

# ESO Response to Frontier Economics Draft Analysis

## Introduction

Frontier Economics have been contracted by Ofgem to create a cost benefit analysis on the recommendations of the Second BSUoS Taskforce. One of those recommendations is the transformation of BSUoS charging from ex-post to an ex-ante fixed BSUoS tariff. This required Frontier to create a model and methodology to assess consumer benefits of moving the BSUoS variability risk fully or partially from the consumer (status quo charged through supplier risk premia) to the ESO.

The following outlines the ESO thoughts and concerns on to the analysis conducted by Frontier Economics and presented to the CMP361 Workgroup 4 on 15<sup>th</sup> June 2021.

The ESO understands that what was presented at the CMP361 Workgroup was a draft and so hopes that this response can help inform further analysis assumptions before a final version is published.

In summary, we are concerned with some of the simplifications and assumptions used in this analysis as they could alter the impact of the solution on consumers. The assumptions are:

1. Assumptions around BSUoS cost variability (Frontier's values for ESO exposure)
2. The ESO is capable to raise a working capital facility (WCF) which can cover a P95 BSUoS cost variability scenario
3. Forecasting accuracy is constant at all time horizons

We will now go into further detail on our feedback on these three assumptions.

## 1) Frontier's values for ESO exposure

Our interpretation of the Frontier draft analysis shows a modelled exposure of under £200m for the 15 months combined fix and notice scenarios, which we believe is the BSUoS variability expectation over this time period. This number is significantly smaller than the outcomes of our own BSUoS cost variability analysis, shown below. We believe this could significantly alter the outcomes of the cost benefit analysis and impact to consumers.

The ESO analysis has broken down BSUoS cost by cost components and assessed their individual variability levels on a forward-looking basis. The amalgamation of those elements and variabilities creates our modelled cost variability.

Cost Variability (£m)	Quarterly	Annual
p90	165	408
p95	203	483
p99	264	574

The estimates use historical data for the variability in services which ESO currently employs (where we have realigned historical expenditure to coincide with current levels and created random samples using the bootstrap methodology to estimate the higher quantiles of the distribution).

For new services we have used what is known of the proposals for purchasing these services through day-ahead auctions, together with assumed policies (as actual policies are still in development).

We have also accounted for the estimated effects of network changes and reinforcements, and the uncertainties that arise for possible delays in completion of reinforcements work.

The exposure to wholesale price volatility has been estimated by examining wholesale prices over a fifteen-year period and considering the largest inter-annual movements of the annually averaged price. This yields two scenarios: a current price scenario, and a high price scenario. We are currently working on developing a more sophisticated approach where we construct a putative distribution for annual wholesale price variability, but this is difficult, and once constructed we will need to test how sensitive results are to the distributional assumptions.

Until that is complete, we have relied on some empirical investigations of a two-state price model acting on a slightly skewed volume distribution. The empirical studies suggest that a reasonable approximation for high end-quantiles of the resultant (multiplicative) distribution is to take 25% of the value from the lower state and 75% from the higher state. This is the approach we have used to estimate the risk levels above.

## 2) ESO ability to absorb BSUoS variability risk

The ESO can credibly secure a WCF of around £300m (assuming TNUoS risk is transferred to TOs) as per what we have stated in CMP361 and consistent with our RIIO-2 business plan. As outlined in the cost variability analysis above, the ESO WCF would not cover any of the annual scenarios shown. We are concerned that assuming the ESO can cover all scenarios will distort the consumer benefits case.

To protect consumers, we suggest BSUoS tariffs are fixed up to a P99 level using a combination of ESO working capital and a BSUoS fund contributed to by suppliers. We have currently suggested P99

to give certainty that Supplier risk premia has been removed and the likelihood of re-setting tariffs significantly reduced which we believe will provide consumer benefits.

It would also be helpful to understand the overall consumer benefits for P99 and P95, to help shape the best solution for consumers.

### 3) Forecasting at different time horizons

For the purpose of their analysis Frontier have assumed that BSUoS cost forecasting error remains unchanged across different time horizons. We don't agree with this assumption as there are a number of factors which lead to forecast accuracy changing at different time horizons and becoming worse the further into the future we have to forecast. Further detail on these drivers are noted in the appendix.

We have estimated how this forecast variability changes with forecast time horizon based on these drivers.

