Moving towards a longer term SO incentive regime

A REPORT PREPARED FOR NATIONAL GRID AND OFGEM

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1 Introduction

System Operator (SO) incentive regimes have been a feature of GB regulation since the mid 1990s – well before the introduction of the New Electricity Trading Arrangements (NETA). To date, however, these schemes have typically been annual in duration. In other words, the targets and incentivisation parameters such as sharing factors and caps and floors of the schemes have been reset annually. Ofgem has long indicated a desire to move to a longer term incentive regime.

As part of the process of setting an SO incentive regime for National Grid Electricity Transmission (NGET) starting April 2010, Ofgem and NGET attempted to agree parameters for a longer term regime. However, in part as a result of volatility in NGET's forecasts of the likely outturn incentivised costs, Ofgem was unable to agree to a longer term scheme. In their document of 11 March 2010, Ofgem stated:

> *"Following discussions with Ofgem, consideration of respondents' views, the inclusion of updated information (including more recent data) and corrections to its forecasting models, NGET revised its 2010/11 forecast from £962m to £715m, then to £691m and then to £601m.*
>
> *However, we have a number of on-going concerns with NGET's forecasting methodology including its models and modelling approach. In particular, we have concerns that NGET does not consider the market fundamentals affecting the key drivers of its costs and how these are likely to develop and influence its costs going forward. We consider that NGET's methodology relies too heavily on historic data, and in particular, the most recent actual costs. This can be seen by the way that NGET's forecast of costs for this year has reduced significantly in a matter of months and the considerable reduction in its forecast for 2010/11 as a result of the expensive period of balancing costs in late 2008 dropping out of its forecast.*
>
> *Given the above, we consider that we are only in a position to propose a one year scheme for 2010/11."*

Following this process, in parallel with the one year scheme, Ofgem proposed a licence condition for NGET (to which NGET consented) requiring NGET to co-operate with the Authority in undertaking a review of the methodology for developing its forecast of system operator external costs, with a view to NGET developing an appropriate methodology so that a multi year SO incentive scheme might be implemented from 1 April 2011.

Ofgem and NGET have specified a three phase process to arrive at proposals for a longer term scheme starting in 2011:

- **Phase 1:** review of NGET's modelling, the use of its models, and the structure of a longer term scheme, culminating with recommendations on an approach for future schemes (undertaken jointly by Ofgem and NGET, six weeks in duration);

- **Phase 2:** development of proposals for models, parameters and a structure for a longer term scheme starting in April 2011 (led by NGET, four months in duration); and
- **Phase 3:** review of these proposals to inform a decision by Ofgem on the proposed regime (undertaken jointly by Ofgem and NGET, eight weeks in duration).

As part of this process, and pursuant to the licence condition, Ofgem and NGET appointed Frontier Economics initially to support Phase 1 of this process. Frontier's review will constitute an input to both NGET and Ofgem's conclusions to Phase 1.

This Phase 1 review is intended to cover:

- the approach taken to modelling costs in NGET's models (including the source of data and the calculations), and potential developments both now and in the future;
- the way in which NGET's models are used in the incentive scheme setting process; and
- the way in which a longer term incentive regime might be structured.

This report sets out our findings from this review. It is structured as follows:

- in **Section 2**, we set out the scope of our review and the process we have followed;
- in **Section 3**, we summarise the objectives of the regime and provide an overview of NGET's current forecasting methodology for each of the main costs items within the SO incentive scheme;
- in **Section 4**, we consider the potential benefits and constraints associated with moving to a longer term incentive regime;
- in **Section 5**, we identify the main drivers of SO costs, and consider NGET's level of control in relation to each;
- in **Section 6**, we consider possible changes to NGET's models;
- in **Section 7**, we discuss longer term scheme design and a number of broader regulatory issues which may be of relevance; and
- in **Section 8**, we summarise our findings and recommendations.

2 Scope and process

In this section, we briefly set out the scope of our review, first in relation to NGET's modelling and then in relation to the incentive scheme design. We go on to summarise the process we have followed to undertake the review.

2.1 Scope of our model review

As noted in the previous section, the scope of our review in relation to NGET's models is to consider:

- the approach taken to modelling costs in NGET's models (including the source of data and the calculations); and
- the way in which NGET's models are used in the incentive scheme setting process.

The objective of this review is to develop recommendations, in the context of a longer term incentive scheme and future physical system developments, for:

- changes to the modelling approach;
- changes to the data inputs; and
- changes to the usage of the models in deriving incentive scheme parameters.

Where relevant, we have also sought to provide an indication of our views on the priority of particular changes, depending on factors such as:

- the development time available for NGET during Phase 2;
- the extent to which particular developments could be expected to improve the accuracy of forecasting or the ability to agree regime parameters; and
- the feasibility of developments (e.g. whether sufficient data on particular aspects of system development are available to commence development work).

To this end, we were provided with 2 sets of Excel based models by NGET:

- one model covering energy related SO costs ("2010.03.31 - BSIS Forecast spreadsheet - post back test adjustments-v2.xls"), including energy imbalance, margin, fast reserve, frequency response, footroom, and reactive power[1]; and

- five models related to modelling of congestion. One of the models is used to model Scottish constraints ("Official Number 153.xls") and the remaining 4 are used to model and calculate the costs of specific constraints in England & Wales ("Grendon – Staythorpe 2010-11_240310.xls", "Cottam – Staythorpe 2010-100_240310.xls", "E&W_forecast_MASTER_250310.xls" and "ESTEX 2010_240310"[2].

NGET also provided us with a number of slidepack presentations that provided details of its current modelling methodology.

During this phase, we have not considered in detail:

- **black start costs**: these are not covered in detail by NGET's models, as their forecasting relates to estimation of the cost under ongoing contracts and the costs associated with black start testing. Given the different nature of this forecasting process (which is largely independent of considerations relating to the energy markets) it is undertaken separately by NGET; and
- **the incentives on NGET in relation to transmission losses**: these are subject to a separate volume target which is captured within the main SO incentive regime.

Neither have we considered in detail the specific inputs to the models (either when these are deterministic or treated probabilistically[3]) or the extent to which they cover a credible range of outcomes. The review of inputs is part of the work which NGET will need to undertake during Phase 2, including a review of the extent to which the historic treatment of uncertainty in relation to individual variables remains appropriate.

1 Although a large number of energy cost items are modelled in one excel-based spreadsheet, in this report we refer to each cost item modelled in the report as a specific model. For example, we refer to the parts of the spreadsheet used to model margin as the "margin model".

2 The model for Scotland is a consolidated model for all of Scotland in that it assesses the expected cost of constraints for all of Scotland. By contrast the models for England estimate the likely costs associated with specific boundary constraints individually. Both models draw relatively extensively on the energy model - for its forecast of BM prices for example.

3 A number of input variables are included in the models as draws from a pre-defined probability distribution. While we have considered the overall treatment of uncertainty in the models, we have not undertaken a detailed review of the parameters of each probability distribution.

2.2 Scope of our scheme design review

In parallel with our model review, we have also considered a number of aspects of scheme design structure.

Our objective has been to consider whether there are aspects of the way in which the overall incentive regime is designed which could support the development of a multi-year scheme.

For the avoidance of doubt, we have not at this stage considered the appropriate definition of scheme parameters (e.g. specific duration, sharing factors, deadbands etc.). These are aspects which will need to be considered as part of Phase 2, in the context of the overall nature of the scheme proposed by NGET. For example, it is only within the context of an understanding of the extent to which the proposed modelling approach insulates NGET from uncontrollable risks that the sharing factor parameters should be set.

2.3 Process followed

Our review has taken place over a six week time period. During this period we have had a number of meetings, including:

- a joint kick off meeting with NGET and Ofgem;
- numerous discussion meetings in relation to the modelling with NGET and Ofgem;
- a discussion of our initial thinking with NGET and Ofgem; and
- discussions on our draft report with NGET and Ofgem.

However, it is important to note that within a six week period, it has not been possible to arrive at firm conclusions in relation to the most appropriate next development steps for the models and model usage. Rather, our approach has been to understand the models and their current usage, and then to recommend potential areas for change and improvement in the light of the overall objectives of implementing a longer term incentive regime.

We understand that Ofgem will consider the findings identified in this report in its preliminary conclusions of Phase 1 of the review. It is for NGET, during Phase 2 of the process, to consider these recommendations and determine which they believe to be most appropriate, as part of the process of proposing a new scheme.

3 Objectives of regime and current approach

In this section, we describe the objectives of the incentive scheme and set out the current approach to determining the key parameters in the scheme. We describe in turn:

- the principles behind the SO incentive schemes;
- the current approach to incentivising NGET;
- NGET's approach to modelling;
- the key historic relationships used in modelling; and
- NGET's use of the models in setting the incentive scheme.

3.1 Principles behind the incentive scheme

Schemes to incentivise the system operator to be efficient in the level of costs it incurred in procuring system services such as constraint resolution and more general ancillary services were first put in place under the Pool in the mid to late 1990s. These schemes were developed further and adapted to be consistent with the NETA market arrangements when these were implemented in 2001.

The underlying rationale for the incentive scheme was and is to encourage the system operator to be efficient in the level of costs it incurs in resolving congestion and procuring ancillary services from generators. To do this the regulator sets a target level of costs for the services and rewards the SO if it incurs actual costs which are lower than the target and penalises it for incurring costs higher than the target.

It is well recognised that the regulator faces a problem of asymmetric information in setting the target for the SO: the SO is far better placed than the regulator to know what the efficient level of costs should be. Therefore the classic regulatory solution that is used is one of dynamic revelation – so that the SO, in responding to the scheme, reveals over time what the true efficient level of costs should be. In other words, by rewarding the SO in one regulatory period, the regulator is better informed as to what the target should be in subsequent periods. In turn this means that over a number of regulatory periods the overall level of costs incurred by NGET should fall (other things being equal) to the ultimate benefit of customers.

This principle of dynamic revelation underpins the regulatory regime. However, as we will discuss throughout this report, to work well it requires relative stability in outturn costs between regulatory periods. In other words, the level of costs that the SO incurs in one period should not vary dramatically from that incurred in the next period for reasons outside of the SO's control. If such variations do occur then the information acquired by the regulator from the SO's performance in a previous regulatory period will be less useful in establishing a target for subsequent periods.

3.2 Current approach to incentivising NGET

The current approach to incentivising NGET is to estimate, *ex ante*, a total target cost across relevant cost categories and then to define an incentive scheme to incentivise NGET to beat this *ex ante* target. This estimating and scheme setting process is typically undertaken annually.

The incentive scheme has a number of components:

- a target cost, which can either be a single number or a "deadband" (an area within which NGET is neutral to different outturns of cost);
- *ex post* adjusters, which amend NGET's target on the basis of outturn values of particular variables (typically those which are judged by Ofgem to have an impact on SO costs which NGET is not well placed to control, and which are difficult to forecast *ex ante*).
- upside and downside sharing factors which define the sharing of outperformance or underperformance between NGET and its customers; and
- caps and floors, which limit the absolute level of profit or loss to which NGET is exposed.

At present, in the definition of the incentive scheme, three[4] *ex post* adjusters have been implemented to help to insulate NGET:

- The first is the Net Imbalance Adjuster (NIA). This adjusts the ex ante target for changes in two cost drivers considered outside of its control. First, for changes in the level of electricity wholesale prices as measured by the Single Price Net Imbalance Reference Price (SPNIRP), and second for the outturn Net Imbalance Volume (NIV) generated by the market (i.e. whether the market as a whole is long or short at Gate Closure).

- The second is in relation to the volume of expected exports across the Anglo-French interconnector (IFA) with reference to its impact on the volume of constraints during the Littlebook – Tilbury 1 circuit outage. In setting the target, a high volume of expected exports across the IFA has been used with an automatic adjuster included in the scheme to amend the target downward should the volumes be lower than assumed.

4 The second and third adjusters are specific to this year's scheme.

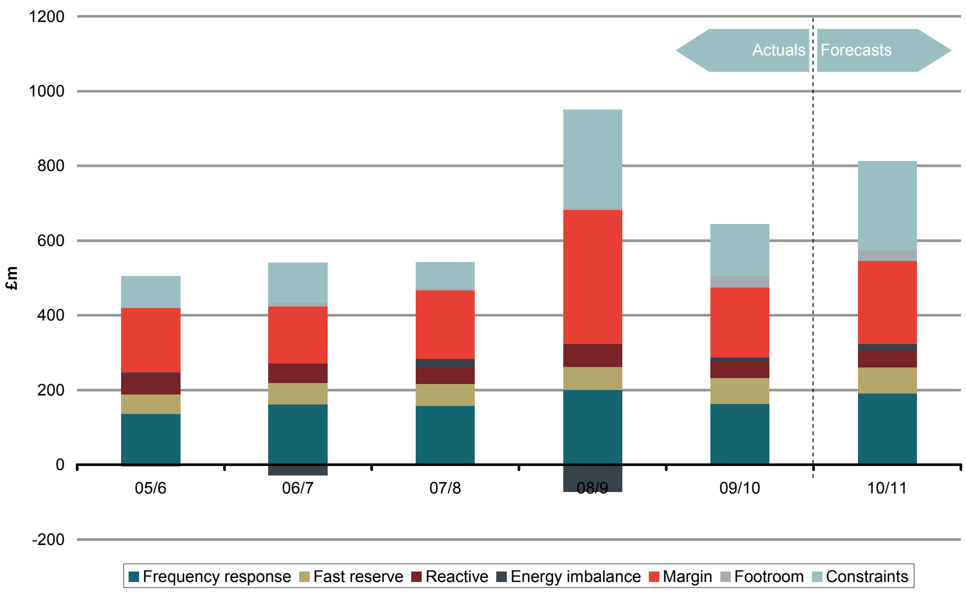
- The third relates to the volume of generation that is likely to connect in Scotland, which has a fundamental effect on the volume of constraints in Scotland. Again in setting the target a high volume of new capacity connecting in Scotland was used. An automatic adjuster is also included which amends the target downward should the volumes connected be lower than assumed.

Beyond these core parameters established at the outset of the scheme, NGET can apply to Ofgem to have the target amended on the basis of an Income Adjusting Event (IAE). This is to provide a route to take account of factors which were not foreseen at the time of the setting of the incentive scheme, are outside of NGET's control but which have a material effect on NGET's SO costs. BSC parties can also apply to Ofgem to have the target amended.

There is a single target and single incentive scheme covering a wide range of incentivised costs. It is worth noting that the level of those costs varies significantly both in absolute scale and in terms of volatility over time.

Figure 1 shows both the scale of individual cost items and their variation over time since the implementation of BETTA in 2005/6. From this figure, it is clear that two aspects of cost – margin and congestion – are both significant in scale and volatile in nature.

Figure 1. Evolution of cost items over time[5]

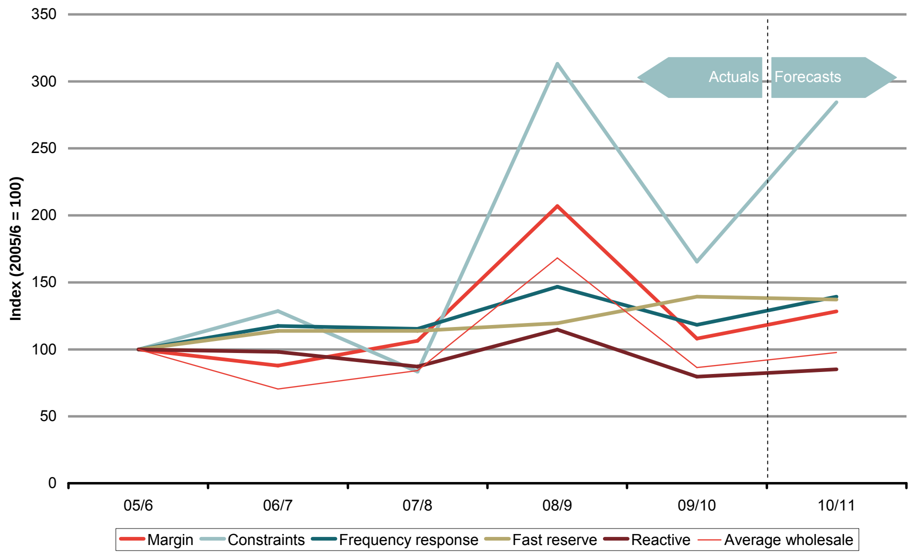


Source: Frontier Economics based on NGET and Ofgem data

Figure 2 below presents the same data in terms of an index with 2005/6 representing 100. It highlights the point that congestion and margin costs are significantly the most volatile of the categories.

5 Here, and in data throughout this report, 2009/10 data are presented as actuals. However, they are subject to ongoing reconciliation.

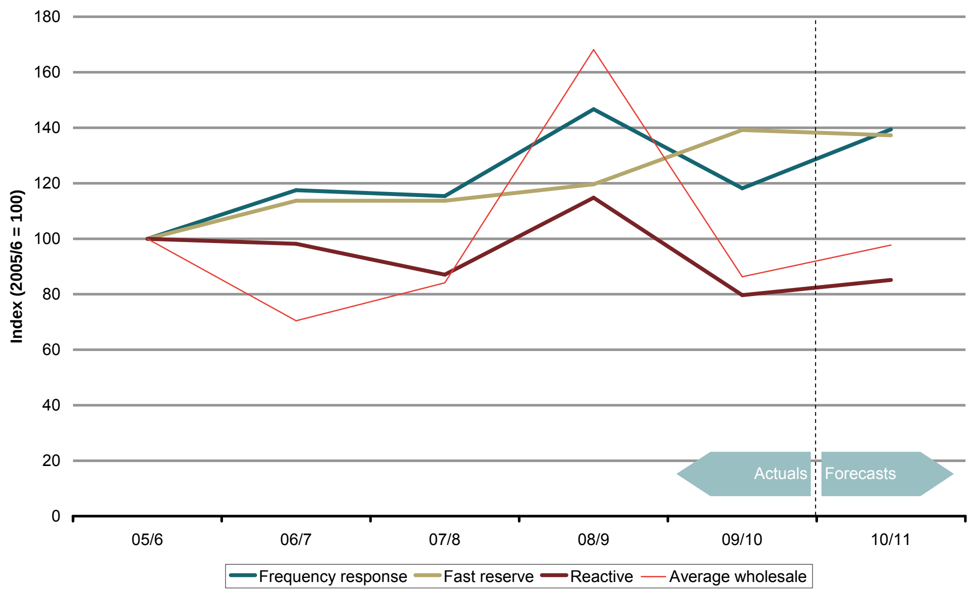
Figure 2. Volatility of cost items over time



Source: Frontier Economics based on NGET and Ofgem data

Figure 3 below presents the same data but excludes the more volatile margin and congestion costs.

Figure 3. Cost categories exhibiting less volatility



Source: Frontier Economics based on NGET and Ofgem data

In relation to these less volatile categories, a number of points are worth noting:

- reactive power costs are highly correlated with wholesale prices (as this is the basis of the indexation of reactive power default provision costs in the Connection and Use of System Code);
- fast reserve costs appear to follow a stable trend over time; and
- following the implementation of CAP 47 in late 2005, frequency response costs have gradually increased over time.

3.3 NGET's approach to modelling

In estimating target costs and setting scheme parameters, NGET uses a number of models. We describe in turn:

- features which are common to all of the models;
- the energy imbalance model;
- the margin model;
- the congestion model;
- the fast reserve model;
- the frequency response model;
- the footroom model; and
- the reactive model.

For each model, we describe:

- key inputs, and how they are determined;
- the key stages of the calculations; and
- the model calculations themselves, and the basis for calculations using relationships derived from analysis of historical data.

3.3.1 Generic model descriptions

The models that NGET use in forecasting the overall level of costs have evolved over a number of years. Hence, some elements of the models are no longer used in forecasting costs as they have been superseded by other approaches yet remain dormant within the models. The overall design and structure of the models therefore reflects this gradual evolution of approach.

