TNUoS Tariffs Five Year View (2023/24 –2027/28) Webinar Questions and Answers

May 2022

Judicial Review

Is the judgement on the JR re CMP317/327 publicly available?

The Judicial Review ruling is publicly available using the following link:
https://www.bailii.org/ew/cases/EWHC/Admin/2022/865.html

The Competition & Markets Authority have also published a short summary, which can be found at:
https://www.gov.uk/cma-cases/sse-code-modifications-appeal#high-court-challenge-to-the-cmas-decision-on-sses-appeal-against-decisions-by-ofgem

Also, Ofgem have now published a statement which can be found here:
https://www.ofgem.gov.uk/publications/updated-statement-tnuos-judicial-review?utm_medium=email&utm_source=dotMailer&utm_campaign=Daily-Alert_05-05-2022&utm_content=Updated+statement+on+the+TNUoS+judicial+review&dm_i=1QCB,7UMCS,97JZT9,W1QEY,1

What is the draft timetable for adjusting forecasts given the Judicial Review? Will there be additional modifications to reflect any rectification of charges?

We are currently working with Ofgem to understand what the outcome of the Judicial Review means in practice, and we will communicate that and engage with you as soon as we have any further information. If there is an impact on the TNUoS Tariff Forecast Timetable, then we will discuss that with you and publish a revised timetable.

If there are payments back from JR result to Generators what is the process?

We are currently working with Ofgem to understand what the outcome of the Judicial Review means in practice, and we will communicate this as soon as we have any further information.

Market Allowed Revenue (MAR)

MAR increased significantly since previous forecast (25/26: MAR increased by c. £650m) which significantly impacts demand tariffs-what has driven this increase?

There are multiple factors as to why Market Allowed Revenue (MAR) increases, however this is not something that the NGESO has any control over and only a small fraction of the MAR can be attributed to NGESO operational costs. The MAR is agreed between the TOs and Ofgem for each price control period. Changes to MAR within a price control period (for any given year) and the breakdown of what makes up the overall MAR can be seen in the TOs and OFTO's.

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Further on the significant increase in allowed revenue since the previous 5-year tariff forecast, could any earlier notice have been provided for this?

On 30th November each year, Ofgem published the results of the Annual Iteration Process (AIP) which gave updates for the Onshore TO allowed revenues for the next regulatory year (for example, the allowed revenue for April 2022 - March 2023 was published on 30th Nov 2021). The AIP weblink is here https://www.ofgem.gov.uk/publications/et2-price-control-financial-model

Under STCP 24-1, Onshore TOs provide their 5-year revenue data to us by 7th January, whereas Offshore TOs provide their 5-year revenue data to us by 25th January, after which we perform our own validation. This gives little scope for any earlier notice to be given ahead of a March publication.

Part of the increase in revenue to be collected, that is seen across the 5 years, is a forecast of revenue for offshore projects that have not yet asset transferred. This forecast uses the latest information available at the time for expected asset transfer dates.

It is worth noting that there is a live CUSC modification, CMP286, which intends to improve the predictability of TNUoS tariffs by bring forward the date at which the target revenue is fixed so this may be of some interest.

Do the Revenue and Demand tariffs include inflation and if so, which OBR forecast do they use, March 2022?

The allowed revenue (MAR) figures are provided by TOs and have been inflated in accordance with their licences (for onshore TOs, the inflation is based on CPIH). The locational elements of onshore TNUoS tariffs are also inflated by CPIH, based on the latest available ONS data at the time of tariff setting.

Additionally, the exchange rate for the gen cap calculation is based on the October 2021 Economic & Fiscal Outlook (EFO), published by the OBR as this was the latest at the time of tariff calculation. The March 2022 EFO data will be included in our August update on 2023/24 tariffs.

Network / Circuits

Can NG improve transparency by detailing which large individual investments (over a threshold e. £1bn) listed in ETYS/NOA are included in the MAR.

The ESO obtain MAR forecasts from the TOs, and the forecasts do not include breakdown of individual projects. The TNUoS transport models reflect future network changes as per the ETYS/NOA recommendation, however, a large investment may incur MAR spending well ahead of its completion date, typically by 3-4 years in advance so not all investments will be reflected in the transport models within the 5-year time frame.

