BSUoS fixed tariff model methodology

Table of Contents

1 Introduction 2
1.1 BSUoS Fixed Tariff Consultation Plan 2
1.2 Key Questions for Industry 2
2 Historic Balancing Costs 3
3 Modelling approach 4
3.1 Time-series modelling (1-18 months ahead) 5
3.1.1 Wholesale electricity costs 5
3.1.2 Renewable proportion of demand 7
3.1.3 Plexos Constraint cost forecast 8
3.2 Scenario Sampling Modelling approach (12-24 months ahead) 8
3.2.1 Frequency Control 8
3.2.2 Constraints - RoCoF 8
3.2.3 Constraints - Transmission 9
3.2.4 Other cost components 9
3.3 Blended forecast 9
4 Forecast Example 10
5 BSUoS chargeable Volume 11
6 Tariff calculation 11
7 BSUoS Fund 11
8 BSUoS Reporting 11
9 Appendix 12

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1 Introduction

National Grid ESO spends money to balance and secure the electricity system. These costs are known as Balancing System Costs and are paid for through the Balancing Services Use of System (BSUoS) charges. The CMP361 code reform seeks to change BSUoS charging by introducing an ex-ante fixed volumetric BSUoS tariff set over a notice period of 15 months. This is currently with Ofgem for decision. From April 2023, the code reform CMP308 will come into effect removing BSUoS charging from generation. CMP 362 facilitates the implementation by introducing and updating required definitions from CMP308 and CMP361.

Whilst we await the final decision on CMP361 we have been planning and preparing for if this modification is approved. As part of this preparation, we would like to share the inputs and methodology with you that would set the fixed BSUoS tariff. This paper outlines the model developed by NGESO to forecast the BSUoS costs and volumes and the corresponding BSUoS fixed tariff.

Throughout this engagement we are seeking feedback and input to help us to improve our approaches ahead of April 2023, drawing on how industry approaches BSUoS modelling at present and what industry needs from the ESO (i.e., in terms of reporting).

1.1 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** – *Monday 27th June (10:00-12:00)*
    - 1h presenting information in consultation documentation
    - 1h Q+A session, inc. identifying any key topics for follow-up discussion
4. **Deliver supporting Webinars** – *28th June - 8th July*
    - Reiterating information from opening session and covering key questions and answers
    - Focussed sessions on key topics as requested
    - Gather feedback from sessions, email and other ESO communications channels
5. **Update draft tariff approach, format and 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*

1.2 Key Questions for Industry

Key questions to consider throughout this engagement and when reading this paper:

- Do you agree with our approach?
- Are they 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?

2 Historic Balancing Costs

The balancing costs have increased significantly over the last three years from £942 million in 2017/18 to £3.1 billion in 2021/22 (see Table 1). A number of factors have contributed to the rising costs including; the increased contribution of renewable generation, the suppression of demand due to COVID-19 restrictions and the corresponding reduction in system inertia, and more recently the increase in wholesale electricity prices.

Component	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Constraints	352	298	374	536	507	725	1352
Energy Imbalance	-22	-80	-22	-31	52	103	99
Frequency Control	293	242	222	223	281	262	561
Negative Reserve	2	24	11	6	0	4	10
Positive Reserve	127	271	180	140	135	221	664
RoCoF	0	32	59	144	211	346	115
Other	117	173	118	169	156	187	297
Total	**869**	**959**	**942**	**1187**	**1341**	**1847**	**3097**

Table 1 BSUoS costs in (£ million) per financial year. Note figures have been rounded to the nearest £ million so may not sum to the total.

Given NGESO procure a range of services to balance demand and supply, and maintain the security and quality of electricity supply, the balancing costs can be divided into several components.

- Constraints: Costs associated with managing constraints on the electricity network.
- Energy Imbalance: Costs associated with managing the imbalance between electricity supply and demand.
- Frequency Control: Costs of services procured to ensure system frequency remains with operational limits. This includes fast reserve and response services.
- Negative reserve: Costs of 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: Costs of 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): Costs of actions taken to protect against the risk of RoCoF losses.

The most significant contributors to balancing costs in 2021/22 were Constraint costs (44%), Positive Reserve (21%) and Frequency Control (18%).

