Consultation Document 2/09

National Grid Electricity System Operator Incentives for 1 April 2010

Consultation on Developments of the Incentive for the Energy Related Components of the Balancing Services Use of System (BSUoS) Costs

Version 1.0

Issued 20 August 2009

Responses requested by 18 September 2009

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Section 1

Executive Summary

In 2007 Ofgem trialled a new consultation process for SO incentives by asking NGET to lead on the development of Initial Proposals. Having reviewed the success of this approach, Ofgem has again asked NGET to lead the on the engagement with industry and development of Initial Proposals for SO Incentives to be implemented 1st April 2010.

To enable the development of robust proposals, NGET will publish 'mini' consultations to address specific key issues surrounding the development of multi-year schemes, and the potential for bundled / unbundled schemes.

This consultation addresses the energy related cost components (energy imbalance, margin, footroom, response and fast reserve), which account for approximately 56% of the Balancing Service Use of System (BSUoS) total costs. The aim of the document is to present and seek views from the industry on how the current incentives for these components could be further developed.

Responses to this consultation will be used to inform the development of our Initial Proposals for SO incentives for implementation in April 2010. We aim to consult on our Initial Proposals in October 2009.

The key themes in this consultation are summarised below:

- A number of key drivers impact the costs of the energy related components, some of which may be considered outside of National Grid control.
- The current incentive scheme contains a factor (Net Imbalance Adjustment or NIA) that adjusts the scheme's target to changes in power price and market length. NIA was amended from April 2009 following industry consultation.
- This consultation considers potential further improvements to NIA
- Potential for a longer term incentive scheme.
- Potential to unbundle energy related components into a separate incentive scheme.

Responses to this consultation should be sent to
soincentives@uk.ngrid.com

by 5pm on 18 September 2009

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Section 1
Overview

This section provides an overview of the SO incentives development process being followed for 2010/11 and places this document in the context of the overall incentive development process.

1.1 Introduction

1. National Grid Electricity Transmission (NGET) is the National Electricity Transmission System Operator (NETSO), defined hereon in as National Grid for simplicity. National Grid is subject to a number of financial incentive arrangements which encourage us to minimise the overall costs to consumers and to support the efficient operation of the wholesale electricity markets.

2. National Grid is incentivised to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives enables National Grid to invest in systems and resources to ensure balancing costs and risks are economically and efficiently managed.

3. The incentive scheme provides a focus on key areas where National Grid is able to create value for the industry and consumers, allowing National Grid to retain a share of any value created or to bear a share of the costs should targets not be met.

4. These incentives are designed to deliver financial benefits to the industry and consumers from reductions in the costs associated with operating the national electricity transmission network.

5. Via an open letter, published on 28 May 2009[1], Ofgem has asked National Grid to lead on the development of initial proposals for the implementation of System Operator (SO) incentives commencing April 2010. The letter summarises Ofgem's views on the objectives, process and timetable for this year's process and topics for this year's consultation. National Grid's response to this letter can be found on the National Grid website[2].

6. In their letter, Ofgem recognise the valuable contribution made by the industry in developing the incentive scheme implemented in April 2009 and go on to state that they are keen to further promote engagement from industry participants, end customers and smaller suppliers in this year's process. In response, National Grid has presented at a number of industry meetings and arranged bilateral discussions with interested

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[1] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Open%20Letter%20final.pdf

[2] http://www.nationalgrid.com/NR/rdonlyres/D68DE8C6-DB21-4513-B60E-98B3AE709305/35809/SOInitialProposalsTimetableNGOpenLetter.pdf

parties to highlight the issues for this year's consultation. A generic copy of the slides used at these meetings can be found on our website.[3]

7. If you would like National Grid to present at any future meeting or would like to meet on a one to one basis to discuss this year's consultation, then please contact us using the contact details at the end of this document.

8. As outlined in Ofgem's open letter, there are a number of key issues that need to be addressed to develop robust Initial Proposals. We intend to break down these issues by publishing a number of mini consultations. National Grid will be issuing three independent mini consultation documents this summer on the development of SO incentives; the focus of each document is summarised below. Each document will have a four week consultation period.

Document	Topics
1	Reactive power, transmission losses and black start
2	Energy (including margin, response, etc.)
3	Constraints

9. The consultations have been split in this way as we believe these topics are to a significant extent standalone and they will benefit from separate consideration. Within each of the mini consultations, we will focus on the reasons for whether it would be appropriate to unbundle the specific components, if there are appropriate external measures to use for adjustments and the suitability or otherwise of multi year schemes. The mini consultation documents will not contain detailed proposals for SO incentives schemes to apply from 1 April 2010. They are intended to invite industry views on a range of issues that might drive the form and structure of incentive schemes.

10. These three consultations cover the majority of Balancing Service Use of System (BSUoS) costs. This consultation document is the second of our proposed consultations and addresses the energy related cost components (energy imbalance, margin, footroom, response and fast reserve). The aim of the document is to present and seek views from the industry how incentives for these components could be further developed.

11. In addition to these three consultations, we are currently considering the development of arrangements that better align the SO and TO incentives on managing constraints. We are planning to publish a consultation on this in September.

[3] http://www.nationalgrid.com/uk/Electricity/soincentives/AnalystArea/

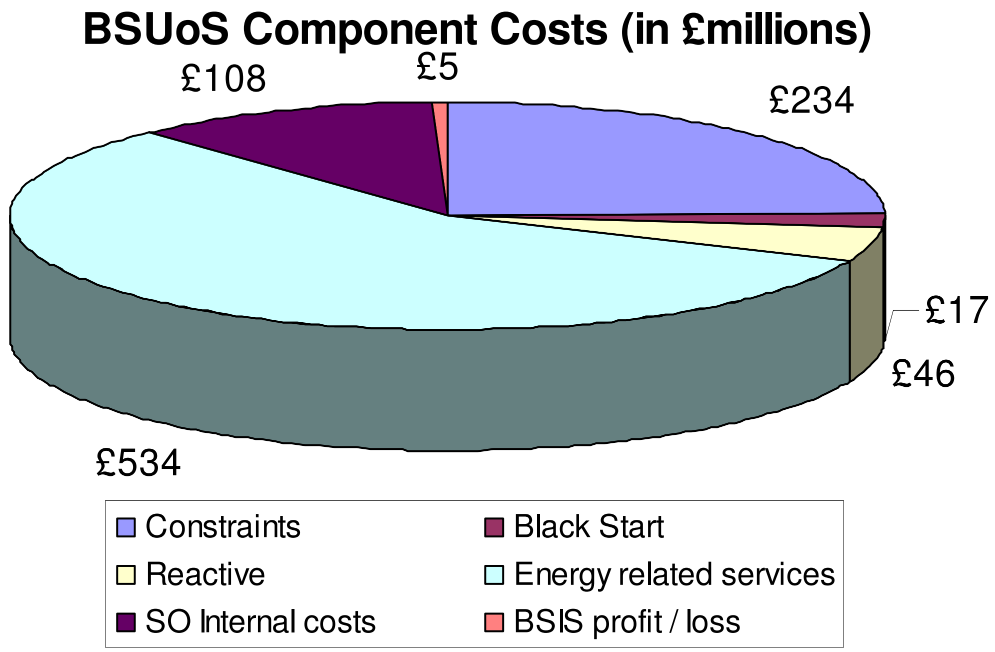

Figure 1 - 2009/10 BSUoS cost forecast (as at July 2009)

12. Figure 1 shows the relative costs of each of the components that make up the BSUoS cost forecast for 2009/10 (approximately £944m). It can be seen from this that the Energy related cost component accounts for approximately 56% of the Balancing Service Use of System (BSUoS) total costs.

13. This document is structured as follows:
    - Section 2 sets out the current incentive arrangements
    - Section 3 introduces the main cost drivers for energy related components
    - Section 4 presents an overview of development options to the incentive scheme
    - Section 5 provides a summary
    - Section 6 lists the consultation questions
    - Appendix A – detailed analysis of Net Imbalance Adjustment (NIA) options
    - Appendix B – detailed explanation of each component
    - Contact Details – has the gas and electricity contact information

14. The outputs from this consultation, along with feedback received through discussions with industry and Ofgem, will be used to develop our Initial Proposals for incentives to apply from 1 April 2010. Our aim is to issue an SO Incentives Initial Proposals consultation in October 2009.

15. On conclusion of the Initial Proposals consultation, National Grid will issue a consultation report incorporating the responses received from interested parties which will be published on our website. The report and all responses will be sent in full to Ofgem. In early 2010, Ofgem will

then develop and consult on its Final Proposals for SO Incentive schemes, prior to implementation.

16. Below is a high level outline of the proposed timetable.

Process Milestone	Proposed Date
Publication of 'mini' consultation documents	July/August 2009
Publication of Initial Proposals	October 2009
Industry event / workshop	November 2009
Ofgem to provide initial comments	November 2009
Initial Proposals consultation period closes	December 2009
Ofgem consultation on Final Proposals	Early 2010
Scheme go live	April 2010

17. Responses to this consultation will be published on National Grid's website (unless a specific request is made not to) and all responses will be sent in full to Ofgem. Responses to this consultation are requested by 18 September 2009.

Responses to this consultation should be sent to
soincentives@uk.ngrid.com

by 5pm on 18 September 2009

Section 2
Current Incentive Arrangements

In this section we set out a high level overview of the current SO incentive scheme, the benefits and drawbacks of such a scheme and the aims of the incentive development.

2.1 Overview

18. National Grid is incentivised to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives enables National Grid to invest in systems and resources to ensure balancing costs and risks are economically and efficiently managed.

19. The Balancing Services Incentive Scheme (BSIS) is designed to deliver financial benefits to the industry and consumers from reductions in the costs or minimising risk associated with operating the electricity transmission network. The current BSIS incentive format has been in place since NETA implementation in 2001

20. The scheme has been designed to allow National Grid to retain a share of any value created or to bear a share of the costs should targets not be met.

21. The current balancing incentive combines all balancing components (i.e. constraints and reserve, amongst others) into a single bundled scheme with overall performance dependent on the management of all aspects of the bundled components.

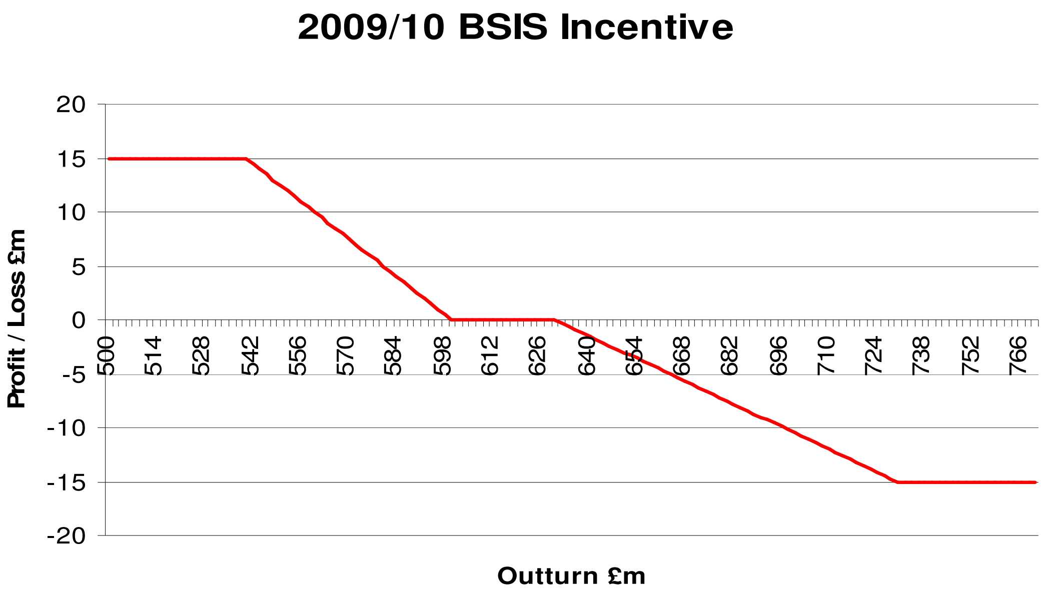

Figure 2 - BSIS Profit / Loss Profile

22. Figure 2 shows the current incentive arrangements. For changes in BSIS costs away from the target, the industry and National Grid share in the benefits or disbenefits.

23. Balancing services procured by National Grid are split into the following categories:
    - Constraints
      Balancing services used to manage system flows
    - Energy related services
      Services used balancing generation and demand. This includes frequency response and reserve as well as final balancing of generation and demand
    - Reactive Power
      Services used to manage system voltages
    - Black Start
      Services used to re-energise the system in the event of a total or partial system shutdown
    - Transmission losses
      The energy lost in the transmission of power across the system

24. Changes in each cost component feeds into the overall BSIS incentive cost pot. To achieve an overall incentive profit, the overall summated costs across all areas must be below the incentive target.

