Issue	Revision
1	0

The Statement of the Energy Balancing Cost Target Modelling Methodology

Effective from 1 April 2013

About this Document

This document contains one of three methodologies that National Grid Electricity Transmission plc (NGET) employs to calculate the Modelled Target Costs, against which its actual balancing costs will be compared, on a month-by-month basis, under the Balancing Services Incentive Scheme (the 'Scheme').

The remaining methodologies are as follows:

- The Statement of the Constraint Cost Target Modelling Methodology; and
- The Statement of the Ex-ante or Ex-post Treatment of Modelling Inputs Methodology.

This document has been published by National Grid in accordance with part K of Special Condition 4C of NGET's Transmission Licence. The methodology was developed as part of the Electricity System Operator (SO) incentives Review process.

If you require further details about any of the information contained within this document or have comments on how this document might be improved please contact the SO Incentives team by e-mail:

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Chapter 1: Modelled Target Costs

1.1 The Energy Balancing Cost target model is a series of individual forecast models. The individual models have been developed using a range of statistical techniques and are combined together to give a total cost target for energy balancing.

1.2 The target costs are split into the following six cost categories:

- Energy Imbalance Cost
- Total Operating Reserve Cost
- Frequency Response Cost
- Fast Reserve Cost
- Reactive Cost
- Minor Costs: AS & BM General Cost & BM Unclassified Cost

1.3 For the avoidance of doubt, black start costs are not modelled as part of the energy balancing cost methodology. The target cost for the Black Start element of the incentive scheme cost target can be found in Special Condition 4G of the Licence. The cost of constrained headroom replacement is modelled as part of the energy model and uses the Constrained Margin Management (CMM) model as an input. However this is a constraint cost so the model is described in the constraint cost target methodology.

1.4 Each of the six cost categories are further broken down into separate components described by individual mathematical models. The figure below demonstrates the structure from total cost through to subcomponent model.

	Model	Cost Variable	Individual Model	
Energy Model Total Costs	Energy Imbalance	EI_C	Volume	EI_V_HH
			Price	EI_P_HH
	Operating Reserve	OR_C	Volume	OR_V_HH
			Price	OR_OOM_P_HH
			Utilisation Volume	STOR_V
			Utilisation Price	STOR_P
		STOR_C	Availablity Cost	STOR_A_C
			Utilisation Volume	STOR_V
			Utilisation Price	STOR_P
		BMSU_C	Cost	BMSU_C
		CMM_C	Volume	CMM_V
			Price	CMM_P
		NR_C	Cost	NR_C
	Frequency Response	FRR_C	Ancilalry Service Costs	FRRA_C
			BM Bid Volume	FRRB_V
			BM Bid Price	FRRB_P
			BM Offer Volume	FRRO_V
			BM Offer Price	FRRO_P
	Fast Reserve	FR_C	Ancilalry Service Costs	FRA_C
			BM Bid Volume	FRB_V
			BM Bid Price	FRB_P
			BM Offer Volume	FRO_V
			BM Offer Price	FRO_P
	Reactive	REAC_C	Volume	REAC_Ratio
			Price	REAC_P
	Minor	AS_BM_C	Cost	GEN_C
		UN_BM_C	Cost	UNC_C

Chapter 2: General Principles

Period of Historical Data

2.1 Except where otherwise stated, all modelled behaviours are assumed to be stationary, hence unless otherwise specified, model coefficients have been determined based on the full range of available history. In practice, historic data is available from 1 April 2006, Settlement Period 1 to 31 March 2013, Settlement Period 48.

Data Correctness

2.2 As part of the model development process, validation checks have been incorporated, where sensible, to ensure correctness of the data. Such examples would be where an aggregated value has been calculated across a set of market participants however, some of the individual values are missing. These specific examples are explained within the methodology statement. Data which is provided at a disaggregated level is assumed to be correct where it exists.

Data Incompleteness and Repair

2.3 The data are assumed to be complete in terms of half-hourly time-stamps and also externally (to NGET) agreed variables such as NIV. Any instances where (other) variables have undefined values (e.g. as indicated by Null, Blank, NaN, NA), numerical Replacement Values shall be used instead. The proportion of cases where such values are undefined is negligible. The Replacement Values shall be fixed Default Values. For each variable, its Default Value shall be computed from the mean of its values over the most recent financial year, namely 1 April 2011 Settlement Period 1 to 31 March 2012 Settlement Period 48.

Chapter 3: Model Production and Execution

Production of the Regression Models

3.1 For the purposes of the Scheme, the coefficients from the linear regression models have been produced during May 2013. This enables the models to make use of out-turn data up to 31 March 2013.

3.2 It is intended that this set of models will remain unchanged for the duration of the scheme. However there is provision in the Licence (paragraph 4C.38 of special condition 4C) for the correction of model errors should they occur and/or to propose revisions to this methodology to Ofgem at the mid scheme point (1 April 2014). In this context model errors are considered to be, for example, where there has been a transcription error in this methodology statement of:

- The sign (i.e. positive or negative) of a model co-efficient within this methodology.
- The magnitude of a model coefficient within this methodology.

3.3 Some data used within the models is subject to change over time as the data are refined through the settlement and reconciliation process. For avoidance of doubt the coefficients stated were calculated using the latest data available on 15 May 2013.

3.4 In developing models a number of variables have been considered as part of the process. These considered variables have been selected based on an understanding of market fundamentals and through back testing.

3.5 Unless otherwise stated, the values of coefficients are determined by Ordinary Least Squares (OLS) linear regression fitting the dependent variable to the given input (explanatory) variables over outturn data covering a given period of time.

3.6 As the energy imbalance and operating reserve models are half hourly, while the rest are monthly; we have used “msum(…)” to indicate the exact step in the calculation process that the half hourly values are summed to give monthly totals. The msum function uses settlement date to determine which month the data belongs to. i.e. the sum is performed on calendar months.

Naming and Formatting Conventions

3.7 In developing models a standard naming convention has been applied to input variables and model outputs. These conventions are:

Prefix	Description
Avg_	Average
VWA_	Volume weighted average
Is_	This variable is a filter that takes value 1 or 0. For example, Is_EFA6_HH takes the value 1 for periods in EFA 6 and value 0 otherwise

Suffix	Description
_V	Monthly Volume (in MWh or MVAr)
_P	Monthly Price (in £/MWh or £/MVAr)
_C	Monthly Cost (in £)
_HH	Half hourly
_V_HH	Half hourly volume (in MWh)
_U_HH	Half hourly average power (in MW)
_P_HH	Half hourly price (in £/MWh)

3.8 In the following descriptions of models, ex-post inputs are coloured blue and ex-ante inputs are coloured in red.

3.9 The coefficients calculated for each model have been referenced in the text using ***C0*** to represent an intercept term if present and ***C1***, ***C2***, ***C3*** … to represent each additional coefficient in the model. The values for these terms can be found in Appendix A.