Although all of the cost items are forecast separately there are a few common themes across models:

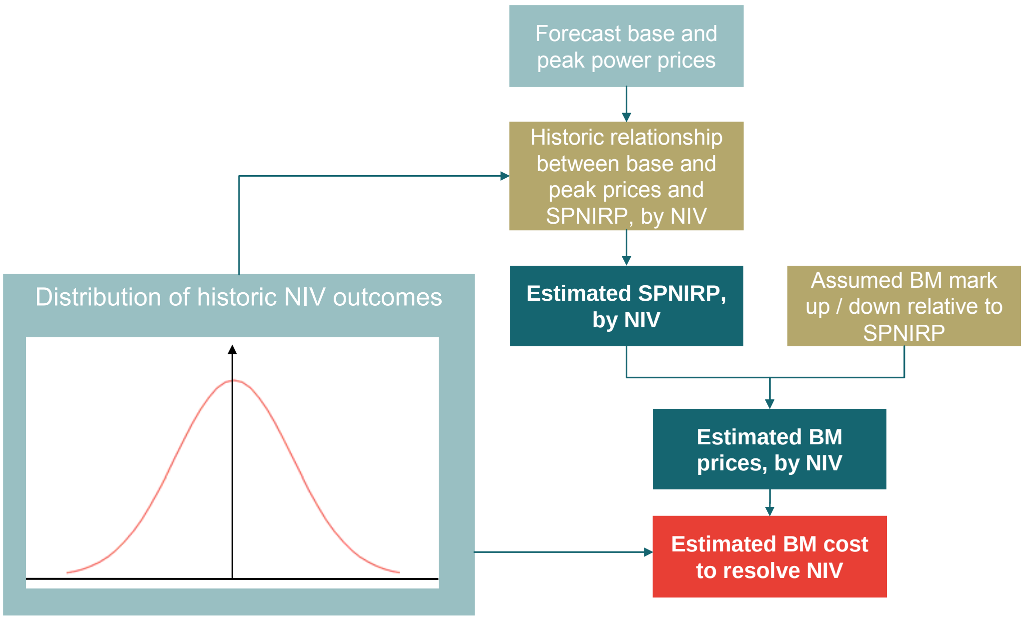
- **Granularity:** All of the models assess costs for a year only and develop cost estimates on the basis of much finer granularity of modelling. Many of the models examine likely performance per EFA block period throughout the year; and

- **Uncertainty.** Many of the variables used as inputs by NGET in the model are treated stochastically. For each of these variables, NGET assume an individually specified probability distribution and use Monte Carlo sampling techniques to simulate the impact of the uncertainty through the model. As a result, the output of the model is both an expected value of target costs and a distribution around this mean.

3.3.2 Energy imbalance model

The energy imbalance model combines inputs on the expected Net Imbalance volume (NIV) and on forecast base and peak power prices to estimate the cost through the Balancing Mechanism (BM) for NGET to resolve the NIV. Figure 4 below provides an overview schematic of the model.

Figure 4. Overview of energy imbalance model



Source: Frontier Economics

The model is based around an analysis of historic NIV outcomes, which are used to estimate a probability distribution of future possible NIV outcomes. The mean of the estimate of probability distribution of NIV is then adjusted by an "offset volume" for some EFA blocks and in some months on the basis of NGET judgement.

The model then draws on a forecast of base and peak GB power prices over the forthcoming year (drawing on data from price reporters as to forward market base and peak prices at the time the model is operated). This forecast, which has quarterly granularity, is then spread into a forecast with monthly granularity according to fixed within-quarter profiles (which we assume are based on historic analysis).[6]

For each value of the probability distribution of possible future NIV outcomes, the model then estimates SPNIRP. It does this through a set of assumed relationships (again, based on analysis of historic data) between base and peak power prices and SPNIRP. The parameters of this relationship vary depending on NIV.

Having estimated SPNIRP, the model then assumes mark-ups and mark-downs between BM bid and offer prices and SPNIRP. This assumed relationship is relatively simple. When the system is long, the BM price is assumed to be 80% of SPNIRP, and when the system is short, it is assumed to be 140%. These ratios do not vary by the absolute magnitude of NIV.

Finally, for each value of the probability distribution of NIV outcomes, the estimated BM price is multiplied by the level of NIV itself to estimate the cost of resolving the NIV. An expected cost is then calculated from the estimated cost of each value of the distribution.

3.3.3 Margin

The margin model first aims to estimate a requirement for margin volume based on the extent to which the market has provided some margin as a result of the NIV, and based on other key determinants of margin requirement (namely, level of wind generation, expected level of Scottish constraints and expected response provision). As a result, the margin model is linked to the energy imbalance model through the distribution of potential values for NIV.

Having estimated a volumetric requirement, the model then allocates the provision of this volume to different generation technologies. Based on this allocation, the margin model estimates the cost of margin actions.

In parallel with this, the model draws on data for expected contracting positions to calculate the cost of "option fees" – principally the cost of warming contracts, and the cost of Short Term Operating Reserve (STOR) availability payments.

Figure 5 below provides an overview of NGET's approach to modelling its costs incurred in procuring margin.

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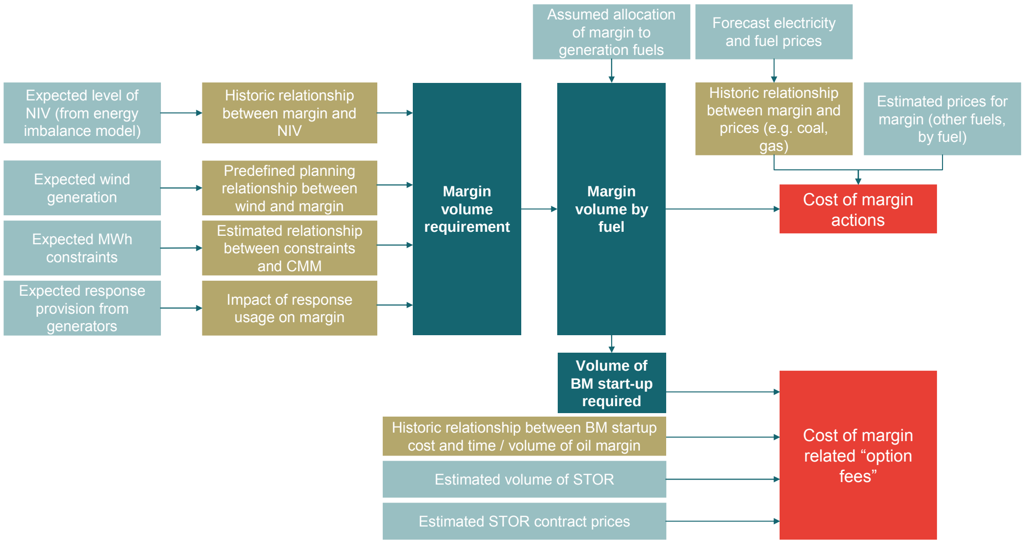
6 "High" and "low" scenarios for market prices are also calculated in the model. We understand that these are no longer used, but previously were a mechanism for reflecting increasing uncertainty as to the level of market prices in the later forecast periods.

Figure 5. Overview of margin model



Source: Frontier Economics

Calculation of margin volume requirement

The volumetric requirement for margin is modelled as being made up from four components.

First, the level of margin varies according to whether the market is expected to be long or short. NGET argue that, when the market is long, they have to buy less operating reserve than when the market is short (in this report, we refer to reserve provided as a result of resolving market length as "free reserve" as it has no incremental cost to NGET once the market length itself has been resolved). However, this is not a 1:1 relationship. NGET estimate a relationship between the level of operating reserve which they need to procure and the level of NIV based on historic data. This relationship indicates that when the system is long, at the margin, a further 1MW of NIV substitutes for around 0.5MW of operating reserve.

Therefore, for each value of the probability distribution of possible future NIV outcomes from the energy imbalance model, the margin model estimates the level of additional operating reserve which needs to be procured.

Second, NGET add margin required to manage volatility in wind generation. NGET have taken a policy decision based on technical security standards that it will manage the system with margin equal to 15% of expected wind generation. This policy decision is reflected in the model, using a NGET forecast of expected wind capacity and wind load factor.

Third, NGET add additional margin expected to be procured as part of "Constrained Margin Management" (CMM). If an operating reserve action taken in a given generation unit is deemed to be completely for the replacement of sterilised headroom behind a constrained boundary, then it is assigned as a constraint cost. However, if only part of the created headroom is deemed to have been necessary for sterilised headroom replacement, then the cost is assigned as CMM.

The volume of CMM margin is estimated as a function of the expected volume of Scottish constraints drawn from the constraints model. The relationship is assumed to be linear with constraint volume. We assume it is based on a historic analysis of CMM volumes.

Fourth, NGET add margin to take into account the level of provision of frequency response from static providers. The addition to take into account response provision is principally a function of the level of static provision of response, and the expected utilisation of the response. This data is drawn from the frequency response model.

Calculation of margin by type

Having calculated the volume of margin required, the model then allocates this margin to types of sources and to time periods.

The allocation to time periods is relatively simple – margin is only assumed to be held during peak periods, which during British Summer Time is assumed to equate to EFA periods 3-6 inclusive, and at other times is assumed to include periods 3-5 as well.

The model allocates the required margin between a range of types of generating plant:

- coal;
- CCGT;
- OCGT;
- oil;
- hydro; and
- pumped storage.

A small proportion of margin is also allocated to trades between System Operators and trade with France.

This allocation is on the basis of fixed percentages, which only vary according to whether it is a period in British Summer Time that is being considered. We assume these percentages are based on analysis of historic holdings of margin .

Objectives of regime and current approach

Calculation of margin costs

Having allocated margin volume to generating technology, the model then multiplies the margin volume allocated to each technology by a price to arrive at a margin cost.

Different approaches are taken to defining the prices by technology – for example:

- the price per MWh for coal is a multiple of UK baseload electricity prices;
- the price per MWh for CCGT is a multiple of UK gas prices; and
- the price per MWh for oil is a fixed value.

Calculation of cost of option fees

Finally, the model calculates the cost of option fees associated with operating reserve.

There are two main components to such fees.

First, the availability payments to participants contracted to provide reserve under STOR contracts. The volume of STOR contracted is a fixed input to the model, as is the level of the availability payment. We understand that the volume is based on the volume of STOR which NGET believes is likely to be available to be contracted, and that the price is based on a mix of historically observed availability prices and prices from tenders relevant to the forthcoming period already received by NGET.

Second, the cost borne by NGET associated with starting up plant in order that it is ready to provide operating reserve. This relates mainly to oil plant. The volume of plant associated with such contracts is assumed to be equal to the allocation of margin to oil plants in the calculation described above. The cost of starting up plant is based on a historic relationship with both time and the allocation of margin to oil plants during British Summer Time and Greenwich Mean Tim.

3.3.4 Congestion

The congestion model derives the overall estimated cost of congestion for certain key boundary constraints. Each individual model does not consider the whole system when modelling the overall cost; instead it examines only individual transmission boundaries that NGET consider critical in formulating an overall assessment of the likely cost. Although the approach for assessing the cost varies between Scotland and England & Wales, there are three generic key steps:

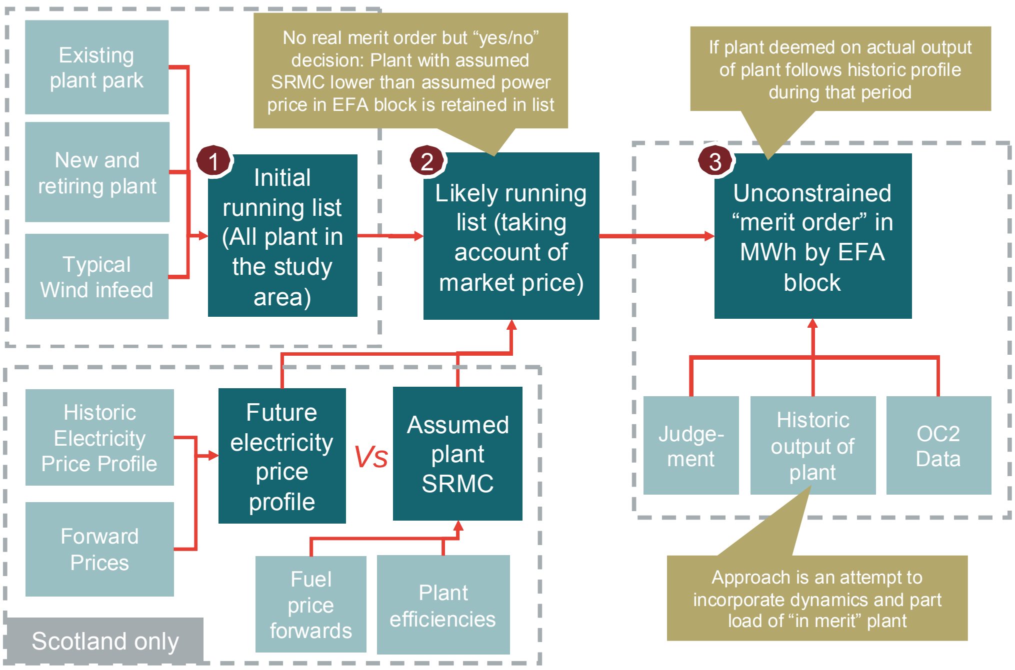
- first, the model calculates the generation background for the zones under study. This will identify the volume and type of generation that would operate in the study area absent a transmission constraint;
- second, the expected running profile of generation absent a transmission constraint is overlaid on the expected transmission capability of the network to determine the overall volume of congestion that will need to be resolved; and
- third, the cost of resolving the defined volume of congestion is estimated.

We discuss each step in more detail below.

Generation background

Figure 6 below provides an overview of the methodology used by NGET to determine the generation background.

Figure 6. Overview of congestion model: generation background



Source: Frontier Economics

First, NGET determines an initial running list of all generating plant in the area under study. This includes the existing plant on the system adjusted for known retirals and for new plant that is likely to connect over the forecast period. The expected wind infeed for the period is also added to the running list. This overall initial list therefore comprises all generating plant that could conceivably be running in the study area.

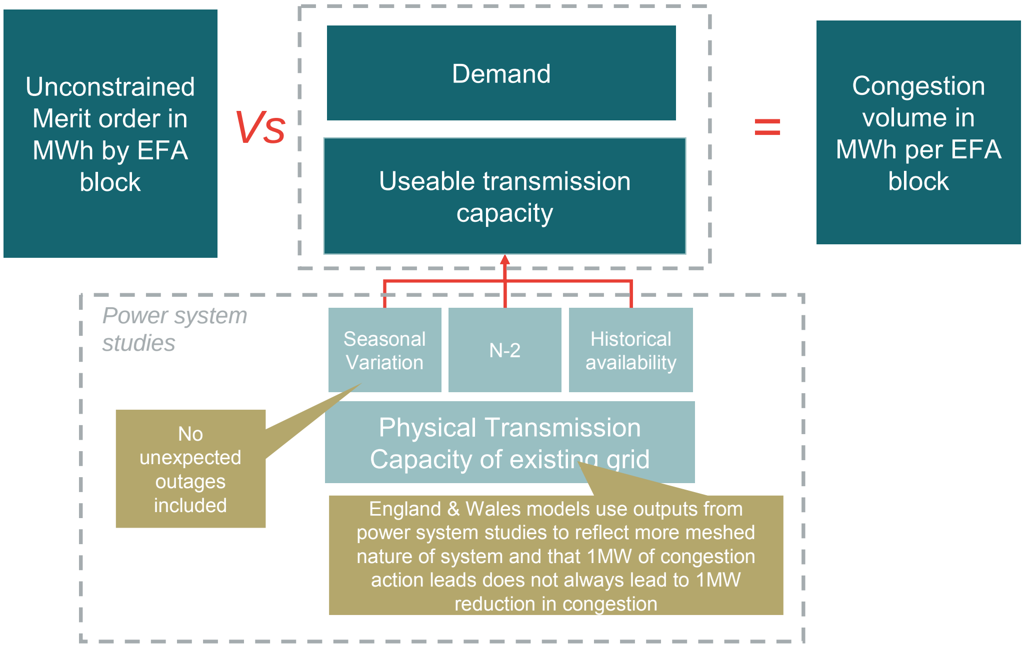
The next step is to adjust this list for the actual likely operating level of each plant in the list in any particular EFA block over the forecast period. For the estimation of the generation background in Scotland, this involves making an assumption on the short run marginal cost of each plant (in turn determined by assumptions on fuel price trends and plant thermal efficiencies). This SRMC is then compared with the forecast electricity price for each EFA block (which, in turn, is determined by the forward prices of electricity profiled by the historic EFA price profile). Those (Scottish) plant that are estimated to have a higher SRMC than the forecast price in that period are then excluded from the list of available plant determined in the first step.

The final step to determine the generation background is to estimate the likely MWh output (absent constraints) of the plant in the EFA block that have been identified in Step 1 for England & Wales and Step 2 for Scotland as available to produce. NGET use a number of approaches to determine the likely output. First it uses the OC2 data that indicate a plant's outage plan and therefore whether it is likely to be available in that EFA block. Second, for those plant not identified as under outage, it uses the historic MWh output of each plant in that EFA block as an estimate of the likely MWh output in the period under the study. Finally, these estimates are adjusted by NGET on the basis of its judgement to derive a final expected MWh output of each plant in the study area. This therefore represents an "unconstrained merit order": the expected level of output from each plant that would occur in the absence of transmission constraints.

Constrained volume

Having determined the unconstrained output of each plant, the next step in the calculation process is to determine the volume of energy that will need to be constrained off because of insufficient transmission capacity. Figure 7 below provides an overview of the approach adopted by NGET.

Figure 7. Overview of congestion model: constrained volume



Source: Frontier Economics

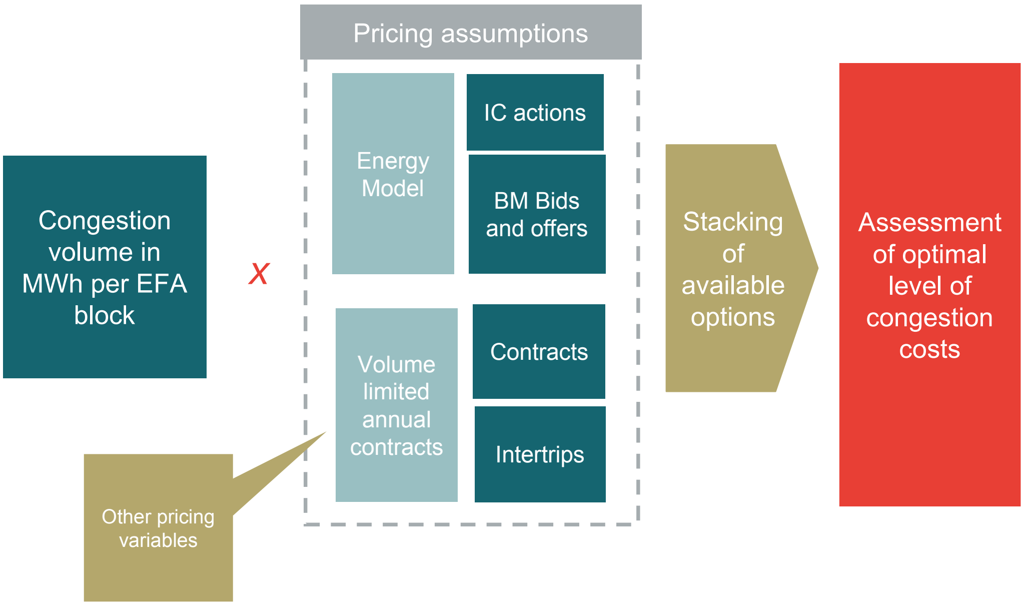
The approach compares the unconstrained MWh output determined in the first stage to the sum of expected demand in the area plus the useable transmission capacity available to export from the study area. The constrained volume is determined by the extent to which output in the unconstrained merit order is higher than the sum of demand and useable transmission capacity for each EFA block.

