BSUoS Fixed Tariff Consultation

Introduction Webinar 27.06.22

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Agenda

Presenters

				
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- ***We will be recording the session*** *– to be shared on ESO website for those not able to attend*
- ***Please capture your questions on*** slido ***code:#1041000*** *– we will have time at the end to run through them*
- ***For more information please refer to our BSUoS Consultation document****, published on ESO website* *here*

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BSUoS Fixed Tariff Consultation Plan

Our plan for this engagement is as follows:

1. **Issue consultation invitations** – *Monday 13th June*
2. **Share consultation documentation** – *Monday 20th June*
3. **Consultation opening session** – *TODAY*
   - 1h presenting information in consultation documentation
   - 1h Q+A session, inc. identifying any key topics for follow-up discussion
4. **Deliver supporting Webinars / Information** – *28th June - 8th July*
   - Reiterating information and covering key questions & answers
   - Focussed sessions or sharing additional information on key topics as requested
   - Gather feedback from sessions, email and other ESO communications channels
5. **Update draft tariff methodology & model based on consultation** – *12th July-1st August*
   - Communicate updates based on consultation – *Monday 1st August*
6. **Second round of consultation for further feedback and updates** – *1st-12th August*
   - Communicate consultation summary – w/c 12th August
7. **Communicate draft tariff, based on updated model and approach** – *September*

Introduction

Context

- BSUoS reform
  - CMP308: Removal of BSUoS charges from generation
  - CMP361 and 362: Introduction of fixed BSUoS tariff
  - Whilst awaiting final decision on CMP361 we would like industry feedback and input to improve our fixed BSUoS tariff methodology.

- Five Point plan: Improve BSUoS forecasting

- Requirements:
  - Forecast of costs to set tariff at correct level
  - Quantify level of uncertainty
  - To determine working capital fund for fixed BSUoS financial risk management

Questions for Industry

Key questions to consider throughout this engagement and during this webinar:

- Do you agree with our approach?
- Are there any areas/details missing?
- Do you have any suggestions or alternative proposals you can share information on / experiences of?
- Are there any topics you would like a focused session on during the consultation?

BSUoS Fixed Tariff Model

Consultation Information

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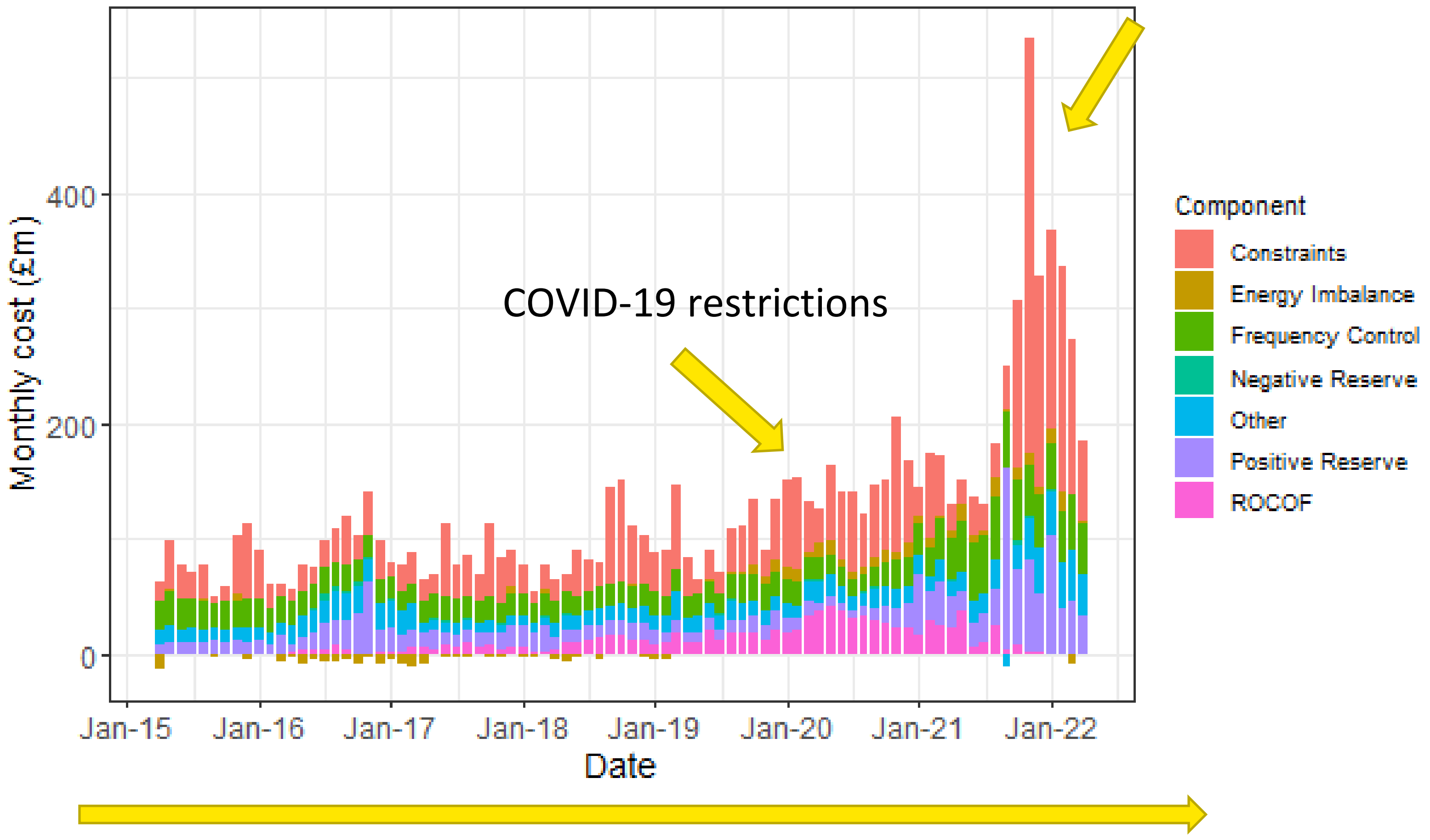
Historic Balancing Costs