Chapter 4: Energy Imbalance Cost Target Model

4.1 Energy Imbalance costs are incurred by NGET to correct for differences between the generation supplied by the market and the demand on the system. If generators generate more energy than they have contracted for and/or suppliers' customers consume less energy than their supplier has bought on their behalf, then the net effect is that there is a surplus of energy. This net imbalance is often described as a 'long' market. Conversely, if generators generate less energy than they have contracted for and/or suppliers' customers consume more energy than their supplier has bought on their behalf, then the net effect is that there is a shortfall of energy. This net imbalance is often described as a 'short' market. The following energy balancing actions are taken to ensure that generation and demand are balanced:

- Buying and selling power in the Balancing Mechanism (otherwise known as accepting bids and offers)
- Pre-gate closure BM unit transactions (PGBT)
- Adjustment of post-gate interconnector flows
- Trading

4.2 The energy imbalance target in this model is calculated using the ex post net imbalance volume and the ex-post energy reference price (defined in **10.18**). This effectively means that the target cost is equal to the calculated energy imbalance costs assuming only the "perfect" availability of BM actions.

4.3 The incentive is effectively to resolve energy imbalance at a cost less than the cheapest actions available in the BM.

Model Overview

4.4 The monthly Energy Imbalance cost target is the monthly sum of the half hourly Energy Imbalance price multiplied by the half hourly Energy Imbalance volume.

EI_C = msum(EI_V_HH * EI_P_HH)

Energy Imbalance Volume

4.5 To ensure no windfall gains or losses as a result of market length, the modelled half hourly Energy Imbalance Volume is ex-post variable NI_V_HH.

EI_V_HH = NI_V_HH

Where

NI_V_HH is the half hourly value of net imbalance volume in MWh, with positive values occurring when the market is short (i.e. demand exceeds sum of FPNs). See **10.4** for more details.

Energy Imbalance Price

4.6 The modelled half hourly Energy Imbalance Price is ex-post variable ER_P_HH.

EI_P_HH = ER_P_HH

Where

ER_P_HH is the half hourly energy reference price which is calculated as the volume weighted average of submitted prices to resolve NIV in any given Settlement Period. See **10.18** for more details.

Chapter 5: Total Operating Reserve Cost Target Model

5.1 Total Operating Reserve costs are those costs associated with creating and maintaining the operating reserve requirement, which is necessary to enable frequency control on the transmission system. Where the difference between the sum of the synchronised generation capacity and the forecast demand is less than the operating reserve requirement, action must be taken to increase the operating reserve.

Model Overview

5.2 The total operating reserve cost target model is the sum of the costs of providing BM Operating Reserve, Short-Term Operating Reserve (STOR), Balancing Mechanism (BM) Start-Up, Constrained Margin Management (CMM) and Negative Reserve. There is a separate sub-model for each of these components.

Total Operating Reserve Monthly Cost Target
= OR_C + STOR_C + BMSU_C + CMM_C + NR_C

Where
OR_C is monthly BM Operating Reserve cost target
STOR_C is monthly STOR cost target
BMSU_C is monthly BMSU cost target
CMM_C is monthly Constrained Margin Management cost target
NR_C is monthly Negative Reserve cost target

BM Operating Reserve Cost

5.3 BM Operating reserve is the level of reserve planned at the final short-term margin analysis stage to ensure that there is sufficient generation to meet real time demand. It is made up of:

a) Scheduled Reserve: BM units or balancing services providers that are able to regulate output or consumption either automatically or on receipt of despatch instructions.
b) STOR: capacity capable of generating (normally from standstill) or reducing demand within a defined period. STOR is made up of contracted generation or demand that can be called upon to reach full output within 240 minutes and be able to provide this level of output for at least two hours.

5.4 The monthly BM Operating Reserve Cost target is the monthly sum of the half hourly operating reserve cost minus the monthly STOR utilisation cost target, which is reported separately in the STOR category.

OR_C = msum(OR_V_HH * OR_OOM_P_HH) - (STOR_V * STOR_P)

Operating Reserve Volume

5.5 The operating reserve volume model uses the difference between the half hourly reserve requirement and the market length and market synchronised headroom to define the volume of reserve required per half hour. The assumption is that when there is sufficient market synchronised headroom or the market is sufficiently long, no reserve requirement will remain and therefore there should be no procured reserve volume.

5.6 A max function is applied to this variable to ensure that the value is always positive. This variable is then used in a linear model with time based dummy variables (daytime GMT, daytime BST and evening BST) to model the volume of reserve that was actually procured. These time based dummy variables reflect the periods in which reserve actions are predominantly taken.

5.7 The model for half hourly Operating Reserve volume includes STOR utilisation volume, this is subsequently subtracted from the BM Operating Reserve costs at the monthly level. The half hourly operating reserve target volume is the result of a linear regression with the variables below.

5.8 The operating reserve requirement variable is not available for dates before 1 April 2009, therefore this model has been trained using data from 1 April 2009 to 31 March 2013. This information is unavailable because National Grid Systems were not capturing this data in its data repository after the event. The coefficients for each of the fitted models can be found in Appendix A.

OR_V_HH
= ***C1*** * Op_Reserve_Req_HH'
+ ***C2*** * Op_Reserve_Req_HH' * Is_EFA6_HH * Is_BST_HH
+ ***C3*** * Op_Reserve_Req_HH' * Is_EFA345_HH * Is_GMT_HH
+ ***C4*** * Op_Reserve_Req_HH' * Is_EFA345_HH * Is_BST_HH

Op_Reserve_Req_HH'
= max(0, Op_Reserve_Req_U_HH + NI_V_HH - Headroom_V_HH)

Where:
Is_EFA6_HH is an ex-ante logic variable that is 1 in settlement periods 39-46, 0 in periods <39 or >46. See **10.3**
Is_EFA345_H is an ex-ante logic variable that is 1 in settlement periods 15-38, 0 in periods <15 or >38
Is_BST_HH is an ex-ante logic variable that is 1 in Apr-Oct, 0 in Nov-Mar
Is_GMT_HH is an ex-ante logic variable that is 0 in Apr-Oct, 1 in Nov-Mar
NI_V_HH is the ex-post half hourly value of net imbalance volume in MWh. See **10.4**
Headroom_V_HH is the ex-post half hourly total market synchronised headroom. See **10.9**
Op_Reserve_Req_U_HH is defined below. See 5.9

Half hourly Operating Reserve Requirement

5.9 The half hourly reserve requirement is modelled as follows:

Op_Reserve_Req_U_HH
= Net_Positive_Regulating_Reserve_Req_U_HH
+ Reserve_For_Response_U_HH

Net_Positive_Regulating_Reserve_Req_U_HH
= Reserve_Req_U_HH
+ Reserve_Wind_Adjustment_U_HH

5.10 The definitions for the reserve for response requirement (Reserve_For_Response_U_HH) is derived from a response requirement in the following way:

Reserve_For_Response_U_HH
=max(0,
Minimum_Dynamic_U_HH – Available_Dynamic_U_HH,
Response_Req_U_HH – Available_Response_U_HH) / 55%

Response_Req_U_HH
= Max(0,
Max_Loss_U_HH – 2% * 0.5 * Demand_U_HH) / 68%

Where
2% is the demand reduction per Hz
0.5Hz is the maximum frequency deviation (specified in the NETS SQSS*)
68% is the typical amount of response delivery at a 0.5Hz deviation (100% corresponds to a 0.8Hz deviation)
55% is the amount of response typically available for 1MW of pullback
Minimum_Dynamic_U_HH is the ex-ante minimum amount of dynamic response (in MW) required. See **10.1**
Available_Dynamic_U_HH is the ex-ante forecast amount of dynamic response procured (in MW)
Available_Response_U_HH is the ex-ante forecast amount of response procured (both dynamic and static) (in MW)
Max_Loss_U_HH is the ex-ante forecast maximum credible generation loss (in MW)
Demand_U_HH is the ex-ante forecast half hourly demand (in MW)