Useable transmission capacity is estimated through the use of (off model) power system studies that determine the boundary limits of the transmission system. The modelling of transmission capability is notably more complex in England & Wales than in Scotland given the more meshed nature of the network. An implication of this is that, for England & Wales, a single MWh reduction in the output of a generator in an export constrained area has a smaller reduction in the overall level of congestion.

Constraint costs

Given the volume of constraints identified above, the final step is to estimate the cost of resolving it. An overview of the approach is set out below in Figure 8.

Figure 8. Overview of congestion model: constraint costs



Source: Frontier Economics

NGET determines the likely price at which congestion is resolved through comparing the available options in any EFA block. The prices used have two main sources:

- First, prices pre-agreed in contracts with generators (including intertrip contractual arrangements) determine the price at which some plant will be constrained off the network (i.e. have output reduced). The percentage of constraints resolved through this approach is based on historic levels. The price for these contracts is estimated as a premium over the forecast spark or dark spread and reflects historical contract prices.
- Second, to the extent that a constraint cannot be resolved through the use of pre-agreed contracts, NGET will use the BM. The prices at which NGET buy and sell at in the BM are the standard assumptions determined in the energy model – namely 0.8 of the forecast SPNIRP for bids used to constrain off plant and 1.4 of the forecast SPNIRP for offers used in constraining on plant. Additional assumptions are used for interconnector actions and for the cost of constraining off wind generation.

The available prices for a given congestion volume are then optimised by NGET to determine an overall level of congestion cost for a particular study area.

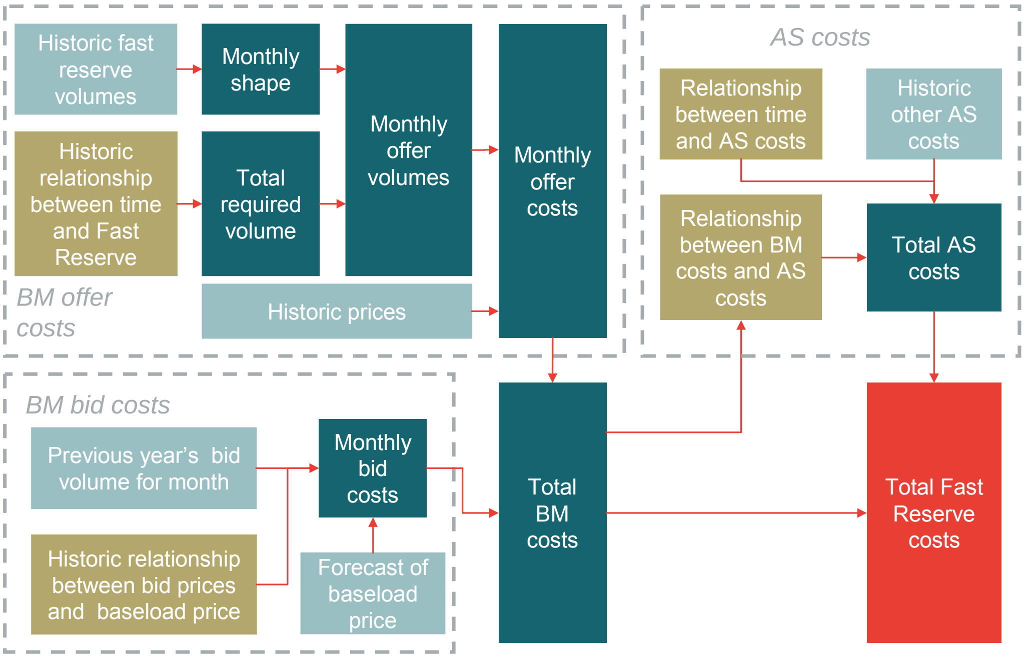
3.3.5 Fast reserve

The fast reserve model calculates three components of fast reserve costs:

- BM offer costs;
- BM bid costs (which are, in fact, negligible); and
- ancillary service fast reserve costs.

As we noted earlier in the section, total fast reserve costs appear to exhibit a fairly steady trend over time. The historic time trend is, in fact, the basis for much of the fast reserve model.

Figure 9. Overview of fast reserve model



Source: Frontier Economics

BM offer costs

The overall required volume of BM offers is calculated on the basis of an observed time trend for volumes (i.e. a linear relationship with time). A monthly shape is applied to the overall volume derived through use of historic monthly volumes.

The monthly volumes are then multiplied by prices, which are again based on historic observed prices to derive monthly BM offer costs.

BM bid costs

BM bid costs are small in absolute magnitude. The volume of BM bids for fast reserve is based on the previous year's volume by month. The price for BM bid costs is based on:

- the estimated baseload power price (the model uses the same figures as the energy imbalance model); and
- the estimated relationship between bid prices for fast reserve and the baseload price.

Ancillary service costs

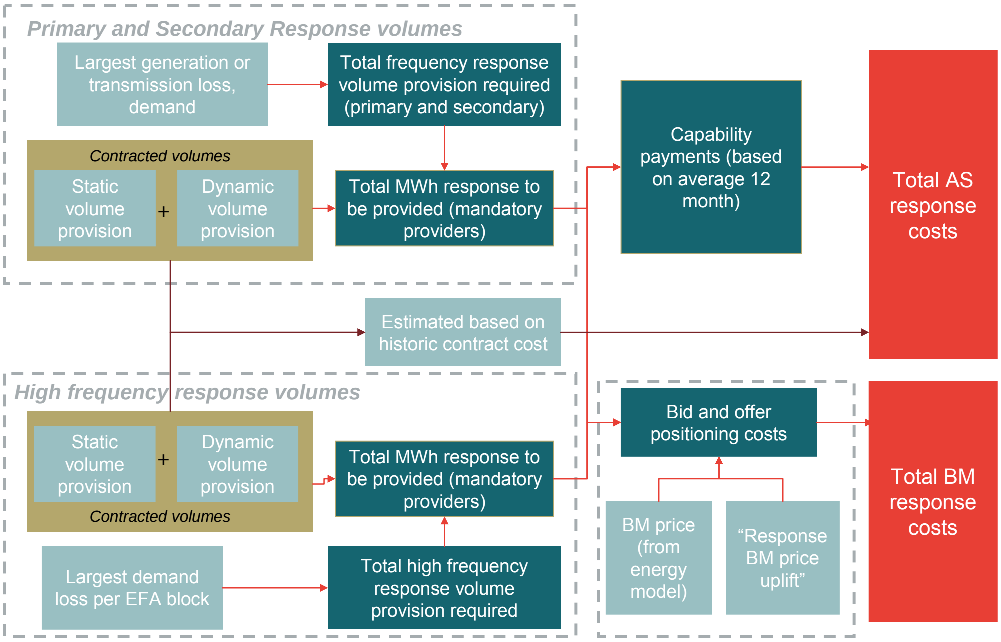
Adding BM bid and offer costs results in a total BM cost related to fast reserve.

Fast reserve ancillary service costs are then calculated on the basis of an observed relationship between historic ancillary service costs and a combination of BM fast reserve costs and time. A small component of "other" ancillary service costs is then added

3.3.6 Frequency response

The approach to determining the overall cost of Frequency Response is shown in Figure 10.

Figure 10. Overview of frequency response model



Source: Frontier Economics

The starting pointing for the determination of the cost of primary and secondary frequency response is an assessment of the overall volume required. This is determined principally by the largest possible generator or transmission loss on the system. This volume is met through a mix of contracted volumes and volumes that are provided as part of generator mandatory obligations under the Grid Code.

Contracted volumes are either provided by static providers (typically large demand side participants) or dynamic providers (typically a few specialised generating units). NGET forecast these volumes for the forthcoming period on the basis of historic volumes, adjusted by any updated information as to whether existing contracting parties are likely to renew their contracts with NGET or whether additional providers may come forward. The prices associated with these contracts are estimated based on historical contract costs.

The volume of frequency response that is procured through mandatory provision is estimated as the difference between the total volume required and that volume that will be provided under contract. NGET incurs two types of costs when procuring frequency response from mandatory providers:

- First, it incurs a positioning cost by accepting bids and offers in the BM. The volume of Bids/Offers required for positioning the plant in the BM is determined by deriving the requirement (which is a function of the largest generation or transmission loss and demand conditions), which is then adjusted for volumes provided through contracted static providers, and then, using historic relationships, to map this to the BM actions required to position the units. The price applied to this volume is forecast from the BM prices determined in the energy model (as described above) and is uplifted by an out of merit uplift factor based on historical observations.

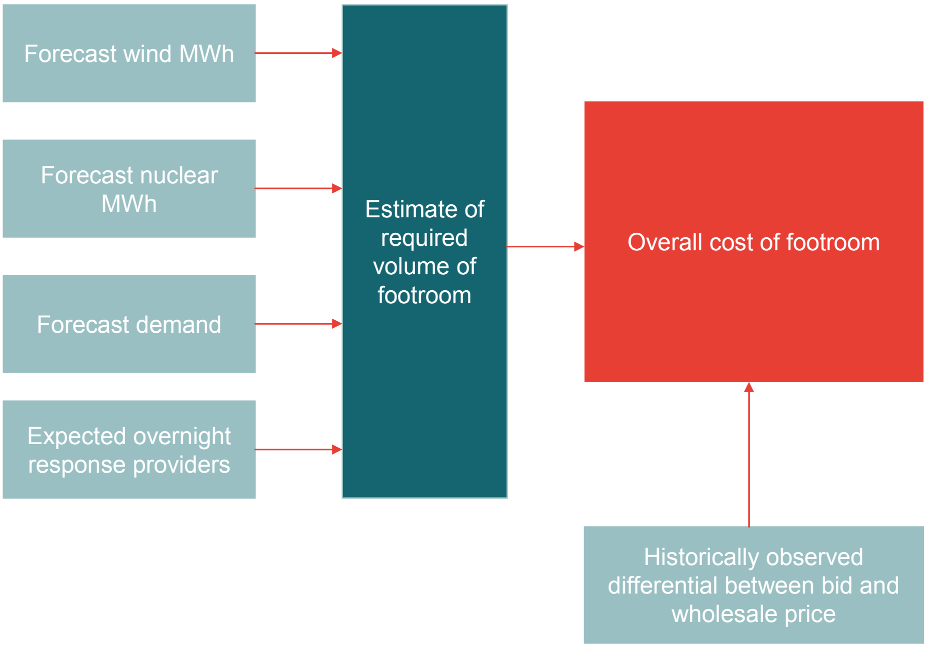
- Second it also incurs a capability payment that it pays to generators for being capable of providing response services once positioned. NGET forecasts the cost of this payment stream on the basis of the volume weighted average of prices from generators providing the service over the previous 12 month period.

A similar approach is used for determining the (much lower) cost of high frequency response. In this case the volume of high frequency response required is determined principally by the largest possible demand loss on the system. The approach to evaluating the overall cost of meeting this volume is broadly similar to the approach described above for primary and secondary response.

3.3.7 Footroom

The footroom model is relatively simple. It uses an observed historic relationship based on the key physical drivers of footroom (demand and the level of "must run" generation) to derive an estimated footroom volume requirement. It then multiplies this cost by an observed historic cost of footroom.

Figure 11. Overview of footroom model



Source: Frontier Economics

The volume of footroom required is a function of the level of must run generation on the system relative to the level of demand. Both nuclear and wind generation are assumed to be must run. Therefore, the volume of footroom required on the system in each month is estimated based on an observed historic function of:

- demand (based on NGET forecast);
- nuclear generation (based on NGET forecast);
- wind generation (based on NGET forecast capacity and load factor); and
- the level of overnight contracted frequency response provision (from the frequency response model).

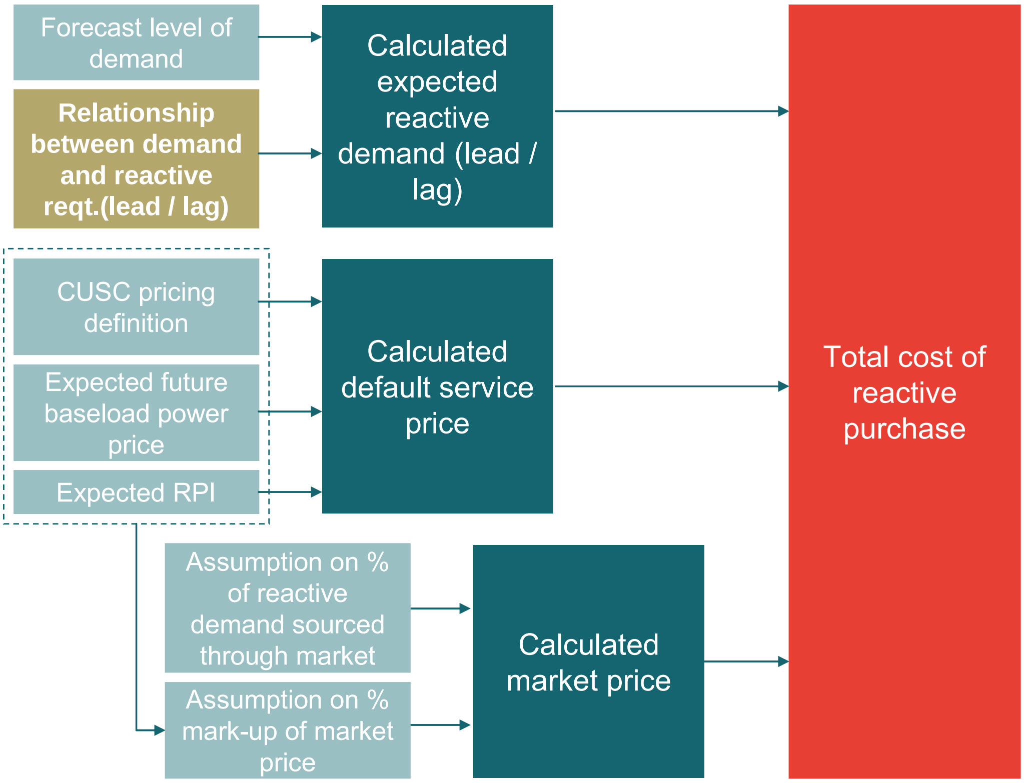
The cost of footroom is estimated based on the historic observed cost.

3.3.8 Reactive power

The reactive power model is also relatively simple. It takes an estimate of the demand for reactive power and multiplies by a price for default service provision, the level and evolution of which is set out in the CUSC.

In theory, NGET is able to procure reactive power through the market. However, at present, given the structure of the market product, it rarely does. In any given situation, either the seller or the buyer would prefer to use the default service. Until this structural issue with the market product is resolved, the model is based entirely around provision via the default service.

Figure 12. Overview of reactive model



Source: Frontier Economics

The model uses a forecast of demand (as in the footroom model) to estimate via a regression equation the level of reactive demand required on the system (leading and lagging).

The CUSC sets out the basis for pricing the default reactive power service – it is an administered price indexed to wholesale power prices and the RPI. The model replicates this indexation formula to estimate the price of default service provision.

The estimated volume of demand is then multiplied by the forecast default service cost to estimate the total cost of reactive power purchase.

Were market provision to be practically possible, the model has a facility for NGET to estimate market reactive power purchase costs. The volume of power purchased through the market is a percentage of the total requirement by month, and the price of market provision is assumed to be a fixed percentage of the default service provision costs.

3.4 Summary of key historic relationships used in modelling

In Table 1 we summarise the key historic relationships used in the modelling of each cost item. For many of the relationships we have not been provided with the calculation underpinning the estimations used in the model. However, we have highlighted the relationships that we believe warrant further consideration given the timeframe available to the study and which we therefore discuss later in this report.

Table 1. Historic relationships

Cost category	Relationships	Merit of relationship addressed in Section 6
Energy Imbalance	SPNIRP ↔ base / peak power prices (by NIV slice)	
	BM ↔ SPNIRP	✓
Margin	Operating Reserve requirements↔ NIV level	✓
	CMM ↔ Scottish Constraints	
	% Margin by technology based on historical observations	✓
	% cost multiples on fuel costs for each technology	✓
Congestion	Output by generator ↔ historic output by generator	✓
	BM bids ↔ SPNIRP	✓
	Electricity price profile ↔ history	✓
	Other constrained off contracts ↔ history	
Fast Reserve	Offer volume ↔ Time	
	Offer profile ↔ Historic profile	
	Ancillary Service costs ↔ BM costs	
	Bid volume ↔ Previous year's bid volume	

Objectives of regime and current approach

Table 1. Historic relationships

Cost category	Relationships	Merit of relationship addressed in Section 6
	Bid prices ↔ Baseload power prices	
Frequency Response	Contract volumes ↔ Historic contract volumes	✓
	Contract prices ↔ Historic contract prices	
	Capability payment prices ↔ volume weighted 12 month historic prices	
	Out of merit uplift ↔ historic out of merit premium	
Footroom	Footroom volume ↔ Forecast Demand and must run generation	
	Price ↔ Historically observed difference between bid and wholesale price	
Reactive Power	Active demand ↔ Reactive demand	

Source: Frontier Economics

3.5 Use of the models to set the incentive scheme

There are three key parts to the definition of the incentive scheme:

- the target cost;
- incentive scheme risk setting parameters (e.g. sharing factors, caps and floors etc.); and
- *ex post* adjusters.

At present, the models are principally used in the definition of the first two parts[7].

7 Although for the 2010/11 scheme we understand that the constraint models were not used to set the target allowance in the scheme for constraint costs. They were, however, still used to determine the relationships for the IFA and wind adjusters.

The use of the models in relation to the establishment of the target is straightforward – it is set with reference to the expected value of SO costs produced by the models.

Since the models treat a number of inputs stochastically, the models also produce a probability distribution for forecast SO costs. This distribution provides an indication of the level of uncertainty related to outturn costs, and hence informs NGET's proposals in relation to risk mitigation factors. However, there is no deterministic link between the distribution of outcomes produced by the model and the risk sharing factors. These factors are developed on the basis of NGET's judgement as informed by the model output.

The models are not directly used to define the *ex post* adjusters. Rather, the adjusters are estimated based on an assumed functional specification[8] and a regression of outturn costs on historic values of variables against which NGET requires insulation (e.g. currently assumed to be wholesale prices and market length).

However, the specification of the incentive regime does need to take account of the impact of NIA to ensure that, given the central forecast of input variables, the sum of target costs plus NIA is equal to the central forecast of SO costs being generated by the model.

Any other *ex post* adjusters (e.g. the Scottish generation connection adjuster) are either calibrated off-model or by running alternative scenarios of input variables through the models.

It is important to note that this approach to calculating *ex post* adjusters means that even if the models themselves capture the impact of certain variables in a complex manner, *ex post* adjustments may be more simplistic.

NGET explicitly recognise that "when the market experiences extreme conditions, both in terms of power price and market length… current NIA does not perform particularly well. This is because, being a linear relationship derived from statistical analysis, NIA coefficients aim at capturing the core of the data points and therefore do not cater for such extreme conditions". They go on to say that "the relative infrequent nature of those extreme market conditions mean that for the significant majority of the time NIA performs satisfactorily". Further, in relation to changes including greater volumes of intermittent generation, they note that "NGET will need to monitor the impact of any

8 For example, the functional specification was changed recently from 0.5*SPNIRP*TQEI to 450*SPNIRP + 0.9*SPNIRP*TQEI (for long market periods). NGET also note that they may consider moving from a linear to a quadratic definition of NIA, and including other variables such as fuel prices.

changes and keep the NIA methodology up to date to ensure continued accuracy”[9].

[9] Letter from NGET to industry on the development of the NIA, 23rd February 2010

4 Benefits and constraints with longer term regimes

As noted at the outset, Ofgem have for some time expressed a desire to move to a longer term incentive regime for SO costs. In order to consider the implications of this for the way in which any long term scheme is structured and for the way in which NGET models SO costs, it is important to understand the potential benefits of such a move. It is also relevant to consider the potential constraints on moving to a longer term scheme. In this section we discuss the benefits and constraints in turn.