Increase in wholesale gas price



Increasing contribution of renewable generation

Balancing costs components

Constraints: actions taken to manage constraints on the electricity network (transmission and voltage).

Energy Imbalance: actions taken to manage the imbalance between electricity supply and demand.

Frequency Control: services procured to ensure system frequency remains close to 50 Hz. This includes fast reserve and response services.

Negative reserve: services which provide the flexibility to reduce generation or increase demand to deal with unforeseen fluctuations in demand, or generation from demand side PV and wind.

Positive Reserve: services required to operate the transmission system securely and provide the reserve energy required to meet the demand when there are shortfalls, due to demand changes or generation breakdowns.

Rate of change of frequency (RoCoF): actions taken to protect against the risk of RoCoF losses.

Modelling approach

- Previous model unresponsive to drivers of variability.
- The aim of the new model is to produce a forecast with explanatory power:
  - Identify drivers for changes in balancing costs in historic data.
  - Explicit drivers capturing what we know about future changes to the system.
- Forecast is at monthly resolution with a horizon of 24 months.
- Forecast individual cost components and then combine to find total costs.
- Forecast is probabilistic to quantify the level of uncertainty.
- Forecast covers a wide range of lead times therefore we use a blended approach
  - Combines the output of different models
  - Capture the variability over different time scales.

Drivers of variability

Driver	Impact
NGESO policies	Uncertainty in future regulatory changes or government and ESO policies affect potential future costs
Government Regulation and Policy	
Network Changes	Network improvements alter constraint costs
Wholesale electricity price	Cost of balancing services linked to wholesale electricity price
Weather variability	Costs dependent on level of renewable generation.
Network and generator outages	Major outages of generators, interconnectors or transmission equipment leads to higher management costs
Large unexpected events	Large unexpected impacts

Drivers of variability

Driver	0-1 year	1-2 years
NGESO policies	Known policies and details	Policy decided but details unclear
Government Regulation and Policy	Known policies and details	Range of policies and regulation possible
Network Changes	Network configuration known	Network upgrades known but completion date / delays unclear
Wholesale electricity price	Variability due to weather and geopolitical factors	
Weather variability	Weather variability: predictability approximately constant across all relevant lead times	
Network and generator outages	Planned outages known	All outages unknown
Large unexpected events	Can occur at any time	

Overview of time-series models

Short-term variability

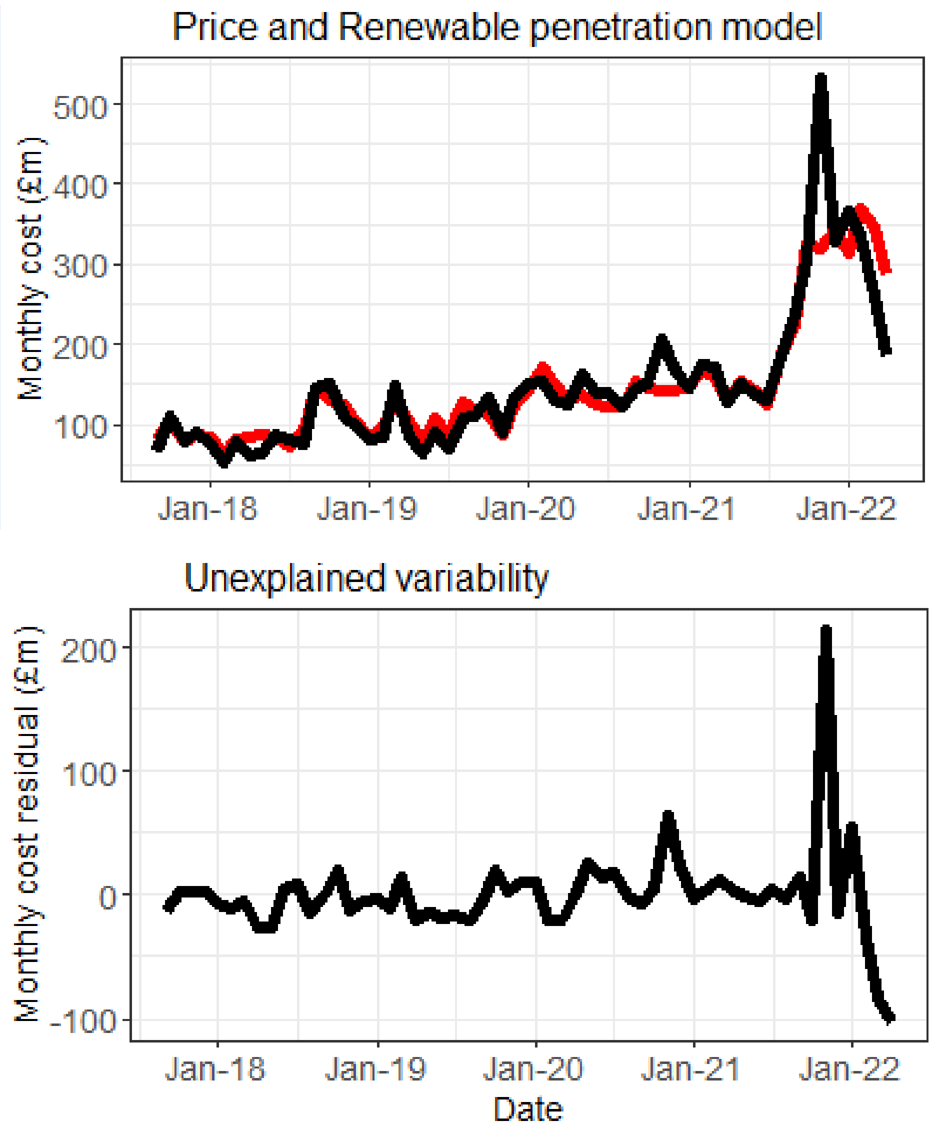
- Short-term cost variability driven by weather and wholesale electricity price.
- Use the relationship between historic costs and weather and wholesale price to forecast the coming months.
- Run multiple simulations to combine different scenarios of weather and wholesale prices to “mix” the different sources of variability.
- Any network or generator outages that are known are factored in based on historic relationships to costs.
- To factor in large unexpected events we add a term to capture potential variability.
- Model output gives us both the central forecast and the probabilistic spread around it.