Generation / Demand

The NG report lists that locational tariffs become more polarised over the next 5 years, mainly driven by the north- south flows - what is driving this?

This is driven by a combination of factors including shifting towards low carbon generation, changes to networks, and also the nodal demand forecasts (provided by DNOs and are known as the week 24 demand data), which show year-on-year increase on nodal demands.

Why are demand locational tariffs floored at zero but generation locational tariffs can go negative?

Flooring the demand locational tariffs was made as part of the decision for CMP343/340, which removes the incentive for demand sites to consume more power at peak times (and in general) to potentially reduce their charges. Negative locational tariffs for generation provide incentive to increase capacity in areas of higher demand, reducing the requirement to increase network capacity.

Demand

Will P432 (migrating CT advanced meters to HH settlement) have a significant impact on TNUoS? Arrangements to avoid double charging in year of migration?

It is hard to say at this point in time and will be dependent on any future charging methodology changes and the approach taken to avoid double charging when meters migrate to HH. Fundamentally there shouldn't be a significant change to tariffs, as the change in charging bases and the revenue to be recovered from the locational element of demand charges with the switch from NHH to HH should be reflective. From a demand residual banded charging perspective, expectation is that steps would also be put in place to ensure no double charging occurs.

Will domestic customers face triads for forward-looking TNUOS after market wide half hourly settlement?

Once migrated through Market wide half hourly settlement, NHH (domestic customers) will be charged HH tariffs (£/kW) rather than the 1600-1900 consumption p/kwh (NHH charges). From April 2023 this will also include the standing demand residual banded charge.

Why have EHV TDR's % increase so much more than other bandings? Have the site counts changed since 2021 5-yearforecast?

Since the previous 5-year view publication there have been changes in the banding thresholds and the associated consumptions and site counts. Across most bands the consumptions have reduced, which in turn will reduce the amount of revenue to be recovered from those bands. In the case of EHV bands the consumption has stayed more or less the same, which has meant that the proportion of the revenue to be recovered from the EHV bands has increased in relation to those bands that have reduced. EHV bands have also seen a reduction in site counts due to these being overstated (due to changes in the way EHV sites are classified) in the data received for the calculation of tariffs in the last 5-year view forecast. In summary, the revenue to be recovered through the demand residual element has increased versus the previous 5-year view forecast which has meant that all tariffs have increase, however due to the changes in consumption (proportions to be recovered) and site counts, EHV bands charges have increase the most comparatively.

Generation

why does the modelled TEC assume ~6% non-completion of contracted TEC in 2023-24 and ~33% non-completion in 2027-28?

This is due to the certainty of those projects being completed within the timescales stated in the TEC register and is representative of the 'best-view' approach as well as aligning with the latest FES forecast.

45% ALF is completely unrealistic for PV and pretty unrealistic for onshore wind (up from 40%?), can NGESO not provide more meaningful generalised tariffs?

The 45% “typical” ALF is to illustrate the wider tariff for an intermittent generator in a specific zone. This was derived from all intermittent generators including onshore and offshore wind (noting that we do not have data from transmission-connected PV projects yet). This number is for illustrative purposes only. Individual power stations will pay TNUoS according to their own station-specific ALFs.

Zone 27 sees a sudden increase in charges for conventional plant in 2027. What is driving this?

In our best view forecast, there is a considerable reduction in generation in Zone 26 from 2026/27 to 2027/28, that has had a knock-on impact on both Zones 26 & 27. This has meant that there has been a sizeable increase in the System Peak tariff for zone 27, which will impact conventional generation tariffs in our forecast for 2027/28.

How can a generator understand what is driving changes in their local circuit tariffs as these can change (e.g. positive to negative) over the forecast period?

Most local circuit tariffs are predictable if the circuit configuration is radial (i.e., only one route leading the generator to the wider network).

A few local circuit tariffs are unfortunately affected by the wider flows and may “flip” from positive to negative (and vice versa). This is due to those local circuit networks having at least two different routes going to the wider network, and the impact on those multiple routes tend to offset one another. To calculate local circuit tariffs for this type of configuration, the whole network modelling will be needed. We provide the TNUoS model for customers to run their own analysis.

