Issue	Revision
1	0

The Statement of the Energy Balancing Cost Target Modelling Methodology

Effective from 01 April 2017

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 2017-18
- The Statement of the Ex-ante or Ex-post Treatment of Modelling Inputs Methodology 2017-18

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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 modelling of System characteristics and market fundamentals, 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 and BM Unclassified Cost

1.3 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 (chapter 6).

1.4 Each of the six cost categories are further broken down into separate components described by individual forecast 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	ER_P_HH
	Operating Reserve	OR_C	Volume	OR_V_HH
			Price	OR_OOM_P_HH
			Utilisation Volume	STOR_V
			Utilisation Price	STOR_OOM_U_P
		STOR_C	Availability Cost	STOR_A_C
			Utilisation Volume	STOR_V
			Utilisation Price	STOR_OOM_U_P
		BMSU_C	Cost	BMSU_C
		CMM_C	Volume	CMM_V
			Price	CMM_P
		NR_C	Volume	NR_V_HH
			Cost	NR_C
	Frequency Response	FRR_C	Ancillary Service Costs	FRRA_C
			BM Bid Volume	FRRB_V
			BM Bid Price	FRRB_OOM_P
			BM Offer Volume	FRRO_V
			BM Offer Price	FRRO_OOM_P
	Fast Reserve	FR_C	Ancillary Service Costs	FRA_C
			BM Bid Volume	FRB_V
			BM Bid Price	FRB_OOM_P
			BM Offer Volume	FRO_V
			BM Offer Price	FRO_OOM_P
	Reactive	REAC_C	Volume	REAC_Ratio
			Price	REAC_P
	Minor	AS_BM_C	Cost	AS_BM_C
		UN_BM_C	Cost	UN_BM_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 an updated range of available history (compared to the 2015-17 scheme). This range of data is from 01 April 2011, Settlement Period 01 to 31 December 2016, 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 is 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 available values over the most recent financial year, namely 01 April 2016 Settlement Period 01 to 31 December 2016 Settlement Period 48 unless otherwise stated.

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 March 2017. This enables the models to make use of out-turn data up to 31 December 2016.

3.2 It is intended that this set of models will remain unchanged for the duration of the scheme. However, in accordance with licence paragraph [4C.38] of licence Special Condition 4C, if NGET considers that an inaccuracy(s) has occurred which prevents any model from reflecting the intent of modelling energy costs, NGET shall notify the Authority of the inaccuracy (s) and its materiality and promptly seek to correct the inaccuracy(s).

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 20 March 2017.

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 The majority of the models are monthly totals, except for Energy Imbalance, Negative Reserve and Operating Reserve which are half hourly. We have therefore used “msum(…)” to indicate the step in the calculation that half hourly values are summed to monthly totals. The msum function uses the settlement date to determine the relevant calendar month.

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
EXP_	Describes an Ex-Post variable where there are instances of both ex-ante and ex-post variables of the same item being used in the methodology

Suffix	Description
_V	Monthly Volume (in MWh or MVArh)
_P	Monthly Price (in £/MWh or £/MVArh)
_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)
_Volatility	Absolute change to half hourly values (=0 for settlement period 1)
OOM_P	Out of money price (in £/MWh)

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

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 each section and also 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 (SO-SO trades)
- 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 **10.21**). 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 therefore to resolve Energy Imbalance at a price more attractive than the actions available in the BM.

Model Overview

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

EI_C = msum(EI_V_HH * ER_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 an 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 in a short market. See **10.4** for more details.

Energy Reference Price

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

Where

ER_P_HH is the half hourly energy reference price which is calculated as the volume weighted average of most economic submitted prices to resolve NIV in any given Settlement Period. See **10.20** 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 Start-Up (BMSU), 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. The BM STOR costs are reported separately in the STOR category.

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

Operating Reserve Volume

5.5 The Operating Reserve volume model uses the half hourly reserve requirement and market length less 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, there will be no reserve requirement 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 relative difference in volume of reserve that was actually procured during these time periods. These time based dummy variables reflect the periods in which reserve actions are predominantly taken.

5.7 The model has been trained on data which includes STOR utilisation volume; this is subsequently subtracted from the BM Operating Reserve costs at the monthly level as there is a separate target for STOR including STOR utilisation (see 5.227). The half hourly Operating Reserve volume target is the result of a linear regression with the variables below.

Model	*C0*	*C1*	*C2*	*C3*	*C4*
Operating Reserve Volume	66.0112	0.301404	-0.02686	-0.05831	-0.0996

OR_V_HH
= ***C0***
+ ***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_V_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. See **10.3**

Is_BST_HH is an ex-ante logic variable that is 1 in Apr-Oct, 0 in Nov-Mar. See **10.3**

Is_GMT_HH is an ex-ante logic variable that is 0 in Apr-Oct, 1 in Nov-Mar. See **10.3**

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_V_HH (MWh) is Op_Reserve_Req_U_HH (MW) / 2 defined below. See **5.8**

Half hourly Operating Reserve Requirement

5.8 The half hourly Operating 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
+ Reserve_PV_Adjustment_U_HH

Where:

Reserve_For_Response_U_HH is defined below. See **5.9**
Reserve_Req_U_HH is the ex-ante half hourly regulating reserve requirement excluding wind reserve. See **10.1**
Reserve_Wind_Adjustment_U_HH is defined below. See **5.10**
Reserve_PV_Adjustment_U_HH is defined below. See **5.11**

5.9 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_Contracted_Dynamic_U_HH,
Response_Req_U_HH – Available_Response_U_HH)
/ 55%

Response_Req_U_HH
= max(0,
Max_Loss_U_HH – 2.5% * 0.4 * Demand_U_HH) / 68%

Available_Response_U_HH
= Available_Contracted_Dynamic_U_HH
+ FCDM_U_HH
+ IC_Response_U_HH
+ SpinGen_LF_Response_U_HH
+ PumpDeload_LF_Response_U_HH
+ Additional_Static_U_HH