Driver	0-1 year
NGESO policies	Known policy and details
Government Regulation and Policy	Known policy and details
Network Changes	Network configuration known
Wholesale electricity price	Persistence and market forward curves
Weather variability	Effect of weather variability from historical data
Network and generator outages	Planned outages known. Effect of unplanned outages from historical data
Large unexpected events	Can occur at any time. Impact estimated from historical incidents

Time-Series Modelling: Persistence

Red = linear model
Black = historic costs

- We fit linear models to components of the balancing cost based on:
    1. Wholesale electricity price
    2. Renewable proportion (wind and solar PV) of demand
- The remaining unexplained variability are the residual costs.
- Persistence model takes the previous month **residual** value and forecasts this flat into the future.
- Separate model for each cost component.



Time-Series Modelling: ARIMAX

- An Auto regressive Integrated Moving Average Exogenous Variable (ARIMAX) class of model was developed.

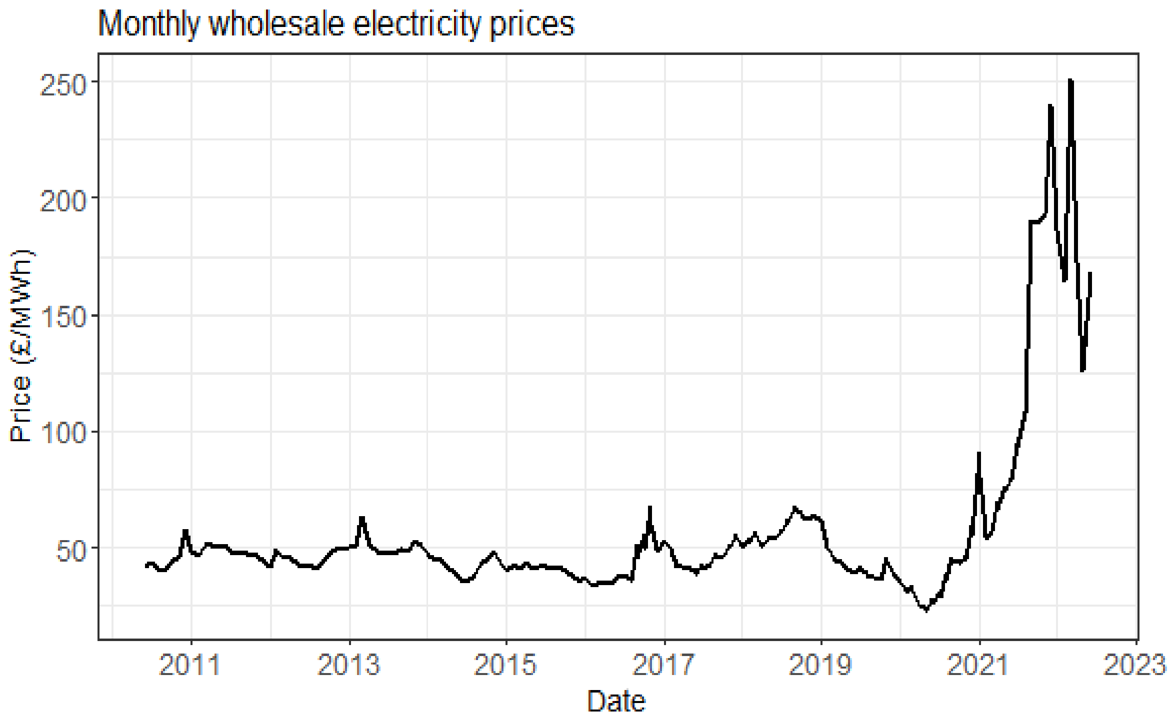
- It uses past costs and also the same two explanatory variables as for the persistence model:
  - Wholesale electricity price
  - Renewable proportion (wind and solar PV) of demand

- A simulation-based approach was chosen given the uncertainty in these variables at forecast lead times (1-18 months).