4.1 Benefits of a longer term regime

The benefits of a longer term regime broadly fall into three categories. There are potential benefits in relation to:

- ensuring the effectiveness of incentives for all of the categories of SO costs;
- incentivising trade-offs between SO activities, other TO activities, and interactions with external parties (e.g. the Scottish TOs, generators); and
- increasing administrative efficiency.

We describe the benefits within each category in qualitative terms below.

It is worth noting that both the incentive and administrative benefits described require any long term incentive regime to be credible over the scheme time period. For example, if the regime is expected to be the subject of either repeated requests for determinations on Income Adjusting Events or clawbacks by the regulator in the event of significant outperformance, the benefits of a longer term scheme will be diluted.

4.1.1 Ensuring effectiveness of incentives

Within the current annual regime, there are a number of situations in which the incentive power of the regime is limited because contracts have already been tendered or struck for the services in question when the target is being established. In such situations, NGET simply include the (known or highly probable) costs based on their existing procurement approach in the estimation of the target. This is the case for STOR contracts and for some of the contracts used to provide frequency response.

The impact of this feature of target setting in an annual regime is to reduce the strength of incentives around procurement. For example, if STOR contracts have already been tendered at the time of target setting and the availability payment levels under the contracts are therefore known with reasonable certainty, these costs effectively become a passthrough item for NGET. In contrast, while unit utilisation prices may also be known and effectively be a passthrough item, utilisation under the contract is not known. There is therefore still an incentive on NGET to optimise STOR contract utilisation against other substitute activities.

Equally, as noted in the previous section, the approach to setting the annual scheme at present bases the *ex ante* target on historic observed NGET behaviour in relation to the level of NIV.

NGET set its target for operating reserve procurement over and above the margin provided by resolving NIV on the basis of an observed historic relationship (with an additional 1 MWh of NIV length resulting in a saving of around 0.5 MWh of operating reserve procured). Yet this relationship is actually simply a function of how much operating reserve NGET have purchased previously for any given level of observed NIV. The relationship is created by NGET's historic control room operations.

This effectively means NGET is being benchmarked against its own behaviour annually, without any "productivity factor" being applied. In turn this means that the incentive to improve or optimise actual control operations is muted.

Finally, there are a range of activities which could potentially be undertaken by the SO business which would have a relatively long term payoff in terms of reduced SO costs. These might relate to capital expenditure (e.g. development of new control room systems to allow improved optimisation of activities) or operating expenditure (e.g. increased spending on encouraging participation in tender processes for particular services or in developing services around new technologies available to market participants). Within an annual scheme, NGET would not have a strong financial incentive to undertake such activities (although it is worth noting that they may still decide to undertake some level of activity pursuant to their general licence obligations).

A longer term scheme would have important benefits in relation to these problems:

- unless NGET strikes contracts with a duration of more than one year, under a multi-year scheme there would be no ability to set the target for the second year and beyond on the basis of actual contract prices. This would result in a stronger incentive on NGET for efficient procurement as it would potentially earn additional revenue in the second and subsequent years by contracting at prices lower than those used to determine the target;
- by setting a multi-year target without recalibrating the relationship between NIV and operating reserve procurement, NGET would have a stronger "productivity" incentive (i.e. an incentive to try to reduce the

operating reserve procured for any given volume of NIV to be resolved) as they would profit from improvements in this relationship over a multi-year period. The relationship could then be recalibrated for subsequent targets on the basis of updated data[10]; and

- by setting a multi-year target, NGET will be able to capture benefits of actions over more than one year. As a result, activities which involve more material upfront investment should become economic under the scheme.

4.1.2 More effective optimisation of trade-offs

There are a number of areas in which trade-off exists between SO activities and either TO or generator actions.

Trade-offs with TO actions

It will always be difficult to define an SO incentive regime which creates an appropriate incentive to optimise TO investment activities. TO investments take a long time to define and deliver (typically around 10 years for new lines), and they are likely to have a long payoff period. Therefore, while some investments[11] may be made more attractive for NGET through a longer term incentive regime, in the main it is unrealistic to believe that efficient investment behaviour is ever likely to be incentivised by the SO regime alone.

The issue is further complicated by the use of sharing factors in the SO incentive scheme. As the benefits of any efficiencies in the SO scheme relative to the target are shared between NGET and its customers as per the pre agreed sharing factors set at the start of the scheme, NGET only retain a proportion of the overall SO efficiency saving. Therefore, the sharing factors in the scheme dilute the incentive for NGET to undertake expenditure in TO activities that might reduce SO costs. For example, with a sharing factor of 50%, a £100 saving in SO costs would only be economic for NGET if the TO operating cost incurred to achieve this saving was less than £50.

However, there are trade-offs between the TO and SO businesses which a longer term incentive regime could incentivise NGET to optimise.

The first relates to TO outage planning.

NGET's ability to trade off SO costs with the timing of TO outage plans for particular parts of the network varies over time in relation to two factors:

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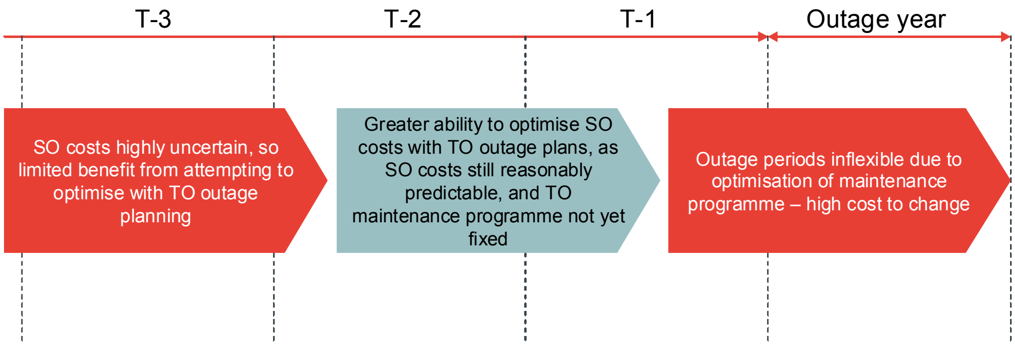
10 Provided structural changes to the relationship between NIV and reserve are not expected to change significantly over time.

11 For example, smaller scale investments with a relatively low lead time, such as quad boosters or voltage compensation equipment.

- close to the time at which the TO undertakes outages, we understand that the TO outage plan is relatively fixed as a result of the need to optimise the overall TO maintenance programme[12]. Therefore, it is more difficult for the SO business to achieve changes to the plan; and
- further away from the time at which the TO undertakes outages, the benefits to the SO business of moving particular pieces of work becomes highly uncertain, reducing the extent to which it makes sense to attempt to optimise across the TO and SO businesses.

From discussions with NGET, we understand that the period between 6-18 months ahead of the start of year in question may offer the greatest opportunities for optimising this trade off. This relationship is highlighted below in Figure 13. The extension of the incentive regime beyond an annual scheme should therefore create further opportunities for the SO business to be incentivised to engage with all TO businesses in order to optimise plans.

Figure 13. Ability to trade off SO cost with TO outage plan over time



Source: Frontier Economics

The second area relates to changes in policies, standards and codes (e.g. CUSC, SO-TO Code, SQSS etc). These can take time to achieve, particularly if lengthy consultation, approval and potentially appeal processes are involved in relation to modifications.

However, in some areas, changes to the way in which responsibilities are allocated or changes in the way in which parties interact commercially may improve the SO's ability to manage the system efficiently. For example, we understand that NGET and the Scottish TOs are already in discussions to work

12 For example, we understand that the Scottish TOs have on previous occasions declined to provide NGET with an indication of the cost of moving outages, on the grounds that the operations are outsourced and that the amount that would have to be paid to the contractors to change their work schedule would outweigh any potential GBSO benefits from moving outages.

out how the SO-TO interactions in relation to outage management can be improved.

Again, a longer term incentive scheme should strengthen the incentives for both NGET's SO and TO businesses to put forward changes to industry arrangements which make operating the system more efficient.

Trade-offs with generation actions

The key trade-off between generator actions and SO actions is also likely to relate to outages, and specifically co-ordination of generation outages both with other generators (so that the reduction in supply of particular services is not too great at any given time) and with the TO (in order to minimise the impact of transmission outages on congestion costs).

Similar considerations apply to the co-ordination of generator outages to those in relation to the TO businesses. Again, therefore, a longer term incentive scheme may allow for greater input by the SO business into generator outage decisions (e.g. through the SO striking contracts which offer generators a payment to move outages, or simply to provide contractual certainty around specific outage dates) than an annual scheme.

4.1.3 Administrative efficiency

At present, both Ofgem and NGET expend significant effort on an annual basis to develop proposals for and then to agree an SO incentive regime. The wider industry is also required to expend effort in responding to the various consultation phases involved in the development of the annual schemes.

Linked to this is the fact that a longer term scheme has the benefit that gains and losses in any particular year might be considered "in the round" rather the current situation where a particular gain or loss is forensically examined on a year-by-year basis. Therefore, it could be argued that a longer term scheme, particular if accompanied with some of the measures suggested in this report, should (at least in some dimensions) make the process of setting targets more straightforward than the current process.

Overall therefore, in addition to the beneficial incentive properties of a longer term scheme, it may also reduce the administrative effort required currently for all parties.

4.2 Constraints on a longer term regime

The key constraint on a longer term incentive regime relates to the extent to which it is feasible or desirable to allocate risk to NGET.

In setting any regulatory control, the duration is typically chosen to balance the strength of incentives on the network operator against the degree of uncontrollable influence on cost which the operator is likely to face. Shorter durations reduce the period for which the operator captures the benefit of actions to improve efficiency and hence reduces the strength of incentives. However, they also provide more protection against unanticipated and uncontrollable changes in the operator's cost base.

We note above that there could be expected to be a number of benefits from a longer term regime in terms of the strength of incentives on the SO in relation to certain activities. However, the corollary is that NGET would be exposed to a fixed regime for a longer period, and hence would be more exposed to changes in its SO costs which were not anticipated or controlled for at the time the regime was established.

It would not be in customers' interests to expose NGET to risks in relation to cost levels which it cannot control. It is a widely accepted principle of efficient risk allocation that risk should be placed with those who are best placed to manage it. Other parties will charge a premium for bearing the risk. In this case, this premium would show through in the cost of capital which NGET would require if exposed to material and uncontrollable risks. Ultimately, this would feed through to a higher regulated cost of capital and, in turn, an increase in costs to customers overall relative to the risk being passed through to customers directly through the regime[13].

Any longer term regime must therefore be designed in such a way as to limit the extent to which NGET is allocated risks it cannot control.

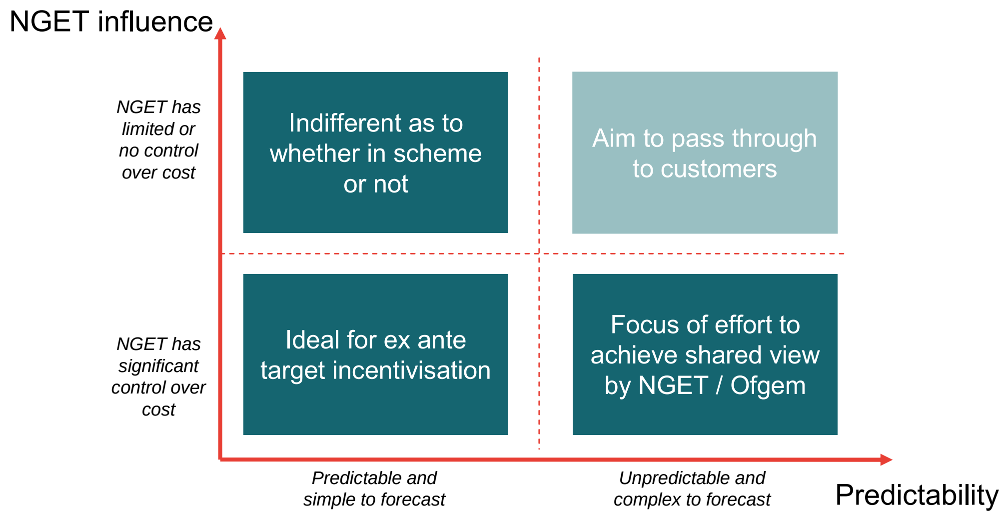
We therefore consider two dimensions in relation to each cost category:

- **controllability**, that is the ability for NGET performance to impact on the overall outturn level of costs for a particular cost category; and
- **predictability**, that is the ability for NGET and the regulator to forecast (and agree) what the efficient level of costs should be for a particular cost item.

Figure 14 below summaries the extent to which a cost item's controllability and predictability influence its suitability for incentivisation.

13 To the extent that the volatility cannot be passed on directly to customers and has to be passed initially to other industry players (i.e. BSC parties), it is important to consider the potential impact of greater volatility from their perspective. We return to this issue below.

Figure 14. Impact of controllability and predictability on incentivisation



If a cost category **is relatively predictable, and NGET has a high degree of control** over the level of the cost, it is an ideal target for incentivisation. Ofgem and NGET are likely to be able to come to an agreement relatively easily over the forecast level of cost, and because of the degree of control NGET has over the cost, they should perceive relatively little increase in risk as a result of a longer term incentive regime.

Even for cost categories which are **less within NGET's control but still relatively predictable**, NGET should see relatively little risk in accepting a longer term incentive regime. Effectively, because they are straightforward to predict, costs of this nature become passthrough items when embedded within an incentive scheme.

The difficulty arises when cost items are unpredictable and difficult or complex to forecast (the case for at least a subset of the categories of SO external costs).

In cases where NGET has a **high degree of control on the outturn level of costs yet the forecast of an appropriate cost level is complex**, although NGET should, in principle, be content to be incentivised against the cost item, the process of agreeing the incentive cost target with Ofgem is likely to be difficult. This is therefore the area to which modelling effort should be devoted, in order to make sure that there is a common understanding of the cost drivers and relationships between NGET and Ofgem for each cost category.

In contrast, **where NGET has little control over the outturn level of costs and the forecast of that cost level is difficult**, it will not be in customers' interests to define a longer term incentive regime which exposes NGET to cost variations. Rather, an effective scheme should insulate NGET from volatility in such costs, and should allocate the risk associated with changes in cost levels direct to customers.

In defining a longer term incentive regime, in relation to each cost category it is therefore important to understand:

- the key drivers of each area of SO cost;
- the extent to which each driver is predictable and its impact on the overall cost level is straightforward to forecast;
- the extent to which NGET can control the impact of changes in each driver on outturn costs; and
- the extent to which NGET and Ofgem can forecast (and agree) the outturn costs.

We consider these questions in Sections 5 and 6.

5 Cost drivers and level of NGET control

In this section, we consider the cost drivers for each of the categories of cost under consideration, and then consider the level of NGET control in relation to those cost drivers. In the light of this, we consider options in relation to the definition of a longer term scheme.

5.1 Cost drivers

In Table 2 below, we summarise the key cost drivers for each of the cost categories considered.

Table 2. SO cost drivers

Cost category	Drivers	Comment
Energy imbalance	NIV	The overall position of the market (long or short) determines the volume which NGET needs to trade to achieve balance
	Wholesale prices	The level of wholesale prices influences the level at which participants are willing to trade
	BM mark-ups	To the extent that NGET trade to balance through the BM, they may face a mark-up (or down) on wholesale market prices.
Margin	Generation reliability	If generation is more reliable (i.e. fewer unplanned outages), other things equal, less margin should be required
	Generation capacity / availability	The level of available generation capacity will affect the supply of plant available to provide margin
	Wind volatility	As with the level of thermal generation reliability, greater wind volatility (in absolute terms) will result in a need for more margin
	NIV	Some reserve is created “free” as a result of NGET resolving a long market imbalance (although as noted previously, this relationship is not 1:1)
	Contract prices (e.g. STOR)	Pricing in contracts for the provision of reserve (option fees and fixed utilisation prices) will influence the cost of margin

Table 2. SO cost drivers

Cost category	Drivers	Comment
	Wholesale prices	The level of wholesale prices influences the price at which participants are willing to offer margin
	BM mark-ups	To the extent that NGET create margin through the BM, they may face a mark-up (or down) on wholesale market prices
Congestion	Generation capacity / availability	Congestion volumes will be driven by the relativities between: ▫ the level of installed generation capacity, its availability, and its planned output in the unconstrained schedule (by location) ▫ the level of demand (by location); ▫ the level of transmission capacity (by location) and its availability to export or import surplus generation or demand. These factors will also determine the level of wholesale prices.
	Wind infeed	
	Demand	
	Transmission capacity / availability	
	Fuel prices & merit order	
	BM mark-ups	The cost of resolving transmission constraints through the BM will depend on the mark up or mark down of BM bids and offers relative to wholesale prices
Fast reserve	Demand volatility	The extent of short term demand volatility will determine the volume of fast reserve required to make sure that generation meets demand beyond frequency response timescales
	Wind infeed	The extent of short term wind volatility will also determine the volume of fast reserve required to make sure that generation meets demand beyond frequency response timescales
	Commercial contract prices	The cost of the fast reserve service is driven by the availability of flexible generation (and demand). This is reflected in the level of commercial contract prices for the service

Table 2. SO cost drivers

Cost category	Drivers	Comment
Frequency response	Largest loss	The volume of frequency response required is a function of the largest single loss on the system
	Commercial contract prices	The cost of frequency response is a function of the availability of generation and demand capable of providing the frequency response service, which is reflected in commercial contract prices for the service, and the prices quoted for mandatory service provision
	Mandatory service prices	
	BM positioning costs	To the extent that it is required, the cost of frequency response will also be driven by the cost of NGET taking actions to "position" plant (through BM offers and bids) to be ready to provide frequency response
Footroom	Demand	The volume of footroom required will be driven by the relativity between the level of demand and the volume of "must run" (nuclear and wind) generation.
	Nuclear generation	
	Wind infeed	
	Wholesale prices	The cost of footroom will be driven by the spread between BM bid prices and wholesale prices
	BM prices	
Reactive	Demand	The volume of reactive power demand will be driven by the level of active power demand
	Ability of network to control voltage	Reactive demand will depend on the switching of some circuits and the deployment and configuration of equipment round the network to control system voltage.
	Wholesale prices	The price of reactive power will be driven (as defined in the CUSC) by the level of wholesale prices and RPI
	RPI	

Source: Frontier Economics

Cost drivers and level of NGET control

5.2 Level of NGET control

Having described the cost drivers for each of the services, we now turn to an assessment of the level of NGET control over each cost driver. We indicate where NGET has no control over a cost driver, and where they do have some element of (albeit shared) control.

It is worth noting that across the categories where NGET has some shared control, the extent of this control may vary (e.g. NGET may have more control over transmission outages in England & Wales than over BM mark-ups).