Where

2.5% 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 remaining at 49.9Hz to ensure frequency is contained to a 0.5Hz deviation.
55% is the amount of response typically available for 1MW of pullback
Minimum_Dynamic_U_HH is the ex-ante minimum required amount of dynamic response (in MW) provided by synchronised, part-loaded units. See **10.1**
Available_Contracted_Dynamic_U_HH is the ex-ante forecast amount of contracted dynamic response procured (in MW). See **10.1**
Demand_U_HH is the ex-ante forecast half hourly demand (in MW). See **10.1**

* National Electricity Transmission System Security and Quality of Supply Standards

Max_Loss_U_HH is the ex-post maximum credible generation loss (in MW). See **10.24**
FCDM_U_HH is the ex-ante amount of contracted static response via Frequency Control by Demand Management (in MW). See **10.1**
IC_Response_U_HH is the ex-ante forecast amount of optional response available on interconnectors (in MW). See **10.1**
SpinGen_LF_Response_U_HH is the ex-ante forecast amount of optional SpinGen available for Low Frequency (LF) response (in MW). See **10.1**
PumpDeload_LF_Response_U_HH is the ex-ante forecast amount of optional Pump Deload available for Low Frequency (LF) response (in MW). See **10.1**
Additional_Static_U_HH is the level of additional static response contracts (in MW). See **10.1**

5.10 The definition for the additional reserve required at times of high wind depends on the level of expected wind output and is defined as follows:

Reserve_Wind_Adjustment_U_HH
= 0 when Wind_U_HH ≤ 1000
= 10% * Wind_U_HH when Wind_U_HH > 1000
Where
Wind_U_HH is the ex-post total metered output of EFS (Energy Forecasting System) modelled BMUs that are wind farms in MW. See **10.14**.

This calculation is derived from recent operational experience and is reflective of current operational protocols.

5.11 The definition for the additional reserve required to manage uncertainty from PV forecasts is:

Utilising actual outturn weather data from the Met Office, an estimate of Solar PV generation is calculated at a number of regions across the country based on the generation capacity within each region. This aligns with National Grid's current solar PV forecasting capability.

Reserve_PV_Adjustment_U_HH is defined within the tables below.

		PV Reserve Requirements for March & BST 2017									
		PV Level (MW):									
		0-1000	1001-2000	2001-3000	3001-4000	4001-5000	5001-6000	6001-7000	7001-8000	8001-9000	9001-10000
Cardinal Point	2F	0	200	250	350	350	350	350	350	350	350
	2A	0	100	200	200	300	300	300	300	300	300
	2B	0	0	150	200	200	200	350	350	350	350
	3B	0	0	150	250	250	250	350	450	450	450
	3C	0	150	250	250	250	250	250	250	250	250
	4A	0	200	200	200	200	200	200	200	200	200

Where the Cardinal point definitions are:

Sett Period	GMT CP	BST CP
1	1F	1F
2	1A	1S
3	1A	1S
4	1A	1A
5	1A	1A
6	1A	1A
7	1A	1A
8	1A	1B
9	1B	1B
10	1B	1B
11	1B	1B
12	1B	1B
13	2A-Ramp Early	2F
14	2A-Ramp Early	2F
15	2A-Ramp Late	2F
16	2A-Ramp Late	2F
17	2A-Ramp Late	2F
18	2A-Ramp Late	2F
19	2A	2A
20	2A	2A
21	2A	2A
22	2A	2A
23	2B	2B
24	2B	2B
25	2B	2B
26	2B	2B
27	3B	3B
28	3B	3B
29	3B	3B
30	3B	3B
31	3B	3B
32	3B	3B
33	DP-Ramp	3C
34	DP-Ramp	3C
35	DP	3C
36	DP	3C
37	DP	4A
38	DP	4A
39	DP	4A
40	4B	4B
41	4B	4B
42	4B	4B
43	4B	4B
44	4B	4B
45	4B	4B
46	4B	4C
47	4B	4C

48	4C	4C

GMT 16/17 PV Reserve Requirement (please note it runs from the start of GMT to the **end of February**) Runs from 2A to 3B (SP19 to SP32):

		PV Level (MW)					
		0-1000	1001-2000	2001-3000	3001-4000	4001-5000	5001-6000
Cardinal Point	2A	0	150	150	150	150	150
	2B	0	100	150	200	200	200
	3B	0	0	100	300	300	300

Note that the values stated in 5.11 for GMT are the requirement used in 2016/17 as this is currently the best forecast for GMT 2017/18.

5.12 Impact Of Certain Transmission Outages on Reserve Requirement

There have been some examples where transmission outages will result in additional positive reserve requirements. Historically it was a reasonable assumption that the underlying level of additional actions which were taken as a result remained stable year-on-year. As a result, historical regression will reflect this underlying trend. However, there is an expectation that the size and frequency of these events will increase, and as a result historical regression will not suffice. NGET will continue to monitor this trend and will propose changes, based on the 8 week ahead boundary limit setting process. This will also be reflected in methodologies to reflect these impacts.

BM Operating Reserve OOM Price

5.13 The half hourly Operating Reserve out of the money price is an ex-post variable based on the outturn price of BM Operating Reserve. There are periods where there is a non-zero modelled half hourly Operating Reserve Volume and there will be no corresponding ex-post Operating Reserve price as there was no actual action taken within this half hour. In this instance a modelled half-hourly Operating Reserve Price will be used as a substitute, this substitute is based on linear regression of historical data.

5.14 The substitution model for half hourly Operating Reserve out of money price model consists of two models. The cash price for creating Operating Reserve is modelled based on a linear model of historic prices. This model uses an intercept and 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.

5.15 The substitution 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 are available to be synchronised the higher the price of these units as they are less efficient machines.