- The ARIMAX model is run 50,000 times. Each simulation samples a different wholesale electricity price trajectory and weather data.

Wholesale electricity prices

- Have large variability, particularly since 2020.
- The model needed to:
  - reflect the spread of possible scenarios in the aggregate
  - produce realistic individual price trajectories that capture potential market behaviour.
- The central case was created by smoothly interpolating forward prices.
- Simulations capture the wide range of possible wholesale price outturns.

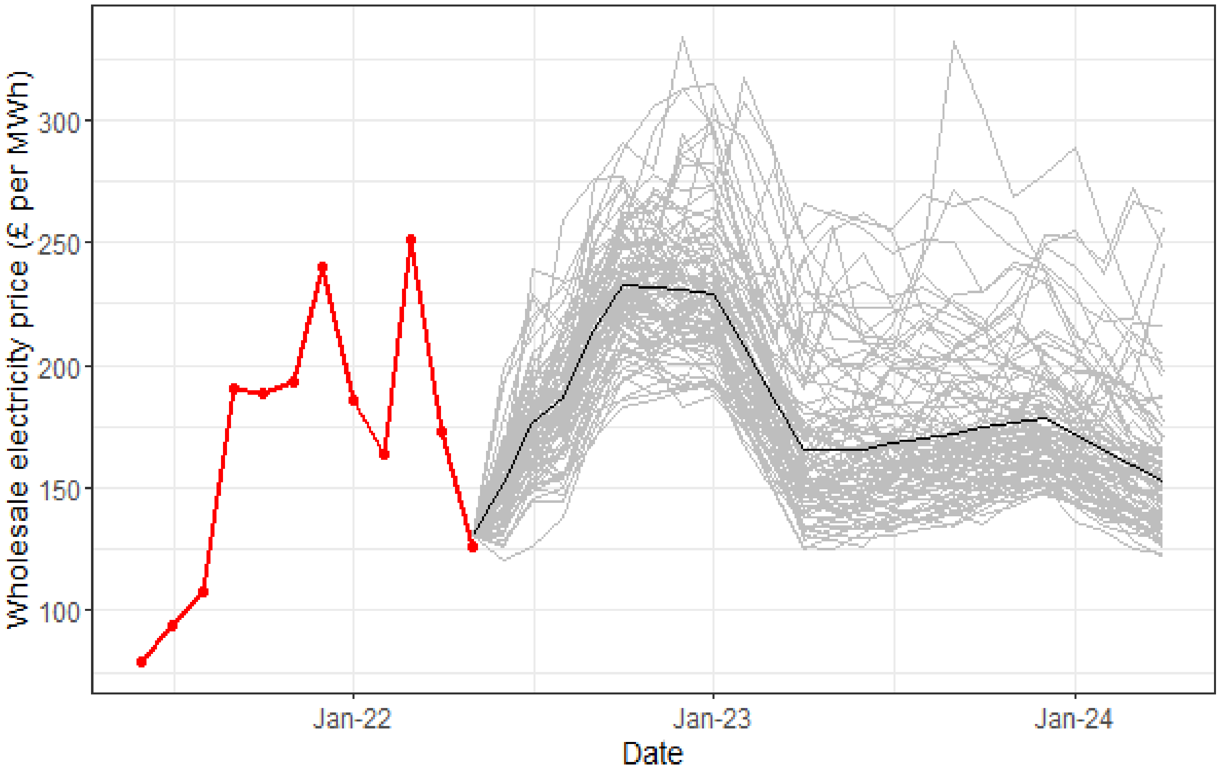


Wholesale electricity prices

- The stochastic differential equation selected to generate price trajectories was: Geometric Ornstein-Uhlenbeck (OU) Process with jumps.

- This is a random walk process that tends to revert to the long-term mean, but with occasional jumps replicating market shocks.

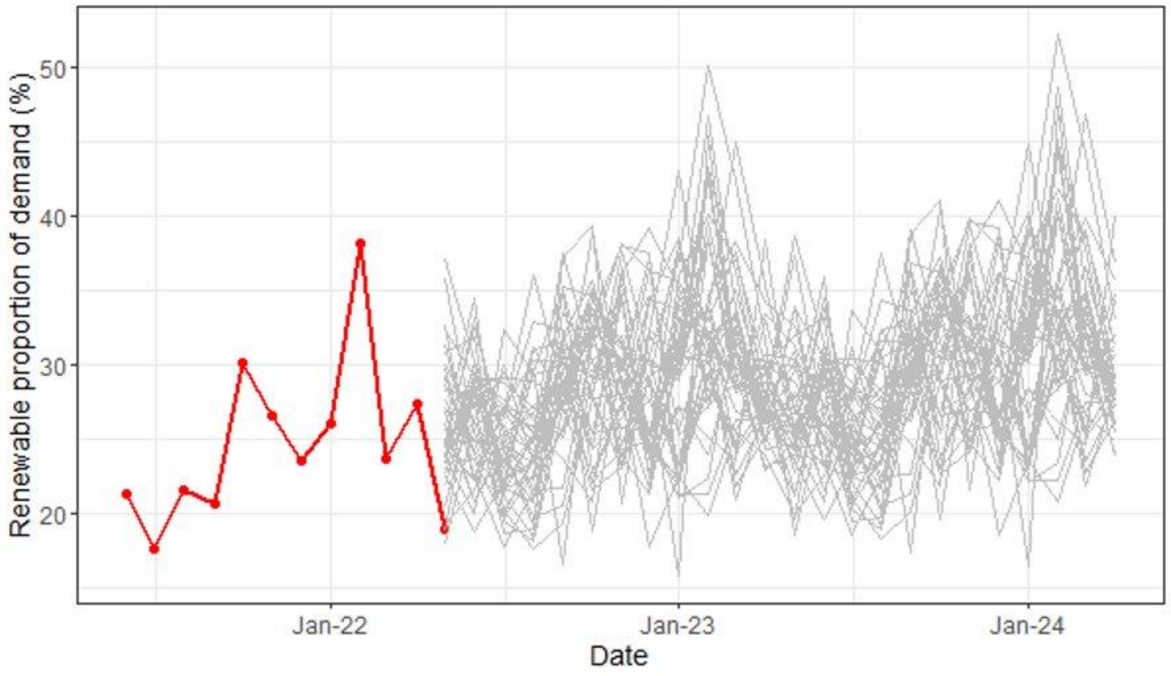
- The steps to model wholesale prices are:
  1) Generate a potential trajectory (with OU process)
  2) A price floor is applied (£10/MWh) and ceiling for jumps
  3) Run the process 10,000 times to produce a huge range of possibilities.
  4) Re-centre around market forward curves