5.11 The definition for the additional reserve required at times of high wind depends on the time of day and the level of expected wind output. During the daytime (07:00 - 23:00) it is defined as follows:

Reserve_Wind_Adjustment_U_HH
= 0 when Wind_U_HH < 1000
= 15% * (Wind_U_HH – 100) when Wind_U_HH >= 1000 and < 1500
= 10% * Wind_U_HH when Wind_U_HH >= 1500

Overnight (2300 – 0700) it is defined as follows:

Reserve_Wind_Adjustment_V_HH
= 0 when Wind_U_HH < 1500
= 10% * Wind_U_HH when Wind_U_HH >= 1500

Where
Wind_U_HH is the ex-post total metered output of WPFS modelled BMUs that are wind farms in MW. See **10.12**.

* National Electricity Transmission System Security and Quality of Supply Standards

BM Operating Reserve OOM Price

5.12 The half hourly operating reserve out of money price model consists of two models. The cash price for creating reserve is modelled based on a linear model of historic prices. This model uses marginal fuel price as the basis of the price information, this is coupled with dummy time variables (daytime GMT and daytime BST) to describe the slight change in price behaviour between these times.

5.13 The model also uses volume variables of unsynchronised MEL, market length and operating reserve volume to create a price stack. This enables the model to account for larger volumes of actions having a higher price as a greater amount of generation is required to be synchronised. Moving further up the stack of units and thus the price of those actions increases. The coefficient for the unsynchronised MEL volume is negative which reflects that the more units that are available to be synchronised the lower the price or conversely the less units that available to be synchronised the higher the price of these units as they are less efficient machines.

5.14 The half hourly "out of money" operating reserve price is the half hourly operating reserve cash price minus the half hourly energy imbalance price.

OR_OOM_P_HH = OR_P_HH - EI_P_HH

5.15 The price of operating reserve is used as an input variable for several of the individual models. The volume weighted average price is calculated at a monthly resolution from the half hourly out of money price and half hourly volume.

VWA_Op_Reserve_P
= msum(OR_V_HH * OR_OOM_P_HH)
/ msum(OR_V_HH)

Operating Reserve Cash Price

5.16 The half hourly cash price for operating reserve is the result of a linear regression with the following variables.

5.17 To improve the robustness of this model, the training data for the model has been filtered to remove prices where there is insignificant volume (<50MWh) and to limit the prices to a feasible range (>£0/MWh <£500/MWh).

5.18 Due to a significant change in the price behaviour in the history the training data used for this model was 01 April 2009 to 31 March 2013.

OR_P_HH
= ***C1*** * Unsync_MEL_V_HH
+ ***C2*** * OR_V_HH
+ ***C3*** * NI_V_HH * Is_EFA345_HH * Is_GMT_HH
+ ***C4*** * NI_V_HH * Is_EFA345_HH * Is_BST_HH
+ ***C5*** * Marginal_Fuel_P_HH
+ ***C6*** * Marginal_Fuel_P_HH * Is_EFA345_HH * Is_GMT_HH
+ ***C7*** * Marginal_Fuel_P_HH * Is_EFA345_HH * Is_BST_HH

Where

Unsync_MEL_V_HH is the ex-post (half hourly) total market unsynchronised capacity available at 6 hours ahead of real time. See **10.5**
OR_V_HH is the volume of operating reserve as defined above. See **5.8**
Marginal_Fuel_P_HH is the ex-post half hourly price, including carbon, of the marginal fuel type. See **10.21**

Total STOR Cost

5.19 The total cost of the STOR service is composed of two main costs, the availability cost for making units available under contract for the defined periods of the contract and the cost of utilising those units. The volume of utilisation is included in the base BM reserve volume forecast. To separate this into STOR utilisation a linear model is used at a monthly resolution this uses the MW of STOR available and total operating reserve volume as variables. This effectively gives a percentage of the total operating reserve volume as STOR utilisation and an adjustment based on the volume of STOR contracted. This adjustment has a positive coefficient meaning the greater the volume STOR contracted, the greater the proportion of BM reserve volume that is delivered via STOR utilisation.

5.20 The availability costs are driven by two main components, existing contract costs and the cost of new contracts. In this instance existing contracts are those considered as long term STOR. The cost of the long term STOR units was considered against a different market background and their benefits assessed over the full period of the contract, hence the costs are forecast for these units separately without using the current market conditions to derive the price. The costs of the new contracts are forecast by using the forecast volume and hours along with a price that is reflective of the existing market conditions.

5.21 The total monthly STOR cost target is the sum of the monthly STOR availability cost target and the monthly STOR utilisation cost target.

STOR_C = STOR_A_C + STOR_U_C

5.22 STOR utilisation costs are subtracted from the BM operating reserve cost target and included in the STOR total cost target for clarity of reporting.

STOR Availability Cost

5.23 The monthly STOR availability cost target is the sum of the ex-ante long term STOR cost and the remaining STOR availability costs. Long term is defined here as STOR contracted in 2010 for a period greater than two years. The remaining STOR availability costs are a calculation of the number of STOR hours per month multiplied by the STOR availability price per month multiplied by the target MW of STOR available minus the MW of long term STOR available.

STOR_A_C = STOR_A_C’ + LT_STOR_A_C

STOR_A_C’
= (Avg_Available_STOR_V – Avg_Available_LT_STOR_V)
* Number_of_STOR_Hours
* STOR_A_P

Where

Avg_Available_STOR_V is the ex-ante forecast volume of STOR that will be procured each month. See **10.1**

Avg_Available_LT_STOR_V is the ex-ante forecast volume of existing long term STOR contracts that will be available each month

Number_of_STOR_Hours is the number of hours in each month that falls in a STOR contracted window

STOR_A_P is the ex-post market derived STOR availability price in £/MW/h. See **10.23**

STOR Utilisation Cost

5.24 The monthly STOR utilisation cost target is the monthly STOR out of money price multiplied by the monthly STOR utilisation volume target.

STOR_U_C =(STOR_V * STOR_P)

STOR Utilisation Volume

5.25 The monthly STOR utilisation volume target is the result of a linear model of the following variables.

STOR_V
= ***C1*** * msum(OP_V_HH)
+ ***C2*** * Avg_Available_STOR_V

STOR Utilisation Price

5.26 The STOR out of money price is the monthly STOR utilisation price minus the average BM pseudo price for the month.

STOR_P
= STOR_U_P
- Avg_ER_P

Where

STOR_U_P is the ex-post market derived STOR utilisation price in £/MWh. See **10.24**

Avg_ER_P is the ex-post average of all half hourly energy reference price values in the month. See **10.26**

Constrained Margin Management (CMM) Cost

5.27 CMM costs are incurred when actions are taken, which have the combined effect of:

- Replacing sterilised operating reserve behind a constraint boundary: Sterilised operating reserve refers to BMUs which are unable to achieve maximum output as they are located behind a constraint boundary which cannot transmit all of the necessary power through the available assets; and
- Increasing the amount of positive reserve available for operation: If a reserve action is undertaken that completely replaces sterilised operational reserve, then the costs are assigned to constraint costs. For the action to be assigned to CMM costs, the action must only partially replace sterilised operating reserve and partially increase the amount of positive reserve available.