Table 3. Level of NGET control

Cost category	Drivers	Level of control	
Energy imbalance	NIV	None	NIV is a function of market participants' forecasting capability and level of risk aversion
	Wholesale prices	None	Wholesale prices are a function of interactions between participants in relation to bulk energy trading
	BM mark-ups	Some	NGET has no real ability to influence bids and offers submitted – however, contracts can be used to reduce risk, and NGET will have some discretion over which bids / offers it accepts
Margin	Generation reliability	None	This is a function of generators' unplanned outages
	Generation capacity / availability	Some	NGET may be able to contract with generators to secure availability at certain times, and at the margin may be able to influence commissioning dates
	Wind volatility	None	Wind volatility is driven by variations in actual wind conditions
	NIV	None	NIV is a function of market participants' forecasting capability and level of risk aversion
	Contract prices (e.g. STOR)	Some	NGET sets the procurement approach for contract provision, and can also encourage new sources of

Table 3. Level of NGET control

Cost category	Drivers	Level of control	
			provision. NGET also publishes reports that give information on recently accepted and rejected volumes and prices
	Wholesale prices	None	Wholesale prices are a function of interactions between participants in relation to bulk energy trading
	BM mark-ups	Little	NGET has no real ability to influence bids and offers submitted – however, contracts can be used to reduce risk, and NGET will have some discretion over which bids / offers it accepts
	Generation capacity / availability	Some	NGET may be able to contract with generators to secure availability at certain times, and at the margin may be able to influence commissioning dates
	Wind infeed	None	Wind infeed is driven by actual wind conditions
	Demand	None	Demand is a function of customer activity
Congestion	Transmission capacity / availability	Some	Within the SO business, NGET can influence the outage planning of TOs[14], and may at the margin be able to influence commissioning times of new capacity
	Fuel prices & merit order	None	Determined by fuel markets and interactions between participants in relation to bulk energy trading
	BM mark-ups	Little	NGET has no real ability to influence bids and offers submitted – however, contracts can be used to

14 Differences in ability to influence NGET's TO business and the Scottish TO business could be considered within NGET's control to a certain extent (e.g. in relation to modifications to the SO-TO Code). However, more structural issues are clearly outside NGET's influence.

Table 3. Level of NGET control

Cost category	Drivers	Level of control	
			reduce risk, and NGET will have some discretion over which bids / offers it accepts
Fast reserve	Demand volatility	None	Demand volatility is a function of customer activity
	Wind infeed	None	Wind infeed is driven by actual wind conditions
	Commercial contract prices	Some	NGET sets the procurement approach for contract provision, and can also encourage new sources of provision. NGET can also publish reports that give information on recently accepted and rejected volumes and prices
Frequency response	Largest loss	None	This is governed by the SQSS, and is a function of the physical development of the system and the unit sizes of new power stations.
	Commercial contract prices	Some	NGET sets the procurement approach for contract provision, and can also encourage new sources of provision. NGET can also publish reports that give information on recently accepted and rejected volumes and prices
	Mandatory service prices	Some	While NGET has no real ability to influence bids for mandatory service provision, they can optimise between mandatory and contract provision, and can also improve their control room optimisation tools to reduce volumes
	BM positioning costs	Little	NGET has no real ability to influence bids and offers submitted – however, contracts can be used to reduce risk, and NGET will have some discretion over which bids / offers it accepts

Table 3. Level of NGET control

Cost category	Drivers	Level of control	
Footroom	Demand	None	Demand is a function of customer activity
	Nuclear generation	None	Nuclear generation is a function of generator decision making
	Wind infeed	None	Wind infeed is driven by actual wind conditions
	Wholesale prices	None	Wholesale prices are a function of interactions between participants in relation to bulk energy trading
	BM mark-ups	Little	NGET has no real ability to influence bids and offers submitted – however, contracts can be used to reduce risk, and NGET will have some discretion over which bids / offers it accepts
Reactive	Demand	None	Demand is a function of customer activity
	Ability of network to control voltage	Some	Within the SO business, NGET can influence the switching of circuits and the configuration of voltage control equipment. Possible more so than the main transmission system, the SO business should also be able to influence the deployment of voltage compensation equipment by the TOs, and the timing of outages to repair such equipment.
	Wholesale prices	None	Wholesale prices are a function of interactions between participants in relation to bulk energy trading
	RPI	None	Macroeconomic variable

Source: Frontier Economics

From Table 3 it is clear that there are a number of drivers of SO costs which are outside NGET's control. Of these, a number are likely to be volatile and relatively difficult to predict at the time of setting a scheme (particularly if it is long term), including:

- the level of NIV;
- the level of wholesale prices;
- the level of fuel prices and the associated merit order; and
- the level of wind infeed and its volatility.

Among these, volatility among the first three drivers is clearly already high. Given the relatively low level of connected wind generation, the fourth may not be a material issue for NGET at present. However, it is highly likely to become a material issue within the next 5 years.

In relation to these drivers, it may therefore be worth considering ways in which NGET can be insulated from the risk of windfall gains and losses associated with volatility and the difficulty of forecasting outturn values, while continuing to ensure that NGET has a day to day incentive to reduce costs (e.g. by improving short term forecasting).

5.3 Implications for the regime

The current regime is based around an *ex ante* target (albeit subject to some *ex post* adjustments). As a result, to determine the *ex ante* target NGET needs to put forward a forecast for all of the key drivers described above, and agree these with Ofgem. The *ex post* adjusters also need to be calibrated in the light of the forecast inputs to the *ex ante* target.

Arguably, this results in NGET attempting to arrive at values for some inputs which are both inherently volatile, complex to forecast and outside their control. It is also likely to create lengthy discussions with Ofgem (particularly if these forecasts evolve significantly over time) over values which are not critical from an incentivisation perspective as a result of them being outside NGET's control.

Ideally, the incentive regime should insulate NGET from the risk of windfall gains and losses as a result of volatility in such variables, and also avoid the need for discussion and agreement between NGET and Ofgem as to their expected level.

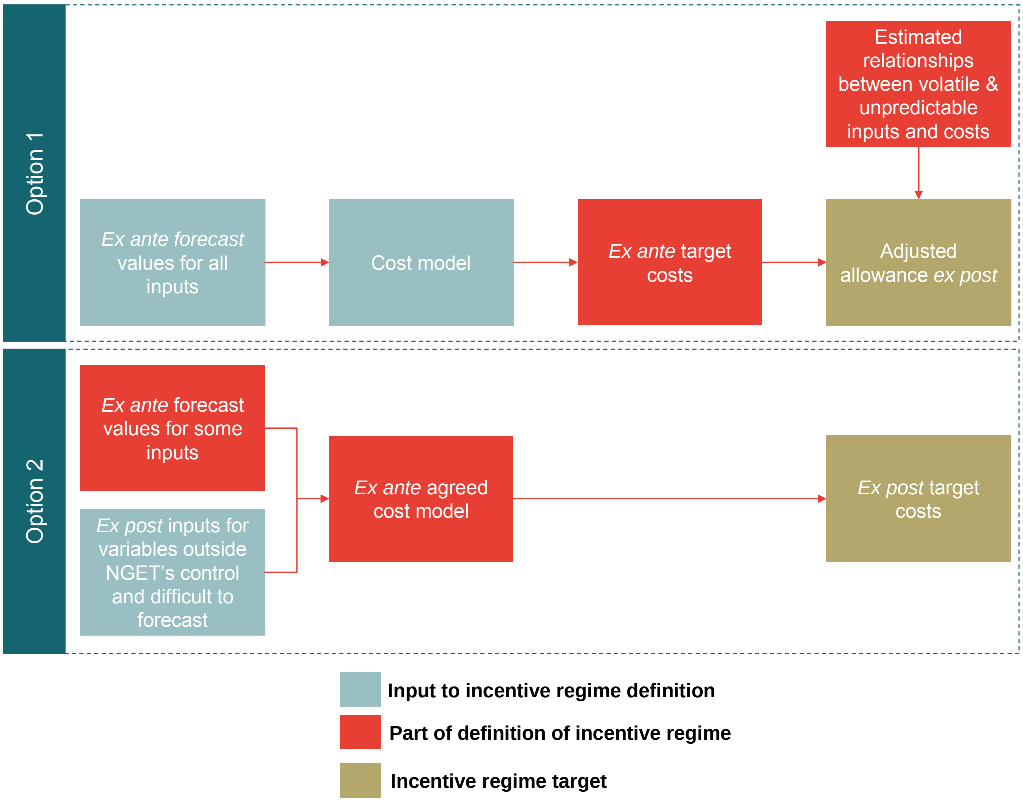
Such "insurance" could be provided to NGET in two ways:

- **Option 1**: continue to set an *ex ante* target, but with increased and refined use of *ex post* adjusters (such as NIA) to adjust NGET's allowances for changes in specific variables; and
- **Option 2**: move away from an *ex ante* target and define a target *ex post* through use of an *ex ante* agreed model, some *ex ante* agreed inputs, and

(where they are difficult to predict and outside NGET's control) some *ex post* agreed inputs.

A stylised model of the operation of both options is shown in Figure 15.

Figure 15. Stylised model of operation of incentive regime options



Source: Frontier Economics

In Section 6 below we provide a work example of how an Option 2 *ex post* regime would work for the Energy imbalance parameter.

Under Option 1, NGET would continue to use models as at present to derive an *ex ante* target for SO costs. However, in parallel, based on a more holistic identification of the variables that are outside its control and the areas of SO costs which they impact, NGET would also propose refined *ex post* adjusters to mitigate the impact of changes in cost drivers which are both difficult to predict and outside their control. Ofgem would then need to agree with NGET both the *ex ante* target (based on NGET's modelling) and the formulation and parameterisation of the adjusters (again, based on NGET's modelling of the impact of changes in key inputs).

In contrast, under Option 2, there would be no *ex ante* target (although an cost estimate may be published based on expected outturn values of key drivers in order to provide some indication of expected costs).

Rather, NGET would present Ofgem with a proposed model of SO costs based on two sets of inputs:

- some to be agreed and fixed *ex ante*, where they are agreed to be either under NGET's control or relatively stable and predictable; and
- some to be determined *ex post* and then input into the model.

Ofgem would agree the model and *ex ante* inputs with NGET. The actual cost target would then be calculated *ex post* when the outturn values of the *ex post* inputs are known. NGET's outturn performance against this *ex post* target would then be evaluated and treated as it would be under an *ex ante* target.

Option 1 has a number of important advantages – for example:

- the approach is an extension of the current treatment using the NIA, and hence there is experience of its operation; and
- it allows the determination of a clear and transparent *ex ante* target and manages adjustment to allowances in a way which can be clearly understood by all parties.

However, it may also have some drawbacks:

- it may be difficult to define *ex post* adjusters where the interaction between cost drivers and outturn costs is more complex;
- *ex post* adjusters may remove some of the risk associated with volatility in cost drivers from NGET, but they are unlikely to be able to remove it all;
- it may require agreement between NGET and Ofgem on values for *ex ante* inputs which are difficult to forecast. This may create difficulties in agreeing the parameters of the scheme and/or divert attention from discussion of more important factors; and
- it effectively requires agreement to be reached between NGET and the regulator on two sets of relationships – the first captured in the models used to derive the *ex ante* target, and the second captured in the formulation of adjusters to reflect the impact of changes in cost drivers.

Option 2 addresses these drawbacks:

- the use of *ex ante* agreed models with *ex post* inputs for key variables removes the need to define adjusters, and should result in NGET being insulated from the impact of volatility in these variables (provided the models are an accurate reflection of the link between cost drivers and costs)

- no *ex ante* agreement is required on the value of drivers which are volatile, difficult to forecast, and outside NGET's control;
- only one set of relationships (those captured in the model agreed *ex ante*) are used in the incentive regime.

However, it also has some downsides:

- it may be seen as less transparent, although an indicative cost estimate could be published to help address this problem[15];
- there would be more emphasis for Ofgem on agreeing the model itself rather than a target and a set of adjusters, and hence more emphasis on ensuring agreement on the form and specification of historic relationships used in the models, defining the interaction between services, and calibrating the models effectively. This would potentially increase the time which Ofgem would need to spend auditing the model(s) [16]. This would be an even more significant issue if changes to the models (discussed in the next chapter) result in them being more complex or having components (e.g. dispatch models) which are more "black box" like in nature[17]; and
- as part of the process of agreeing the model as the basis for the incentive regime, Ofgem would need to be comfortable that it was well calibrated such that it reflected NGET's historic level of efficiency and effectiveness in relation to each cost category.

A move to an approach based on Option 2 may also see a reduction in the predictability of BSUoS charges as a result of a greater proportion of the volatility of SO costs being allocated to customers than to NGET. To the extent that refined *ex post* adjusters were successful, this may also happen under Option 1.

However, under an Option 2 approach, provided the *ex post* inputs are chosen appropriately, and assuming that industry participants will on average over the medium term be able to pass through BSUoS costs accurately (or at least without any persistent bias), this increase in volatility should reflect more efficient risk

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15 Arguably, there is little difference between the publication of an indicative cost estimate and then determination of the target *ex post* and publication of a formal target *ex ante* and then adjusting allowances according to *ex post* mechanisms. The key issue is the likely magnitude of the adjustments.

16 There is arguably a general need for the modelling to be more transparent and accessible, even if Option 2 is not followed. However, this becomes more important under Option 2.

17 There may be some need for external verification of models, in order to increase the level of comfort of Ofgem and/or the industry as to their operation.

allocation between NGET and customers. Equally, the extent of any increase in volatility is likely to be small, as a result of the interaction of caps and floors on NGET's current exposure.

Nevertheless, if participants were concerned about the short term impact of an increase in volatility, there are a number of additional steps that could be taken to mitigate its impact – for example:

- providing the market with indications of the outturn value under a range of different scenarios for inputs;
- providing the market with a version of NGET's model, to allow them to estimate the likely cost for themselves[18]; and
- providing the market with an ongoing forecast of outturn values by NGET.

It is important to note that, under both options, while NGET may be insulated from windfall gains and losses associated with volatility in key cost drivers, they will still have an incentive to react to changes in cost drivers to reduce costs. This is because the impact of either *ex post* adjusters or the adoption of an *ex post* target only changes the revenue which NGET is allocated in relation to SO costs. For any given level of revenue, subject to caps and floors binding, NGET should always have an incentive to react to manage outturn costs levels (e.g. by more efficient procurement, consideration of changes to policies etc.).

On balance, we believe there would be merit to NGET considering the feasibility of including variables which are difficult to forecast and outside their control as *ex post* inputs to agreed *ex ante* models as part of their Phase 2 development of proposals for a longer term incentive regime.

18 In that a number of the potential *ex post* inputs relate to the energy markets, arguably participants may be in a better position to estimate outturns than NGET or Ofgem.

6 Possible changes to models

In this section, in the light of the discussion above on NGET's ability to forecast and control the key drivers of the external costs under consideration, we return to the models currently used by NGET.

For each model, we consider three questions.

First, we consider whether there are **changes in the way in which the models are used** which could either increase the accuracy of external cost forecasts or reduce NGET's exposure to risk relating to drivers which are difficult to forecast or control which would make it easier to agree a long term regime.

Second, we consider whether there are **improvements to the definition of the models** (in other words, the calculations within it and the use to which forecasts of drivers are put) which could be made to increase the accuracy with which external costs are forecast and hence make it easier for NGET and Ofgem to agree a longer term incentive regime *given the characteristics of the system as it stands today*.

Third, we consider **improvements to the definition of the models** *in the light of the potential future evolution of the system*. It is useful to separate these two questions because there may be constraints on the extent to which "futureproofing" changes can be made as part of the current process:

- it is our understanding that during Phase 2, NGET will have around four months to update its models and consider alternative uses prior to coming back to Ofgem with new proposals for a longer term regime. In this time period, NGET may not have time and resources to evaluate all the potential changes we suggest, and hence may have to prioritise. If this is the case, it may make sense to prioritise those changes which are relevant for the system as it stands; and

- in some cases, there may not be sufficient data available to allow modelling of the impact of some future changes. For example, there may not be a sufficiently clearly established relationship between the impact of significant wind generation and particular cost categories.

Across all three questions which we seek to address, it is important to bear in mind the scope of our work. We have undertaken a review over a six week period of models which have, in some cases, been developed over years. During that development time, many alternative formulations will have been tested by NGET, and many modelling possibilities will have been evaluated and ruled out because they were did not add sufficient accuracy to merit additional complexity.

Our analysis should therefore be seen as providing suggestions of areas in which we believe further consideration of modelling approaches would be beneficial, rather than indications of areas in which the models are clearly deficient. It is not until an evaluation of the benefit (in terms of accuracy) and the cost (in terms of modelling complexity) of each of the suggestions we make has been assessed that a clear conclusion can be reached.

Finally, we note that one of Ofgem's concerns with the models which led to this review was the volatility in forecasts of costs by NGET during the scheme setting process itself. Some of the suggestions we make – and in particular, those related to the removal of volatile and uncontrollable cost drivers from the incentive regime – may help in this regard. However, it is important to recognise that nothing will remove the problem completely because the inherent volatility of drivers of SO costs and the immediacy of the requirement to incur costs[19] is likely to be greater than, say, those in the TO business.

As in section 3, after considering modifications relevant to all of the models, we address each of the models in turn – we consider:

- energy imbalance;
- margin;
- congestion;
- fast reserve;
- frequency response;
- footroom; and
- reactive.

6.1 Generic modifications

The models all make extensive use of Monte Carlo analysis to model the impact of uncertainty. A range of distributions around key inputs are assumed, and then draws are taken from these distributions as part of the process of deriving an overall estimate of target costs.

The majority of the parameters associated with these distributions are direct inputs to the model. We have not therefore sought to review the appropriateness either of the choice of distribution (e.g. normal, uniform, etc.) or the parameters associated with them.

However, it appears that the variables subject to Monte Carlo analysis are treated as being independent. In other words, the draw from a distribution of one

19 In other words, within the SO business it is more difficult to delay taking actions in the face of increased prices than in an asset owner business.

variable is not modelled as being correlated with the draw taken from other variables.

In some cases, this will be appropriate. However, in other cases it will not be. For example, in the calculation of margin costs, independent uniform distributions are associated with electricity and gas prices. In reality, there is likely to be a degree of correlation between these prices, and hence the assumption of independence will result in a greater level of uncertainty being modelled than actually exists.

The impact of the absence of correlation will not be on the modelled estimate of target cost itself. Rather, it will be on the distribution of potential cost outcomes produced by the model. To the extent that this distribution informs the incentive parameters (e.g. sharing factors, caps and floors etc) which NGET is willing to accept, the absence of correlations between positive correlated variables may lead NGET to be unduly risk averse.

One area for future development would therefore be to investigate the extent of correlation between variables which are modelled stochastically through a Monte Carlo process.

That said, we note that there are a large number of variables in the model which are treated stochastically, and that to assess and then implement correlations between all of them would be a major undertaking.

To reduce the level of effort, the number of variables treated stochastically could be reduced. In particular, the input parameters with stochastic treatment could be limited to those around which there is material uncertainty (as the independent stochastic treatment of other variables could be considered as spurious accuracy).

Among these stochastic variables, attention could then be focused on those where the correlation was believed to be the strongest, and where the sensitivity of model output to changes in input is the highest. Within the scope of this review, we have not had the opportunity to assess which might be the priority inputs.

6.2 Energy imbalance

6.2.1 Changes to the use of the model

The energy imbalance model currently involves calculations across a distribution of possible outcomes of NIV. The expectation across this distribution is used for target setting. The NIA *ex post* adjustment then attempts to remove NGET's exposure to the actual outturn NIV volume. However, it does this through a relatively simplistic formula rather than going back through the detailed calculations and looking at all of the potential areas of SO cost into which the level of NIV was believed to feed.

Similarly, the model takes as inputs power prices (both base and peak). Again, NIA attempts to remove NGET's exposure to outturn power prices (by using SPNIRP as a reference).

We noted in the previous chapter that both the outturn level of NIV and the level of power prices (as distinct from BM prices) were variables which were outside NGET's control, and volatile in a way which makes them difficult to model.

There may therefore be benefits in removing the estimation of these two variables from the model and simply using *ex post* inputs of their outturn levels in the modelling to derive an *ex post* forecast of efficient energy imbalance costs.

Indeed, using this approach in relation to power prices would remove the need to model the relationship between base and peak power prices and SPNIRP. The outturn level of SPNIRP could be an input to the model, with the model then using this level to estimate the level of BM bid and offer prices which would be expected with such an outturn.

This would then imply that NGET was only incentivised on the mark-up paid relative to wholesale prices to resolve the outturn level of NIV, rather than on any aspect of the level of NIV itself or the level of wholesale prices.

The text box below sets out a worked example of how the scheme might work in practice.