Figure 1 shows the large variability in the monthly balancing costs and highlights the recent significant increases during the periods of COVID-19 restrictions in 2020 and the high wholesale electricity prices in 2021. In the most recent financial year the monthly mean total cost is £258 million with a range from £129 million (April and July 2021) to £533 million (November 2021). Much of this variability is driven by constraints and positive reserve.

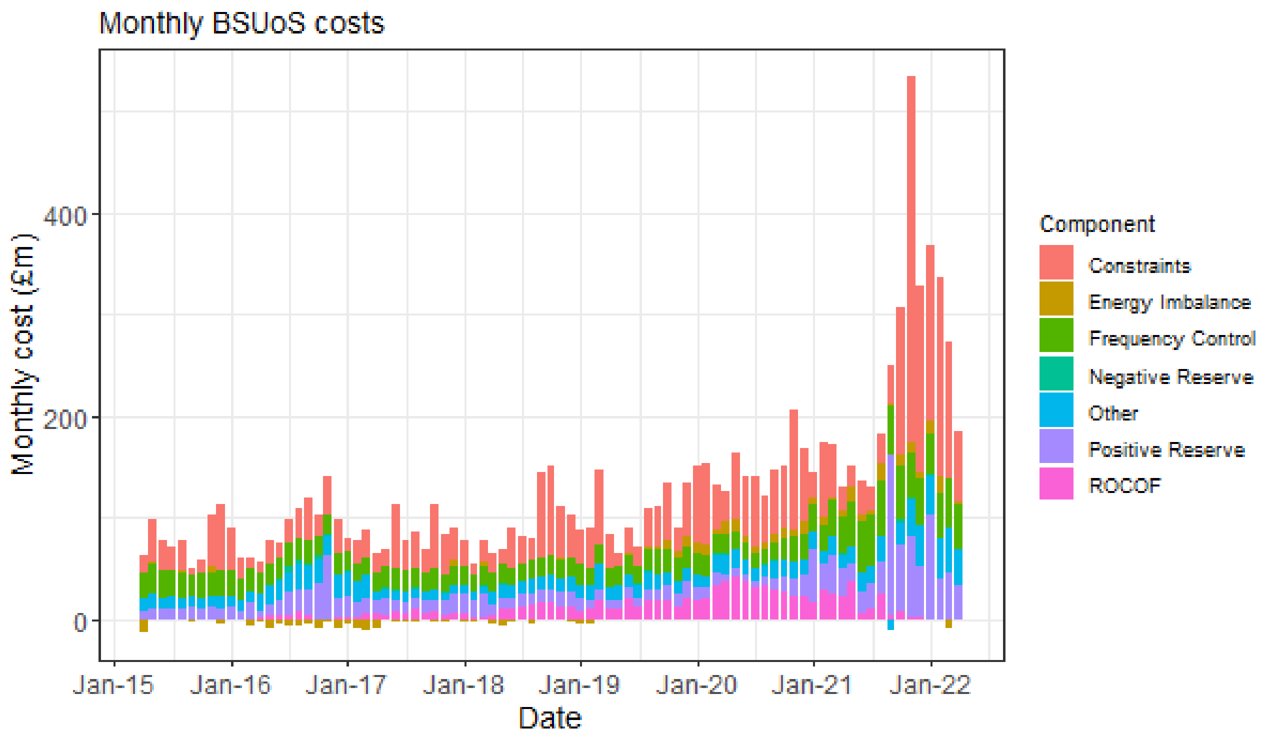

Figure 1 Monthly balancing costs by component from April 2015 to present.

3 Modelling approach

The aim of the model is to provide a forecast of the balancing costs which can then be used to calculate the fixed rate tariff. The principle of the model is to consider the drivers for changes in the balancing costs, and to use historical data and future plans and policies to quantify expected future costs associated with these drivers. An analysis of the cost component breakdown has identified the key drivers of variability in control room balancing costs. These drivers have varying influence on the cost at different time horizons. The drivers are:

- **Wholesale electricity costs:** The cost of the services procured to balance and secure the electricity system are impacted by variations in electricity costs.
- **Weather variability:** The variability of weather impacts demand variability, quantity and location of thermal constraints, reserve and response costs. The variability of these costs is affected by factors including the demand and wind level.
- **Network and generator outages** - There is variability in the daily cost associated with generator and network outages. The cost impact of a particular outage depends on the state of the rest of the network, including which constraints are active.
- **ESO Policies** - All actions taken by the Electricity National Control Centre (ENCC) to balance and secure the system are taken in accordance with ESO policies. As these policies change, the costs change.
- **Government and Regulatory policy** - The nature, quantity and cost of ENCC actions required to meet ESO policy can be significantly affected by government or regulatory policy, in addition to that by changes in ESO policy.
- **Network changes** – The cost of operating the network changes in response to changes in the network, both in terms of connection (such as different loads from changed consumer technologies,

different balances in generation technologies) and physical network assets (such as new lines, new network equipment).

- **Large unexpected events** - Outages of parts of the network, particular generators, interconnectors, or combinations thereof, can have very large costs associated with them. Sometimes combinations of unexpected events can reduce costs (for example if a generation outage behind an outage reduces the cost of that network outage).

The first three drivers discussed, namely wholesale electricity costs, weather variability, and network and generator outages, explain much of the variability in the cost. We can summarise these drivers using two explanatory variables; the wholesale electricity price and the proportion of demand provided by renewables. We fit linear models to components of the balancing cost based on these two variables, leaving a residual error term. This approach assumes that the relationships shown in the historic data are applicable for the forecast target date.

Such an assumption is not valid at large lead times, for which the other large-scale drivers mentioned significantly change these relationships. We thus have developed a collection of models specialising in the short and long-term time horizons, which are blended to produce a single forecast.

At short term lead times, the forecast uses time-series modelling based on historic costs and explanatory variables to capture weather and wholesale electricity price variability. For longer lead times all drivers outlined above can contribute, and the model produces a central forecast based on the most likely scenario of network and market development and uses Monte Carlo techniques to find the variability around the central forecast (capturing the inherent variability driven by the explanatory variables and the uncertainty in the future scenarios).

3.1 Time-series modelling (1-18 months ahead)

To forecast the overall costs, we model several component costs, each with different drivers and magnitude of variability: (1) Positive Reserve, (2) Negative Reserve, (3) Frequency Control, (4) Constraints, (5) Energy Imbalance, (6) error term and (7) all other costs. These are then aggregated to determine the total control room balancing cost.

Two time-series modelling approaches have been used to forecast the monthly cost of each component:

Persistence: We fit linear models to components of the balancing cost based on wholesale electricity price and renewable proportion of demand, leaving a residual error term. The persistence model assumes the residual costs from the previous months persist into the future.

Auto regressive time-series models: Use the relationships in the historic time series of costs to forecast the future costs, utilising an Auto Regressive Integrated Moving Average (ARIMAX) class of model. These models explain a given time series based on its own past values, that is, its own lags and the lagged forecast errors, so that an equation can be used to forecast future values. Two exogenous variables are used

1. Wholesale electricity price
2. Renewable proportion (wind and solar PV) of demand

To apply the ARIMAX models in forecast mode an estimate of these explanatory variables is required. Given the uncertainty in these values at the leadtimes of concern (1-18 months), we have used a scenario-based approach (i.e., forecast a range of possible values). To generate a forecast, we run the ARIMAX model 50,000 times, each simulation samples a different wholesale electricity price and month of weather data.

3.1.1 Wholesale electricity costs

Wholesale electricity costs have large variability across a range of temporal scales, particularly since 2020, as shown in Figure 2. There can be large changes from month to month, and there is a seasonal cycle, with prices generally higher in the winter. Historic data suggests uncertainty about price flattens out after about a year, meaning there is no less information about prices for dates more than a year into the future.