5.28 The volume of CMM actions are forecast using a linear model that has an intercept term and using the volume of constraint bids as forecast by the constraint model. This effectively means there is a baseline constant volume of CMM per month, and a volume that increases with increasing volume of constraint bids required.

5.29 The monthly CMM target costs are calculated as the monthly CMM price multiplied by the monthly CMM volume where neither price or volume can be negative.

CMM_C = max(0, CMM_V) * max(0, CMM_P)

CMM Volume

5.30 The monthly CMM volume target is the result of a linear model with the following variables.

CMM_V
= ***C0***
+ ***C1*** * Constraint_Bid_V

Where

Constraint_Bid_V is the total bid volume (in GWh) taken in the constrained run in Plexos. See **10.27**

CMM Price

5.31 The monthly CMM target price is the result of a linear regression with the following variables.

CMM_P
= ***C0***
+ ***C1*** * CMM_V
+ ***C2*** * VWA_Op_Reserve_P

Where

CMM_V is the forecast volume of CMM as described above. See **5.30**
VWA_Op_Reserve_P is the volume weighted operating reserve price as defined above. See **5.15**

BM Start-Up Cost

5.32 The BM Start-up Service gives National Grid on-the-day access to additional generating BMUs that would not otherwise have run, and could not be made available in BM timescales due to their technical characteristics and associated lead-times. BM start up costs relate to the actions that National Grid has to take to ensure that BMUs are ready for use within BM timescales; this includes the process of BMUs “warming up”, during which the BMU is being prepared to generate if and when an offer is issued by National Grid. Once a BMU has reached critical operating temperatures, additional fees may be incurred to hold the unit at readiness to synchronise, this is known as hot standby.

5.33 The model for BMSU costs is a linear regression that uses an intercept, the volume of unsynchronised MEL at 6 hours ahead on Gas fuelled plant for daytime hours and the volume weighted operating reserve price. The model essentially assumes a standard cost per month, a proportion of which is dependent on the operating reserve price. The unsynchronised MEL term is specifically the average of daytime values as this is the typical period during which BMSU actions would be taken. The term is limited to Gas plant to reflect the fact that gas plant does not typically require warming due to it’s technical parameters. The term has a negative coefficient which means if gas is marginal and there is a large volume of gas plant available then BMSU costs should decrease.

5.34 The BMSU cost target should not be negative so the maximum of 0 or the modelled costs are used.

BMSU_C = max(0, BMSU_C’)

5.35 The monthly BMSU cost target is the result of a linear model on the following variables.

5.36 Due to a significant change in the BMSU costs over the training data period this model has only been trained using data from 1 April 2009 to 31 March 2013.

BMSU_C’
= ***C0***
+ ***C1*** * Avg_Daytime_Unsync_Gas_MEL_V
+ ***C2*** * VWA_Op_Reserve_P

Where
Avg_Daytime_Unsync_Gas_MEL_V is the ex-post unsynchronised available gas capacity per half hour averaged per month, where the settlement periods are between 15 and 46. See **10.28**

Negative Reserve Costs

5.37 Negative reserve, also known as downward regulation and footroom, refers to the capability that National Grid has to reduce the amount of generation output there is on the system. It is necessary to control the level of negative reserve held on the system to ensure that the frequency can be kept within its statutory limits and does not rise out of control due to an excess of generation. In circumstances where demand is low and the majority of generation is operating inflexibly at or near its minimum stable output (i.e. the level at which it can not operate below), there may be insufficient available MW reduction capability. Actions have to be taken to exchange this inflexible generation with flexible generation. This is achieved by the desynchronising of some of the BMUs, allowing the output of other BMUs to be increased above their minimum stable output. Taking such actions increases the negative reserve available and gives National Grid more flexibility to respond to changes in the frequency either automatically via frequency response or by instruction.

5.38 The volume of negative reserve actions required is significantly impacted by the availability and the running regime of generation, in particular inflexible plant types like nuclear power stations and wind turbines. High levels of inflexible plant generating during periods of low demand results in flexible generation reducing output, moving towards their minimum stable output, leaving little ability for National Grid to further reduce generation output. This therefore results in an increased volume of negative reserve actions being required so that National Grid can further reduce output on synchronised machines. The volume of negative reserve actions and hence costs is likely to increase in the future as the proportion of inflexible plant, in particular nuclear and wind generation, increases.

5.39 The negative reserve cost model uses a linear regression that uses the market synchronised footroom as a variable along with demand volatility and a dummy variable for summer time. The market synchronised footroom variable has a negative coefficient due to the fact that the higher the volume of market synchronised footroom the less costs should be incurred in creating negative reserve. Demand volatility is a shape variable that also contains correlations to running patterns of generation and response requirements, whilst the summertime dummy variable represents the month's when the demand is lowest and the negative reserve requirement is most onerous.

5.40 The monthly negative reserve cost target is the result of a linear regression model with the following variables.To improve the robustness of this model the training data was filtered to remove negative costs.

NR_C
= ***C1*** * Footroom_V
+ ***C1*** * Demand_Volatility_V
+ ***C2*** * Is_Summer

Where

Footroom_V is the ex-post total market synchronised footroom volume per month. See **10.27**

Demand_Volatility_V is the ex-ante forecast volatility of demand for each month. See **10.1**

Is_Summer is an ex-ante logic variable of 1 during Jun-Aug. See **10.2**

Chapter 6: Frequency Response Cost Target Model

6.1 National Grid must maintain the continuously changing system frequency within the statutory limits, as defined in the NETS SQSS. To assist with this, National Grid procures frequency response from BMUs, which can be categorised as either dynamic response or static response. Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system, whilst static frequency response is usually a discrete service triggered at a defined frequency deviation. National Grid procures three different types of balancing services to assist with frequency control:

- Mandatory Frequency Response (MFR),
- Firm Frequency Response (FFR),
- Frequency Control by Demand Management (FCDM).

6.2 The amount of response required at any one time must be enough to maintain the system frequency within the statutory limits if a significant event occurs, such as the loss of the largest power plant on the system. National Grid incurs two main costs associated with response provision; the cost of positioning BM units to provide response under the MFR mode (bids and offers in the BM) and the ancillary service fees which include the response energy payment and holding fees for MFR and contract fees for FFR and FCDM.

Model Overview

6.3 The monthly total Frequency Response cost target is modelled in terms of the following components:

- Frequency response ancillary services costs
- Frequency response bid costs
- Frequency response offer costs

FRR_C = FRRA_C + (FRRB_P * min(0, FRRB_V)) + (FRRO_P * max(0, FRRO_V))

Frequency Response Bid Cost

6.4 The monthly frequency response bid cost target is the monthly frequency response bid price multiplied by the frequency response bid volume. Since there should not be a positive bid volume the min of 0 or the modelled bid volume is used.