STYLIZED EXAMPLE OF *EX POST* APPROACH (AS PER OPTION 2)

To derive the *ex post* target for energy imbalance would involve the following steps:

- Agree *ex ante* the expected mark up or down in the BM (the current 0.8 and 1.4) that NGET should be incentivised against. This relationship is essentially the incentive scheme.
- For each EFA block (or whatever time period granularity is deemed appropriate), record the actual NIV volume in MWh in that period;
- For each EFA block, record the level of wholesale price or SPNIRP.

For example, supposing that NIV was 300MW short in a particular EFA block and that the SPNIRP outturn was, in the same EFA block, £60/MWh. The incentive scheme for that period sets the mark up, as it is short period, at a 1.4 multiple of SPNIRP. In this case, therefore, the allowance for NGET would be 300MW *£60/MWh * 1.4 = £25,200.

NGET would be exposed to the actual costs incurred in resolving the 300MW short NIV in this period and, in return, receive the £25,200 determined by the *ex post* values and the pre agreed relationship (in this example case of 1.4).

Therefore, the focus of the incentive scheme debate between Ofgem and NGET is whether the 1.4 mark up represents a sufficiently challenging target for NGET, Indeed, as we suggest, it might be possible to be more sophisticated with this relationship by having more extreme mark ups in periods when the market is particularly short or long and lower mark ups in other periods. As we discuss below, this could be calibrated on the basis of historic evidence.

We also suggest that other factors, such as generation availability, might be influential in the degree of mark up applied to a particular wholesale price and it might be possible to calibrate the mark up on the basis of actual generation availability in the EFA block period.

6.2.2 Definition of the model for the current system

The model as it stands aims to calculate, for a given volume of NIV, the cost of the balancing actions required to resolve it. Based on our review, the key areas for potential further development in the model for the system as it stands relate to:

- the estimation of SPNIRP; and
- the modelled relationship between BM bids and offers and the level of SPNIRP.

However, with the change of use discussed above, the first of these would become irrelevant (in that outturn SPNIRP would be used). Therefore the remaining issue would be the modelled relationship between BM bids and offers and the level of SPNIRP.

At present, the price of BM bids and offers are estimated as a simple multiplier of SPNIRP:

- when the system is long (but irrespective of length), BM prices are estimated at 0.8 * SPNIRP; and
- when the system is short (but irrespective of length), BM prices are estimated at 1.4 * SPNIRP.

This relationship is assumed to be constant through the day and throughout the year.

In considering the further development of this relationship, it is important to understand what the multipliers are trying to capture. SPNIRP itself will already be reflecting the overall balance of supply and demand for power on the system. The multipliers are therefore intended to capture any extent of scarcity rent associated with bids to the BM by more flexible generation or load.

It might be worth considering whether these mark-ups do actually vary over time and how significant the improvement in modelling accuracy would be if such variance were captured. Conceptually at least, there is reason to believe there may be some variance over time – for example:

- at higher demand levels, the premium required to resolve an overall short market position might be expected to be higher;
- similarly, more extreme divergences of NIV from zero might be expected to have higher premium or discounts in the BM relative to the SPNIRP;
- at periods of predictable low levels of generation availability (e.g. during the summer outage season), BM participants may also be able to increase the prices at which they offer power in order to extract more scarcity rent.

This may therefore be an area worth exploring further, particularly since with the change of use discussed above, this would be the key area of incentivisation in relation to energy imbalance.

6.2.3 Evolution of the system

Looking forward, significant changes to the distribution of outturn NIV might be expected as a result of greater wind integration. However, the precise impact will depend on the way in which participants with significant wind in their portfolio decide to manage the risk associated with wind forecast error (and indeed how that wind forecast error evolves over time).

However, with the approach described above, such changes would not have to be modelled, because the outturn level of NIV would be used in the modelling *ex post*.

The only structural evolution which would have to be taken into account is the extent to which the level of BM bid and offer mark ups relative to SPNIRP changes over time. There may be reason to believe these mark ups will change. For example, increasing wind penetration will imply an increasing demand for flexible generation to manage intermittency. Absent a supply side response, this would drive up BM offer prices.

However, such changes in the premium paid over SPNIRP would be very complex to model. Equally, since they are likely to evolve gradually over time, it may be more appropriate to review them periodically at the point of resetting of longer term controls, using information from the impact of incentivisation from the previous control to inform the new forward looking level.

6.3 Margin

6.3.1 Changes to the use of the model

The margin model makes use of the expected level of NIV from the energy imbalance model. It also makes use of *ex ante* estimates of both electricity and fuel (e.g. gas, oil) prices.

In line with the approach suggested above in relation to energy imbalance, there may be benefits in removing the need to forecast these elements from the model by using *ex post* values to calculate an *ex post* target for efficient margin costs.

Similarly, the model uses an input of the expected level of wind generation (in MWh) on the system. Again, we noted in the previous chapter that the level of wind output (as distinct from the accuracy of NGET's wind forecast) was a variable which is outside NGET's control, and volatile in a way which makes it difficult to model.

Particularly looking forward, there are likely to be benefits in removing the need to forecast wind output for the purposes of deriving an incentive target. As wind penetration grows, this would almost certainly become a very important variable in determining the level of incentivised costs, and therefore a significant aspect for debate between Ofgem and NGET.

However, this is more problematic from a modelling perspective, because the full impact of wind volatility is not necessarily modelled explicitly – and hence changes to the modelling approach may be required in order to be able to accommodate an outturn input of wind generation. We return to this point below when we consider changes to the modelling approach given the evolution of the system.

6.3.2 Definition of the model for the current system

At a high level, the model aims to calculate:

- the volume of STOR required, and therefore the costs of those contracts;
- the level of "free margin" as a result of NIV; and
- the volume of additional margin (e.g. operating reserve) required, and the costs of this reserve by technology.

Based on our review, the key areas for potential further development in the model for the system as it stands relate to:

- the estimation of the level of free margin;
- the allocation of margin actions to technology; and

- the pricing of margin actions by technology.

The level and pricing of availability payments for STOR are effectively direct inputs currently. In part this is a function of the one year scheme – in some cases contract prices for STOR will already be known, and these can be used to inform the model directly. This implies there may be little or no effective incentive in relation to STOR procurement.

In terms of a longer term scheme, provided STOR availability costs were not subject to significant volatility, using an estimate based on existing levels and then providing a more effective incentive on procurement may be a reasonable approach. We note, however, that with increasing levels of wind on the system and with the resulting increase in levels of demand for STOR, continued stability of STOR contract pricing will depend on the extent of supply side response.

Level of free reserve

A key element of the margin model at present is the estimation of the level of free reserve. This is estimated on this basic of an observed historic relationship between:

- the level of margin creating actions taken by NGET over time; and
- the outturn level of NIV over time.

Based on this relationship, the model projects a level of free reserve provided based on the expected level of NIV derived in the energy imbalance model.

However, as we have noted above, the relationship on which NGET model the level of free reserve is one which is within their control. It is NGET which decide which margin actions to take on a half hour by half hour basis, based on their estimate of the effectiveness of the free reserve likely to be available to them at that time. Therefore it is NGET who are determining the history on which the observed time series relationship is being based.

If applied on a short term basis, the incentive properties of this arrangement are relatively weak. If NGET behave relatively conservatively over time, they will be set an incentive target which implicitly assumes this relatively conservative behaviour, and within a short term scheme will have little financial incentive to try and consider whether there are alternative approaches they could follow.

That said, absent structural change to the relationship (which we return to below), within the context of a longer term incentive scheme, this approach may be reasonable. Under a longer term scheme, NGET would arguably have more incentive to increase the extent to which they could use NIV as free reserve, and hence to reduce costs over time. This would in turn feed through to the observed historic relationship between margin actions and NIV, resulting in a more aggressive target being set at the start of the next longer term scheme.

There would, however, still be benefit in exploring further the functional form and specification of this relationship prior to the introduction of a longer term scheme in order to reduce the risk of resulting windfall gains or losses to NGET as a result of an inaccurate specification.

Allocation of margin actions to technology

Once a level of required additional operating reserve volume is calculated, at present, the allocation of that volume to generation technologies is based on a fixed[20] percentage allocation during peak hours (no additional margin is assumed to be required in off-peak).

Actual fuel costs or likely operating conditions of plant by technology are not considered within the model. For example, if gas prices (or carbon prices) were such that gas plant was operating close to full load factor, it might be expected that less operating reserve would be provided by that technology, and that more reserve might be provided by coal or oil plant.

An alternative approach to allocating margin to technologies would be to attempt to build a fundamental model of the plant on the system and of demand and to attempt to co-optimise both provision of energy and provision of reserve across the plant park given its technical and economic characteristics. Models which carry out this optimisation process are used in energy markets in some jurisdictions.

However, it is unlikely that such an approach would be appropriate in GB, largely because of the significance of the contribution of NIV to reserve holding.

The decision to go into gate closure long is made at the portfolio level. It is related to the forecasting capability and preferences in relation to potential imbalance risk exposure of individual portfolio managers. It is not related to the underlying economics of the plant park, and hence cannot be modelled through simulation of economic dispatch.

Given the significance of NIV in relation to margin costs, it seems likely that any attempt to model margin using an economic dispatch model alone would therefore be relatively inaccurate.

That said, as a general principle it could be expected that cheaper plant would tend to be full loaded, and therefore that more operating reserve would be provided by more expensive technologies. Indeed, this is implicit in the current percentage allocations, where gas plant are expected to provide more reserve in winter (when gas is more expensive) and less in summer. However, the current

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20 The allocation varies depending on whether the period under consideration is during British Summer Time or not.

approach "hard codes" a particular assumption on merit order switching, and only considers this difference between summer and winter.

It may therefore be worth exploring whether an allocation methodology which is more tightly linked to fuel price fundamentals would better reflect costs. While, as we note above, this would be difficult to achieve through an economic dispatch model, further analysis of statistical relationships between margin volumes by technology and fuel price may be beneficial.

Previously, this may not have been considered worthwhile as a result of the difficulty of estimating relative fuel costs month by month. However, it may also be worth exploring whether the use of *ex post* fuel costs would make further developments in this area more effective in terms of accuracy.

Pricing of margin actions by technology

Having allocated margin actions to different types of generation technology, the model estimates the pricing of margin actions in two ways:

- with reference to other electricity or fuel costs (e.g. as a multiplier on baseload electricity costs for coal generation, as a multiplier on gas wholesale prices for CCGT, and as a multiplier on French peak electricity prices for trade with France); and
- as a fixed cost per technology.

As we note above, there may be benefit in using *ex post* wholesale or fuel price outturns for those cost elements where a multiplier is used. Beyond this, there are a number of potential areas in which further development of the pricing approach might be considered – for example:

- there is no within day structure to prices at present (although only peak periods are being considered); and
- there is no within year structure of multipliers or absolute prices – for example, in periods where overall generation and supply is tighter, the multiplier over fuel prices could be higher.

While difficult to say definitively, these developments seem likely to be less important in terms of overall accuracy than those relating to the allocation of reserve volume to technology.

6.3.3 Evolution of the system

There are three areas of evolution which we consider here

- connection of wind generation;
- changes to the pricing of STOR and operating reserve; and
- ongoing development of generation and transmission on the system.

Possible changes to models

Connection of wind generation

The addition of significant wind generation to the system is likely to create the need for more reserve. At present, the impact of wind volatility on reserve requirements is largely captured in three ways in the model:

- the volume of contracted STOR;
- the historic relationship which determines, for a given level of free reserve, how much additional reserve is required; and
- an explicit additional requirement for reserve depending on how much wind is on the system, currently set at 15%[21,22].

This means that the overall impact of wind volatility on required margin is not explicitly modelled. Rather, it is implicit in other relationships.

This has a number of implications.

If this approach is maintained, the specification of those relationships may change over time – changes which would need to be considered carefully at each resetting of the regime.

Equally, adopting an *ex post* approach to the treatment of wind[23] will be difficult, as there is no way for the calculations to update automatically based on the level of wind on the system, unless the policy driven volume of incremental reserve resulting from wind generation turned out to capture the vast majority of the incremental reserve volume required[24].

There may therefore be benefit in exploring an alternative approach to the formulation of reserve requirements in which the level of wind generation is

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21 It is worth noting that this additional requirement for reserve based on wind generation levels is an NGET policy rather than an estimate. As part of the determination of the total level of reserve required to meet the 1/365 day generation security standard, NGET estimates this incremental requirement linked to the level of wind generation. In the same way as for other "policy driven" variables, there is no discretion for the control engineers to vary this standard. NGET periodically reviews the standard.

22 As with the impact of other cost drivers, in theory NGET is incentivised to review this policy (particularly under a longer term scheme when there would be longer to capture the benefits of a less conservative approach). However, this narrow financial incentive will be constrained both by governance arrangements associated with changes to such policies, and by the potential impact of less conservative policies on NGET's reputation should the level of system reliability fall.

23 Potentially both in relation to the uncertainty as to the output from the wind fleet at any given time, and uncertainty as to the timing of wind connections, to the extent they are more numerous and more difficult to predict than individual generation connections.

24 There is evidence from the German market that the volume of additional reserve required to accommodate new wind generation on the system becomes relatively linear beyond a certain level of wind generation. However, we are not aware of similar analysis having been conducted for the GB system.

modelled explicitly. This is complicated by the fact that the approach would also need to capture the impact of NIV.

One potential approach might be to model total margin requirement and then subtract off the various sources of margin (including NIV) to leave the level of additional operating reserve required. The modelling process could be as follows:

- model the total margin requirement for the system as a whole (as a function of key variables such as demand and its forecast error, wind and its forecast error, generation reliability etc.)[25];
- use this model to estimate a reserve requirement given outturn values of key variables including wind generation[26] *ex post*;
- subtract from this modelled value the STOR that is expected to be contracted *ex ante*; and
- subtract from this value the estimated impact of outturn NIV *ex post*, based on an assumed relationship between NIV and effective free reserve[27].

If each step of this calculation could be carried out, the result would be the level of reserve requiring to be procured *given* the level of outturn wind and NIV. Depending on the modelling approach, it might be necessary to take one further step to separate this volume of reserve between operating reserve and fast reserve (only the former would be relevant from the perspective of margin, as the latter is modelled separately).

Under this approach, NGET would still be incentivised to contract as effectively as possible (e.g. through an appropriate mix of STOR contracts and additional operating reserve) as the *ex post* target would not adjust for the actual split of margin between products.

An alternative, which would be closer to the current approach, would be to include the level of wind output as a further explanatory variable in the analysis of the relationship between the level of NIV and the level of actual margin required.

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25 Such a model is presumably used by NGET in the formulation of policy driven variables such as the requirement for incremental reserve given a level of wind generation. Equally, we are aware of other such models which have been used for policy estimation purposes in other jurisdictions.

26 An *ex ante* estimate of wind forecast error would need to be used in order to give NGET an ongoing incentive to improve its forecasting ability.

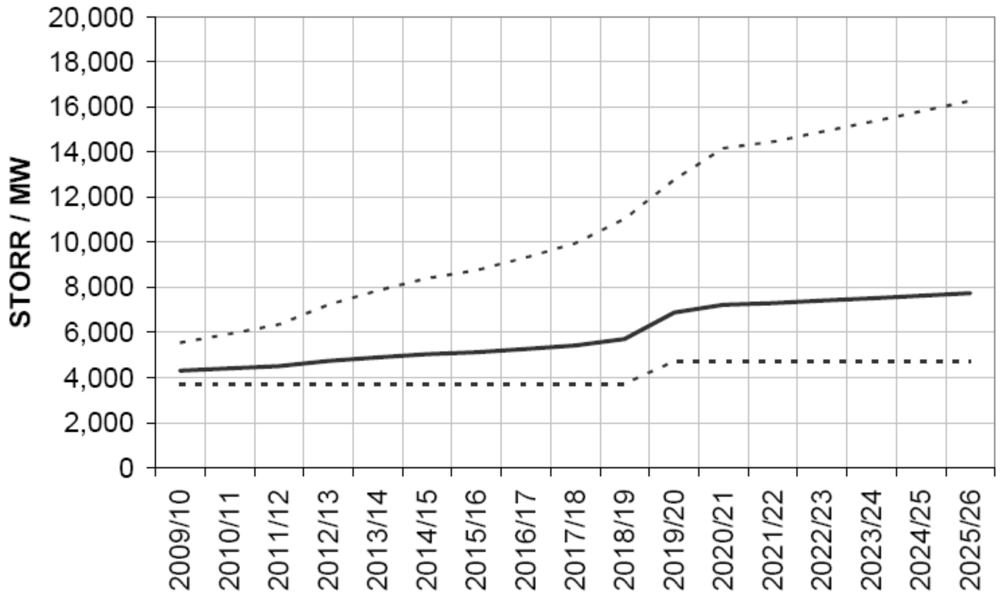
27 There would need to be a discussion between NGET and Ofgem on this NIV:free reserve relationship at the time of setting the regime, just as there is currently a discussion about the relationship between NIV and the additional operating reserve required.

Irrespective of approach, in considering the treatment of wind, it will be important to consider the interaction with other SO actions and particularly the interaction between congestion management and margin. For example, suppose NGET expects to have to constrain off wind in certain conditions (e.g. high wind at a time of transmission outage). In this situation, it is actual wind infeed (rather than the level of wind infeed absent congestion) which should feed into margin calculations. If, however, it only became evident very near real time that wind generation would need to be constrained off, there may be a case for including the constrained off wind generation in the margin volume assessment.

Pricing of STOR and operating reserve

NGET are projecting significant increases in the requirements for STOR (and presumably other margin) as a result of wind integration, as shown in Figure 16.

Figure 16. Projected future Short Term Operating Reserve requirements (STORR)



Source: NGET

Depending on the balance of supply and demand for STOR, the price of availability of the service to NGET may vary significantly.

At present, the price is estimated off model, based on a combination of historic prices and/or actual tenders. With a longer term scheme, actual tenders will be less relevant.

However, without a clearer understanding of volume / price relationship and the likely reaction of potential providers, it is difficult to see how the models could be further amended to take this into account. Absent other information, it might be expected that such changes take place gradually over time. This may be an area in which further development needs to be considered following gathering of experience of greater wind connection.

Ongoing development of generation and transmission on the system

More generally, there will be ongoing changes to generation and transmission capacity which may influence the level of margin required. For example, connection of new thermal generation may change the distribution of availability (for example, newer plant may exhibit higher levels of reliability). Equally, commissioning of new transmission capacity may reduce the extent to which specific margin needs to be procured outside currently export constrained areas.

NGET will need to consider the impact of such factors in defining new model parameters. For example, under a longer term scheme, the impact of changes in transmission capacity on CMM would need to be considered and built into the model inputs, following debate and discussion with Ofgem.

However, at this stage it is difficult to see how any changes to the calculations of the models as they stand would be beneficial in this regard. The impact of these evolutions may be best considered off-model and then incorporated into model inputs. This is particularly the case for large discrete changes such as the commissioning of new transmission capacity, as the alternative would be to try to build into the model the relationship between CMM and transmission capacity, which is likely to be complex would only be relevant in a small number of situations (i.e. when there are major changes in Scottish export capability).

6.4 Congestion

6.4.1 Changes to the use of the model

The congestion models make use of a number of *ex ante* inputs over which NGET has relatively little control and which are volatile and complex to model. Principally, these include fuel prices and the implied generation merit order, and the level of wind generation.

In line with the approach suggested above, there may be benefits in removing the need to forecast these elements from the model by using *ex post* values in the model to calculate an *ex post* target for efficient congestion costs.

6.4.2 Definition of the model for the current system

A number of models are currently used to examine congestion on key parts of the GB system in order to derive an *ex ante* forecast.

