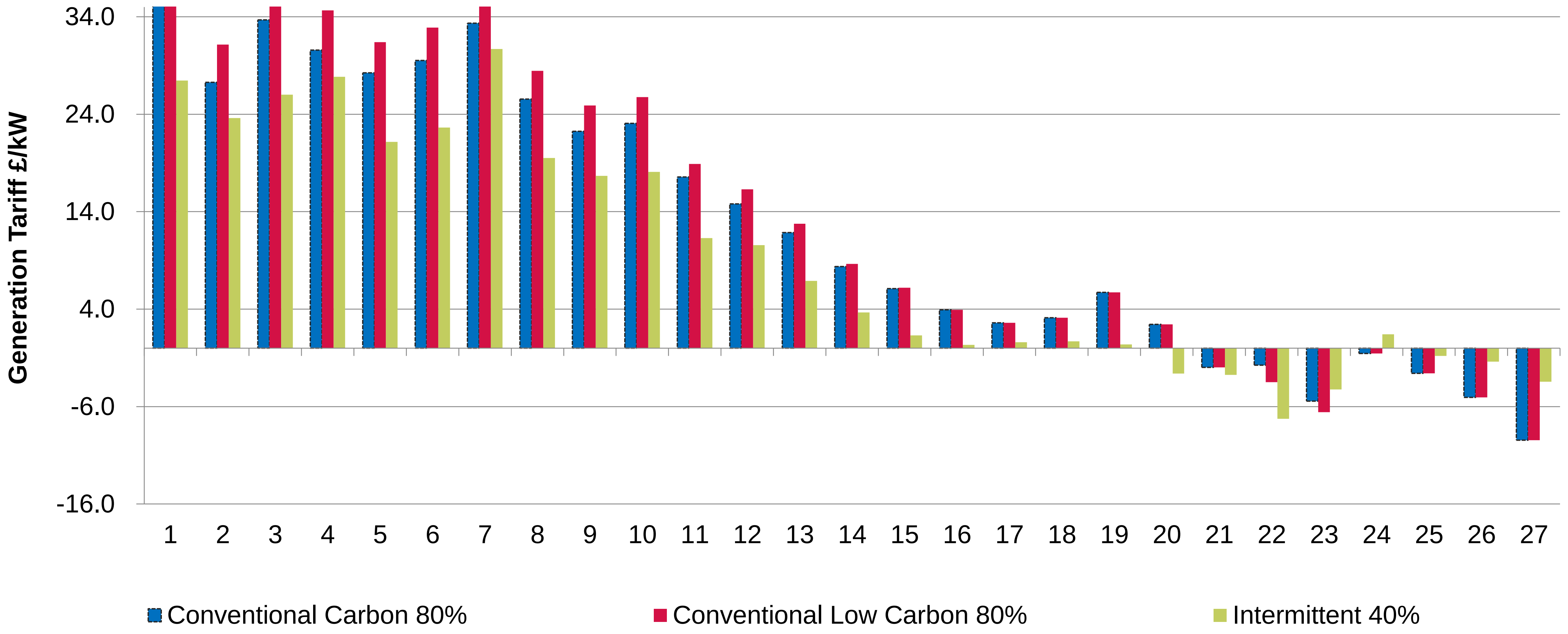
Year Round Not Shared

Year Round Shared and Year Round Not Shared elements are multiplied by Annual Load Factors (ALFs) dependent on generation type

We publish examples for each generation type calculation using example ALFs:

Conventional Carbon 80%	Conventional Low Carbon 80%	Intermittent 40%
Biomass	Nuclear	Offshore wind
CCGT/CHP	Hydro	Onshore wind / Solar
Coal		Tidal
OCGT/Oil		
Pumped storage (including battery storage)		

Example tariffs for a generator of each technology type



- Mainly consistent increase across zones
- Large increase in zone 4 due to changes in locational data input updates.
- There are large decreases in zones 20,21 and 27 due to updates in nodal demand forecasts and changes in generation connecting in that area.