Which FES scenario is assumed?

In our best view forecast, there is a considerable reduction in generation in Zone 26 from 2026/27 to 2027/28, that has had a knock-on impact on both Zones 26 & 27. This has meant that there has been a sizeable increase in the System Peak tariff for zone 27, which will impact conventional generation tariffs.

How many new interconnectors do you assume will connect during the period of the forecast?

The contracted view (as per TEC register) is that there are 14 additional interconnectors from 2023/24 to 2027/28. The number of new interconnectors / additional capacity (increase in TEC across this forecast period) is lower in our best view in comparison to the contracted position.

Do generation zones need to be at least partially onshore, or could an entirely offshore zone exist under any re-zoning?

The current wider zones are onshore only, and the relevant TNUoS parameters (for example, expansion constant/factors) and methodology are based on onshore TOs’ regulation. The definition of MITS node (which separates local networks from the wider network) was also introduced before the offshore regime/charging was introduced. If the wider zones were to be expanded to cover offshore, discussion would be needed to ensure the charging methodology delivers what it is designed to deliver.

What expansion factor has been used for HVDC circuits? what assumptions have been taken to arrive at the nominal EF?

Each HVDC circuit has its own expansion factor, which is based on the assumed capital cost and relevant parameters. For future HVDC projects, as the data is not available in the public domain, we derive the project costs by averaging the costs from a few similar projects that are planned for future years. We have included a table (tab TC) showing the derived expansion factors.

TNUoS Demand Residual (TDR)

Can include a risk scenario for site counts changes in future TDR forecasts?

We will take it into consideration for future publication(s). It is worth noting that the change in site counts across bands is inversely proportional to the change in charge. Fluctuations in site counts within price control periods are expected to be stable year on year. There will likely be larger fluctuations at the point of re-banding (occurs at the start of each transmission price control period).

Are demand sites pegged to a TDR Charging Band like DUoS where they are linked by LLF, or can they jump bands on an annual basis?

Sites will remain in charging bands for TNUoS as per DUoS and will be re-banded at the start of each price control as per current DCUSA and CUSC (as of April 2023) methodology. If there are changes to a site banding within a price control period (due to an error or through the review process), it will apply for both DUoS and TNUoS.

Re the TDR slide, T-Demand3 consumption is less than T-Demand2, but will be subject to higher £/site/annum charges? or am I reading it wrong?

There was an error in the values shown in the table, this has been corrected in the revised version of the published tables file and webinar slide pack. For clarification, there are two factors for calculating the banded charges. The consumption for each band dictates the proportion of the overall revenue to be recovered for any given band. The revenue to be recovered through each band is then split across the number of sites within the equivalent band.

Why are the impacts of the TDR sensitivity not symmetrical?

The changes in demand residual banded charges are symmetrical in relation to the change in total revenue (+/-£100m, +/-£500m) for the two years shown in the sensitivity. The variance in proportions of revenue recovery between demand and generation (including connection exclusion) in the scenarios will scale differently due to revenue from generation being capped.

For charges on transmission connected demand supplies, please could you explain what the considerations are for potential threshold changes? and update timings?

For consideration, timings and updates on potential changes to the t-connected thresholds please refer to CMP389.

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Financial Parameters

Why is CPIH of 2% being assumed (Table 21)?

Actual CPIH data is obtained from ONS website. For our long-term forecast assumptions, we use the historical average figure, which is approximately 2% for CPIH.

G/D Split

For clarity, is the increase in generation share in the G/D split driven by the expected considerable increase in generation?

Yes, the main driver is the increased revenue that falls within the Connection Exclusion; in particular, the increase in offshore local charges which arise from the expected asset transfer of new offshore wind projects to an OFTO within the next 5 years.

To be Answered

What are the biggest impacts on Scottish generation?

Can we ask that the originator of this question, to please contact us directly (tnuos.quiries@nationalgrideso.com), we would like to seek further clarification, to enable us to provide a more bespoke answer.