FRRB_C = min(0, FRRB_V) * FRRB_P

Frequency Response Bid Volume

6.5 The volume of frequency response bids required is dependent on the relative market synchronised position of the generation based on it's upper and lower output limits. The bid volume model uses a linear model using market length, market synchronised headroom, contracted static response volumes and forecast operating reserve volume. The intercept gives a baseline volume which is then modified with a long market reducing the volume required (resolving the long market will provide more headroom on the units). The more market provided headroom will also reduce the volume required as will the level of contracted static response. The volume of operating reserve volume has a negative coefficient due to the reserve for response requirement in operating reserve volume; an increase in reserve requirement will correlate with an increase in response bids.

6.6 The monthly frequency response bid volume target is the result of a linear model with the following variables.

6.7 Due to a significant change in the FRRB_V over the full training data period this model has only been trained using data from 1 April 2009 to 31 March 2013.

FRRB_V
= ***C0***
+ ***C1*** * Avg_NI_V
+ ***C2*** * Avg_Headroom_V
+ ***C3*** * Avg_Available_Static_V
+ ***C4*** * msum(OP_V_HH)

Where

Avg_Available_Static_V is the ex-ante forecast volume of static frequency response procured each month. See **10.1**

Frequency Response Bid Price

6.8 The price of frequency response bids is modelled based on two price variables the average energy reference price and the average marginal fuel price along with a volume variable of the average market length. The two price variables have opposite signs which means this is modelling the difference between two prices this mimics reality where the "out of money" bid price is the cash price of the bid minus the energy reference price. The average market length creates a price stack which effectively means the longer the market the more negative the price.

6.9 The monthly frequency response bid price target is the result of a linear model with the following variables.

6.10 Due to a significant change in the FRRB_P over the full training data period this model has only been trained using data from 1 April 2009 to 31 March 2013.

FRRB_P
= ***C1*** * Avg_NI_V
+ ***C2*** * Avg_ER_P
+ ***C3*** * Avg_Marginal_Fuel_P

Frequency Response Offer Cost

6.11 The monthly frequency response offer cost target is the monthly frequency response offer price multiplied by the frequency response offer volume. Since there should not be a negative offer volume the max of 0 or the modelled offer volume is used.

FRRO_C = max(0, FRRO_V) * FRRO_P

Frequency Response Offer Volume

6.12 Frequency response offers are predominantly required overnight when generation is running closer to it's SEL and offers are required to lift a unit's position to enable them to provide high frequency response (reducing output). For this reason the variables in the response offer volume model focus on the average values for the overnight periods only. The offer volume model uses a linear model that includes market synchronised footroom, this has a negative coefficient describing the fact that the more footroom on the system the less offers are required to meet the response requirement

6.13 The monthly frequency response offer target volume is the result of a linear model with the following variables.

FRRO_V

= ***C0***
+ ***C1*** * Demand_V
+ ***C2*** * Avg_Overnight_Footroom_V
+ ***C3*** * Avg_Overnight_Wind_Volatility_V
+ ***C4*** * Avg_Overnight_IC_Flow_V
+ ***C5*** * Avg_Overnight_NI_V

Where

Avg_Overnight_Footroom_V is the ex-post average market synchronised footroom per month for settlement periods between 46 and 15. See **10.28**
Avg_Overnight_Wind_Volatility_V is the ex-post average half hourly wind volatility per month for settlement periods between 46 and 15
Avg_Overnight_IC_Flow_V is the ex-post average half hourly interconnector flow per month for settlement periods between 46 and 15
Avg_Overnight_NI_V is the ex-post average half hourly net imbalance volume per month for settlement periods between 46 and 15

Frequency Response Offer Price

6.14 The monthly frequency response offer price is the result of a linear model using the following variables.

FRRO_P
= ***C1*** * FRRO_V
+***C2*** * Avg_SPNIRP_P

Where

FRRO_V is the forecast volume of frequency response offers as defined above. See **6.13**
Avg_SPNIRP_P is the average short term wholesale power price in £/MWh. See **10.26**

Frequency Response Ancillary Services Cost

6.15 The frequency response ancillary service costs are composed of the response holding costs and response energy costs along with the contract costs for the FFR and static response services. The cost model uses a linear model that has available static response volume, available FFR volume and the number of days in the month as volume variables whilst price information comes from marginal fuel price and RPI. Number of working days is relevant for contract costs as well as the volume of response energy. The volume of static response available has a negative co-efficient, this is because in the training history static response has cost less than dynamic, so the more static available the lower the overall cost.

6.16 The monthly ancillary services frequency response cost target is the result of a linear model using the following variables.

6.17 Due to the unavailability of some of the variables used in this model and significant changes in the historic FFRA_C this model has been trained from 1 April 2009 to 31 March 2013.

FRRA_C
= ***C1*** * Avg_Available_Static_V
+ ***C2*** * Avg_Available_FFR_V
+ ***C3*** * Number_of_Working_Days
+ ***C4*** * Avg_Marginal_Fuel_P
+ ***C5*** * RPI

Where

Avg_Available_Static_V is the ex-ante forecast level of static response contracted in MW of secondary response provision. See **10.1**

Avg_Available_FFR_V is the ex-ante forecast level FFR contracted in MW of secondary response provision

Number_of_Working_Days is the number of working days in the month

Avg_Marginal_Fuel_P is the ex-post average marginal fuel price for the month. See **10.26**

RPI is the ex-post Retail Price Index (Jan 1987 base 100). See **10.22**

Chapter 7: Fast Reserve Cost Target Model

7.1 Fast Reserve is a balancing service that is used to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand. For example; an incident involving generation disconnection or rapid demand changes resulting from TV pickups. Fast Reserve delivers active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from National Grid. Fast reserve costs are composed of two main components, the utilisation of generating or demand fast reserve (bid and offers) and ancillary service costs. Fast reserve prices are mostly dependant on tendered and accepted prices, submitted by service providers although non firm services are also offered by providers with a framework agreement but not under a specific contract.

Model Overview

7.2 The total monthly Fast Reserve target costs are modelled in terms of the following components:

- Fast reserve ancillary services costs
- Fast reserve bid costs
- Fast reserve offer costs

FR_C = FRA_C + (FRB_P * FRB_V) + (FRO_P * FRO_V)

Fast Reserve Bid Cost

7.3 The monthly fast reserve bid cost target is calculated from the monthly fast reserve bid price multiplied by the monthly fast reserve bid volume.

FRB_C = (FRB_V * FRB_P)

Fast Reserve Bid Volume

7.4 The volume, and cost, of fast reserve bids is a very small component of the total fast reserve costs. The volume has been fairly stable across history, in part due to the limited number or providers and requirement for this service. Identifying specific drivers for the monthly variation is difficult as the service is used in response to random events.

7.5 The monthly fast reserve bid volume is forecast to be a static value (this value is the average outturn fast reserve bid volume since January 2008 when the service first started).

FRB_V = ***C0***

Fast Reserve Bid Price

7.6 The monthly fast reserve bid price is the result of a linear model with the following variables.

7.7 Due to the introduction of the service occurring in January 2008, this model is trained from 01 January 2008 to 31 March 2013.

FRB_P
= ***C0***
+ ***C1**** Avg_ER_P

Fast Reserve Offer Cost

7.8 The monthly fast reserve offer cost target is calculated by the monthly fast reserve offer price multiplied by the monthly fast reserve offer volume.