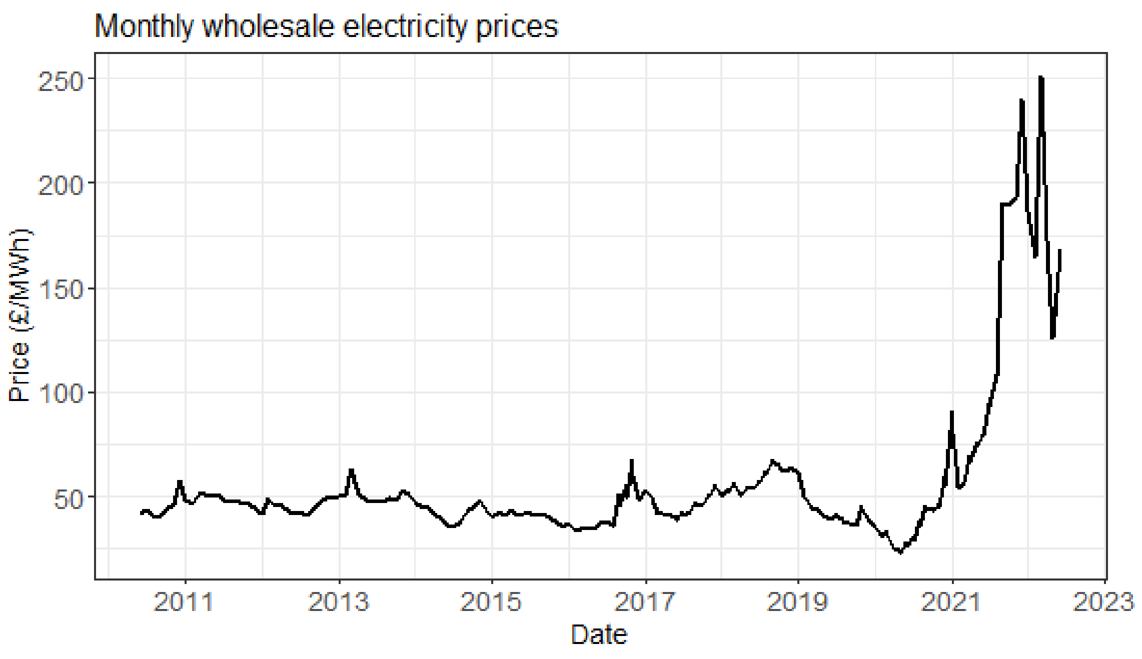

Figure 2 Time series of the monthly wholesale electricity price.

To capture the wide range of possible wholesale price outturns, a simulation-based approach has been taken. The simulations are designed based on; (1) the prices in the futures markets and (2) the observed historical variability (data provided by Bloomberg). The central case for the wholesale electricity cost forecast was created by smoothly interpolating forward prices. Further out, where forward prices based on sufficient trades are not available, the costs revert to the long-term seasonal mean.

The model selected needed to reflect the spread of possible scenarios in the aggregate, as well as allowing individual realisations of the price trajectory to capture potential market behaviour. This was modelled using simulations of a Stochastic Differential Equation, which is a common approach to model commodity prices.

Specifically, the price modelling is based on a Geometric Ornstein-Uhlenbeck (OU) Process with jumps (applied multiplicatively). An OU Process is essentially a random walk process that tends to revert to the long-term mean, where the jumps give a chance for prices to spike (see example simulations in Figure 3), replicating shocks in the market. A Geometric OU process is one where the random movements multiply the current price. Further restrictions are imposed on the model - in each trajectory simulations cannot go beneath a price floor (currently set at £10/MWh) and jumps in price cannot occur if the price is above a certain threshold (currently at £300/MWh). These simulations are then re-centered around the forward prices, which captures expected seasonality of future prices.

The model output thus represents the range of variability in wholesale prices around the central forecast, where the central forecast is taken from the forward prices.