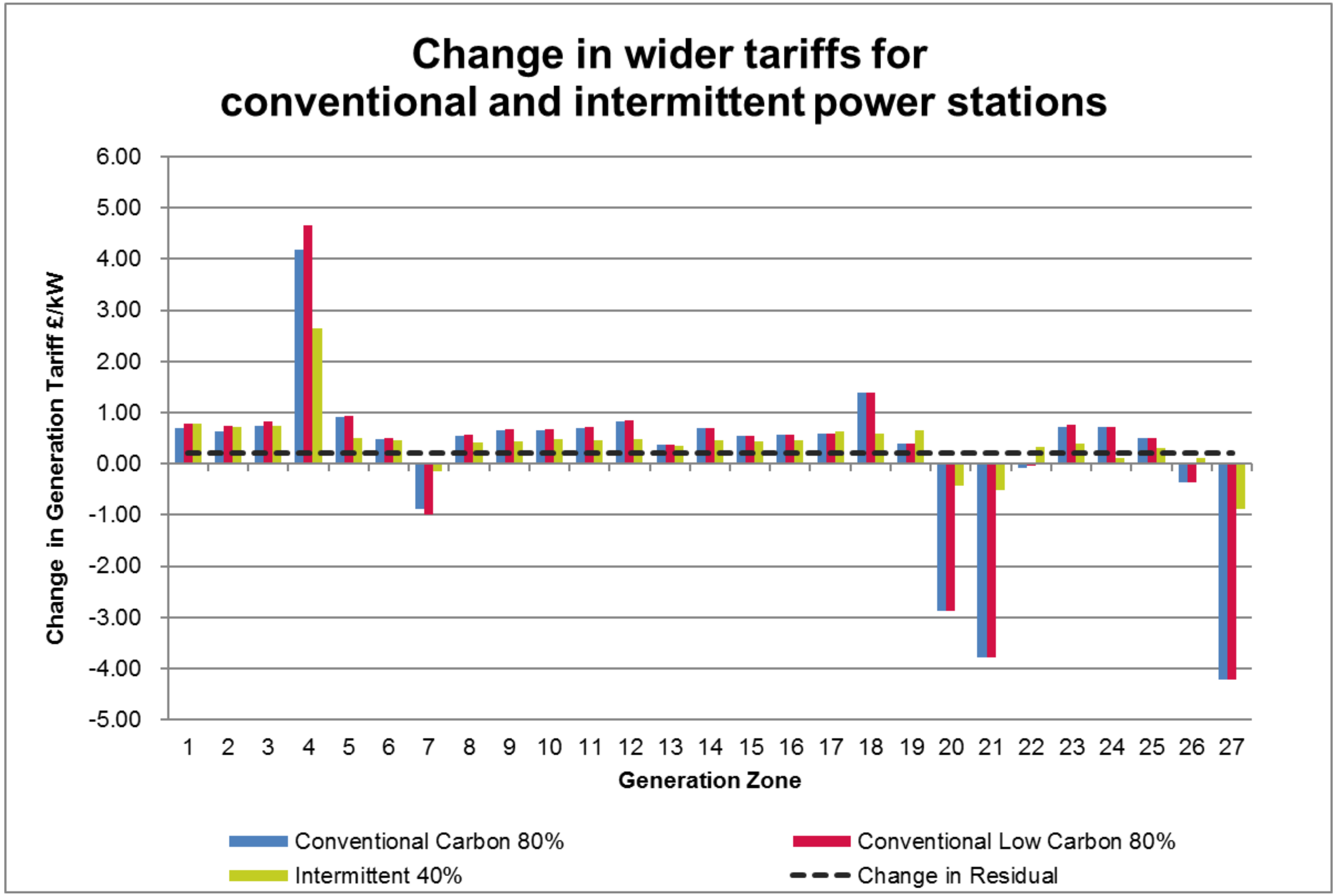


Figure 1

- TEC values have been updated in line with the 31 October 2020 TEC register
- Generation chargeable TEC forecast has decreased by 5GW since the August forecast due to several generators delaying or cancelling their connection. This includes our internal best view.
- A decrease to the charging base has increased the average generation tariff.

	2020/21	2021/22 Tariffs		
Generation (GW)	**Final**	**March**	**August**	**Draft**
Contracted TEC	84.9	93.6	92.7	89.9
Modelled Best View TEC	84.9	85.8	86.7	89.9
Chargeable TEC	70.7	76.8	76.9	71.7

Table 24

- CONTRACTED:
  - Full TEC register used
- MODELLED:
  - Reduction in TEC in line with our best view
- CHARGEABLE:
  - Modelled TEC minus interconnector capacity

Local Tariffs

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- Local circuits are modelled using the best information available. The list of local circuits are confirmed based on the TEC register.
- Local circuit tariffs have remain relatively stable due to the topologies of local circuits.
- Various definitions of GOS in CMP317/327 will change generation revenue, but won’t change the local charges paid by individual generators.
- The local circuits tariffs are listed here.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.693170	Dunhill	1.465377	Marchwood	0.390470
Aberdeen Bay	2.667514	Dunlaw Extension	1.545644	Mark Hill	0.895774
Achruach	4.393209	Edinbane	7.002587	Middle Muir	2.350844
Aigas	0.669121	Ewe Hill	2.490034	Middleton	0.155508
An Suidhe	-0.982412	Fallago	0.448201	Millennium South	0.482939
Arecleoch	2.124876	Farr	3.647698	Millennium Wind	1.867943
Baglan Bay	-0.148579	Fernoch	4.499988	Moffat	0.194852
Beinneun Wind Farm	1.536078	Ffestiniogg	0.258837	Mossford	2.945741
Bhlaraidh Wind Farm	0.660552	Finlarig	0.327589	Nant	- 1.256241
Black Hill	1.588833	Foyers	0.299677	Necton	1.149609
Black Law	1.787702	Galawhistle	3.579857	New Deer	0.194692
BlackCraig Wind Farm	6.440343	Glen Kyllachy	- 0.467985	Rhigos	0.105510
BlackLaw Extension	3.791055	Glendoe	1.881871	Rocksavage	0.018108
Clyde (North)	0.112198	Glenglass	4.922579	Saltend	0.017751
Clyde (South)	0.129752	Gordonbush	0.071177	Sandy Knowe	2.386571
Corriegarth	2.963905	Griffin Wind	9.936006	South Humber Bank	- 0.189686
Corriemoillie	1.702135	Hadyard Hill	2.831775	Spalding	0.289946
Coryton	0.051762	Harestanes	2.586255	Strathbrora	- 0.049415
Cruachan	1.866754	Hartlepool	0.091179	Strathy Wind	1.784321
Crystal Rig	0.141327	Invergarry	0.374388	Stronelairg	1.093264
Culligran	1.773187	Kilgallioch	1.076739	Wester Dod	0.489456
Deanie	2.913092	Kilmorack	0.202051	Whitelee	0.108579
Dersalloch	2.464404	Kype Muir	1.517485	Whitelee Extension	0.301849
Dinorwig	2.454656	Langage	- 0.344948		
Dorenell	2.147072	Lochay	0.374388		
Dumnaglass	1.159563	Luichart	0.586727		

- Local Substation tariffs have been updated as part of the RIIO-2 Parameter refresh for 2021/22 in the latest forecast.
- Whilst there has been an increase in base costs provided by the TOs, the decrease in the indicative annuity in Ofgem's RIIO-2 Draft Determination has meant overall the tariffs have reduced vs the uplifted RIIO-1 values used in the August forecast.
- These tariffs are subject to change and will be impacted by any variations relating to the annuity factor calculation from Ofgem's final determination as well as any changes to RPI.

2021/22 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.167824	0.070749	0.057144
<1320 MW	Redundancy	0.375090	0.161831	0.135062
>=1320 MW	No redundancy	n/a	0.219716	0.180959
>=1320 MW	Redundancy	n/a	0.343997	0.290898

- Tariffs are set at asset transfer, or the beginning of a price control, and are indexed in line with the revenue of the associated OFTO.
- These offshore tariffs have been recalculated, in preparation for the RIIO-2 period.
- Offshore tariffs will be finalized in January based on OFTO revenues and inflation data.
- The offshore substation discount is recalculated and would be updated based on Final Determination.
- Projects expected to asset transfer during 2020/21 will have tariffs calculated later this year.
- Since August, the civils discount has been updated with RPI and are included in these tariffs.