There are a number of areas in which these models could be improved:

Possible changes to models

- the models at present do not consider the GB system in a holistic manner in relation to congestion – therefore, there is no guarantee that they are based on a consistent pattern of generation and demand across the GB system;
- the models do not make use of fundamentals (i.e. a view on the short run costs of generation from different plant) to construct a merit order of expected generation against which congestion costs can be considered. Rather, for Scottish plant, a view on whether each plant is expected to be available is taken based on assumed short run marginal costs, and then for all plant, an output level is estimated based on historic production levels for the period in question;
- a relatively simplistic approach is taken to representing plant dynamic constraints (effectively, the constraints are reflected by using historic production profiles which must, by definition, be within the envelope of technical constraints); and
- only one set of prices for resolving congestion is applied irrespective of the volume of congestion or the fuel type of the constrained-on or constrained-off plant.

Elsewhere, NGET has used alternative types of models to examine constraints both historically (e.g. ESCORT, ESCARGOT) and more recently (e.g. the simpler stochastic models used as part of the SQSS process). To some extent, these models have addressed the issues highlighted above in relation to the current models used for the purpose of deriving SO incentive regime targets.

Given the increased importance of congestion costs in the overall incentive scheme, and the complexity of the modelling process required to arrive at an estimate, we believe there may be merit in adopting an alternative modelling approach to that currently used – specifically, one which is closer to the approach which NGET has used as part of its SQSS modelling.

Under such an approach, an unconstrained and constrained schedule across GB would be derived on an internally consistent basis, based on inputs relating to:

- locational generation capacity and availability and its evolution over time;
- locational generation running patterns, based on fuel prices, thermal efficiencies, and potentially plant dynamic constraints, as well as wind output;
- locational transmission capacity and availability, its evolution over time, and the interaction between transmission capacity at different locations;
- locational demand, and its evolution over time;

- locational reserve holding constraints leading to part loading of in merit plant; and
- the cost of resolving congestion, based on expectations of BM mark-ups relative to power and fuel prices (potentially by location).

As noted above in relation to margin, modelling reserve holding requirements accurately is difficult as a result of the reserve contribution of NIV. However, it is likely to be important to include some recognition of reserve holding by location in the congestion model in order to represent accurately the unconstrained and constrained schedule, and in order to ensure some level of consistency between models[28].

On the basis that the relationship between free reserve and congestion is less direct than that between free reserve and margin requirements, it may be possible to model congestion with reasonable accuracy without explicitly modelling the impact of NIV on reserve holding patterns. It may be that reserve holding can be included in the model through a full co-optimisation of energy and reserve, or via simpler processes which define a certain capacity of plant by location as reserve (e.g. based on historic provision) while maintaining reasonable accuracy.

However, irrespective of the approach taken in relation to reserve, this clearly represents a complex modelling development.

There are a number of ways in which it could be simplified. For example, if (as discussed above) the level of fuel prices and the level of wind infeed are treated as *ex post* inputs, this would reduce significantly the number of inputs which need to be treated stochastically in the model[29].

It is important to note that, if *ex post* wind infeed is to be an input to the model, adjustments will need to be made to metered wind output to ensure that any wind output which was in fact constrained off by NGET (at a cost) is included in the model for cost estimation purpose. This could be achieved, for example, by adjusting wind BMU metered output data for any BM bid acceptances in the relevant period.

Even then, the development and implementation of such a model is likely to be a challenge. Developing, implementing and calibrating a model from scratch with this functionality could, as an activity in itself, take longer than the time available during Phase 2 of the process as defined. The alternative would be to attempt to

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28 We note that unless the aim is to incentivise separately congestion and margin costs, from an incentive scheme perspective it is more important to estimate the total of costs accurately rather than to ensure an appropriate allocation between cost categories. That said, we also note that if NGET develop a congestion cost model, it may be used for other purposes where the allocation of costs may be more relevant.

29 It would be for further consideration whether thermal generation availability would still need to be treated stochastically.

find an "off the shelf" product, in which case an important part of the process may be deciding which areas of "ideal" functionality are critical and which could be sacrificed (if not available in existing products) with relatively little loss of accuracy. With either development approach, the model calculations themselves are likely to be complex. For example, we would not expect it to be possible to develop the model in Excel. This could lead to issues in relation to Ofgem's ability to verify the calculations and hence degree of comfort with using the model as a core part of the incentive regime.

Furthermore, even with an "ideal" fundamentals model, the extent of improvement of accuracy is difficult to estimate in advance. Fundamentals models are routinely used in policy and investment analysis to estimate potential congestion costs. However, their use in an incentive regime of this nature is less well tested.

Nevertheless, given the deficiencies identified in the current models, we believe it is an approach worthy of consideration.

6.4.3 Evolution of the system

Under the alternative modelling approach described above, inputs would be required in relation to key future developments on the system (such as changes to generation capacity, changes to transmission capacity etc.) These inputs would need to be considered carefully at the time which the regime was agreed.

However, using a fundamentals model would have the advantage that the key drivers would form explicit inputs to the model, and once the inputs were agreed, they would feed through directly into the results.

We discussed above the potential for fuel prices and wind infeed to be *ex post* inputs, with the other inputs being agreed *ex ante*.

However, looking forward to the evolution of the system, it may also be appropriate to consider variants in the way in which some of the *ex ante* inputs are treated.

For example, the commissioning of new transmission capacity represents a major discrete input to the cost of congestion, and since it can be subject to changes outside NGET's control (e.g. planning difficulties, the foot and mouth outbreak), it may also be possible to agree conditions under which reopeners to the *ex ante* inputs into the congestion cost model (as an alternative to relying on *ex post* IAEs). This would be analogous to the way in which Ofgem has treated "known unknowns" within other network operator controls (e.g. the impact of the Traffic Management Act on distribution network owners).

6.5 Fast reserve

6.5.1 Changes to the use of the model

Costs to date associated with fast reserve have been relatively stable (partly as a result of the relatively low materiality of wind volatility to date on the system). In this context, there would appear to be little benefit in changing the use of the model to rely on more *ex post* inputs.

Looking forward, however, it is possible that growing levels of wind volatility on the system will mean that an important driver of fast reserve costs is outside NGET's control and is volatile and complex to model. If this is the case, as with other cost categories, there may be benefit in including wind output as an *ex post* input.

It is difficult to predict whether this will be important to consider. It is clear that difficulty in forecasting wind output will result in a need for more reserve on the system. However, the allocation of this additional reserve between products will depend on the "nature" of wind volatility. Conceptually, if unexpected changes in wind output typically happen over relatively long time periods, it might be expected that the majority of the impact would be on STOR as a product. Conversely, if there are frequent unexpected changes in wind output over a very short period, the impact on fast reserve may be greater.

While experience in other jurisdictions may provide some indications, care should be taken in assuming that the GB experience will be similar. Germany and Spain both have significantly more experience as systems in relation to wind integration than GB. However, both are also geographically larger systems, and arguably have more diverse wind conditions than GB. As a result they are likely to have more diversity within their wind portfolios.

Since there is at least potential benefit in an *ex post* treatment of wind, we consider possible approaches to this below when we discuss cost estimation in the light of evolution of the system.

6.5.2 Definition of the model for the current system

The current approach to modelling of fast reserve costs is almost entirely based on an approach which assumes the continuation of estimated historic relationships. The key inputs to the model are:

- historic prices for BM costs;
- historic time trends for BM volumes and ancillary service costs; and
- historic relationships between BM costs and ancillary service contract costs.

Relative to other components of SO costs, the total cost of fast reserve does show a relative stable relationship to time. While historic relationships remain stable (i.e. in the absence of significant structural breaks), the current approach to modelling may therefore continue to prove fit for purpose. Indeed, if anything, the number of individual components into which the modelling is split may be overcomplicated.

The alternative approach would be to attempt to replace the current relationship to a time trend with a relationship to more fundamental drivers of fast reserve costs. However, it is not clear what additional value such a change would bring at present.

6.5.3 Evolution of the system

As discussed above, looking forward, an increase in wind volatility may constitute a structural break in these relationships.

In relation to the discussion of margin above, we considered one potential approach to including wind output and volatility explicitly in the calculation of total reserve requirements, and noted that depending on how this modelling was undertaken, the final step may be to allocate the reserve between products with different temporal characteristics.

If this approach is followed for margin, then it could also be used to determine the impact of wind generation on fast reserve requirements (as that reserve which is not allocated to operating reserve would be allocated to fast reserve). This would allow wind volatility to be taken into account explicitly for fast reserve, and hence for wind output to be included as an *ex post* input.

If this approach is not followed, or is not considered to be appropriate for fast reserve, then an alternative approach (once sufficient data were available) would be to stay with the current estimation approach based on the estimation of regression equations from historic data, but to include the level of wind capacity or generation as an explanatory variable in the regressions. Again, this would allow for wind volatility to be treated as an *ex post* input.

6.6 Frequency response

6.6.1 Changes to the use of the model

The frequency response model uses BM prices and the level of expected NIV[30] from the energy imbalance model as inputs (in relation to positioning costs). In relation to the energy imbalance model, we discuss above the potential to use *ex*

30 The level of NIV is only used to assess whether the system is expected to be long or short overall.

post inputs for both NIV and SPNIRP, with BM prices being calculated on the basis of *ex ante* defined mark ups to SPNIRP.

The *ex post* treatment of these variables in the energy imbalance model could, for consistency, be carried through into the response model.

6.6.2 Definition of the model for the current system

The model is largely based on historic data on the volume of provision from different sources, and estimates of the cost of provision again based on history. These relationships (and hence frequency response costs) appear to have been relatively stable over time compared to other SO cost categories.

Other than to accommodate the *ex post* treatment of BM prices and NIV noted above, there are few obvious modifications to the modelling approach which would seem likely to improve the accuracy of estimation.

6.6.3 Evolution of the system

The key evolution to the system in relation to frequency response relates to a change in the largest unit loss likely to result from the connection of new, larger nuclear units.

The direct impact of this would automatically be captured under the existing modelling approach, where the largest unit loss is an explicit input.

There may be a further indirect effect, if the increase in the volume of response required results in an increased requirement for the service and hence an increase in the prices charged by providers. However, without a clear understanding of the volume / price relationship, it is not clear how this could be built into the model in advance. Equally, given the likely timing of new nuclear connections, it is unlikely to represent a priority from a model development perspective.

6.7 Footroom

6.7.1 Changes to the use of the model

The footroom model makes use of the expected level of wind output to estimate footroom costs.

In line with the discussions suggested above in relation to other cost components, there may be benefits in removing the need to forecast this element from the model by using *ex post*.

The footroom model also makes use (albeit implicitly) of wholesale prices as an input. The unit price of footroom effectively represents the spread between BM bid prices and wholesale prices as an expression of the willingness to reduce output to accommodate must run plant.

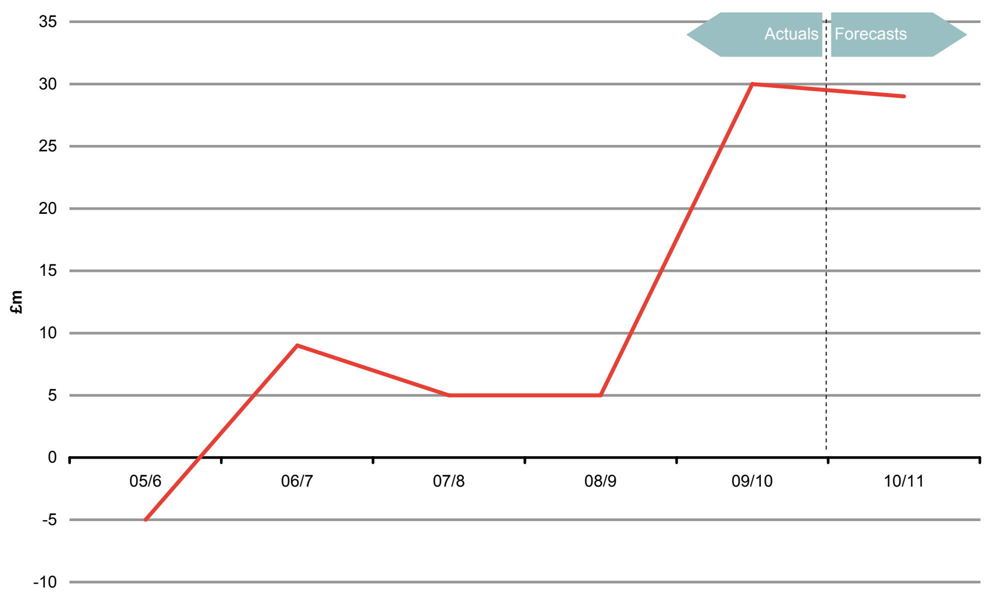
However, our understanding from NGET is that this unit cost is relatively stable over time. Hence, there may not be any advantage in attempting to model separately wholesale costs and their relation to bid costs in order to accommodate wholesale prices as an *ex post* input in the same way as has been suggested for other cost categories.

6.7.2 Definition of the model for the current system

The current approach to modelling footroom is based on a regression analysis of the historic requirements for footroom given levels of demand and must run generation output. Volumes estimated through this analysis are multiplied by historic observed unit costs.

Provided these historic relationships remain stable, this modelling approach may be appropriate. However, compared to other cost categories which rely heavily on a regression based approach (e.g. fast reserve), footroom costs have shown some degree of volatility.

Figure 17. Footroom costs



Source: NGET

Our understanding is that the significant increase in footroom costs have been driven by lower demand levels relative to must run generation. This has been caused by reductions in demand in sensitive periods as a result of reduced industrial load, combined with increased must run generation as a result of some growth in wind output.

There is not an obvious alternative approach to modelling footroom volume requirements. Equally, while footroom remains a relatively small component of overall balancing costs, there may not be significant benefit to be gained from significant time spent on modelling developments. However, at the very least it would appear that, as part of Phase 2, updating the regression relationship in the light of more recent experience would be beneficial.

6.7.3 Evolution of the system

Wind generation is clearly a relevant consideration for the volume of footroom required. Equally, the level of wind output is treated as an explanatory variable in the regression relationship on which the model is based, and as such forms an explicit input to the footroom model.

If greater levels of wind infeed results in footroom becoming a more significant element of SO costs, there may be benefit in treating wind generation as an *ex post* input to an updated regression relationship. The ongoing applicability of the functional relationship will also need to be kept under review.

We note that, in the longer term, increases in the level of overnight demand (e.g. as a result of electric vehicle charging or load shifting driven by smart metering and time of use tariffs) may reduce footroom requirements.

6.8 Reactive power

6.8.1 Changes to the use of the model

The reactive model makes use of the expected level of the RPI index and wholesale electricity prices to estimate reactive costs (as the pricing of the default reactive power provision service in the CUSC is indexed to these two variables).

The level of wholesale electricity prices is both outside NGET's control and is volatile and complex to model. In line with the discussions above, there may therefore be benefit in treating it as an *ex post* input. The level of RPI is less volatile. However, if the level of wholesale prices is included as an *ex post* input, the additional complexity of doing the same for the level of the RPI is likely to be relatively small.

6.8.2 Definition of the model for the current system

The volume of reactive power required is estimated on the basis of an established relationship between active and reactive demand. The evolution of pricing for the default service is mechanistic (a function of wholesale prices and RPI, as noted above). There appear to be few alternatives to the current approach to modelling the default service costs.

At present, the approach to modelling market costs is relatively simple. The model takes as inputs the proportion of reactive power demand likely to be sourced through the market, and the estimated mark-up of market prices over the default service. There is no consideration, for example, of a linkage between the mark-up of market prices and the proportion of reactive demand satisfied through the market.

However, we understand that at present, the market for reactive power is unused as a result of a structural problem with the definition of the product[31]. Until this issue is resolved, there is little merit in spending time to develop a more sophisticated modelling approach.

6.8.3 Evolution of the system

We are not aware of any significant future developments in relation to the demand or pricing of reactive power which might require a change in modelling approach.

31 The market and product is structured in such a way that in all cases either NGET or the provider would prefer to use the default product, and therefore sales through the market do not take place.

7 Scheme design and wider regulatory issues

In this section, in the light of the proposals in the previous section, we consider structural options for the design of a longer term incentive scheme. We then turn to a number of broader regulatory issues which might be complementary to the operation of an effective longer term scheme.

7.1 Scheme design

Beyond agreement on the approach to modelling and the treatment of variables as either *ex ante* or *ex post* as discussed in the previous section, the design of a longer term incentive regime will involve specification of a number of parameters including:

- the duration of the scheme; and
- sharing factors, the deadband, and caps and floors.

However, at this stage, without analysis by NGET as to the impact of the possible approaches outlined in section 6, it is difficult to come to a view on these parameters. This will be a key part of Phase 2 of the process defined by Ofgem and NGET.

We therefore restrict our review to structural considerations in relation to the design of the scheme. Specifically, we consider two major structural issues:

- whether all cost categories should be incentivised within the same regime ("one pot") or whether there should be regimes with different incentive parameters for different groups of cost categories ("multiple pots"); and
- how the scheme should be structured over time.

7.1.1 One pot vs. multiple pots

The current regime specifies a single incentive target covering all cost categories. This is, in many ways, preferable as an approach because lots of the activities undertaken by NGET across categories are, to some extent, substitutes for one another. Funding them from a common incentive target therefore encourages NGET to consider trade-offs between then appropriately.

In contrast, moving to a multiple pot regime could introduce perverse incentives. For example, suppose NGET had incurred significant costs in relation to cost category A and as a result were up against the floor in terms of their exposure to incremental cost. This would effectively mean that incremental costs in category A would be passed through directly to customers. To the extent that actions in category A were good substitutes for actions category B, NGET would have an incentive to take actions resulting in costs under category A rather than category B, even if this were not the most efficient approach to system management.

The issue with adopting a single pot approach is that it may be more difficult to agree a longer term incentive regime for some cost categories than others. Therefore, remaining with a single pot approach may result in the incentive regime duration and strength being determined by the ability to incentivise NGET on the most "difficult" cost category.

However, with the proposals in section 6 for the use of *ex post* inputs to set an incentive regime, it is not clear whether this will remain an issue. Using this approach, it should be possible to insulate NGET from a significant proportion of the uncontrollable risks.

Given the benefits of a single pot regime, until NGET demonstrate that these approaches still will not provide sufficient insulation from uncontrollable risks, it would not seem necessary to consider a move towards a multiple pot regime at this stage.

7.1.2 Structure of scheme

Objectives of the scheme structure

As we noted in section 4, in setting a regulatory control, the duration is typically chosen to balance the strength of incentives on the network operator against the degree of uncontrollable influence on cost which the operator is likely to face.

At present, the single year regime is close to the extreme of possible schemes. In section 6 we describe a number of proposals which may help to insulate NGET from uncontrollable cost items, and which may therefore make a longer term incentive regime consistent with an efficient allocation of risk.

However, the inherent difficulty of incentivising SO costs will still need to be recognised. The nature of the costs is that, as was made clear in section 5, even with greater insulation from uncontrollable cost items, NGET has at best only shared control. In other words, NGET will still face a level of uncontrollable risk in relation to the areas in which they are incentivised. Moreover, even *ex post*, the complexity of the interactions between cost categories and market outturns means that it is difficult to work out whether certain cost movements were controllable or uncontrollable.

This means that any longer term incentive regime needs to be defined to ensure that:

- NGET has a meaningful payoff to actions which increase efficiency;
- NGET has some incentive in relation to impact of actions beyond the first year of the control period; but that

- NGET's exposure to the remaining uncontrollable elements of cost is not excessive.

The key levers which can be used in the scheme design to balance these objectives are:

- the duration over which key inputs to the regime are fixed; and
- the overall strength of incentive on NGET (e.g. as determined by sharing factors, level of caps and floors etc.)

Options for scheme structure

We consider three potential approaches to defining an incentive scheme which balance these objectives (all defined in the context of setting an *ex post* target, but all equally applicable to an approach involving refined *ex post* adjustment mechanisms).

The models are summarised in Table 4.