5.16 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 - ER_P_HH

Where

OR_P_HH is the half hourly Operating Reserve cash price. See **5.18**.

ER_P_HH is the half hourly Energy Reference Price. See **4.6**.

5.17 The Operating Reserve price is used as an input variable for several of the individual models. See **5.20**.

Operating Reserve Cash Price

5.18 Operating Reserve Cash Price Model is a half-hourly model. Historically we have seen large variations in Operating Reserve Price and as such any historical model alone is insufficient to forecast costs. There is difficulty in forecasting prices as a result of this variability.

5.19 The training data for the substitution linear regression model has been filtered to remove prices where there is insignificant volume (≤50MWh) and to limit the prices (>£0/MWh and <£500/MWh). Below are the refreshed co-efficients for the substitution Operating Reserve cash price model

Model	C0	C1	C2	C3
Operating Reserve Cash Price	52.90683129	-0.004977788	-0.013574913	0.009170334
	C4	**C5**	**C6**	**C7**
	0.017893446	1.202039766	0.284188712	0.075148916

OR_P_HH = if (EXP_OR_V_HH ≠ zero) then VWA_OR_P_HH otherwise
(***C0***
+ ***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 Operating Reserve volume as defined above. See **5.7**

Marginal_Fuel_P_HH is the ex-post half hourly price, including all elements of carbon, of the marginal fuel type. See **10.23**

EXP_OR_V_HH is the ex-post actual operating reserve volume (half hourly). See **10.11**

VWA_OR_P_HH is the volume weighted average price of all accepted actions taken in the half hour for operating reserve.

5.20 The Operating Reserve price, as described above, 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 Operating Reserve price and half hourly Operating Reserve volume.

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

5.21 Historically we have noticed a period where the model does not follow the trend of actual spend due to highly priced Operating Reserve actions. This trend has continued where there have been continuing instances of highly priced Operating Reserve Actions, specifically in July, October, and November 2016. We have proposed a change to 2015/17 methodology and we are continuing to use this change in this methodology. The PAR (Price Average Reference) volume is going to continue to be narrowed, which makes the imbalance penalty sharper which could continue to cause price spikes.

Total STOR Cost

5.22 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 Operating Reserve volume forecast. To separate this into STOR utilisation, a linear model is used at a monthly resolution which 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 Operating Reserve volume that is delivered via STOR utilisation.

5.23 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.

5.24 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

5.25 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

5.26 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

LT_STOR_A_C is the ex-ante forecast cost of long term STOR contracts

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. See **10.1**

Number_of_STOR_Hours is the number of hours in each month that falls in a STOR contracted window. See **10.1**

STOR_A_P is the ex-post market derived STOR availability price in £/MW/h. See **10.28**

STOR Utilisation Cost

5.27 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_OOM_U_P)

STOR Utilisation Volume

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

Model	*C1*	*C2*
STOR Utilisation Volume	0.025593212	4.406422

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

STOR Out of Money Price

5.29 The STOR out of money price is the monthly STOR utilisation price minus the average Energy Reference price for the month.

STOR_OOM_U_P
= STOR_U_P
- Avg_ER_P

Where

STOR_U_P is the ex-post market derived STOR utilisation price in £/MWh. See **10.30**

Avg_ER_P is the ex-post time-weighted average of all half hourly Energy Reference price values in the month. See **10.33**

Constrained Margin Management (CMM) Cost

5.30 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.

5.31 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 that there is a baseline constant volume of CMM per month, and a volume that increases with increasing volume of constraint bids required.

5.32 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

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

Model	*C0*	*C1*
Constrained Margin Management (CMM) Volume	34568.61	190.6652

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 **10.34**

CMM Price

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

Model	*C0*	*C1*	*C2*
Constrained Margin Management (CMM) Price	8.625765	-3.07266E-05	0.289899

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

Where

CMM_V is the forecast volume of CMM as described above. See **5.33**
VWA_Op_Reserve_P is the volume weighted operating reserve price as defined above. See **5.17**

BM Start-Up (BMSU) Cost

5.35 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.

5.36 The model for BMSU costs is a linear regression that uses an intercept, the volume of unsynchronised MEL at 6 hours ahead on coal fuelled plant for daytime hours and the volume weighted average 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.

5.37 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’)

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

Model	*C0*	*C1*	*C2*
BM Start-Up Cost	47873.72	49.36228	3217.569

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

Where
Avg_Daytime_Unsync_Coal_MEL_V is the ex-post unsynchronised available coal capacity per half hour averaged per month, where the settlement periods are between 15 and 46. See **10.35**
VWA_Op_Reserve_P defined in **5.17**.

Negative Reserve Costs

5.39 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 cannot 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 or through changing the level of flow on the interconnectors through trades, 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.

5.40 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 (technically inflexible) and wind turbines (commercially inflexible). 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 and solar generation, increases.

5.41 Actions taken by National Grid can either increase or decrease the volume of actions which needs to be taken to manage Negative Reserve. Trading on the interconnectors to manage RoCoF (to manage the size of the potential largest instantaneous loss) will offset the requirement to take actions to manage Negative Reserve. Conversely actions such as trading-on BM units to manage voltage constraints will increase the requirement to take actions to increase footroom. It is important to take account of these relationships in any Negative Reserve model.

5.42 Negative Reserve Volume is calculated based on a deterministic model. It is calculated by understanding the underlying total requirement, and also the amount of negative reserve delivered by the market and the adjustments needed for actual RoCoF interconnector trades, actual voltage actions and market length. This replicates the approach used by the control room.