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	8.847343	46.675227	1.159010
Burbo Bank	11.057328	21.346582	-
Dudgeon	16.213542	25.417361	-
Galloper	16.549490	26.155193	-
Greater Gabbard	16.455306	38.045116	-
Gunfleet	19.239008	17.730507	3.313933
Gwynt Y Mor	17.844372	17.710590	-
Humber Gateway	12.188327	27.939147	-
Lincs	16.957830	66.640797	-
London Array	11.475403	39.308601	-
Ormonde	27.175448	50.773900	0.404625
Race Bank	9.794833	27.170573	-
Robin Rigg	- 0.583944	33.842704	10.842987
Robin Rigg West	- 0.583944	33.842704	10.842987
Sheringham Shoal	25.429358	29.935070	0.650700
Thanet	19.382584	36.292362	0.873685
Walney 1	23.47605	46.90995	-
Walney 2	21.84251	44.42657	-
Walney 3	10.06170	20.35939	-
Walney 4	10.06170	20.35939	-
West of Duddon Sands	8.89648	44.31827	-
Westermost Rough	18.28621	31.09982	-

Table 14

Demand Forecasts

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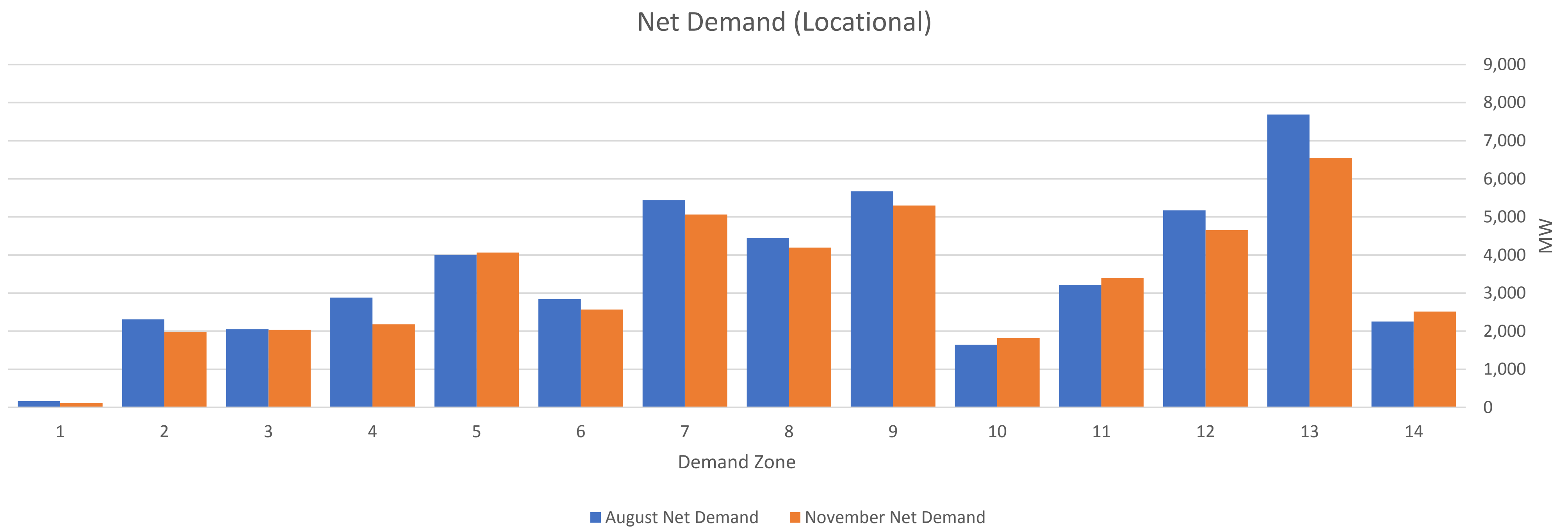
- Demand charging base has been updated for this forecast with updated simulations including outturn data up to the end of September.
- Whilst adjustments have been made to the inputs to the demand forecasting simulations in relation to COVID-19, there will be further review in the run up to the final tariffs, which will be supported by winter out-turn demand data giving further insight into the impacts COVID-19 on Peak demand (Triads) for 2020/21.
- HH net demand increased compared to August forecast, due to the updated demand charging base and a reduction in forecast to Embedded Export over Triads.
- HH Gross 'Chargeable' Zonal Triad Demand increased slightly, up 0.08GW to 18.95GW.
- NHH Demand has increased slightly. But proportionally there has been little change between the forecasted HH and NHH revenue

Charging Bases	2021/22 March	2021/22 August	Change
NHH Demand (4pm-7pm TWh)	23.97	24.43	0.46
Total Average Gross Triad (GW)	50.03	50.16	0.13
HH Demand Average Gross Triad (GW)	19.43	18.87	-0.56
Embedded Generation Export (GW)	6.82	7.31	0.49

Modelled Demand – Week 24 Data



- Changes in locational demand based on updated ETYS2020 – Week 24 data vs ETYS2019 Forecast
- Overall reduction in locational demand for GB
- Majority of Zones have decreased with the overall reduction
- The largest proportional zonal increases can be seen in zones 10 & 14

Demand Tariffs

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- Transmission Demand Residual Banding changes are not applicable to 2021/22 tariffs.

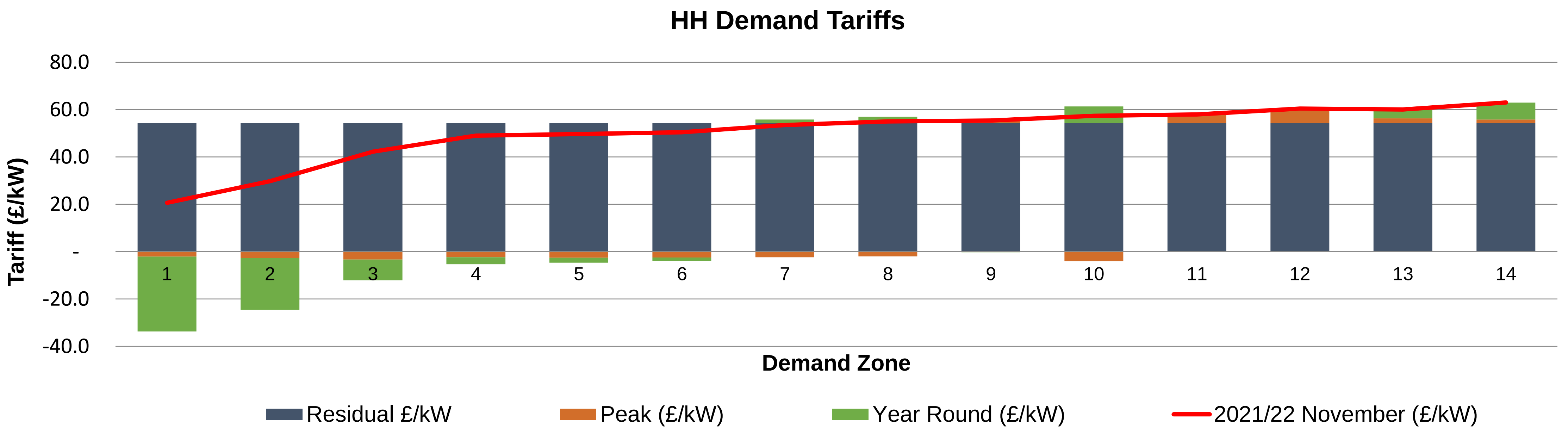
- Due to the total revenue increase, revenue to be recovered through demand has increased since August forecast resulting in an increase in HH and NHH tariffs.