25. Figure 3 shows the relative cost of each of the incentivised balancing components.

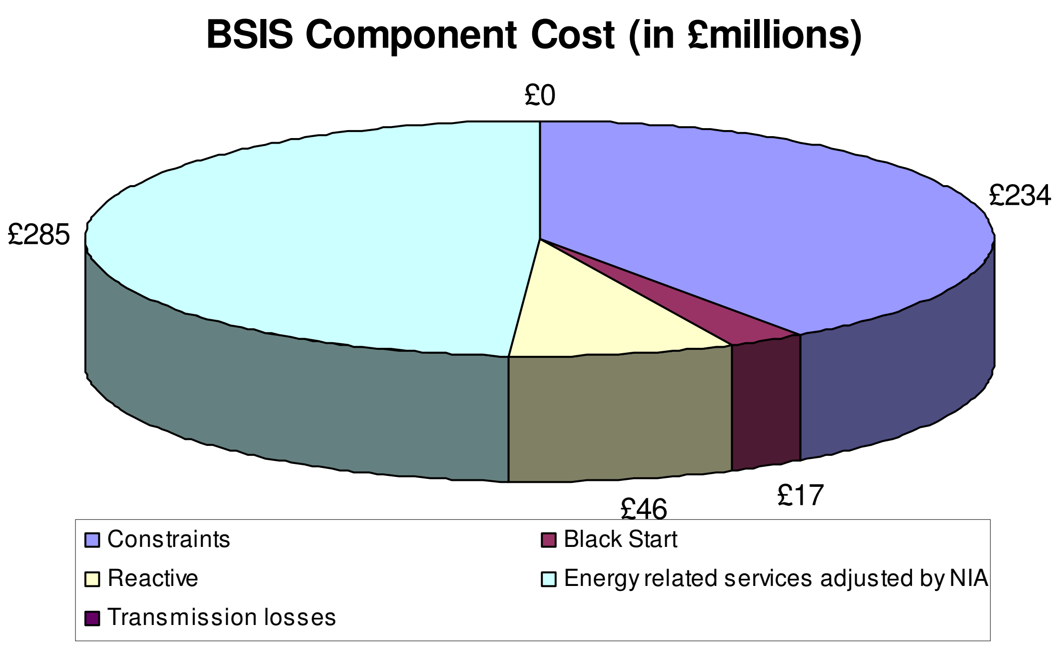

Figure 3 - 2009/10 BSIS cost forecast (as at July 2009)

26. BSIS, which is presently forecast at £582m and BSUoS, as would be expected, share a number of components. To move from BSIS to

BSUoS (as detailed in Section 1, Figure 1) the following elements need to be added:

- The Net Imbalance Adjustment (NIA) is an adjustment used in BSIS with respect to the energy 'component' for changes to market length and wholesale power prices. This is presently forecast at £249m
- SO internal costs relates to National Grid's costs associated with its SO activities, such as building, staff and IT costs. These costs are also incentivised with the scheme comprising of an 'incentivised' element and a 'non-incentivised' element, which passes through certain of National Grid's costs. The latter consist of costs that National Grid cannot control for example business rates. The overall internal forecast is presently at £108m
- Transmission losses adjustment, as further described in the first mini consultation. This is presently forecast at £0m
- Profit or loss from BSIS. This is presently forecast to be £4.5m profit for 2009/10. This is National Grid's share of the reduction in incentivised costs; currently forecast to be £33m below the BSIS target. Figure 2 provides further detail on how this share is calculated.

2.2 Features of the Current Bundled Scheme

27. The current BSIS incentive is a bundled scheme that places incentives on all cost components in a single pot. There are a number of benefits of a bundled scheme:
    - Interaction between components
      When taken balancing actions, there may be more than one service that the action can be attributed; e.g. when synchronising a generator to resolve a constraint issue, the generator may also be able to supply reserve and frequency response services. Allocating costs to each component is performed via a set of rules. In a bundled scheme these rules do not impact on the overall incentive performance.
    - Overall focus on driving down costs where most benefit can be achieved
      A bundled scheme generally focuses attention areas where National Grid can most drive value to the consumer.
    - Simpler to manage and administer
      A fully bundled scheme is generally easier to monitor and determine the overall direction of balancing costs.

28. Whilst there are a number of benefits of a bundled scheme as outlined above, there are a number of disadvantages of such a scheme. Some of these disadvantages are highlighted below:
    - Different risk profiles for each cost component
      The bundled scheme incentives National Grid to minimise overall balancing costs. However, due to the interaction between each cost component and their drivers, there will be different risk profiles for each component cost. This risk profile differential cannot easily be reflected in the overall scheme.

- Impact on the overall scheme for changes in one cost component
  A bundled scheme means that increases in costs in one component due to unforeseen changes (e.g. constraint costs) impacts on the overall scheme, reducing or removing the reward for cost reductions in other components.
- Inability to create specific focus on areas of greatest concern to the industry, regulator and government
- Potential barrier to longer-term schemes
  Certain components may not easily lend themselves to a longer-term scheme at present, such as constraints due to uncertainties around Transmission Access Reform. The development of longer term schemes may be able to be developed by unbundling certain components or by implementing separate adjustment methodologies for each component of the bundled scheme.

2.3 Features of a one year scheme

29. Currently the BSIS target is agreed and implemented on a one year scheme. Therefore each year, a revised target is agreed.

30. There are a number benefits in the current one year scheme:
    - Accuracy of forecast
      The development of a robust yearly BSIS and BSUoS forecast is dependant on a number of external drivers such as power price. A yearly scheme is better able to adapt a revised forecast and hence updated target rather than a scheme of longer than one year duration.
    - Ability to reflect market changes
      For market changes that impact balancing costs (such as Transmission Access), a yearly (or a shorter) scheme is more able to reflect these changes than one of a longer duration.

31. Although there are a number of benefits associated with a one year scheme, there may be benefits in changing the duration of the incentive:
    - Accuracy of forecast
      A shorter scheme length would improve the accuracy of the forecast e.g. for a 6 month scheme, there would be more certainty of assumptions than for a year long scheme or for a scheme of longer duration
    - Consideration of investments in cost reduction with a longer than one year payback
      A scheme that has a duration of longer than one year would increase focus on investments that have a longer than one year payback
    - Regular oversight
      A scheme of shorter duration provides the opportunity for more regular oversight and review of performance with the ability to adjust the scheme accordingly
    - Targeting of costs to specific aims
      A change in duration of the incentive arrangements may facilitate the implementation of more specific aims and objectives, such as, a

shorter term scheme focusing attention on minimising costs over a shorter period (e.g. constraint costs over the summer outage period) where as a longer term scheme may better facilitate the aim of attracting new entrants.

32. The continuation of a one year scheme or the move towards a shorter or longer incentive timescale has both benefits and risks. These factors need to be considered when deciding on what scheme duration is best to implement.

33. To develop a longer-term incentive scheme it is necessary to consider the appropriateness of the unbundling of components and the further use of adjustments. Unbundling and enhancing the use of adjustment factors will ultimately result in increased governance and complexity. In addition, an unbundled scheme may divert valuable resources from key areas into incentive areas where there is less impact to the consumer. Therefore, the development of adjustment factors and unbundling will need to ensure that the risk / rewards are proportional to the benefit derived for the industry and the consumer.

2.4 Summary

34. The current BSIS incentive format has driven investment in cost reduction by National Grid that has provided considerable benefits to the industry in managing costs and risk.

35. There are a number of benefits that are provided by such a scheme as highlighted above. In addition, the current scheme is familiar to the industry and provides a simple year on year comparison of costs.

36. In line with the priorities set out in Ofgem's open letter, National Grid aim to explore longer-term incentive schemes. When considering the incentive development, National Grid and the industry must consider the benefits for such changes over and above the current arrangements.

37. Currently NIA adjusts the incentive target to changes in market length and power price. Within this consultation, we consider potential development to the incentive scheme, focusing on energy related cost components (energy imbalance, margin, footroom, response and fast reserve), including the improvement of NIA, implementing a longer-term incentive scheme and unbundling such components from the rest of BSIS.

> Question 1 – Are there any other risks or benefits associated with the existing 1 year bundled scheme?

Section 3
Components Cost Drivers

This section introduces the energy related cost components of the Incentive Scheme and presents our best view of drivers for those costs. This is a descriptive section and not the forecast. The forecast will be covered in the initial proposal.

3.1 Introduction

38. The Balancing Services Incentive Scheme (BSIS) is formed by the main following components, representing actions taken by National Grid in our role as system operator:

- Energy Related Components
- Constraints
- Reactive
- Other components (including Black Start and Transmission Losses)

39. Costs for operating the system are classified (e.g. split between energy and constraints, etc) according to our internal Balancing Actions Autopsy Report (BAAR) costing methodology. The scope of this consultation is on the components related to energy which are used to manage the system frequency.

3.2 Overview of the energy related cost components

40. Energy related components refer to the costs incurred by National Grid to balance generation and demand, maintaining the system frequency at 50 Hz. Excess of generation causes frequency to increase, while lack of generation causes frequency to collapse.

41. To manage system frequency, National Grid utilises a number of different services:
    - Energy Imbalance costs are incurred by National Grid by taking bids, offers in the Balancing Mechanism and by trading power in the wholesale market in order to ensure demand and generation are always balanced;
    - Margin costs are incurred when National Grid synchronises additional units into the system in order to ensure that the Short Term Operating Reserve Requirements (STORR) are met. STORR are set so that there is only a 1 in 365 risk of demand not being fully met by generation in the unlike combination of significant plant losses with higher than expected demand levels
    - Footroom costs are related to de-synchronisation of units by National Grid to maintain the flexibility of being able to reduce generation in the event of lower than expected demand levels

- Response costs are incurred by National Grid to instruct providers (generators and demand units) to act in a frequency responsive mode, i.e. changing their output or outtake automatically according to the system frequency or manually following direct instruction from National Grid
- Fast Reserve cost relate to the use of generation and demand units with enhanced dynamic capabilities, utilised in periods with high rate of changes in demand and generation (such as TV pick-ups).

42. More detailed explanation of each cost component can be found in Appendix B and at National Grid's website: http://www.nationalgrid.com/uk/Electricity/Balancing/services/.

3.3 Cost drivers

43. National Grid is incentivised through the BSIS to reduce the cost of operating the system. Such costs are dependent on a number of factors, each with different degrees of predictability, volatility and controllability by National Grid. This section outlines the main cost drivers, with a brief description and our view on how controllable, predictable and volatile they are.

44. The cost of energy component actions are the result of the volume of services required and the price of these services. Their main drivers are:
    - Electricity market price
    - Balancing Mechanism prices
    - Ancillary Services Contracts
    - Volume of Wind generation
    - Level of market imbalance (market length)
    - Generator availability and operating regimes
    - Volume of services required to maintain system security levels

3.3.1 Electricity market price

45. One important driver of the costs incurred by National Grid to manage the system's frequency is electricity market price. Impacts of market price include pre-Gate trades, BM actions and the volume and direction of flows across the Anglo-French interconnector.

46. Whilst the prices to which National Grid is exposed have a half-hour granularity, the current incentive target is based on forward power price forecast that is up to 16 months ahead. Utilising forward market price curves have the advantage of using a relevant external, transparent and well understood market based index. However, the uncertainty of power prices introduces a risk into the forecast and can also lead to windfall gains and losses for changes in power price outside the forecast.