5.43 The following formula defines the net volume of actions which are required to be taken to deliver the required amount of Negative Reserve:

Net Requirement NR_V_HH = max(0,NR_V_HH') where
NR_V_HH' = Max(0, Negative_Reserve_Requirement_V_HH – (Footroom_V_HH + NI_V_HH - Voltage_V_HH)) + IC_RoCoF_V_HH)

Where:
IC_RoCoF_V_HH is calculated in the constraint/RoCoF model and represents the volume of required interconnector actions modelled in MWh
Voltage_V_HH is the actual total volume of trades, half hourly in MWh, undertaken to manage voltage constraints

5.44 Of the required volume of actions these are taken on:

- French Interconnector
- Netherlands Interconnector
- Conventional generation
- Pumped storage and Hydro
- Wind generation

Proportional factors have been calculated for each of these categories using historical data between 1-Apr-2015 and 31-Jan-2017.

Option	Weighting Factor Name
French	FR_NR_WGHT_PROP
Netherlands	NL_NR__WGHT_PROP
Conventional	CONV_NR_WGHT_PROP
Pumped storage and Hydro	PS_NR_WGHT_PROP
Wind	WD_NR_WGHT_PROP

5.45 The Weighting Factors are described following:

FR_NR_WGHT_PROP
The proportion of the total negative reserve requirement allocated to French interconnector actions. It comprises two components – the proportion of total BM and interconnector actions taken on interconnectors and the proportion of these which are on the French interconnector.

NL_NR_WGHT_PROP
The proportion of the total negative reserve requirement allocated to Netherlands interconnector actions. It comprises two components – the proportion of total BM and interconnector actions taken on interconnectors and the proportion of these which are on the Netherlands interconnector.

CONV_NR_WGHT_PROP
The proportion of the total negative reserve requirement allocated to BM conventional plant actions. It comprises two components – the proportion of total BM and interconnector actions taken in the Balancing Mechanism and the proportion of these which are on conventional plant (coal/gas).

PS_NR_WGHT_PROP
The proportion of the total negative reserve requirement allocated to BM pumped storage and hydro plant actions. It comprises two components – the proportion of total BM and interconnector actions taken in the Balancing Mechanism and the proportion of these which are on pumped storage and hydro plant.

WD_NR_WGHT_PROP
The proportion of the total negative reserve requirement allocated to BM wind actions. It comprises two components – the proportion of total BM and interconnector actions taken in the Balancing Mechanism and the proportion of these which are on wind plant.

5.46 The minimum duration of a tradable block on the interconnectors is one hour and so this is reflected in the model. For each hourly block on the interconnector the maximum of the two calculated half-hourly volumes must be traded for that hour to ensure that the negative reserve requirement is met in each period. This increases the volume that must be traded compared to the half-hourly profile.

5.47 In reality interconnector trades are only enacted to a minimum resolution. To reflect this, a clip size of 5 MW is used for interconnector trades in the model to reflect what is possible in reality.

5.48 Negative Reserve Cash Price

A Negative Reserve Cash Price is calculated for each of the five categories for meeting the volume of Negative Reserve actions. These are calculated as follows:

For French and Netherlands interconnectors, day-ahead market price for the countries (FR_DA_P_HH, NL_DA_P_HH) is multiplied by a factor to ensure the volume is delivered on the interconnectors. This factor is calculated based on historical analysis of data between 01 April 2015 and 31 January 2017.

For conventional and wind or hydro generation the Energy Reference Price is multiplied by either a premium or discount factor to represent the price of taking actions on these technologies.

The following table represents the premium factor across these technologies:

Category	Factor Name
French	FR_NR_PREM
Netherlands	NL_NR_PREM
Conventional	CONV_NR_PREM
Hydro	PS_NR_PREM
Wind	WD_NR_PREM

5.49 The Premium Factors are described following:

FR_NR_PREM

The multiplication factor applied to the modelled volume of French interconnector trades, calculated from the actual prices achieved compared with market prices.

NL_NR_PREM

The multiplication factor applied to the modelled volume of Netherlands interconnector trades, calculated from the actual prices achieved compared with market prices.

CONV_NR_PREM

The multiplication factor applied to the modelled volume of actions required on conventional units, calculated from the actual prices achieved compared with the most attractive bid prices.

PS_NR_PREM

The multiplication factor applied to the modelled volume of actions required on pumped storage units, calculated from the actual prices achieved compared with the most attractive bid prices.

WD_NR_PREM

The multiplication factor applied to the modelled volume of actions required on wind units, calculated from the actual prices achieved compared with the most attractive bid prices.

5.50 NR_C = Total Sell Cost + Total Replacement Cost

= ((NR_V_HH * FR_NR_WGHT_PROP * FR_DA_P_HH * FR_NR_PREM†) +
(NR_V_HH * NL_NR_WGHT_PROP * NL_DA_P_HH * NL_NR_PREM) +
(NR_V_HH * CONV_NR_WGHT_PROP * MAB_P_HH * CONV_NR_PREM) +
(NR_V_HH * PS_NR_WGHT_PROP * MAB_P_HH * PS_NR_PREM) +
(NR_V_HH * WD_NR_WGHT_PROP * MAB_P_HH * WD_NR_PREM)) * -1
+
NR_V_HH * ER_P_HH * FEF_NR_PREM

Where:

MAB_P_HH is the most attractive accepted bid price in each half hour.

FEF_NR_PREM is a factor to reflect any premium over and above the Energy Reference Price required to account for the cost of any flipped energy. This factor is derived from historical analysis of data between 01 April 2015 and 31 January 2017 and is currently set to 1.0.

5.51 Impact Of Certain Transmission Outages on Reserve Requirement

NGET is seeing an increase in the requirement for delivering response for specific system conditions, typically Dinorwig-Pentir and Dinorwig-Trawsfynydd transmission circuit outages, where Dinorwig is at risk of trip on a single circuit loss and there needs to be sufficient response to manage the loss of the pumping demand overnight.

This results in an additional requirement to ensure sufficient response. When these events occur, an additional volume will be added to the net requirement (see 5.55 below).