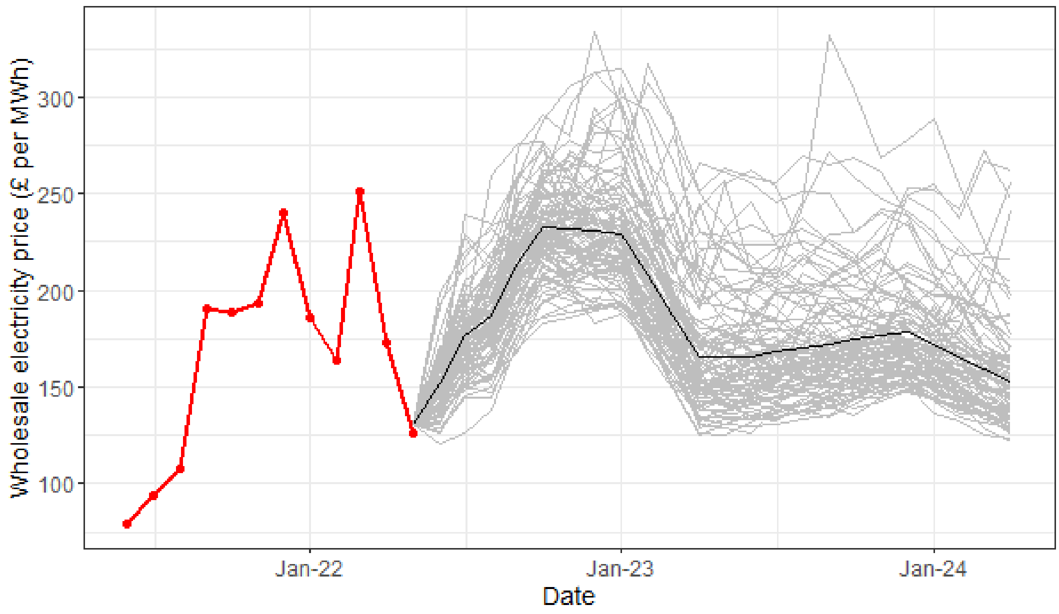

Figure 3 Historic wholesale electricity price (red curve), forward curve giving central forecast (black curve), and example simulated trajectories using the Geometric OU process with jumps (grey).

3.1.2 Renewable proportion of demand

For the renewable proportion of demand, the wind load factors, solar load factors and national demand have been sampled from a historic time series data. This data has been determined using historic weather data and NGESO wind, solar PV and demand models and is not currently published. The data set covers the period of 1980-present and therefore provides 42 years of possible conditions for the forecast month. As with the wholesale cost data, each simulation randomly samples a weather scenario, thus implicitly assumes the mean wholesale electricity price is independent of the weather. Once the load factors for wind and solar PV have been sampled, the values are converted to generation in MW by multiplying by NGESO's best view of the installed capacity in each of the forecast months. Figure 4 shows a range of scenarios of the renewable proportion of demand across the forecast period.

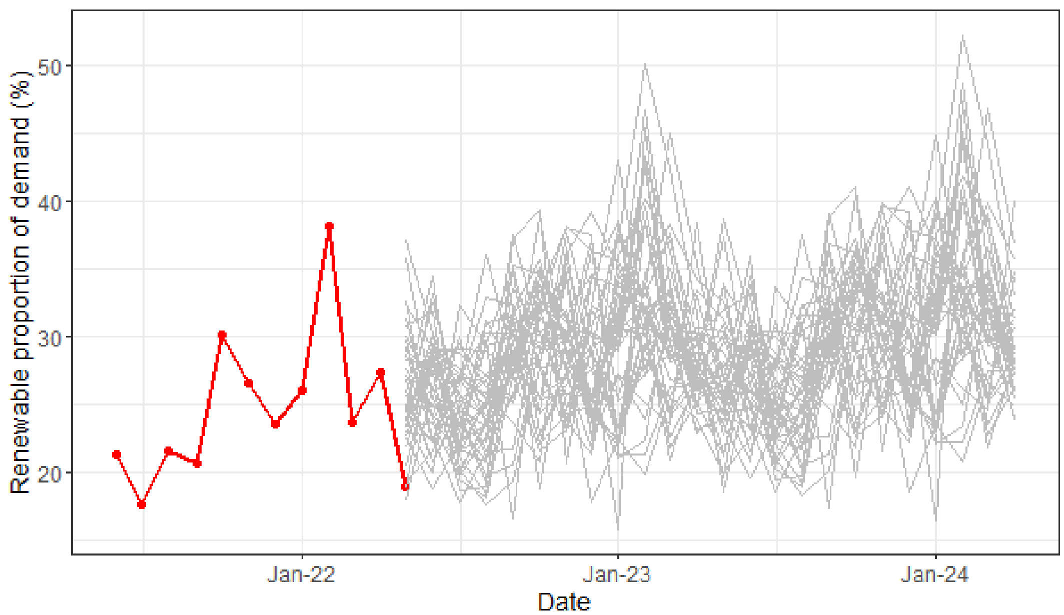

Figure 4 Historic renewable proportion of demand (red) and example simulated trajectories using sampling from historic weather data and NGESO best understanding of future installed capacity of wind and solar PV (grey).