47. Figure 4 illustrates the accuracy of forecasting forward prices over time. The range has been developed comparing forward power prices and day ahead price. The P90 and P10 lines indicate the statistical boundaries for the accuracy of forecast power price when compared to the day

ahead power price. There is a 10% chance that day ahead price will be below the P10 range and a 10% chance that the day ahead price will be above the P90 range. Therefore, there is an 80% chance that the day ahead price will be within the P10 – P90 range. As can be seen, the range of day ahead power prices when compared to the year ahead forecast increases the farther ahead the forward power price forecast has been developed. The graph indicates that:

a. at 4 weeks ahead the ability to forecast power prices accurately sits within a range of around +/-20% of actual prices
b. at 16 weeks ahead (approximate time between of the year ahead 'final forecast' and the start of the incentive scheme), the ability to predict forward power prices is only +50% / -30%

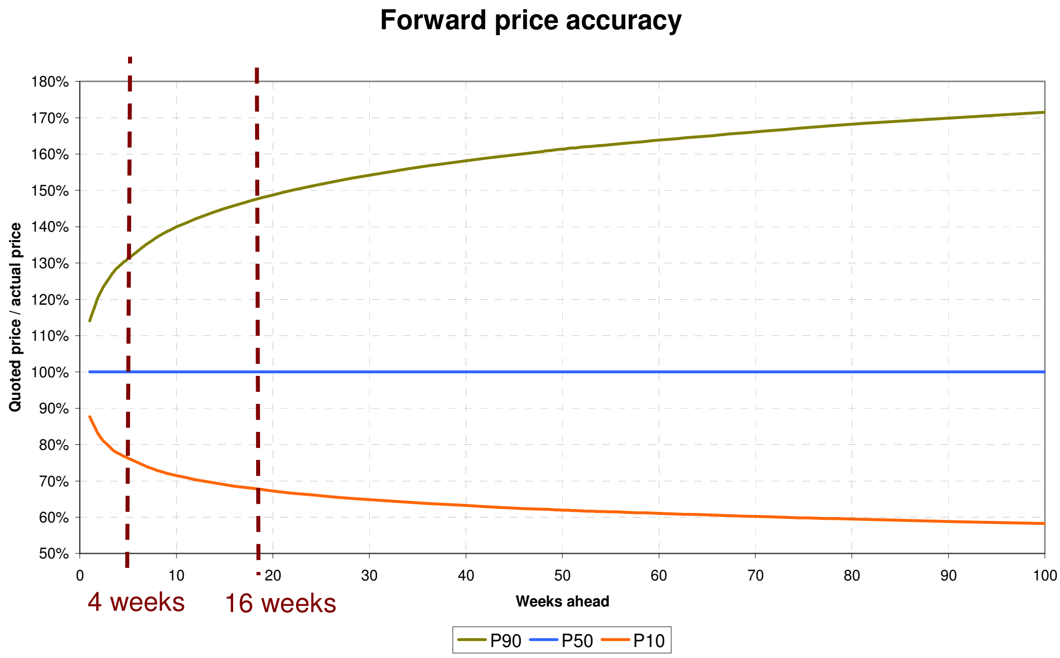

Figure 4 - Volatility of power price forecast

48. The actual power price which National Grid is exposed to present a significant volatility. Figure 5 illustrates the volatility of half-hourly, mean daily and mean monthly power prices (SPNIRP)[4]

[4] SPNIRP, as defined in NGET transmission licence, is the Single Price Net Imbalance [volume] Reference Price for each settlement period

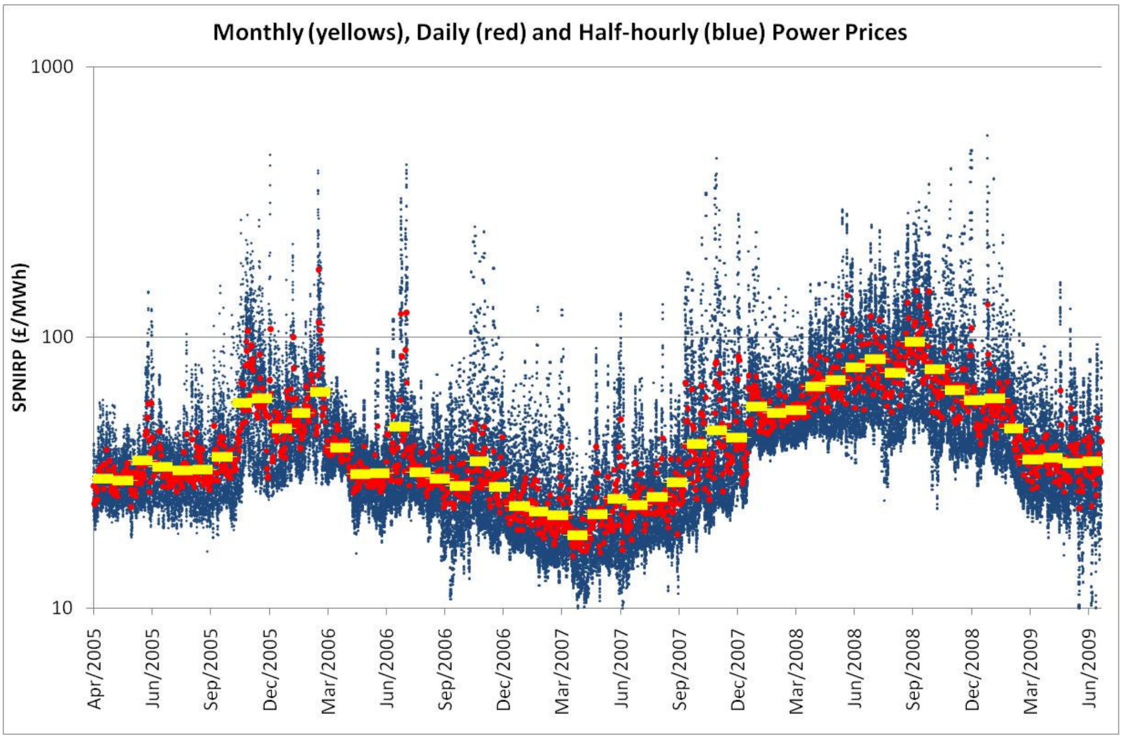

Figure 5 - Power price volatility, as represented by SPNIRP

49. It can be seen that the risk of forecasting power price is directly related to the time between the forecast and real time. This demonstrates the difficulty for National Grid in accurately forecasting wholesale power prices at the year ahead stage.

3.3.2 Balancing Mechanism prices

50. Prices in the Balancing Mechanism (BM) directly impact on the costs of balancing actions taken in the BM and (indirectly) pre Gate closure.

51. The average Bid and Offer prices accepted in the BM depend upon:
- the Bid and Offer prices submitted (which reflects the degree of competition in the BM as well as generators' behaviour); and
- the volume of actions taken to balance the system

52. Figure 6 below shows the ratio between volume weighted average accepted BM Offer and Bid prices and the prevailing electricity market price.

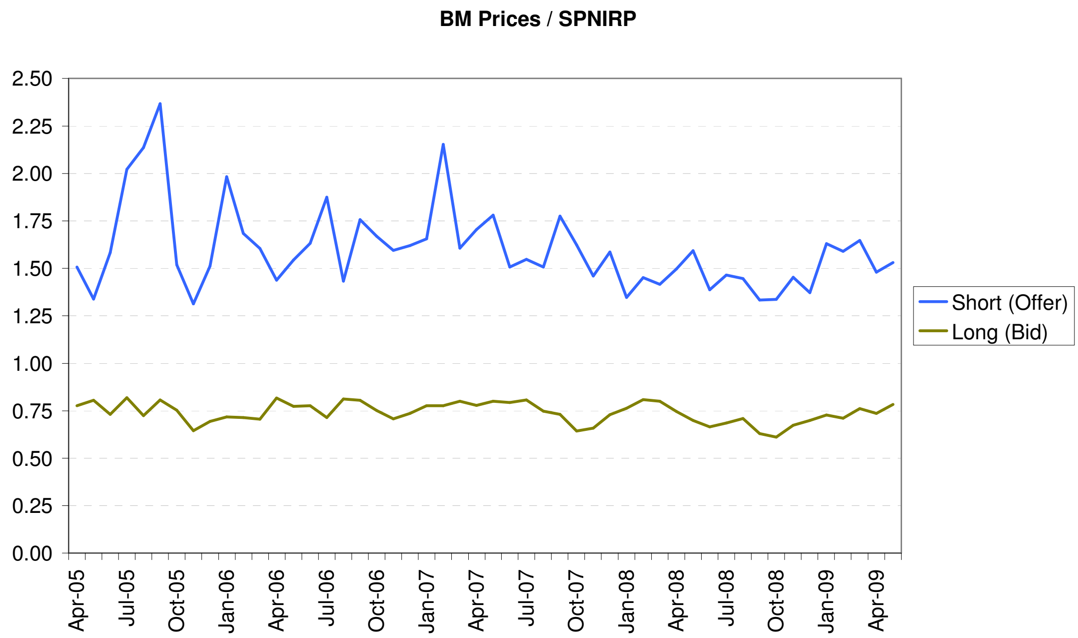

Figure 6 - Ratio between BM prices and Power Price

53. As can be seen, there is a strong (and relatively stable) relationship between power prices and BM prices, meaning that any uncertainty and volatility associated with power price (as pointed out previously) will directly reflect in a similar level of uncertainty and volatility in the BM prices.

3.3.3 Ancillary Services Contracts

54. Ancillary Services (AS) contracts for the provision of Margin (Short Term Operating Reserve (STOR) contracts), Response (mandatory and commercial response services) and Fast Reserve are assessed against the relevant economics when compared with their alternatives.

55. National Grid can develop the terms and procurement methods for these ancillary service contracts to create efficiencies in the provision of these services and to encourage competition. National Grid constantly reviews market arrangements to ensure a wide range of options are made available for managing the system. Indeed National Grid has recently completed a review the STOR, Fast Reserve and Firm Frequency Response services, specifically making changes to better facilitate longer-term services and demand side provision.

56. The contract is dependant on the provider submitting suitable prices and terms and these being accepted by National Grid. Therefore, National Grid has control over the acceptance of contracts and can influence this cost driver. National Grid is subject to changes in the bidding behaviour of submitted prices from service providers. These may be influenced by the level of competition for the services, underlying cost drivers (e.g. maintenance costs), fuel prices and, changes to service terms and conditions.

57. As shown in Appendix B (Figure AP.26, Figure AP.28 and Figure AP.29), the volume of services procured via Ancillary Services contract vary through the years. As mentioned previously, the volume of contracts depend both on the number of providers, the system requirements and on the relevant economics assessment against available alternatives.

3.3.4 Volume of Wind generation

58. Increased wind output and the corresponding greater generation intermittency places greater balancing costs on both market participants and National Grid. How this burden falls between National Grid and the market depends on the incentives (efficient avoidance of imbalance charges) to do so and the market's ability to forecast wind output and balance its own position. At current relatively low levels, it is still difficult to clearly quantify the impact of intermittent generation in the balancing costs. However, the level of wind generation is forecast to rise significantly over the next 2 years, more than doubling the current levels.

59. While increased renewable generation is likely to have benefits from a carbon perspective, from a balancing perspective higher densities of wind generation will lead to an increased volatility for forecasts of plant output at all lead times. This increased unpredictability of plant output impacts most of the activities National Grid undertakes to balance the system.

60. All energy related products will be affected as the wind penetration level becomes more significant, but margin costs are likely to be specially affected in the near term. This is due to the fact that, with greater uncertainty of generation output, it will require National Grid to hold greater levels of margin. The geographic location of these wind farms only affect the energy related products on the sense that more disperse wind farms tend to reduce the overall wind generation volatility, with a positive effect on the margin requirements. This impact is further considered in our consultation on Operating the Electricity Transmission Networks in 2020[5].

61. The risk of forecasting wind power generation creates the possibility for limited windfall gains or losses due to unforeseen conditions.

3.3.5 Market length

62. The amount of actions taken by National Grid, especially in terms of Energy Imbalance and Margin, are directly affected by the market imbalance level, i.e. the difference between contracted and actual demand. For example if the market is long (excess generation to demand) then National Grid will require fewer margin actions than in a short market.

[5] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/2020+Consultation.htm

63. Market length is dependent upon the demand expectation from generators and suppliers, their respective contracting strategies and the market incentives (efficient avoidance of imbalance charges). National Grid forecast market imbalance levels when setting the incentive's cost targets however, this is done with some uncertainty.

64. The uncertainty in market length forecast can be divided in two areas: the expected mean value and the expected half-hourly volatility.

65. Figure 7 demonstrates the uncertainty of forecasting a mean value or market length. The blue line shows the monthly value along with some milestones that may have had an impact on market behaviour (e.g. p78 was a change to the imbalance price calculation), the black line is the 3-month moving average. The graph uses negative TQEI[6] to represent market length, since most industry participants are more familiar with this measure[7].

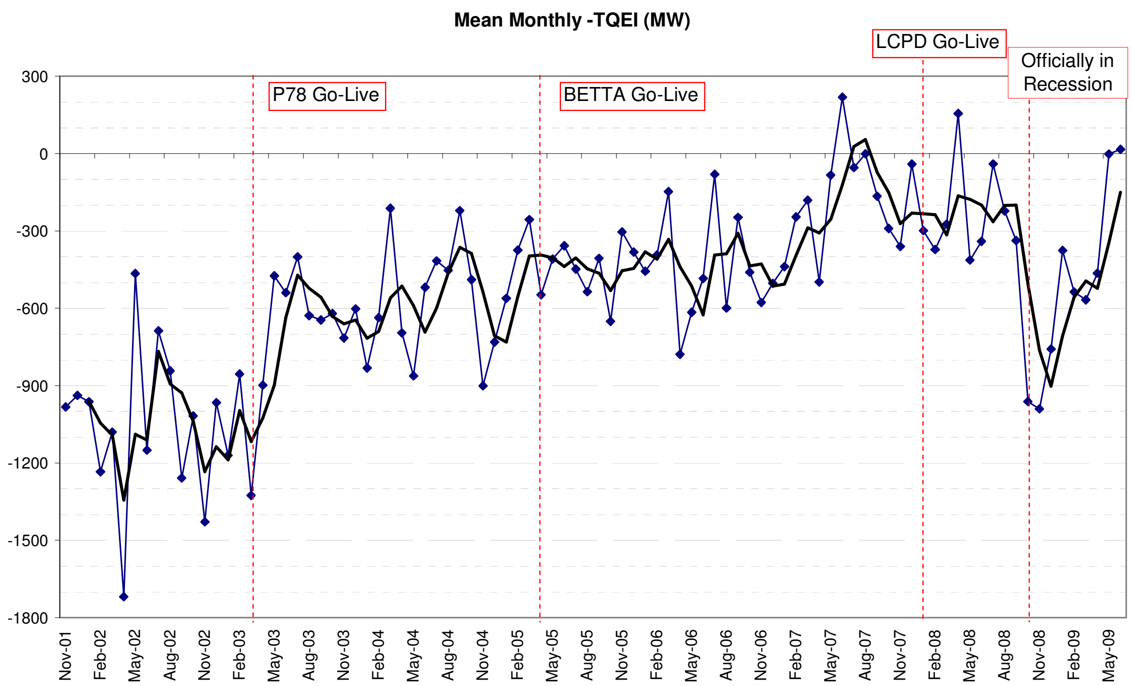

Figure 7 - Trajectory of market imbalance, as represented by mean TQEI

66. Apart from the unpredictable nature of the mean value of market length, the values to which National Grid are actually exposed to have a half-hourly granularity with significant volatility, as illustrated in Figure 8.