- 2021/22 Tariffs do not include the impact of Small Generation Discount, which will discontinue from 01 April 2021

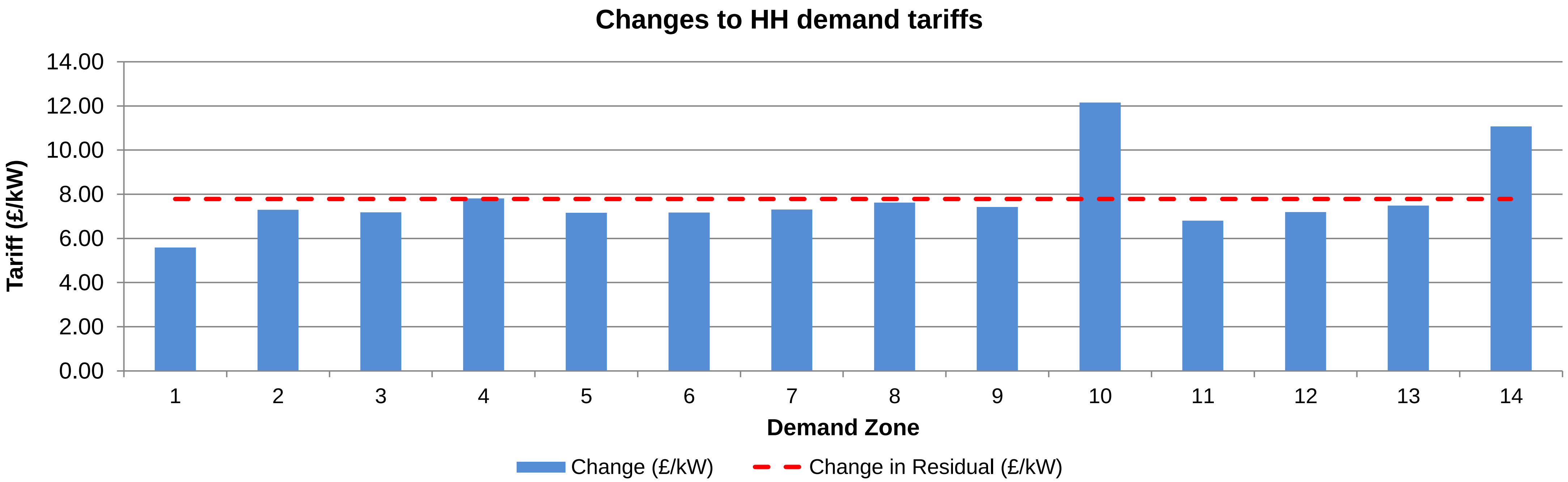
Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	20.631769	2.731383	-
2	Southern Scotland	29.787898	3.774643	-
3	Northern	42.247971	5.168770	-
4	North West	49.012126	6.135768	-
5	Yorkshire	49.688949	6.035617	-
6	N Wales & Mersey	50.465171	6.122775	-
7	East Midlands	53.518073	6.711876	1.458513
8	Midlands	55.089779	7.022124	3.030219
9	Eastern	55.422177	7.388941	3.362617
10	South Wales	57.425898	6.570524	5.366338
11	South East	57.975131	7.861029	5.915571
12	London	60.452238	6.340861	8.392678
13	Southern	60.122730	7.653066	8.063170
14	South Western	63.007529	8.596217	10.947969

Residual charge for demand:	54.342512

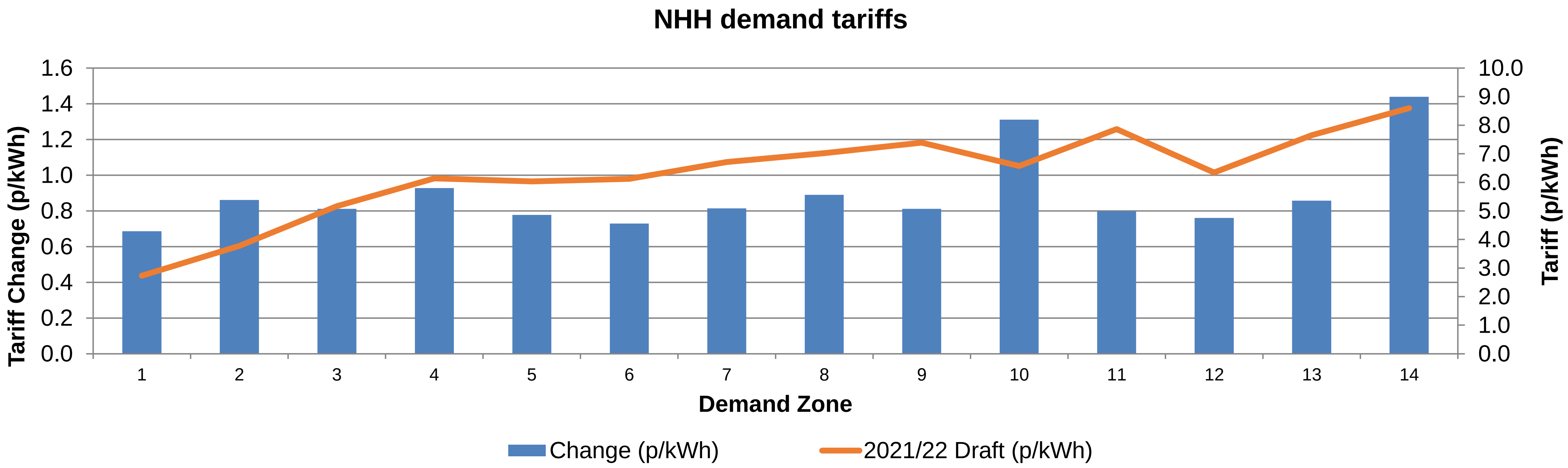
- The average HH tariff is £52.81/kW, an increase of £7.64/kW compared to August forecast due to the increase in revenue to be recovered.
- The residual element of the tariffs has increased by £7.78/kW for 2021/22 in this forecast up to £54.3/kW