5.52 Negative Reserve Volume Requirement

Negative_Regulating_Reserve_Req_V_HH
= (Negative_Reserve_Req_U_HH
+ Neg_Reserve_PV_Adjustment_U_HH
+ Negative_Reserve_for_Response_U_HH) ÷ 2

Where:

Negative_Reserve_Req_U_HH is the ex-ante half hourly regulating reserve requirement excluding wind and PV negative reserve. See 5.53

Neg_Reserve_PV_Adjustment_U_HH is defined below. See 5.54

Negative_Reserve_for_Response_U_HH is defined below. See 5.55

5.53 The definition for Negative_Reserve_Req_U_HH is the core reserve volume required to manage the normal movements in supply and demand. It is calculated from historical analysis of regulating reserve requirements for frequency control of 0.1Hz-0.3Hz high frequency deviations.

† Interconnector volumes are rounded upwards to the nearest 5 MW and assumed to be same for each half hour within every hour.

5.54 The definition for Neg_Reserve_PV_Adjustment_U_HH is the additional requirement arising from the need to exchange inflexible PV generation for flexible generation able to respond to changes in frequency either automatically via frequency response or by manual instruction.

This is calculated from the following lookup table

PV Output Range (MW)	Additional MW Requirement
0-1500	0
1501-2500	100
2501-3500	250
3501-4500	350
4501-5500	400
5501-6000	400
6001-7000	400
7001-8000	400
8001-9000	400
9001-10000	400

These additional requirements are based on analysis of the historical relationship between demand forecast error and levels of PV generation. As actual PV levels are not known until after the event, this component is an ex-post variable.

5.55 The definition of Negative_Reserve_for_Response_U_HH is the additional response to manage the largest potential demand loss on the system or the dynamic response requirement to manage high system frequency. This could also include an additional response requirement (Negative_Reserve_Constraint_Adjustment_U_HH) to address the risk of higher than normal demand trips as a result of the changes in configuration of the transmission system during outages (see 5.51 above). Typically the largest demand loss is 2 pumps or one interconnector bipole, but can rise to 6 pumps during Dinorwig-Pentir outages.

5.56 Generally the dynamic response requirement for management of system frequency is greater than that to meet the normal instantaneous demand loss. The dynamic response requirement depends on system inertia which is variable and dependent on the system demand and how much of that demand will be met by conventional (non-renewable) generation that can contribute to system inertia. Hence on windy days with high volumes of wind generation and low demand periods, the dynamic high response increases. The actual incremental amount is dependent on the system conditions highlighted above and is variable. For this reason, this component is an ex-post variable which will reflect the actual holding in real-time during the specific outage periods which result in the requirement for the additional response to meet the increased risk of higher demand trips.

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, 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 different types of balancing services to assist with frequency control:

- Mandatory Frequency Response (MFR), Dynamic only
- Firm Frequency Response (FFR), Static and Dynamic
- Frequency Control by Demand-side services typically static only
- Enhanced Frequency Response

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 the provision of response services.

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_OOM_P * min(0, FRRB_V)) + (FRRO_OOM_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_OOM_P

Frequency Response Bid Volume

6.5 The required Frequency Response Bid volume is dependent on the relative market synchronised position of the generation based on its 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 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.

Model	*C0*	*C1*	*C2*	*C3*	*C4*
Frequency Response Bid Volume	-116581.4693	600.6615	53.30897	151.2611	-0.67626

FRRB_V
= ***C0***
+ ***C1*** * Avg_NI_V
+ ***C2*** * Avg_Headroom_V
+ ***C3*** * Avg_Available_Contracted_Firm_Static_V
+ ***C4*** * msum(OR_V_HH)

Where

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

Avg_NI_V is the ex-post monthly average of half hourly net imbalance volume. See **10.33**

Avg_Headroom_V is the ex-post monthly average of the half hourly headroom volume. See **10.33**

Frequency Response Out of Money Bid Price

6.7 The Frequency Response Out of Money Bid price 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.

6.8 The monthly Frequency Response Bid price target is the result of a linear model with the following variables.

Model	*C1*	*C2*	*C3*
Frequency Response Out of Money Bid Price	-0.01431270	-0.32608	0.065922

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

Where

Avg_NI_V defined in **10.33**

Avg_ER_P defined in **10.33**

Avg_Marginal_Fuel_P defined in **10.33**

Frequency Response Offer Cost

6.9 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_OOM_P

Frequency Response Offer Volume

6.10 Frequency response offers are predominantly required overnight when generation is running closer to its 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 Frequency 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.

6.11 The monthly Frequency Response Offer volume target is the result of a linear model with the following variables.

<table>
<tr><th rowspan="4">Model

Frequency Response Offer Volume</th><th>C0</th><th>C1</th><th>C2</th></tr>
<tr><td>65881.63293</td><td>0.002319</td><td>-24.6518</td></tr>
<tr><th>C3</th><th>C4</th><th>C5</th></tr>
<tr><td>-1089.8501</td><td>-38.76540277</td><td>29.89791</td></tr>
</table>

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

Demand_V is the monthly sum of half hourly Demand. See **10.1**
Avg_Overnight_Footroom_V is the ex-post average market synchronised footroom per month for settlement periods between 46 and 15. See **10.35**
Avg_Overnight_Wind_Volatility_V is the ex-post average half hourly wind volatility per month for settlement periods between 46 and 15. See **10.35**
Avg_Overnight_IC_Flow_V is the ex-post average half hourly interconnector flow per month for settlement periods between 46 and 15. See **10.35**
Avg_Overnight_NI_V is the ex-post average half hourly net imbalance volume per month for settlement periods between 46 and 15. See **10.35**

Frequency Response Out of Money Offer Price

6.12 The monthly Frequency Response Out of Money Offer price is the result of a linear model using the following variables.