3.1.3 Plexos Constraint cost forecast

NGESO produce a 24-month ahead constraint cost forecast using the Plexos Integrated Energy Model. The model uses the best view of the position of the network, such as the latest outage plan and constraint boundary limits, and runs the simulations based on the historic weather and wholesale electricity market prices provided by the futures markets. The output of the model is a forecast of the monthly costs for managing constraint boundaries (for thermal, voltage and stability) plus the cost of meeting the voltage requirements. The results are published monthly on the NGESO data portal.

For constraints, we blend the Plexos forecast and the ARIMAX forecast, with the weightings of the blend dependent on forecast lead time. The weights are chosen by assessing performance of the model against outturn with historical data.

3.2 Scenario Sampling Modelling approach (12-24 months ahead)

At long lead times a central forecast is made for each cost component based on the most likely scenario of network and market development (details of each central forecast is provided below). We then use Monte Carlo techniques to find the variability around the central forecast (capturing the inherent variability driven by the explanatory variables and the uncertainty in the future scenarios). The Monte Carlo approach involves running multiple simulations (50,000) in which different values of the explanatory variables are used.

As with the time series-models, each simulation randomly samples:

- A trajectory of the Monthly mean wholesale electricity price
- Renewable proportion (wind and solar PV) of demand

For the longer time scales, we also need to consider the variability associated with the other drivers outlined in Section **Error! Reference source not found.**, therefore each simulation samples from a system conditions p ipeline file which outlines different scenarios of the market changes, network upgrades and NGESO and government policies which could occur.

3.2.1 Frequency Control

Over the next few years, the ESO aims to deliver a new suite of faster-acting frequency response services to support operations as the electricity system is decarbonised and to ensure that these new services enable a level playing field for all technologies. These services include Dynamic Containment, Dynamic Moderation and Dynamic Regulation.

To model the cost of these new services we assume a pipeline of the market development. Given there is large uncertainty in the development of these new markets, a scenario approach is again used. For each simulation, a future pipeline is randomly sampled from 1 of 12 pre-defined scenarios however a greater weighting is given to the central scenario. The future system pipelines have been developed in collaboration with the Structuring and Optimisation team in NGESO and outline at a monthly resolution for the whole forecast period: (1) volume requirements and (2) service price (£ per MWh) and (3) reduction in traditional frequency control services. This data is not currently published due to commercial sensitivity.

The central forecast has been calculated using the analysis carried out for the Frequency Risk and Control Report (FRCR) which determines the amount of response services required to protect against the largest loss (both high and low frequency). The other scenarios provide a credible range of both the volumes and the costs.

3.2.2 Constraints - RoCoF

In the spring of 2021, NGESO published the first Frequency Risk and Control Report which has led to a change in the RoCoF protection policy. The report recommended allowing a consequential RoCoF loss if the resulting loss can be contained to 49.2 Hz to 50.5 Hz. Following this change in policy, there was a significant reduction in the RoCoF costs throughout the second half of 2021 and the costs are now negligible. The central forecast is therefore taken to be zero.

3.2.3 Constraints - Transmission

As the network changes, both in terms of what is connected to it (different loads from changed consumer technologies, different balances in generation technologies) and different physical network assets (new lines, new network equipment), the cost of constraints changes. Without any changes to the network, the constraint costs will continue to rise as the capacity of renewables increases. As such, large investments are planned to mitigate this. However, there is uncertainty in the cost benefit of these network upgrades and also uncertainty in whether all work will be done on time.

For 2023 there is considerable variability in the central estimates for annual thermal constraint costs. The estimates vary according to the future scenario (as defined in National Grid ESO publication Future Energy Scenarios).

The central forecast of the constraint costs is:

- The annual constraint costs for 2023 for the consumer transformation scenario split to monthly resolution using historic breakdown.
- Assume cost is 50% optimal path cost and 50% before network reinforcements cost.
- The costs are scaled based on projected wholesale electricity prices.

To capture the uncertainty, each simulation randomly selects a future scenario (Consumer Transformation, Leading the Way, Steady Progression or System Transformation) with a greater weighting given to the central forecast. A second sample is then taken to determine how much progression to the optimal path has been achieved, with the greatest weighting given to 50%.