FRO_C = (FRO_V * FRO_P)

Fast Reserve Offer Volume

7.9 Fast reserve offer volumes are dependent on the requirement for increasing rapidly increasing active power in response to generation and demand volatility. As such the model for fast reserve offers uses a linear regression on generation volatility in the form of interconnector flow volatility and wind volatility. It also uses forecast demand volatility along with a summertime variable that represents when the demand is lower a smaller change in generation or demand has a greater impact.

7.10 The monthly fast reserve offer volume is the result of a linear model with the following variables.

FRO_V
= ***C1*** * IC_Flow_Volatility_V
+ ***C2*** * Wind_Volatility_V
+ ***C3*** *Demand_Volatility_V
+ ***C4*** * Is_Summer

Where
IC_Flow_Volatility_V is the ex-post monthly total of the absolute half hourly change in interconnector flow. See 10.27
Wind_Volatility_V is the ex-post monthly total of the absolute half hourly change in wind power output.
Demand_Volatility_V is the ex-ante monthly total of the absolute half hourly change in demand.

Fast Reserve Offer Price

7.11 The fast reserve offer price model models the out of money price by using a linear regression on average energy reference price and average marginal fuel price with an intercept term. The two price variables have opposite signs which again mimics the real price which is the difference of cash price and reference price.

7.12 The monthly fast reserve offer price is the result of a linear model with the following variables.

FRO_P
=***C0***
+ ***C1*** * Avg_ER_P
+ ***C2*** * Avg_Marginal_Fuel_P

Fast Reserve Ancillary Services Cost

7.13 Fast reserve ancillary service costs are the costs associated with firm fast reserve contracts, or any optional service fees. One of the main drivers of the price of fast reserve services is the maintenance of the plant required to provide the service, so the model uses RPI as a monthly variable to index these costs. The wind volatility is used as a driver for the volume of contracted fast reserve services.

7.14 The monthly fast reserve ancillary services cost target is the result of a linear model with the following variables.

FRA_C
= ***C0***
+ ***C1*** * Wind_Volatility_V
+ ***C2*** * RPI

Chapter 8: Reactive Cost Target Model

8.1 National Grid manages the voltage of the GB system, to meet transmission licence requirements for secure and stable power transmission and to ensure quality of supply to customers. Voltages are largely determined by the flows of reactive power on the system. National Grid ensures that reactive power is provided on a local basis to meet the constantly varying needs of the system so that there are sufficient reactive power reserves available to meet contingencies, such as generation plant losses and circuit trips. All equipment on the transmission system will generate or absorb reactive power, but not all can be used economically to control the voltage. To assist with controlling reactive power flows, National Grid procures reactive power as a balancing service. It is obligatory for generators that are party to the Grid Code to have the capability to provide reactive power. These synchronous generators can be controlled to absorb or generate reactive power depending on the excitation (a form of generator control). National Grid instructs these generators as to the level of reactive power that should be generated or absorbed to keep the system voltages within acceptable limit.

8.2 National Grid pays generators using a reactive power default price, which is defined in the CUSC as a function of wholesale prices and retail price index for reactive utilisation based on metered volumes. The same payment arrangements apply to both absorption and generation of reactive power.

Model Overview

8.3 The Reactive Power model derives Reactive Power cost (in £) from the multiple of a forecast reactive demand (in MVAr-h) and an assumed (“default”) price of reactive power. Due to the reactive power requirement being driven by the transmission of power on the system the reactive demand is modelled as a proportion of active-demand forecast. Reactive Power price is the default price as specified in the CUSC†.

Reactive Cost

8.4 The monthly reactive power cost target is calculated from the monthly reactive power price multiplied by the monthly reactive demand as a ratio of total monthly demand multiplied by total monthly demand.

REAC_C = (REAC_Ratio * DEM_V) * REAC_P

† Connection and Use of System Code

Reactive Power Volume

8.5 The monthly reactive power volume is calculated as the reactive demand ratio to active demand, multiplied by active demand. The reactive demand ratio is the modelled using a linear regression that includes an intercept term, monthly demand, dummy time variables for winter and BST along with an increasing time trend variable called Month ID. The intercept term gives a baseline value whilst the demand volume has a negative coefficient which means the greater the demand, the lower the ratio of reactive to active power. The increasing time trend represents changes to the amount of reactive demand due to changes in the make up of the transmission system and connected assets.

8.6 Due to significant changes across the historic time series this model has been trained only using data from 1 April 2009 to 31 March 2013.

REAC_Ratio
= ***C0***
+ ***C1*** * Month_ID
+ ***C2*** * Demand_V
+ ***C3*** * Is_Winter
+ ***C4*** * Is_BST

DEM_V
= Demand_V

Where
Month_ID is a monthly increasing integer where Apr 2005 is 1. **See 10.2**

Reactive Power Default Price

8.7 The monthly reactive power price is the default reactive power price as defined in the CUSC schedule 3.

REAC_P = Reactive_Default_P

CHAPTER 9: Minor Costs

9.1 The minor cost category is made up of two components, AS & BM General Costs and BM Unclassified costs.

AS & BM General Costs

9.2 The monthly AS (ancillary services) and BM General Costs are modelled as the historic percentage of total BM costs. This historic ratio is multiplied by the total BM target cost for the month.

AS_BM_C
= ***C1*** * TOT_BM_C

Where
TOT_BM_C = EI_C + FR_C + OR_C + NR_C + STOR_C + BMSU_C + (FRRB_P * FRRB_V) + (FRRO_P * FRRO_V) + CMM_C

BM Unclassified Costs

9.3 The monthly BM Unclassified Costs are modelled as the historic percentage of total BM costs. This historic ratio is multiplied by the total BM target cost for the month.

UN_BM_C
= ***C1*** * TOT_BM_C

Where
TOT_BM_C = EI_C + FR_C + OR_C + NR_C + STOR_C + BMSU_C + (FRRB_P * FRRB_V) + (FRRO_P * FRRO_V) + CMM_C

Chapter 10: Variables

Ex-ante Variables

10.1 Several variables used in the models are forecast at the beginning of the scheme (i.e. they are ex-ante). These variables are as follows:

Monthly Variable	Definition
Demand_V	the monthly sum of half hourly forecast demand (in MW) for each month
Demand_Volatility_V	the forecast volatility of that demand for each month
Number_of_STOR_Hours	the number of hours in each month that falls in a STOR window
Number_of_Working_Days	the number of working days in each month (including Saturdays and Good Friday)
Avg_Available_STOR_V	the forecast volume of STOR that will be procured each month
Avg_Available_LT_STOR_V	the forecast volume of existing long term STOR contracts that will be available each month
STOR_Availability_Ratio	the ratio of contracted STOR to available STOR
Avg_Available_Static_V	the forecast volume of static frequency response procured each month (MW Secondary response provision between periods 15 and 46)
Avg_Available_FFR_V	the forecast volume of firm frequency response procured each month (MW Secondary response provision between periods 15 and 46)
LT_STOR_A_C	the forecast availability cost for the long term STOR contracts that have already been let.