Model	*C1*	*C2*
Frequency Response Out of Money Offer Price	6.04E-05	0.367571082

FRRO_OOM_P
= ***C1*** * FRRO_V
+ ***C2*** * Avg_SPNIRP_P

Where

FRRO_V is the forecast volume of frequency response offers as defined above. See **6.11**
Avg_SPNIRP_P is representative of the average short term wholesale power price in £/MWh. See **10.33**

Frequency Response Ancillary Services Cost

6.13 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 and available FFR (Dynamic) as volume variables whilst price information comes from Marginal Fuel price and RPI. 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.

6.14 The monthly Frequency Response Ancillary Services cost target is the result of a linear model using the following variables.

Model	*C1*	*C2*	*C3*	*C4*
Frequency Response Ancillary Services Cost	-1828.19	409.4375	12885.99	43255.34

FRRA_C
= ***C1*** * Avg_Available_Contracted_Firm_Static_V
+ ***C2*** * Avg_Available_Contracted_Firm_Dynamic_V
+ ***C3*** * Avg_Marginal_Fuel_P
+ ***C4*** * RPI

Where
Avg_Available_Contracted_Firm_Static_V is the ex-ante forecast level of contracted static response contracted in MW of secondary response provision. See **10.1**
Avg_Available_Contracted_Firm_Dynamic_V is the ex-ante forecast level of contracted FFR in MW of secondary response provision. See **10.1**
Avg_Marginal_Fuel_P is the ex-post average marginal fuel price for the month. See **10.33**
RPI is the ex-post Retail Price Index (Jan 1987 base 100). See **10.27**

6.15 With the potential commissioning of the High Voltage Direct Current (HVDC) Western link during 2017-18, it is possible that this will have an impact on frequency response costs due to decreased constraining off of wind generation in Scotland. This impact is currently not fully understood and will be monitored. If appropriate, NGET will submit a solution for approval to the Authority to change the methodology.

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 (bids 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_OOM_P * FRB_V) + (FRO_OOM_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_OOM_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 Whilst there has been an increase in Fast Reserve Bid volume over the last 2 years, the monthly Fast Reserve Bid volume is forecast to be a static value.

Model	*C0*
Fast Reserve Bid Volume	-2959.55

FRB_V = ***C0***

Fast Reserve Out of Money Bid Price

7.6 The monthly Fast Reserve Out of Money Bid price is the result of a linear model with the following variables.

Model	*C0*	*C1*
Fast Reserve Out of Money Bid Price	30.28262998	-2.05559

FRB_OOM_P
= ***C0***
+ ***C1*** * Avg_ER_P

Where
Avg_ER_P is defined in **10.33**

Fast Reserve Offer Cost

7.7 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_OOM_P)

Fast Reserve Offer Volume

7.8 Fast Reserve Offer volumes are dependent on the requirement for rapidly increasing active power in response to generation and demand volatility. As such the model for Fast Reserve Offer volume 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.

7.9 The monthly Fast Reserve Offer volume is the result of a linear model with the following variables.

Model	*C1*	*C2*	*C3*	*C4*
Fast Reserve Offer Volume	-0.030509372	0.132054	0.014291	-805.287

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 **10.34**
Wind_Volatility_V is the ex-post monthly total of the absolute half hourly change in wind power output. See **10.34**
Demand_Volatility_V is the ex-ante monthly total of the absolute half hourly change in demand. See **10.1**

Fast Reserve Out of Money Offer Price

7.10 The Fast Reserve Out of Money 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.

7.11 The monthly Fast Reserve Offer price is the result of a linear model with the following variables.

Model	*C0*	*C1*	*C2*
Fast Reserve Out of Money Offer Price	85.91353832	0.611673	-0.73739

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

Where
Avg_Marginal_Fuel_P is defined in **10.33**

Fast Reserve Ancillary Services Cost

7.12 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.

7.13 The monthly Fast Reserve Ancillary Services cost target is the result of a linear model with the following variables. This model was derived from a four year historical regression rather than the normal five year period (see section **2.1**).

Model	*C0*	*C1*	*C2*
Fast Reserve Ancillary Services Cost	58393885	18.120414	-204180.66

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

Where
Wind_Volatility_V is defined in 10.34
RPI is defined in **10.27**

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 limits.

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 MVArh) 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 Power volume.

$$REAC\_C = (REAC\_Ratio * DEM\_V) * REAC\_P$$

‡ Connection and Use of System Code – Schedule 3

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 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 Active Demand volume has a negative coefficient which means the greater the Active 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 makeup of the transmission system and connected assets.

Model	*C0*	*C1*	*C2*	*C3*	*C4*
Reactive Ratio	0.070399743	0.000196	-9.92579E-10	0.003489	0.005948181

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**
Demand_V is defined in **10.1**

Reactive Power Default Price

8.6 The monthly Reactive Power price is the default Reactive Power price as defined in the CUSC schedule 3.

REAC_P = Reactive_Default_P

Where
Reactive_Default_P is the ex-post monthly reactive default price. See **10.32**

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 AS & BM General Costs are incurred from operating the system which don't directly correlate to any of the above categories. Examples of these include Non-Delivery charges, Unwinding of NGET actions within a settlement period, SO-SO actions invoked by external parties, Trading fees and Bank charges.

9.3 The monthly AS (Ancillary Services) & 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. Unlike earlier models, this is not based on regression but on the ratio of Average (AS_BM_C) / Average (TOT_BM_C).

Model	*C1*
AS & BM General Costs	-0.006278010

AS_BM_C
= ***C1*** * TOT_BM_C

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

BM Unclassified Costs

9.4 BM Unclassified Costs are those costs which do not meet any of the defined rules for assigning actions to the above categories. These might include, for example, synchronising a GT on an already synchronised CCGT, or untagged constraint actions which do not meet any of the criteria for the other categories.

9.5 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. Unlike earlier models, this is not based on regression but on the ratio of Average (UN_BM_C) / Average (TOT_BM_C).