3.2.4 Other cost components

For all the other cost components, it is assumed that there is no change to the large-scale drivers in the forecast period. Consequently, the central forecast is based on the relationships between the historic costs and the explanatory variables.

3.3 Blended forecast

The persistence forecast and the ARIMAX forecast are blended to produce the time-series modelling based balancing cost forecast, with the weightings of the blend dependent on forecast lead time. The weights are chosen by assessing performance of the model against outturn with historical data (based on the total balancing costs). The blend currently used gives the persistence model a decreasing contribution with forecast horizon. There is a subsequent blend between the combined time-series forecast and the Scenario Sampling model forecast, in which the relative weightings change considerably within the twelve-to-eighteen-month time horizon, beyond which only the Scenario Sampling model forecast contributes (see Figure 5 for illustration).

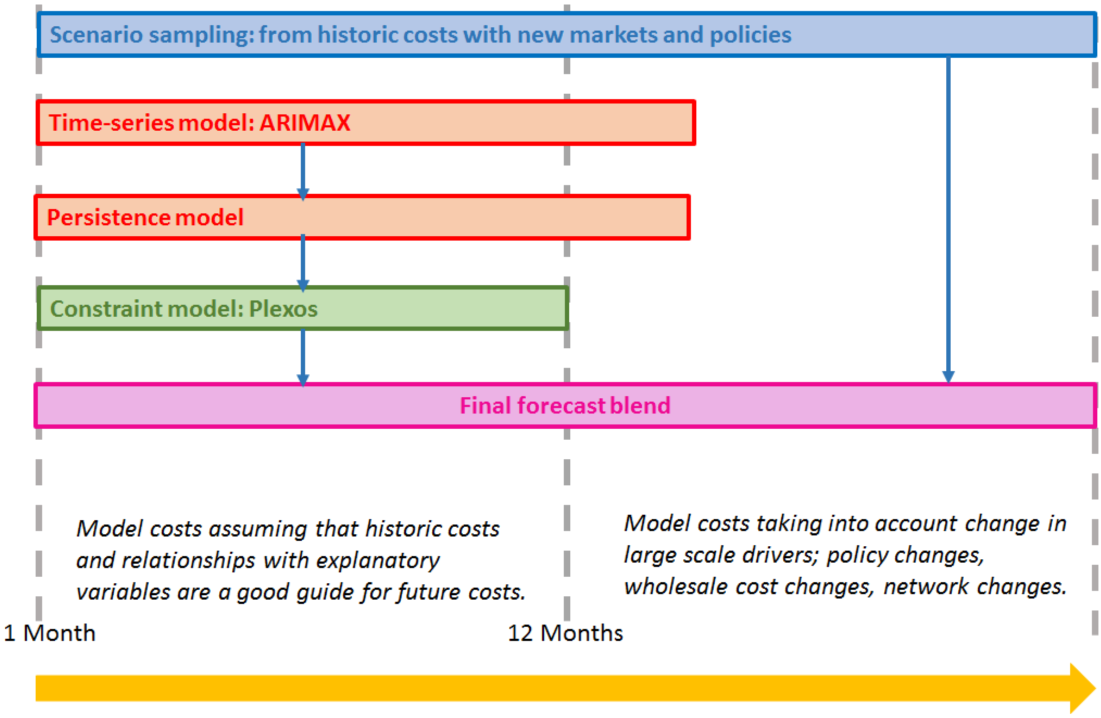

Figure 5 Model Blending (dates are for illustration only)

4 Forecast Example

The forecast is probabilistic and therefore provides a central forecast and plume representing the uncertainty. An example forecast is shown in Figure 6.