Half Hourly Variable	Definition
Minimum_Dynamic_U_HH	the minimum amount of dynamic response (in MW) required
Available_Dynamic_U_HH	the forecast amount of dynamic response procured (in MW)
Available_Response_U_HH	the forecast amount of response procured (both dynamic and static) (in MW)
Max_Loss_U_HH	the forecast maximum credible generation loss (in MW)
Demand_U_HH	the forecast half hourly demand (in MW)

Time based Ex-ante Variables

10.2 Several monthly variables have values that can be determined purely from the date and time, these variables are listed below along with the definitions of those variables:

Monthly variable	Definition
Month_ID	1 in Apr 2005, 2 in May 2005, …
Is_Summer	1 in Jun, Jul, Aug; 0 otherwise
Is_Winter	1 in Nov, Dec, Jan; 0 otherwise
Is_BST	1 in Apr-Oct, 0 in Nov-Mar

10.3 Several half hourly variables have values that can be determined purely from the date and time, these variables are listed below along with the definitions of those variables:

Half hourly variable	Definition
Is_GMT_HH	0 in Apr-Oct, 1 in Nov-Mar
Is_BST_HH	1 in Apr-Oct, 0 in Nov-Mar
Is_EFA6_HH	1 in periods 39-46, 0 in periods <39 or >46
Is_EFA345_HH	1 in periods 15-38, 0 in periods <15 or >38

Half hourly Ex-post Variables

NI_V_HH

10.4 NI_V_HH is the half hourly value of net imbalance volume in MWh, with positive values occurring when the market is short (i.e. demand exceeds sum of FPNs).

Unsync_MEL_V_HH

10.5 Unsync_MEL_V_HH is the (half hourly) total unsynchronised available capacity.

Unsync_MEL_V_HH
= sum over units (max(0, MEL_{6HA}))

Where
PN_{6HA} is the integrated value of the minutely PN submissions valid at 6 hours before the beginning of the settlement period (in MWh)
MEL_{6HA} is the integrated value of the minutely MEL submissions valid at 6 hours before the beginning of the settlement period (in MWh)

units is the list of BMUs that meet all the following criteria
- have a value of zero for PN_{6HA}
- have a value of less than 360 minutes for NDZ
- are not CCGTs that have been made available under the STOR service for the settlement period

10.6 For periods where missing data was detected, the average of the full historic timeseries by settlement period per month was used. i.e if period 13 on 1 April 2011 was missing the average of all period 13 from all days in April between 1 April 2006 and 31 March 2013 was used to replace the missing data

Unsync_Gas_MEL_V_HH

10.7 Unsync_Gas_MEL_V_HH is the total unsynchronised available gas capacity for a halfhour.

Unsync_Gas_MEL_V_HH
= sum over units (max(0, MEL_{6HA}))

Where
PN_{6HA} is the integrated value of the minutely PN submissions valid at 6 hours before the beginning of the settlement period (in MWh)
MEL_{6HA} is the integrated value of the minutely MEL submissions valid at 6 hours before the beginning of the settlement period (in MWh)

units is the list of BMUs that meet all the following criteria
- have a value of zero for PN_{6HA}
- have a value of less than 360 minutes for NDZ

- are CCGTs
- have not been made available under the STOR service for the settlement period

10.8 Missing data is dealt with in the same manner as for Unsync_MEL_V_HH

Headroom_V_HH

10.9 Headroom_V_HH is the (half hourly) total synchronised headroom.

Headroom_V_HH
= sum over units (MEL_{RT} - min(FPN_{RT}, MEL_{RT}))

Where
FPN_{RT} is the integrated value of the final PN submissions (in MWh)
MEL_{RT} is the integrated value of the latest minutely MEL submissions (in MWh)

units is the list of BMUs that meet all the following criteria
- have a value greater than zero for PN_{RT}
- have a value greater than zero for MEL_{RT}
- are CCGTs, coal fired or oil fired

Footroom_V_HH

10.10 Footroom_V_HH is the (half hourly) total synchronised footroom.

Footroom_V_HH
= sum over units (FPN_{RT} - min(FPN_{RT}, SEL_{RT}))

Where
FPN_{RT} is the integrated value of the final PN submissions (in MWh)
MEL_{RT} is the integrated value of the latest minutely MEL submissions (in MWh)
SEL_{RT} is the integrated value of the latest minutely SEL submissions (in MWh)

units is the list of BMUs that meet all the following criteria
- have a value greater than zero for PN_{RT}
- have a value greater than zero for MEL_{RT}
- have a value greater than zero for SEL_{RT}
- are CCGTs, coal fired or oil fired.

Wind_V_HH

10.11 Wind_V_HH is the total metered output of settlement metered BMUs that are wind farms in MWh.

Wind_U_HH

10.12 Wind_U_HH is the total metered output in MW of BMUs that are wind farms and are modelled in National Grid's Wind Power Forecasting System (WPFS).

IC_Flow_V_HH

10.13 IC_Flow_V_HH is the total flow of all the interconnectors (IFA, BritNED, Moyle and East-West) at real-time in MWh for the half hour (where positive values are used for flows into GB).

Wind_Volatility_V_HH

10.14 Wind_Volatility_V_HH is change in the value of Wind_V_HH from one half hour to the next.

Wind_Volatility_V_HH = abs(Wind_V_HH – Wind_V_HH-1)
Wind_Volatility_V_HH = 0 for settlement period 1

Where
Wind_V_HH-1 is the value of Wind_V_HH for the last half hour

IC_Flow_Volatility_V_HH

10.15 IC_Flow_Volatility_V_HH is change in the value of IC_Flow_HH from one half hour to the next.

Delta_abs IC_Flow_V_HH = abs(IC_Flow _HH – IC_Flow _HH-1)
Delta_abs IC_Flow_V_HH = 0 for settlement period 1

Where
IC_Flow_HH-1 is the value of IC_Flow_HH for the last half hour

Constraint_Bid_V_HH

10.16 Constraint_Bid_V_HH is the total bid volume (in GWh) taken in the constrained run in Plexos (see constraint methodology statement).

10.17 The value of Contraint_Bid_V_HH is calculated by summing the absolute difference, for each unit, between the two runs by period and dividing by 2.

ER_P_HH

10.18 ER_P_HH is the half hourly energy reference price used for reporting costs. The definition is in section 3.1 of the Constraint Costing Methodology and is repeated here:

10.19 This leads to the concept of an "Energy Reference Price" (ERP) which is calculated as the volume weighted average of submitted‡ prices to resolve NIV in any given Settlement Period. For simplicity, this calculation ignores dynamics parameters such as run-up and run-down rates, notice to deviate from zero, minimum non-zero times and/or two shift limits.

SPNIRP_HH

10.20 Defined in chapter 11.

‡ When taking actions for 'system' reasons, such as for constraint management purposes, some actions which would have been 'in merit' to resolve NIV may not be taken and are now not required as a single action has resolved market length and the constraint. Using submitted prices for the Energy Reference Price allows the incremental cost of these out-of-merit actions to be determined.

Marginal_Fuel_P_HH

10.21 Marginal_Fuel_P_HH is the half hourly price, including carbon, of the marginal fuel type. The easiest way to define these prices is to calculate the costs of generating from coal and gas (Coal_P_HH and Gas_P_HH) and take the maximum of those two values. The definitions of all three variables are below:

Marginal_Fuel_P_HH = max(Coal_P_HH, Gas_P_HH)

Coal_P_HH = MSCMUSDT / GBPUSD / 6.97 / 36% + 0.92 * ICEDEUA / GBPEUR

Gas_P_HH = NBPGDAHD / 100 / 0.0293071 / 49.13% + 0.41 * ICEDEUA / GBPEUR

Where

MSCMUSDT, NBPGDAHD, ICEDEUA, GBPEUR, GBPUSD are the values of Bloomberg indices.