Historic wholesale electricity price (red curve), forward curve giving central forecast (black curve), and example simulated trajectories using the Geometric OU process with jumps (grey).

Renewable Proportion of Demand

- Weather data: Hourly time series from 1980-2022 provided by MERRA2 reanalysis.
- Derived a time-series of wind and PV load factors and National demand using historic weather and NGESO power conversion models.
- Wind and Solar MW calculated based on NGESO best view of capacity growth.
- Each simulation randomly selects a scenario of the monthly renewable proportion of demand.



Plexos Constraint Cost Forecast

- NGESO produce a 24-month ahead constraint cost forecast using the Plexos Integrated Energy Model, published monthly on the data portal

- It forecasts costs associated with managing constraint boundaries (for thermal, voltage and stability) and meeting voltage requirements.

- It does this using the best view of the position of the network, such as the latest outage plan and constraint boundary limits, and runs a simulation based on the historic weather and wholesale electricity market prices provided by the futures markets.

The Plexos constraint forecast is blended with the ARIMAX simulations of constraints, with the weightings of the blend dependent on lead time.

https://data.nationalgrideso.com/constraint-management/24-months-ahead-constraint-cost-forecast

Overview of scenario sampling approach

Scenario sampling modelling

- At longer lead times can no longer rely on historic relationships.
- Produce a central forecast for each cost component based on the most likely scenario of network upgrades, market development and policy changes.
- We then use Monte Carlo techniques to find the variability around the central forecast.
- **Frequency Control** and **Constraints** have been modelled with bespoke assumptions, described in the following slides.
- For all the other cost components, it is assumed there is no change to large-scale drivers in the forecast period therefore the central forecast is based on the relationships between historic costs and explanatory variables.

Driver	1-2 years
NG ESO policies	Policy decided but details unclear
Government Regulation and Policy	Range of policies and regulation possible
Network Changes	Network upgrades known but completion date and delays unclear
Wholesale electricity price	Variability due to weather and geopolitical factors
Weather variability	Weather variability approximately constant across all lead times
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Long-term variability: Policy

At lead times of 1-2 years, NGESO policy is likely to be decided but details unclear.

- Example: Frequency Risk and Control Report (FRCR) provides clarity of the losses we protect against, but no historical data to draw upon

- Model possible market strategies to estimate the cost of new services (generate scenarios)

Government policies affect how whole system develops / evolves (e.g. 2016 moratorium on on-shore wind)

- No way of knowing what government policies could be introduced or their impacts

- Use Future Energy Scenarios as a proxy: assume that policy moves us from one scenario to a different one

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Frequency Control

- NGESO aims to deliver a new suite of faster-acting frequency response services to support operations. These services include **Dynamic Containment**, **Dynamic Moderation** and **Dynamic Regulation**.
- Large uncertainty in the development of these new markets, so have developed a range of scenarios for the volume procured and the price of the services.
- The central forecast has been calculated using the analysis carried out for the Frequency Risk and Control Report (FRCR) which determines the response services required to protect against the largest loss (both high and low frequency) and our best view on the price of the services.
- We have created 11 other scenarios to provide a credible range of both the volumes and the costs.
- Each of the 50,000 simulations randomly selects a scenario, with a greater weighting given to the central scenario.

Long-term variability: Network Changes

- Network improvements alter constraint costs

- Network Options Assessment (NOA) analyses the potential future requirements of the system and recommends optimum timing of investments.

- Provides cost under the different Future Energy Scenarios:
  - Before network reinforcements
  - Optimal path

- Run multiple simulations with different progression of network upgrades, based on FES scenario from Government Regulation module.

https://www.nationalgrideso.com/research-publications/network-options-assessment-noa/methodology

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Constraints

- Each of the 50,000 simulations selects a Future Energy Scenario with a greater weighting given to Consumer Transformation (central forecast).

- Collect the corresponding constraint cost from NOA study.
  - Before network reinforcements
  - Optimal path

- Correct based on the wholesale electricity price trajectory.