- HH tariffs have increased in all zones since August, the increase varies across the 14 zones with a greater increase seen in zones 10 & 14 due to locational demand update (week 24 data). The increases can be seen with the change in demand residual.
- Overall the HH demand tariffs have increased due to the increase in demand revenue.



- The average NHH tariff is 6.56p/kWh, which has increased by 0.87p/kWh in comparison to August Tariffs
- Proportionally, there has been no significant change between the HH/NHH charges.
- As per the changes seen in HH tariffs, the impact of the changes to locational demand through the week 24 update result in an increase in NHH tariffs across all zones, with zones 10 & 14 showing the greatest increase



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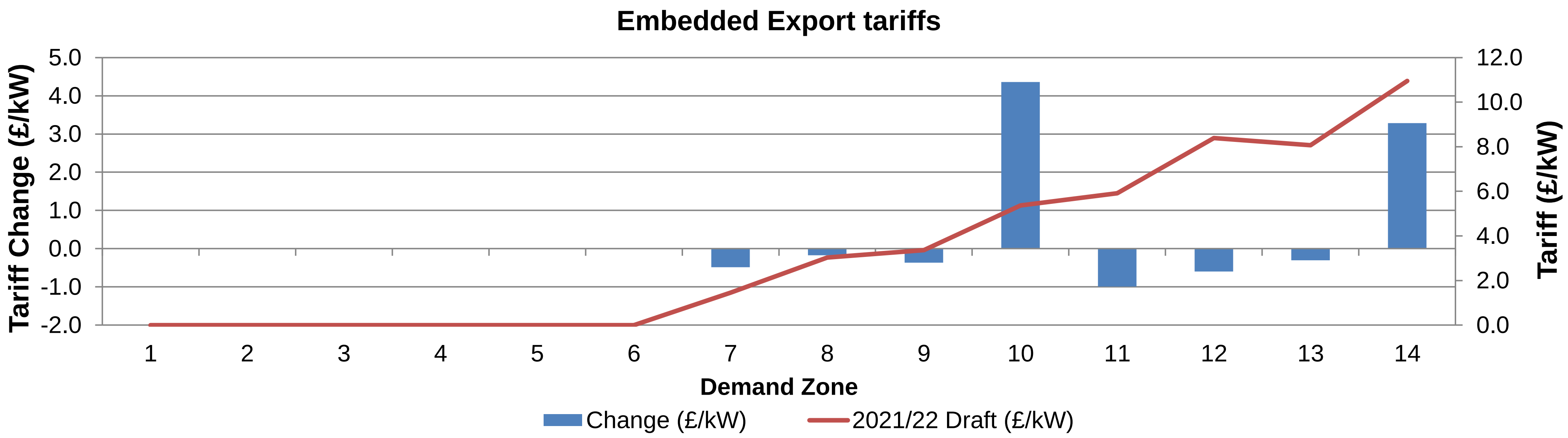
- There has been a considerable increase in the average Embedded Export Tariffs in comparison to the August forecast, the average tariff has increased by £0.41/kW to £2.27/kW, due to the changes in the locational demand.
- Zones 10 &14 have increased significantly in line with the updated locational demand profile for those zones vs the wider network.
- The remaining zones (non floored) have had small decreases inline with the overall reduction in forecasted locational demand



Sensitivity Analysis

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We are conscious that there is considerable uncertainty given the changes to the underlying framework. We believe that it would be helpful to provide a number of sensitivity scenarios, including:

1. Treatment of revenue adjustments in the charging
2. Inclusion of congestion management in the EU cap
3. Revenue forecast sensitivity
4. Gen Cap Sensitivity
5. Security factors sensitivity
6. Expansion Constant & Factors Sensitivity

- We have assumed £2.8m of revenue, due to unforeseen events, would move from offshore local tariffs to the demand residual under CMP344.
- This will increase the demand residual by £0.06/kW.
- It will decrease the tariffs for Gwynt Y Mor and Humber Gateway offshore generators. The tariffs remain the same for other offshore local tariffs.

		2021/22 Base Case	2021/22 CMP344 Sensitivity	Change
OFTO Local Revenue (£m)		422.69	422.26	- 0.430132
Revenue from Generation (£m)		813.71	813.28	- 0.430132
Revenue from Demand (£m)		2,596.96	2,599.77	2.811000
Generation Residual	£/kW	- 0.027640	- 0.027640	- 0.000000
Average Generation Tariff*	£/kW	11.351149	11.345149	- 0.006000
Average HH demand tariff	£/kW	52.460812	52.525658	0.064846
Demand Residual	£/kW	54.342512	54.407358	0.064846
Average NHH demand tariff	p/kWh	6.563620	6.571785	0.008165
Average EET tariff	£/kW	2.272481	2.272481	0.000000

*N.B These generation tariffs include local tariffs

Offshore Generator	Tariff Component (£/kW)			Change from base case (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Gwynt Y Mor	17.844372	17.710590	-	- 0.190882	- 0.183448	-
Humber Gateway	12.188327	27.939147	-	- 0.306977	- 0.671508	-

- As part of CMP317/327, it is thought according to EU definitions congestion management costs may be included in the EU cap.
- For this sensitivity, we have included £547.6m of congestion management cost for 2021/22 based on the latest BSUoS forecasts. This is an increase of £83.9m since the August forecast.
- It is expected to decrease generation charges by £7.63/kW and increase the demand residual by £10.95/kW compared to the base case.