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[6] TQEI, as defined in the Balancing and Settlement Code, is the Total System Energy Imbalance Volume

[7] In reality, most industry participants are more familiarised with NIV, Net Imbalance Volume, which can be approximated by negative TQEI

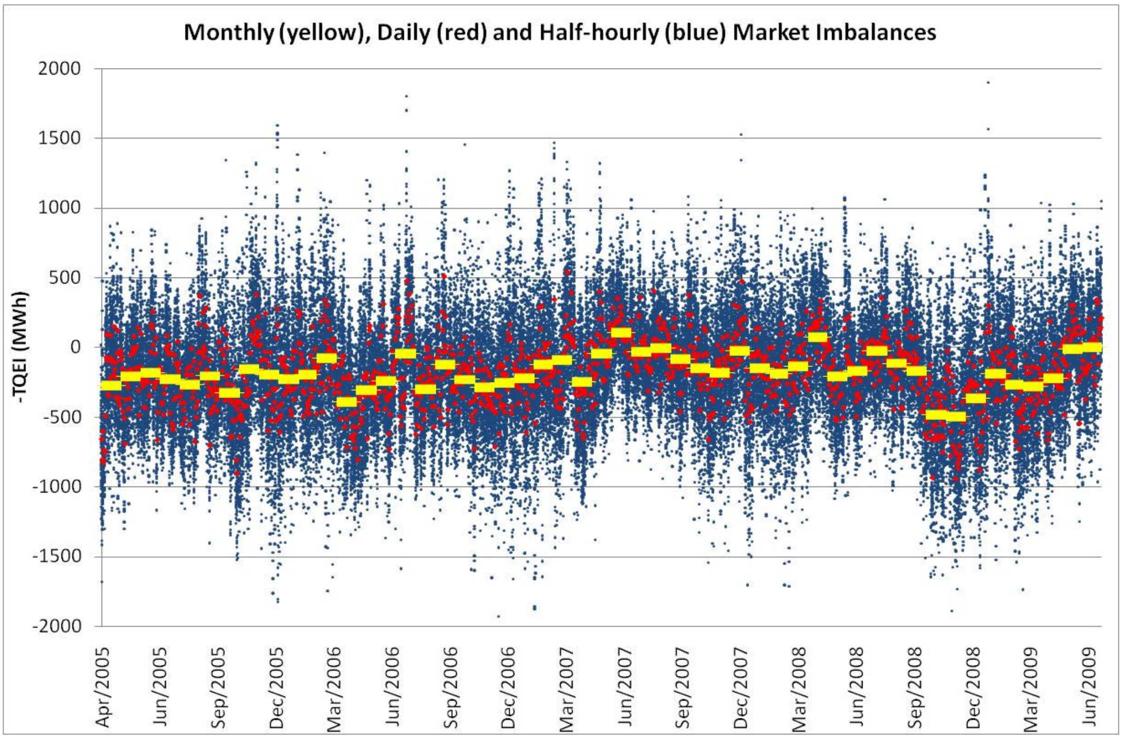

Figure 8 - Volatility of market imbalance

67. It can be seen that the difficulty for National Grid in accurately forecasting market imbalance can generate limited windfall gains or losses due to unforeseen conditions.

3.3.6 Generator availability and operating regimes

68. The availability of certain generators, especially inflexible ones as Nuclear and Wind, allied to changes in operating regimes as result of regulatory conditions (such the Large Combustion Plant Directives, LCPD) and the impact of changing fuel prices can and do affect the system conditions. For instance, under the LCPD there is approximately 8.5 GW of opted out[8] coal plant that has significantly changed its operating regime and, in the longer term, those generators along with additional 3.5 GW of oil plants are due to close by 31st December 2015 (totalling 12 GW of plant closures).

69. Two extreme situations can be described to illustrate the effect of generation availability and changing operating regimes. On one extreme, the combination of low demand periods (such as summer overnight), high inflexible (nuclear and wind) generation and the self-positioning of flexible generation at minimum levels rather than desynchronising[9] causes a situation whereby there is insufficient flexibility to reduce generation to meet demand levels and therefore balance the system. As

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[8] Under LCPD, coal and oil plants had two basic options:

- Fit Flue Gas Desulphurisation (FGD), thus being allowed to run as usual ("opt in"); or
- Continue to run with a limited life derogation, with 20,000 hours of operation between 1st January 2008 and 31st December 2015 ("opt out")

[9] Possibly due to wear and tear on plant and the increased risk of start up failures the next morning

a result National Grid is required to de-synchronise units at high Footroom costs.

70. Conversely, low Nuclear generation availability and generation subject to LCPD rules not running (LCPD rules places a strong incentive to run all generation units together) has historically seen a reduction in the amount of margin inherent on the system, known as headroom. As a result, the volume of actions taken by National Grid to procure operating reserve increases.

71. The uncertainty of generation availability and operating regimes is limited by National Grid's ability to accurately forecast prevailing market conditions. The ability of National Grid to accurately forecast the required volume of actions results in limited windfall gains or losses due to unforeseen changes.

3.3.7 Volume of services required to maintain system security levels

72. The volume procured for certain services depend on the requirements of the National Electricity Security and Quality of Supply Standards[10]. For instance, the largest infeed loss in the system (both in the generation and in the demand side) dictates the amount of frequency responsive units required to secure the system. In the longer-term the largest infeed loss is likely to increase as a larger generating units connect to the system.

73. Additionally, National Grid sets Short Term Operating Reserve Requirements (STORR) according to a statistical analysis process that seeks to ensure that the risk of loss of supply is lower than 1 in 365. These requirements are set depending on the level of demand forecast error, plant loss frequency, wind forecast error, etc.

74. Therefore, whilst the volume of certain services are dependant upon the requirements set in industry codes in order to ensure desired system security levels, some proportion can be controlled by National Grid through the continuous assessment of system conditions and optimisation of internal processes.

[10] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/

Question 2 – Have all cost drivers been captured and correctly identified as being within or outside National Grid control?

Question 3 - Do you consider that there are elements within these cost drivers that are within National Grid control? What are these and how do you believe these should be considered going forward?

Question 4 – Do you agree that Energy Imbalance, Margin, Footroom, Response and Fast Reserve share the same cost drivers and should be considered together as the Energy component?

3.3 Summary

75. This section introduced the energy related cost components of the Incentive Scheme and presented our best view of drivers for such costs.

76. The level of inflexible generation (specifically wind), wholesale electricity prices and market length are drivers that may be considered as unpredictable, volatile and as being outside National Grid's control to accurately forecast. However National Grid has the ability to use Ancillary Services Contracts which can provide a hedge against these drivers, and can minimise costs, as drivers influence, via dispatch tools and contract strategy.

77. When considering the development of an appropriate incentive, the development of adequate adjustment factor needs to be considered to remove the potential for windfall gains and losses as a result of inaccurate forecasts when setting appropriate incentive targets.

Section 4
Incentive Development Options

This section presents our view of options for improvement to the incentivisation of the energy related components, including improvements to NIA, unbundling and longer-term incentives.

4.1 Introduction

78. The current incentive scheme is a one-year, bundled scheme with an adjustment factor for changes in power price and market length. Developments to the current incentive scheme, focused on the energy related components, may be possible through improvements to the current adjustment factor, the introduction of longer term incentive periods and the unbundling of the energy related components into a separate incentive scheme.

4.2 The role of the adjustment factor

79. Section 3 covered the main drivers for energy related products costs. There are a number of drivers that National Grid can control or is able to forecast. However, there are a number of drivers that National Grid is unable to control or accurately forecast.

80. To manage these external drivers that are outside the direct control of National Grid or cannot be accurately forecast, it may be appropriate to develop an adjustment methodology that updates the cost target in line with fundamental changes to the assumptions agreed at the time of the original forecast.

81. There are a number of possible benefits from the development of an improved adjustment methodology:
    a. limits the potential for windfall gains and losses associated with changes to external factors outside the control of National Grid
    b. appropriately targeted incentive based on cost drivers within the control of National Grid
    c. enable the develop of a longer term incentive

82. Any changes to the adjustment factor should not have an impact on any other BSIS cost drivers and, if possible, not be overly complex to implement.

Question 5 – Do you agree with the need for an adjustment factor to mitigate the risk of variations to cost drivers outside National Grid control?

4.3 The Net Imbalance Adjustment Factor (NIA)

83. In the current scheme format, NIA adjusts the overall BSIS target for the impact of changes in power price and market length on the cost of procuring energy related products.

84. NIA has been in place since the start of NETA and had been reviewed for the start of the current incentive scheme after industry consultation last year[11]. It is designed to adjust incentivised costs (i.e. BSIS), with respect to the energy 'component', to changes in power price and market length. For 2009/10, the NIA component is forecast to be approximately £250m using forecast power price and market length. The outturn will depend on actual power prices and market length.

85. NIA is described in National Grid's transmission licence definition of IBC (Incentivised Balancing Costs):

$$IBC = CSOBM + BSCC + TLIC + NIA$$

Where:

CSOBM – this is the Cost of System Balancing Mechanism, i.e. total costs of all Balancing Mechanism actions

BSCC – this is the Balancing Services Contract costs, i.e. all commercial and ancillary service contract costs, including trading

TLIC – is an adjustment based on performance against transmission losses target

NIA – adjustment to reflect the costs that are dependent on market length and wholesale power prices

86. Up to the 2009/10 incentive year, NIA was calculated as:

0.5 x SPNIRP x TQEI for long market periods (generation > demand, such that National Grid took more bids than offers); and
2.5 x SPNIRP x TQEI for short market periods (demand > generation, such that National Grid took more offers than bids)

where
SPNIRP is Single Price Net Imbalance [volume] Reference Price, calculated according to the transmission licence
TQEI is the Total System Energy Imbalance Volume as defined in the Balancing and Settlement Code

87. For the incentive year 2009/10 a new formulation for NIA has been introduced, recognising that the previous formulation did not cater for costs incurred by National Grid when the system was close to balance. The 2009/10 NIA formulation is as follows:

450 x SPNIRP + 0.9 x SPNIRP x TQEI, for long market periods; and

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[11] http://www.nationalgrid.com/NR/rdonlyres/E1C3C89D-1F71-467D-A052-C204B29C7F04/28024/Indexationconsultationdocument_posted.pdf

450 x SPNIRP + 1.25 x SPNIRP x TQEI, for short market periods.

88. The main improvement in representing the costs incurred was the offset obtained with the term 450 x SPNIRP, allowing for the recovering of costs when the system is close to balance. This improvement reduced National Grid exposure to the risk of significant changes in incentivised costs caused by minimal changes in market length around the balanced position (zero NIV). As such, a scheme that better reflected the risk profile and better incentivised National Grid to pursue cost reductions in controllable areas could be agreed.

89. The graph below compares the previous NIA formulation, the current NIA formulation and the actual costs incurred by National Grid. Black dots represent half-hourly costs for different market imbalance levels, the blue line is NIA pre 2009/10, and the red line is current NIA. A good adjustment factor would be represented by a best fit line within the dots. As can be seen in the graph, the mentioned offset brings NIA closer to the core of the black dots.