We calculated total variability at each lead-time as:

$$\text{Total variability} = (\text{Snapshot} + \text{ESO Policy} + \text{External Policy} + \text{Network changes}) * \text{Wholesale cost variability}$$

The results for quarterly variability in £m are shown in the table below:

Quarterly cost variability (£m)						
Leadtime	Snapshot variability	ESO Policy	External Policy	Network changes	Wholesale costs	Total variability
3 months	125	0	0	0	1.13	141
1 year	125	5	0	35	1.31	216
2 years	125	27.5	27	70	1.41	352
3 years	125	43.75	54	105	1.52	498

We assume that any claim that forecast time horizon does not affect accuracy has been based on analysis which only considers drivers such as weather variability, which form part of the 'snapshot variability' in our analysis, and can be derived from a statistical analysis of historic costs, as per Frontier's stated methodology (see appendix for more detail).

## Appendix: Further detail into BSUoS forecast error variability

### Effect of forecast time horizon

To analyse the effect of forecast time horizon, we have split the forecast variability into components we do not believe are materially affected by the time horizons under examination (3 months, 1 year, 2 year, 3 years), and those which are.

#### Unaffected by time horizon: snapshot variability

We consider the case where we are given assumptions about the structure of the network, generation and interconnectors connected to the network, wholesale costs, and a specific outage plan. We refer to these assumptions as a snapshot scenario.

In this snapshot scenario, we can analyse the cost variability that arises from the following categories that we enumerated above:

- Large unexpected events
- Weather variability
- Network and generator outages

The variability for these components is independent of the time horizon because, given the assumptions in the snapshot scenario, there is no skill in our ability to forecast either weather effects or occurrence of unexpected events in the 3 month – 3 year time window.

The snapshot variability at £125 million per quarter for all time horizons.

#### Affected by time horizon: Policy, network and wholesale cost variability

The cost drivers which are affected by the forecast time horizons are those where we do have changing levels of knowledge about the future, dependent on the time horizon.

The cost drivers that fall into this category are:

- ESO Policies
- Government and Regulatory policy
- Wholesale electricity costs
- Network changes

We outline the assumptions we have made in each of these categories, only noting that the quantitative values we have assigned are speculative, as we are attempting to quantify the effects of as yet unknown factors at some point in the future when we are making a forecast for a point that is even further in the future. Nonetheless, we believe that the quantitative values are realistic, and sufficient to give an illustration of how the overall accuracy is time-horizon-dependent.

#### ESO policies

We assume that at lead times of 3 months these policies are known, so there is no extra variability.

At one year we assume that policies are largely determined. We have modelled the quantity by considering the difference between setting the largest loss to be covered by the new Dynamic Containment service at either 1800MW or 1400MW, and assuming there is a preference toward one or the other giving a 25%/75% split.

At two and three years we have used the example of changes in RoCoF policy between 2017/18 to 2019/20. During this time ESO accounted firstly for much many more potential generators being affected, and then for the effects of Vector Shift protection.

We calculated the increase in ESO spending at a 1 year and 2 year lead time, and applied these differences to 2 year and 3 year forecast lead-times respectively, to allow for a 1 year period during which knowledge of the policy change would be available to forecasters.

### External Policies

Here we are trying to estimate for different forecast lead-times the effects of changes in policy originating outside the ESO, either from government, the regulator, the electricity industry, or some other source.

We know such policy changes affect how much is spent in balancing the system, but without specifics of what future changes might be introduced, it is not possible to produce definitive valuations of the cost implications.

We assume that external policy changes are announced early enough that they can be assessed both at the 3 month and 1 year forecast time-horizon. For the 2 year and 3 year time horizon, we have assumed that external policy can move the direction of the future from one FES scenario to another.

For the 2 year lead-time we assumed that the policy change could shift the future between the Customer Transformation (CT) scenario and the Steady progression (SP) scenario, then used the thermal costs in the NOA6 Optimal path for 2022, with annual cost apportioned uniformly to quarters.

For the 3 year lead-time we assumed a larger behavioural shift was possible, using a shift between Leading the Way (LW) and Steady progression (SP). However, we used the values from 2023, where the difference between thermal costs for these scenarios is smaller.

### Network Changes

We modelled this by considering the difference in the System Transformation (ST) scenario between network changes in the NOA6 Optimal path and NOA6 without reinforcement for 2023. We assume that at a 3-month time-horizon the future state will be known. However, new infrastructure projects do not always run to timetable, so we have tried to plan for the cost uncertainty associated with these projects. As such, for 1, 2- and 3-year lead times we have made some pragmatic assumptions which we believe are reasonable to capture the uncertainties associated with network changes and accompanying infrastructure projects.

### Wholesale costs

We analysed wholesale costs from 2010 to 2021 and calculated the % change at the relevant lead-times. We then found the 70<sup>th</sup> percentile of the percentage change in wholesale price at the relevant lead-time. We used this percentage change to rescale the cost variability in the other cost driver categories.