		2021/22 Base Case	2021/22 Congestion Management Sensitivity	Change
Generation Residual	£/kW	- 0.027640	- 7.666583	- 7.638943
Average Generation Tariff*	£/kW	11.351149	3.712207	- 7.638943
Average HH demand tariff	£/kW	52.460812	63.416751	10.955939
Demand Residual	£/kW	54.342512	65.298452	10.955940
Average NHH demand tariff	p/kWh	6.563620	7.943205	1.379585
Average EET tariff	£/kW	2.272481	2.272481	0.000000
Revenue from Generation	£m	813.71	266.11	- 547.597908
Revenue from Demand	£m	2,596.53	3,144.13	547.597908

*N.B These generation tariffs include local tariffs

- Onshore TOs submitted their revenue forecast, which were largely based on their RIIO-2 business plan
- Ofgem has indicated in their draft determination that lower rate of return may be used. Thus will lead to lower annuity factor on the regulated asset base, and lower annual revenue for onshore TOs.
- In light of the steer from the industry at TCMF, this sensitivity analysis was based on CMA's recent decision (on water utilities), and is subject to a list of assumptions:

1. Assuming "other revenue items" in onshore TOs' revenue breakdown, remain the same as in the August forecast.
2. Assuming generic asset life of 50 years
3. Assuming onshore TOs' base revenue figures reflect regulated asset base only, and are proportional to the total of (annuity factor + overhead factor).

<table>
<tr><th></th><th>NGET Base Revenue (£m)</th><th>Other NGET revenue items (£m)*</th><th>SPT Base Revenue (£m)</th><th>Other SPT revenue items (£m)*</th><th>SHETL Base Revenue (£m)</th><th>Other SHETL revenue items (£m)*</th><th>Other ESO revenue items (£m)**</th><th>Total (£m)</th></tr>
<tr><td>Base case (£m)</td><td>1961.8</td><td>-41.9</td><td>378.2</td><td>12.4</td><td>541.7</td><td>-2.0</td><td>560.0</td><td>3410.2</td></tr>
<tr><td>Assumption on financial parameters***</td><td colspan="8">ESO assumes that onshore TOs based their revenue forecast on the same annuity and overhead factors as in RIIO-T1 (5.81%+ 1.8%). The sensitivity analysis uses an alternative annuity factor (4.79%) which is in line with CMA's decision on water utilities price control, and same overhead factor (1.8%) as in RIIO-T1</td></tr>
<tr><td>Revenue Sensitivity (£m)</td><td>1698.9</td><td>-41.9</td><td>327.5</td><td>12.4</td><td>469.1</td><td>-2.0</td><td>560.0</td><td>3024.0</td></tr>
<tr><td>Variation (£m)</td><td>-262.9</td><td>0.0</td><td>-50.7</td><td>0.0</td><td>-72.6</td><td>0.0</td><td>0.0</td><td>-386.2</td></tr>
</table>

Sensitivity 4 – Gen cap and generator only spurs

- We assumed the original definition of GOS in the base case (including TNUoS charges in respect of an Onshore local circuit, Onshore local substation, Offshore local circuit and Offshore local substation).
- Alternative definition of GOS under CMP317/327 (TGR) - "In terms of an onshore generator, a spur consists of (a) an onshore substation (the Onshore Local Substation); and (b) underground cables, or overhead line that is not shared with demand, or another generator, which run from the Onshore Local Substation to an Onshore Substation, from where electricity can be transmitted towards its ultimate users."
- This led to a reduction to generation revenue by £2.8m under this scenario.

	Peak Security (£m)	Year Round Shared (£m)	Year Round Not Shared (£m)	Residual (£m)	Onshore Local Circuit (£m)	Onshore Local Substation (£m)	Offshore Local (£m)	Total (£m)	Generation adjustment factor (residual) (£/kW)
Base case	109.0	109.2	148.3	-2.0	15.2	11.4	422.7	813.7	-0.027640
GOS sensitivity	109.0	109.2	148.3	-4.8	12.7	11.0	422.7	810.9	-0.067091
Variation	0.0	0.0	0.0	-2.8	-2.4	-0.4	0.0	-2.8	-0.039450

Sensitivity 5 – Security factor sensitivity

- The Locational Onshore Security Factor reflects the level of capacity redundancy in the wider network. All wider tariffs are all scaled by this figure.
- We have re-calculated the new value for RIIO-2, using 5 years' models. The new value is around 1.7555 (if rounded to 4 decimal places). In our forecasts, we have been using 1.8 (rounded to 1 d.p.)
- This sensitivity shows wider tariffs with different accuracy level (to 2d.p. and to 8d.p.)
- In parallel, we have also undertaken a consultation on this approach. We aim to communicate the outcome before Christmas.

		Tariffs (£/kW)				Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	4.139437	19.913375	18.906466	0.000000	35.195310	38.976603	26.871816
2	East Aberdeenshire	3.162051	10.510472	18.906466	0.000000	26.695601	30.476895	23.110655
3	Western Highlands	3.854210	18.183520	18.195770	0.000000	32.957642	36.596796	25.469178

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	21.454043	2.840242	0.000000
2	Southern Scotland	30.406702	3.853056	0.000000
3	Northern	42.589884	5.210601	0.000000

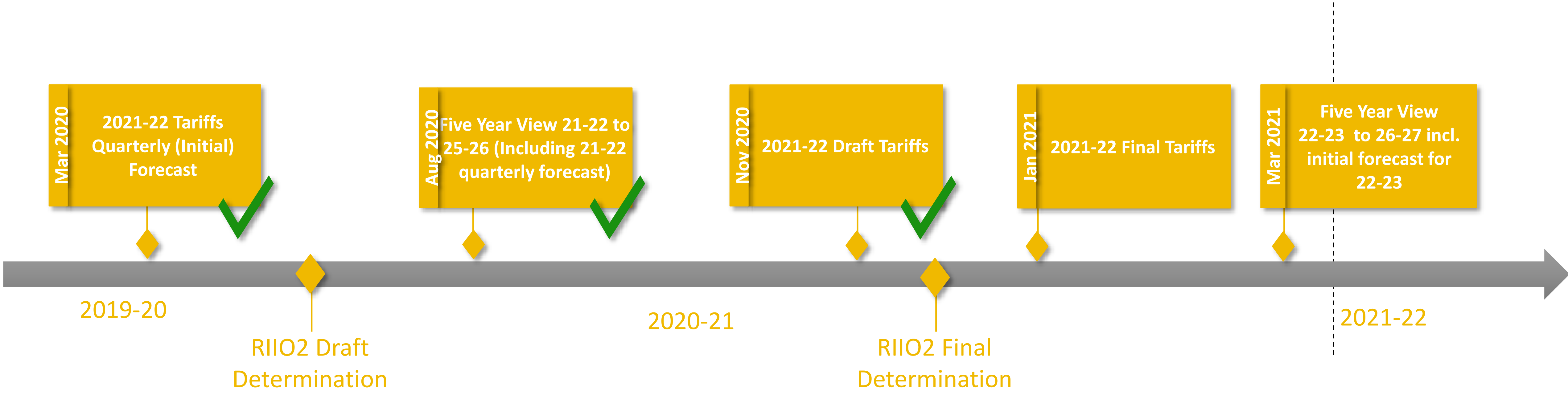
Sensitivity 6 – Expansion Constant & Factors (CMP353)