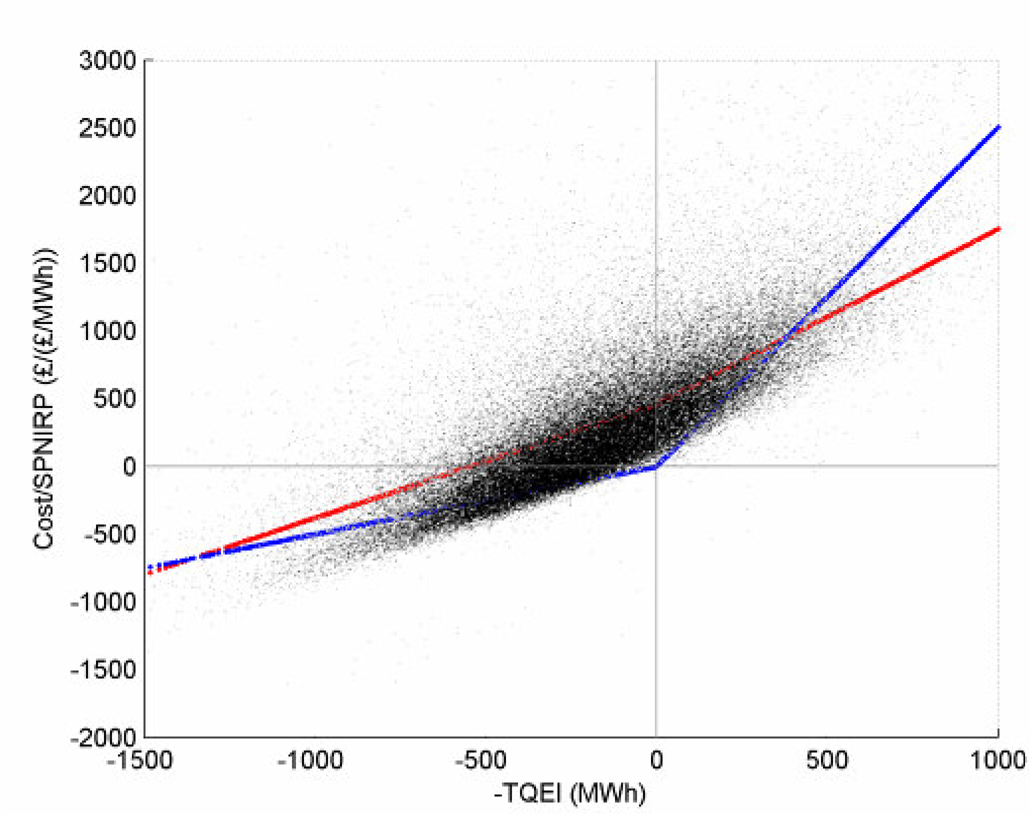


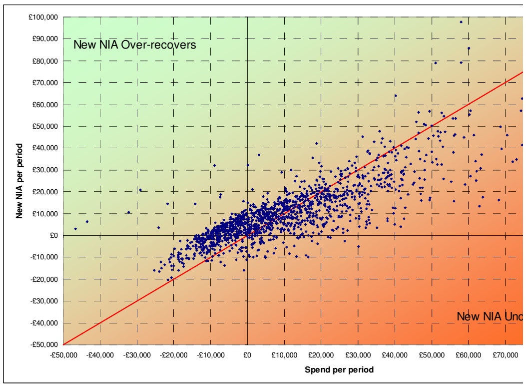
Figure 9 - Relationship of costs with market imbalance

4.4 Evaluating the performance of current NIA

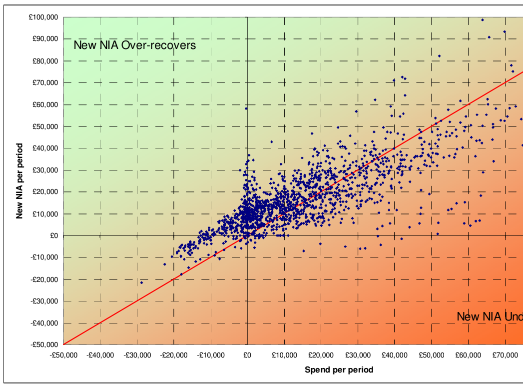
90. NIA was developed to mitigate National Grid's exposure to changes in power price and market length, with the adjustment being formulated to average across the whole of the year. In other words, NIA may well over or under compensate in certain periods, but it is expected that the net effect over the whole year will be null.

91. There are a number of ways of evaluating NIA, one possible way is by plotting in a graph the relationship between the targeted costs and the adjustment factor. The charts below present the results for the first four months of the current incentive year. The x-axis represents the cost per settlement period and the y-axis represents the value of the adjustment factor for the same period.

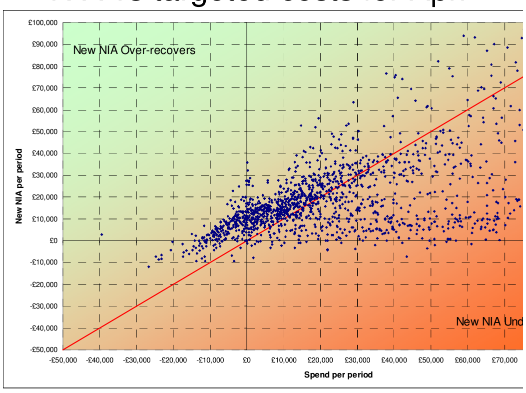
92. According to this evaluation methodology, the closer the points are to the diagonal line (targeted costs = adjustment factor), the better NIA is performing. Points above the line indicate NIA is over-recovering for that period; points below the line indicate NIA is under-recovering for that period.



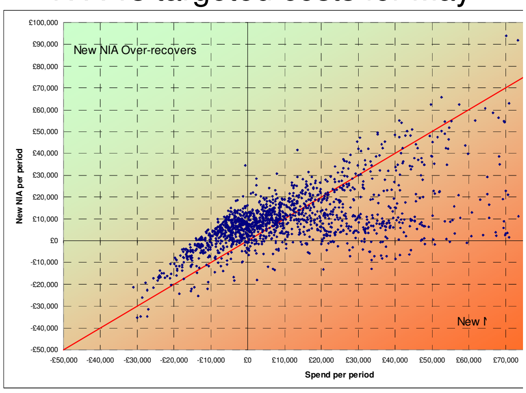
NIA vs targeted costs for April



NIA vs targeted costs for May



NIA vs targeted costs for June

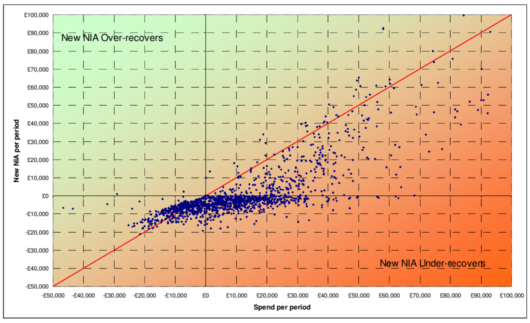


NIA vs targeted costs for July

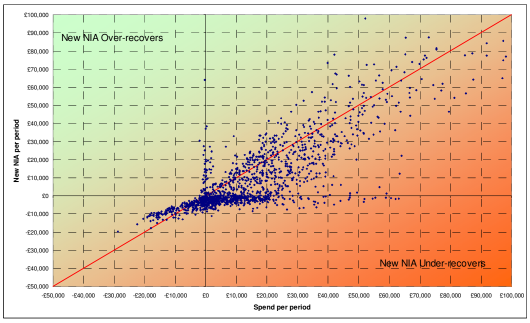
93. The graphs suggest that NIA has performed reasonably well in the months of April and May. June and July saw a relative degradation of NIA performance mainly due to increased Footroom costs (see section 3.2.5 and Appendix B for an explanation of this cost component).

94. It should be noted, however, that the main causes for the increase in Footroom costs are not drivers that form part of current NIA formulation.

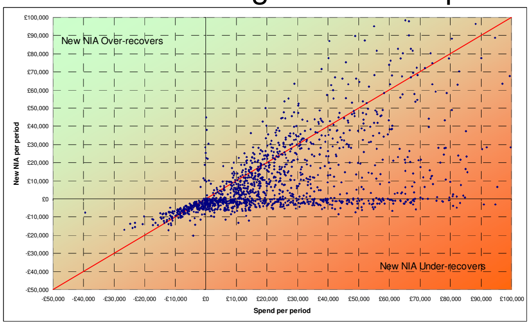
95. Another important comparison can be made with the previous NIA formulation. As can be seen from the four charts below, the current NIA is performing better than the previous formulation would have done.



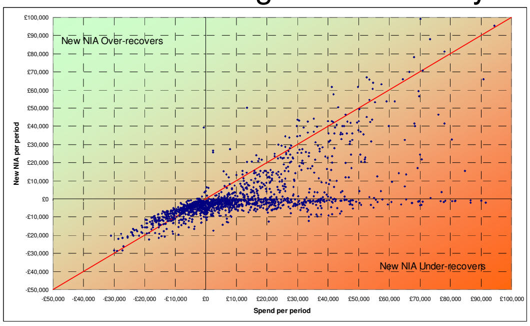
Old NIA vs targeted costs April



Old NIA vs targeted costs May



Old NIA vs targeted costs June



Old NIA vs targeted costs July

4.5 Potential improvements to NIA

96. Although current NIA presents an improvement on the old formulation, further enhancements are possible. In their final proposal consultation[12], Ofgem suggested that further analysis should be undertaken by National Grid to investigate further improvements to NIA.

97. We have analysed options to further improve NIA, based on the principle of adjusting the scheme for only part of the mentioned costs that we believe are most sensitive to the drivers of power price and market length. Clearly there are other options for change to NIA however and National Grid welcomes views on where these would be beneficial. However, the options we have considered initially are:

- All of Energy Imbalance Costs
- All of Operating Reserve costs and STOR BM utilisation fees, but not BM Start Up, BM availability fees and Non-BM fees
- All of Footroom costs
- Only the costs to position Response units through the BM (bids and offers)
- Only Fast Reserve costs incurred in the BM

[12] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Final%20proposals%20consultation%20document.pdf

Question 6 – Do you agree that it would be appropriate for any adjustment term to cover the identified items?

Question 7 – Are there any other terms that you believe it would be appropriate for any adjustment term to cover? If so, what would these be and how would these work?

98. The analyses carried out by National Grid utilised ordinary least square linear regressions. The linear regression is just the first step at analysing options for NIA and, as such, dealing with issues as heteroscedasticity and autocorrelation have been postponed for the initial proposal consultation. We invite views from the industry as for which diagnostic tests should be carried out and suggestions of remedial actions.

99. Within the linear regressions, one possible way of measuring the effectiveness of an adjustment term such as NIA is through the coefficient of determination. The coefficient of determination, (R-squared) is a statistical model and provides a measure of how well future outcomes are likely to be predicted, i.e. it provides a measure of 'the goodness of fit'. In fact, the models have been evaluated according to the adjusted R-squared, which accounts for the number of variables utilised.

100. The (adjusted) coefficient of determination ranges in value from 0 to 100%. If it is 100%, there is a perfect correlation in the sample – there is no difference between the adjusted value and the actual value. At the other extreme, if the coefficient of determination is 0, the regression equation is not helpful in defining an adjustment value. There is no absolute value above which R-squared can be considered good, so it should only be used as a means of comparison between models.

101. The original NIA (pre 2009/10) had an adjusted R-squared of approximately 57%. Current NIA has an adjusted R-squared of approximately 73%.

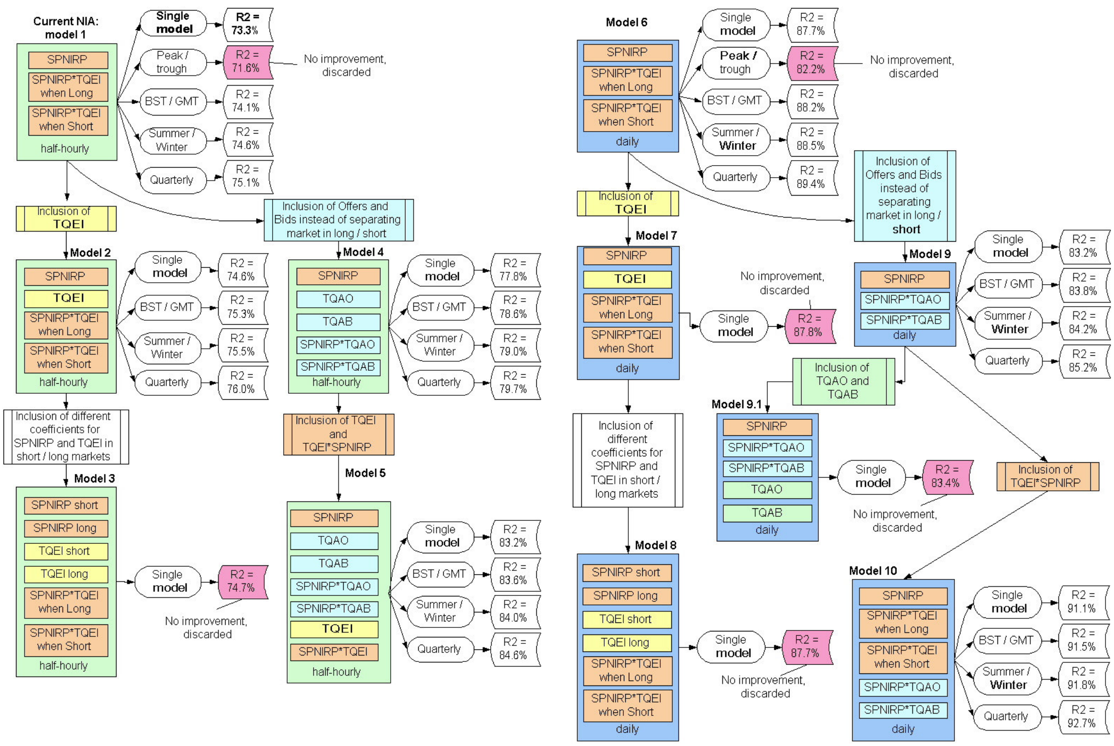
102. Appendix A provides a series of possible new formulations for NIA with adjusted R-squared around 80% to 90%. This can be achieved by:
- the inclusion of new variables, such as volumes of accepted bids and offers:
- splitting NIA into shorter periods such as seasonal or quarterly periods; and
- changing the calculation periodicity from half-hourly to daily.