9.6

Model	*C1*
BM Unclassified Costs	0.063477

UN_BM_C
= ***C1*** * TOT_BM_C

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

Chapter 10: Variables

Ex-ante Variables

10.1 Several variables used in the models are forecast by NGET, and agreed with the Authority, 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, msum(Demand_U_HH).
Demand_Volatility_V	the monthly sum of half hourly forecast demand volatility (in MW) for each month, msum(Demand_Volatility_V_HH).
Number_of_STOR_Hours	the number of hours in each month that falls in a STOR window. NGET specify the hours during the day when STOR contracts will be offered, these are published on the website (found under 'Technical Requirements' - document name 'Short Term Operating Reserve Tender Round Dates – 2017') http://www2.nationalgrid.com/uk/services/balancing-services/reserve-services/short-term-operating-reserve/
Avg_Available_STOR_V	the forecast volume of STOR that will be procured each month. This is the minimum required STOR volume for tender assessment and contracting purposes, under current operational protocols.
Avg_Available_LT_STOR_V	the forecast volume of existing long term STOR contracts that will be available each month. This is derived from the contracted volume within the current long term contracts.
STOR_Availability_Ratio	This is split into separate historic ratios for committed and flexible STOR services, and is the ratio of average available volume to contracted volume.
STOR_Service_Ratio	the ratio of Committed STOR to Flexible STOR.
Avg_Available_Contracted_ Firm_Static_V	the forecast volume of static frequency response procured each month (MW Secondary response provision between periods 15 and 46). This is the average contracted static element of Available_Response_U_HH between settlement periods 15 and 46.
Avg_Available_Contracted_ Firm_Dynamic_V	the forecast volume of firm frequency response procured each month (MW Secondary response provision between periods 15 and 46). This is the average of Available_Dynamic_U_HH between settlement periods 15-46. This was previously referred to as Avg_Available_FFR_V.
LT_STOR_A_C	the forecast availability cost for the long term STOR contracts that have already been let. This is calculated based on the individual contract details including availability price, and is linked to RPI. Availability is assumed to be 100% and the ex-ante RPI is set at 3%

Half Hourly Variable	Definition
Minimum_Dynamic_U_HH	the minimum amount of dynamic response (in MW) required from synchronised, part-loaded units. This is derived from recent operational experience and is reflective of current operational protocols.
Available_Contracted_ Dynamic_U_HH	the forecast amount of contracted dynamic response procured (in MW). This is derived from historic data, NGETs contracting strategy and is reflective of current operational protocol.
FCDM_U_HH	the forecast amount of static response procured via Frequency Control by Demand Management (in MW). This is derived from historic data, NGETs contracting strategy and is reflective of current operational protocol.
IC_Response_U_HH	the forecast amount of optional static response available on interconnectors (in MW). This is derived from historic availability and expected response volumes.
SpinGen_LF_Response_ U_HH	the forecast amount of optional static response available through the SpinGen service (in MW). This is derived from historic data and is categorised by Mon-Fri, Sat, Sun and BST or GMT.
PumpDeload_LF_Response_ U_HH	the forecast amount of optional static response available through the Pump Deload service (in MW). This is derived from historic data and is categorised by Mon-Fri, Sat, Sun and BST or GMT.
Additional_Static_U_HH	the forecast amount of static response contracts (in MW) in addition to FCDM, IC, SpinGen and PumpDeload.
Demand_U_HH	the forecast half hourly demand (in MW).
Demand_Volatility_V_HH	the absolute change in value of Demand_U_HH from one half hour to the next = abs(Demand_U_HH – Demand_U_HH-1)) = 0 for settlement period 1 Where Demand_U_HH-1 is the value of Demand_U_HH for the last half hour.
Reserve_Req_U_HH	the forecast regulating reserve requirement, excluding wind reserve (in MW). This is derived from recent operational experience and is reflective of current operational protocols. Differs based on BST, GMT and Day of the Week.
FEF_NR_PREM	the factor to reflect any premium over and above the Energy Reference Price required to account for the cost of any flipped energy. An uplift factor to reflect the additional cost incurred for this balancing action. This factor is derived from historical analysis of data between 01 April 2015 and 31 January 2017 and is currently set to 1.0.

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 For each Settlement Period, the Net Imbalance Volume is the volume of the overall System energy imbalance, as a net of all System and energy balancing actions (including Balancing Service Adjustment Data/BSAD) taken by the Transmission Company for the Settlement Period. NI_V_HH is the half hourly value of net imbalance volume in MWh, with positive values occurring when the market is short.

Unsync_MEL_V_HH

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

Unsync_MEL_V_HH
$= \text{sum over Units} (\max(0, MEL_{6HA}))$

Where

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

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

NDZ is the time period required to output from time notice is issued (Notice to Deviate from Zero)

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 units that have been made available under the STOR service for the settlement period

10.6 For periods in which missing data was detected, the average of the full historic time series by settlement period per month was used i.e. if period 13 on 1 April 2015 was missing the average of all period 13 from all days in April between 1 April 2011 and 31 December 2016 was used to replace the missing data.

Unsync_Coal_MEL_V_HH

10.7 Unsync_Coal_MEL_V_HH is the total unsynchronised available coal capacity for a half hour.

Unsync_Coal_MEL_V_HH
= sum over Units (max(0, MEL_{6HA}))

Where
PN_{6HA} is the integrated value of the minutely PN (generator output) submissions valid at 6 hours before the beginning of the settlement period (in MWh)
MEL_{6HA} is the integrated value of the minutely MEL (maximum output) submissions valid at 6 hours before the beginning of the settlement period (in MWh)
NDZ is the time period required to output from time notice is issued (Notice to Deviate from Zero)

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 Coal fuelled

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 (Real Time) PN (generator output) submissions (in MWh)
MEL_{RT} is the integrated value of the latest (Real Time) minutely MEL (maximum output) 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

10.10 VWA_OR_P_HHThis is the volume-weighted average price of the volume of the actions taken to meet operating reserve, including STOR (this is an ex-post variable).