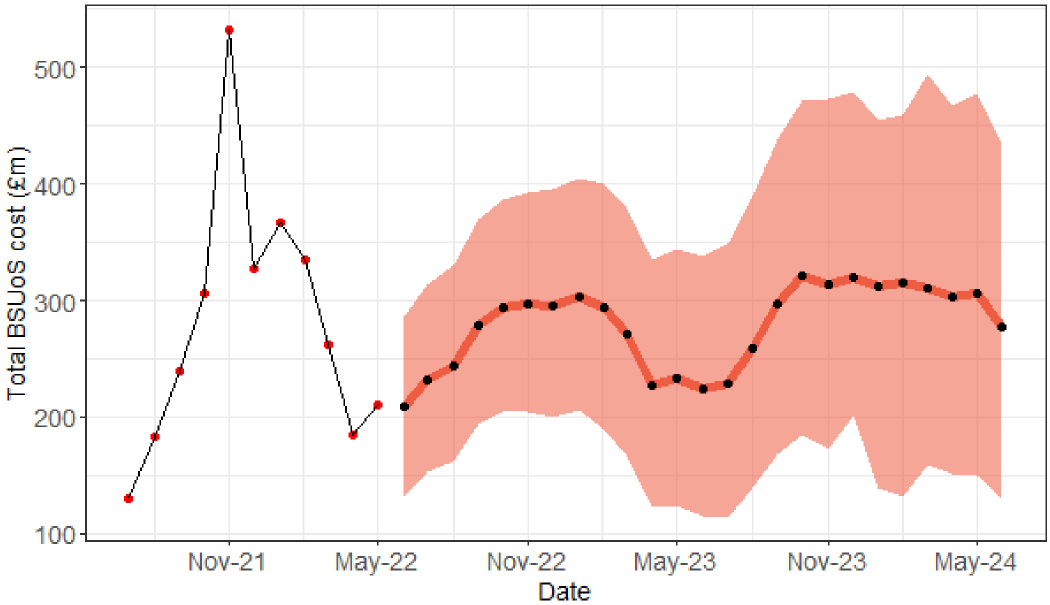

Figure 6 Example monthly BSUoS cost forecast (red curve with black dots). The plume represents the range between the 10th and 90th percentiles. Historic costs are shown in the black curve (red dots).

5 BSUoS chargeable Volume

From April 2023, the code reform CMP308 will come into effect which will move the charging of BSUoS from generation and demand to “Final Demand” only. Final Demand is currently defined as electricity consumed other than for the purposes of generation or export onto the electricity network. The BSUoS chargeable volume has therefore been estimated using a simple linear regression using the NGESO national demand forecast as the explanatory variable. This will be further refined on conclusion of the ongoing declaration of final demand being managed by Elexon and by the ESO, which is due to finish before April 23.

6 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. The additional costs are subject to change, but are currently:

- Estimated Internal BSUoS & ESO Incentive
- Accelerated Loss of Mains Change Programme (ALoMCP) – included in BSUoS charges up to Feb-23 only.
- Deferred Costs associated with Connection and Use of System Code (CUSC) modifications (e.g. CMP345) – current modifications impact up to Feb-23 only.

The forecast for the above additional costs are then added to the central forecast for the balancing costs to calculate the total BSUoS Costs. These total BSUoS Costs are then divided by the BSUoS volumes to get to the final BSUoS tariff estimation (see Table 2 for example tariff).

	Financial Year 23/24
Balancing Costs (Central) £m	3483.5
Estimated Internal BSUoS & ESO Incentive £m	313.5
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

Table 2 Indicative example tariff based on the published June 2022 forecast.

7 BSUoS Fund

As articulated in the CMP361 and CMP362 Final Modification Report (8th March 2022), there are several Workgroup Alternative CUSC Modifications (WACMs) options associated with introduction of an ex ante fixed volumetric BSUoS tariff, several of which include a BSUoS Fund. This would be an industry-funded, ring-fenced fund used to cover an agreed probability of tariffs being reset, which would be calculated using the BSUoS fixed tariff model.

Ofgem is currently reviewing the WACM options and a decision is expected in August.

8 BSUoS Reporting

We have committed to providing industry with visibility of upcoming costs and the potential for tariffs to be reset. To fulfil this, we will provide 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). This would include:
    - 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

9 Appendix

List of publicly available datasets used in the study

Dataset	Source
Plexos constraint forecast	https://data.nationalgrideso.com/constraint-management/24-months-ahead-constraint-cost-forecast
Historic daily balancing costs	https://data.nationalgrideso.com/balancing/daily-balancing-costs-balancing-services-use-of-system
Future energy scenarios	https://www.nationalgrideso.com/future-energy/future-energy-scenarios
Network Options Assessment (NOA)	https://www.nationalgrideso.com/research-publications/network-options-assessment-noa/methodology
Weather data	https://gmao.gsfc.nasa.gov/reanalysis/MERRA-2/