103. The charts below illustrate the options investigated in Appendix A. The diagrams show the progress of the analysis undertaken and the output results. As can be seen, a number of models were discarded as they did not improve results. The inclusion of volumes bids and offers or separating out the volumes of long and short market over the day show significant improvement on other models. However, the introduction of

additional terms means that there is added complexity in forecasting and determining the impact of such a revised NIA.

104. The dataset utilised to calculate the options are available at http://www.nationalgrid.com/uk/Electricity/soincentives/AnalystArea/. We recognise that there are a number of alternative formulations and welcome views from the industry as for which other options would be appropriate.

½ hourly assessment Daily assessment



105. The main advantage of including Bids and Offers in the adjustment factor is that they are already consequences of the overall system conditions, thus largely reflecting the effect of most cost drivers. The disadvantages include the necessity of forecasting volumes of bids and offers in the scheme agreement stage and the creation of a potential opportunity for arbitrage by National Grid on the amount of actions taken to drive NIA (although in real time, National Grid wouldn't have the visibility of the consequences of its actions on NIA, even more so if it were calculated on a daily basis). In addition, there may be interaction between the incentive to contract with non-BM providers that, if accepted, would interact with the volume of bids and offers taken in balancing the system.

106. Having different coefficients for each season of the year is a recognition that the cost sensitivities to power price and market length change depending on the overall state of the system, which in turn is considerably seasonal.

107. Calculating NIA daily recognises that, although the market settlement is in a half-hour fashion, National Grid operates the system in a second-by-second basis and plans this operation over a longer period of time using "cardinal points", as illustrated in Figure 10. In addition, dynamic parameters of service providers can result in costs being incurred over a number of settlement periods to manage a single cardinal point (e.g. minimum period for the output of a synchronising generator is generally longer than one settlement period). As such, actions taken in a given notional half-hour will affect the operating costs for a longer period.

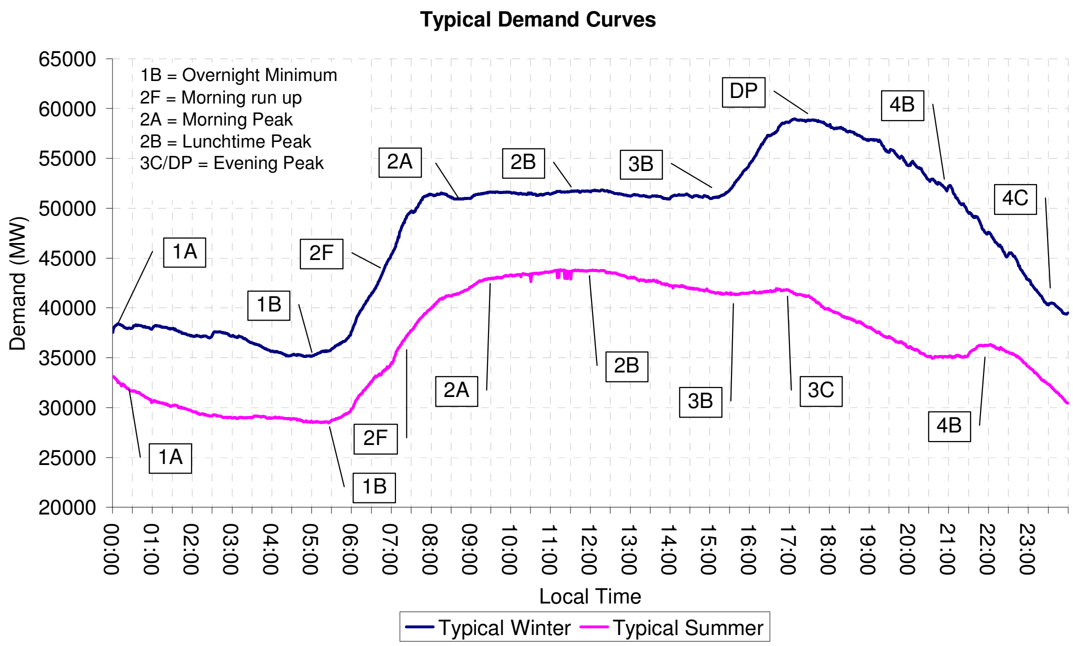


Figure 10 - Examples of Cardinal Points

108. Our view is that a balance between fitness and simplicity must be struck and, as such, we invite views from the industry as how NIA could be improved.

Question 8 – Do you agree that there is a balance between improving the fit and simplicity or should simply the best fit be found?

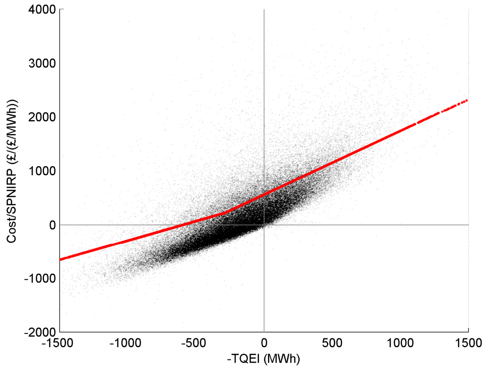
4.4.1 Potential improvements to best fit line of NIA

109. A suggestion that has been made in response to previous consultations on NIA, is the introduction of additional "kinks"[13] or by utilising a quadratic function[14] to improve the best fit line.

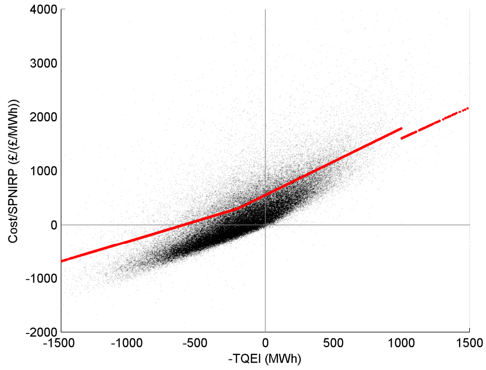
[13] A "kink" is a breakpoint in NIA function such that different coefficients are calculated for different TQEI levels. Current NIA is said to have one "kink", as it contains one set of coefficients for short markets (TQEI<0) and another set of coefficients for long markets (TQEI>0).

[14] A quadratic function for NIA is of the shape NIA = a * SPNIRP + b * SPNIRP * TQEI + c * SPNIRP * $TQEI^2$

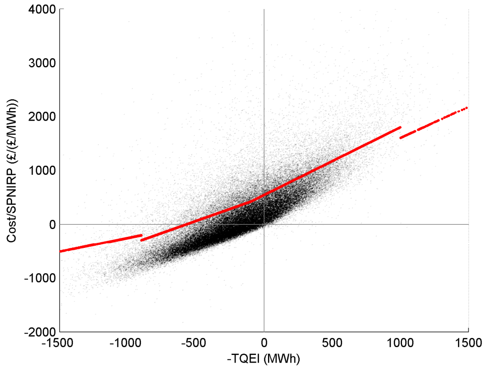
110. Current NIA has a one kink at a balanced market i.e. market length of zero. The assessment of new kinks has been performed by an optimiser looking for best points to insert such kinks to maximise the adjusted R-squared. The results are illustrated in the graphs below, utilising the half-hourly data from April 2005 to June 2009. Despite the increased complexity introduced by the different formulations, all showed a similar marginal improvement to adjusted R-squared values of around 0.5%.



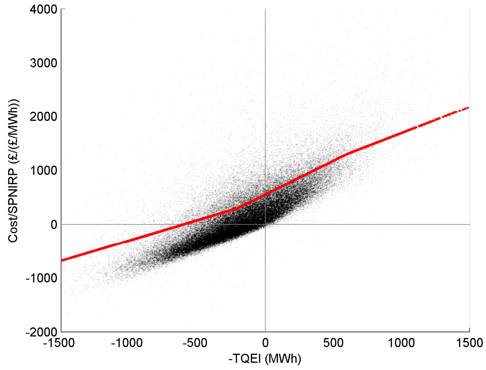
One-kinked optimised NIA



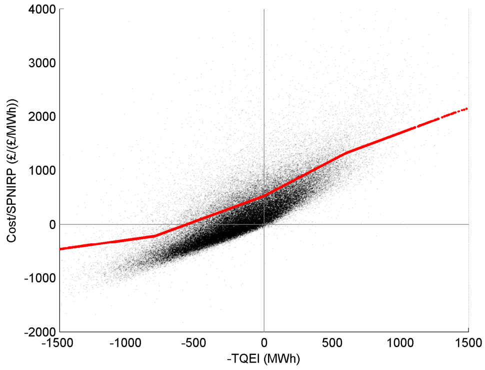
Two-kinked optimised NIA



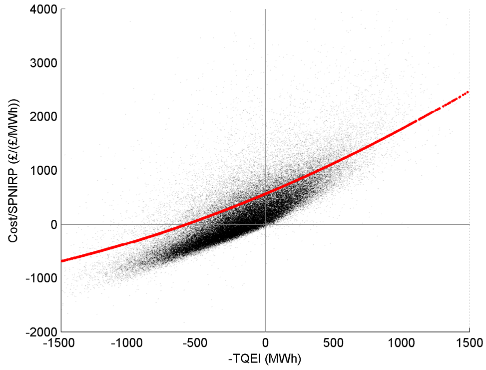
Three-kinked optimised NIA



Two-kinked optimised NIA, subject to continuous line



Three-kinked optimised NIA, subject to continuous line



Quadratic NIA

4.4.2 Cost Drivers Included in NIA

111. Although the models developed in Appendix A only include four drivers (e.g. power price, market length, bids and offers), other cost drivers mentioned in section 3 as being outside of National Grid control could also be potentially part of an adjustment factor, such as the level of wind generation on the system and largest infeed loss.

112. Including new cost drivers as variables to NIA would have the advantage of giving additional accuracy to the adjustment factor. Indeed for a longer-term incentives of two years plus it may be necessary to adjust the target if largest infeed loss was to change that would have a significant impact on the volumes of services to be procured.

> Question 9 – Which calculation period do you think is more appropriate, half-hourly, daily or other?
>
> Question 10 – Which variables do you think should be included in an improved NIA?
>
> Question 11 – What other NIA formats should be considered? Do you believe that there are benefits in including a NIA methodology that has a kinked line?

113. As the formulation gets more detailed and becomes a multi-dimension model, representing the adjustment term in graphs as in the previous section is no longer possible.

114. The improvement of NIA should mitigate some of the uncontrollable risks to National Grid, reducing the possibility of windfall gains and losses, incentivising us in finding innovative solutions that will reduce the overall costs of managing the system.

4.5 Longer term schemes

115. A more reflective adjustment term can facilitate the establishment of longer term incentive schemes.

116. As discussed in section 2, there are a number benefits in the current one year scheme:
    - Accuracy of forecast
      The development of a robust yearly BSIS and BSUoS forecast is dependant on a number of external drivers such as power price. A yearly scheme is better able to adapt a revised forecast and hence updated target rather than a scheme of longer than one year duration.
    - Ability to reflect market changes

For market changes that impact balancing costs (such as Transmission Access), a yearly (or a shorter) scheme is more able to reflect these changes than one of a longer duration

117. With a longer term scheme in place, National Grid would be able to implement strategies where the set-up costs can be recovered over the longer timescales and longer term reductions in the costs of System Operation achieved with the resultant savings in BSUoS.

118. With the current one year scheme structure, these costs would either have to be directly funded by industry or it would not be feasible to recover in a one year scheme, after which any derived benefit would be rolled up in to the target and so the reward for the innovation not realised.

119. In addition to these benefits, there are various administrative benefits that can be achieved across the industry by reducing the need for individuals to develop, review and provide feedback on the target being discussed.

120. In general, therefore, a longer term scheme with appropriate adjustments would stabilise the elements of BSUoS under the control of the System Operator whilst reducing administrative burdens across the industry.

121. The introduction of a longer term scheme would impact on the appropriateness of the adjustment. As the development of the adjustment is based on historic information and relationships between the key components, a longer term scheme relies upon the underlying relationship between the adjustment factors remaining unchanged. The longer the duration of the scheme, the lower the opportunities to review these relationships and ensure that the adjustment remains appropriate.