Monthly Ex-post Variables

RPI

10.22 RPI is the monthly value of the “CHAW: RPI: All items retail price index (January 1987 = 100)” index available from the Office of National Statistics.

STOR_A_P

10.23 STOR_A_P is the derived STOR availability price in £/MW/h. The price is derived from all tenders submitted for the STOR service for delivery in the target month. The highest priced tender from each STOR unit across any of the tender rounds for the target month is selected to create a price stack. The least expensive ***x***MW (where ***x*** is the contracted MW defined by (Avg_Available_STOR_V-Avg_Available_LT_STOR_V) / STOR_Availability_Ratio)of these selected tenders are used to calculate the volume weighted average price.

STOR_U_P

10.24 STOR_U_P is the derived STOR utilisation price in £/MWh. The volume weighted average utilisation price for those tenders selected for the calculation of availability price as described above, is calculated for the target month.

Reactive_Default_P

10.25 Reactive_Default_P is the monthly reactive default price as define in schedule 3 of the CUSC.

Monthly Ex-post Variables (Derived from Half hourly)

10.26 Several monthly variables contain the average value of the half hourly variables defined above. In all of these cases the average is calculated using settlement date to determine which month a period is in. (i.e. the averages are performed over calendar months).

Monthly variable	Based on half hourly variable
Avg_Headroom_V	Headroom_V_HH
Avg_ER_P	ER_P_HH.
Avg_SPNIRP_P	SPNIRP_HH.
Avg_Marginal_Fuel_P	Marginal_Fuel_P_HH

10.27 Several monthly variables contain a total of half hourly variables for a month. In all of these cases the average is calculated using settlement date to determine which month a period is in. (i.e. the totals are performed over calendar months).

Monthly variable	Based on half hourly variable
Footroom_V	Footroom_V_HH.
Wind_Volatility_V	Wind_Volatility_V_HH
IC_Flow_Volatility_V	IC_Flow_Volatility_V_HH
Constraint_Bid_V	Constraint_Bid_V_HH

10.28 Several monthly variables contain a filtered average value of half hourly variables for a month. In all of these cases the average is calculated using settlement date to determine which month a period is in. (i.e. the averages are performed over calendar months). In all cases the data is first filtered by settlement period, so that only the specified settlement periods are included in the average.

Monthly variable	Based on half hourly variable	Where settlement period is
Avg_Daytime_Unsync_Gas_MEL_V	GAS_Unsync_MEL_6A_adjusted_for_STOR_V	15-46
Avg_Overnight_Footroom_V	Footroom_V_HH	>46 or <15
Avg_Overnight_Wind_Volatility_V	Wind_Volatility_V_HH	>46 or <15
Avg_Overnight_IC_Flow_V	IC_Flow_V_HH	>46 or <15
Avg_Overnight_NI_V	NI_V_HH	>46 or <15

CHAPTER 11: SPNIRP

11.1 This chapter defines the Single Price Net Imbalance Reference Price (SPNIRP), which is a form of market reference priced used by National Grid in its BSIS models.

11.2 As of March 2011, SPNIRP is defined as part of the Transmission Licence, in support of the definition of NIA. However the Scheme will not include NIA. For that reason, the definition of SPNIRP is presented here.

11.3 SPNIRP shall be derived as follows:

(i) where $APXUKHH_j$ and $APXUK4H_j$ data are published in respect of the relevant settlement period j then:

$$SPNIRP_j = (0.5 * APXUKHH_j) + (0.5 * APXUK4H_j)$$

(ii) where $APXUKHH_j$ data are published and $APXUK4H_j$ data are not published in respect of the relevant settlement period j then:

$$SPNIRP_j = APXUKHH_j$$

(iii) where $APXUKHH_j$ data are not published and $APXUK4H_j$ data are published in respect of the relevant settlement period j then:

$$SPNIRP_j = APXUK4H_j$$

(iv) where neither $APXUKHH_j$ data nor $APXUK4H_j$ data have been published in respect of the relevant settlement period j then:

$$SPNIRP_j = SPNIRP_{j-1}$$

11.4 where:

11.5 $SPNIRP_j$ means the single price net imbalance volume reference price for each settlement period j.

11.6 j in all cases shall mean a settlement period (being a half an hour) as defined in the BSC.

11.7 j-1 the settlement period immediately preceding the relevant settlement period j.

11.8 $APXUKHH_j$ means the APX Power UK volume weighted reference price for each settlement period j based on the traded prices of half hourly spot contracts.

11.9 $APXUK4H_j$ means the APX Power UK weighted average price in respect of all four (4) hour block market contracts delivered within the EFA block applying to those settlement periods j. In order to derive the APXUK4Hj price in respect of each relevant settlement period j the EFA block containing the relevant settlement period j shall be used.

11.10 *EFA Block* means the six four hourly blocks within the EFA day (being 23.00 hours to 23.00 hours in the immediately following day) as set out in the table below:

EFA Block	Time
1	23:00 to 03:00
2	03:00 to 07:00
3	07:00 to 11:00
4	11:00 to 15:00
5	15:00 to 19:00
6	19:00 to 23:00

Appendix A: Table of Model Coefficients

Model	C0	C1	C2	C3	C4	C5	C6	C7
Operating Reserve Volume		0.151739	0.0429142	0.00664186	-0.0190653			
Operaring Reserve Cash Price		-0.00189907	0.00961657	0.0135081	0.0200595	1.85506	0.28346	0.342144
STOR Utilisation Volume		0.0169527	3.92224					
Constrained Margin Management (CMM) Volume	16778.1	525.54						
Constrained Margin Management (CMM) Price	8.56015	$-9.89711*10^{-5}$	0.0658111					
BM Start-Up Cost	492850	-188.192	9460					
Negative Reserve Costs		-0.65659	4.50333	1732680				
Frequency Response bid volume	-253711	629.916	129.877	300.414	-0.735228			
Frequency Response bid price		-0.00905392	-0.494396	0.280163				
Frequency Response offer volume	64405.2	0.00269078	-47.5944	1473.34	-27.0371	48.4706		
Frequency Response offer price		$7.33647*10^{-5}$	0.321644					
Frequency Response Ancillary Services Cost		-3041.87	15805.5	100759	70870.5	4618.09		
Fast Reserve Bid Volume	-862.115							
Fast Reserve Bid Price	-40.3541	-0.795358						
Fast Reseve Offer Volume		0.029491	0.35174	0.00544884	1165.42			
Fast Reserve Offer Price	98.8773	-1.03497	0.646978					
Fast Reserve Ancillary Services Cost	4119480	97.8427	35127.7					
Reactive Power Volume	0.0457861	0.00026757	$-6.83946*10^{-10}$	0.00381593	0.00587249			
AS & BM General Costs		0.0209304						
BM Unclassified Costs		0.0558787						

Revisions

Issue	Modifications	Changes to Pages
Revision 01	DRAFT	