- CMP353 was raised as an urgent mod at the end of October 2020 to stabilise the Expansion Constant (EC) and relevant Expansion Factors (EF) for 2021/22
- The mod was raised due to a significant increase in the EC and considerable variation in the EF; Based on the data received to date and the current methodology that sets these values at the start of each price control
- The sensitivity analysis in the report shows the impact of the re-calculated EC & EF using TO's data on tariffs.
- After consultation with industry, Ofgem has approved CMP353 on 3rd December 2020
- We are currently working on the plan on EC&F review as directed in Ofgem's decision letter.

Next Steps

Go to: www.slido.com
Event code: #DraftTariffs

Next Steps



- The final tariffs for 2021/22 will be published by 31st January 2021 and take effect from 1st April 2021.
- We will incorporate RIIO-2 Final Determinations, TOs' final data submission as well as Ofgem's decisions on the applicable regulatory changes.
- We are currently planning to issue the next five year view by the end of March 2021.

Getting involved

- **Transmission Charging Methodology Forum (TCMF)**

We will continue to engage with you on our TNUoS forecast via the monthly TCMF meetings.

Further details can be found on the NGESO website

- **Charging Future Forum**

One place to learn, contribute and shape the reform of GB's electricity network access and charging arrangements

Further information can be found on the Charging Futures Website or sign up to receive more information here.

- **Subscribe to our TNUoS mailing list**

If you’re not already subscribed to our mailing list you can subscribe here

Q&A

Go to: www.slido.com
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Q&A

Q1. What is the impact of RII02 determination on the draft tariffs (especially the demand residual)?

The RIIO-2 draft determination contains the indicative annuity factor, which was applied to TNUoS parameters which were used for the draft tariffs calculation. On the allowed revenue for TOs, we didn't take into account of the Draft Determination, as we do not have sufficient information to calculate allowed revenue (only TOs have the relevant data which feed into revenue calculation). The allowed revenue will have a direct impact on demand tariffs, because the generation revenue is capped to 2.50 Euro/MWh. The RIIO-2 Final Determination will set the allowed revenue for onshore TOs for 2021/22. As per STC (SO-TO Code), we need TOs submission of their revenue figures in January to calculate the final tariffs, and this will have an impact on demand residual tariff.

Q2. Compared to the TO's forecast is the final determination higher or lower?

At the time of the webinar, we hadn’t had the chance to study Ofgem’s Final Determinations. But an attendee from NGET confirmed that under the Final Determination, NGET’s revenue forecast for 2021/22 will be lower than the forecast for the draft tariffs).

Q&A

Q3. The TOs business plans were published a year ago. Why has it taken a year for this to be included in your TNUoS forecast?

Although the business plans were published a year ago, they did not contain adequate information for the ESO to forecast the TNUoS charges. For example, asset base and depreciation of individual assets, are not in business plans. We are obliged to use the latest data submitted by TOs in our forecast.

Q4. When is the next 5 year forecast to be published? I strongly believe a revenue update must be published by the TOs ASAP to capture the RIIO-2 final determination.

We're planning to publish the next 5 year forecast by the end of March. We agree that a revenue update by the TOs ASAP will help us finalised tariffs by end of January.

Q5. Will decommissioning power stations be charged TNUoS as 'final demand' from April 2022?

The Non-Final Demand classification for a power station includes commissioning, operation and decommissioning; therefore as long as there's no other reason, decommissioning power station wouldn't be classed as 'Final Demand, and they will not pick up the TDR charge.

Q&A

Q6. Are you confident you will be able to include CMP317/327 in the Final tariffs? Slide 4 suggests yes but slide 5 potentially not as it mentions April.

This was a confusion caused by the wording on the slide. If CMP317/327 is approved by Ofgem prior to the Final tariffs (due to be published by end January), we will include CMP317/327 in the Final tariffs for 2021/22. The final tariffs will go live from April 2021.

Q7. will tariffs indexation switch from RPI to CPI in RIIO-2?

We believe that's the case, as CPIH was used in Ofgem's Final Determination. We are working to raise on this to understand more, and we will need some clarity on the legal text for the CUSC modification, which will be driven by the licence change.

Q8. what is NGESO plan to deal with expansion constant?

In Ofgem's decision letter on CMP353 (expansion constant/factors), the ESO is requested to submit a plan by the end of January to further review the expansion constant/factors. It was eluded that other relevant elements (e.g. review of generation zoning) will also be included in the plan. We are working on the plan and are aiming to share the proposal in the January TCMF (Transmission Charging Methodology Forum).

Q&A

Q9. Does NGESO intend to pursue rezoning for generation towards 14 zones again in 2021 (as alluded to in CMP 353 decision)?

Please See Q8. The review of gen zoning is not specifically for 14 zones; instead, we are required to consider it in conjunction with expansion constant due to the interactivity.

Q10. Any plans to have a generic ALF for Solar?

Generic Solar ALF is currently 10.8%. This figure was based on BEIS's data, as no sufficient data available for us to calculate Solar ALFs. We have shared this approach in November TCMF.

Q11. Why is the TO data processed so late, consultations like 'security factor' taking place so close to the final tariffs being calculated? All a bit last minute.

We agree with the comment. On the TO data, we didn't receive the full set of TO data in time; in addition, there have been a lot of discussions around detailed data specification and information granularity, which delayed the process. On the security factor, we didn't expect the consultation was needed. The re-calculated result was shared with the industry straight after the 5-year view, in September TCMF, however we were challenged on the number of decimal places we should apply. The consultation was suggested at November TCMF to seek view from the wider industry, instead of just TCMF attendees. We appreciate that it introduced some uncertainties to the final tariffs.