Question 12 – Do you believe there are benefits in the implementation of a longer than one year scheme?

4.6 Unbundled schemes

122. The costs and volumes of services used to balance energy are very much inter-related. The relationship between these energy balancing components and other of system costs is lower. However, there is some relationship between reserve and constraint costs. This is covered in more detail in our third mini consultation that is planned to be published in late August.

123. As mentioned in section 2, there are a number of benefits of a bundled scheme:

- Interaction between components
  When taken balancing actions, there may be more than one service that the action can be attributed; e.g. when synchronising a

generator to resolve a constraint issue, the generator may also be able to supply reserve and frequency response services. Allocating costs to each component is performed via a set of rules. In a bundled scheme these rules do not impact on the overall incentive performance.

- Overall focus on driving down costs where most benefit can be achieved
  A bundled scheme generally focuses attention areas where National Grid can most drive value to the consumer.
- Simpler to manage and administer
  A fully bundled scheme is generally easier to monitor and determine the overall direction of balancing costs.

124. Unbundling the energy related components into a separate scheme is a way of recognising the asymmetrical risk profiles of different areas of the overall cost of system operation. Such a scheme should incentivise National Grid to focus resources to pursue achievable savings in these components, which form a significant proportion of the Balancing Services Use of System costs and provide an appropriate level of risk and reward for the level of control National Grid has in influencing costs.

125. Unbundling the current incentive scheme would require an agreed and robust methodology to apportion costs between separate cost components e.g. deciding if a given action has been taken for energy or constraint reasons.

Question 13 – Are there any additional benefits or drawbacks in the development and implementation of an unbundled incentive?

4.7 Summary

126. This section sets out the potential options for the development of an incentive on energy balancing.

127. A number of options to improve NIA fitness as an adjustment term for changes in cost drivers have been developed. The balance between simplicity and best fit is outlined when deciding on what NIA option to implement. In Appendix A we outline the options in more detail.

128. The value of improving NIA as a means to enable longer term incentive schemes has been presented and a brief discussion of the benefits of longer term and unbundled schemes has been developed.

Section 5
Summary / Conclusion

5.1 Summary

129. National Grid is incentivised to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives enables National Grid to invest in systems and resources to ensure balancing costs and risks are economically and efficiently managed.

130. The Balancing Services Incentive Scheme (BSIS) is designed to deliver financial benefits to the industry and consumers from reductions in the costs associated with operating the national electricity transmission network.

131. The incentive scheme provides a focus on key areas where National Grid is able to create value for the industry and consumers, allowing National Grid to retain a share of any value created or to bear a share of the costs should targets not be met.

132. This consultation considers development options to the incentive scheme, focusing on energy related cost components (energy imbalance, margin, footroom, response and fast reserve), including the improvement of Net Imbalance Adjustment factor (NIA), implementing a longer-term incentive scheme and unbundling such components from the rest of BSIS.

133. Section 3 introduced the energy related cost components of the Incentive Scheme and presented our best view of drivers for such costs. A number of those drivers have been identified as unpredictable, volatile and as being outside National Grid's control.

134. Section 4 set out the potential options for the development of an incentive on energy balancing, including the potential improvements to NIA and the benefits and drawbacks of an unbundled scheme with the option of a multi year scheme.

135. Input from industry will be vital in the development of incentive proposals. Therefore, we would welcome any feedback from the industry on the content of this consultation.

136. If you would like to discuss any items, please contact National Grid using the details contained at the end of this document.

Question 14 – Do you have any comments regarding this consultation process?

Section 6
Consultation Questions

This section lists the consultation questions from the document.

6.1 Consultation Questions

137. The questions below have been constructed to help us determine the industries view on the potential for the development and implementation of an adjustment methodology.

138. Answering the questions will allow us to focus our attention on developing a methodology for inclusion in our initial proposals for the introduction of a scheme for April 2010.

139. The questions are not an exhaustive; if you have any further points you would like to raise please do so.

6.2 List of Consultation Questions

1	Are there any other risks or benefits associated with the existing 1 year bundled scheme?
2	Have all cost drivers been captured and correctly identified as being within or outside National Grid control?
3	Do you consider that there are elements within these cost drivers that are within National Grid control? What are these and how do you believe these should be considered going forward?
4	Do you agree that Energy Imbalance, Margin, Footroom, Response and Fast Reserve share the same cost drivers and should be considered together as the Energy component?
5	Do you agree with the need for an adjustment factor to mitigate the risk of variations to cost drivers outside National Grid control?
6	Do you agree that it would be appropriate for any adjustment term to cover the identified items?
7	Are there any other terms that you believe it would be appropriate for any adjustment term to cover? If so, what would these be and how would these work?
8	Do you agree that there is a balance between improving the fit and simplicity or should simply the best fit be found?
9	Which calculation period do you think is more appropriate, daily or half-hourly?
10	Which variables do you think should be included in an improved NIA?
11	What other NIA formats should be considered? Do you believe that there are benefits in including a NIA methodology that has a kinked line?
12	Do you believe there are benefits in the implementation of a longer than one year scheme?
13	Are there any additional benefits or drawbacks in the development and implementation of an unbundled incentive?
14	Do you have any other comments regarding this consultation? - Document structure - Overall content and level of information provided - Process

Appendix A

A.1 Detailed analysis of further improvements for NIA

Introduction

The following section outlines the process that was followed when analysing data for the calculation of NIA for the incentive scheme starting in 1st April 2010. It is arranged into models, with each model representing a separate attempt to increase the accuracy of NIA. The first five models were produced using the half hourly data, and models 6 - 10 using daily data.

The analyses were performed using ordinary least squares regressions. This method takes a set of input variables and searches for the most efficient placement of a line of best fit through them. This is done by summing the squares of the distances from each point of data to the line of best fit.

The linear regression is just the first step at analysing options for NIA and, as such, dealing with issues as heteroscedasticity and autocorrelation have been postponed for the initial proposal consultation. We invite views from the industry as for which diagnostic tests should be carried out and suggestions of remedial actions.

Each regression was carried out including a constant so that the line of best fit line was not forced through the origin of the graph. However, since the role of NIA, they have been omitted in the results (represented is to reduce risk exposure to variances in power price and market length and the constant is, by "+C").definition, a stand-alone component not being part of NIA formulation, its value is not shown in the results.

Data utilised covers the period from BETTA go-live (1st April 2005) to 30th June 2009. The fundamental relationships analysed were the dynamics between power price, market length and targeted costs for the adjustment term (energy imbalance, margin, footroom action, fast reserve and response actions).

Ten different models were considered to represent NIA. These models included variations for different times of day and of year. The first five models utilised half hourly data and the final five were based on summing the half hourly periods into daily data.

The full outputs from each regression will be made available at http://www.nationalgrid.com/uk/Electricity/soincentives/AnalystArea/ along with the complete dataset.

Having analysed half hourly data and aggregated daily data, the results prove that using aggregated data improves the accuracy of NIA by a minimum of 10%. Further analysis into aggregated data including different coefficients for different periods of the year further improved it.

The final component of the analysis involved using the daily data, taking market length and energy imbalance in conjunction with the quantity of accepted bids and offers in the control room and applying them together in one model.

Definitions

The following terms are used throughout the report:

- **Adjusted R^2** – a value used to quantify the efficiency of the line of best fit on each model. The line with perfect fit would have an R^2 value of 100%. The objective of the analysis that has been carried out was to obtain a model with as high an adjusted R^2 as possible with a valid model.

- **Standard Deviation** – a measure of variability in data. When averaging a set of values, a low standard deviation is usually desired as this indicates consistency in results.

- **T-stat** – Each variable which is regressed upon has a t-stat that describes its reliability. Variables with a t-stat indicating unreliability greater than 5% were removed from the final models and are shown in grey italics.

- **TARGET** – Target consists of the following costs: energy, margin, fast reserve, response and footroom.

- **EFA Block** – Electricity Forward Agreement Block. A set of six four hourly periods throughout the day. EFA block 1 starts at 11.00 pm on a particular day and EFA block 6 will finish at 11.00 pm the following day.

- **Peak** – The half of the day where UK demand is at a maximum. EFA blocks 3, 4 and 5 make up the peak period.

- **Trough** – The half of the day where UK demand is at a minimum. EFA blocks 1, 2 and 6 made up the trough period.

- **BST/GMT** – BST is British Summer Time and GMT is Greenwich Mean Time. BST and GMT split the year into two time periods, BST lasting 7 months and GMT 5 months. This split corresponds to changes in the clock and so BST runs from the last Sunday in March until the last Sunday in October. Conversely, GMT corresponds to the last Sunday in October until the last Sunday in March.

- **Summer/Winter** – Divides the year into two 6 month blocks. Summer starts on the 1st of April and ends on the 30th of September each year. Winter begins on the 1st of October and runs through to the 31st of March of the following calendar year.

- **Quarters** – The four 3 month sections that make up the year. These correspond to the calendar year (i.e. quarter 1 includes January, February, March; quarter 2 includes April, May, June etc.)

- **NIV** – This is the Net Imbalance Volume and represents by how much the market is short or long.

- **TQEI** – This is the Total Quantity of Energy Imbalance, a measure of market imbalance as defined in the Balancing and Settlement Code, comprising of accepted offers, accepted bids, response energy and trades by National Grid.

Model 1

Model 1 is the regression model used to calculate the current NIA (which has been explained previously in this report). The relationship between power price (SPNIRP) and market length (TQEI) is examined. There is a split in the analysis between long and short markets which produces two sets of coefficients, each for the different market length situation. The current NIA model gives an adjusted R^2 value of 73.3%.

The variables included in the model were:

- SPNIRP
- SPNIRP * TQEI in a Long Market
- SPNIRP * TQEI in a Short Market

The equations which describe this regression are:

In a **short** market:
TARGET = 533*SPNIRP – 1.24*SPNIRP*TQEI + C
In a **long** market:
TARGET = 533*SPNIRP – 0.88*SPNIRP*TQEI + C

The observed different between the model results and the current coefficients (especially for the SPNIRP coefficient) arise from the fact that, before implementing current NIA coefficients, National Grid performed a final refinement to the model to ensure minimum volatility in within months data (while the pure regression minimises volatility in a half-hourly basis). If a new NIA formulation were to be implemented from 1st April 2010, its coefficients would also be subject to a similar final refinement

Peak/Trough Analysis
A peak/trough analysis was carried out to see if splitting the day into its peaks and troughs would give a better adjusted R^2 value for this model. This produced the following adjusted R^2 values:

	Peak	Trough	Average	Standard Dev.

Adjusted R^2	74.6%	68.5%	**71.6%**	**4.31**

Figure AP. 1

The equations which represent this regression are:

For a **short** market in a **peak**:
TARGET = 517*SPNIRP – 1.23*SPNIRP*TQEI + C
For a **long** market in a **peak**:
TARGET = 517*SPNIRP – 0.777*SPNIRP*TQEI + C
For a **short** market in a **trough**:
TARGET = 588*SPNIRP – 1.43*SNIRP*TQEI + C
For a **long** market in a **trough**:
TARGET = 588*SPNIRP – 1.05*SNIRP*TQEI + C

Although this shows that the adjusted R^2 for the peak is slightly improved, the trough value is significantly lower and so brings the average adjusted R^2 below the value obtained from the current NIA. Given that this result held for all the other models, the idea of splitting into Trough and Peak has been discarded.

Seasonal Analysis

To begin with, the year was analysed according to BST/GMT and summer/winter split, with results in Figure AP. 2:

	BST	GMT	Average	Standard Dev.
Adjusted R^2	73.9%	74.2%	**74.1%**	**0.21**

	Summer	Winter	Average	Standard Dev.
Adjusted R^2	76.5%	72.7%	**74.6%**	**2.69**

Figure AP. 2

The equations which describe the BST/GMT model are:

For a **short** market in **BST**:
TARGET = 459*SPNIRP – 1.24*SPNIRP*TQEI + C
For a **long** market in **BST**:
TARGET = 459*SPNIRP – 0.94*SPNIRP*TQEI + C
For a **short** market in **GMT**:
TARGET = 672*SPNIRP – 1.17*SPNIRP*TQEI + C
For a **long** market in **GMT**:
TARGET = 672*SPNIRP – 0.806*SPNIRP*TQEI + C

The equations which describe the summer/winter model are:

For a **short** market in **summer**:
TARGET = 450*SPNIRP – 1.20*SPNIRP*TQEI + C
For a **long** market in **summer**:

TARGET = 450*SPNIRP – 1.04*SPNIRP*TQEI + C

For a **short** market in **winter**:

TARGET = 641*SPNIRP – 1.22*SPNIRP*TQEI + C

For a **long** market in **winter**:

TARGET = 641*SPNIRP – 0.82*SPNIRP*TQEI + C

Both BST/GMT and the summer/winter splits yield better adjusted R^2 values than the current NIA model (with the summer/winter split providing a slightly higher value, but with higher variance too).