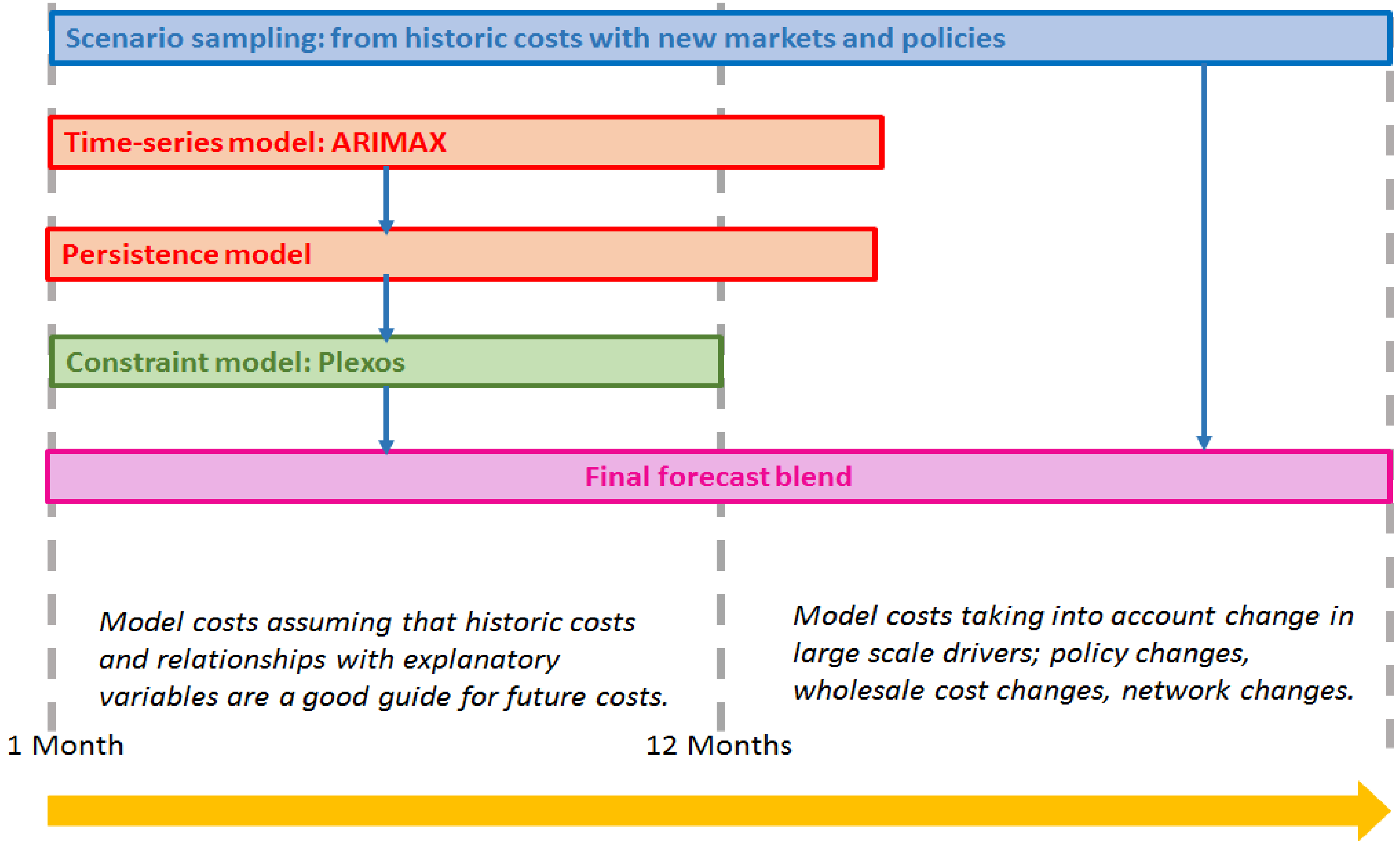
- Add variability to capture the uncertainty in the progression of the network upgrades. Randomly sample variable to quantify how far progressed to optimal path.

Tariff Calculation

Blending of Balancing Cost Models

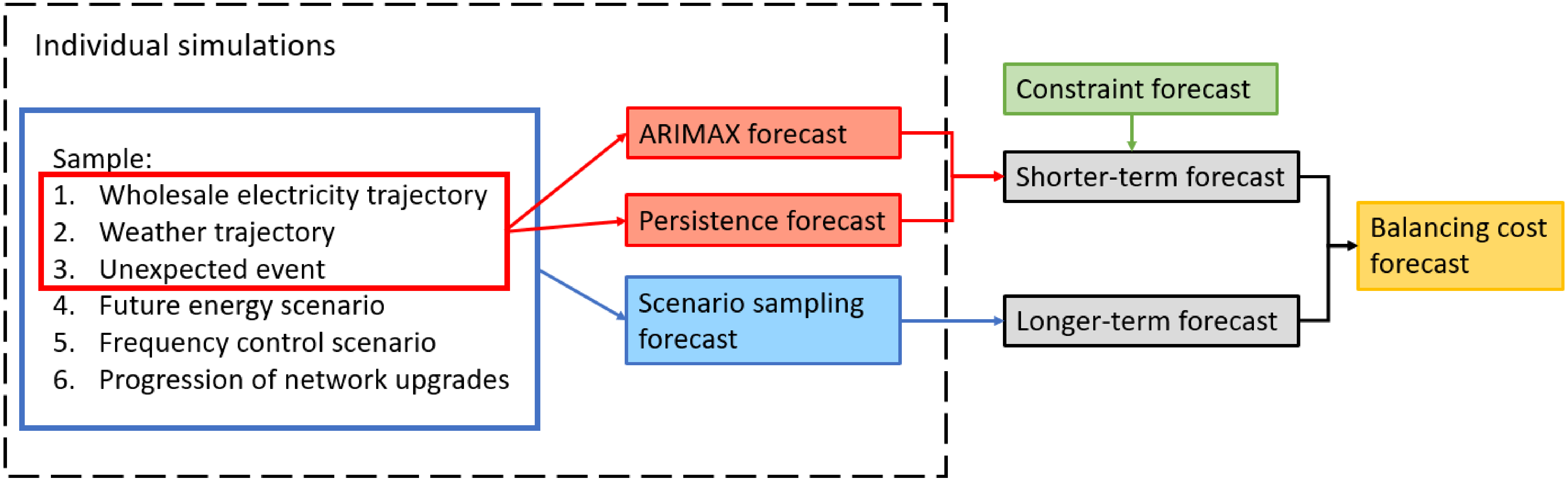
- Weightings of the blend are dependent on forecast lead time.