Q&A

Q12. Would you welcome obligations on parties to supply data in sufficient time? Will you raise a modification for this?

We have not got a plan to raise a modification on data submission. In terms of TOs data submission, the STC has defined the timescale for TOs to provide information to the ESO for tariff forecasting and setting.

Q13. You are predicting a negative residual tariff for Generation is this right in light of Ofgem's licence direction for TCR?

We understand the direction of TGR, which is to set generation residual to zero. However, we still need to be compliant with the [0-2.5]Euro/MWh range, and thus we assumed that a small negative adjustment factor is required to ensure that we continue in complying with the EU gen cap. For the purpose of the report, we still call it "residual" and therefore may have caused the confusion. We will update the wording in our reports in future, to align with the terms used in the CUSC.

Q14. NHH tariffs go negative in North Scotland under the EC sensitivity, while HH are floored. Is this the intention for future locational changes / model required?

There is an error with table S13 in the Draft Tariffs publication. Zone 1 – Northern Scotland '(EC&F RIIO-2 Update)' value should show as 0.00000 not -0.162748, as this should be floored.

Q&A

Q15. Why are demand tariffs given less than 5 minutes time on this webinar vs. 40 minutes for generation? Demand is the largest component of revenues.

Demand charges are the largest component of TNUoS revenues. Regarding proportion, there are 7 slides on generation and 5 slides on demand. More generation slides are mainly driven by more types of generation tariffs e.g. local substation, local circuits, wider, onshore / offshore. We will take this comment onboard, and consider providing more information on demand tariffs going forward.

Q16. Any plans to issue a MITS list?

At the moment, producing a MITS list is a labour-intensive manual process, as unfortunately we do not have an automated tool to do it. We are considering ways to share the information with the industry going forward.

Q&A

Q17. Can you share the assumptions made on the demand reduction as impact of Covid-19?

The demand forecast tool uses Monte-Carlo simulation to forecast next year's demand, utilising a wide variety of data, including metered demand data from this year, weather conditions (wind speed, illumination etc), and many other factors. As it utilises actual data that we have no control over, it is not straightforward to separate the Covid-19 effect from other factors that also affect the demand level.

So far and based on the existing demand data, we are predicting ~4% of revenue under recovery due to Covid-19 impact. However, we've seen a trend of recovery over the last couple of months. Going into winter we will have more data feeding into the simulation, and particularly HH demand data. We will monitor outturn demand data closely, and re-run the Monte-Carlo simulation for the Final tariffs.

Q18. NG ESO published a sensitivity on expansion constant for 2021/22, is there also a sensitivity for 2024/25 and 2025/26 available?

We have not produced the analysis for 2024/25 or 2025/26. The expansion constant needs to be reset at the start of a price control period, and then will be RPI-indexed year on year throughout the price control period. We published the sensitivity for 2021/22, and if there is a need to undertake the sensitivity for future years, it is likely to be required by the CUSC modification workgroup to review the expansion constant.

Q&A

Q19. why have you kept demand under review due to covid but are not doing the same for generation output? Inconsistent. given amount of uncertainty need to be flexible about what is "locked down" if clearly out of date then should consider updating in final tariffs?

We have received some comments on generation output from other parties that whether adjustment needs to be made to the generation output. We will consider these feedbacks and assess whether we need to review this figure for the Final tariffs.

Q20. You mentioned that moving from RPI to CPI indexation will require a modification, will this be in place for April '21?

Yes.

Q21. Are demand and generation zones different? Is there a map showing the zones?

Yes, they are different. There are 14 demand zones and 27 generation zones. The maps are part of the report in Appendice H & I.

The link to the report is given here https://www.nationalgrideso.com/document/181866/download

Q&A

Q22. If local charges are removed (eg £10/kW charge removed) and the residual is adjusted in line (e.g. a -£10/kW charge removed) why have TNUOS charges increased?

The local charges are removed out of the EU gen cap, but they will still be charged to the relevant generators. By removing these charge out of the EU gen cap, they no longer affect the generation residual tariffs, and generation residual doesn't need to offset the local charges. Therefore total TNUoS charge for generators (including wider charges and local charges) increased.

Q23. The GOS sensitivity table numbers are confusing - it seems as though there should be either zero or 4.8 as the total change?

Apologies for the confusion. We can confirm the total change is £2.8m as in the report.

Getting in touch

Your Questions

We will publish a Q&A document on our website, including the questions received regarding this five year view report

Your Feedback

We are continuously looking at ways we can improve the experience of our customers

We welcome your feedback on the TNUoS tariff forecasting and setting process

Your Questions & Feedback survey:

Go to: www.slido.com
Event code: #DraftTariffs
Respond to 3 questions under 'Polls'

TNUoS Queries

E: Tnuos.Queries@nationalgrideso.com

Thank You

Go to: www.slido.com
Event code: #DraftTariffs
Please respond to
3 questions under ‘Polls’

RIIO-2 Parameters Overview

Parameter	Changes
Generation zones	• Following approval of CMP325, the generation zonal boundaries have been fixed and remain as 27 for the time being.
Expansion Constant and Onshore Factors	• The assumption for draft tariffs is that the expansion constant for RIIO1 (uplifted) continues and that the expansion factors are unchanged. With the approval of CMP353; Final Tariffs will use the same assumption as per the proposal.
Locational Onshore Security Factor	• The security factor remains as 1.8 in the draft tariffs. We are currently consulting the industry on the different decimal places for the security factor and will apply the consultation outcome in the final tariffs.
Local Substation Tariffs	• Tariffs have been updated for 2021/22 as part of the RIIO-2 parameter refresh. Variations to the annuity and overhead factors between Draft and Final Determination will impact these tariffs for our final tariffs publication.
Offshore Local tariffs	• Offshore tariffs have been recalculated to adjust for differences in actual OFTO revenue to forecast revenue in RIIO-T1. An indicative Offshore substation discount has been calculated.
Avoided GSP Infrastructure Costs (AGIC)	• The AGIC which forms part of the Embedded Export Tariffs has been updated for 2021/22 Tariffs. Changes to annuity factor calculation and RPI will adjust this value in the run up to final tariffs.