Table 4. Options for longer term scheme design

Option	Incentive strength (e.g. level of sharing factors)	Treatment of inputs to the regime (i.e. those model inputs agreed *ex ante*, and the overall structure of models)
1	Falling over duration of control (e.g. lower sharing factors)	Fixed – updating only for those variables defined as *ex post* inputs
2	Constant over duration of control	Fixed – updating only for those variables defined as *ex post* inputs
3	Constant over duration of control	Updating agreed only in relation to changes in model inputs or structure to reflect factors outside NGET's control

Source: Frontier Economics

Under the first option, all variables which were not defined as *ex post* inputs would be fixed for the duration of the regime, as would be the overall structure (i.e. the model calculations, historic relationships etc.) of each of the models used by NGET.

However, the incentive strength of the control would decline over time, reflecting the greater uncertainty (and hence risk of windfall gains and losses) in relation to outturns in the later years of the scheme.

Under the second model, the incentive strength would remain constant over time, and again all variables not defined as *ex post* inputs would be fixed for the duration of the scheme.

Under the third option, the incentive strength would also remain constant over time. NGET and Ofgem would agree that the *ex ante* defined inputs to the incentive regime models and even the model structures themselves could be updated during the scheme. However, this ability to change *ex ante* variables would be limited to reflect only factors outside NGET's control.

Evaluation of structural options

Option 1 is attractive from NGET's perspective. There are low incentive rates (e.g. low sharing factors, tightly defined caps and floors) on years when uncertainty is highest.

From a customer perspective, it is more mixed.

In some ways, it is better than the current situation, in that at least there would be some incentive on NGET in relation to longer term actions at the start of the regime. However, the regime also has some less attractive features:

- the company would be remunerated most highly for outperformance in years where the asymmetry of information is at its highest (i.e. in the early years of the control when NGET is more likely to have an informational advantage over Ofgem as to the true level of efficient costs);
- towards the back end of the regime, the incentives on NGET would be lower than they would have been had a sequence of annual regimes been put in place (even though by the time those years come around, uncertainty in relation to outturn variables will have reduced significantly as a result of the passage of time). Therefore, NGET may fail to optimise actions with a short term payoff; and
- inefficient periodicity may be introduced into NGET actions – in other words, NGET may fail to optimise costs effectively in the last period of the regime (when incentive rates are at their lowest) in order to condition regulatory expectations for the start of the next regime (when incentive rates will once again be high).

Option 2 removes some of the problems associated with incentive rates falling over time. The potential for outperformance in early years of the regime would also provide some degree of "insurance" for NGET against the risks in the later years, as would the potential for performance to "average out" over time in a longer term regime.

However, in order to avoid allocating excessive risk to NGET, the incentive rates associated with the option may still have to be low relative to those seen in annual controls with an equivalent degree of insulation of NGET from risk.

Implementing Option 2 would therefore depend upon a view as to the best balance between:

- higher strength, but time limited, incentives in a succession of short term schemes; and
- lower strength, but longer term, incentives.

This will in turn fundamentally depend on a view as to the importance of the benefits of a longer term scheme (as outlined in Section 3) relative to the benefits of high incentivisation within, say, a series of annual schemes.

Option 3 attempts to provide the benefits of Option 2 while providing a framework to allow higher incentive rates (namely the ability of inputs to the regime to be varied if it can be shown they were outside NGET's control).

From the NGET perspective, the ability to change inputs to the scheme is similar to the current IAE process. However, Ofgem would also be able to propose changes to inputs (as BSC parties currently can) if they believe that uncontrollable events unforeseen at the time of the establishment of the regime have reduced (or increased) the efficient SO cost levels.

The acceptability and effectiveness of Option 3 will depend on the perceived level of shared information between Ofgem and NGET. The regime would become ineffective if NGET believed that clawing back of repeated outperformance would occur. This may happen for two reasons:

- a lack of information and computational ability meaning that Ofgem could not accurately separate the impact of controllable and uncontrollable factors on outturn costs (indeed, NGET may not be able to separate the impact themselves); and
- a desire on the part of Ofgem to clawback outperformance to the benefit of customers in the short term.

If, for either reason, NGET believed that there was a risk that Ofgem would attempt to claw back the proceeds of repeated outperformance, the incentive strength of the regime over the longer term would be removed.

However, even if there is a relatively low level of shared information and trust, the regime would not have worse incentive properties than a succession of annual schemes. And if sufficient trust builds between NGET and Ofgem in relation to the appropriate limits of any changes to inputs, its incentive properties could be significantly better.

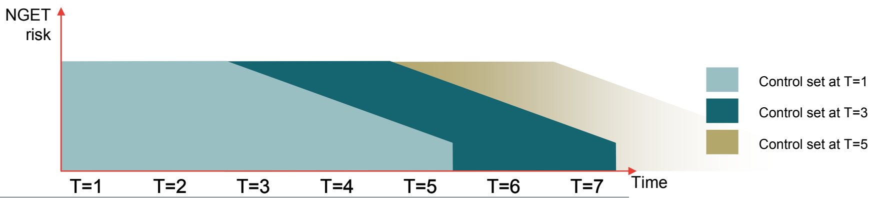
Since the key issue with Option 3 relates to the need to constrain changes to the incentive scheme target during the scheme to those which relate only to uncontrollable cost changes, it is possible to think of further developments of Option 3 which would reduce the risk (from the perspective of the operator) that the regulator would opportunistically claw back incentive scheme profits.

For example, one approach might be to:

- define a scheme with an incentive rate which tapers down over time for, say, a 5 year period; and
- agree to set a new scheme which would run in parallel with the first scheme after, say, 2 years.

NGET would continue to get (successively smaller) payoffs for outperformance against the target in the first scheme, and would in addition get (increasingly large) payoffs for outperformance against the new target in the second scheme. Figure 18 provides a simplistic worked example of the operation of such a scheme, in which three schemes are overlaid on one another while the overall sharing factor is maintained at 30% in each year.

Figure 18. Overlaying of incentive schemes



	T=1	T=2	T=3	T=4	T=5	T=6	T=7
Target cost, scheme 1	50	50	50	50	50	-	-
Sharing factor, scheme 1	30%	30%	20%	10%	5%	-	-
Target cost, scheme 2	-	-	40	40	40	40	40
Sharing factor, scheme 2	-	-	10%	20%	25%	10%	5%
Target cost, scheme 3	-	-	-	-	-	30	30
Sharing factor, scheme 3	-	-	-	-	-	20%	25%
Outturn	30	30	30	30	30	30	30
Payoff scheme 1	6	6	4	2	1	-	-
Payoff scheme 2	-	-	1	2	2.5	1	0.5
Payoff scheme 3	-	-	-	-	-	0	0
Total payoff	6	6	5	4	3.5	1	0.5

Source: Frontier Economics

Under such a scheme, it would clearly be possible for the regulator to define the second scheme in a way which would claw back outperformance under the first scheme. However, the fact that successive schemes have low sharing factors early in the period in which they are implemented makes clawing back more difficult. Against a low sharing factor, the regulator would have to set a very low target to claw back gains made in earlier periods than were the sharing factor higher.

This approach is not without its downsides. For example:

- it is only really applicable for longer scheme durations;
- it results in greater complexity in relation to the incentive scheme definition;

- from the company perspective, were NGET to be losing money under the first scheme, it would take longer for a higher target under the second scheme to bring about more significant positive payoffs; and
- if the scheme involves caps and floors which bind, it could result in schemes with very low effective incentive rates in some years.

Before working up this or other ideas to attempt to constrain the risk of regulatory opportunism further, consideration will need to be given as to the need for frequent updating of the scheme in the context of the changes proposed in section 6, and hence the importance of attempting to constrain the risk of opportunistic claw back to ensure the incentive regime is effective.

7.2 Wider regulatory issues

There are a number of broader regulatory and market design issues which it may be worth considering as complements to the implementation of an effective longer term incentive regime.

- **SO-TO Code**: there may be benefits in considering modifications to the SO-TO Code (discussions in relation to which we understand are underway between NGET and the Scottish TOs) in order to allow the SO to reflect through to the TOs the incentives which they face. If this does not work, or if further incentives are felt necessary[32], then there may be some logic to considering (within the overall output-based framework proposed as part of the RPI-X@20 project) setting the (external) TOs output measures in relation to the cost of congestion on their networks and the cost of the congestion they impose on other networks.

- **Regulation of BM bids**: NGET can be exposed to significant risks as a result of the exploitation of market power in relation to constrained-on BM offers or constrained-off BM bids. It is possible that this issue becomes more important over time with the foreseen increase in wind generation capacity onshore in Scotland, and the proposed move to a Connect and Manage transmission access regime. Some form of regulation of bids and offers (either under the Market Power Licence Condition or more explicit *ex ante* regulation) may therefore be beneficial in terms of the risks to which NGET is exposed.

32 For example, this may be because it is perceived that corporately ScottishPower and Scottish and Southern Energy face conflicting incentives in relation to their transmission and generation businesses, and can respond to the incentives facing their generation business without breaching any unbundling regulations or competition law requirements.

- **Imbalance regime**: NGET incurs significant cost as a result of taking "positioning" actions in the BM, to make sure that generation plant are on the system and ready to respond to demands for balancing energy through the BM. However, the original intent at the time of implementation of NETA was that participants would be incentivised (through the imbalance regime and the operation of the BM) to undertake some positioning actions themselves. If they did this, arguably the allocation of costs through time and across players would be more efficient. It may therefore be worth analysing whether participants can be relied upon to "self-position", and if not, what the barriers are and whether they could be removed without other unintended consequences.

- **Balancing of wind output**: the impact of greater wind capacity on the positioning of individual portfolios (e.g. the extent to which it will increase risk aversity and the average "length" of portfolios at Gate Closure) is difficult to predict. However, it may have a significant impact on the way in which the system as a whole is operated. Equally, as a result of diversity in the portfolio, it might be easier to predict accurately the output of the overall wind portfolio and for a single party (e.g. the GBSO) to balance it in aggregate. It may therefore be worth at least considering the benefits of a move away from the self-balancing obligation in relation to wind generation.

8 Summary

In this section, we summarise our views on:

- NGET's modelling, the potential changes suggested, and their prioritisation;
- scheme design and wider regulatory issues; and
- the broader set of activities which NGET will need to undertake as part of Phase 2 of the process.

8.1 Summary of views on modelling

In this section, we present:

- an assessment of the extent to which the models as they stand can be considered "fit for purpose";
- a summary of the potential changes to the models and their usage that we suggest in Section 6; and
- our views on the prioritisation of these changes.

8.1.1 Assessment of the models as they stand

First, we have considered the extent to which the models are appropriate for their current purpose, and for use in a longer term regime. In doing so, we have not considered:

- changes in model usage;
- updating of model inputs; and
- updating of the structure and/or parameterisation of historic relationships where relevant in the models.

Were an Option 2 type approach to be adopted the factors listed above would need to be considered carefully and we assume that it would be a key component of the work in Phase 2.

Instead, to date, we have simply considered the structure and calculations set out in each of the models, within the context of a longer term incentive regime. It should also be noted that our views on fitness for purpose are based on a relatively short review, during which we have focused on structural issues in relation to the models rather than their quantitative performance over time or the validity of the estimated quantitative relationships on which they are based.

In Table 5 we provide a summary of our view, along with a brief commentary.

Table 5. Assessment of fitness for purpose of current models

Model	Assessment (X / – / ✓)	Commentary
Energy imbalance	–	The energy imbalance model is, in terms of calculations, relatively simple. The main issue relates to the simplicity of the treatment of BM bid and offer pricing.
Margin	X	There are a number of potential changes to the margin model which we believe have the potential to increase its accuracy. These relate principally to the allocation of reserve volume to generating technology, and also the implicit approach to modelling total margin requirement.
Congestion	X	There are a number of deficiencies with the congestion models as they stand. These relate to both the derivation of the volume of congestion (and the absent of an explicit merit order) and the pricing of constraint-relieving trades. Changes could improve the overall level of accuracy.
Fast reserve	–	The fast reserve model is heavily based on observed historic relationships. There may be changes that could be made to model certain drivers more explicitly and attempt to replace time-trend variables with physical or market-based drivers. However, set against that, the historic trend of fast reserve costs does appear relatively stable. Prior to significant growth of wind on the system, therefore, the model's performance may be fit for purpose.
Frequency response	✓	We have not identified any significant structural improvements to the frequency response model
Footroom	✓	We have not identified any significant structural improvements to the footroom model
Reactive power	✓	We have not identified any significant structural improvements to the reactive power model

Source: Frontier Economics

As indicated in Table 5, we believe that in relation to a longer term incentive regime (and potentially even with the context of annual regimes), there would

Summary

appear to be benefit in considering refinements to both the margin and the congestion models.

Specifically within a longer term regime, however, we believe there would also be benefit in refining the approach to insulating NGET from volatility in cost drivers beyond their control (either by more refined adjustment mechanisms or through a move to inclusion of such variables as *ex post* inputs).

8.1.2 Proposed changes to models and their use

Table 6 summarises the suggestions resulting from our review in terms of possible changes to model use and possible model developments, looking at both the system as it stands now and over time.

Particularly in relation to the suggestions of possible model developments, we believe it is important to stress that, given the length of this review process, these can only be considered as options for further exploration. It is not possible to say definitively whether they will result in sufficient increases in the accuracy of the modelled outcomes given the additional complexity which some changes would imply.

Table 6. Summary of model use and calculation suggestions

Model	Possible changes to use[33]	Possible developments of calculations
All		▫ Consider correlations between inputs treated stochastically
Energy imbalance	*Ex post* inputs for ▫ NIV ▫ SPNIRP	▫ Development of calculation of mark up of BM bids and offers over SPNIRP
Margin	*Ex post* inputs for ▫ NIV ▫ Electricity and fuel prices ▫ Wind output	▫ "Top down" calculation of margin requirement ▫ Explicitly model impact of wind on total reserve (rather than just incremental policy requirement) ▫ Improve basis of allocation of reserve volume to generating technology ▫ Improve pricing of generation technology ▫ Off model treatment of changes to transmission and generation capacity over time

33 For each of the variables listed here, more refined *ex post* adjustment mechanisms could be adopted in place of *ex post* inputs if it were felt that this overall approach were preferable.

Table 6. Summary of model use and calculation suggestions

Model	Possible changes to use[33]	Possible developments of calculations
Congestion	*Ex post* inputs for ▫ Fuel prices ▫ Wind output	▫ New GB-wide fundamentals model
Fast reserve	*Ex post* input for wind output	▫ Explicitly model impact of wind on reserve
Frequency response	*Ex post* inputs for ▫ NIV ▫ SPNIRP	
Footroom	*Ex post* input for wind output	
Reactive	*Ex post* inputs for ▫ Electricity prices ▫ RPI	

Source: Frontier Economics

It is clear from Table 6 that there are a significant number of potential changes which could be made. From a practical point of view, it will therefore be important to prioritise them. It is to this issue which we now turn.

8.1.3 Prioritisation of modifications

We have considered the prioritisation of the modifications against three criteria:

- **value added:** the potential of the modification to improve both the accuracy of target setting and the ease of securing agreement on a longer term incentive scheme between NGET and Ofgem. The overall importance of the cost category relative to total SO costs is clearly also a relevant consideration here;
- **feasibility:** NGET's ability to perform the modification currently, given the available data and experience of operating the system; and
- **complexity:** the likely difficulty associated with the design and implementation of the modification, and hence the potential constraints arising from the four month time limits placed on Phase 2 of the process.

In considering prioritisation, we have made the assumption that the duration of the next incentive regime would ideally be in the region of 2-3 years.

Summary

We summarise our analysis in Table 7 below.

Table 7. Prioritisation of modifications

Modification	Value added	Feasibility	Complexity
Modifications to congestion model	Potentially high, but uncertain	✓	? – probably the most time consuming modification
Improved *ex post* treatment of fuel prices	Linked to modifications of congestion model		
Modifications to margin model	Medium	✓ – apart from changes related to modelling of wind	✓
Improved *ex post* treatment of NIV / **Improved *ex post* treatment of SPNIRP**	Low – given current operation of NIA	✓	✓
Changes to stochastic variable correlations	Low – for target Medium – for NGET risk assessment	✓	✓ – but need to prioritise key correlations
Improved *ex post* treatment of wind	Low – issues arising from wind are likely to be in 3-5 year horizon	X – data only available on narrow range of wind conditions[34]	N/A
Modifications to fast reserve model	Low – issues arising from wind are likely to be in 3-5 year horizon	X – data only available on narrow range of wind conditions[35]	N/A

34 To link wind output to costs more explicitly, it would be beneficial to have data on wind output and volatility levels over a long time period and exhibiting a greater degree of variation. This would allow more robust relationships with physical requirements and cost to be estimated.

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Table 7. Prioritisation of modifications

Modification	Value added	Feasibility	Complexity
Modifications to energy imbalance model	Low	✓	✓
Improved *ex post* treatment of RPI	Very low	✓	✓

Source: Frontier Economics

On the basis of Table 7, we believe:

- amendments to the models in relation to the treatment of wind generation could be de-prioritised on the assumption that the next incentive scheme will be less than 3 years in duration;
- there would appear to be benefit in prioritising consideration of the potential changes to the margin and congestion models, while recognising that fundamental change to the congestion model will be both challenging and uncertain in terms of outcome; and
- assuming their implementation does not detract from consideration of the margin and congestion models, changes to refine the *ex post* treatment of NIV and SPNIRP, modifications to the energy imbalance model in relation to BM bid and offer pricing, and consideration of the correlations of stochastic inputs in the model could be progressed in parallel.

Given the complexity of developing a new congestion model in particular, there may be benefit from an ongoing interaction between Ofgem and NGET during the four months of Phase 2. If a new congestion modelling approach is adopted, there will be important design decisions to take (e.g. where simplifications are acceptable and where they create a risk to accuracy). Particularly if *ex post* inputs are to be used in relation to congestion modelling, it will be critical that Ofgem is comfortable with the model design. Ongoing engagement throughout the "model specification" process will help to ensure that Ofgem is bought into the decision being made.

8.2 Scheme design and wider regulatory issues

A number of important aspects of scheme design (e.g. duration, parameterisation) will only be possible following updated analysis of costs and uncertainty.

At this stage, in relation to the structure of the scheme, we believe:

- it is appropriate to continue to attempt to define a "single pot" scheme, until it is demonstrated that even with the modifications to modelling approach suggested above, there remain significant differences in the levels of uncertainty and risk around individual cost categories; and
- there is benefit in considering a scheme with a constant incentive strength over time, which allows limited updating to the parameters involved in establishing the incentive scheme target. Such a scheme should be no worse than the current arrangements, and provided sufficient trust is established between NGET and Ofgem, should be a material improvement.

8.3 Other activities for NGET during Phase 2

Finally, we note that in addition to considering the changes discussed in this report, NGET will need to undertake a range of other tasks in relation to modelling and the definition of the scheme in order to develop concrete proposals for review by Ofgem during Phase 3.

These include:

- improving the layout and documentation of the models;
- where relevant, updating the functional specification and parameterisation of the historic relationships on which the models are based in order to capture recent operating and market experience. In particular if an *ex post* approach to setting the target is adopted, it will be important to ensure that both NGET and Ofgem are comfortable with the specification of these historic relationships which will (through the models) form the critical part of the incentive regime definition;
- updating data inputs, including updating the specification of the probability distributions for variables treated stochastically;
- if still relevant, updating the specification and parameters of *ex post* adjustment formulae (e.g. NIA) and considering any further specific adjusters (such as those currently in place in relation to Scottish generation connections) that may be required;

- developing views on the appropriate parameterisation of the scheme (e.g. target, if still relevant, and sharing factors, caps and floors and deadband), including any time variation in parameterisation; and
- if an *ex post* approach to setting the target is taken, defining the way in which an incentive scheme can be specified based on agreed models (e.g. how are the models referred to in the licence, the process for agreeing that a specific model is the basis for the scheme, the change control process in relation to the model, definition of who holds and operates the model)

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