- Weights are chosen by assessing performance of the models against outturn with historical data.

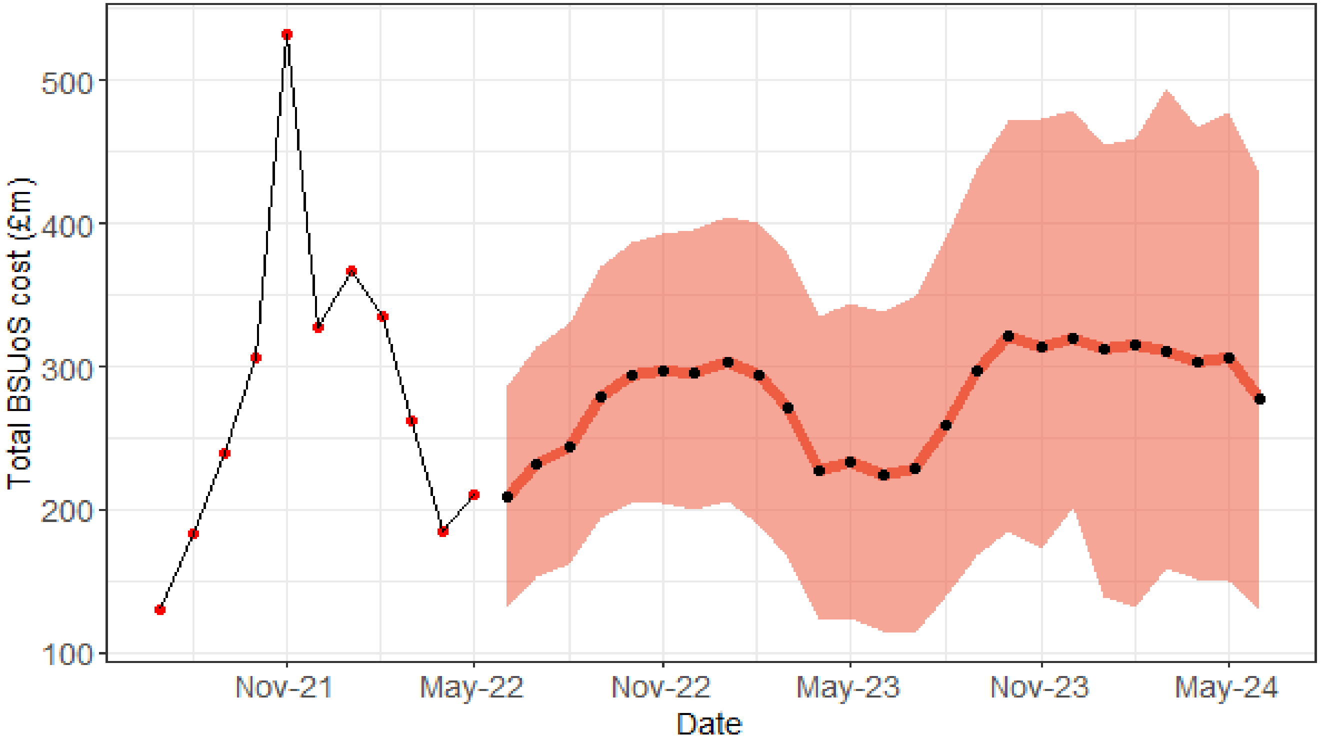


Example model blending (dates are for illustration only)

Modelling summary



Balancing Cost Forecast Example (June)



Probabilistic uncertainty

Increasing uncertainty

BSUoS Chargeable Volume

- CMP308 BSUoS Charges onto final demand only
- Implementation date: 1st April 2023
- For financial years 2020-21 and 2021-22 determined chargeable volume (current best view) based on CMP308.
- Determine the relationship between National Demand and the Final chargeable demand, and use this to forecast.
- In forecast mode, use the latest National Demand forecast produced by NGESO.