EXP_OR_V_HH

10.11 This is the sum of the volume of the actions taken to meet operating reserve, including STOR (this is an ex-post variable).

Footroom_V_HH

10.12 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 (Real Time) PN (generator output) submissions (in MWh)
MEL_{RT} is the integrated value of the latest (Real Time) minutely MEL (maxmimum output) submissions (in MWh)
SEL_{RT} is the integrated value of the latest (Real Time) minutely SEL (minimum output) 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
10.13 Wind_V_HH is the total metered output of settlement metered BMUs that are wind farms (in MWh).

Wind_U_HH
10.14 Wind_U_HH is the total metered output in MW of BMUs that are wind farms, and are modelled in National Grid's Energy Forecasting System (EFS).

IC_Flow_V_HH
10.15 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
10.16 Wind_Volatility_V_HH is absolute 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
10.17 IC_Flow_Volatility_V_HH is absolute change in the value of IC_Flow_HH from one half hour to the next.

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

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

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

10.19 The value of Constraint_Bid_V_HH is calculated by summing the absolute difference in output (MW), for each unit, between the Unconstrained and Constrained model runs by period and dividing by 2.

ER_P_HH

10.20 ER_P_HH is the half hourly energy reference price used for reporting costs and is defined below:

10.21 "Energy Reference Price" (ERP) is calculated as the volume weighted average of most economic 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

10.22 Defined in chapter 11.

Marginal_Fuel_P_HH

10.23 Marginal_Fuel_P_HH is the half hourly price, including the full cost of 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 = API21MON / GBPUSD / 6.97 / 36% + 0.92 * ((ICEDEUA / GBPEUR) + CSP))

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

Where

API21MON, NBPGDAHD, ICEDEUA, GBPEUR, GBPUSD are the values of Bloomberg indices.

CSP is the value of the carbon support price (in £/kg) as set by the government and referenced in **3.9** of the Constraint Cost Target Methodology statement.

Where any of the above indices become discontinued or unavailable, a decision will be sought from Ofgem regarding a suitable alternative and whether it should be applied retrospectively.

Max_Loss_U_HH

10.24 Max_Loss_U_HH is the half hourly maximum credible generation loss (in MW), unwound for any NGET trades or Balancing Mechanism actions.

RoCoF_V_HH

10.25 RoCoF_V_HH is the half hourly shortfall volume (in MW) required to resolve RoCoF calculated from values provided by the constrained run in Plexos (see **7.16** in the Constraint Cost Target methodology statement).

§ 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.

MAB_P_HH

10.26 MAB_P_HH is the most attractive accepted bid price in each half hour.

Monthly Ex-post Variables

RPI

10.27 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

10.28 STOR_A_P is the volume weighted STOR availability price in £/MWh calculated from Flexible STOR and Committed STOR. The price for both services is derived in the same way, using all tenders submitted for that STOR service (Flexible or Committed) for delivery in the target month.

10.29 Separately for committed and flexible providers, the highest priced tender submitted by each STOR unit, across all tender rounds for the target month, is used to create a price stack for the volume of STOR. For committed and Flexible providers the least expensive ***x*** MW of these selected tenders is used to create a volume weighted average price; where ***x*** is the contracted MW defined by (Avg_Available_STOR_V – Avg_Available_LT_STOR_V) / STOR_Service_Ratio / STOR_Availability_Ratio.
Variables defined in **10.1**

STOR_U_P

10.30 STOR_U_P is the derived STOR utilisation price in £/MWh calculated from Flexible STOR and Committed STOR. Using the least expensive tenders from the STOR_A_P calculation, each tender has a corresponding utilisation price. These utilisation prices are used to calculate a volume weighted average utilisation price.

STOR_OOM_U_P

10.31 STOR_OOM_U_P is the monthly STOR out-of-money price calculated as the STOR utilisation price in £/MWh minus the average Energy Reference Price for the month..

Reactive_Default_P

10.32 Reactive_Default_P is the monthly reactive default price as defined in Appendix 1, Schedule 3 of the CUSC, para 2 and 3.

Monthly Ex-post Variables (Derived from Half hourly)

10.33 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
Avg_NI_V	NI_V_HH

10.34 Several monthly variables contain a total of half hourly variables for a month. In all of these cases the total 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
RoCoF_V	RoCoF_V_HH

10.35 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_ Coal_MEL_V	Unsync_Coal_MEL_V_HH	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
OR_V_HH	66.0112	0.301404	-0.02686	-0.05831	-0.0996			
OR_P_HH	52.90683129	-0.004977788	-0.013574913	0.009170334	0.017893446	1.202039766	0.284188712	0.075148916
STOR_V		0.025593212	4.406422					
CMM_V	34568.61	190.6652						
CMM_P	8.625765	-3.07266E-05	0.289899					
BMSU_C	47873.72	49.36228	3217.569					
FRRB_V	-116581.4693	600.6615	53.30897	151.2611	-0.67626			
FRRB_OOM_P		-0.01431270	-0.32608	0.065922				
FRRO_V	65881.63293	0.002319	-24.6518	-1089.8501	-38.76540277	29.89791		
FRRO_OOM_P		6.04E-05	0.367571082					
FRRA_C		-1828.19	409.4375	12885.99	43255.34			
FRB_V	-2959.55							
FRB_OOM_P	30.28262998	-2.05559						
FRO_V		-0.030509372	0.132054	0.014291	-805.287			
FRO_OOM_P	85.91353832	0.611673	-0.73739					
FRA_C	59393885	18.120414	-204180.66					
REAC_Ratio	0.070399743	0.000196	-9.92579E-10	0.003489	0.005948181			
AS_BM_C		-0.006278010						
UN_BM_C		0.063477						

Revisions

Issue	Modifications	Changes to Pages
1.0		