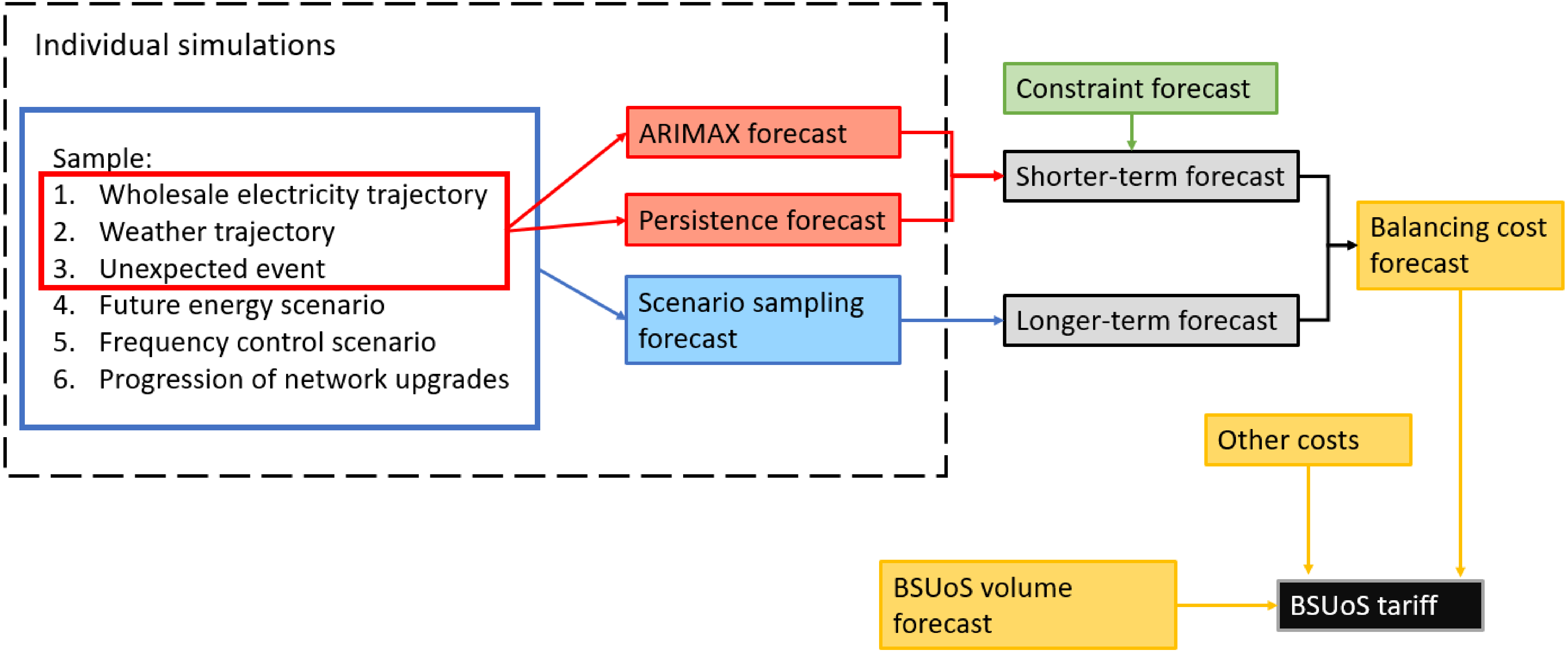
Tariff Calculation

Before a tariff can be calculated, there are other non-balancing costs that need to be included. These are provided as a single central forecast only.

	Financial Year 23/24
Balancing Costs (Central) £m	3483.5
Estimated Internal BSUoS & ESO Incentive £m	313.5
Accelerated Loss of Mains Change Programme (ALoMCP) £m	0.0
CMP345/350 Deferred Costs £m	0.0
Total BSUoS £m	3797.0
Estimated BSUoS Volume TWh	229.2
Estimated BSUoS Charge (Central) £/MWh	16.6

Indicative example tariff based on the published June 2022 forecast

Modelling summary



Supporting Tariff Information

BSUoS Fund

- Several Workgroup Alternative CUSC Modifications (WACMs) options associated with introduction of an ex ante fixed volumetric BSUoS tariff include a BSUoS Fund.
- See CMP361 and CMP362 Final Modification Report (8th March 2022) for more information
- A BSUoS fund would be:
  - Industry-funded and ring-fenced fund
  - Used to cover an agreed probability of tariffs being reset
  - Calculated using the BSUoS fixed tariff model.
- Ofgem is currently reviewing the WACM options and a decision is expected in August.

BSUoS Reporting

We have committed to providing industry with visibility of upcoming costs and the potential for tariffs to be reset, through providing the following reporting:

1. Quarterly forecasts of the upcoming BSUoS tariff
   - This would include information on model inputs (inc. data sources and availability) and their values
2. Monthly updates on the tariff and usage of funds available (ESO WCF & BSUoS Fund);
   - Model inputs (inc. data sources and availability) and their values
   - What the ESO has spent on balancing costs this period
   - What the ESO has recovered this period
   - Use of WCF and BSUoS fund (*subject to Ofgem decision*)
   - Narrative to support figures
3. Monthly publications of balancing service forecast cost over a 2-year time horizon (as today)
4. In the event that 80% of total funds available have been used, the ESO will provide updates on the tariff and usage of funds each working day

Q & A

Please open **slido** *and enter code:***#1041 000**

Joining as a participant? # Enter code here

Next Steps

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Call to action!

- *Get in touch with further questions via bsuos.queries@nationalgrideso.com*
- *Highlight topics for follow-up webinars / information shares*
- *Look out for upcoming webinars / additional information via our ESO Charging Updates mailing list – sign up here if you haven't already*

Thank you!