Quarterly Analysis

Splitting the year into quarters was used to try and improve the fit of the data. The resultant adjusted R^2 values are below:

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Average	St. Dev.
Adjusted R^2	76.9%	73.7%	79.0%	70.6%	**75.1%**	**3.68**

Figure AP. 3

The equations which make up this quarterly model are:

Quarter 1

For a **short** market:

TARGET = 523*SPNIRP – 1.33*SPNIRP*TQEI + C

For a **long** market:

TARGET = 523*SPNIRP – 0.826*SPNIRP*TQEI + C

Quarter 2

For a **short** market:

TARGET = 353*SPNIRP – 1.38*SPNIRP*TQEI + C

For a **long** market:

TARGET = 353*SPNIRP – 1.09*SPNIRP*TQEI + C

Quarter 3

For a **short** market:

TARGET = 506*SPNIRP – 1.10*SPNIRP*TQEI + C

For a **long** market:

TARGET = 506*SPNIRP – 0.992*SPNIRP*TQEI + C

Quarter 4

For a **short** market:

TARGET = 704*SPNIRP – 1.14*SPNIRP*TQEI + C

For a **long** market:

TARGET = 704*SPNIRP – 0.864*SPNIRP*TQEI + C

Figure AP. 3 shows that the average adjusted R^2 value is again slightly improved at 75.1%, compared to the current NIA of 73.3%. The results, however, are quite spread with a range of 8.4% and a standard deviation of 3.68.

It was decided that the three months which made up this quarter should be split into two parts; October and November plus December; to see if this improved the adjusted R^2 value. These results are shown in Figure AP. 4 below:

	October	Nov and Dec	Volume Weighted Average	St Dev
Adjusted R^2	61.6%	73.6%	**69.6%**	5.66%

Figure AP. 4

These results prove that the problematic month is October, which could be due to the volatility of the demand and generation profiles commonly seen. Splitting up the quarter into two separate parts proved ineffective because it made the model more complicated and didn't increase the average adjusted R^2. In fact, the overall average when splitting up the quarter was lower than when left as a whole.

<u>Removing 2005/2006 data</u>

With the introduction of BETTA in April 2005, there was a significant change in operational environment. The industry suggested in its response to the 2008/09 NIA report that removal of this old data would produce a more accurate model. To determine the validity of this suggestion, an analysis was performed on the same model with different data sets - one with the 05/06 data and one without. If the model with the 05/06 data has coefficient error bands that overlap with the coefficient error bands of the model without the 05/06 data, it would not have a significant impact on the analysis. An error range of ± 2 standard errors was used to generate the error range in each case. An example of this process is shown in Figure AP. 5, using the coefficients which correspond to the initial regression for this model:

Variable	Coefficient with 05/06 data	2 x Standard error	Minimum Value of Range	Maximum Value of Range	Coefficient without 05/06 data
SPNIRP	**533**	6.17	527	539	**516**
SPNIRP*TQEI (short market)	**-1.24**	0.0432	-1.20	-1.28	**-1.24**
SPNIRP*TQEI (long market)	**-0.883**	0.0116	-0.895	-0.871	**-0.877**

Figure AP. 5

If the second coefficient lies within the range of the first, it is deemed unlikely to change the results. The SPNIRP*TQEI coefficients for both short and long markets without this data lie within the range of the initial coefficient. Although this is not strictly the case for the coefficient of SPNIRP, it is clear that both figures lie within the same order of magnitude. This shows that it can be considered unnecessary to remove this data and so this has not been shown for the rest of the models.

Summary

To briefly summarise model 1, the results in Figure AP. 1, Figure AP. 2 and Figure AP. 3 show a steady improvement in the adjusted R^2 value from the previous analysis. Analysing the data in quarterly splits yields the best adjusted R^2 value on average. However, this is only a 1% improvement on the BST/GMT split and the BST/GMT model is less complex. This split also produces two adjusted R^2 values which are quite similar, making the model reliable also.

Model 2

The second model looks into a way of improving the adjusted R^2 by regressing on the same variables as model one, but also includes TQEI (market length) as a variable on its own. This is done so that it can be seen whether or not there is a relationship which is not dependent on power price (SPNIRP). If the results of the regression including TQEI have a significant improvement on the adjusted R^2, it would prove that it would be beneficial to include it in the final model.

The variables used in this model were:

- SPNIRP
- TQEI
- SPNIRP * TQEI in a long market
- SPNIRP * TQEI in a short market

Before other considerations were taken into account, the model was calculated using all the data. This gave an overall adjusted R^2 of 74.6%. This is higher than the initial value in the previous model, showing that market length is involved in the relationship.

The equations which describe this regression model are:

In a **short** market:

TARGET = 477*SPNIRP – 20.1*TQEI – 1.11*SPNIRP*TQEI + C

In a **long** market:

TARGET = 477*SPNIRP – 20.1*TQEI – 0.476*SPNIRP*TQEI + C

Seasonal Analysis

The next stage was then to split the data seasonally; looking at GMT/BST and summer/winter to allow a comparison to be made:

	GMT	BST	Average	Standard Dev.
Adjusted R^2	75.6%	74.9%	**75.3%**	**0.49**

	Summer	Winter	Average	Standard Dev.
Adjusted R^2	77.2%	73.9%	**75.5%**	**2.33**

Figure AP. 6

The equations which describe the BST/GMT model are:

For a **short** market in **BST**:
TARGET = 415*SPNIRP – 16.7*TQEI – 1.12*SPNIRP*TQEI + C
For a **long** market in **BST**:
TARGET = 415*SPNIRP – 16.7*TQEI – 0.614*SPNIRP*TQEI + C
For a **short** market in **GMT**:
TARGET = 596*SPNIRP – 25.1*TQEI – 1.04*SPNIRP*TQEI + C
For a **long** market in **GMT**:
TARGET = 596*SPNIRP – 25.1*TQEI – 0.297*SPNIRP*TQEI + C

The equations which describe the summer/winter model are:

For a **short** market in **summer**:
TARGET = 413*SPNIRP – 14.4*TQEI – 1.11*SPNIRP*TQEI + C
For a **long** market in **summer**:
TARGET = 413*SPNIRP – 14.4*TQEI – 0.710*SPNIRP*TQEI + C
For a **short** market in **winter**:
TARGET = 569*SPNIRP – 22.5*TQEI – 1.09*SPNIRP*TQEI + C
For a **long** market in **winter**:
TARGET = 569*SPNIRP – 22.5*TQEI – 0.402*SPNIRP*TQEI + C

These results show that there is a slight improvement on the original fit by analysing the data seasonally. The best seasonal adjusted R^2 value is for the summer section, whereas the lowest value is the winter section. However, it can be seen from the standard deviation that GMT/BST is vastly superior in terms of consistency.

Quarterly Analysis
Next, a quarter split was used, with results in Figure AP. 7 below:

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Average	St. Dev.
Adjusted R^2	78.1%	73.9%	79.9%	71.9%	**76.0%**	**3.69**

Figure AP. 7

The equations which represent this quarterly model are:

Quarter 1
For a **short** market:
TARGET = 465*SPNIRP – 21.6*TQEI – 1.19*SPNIRP*TQEI + C
For a **long** market:
TARGET = 465*SPNIRP – 21.6*TQEI – 0.340*SPNIRP*TQEI + C

Quarter 2
For a **short** market:
TARGET = 328*SPNIRP – 8.66*TQEI – 1.30*SPNIRP*TQEI + C
For a **long** market:
TARGET = 328*SPNIRP – 8.66*TQEI – 0.855*SPNIRP*TQEI + C
Quarter 3
For a **short** market:
TARGET = 466*SPNIRP – 19.0*TQEI – 1.01*SPNIRP*TQEI + C
For a **long** market:
TARGET = 466*SPNIRP – 19.0*TQEI – 0.629*SPNIRP*TQEI + C
Quarter 4
For a **short** market:
TARGET = 622*SPNIRP – 24.1*TQEI – 1.02*SPNIRP*TQEI + C
For a **long** market:
TARGET = 622*SPNIRP – 24.1*TQEI – 0.452*SPNIRP*TQEI + C

These results show that the best fit for this model is to split the data up into quarters. The best adjusted R^2 value was in the third quarter at 79.9%; and the lowest was the fourth quarter at only 71.9%. This is because October is the most volatile month and so skews the results. The difference between quarter three and quarter four is 8%, which means that the average doesn't truly reflect individual values, as is evident from the standard deviation of 3.69.

Summary
This second model improves on the current NIA model by 1.3%, which indicates that including TQEI does yield a small improvement in the adjusted R^2 value. The best fit obtained from model two was when the data was split up into the four quarters, with each quarter having its own separate coefficients.

Model 3

The third model that was used looked at determining whether the direction of the market affected the coefficient of power price (SPNIRP).

The variables included were:

- SPNIRP in a Long Market
- SPNIRP in a Short Market
- TQEI in a Short Market
- TQEI in a Long Market
- SPNIRP * TQEI in a Long Market
- SPNIRP * TQEI in a Short Market

The initial regression model is represented by the equations:

In a **short** market:
TARGET = 529*SPNIRP – 33.48*TQEI – 0.961*SPNIRP*TQEI + C
In a **long** market:
TARGET = 513*SPNIRP – 11.3*TQEI – 0.604*SPNIRP*TQEI + C

The initial regression for this model gave an adjusted R^2 value of 74.7%, meaning no material improvement has been achieved; therefore this model has been discarded.

Model 4

The fourth model looked at whether or not an improvement could be made if instead of splitting the model into short/long markets, total quantity of offers and bids should be used.

When this model was initially regressed (without any of the considerations), the adjusted R^2 improved to 77.8%. This proved that separating the offers and bids made a significant improvement to the fit, rather than keeping it as the NIV.
The variables included were:

- SPNIRP
- Accepted Bids (TQAB)
- Accepted Offers (TQAO)
- SPNIRP * Accepted Bids
- SPNIRP * Accepted Offers

The equation which represents the initial regression is:

TARGET = 183*SPNIRP + 20.7*TQAO + 18.3*TQAB
+1.32*SPNIRP*TQAO + 0.241*SPNIRP*TQAB + C

Seasonal Analysis
The next step was to split the data seasonally, including a GMT/BST and summer/winter split. These results can be seen below in Figure AP. 8:

	BST	GMT	Average	St Dev
Adjusted R^2	78.9%	78.3%	**78.6%**	0.424

	Summer	Winter	Average	St Dev
Adjusted R^2	80.8%	77.2%	**79.0%**	2.55

Figure AP. 8

The equations which represent the BST/GMT split for this model are:

In **BST**:
TARGET = 130*SPNIRP + 16.8*TQAO + 13.7*TQAB
+1.38*SPNIRP*TQAO + 0.362*SPNIRP*TQAB + C

In **GMT**:
TARGET = 303*SPNIRP + 28.9*TQAO + 23.2*TQAB
+1.19*SPNIRP*TQAO + 0.126*SPNIRP*TQAB + C

The following equations represent the summer/winter split for this model:

In **summer**:

TARGET = 174*SPNIRP + 17.5*TQAO + 10.1*TQAB
+1.34*SPNIRP*TQAO + 0.469*SPNIRP*TQAB + C

In **winter**:

TARGET = 253*SPNIRP + 26.5*TQAO + 22.0*TQAB
+1.28*SPNIRP*TQAO + 0.165*SPNIRP*TQAB + C

The adjusted R^2 values are much improved from the previous models, and so emphasises that looking at the offers and bids separately improves the fit.

Quarterly Analysis

The data was split up into the four quarters that run through the year. The results can be seen in Figure AP. 9 below:

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Average	St Dev
Adjusted R^2	81.0%	79.9%	81.4%	76.3%	**79.7%**	2.32

Figure AP. 9

The equations which represent this quarterly model are:

Quarter 1:

TARGET = 251*SPNIRP + 27.0*TQAO + 16.9*TQAB
+1.19*SPNIRP*TQAO + 0.332*SPNIRP*TQAB + C

Quarter 2:

TARGET = 150*SPNIRP + 17.0*TQAO + 8.10*TQAB
+ 1.40*SPNIRP*TQAO + 0.578*SPNIRP*TQAB + C

Quarter 3:

TARGET = 208*SPNIRP + 16.6*TQAO + 9.19*TQAB
+1.30*SPNIRP*TQAO + 0.445*SPNIRP*TQAB + C

Quarter 4:

TARGET = 121*SPNIRP + 18.3*TQAO + 27.7*TQAB
+1.59*SPNIRP*TQAO + *0*SPNIRP*TQAB* + C

These results show that quarter three has the highest value and that quarter four has the lowest. This is again due to October being the most volatile month in terms of weather. The quarterly data gives the best average adjusted R^2 at 79.7%%, which is greater that the initial regression for this model by almost 2%. It also shows an improvement on the quarterly analysis of model two by almost 4%

Summary

The results from this model show that it is beneficial to split up model into offers and bids to calculate a more accurate NIA. This resulted in an average adjusted R^2 of 80.4%, which is significantly better than the current NIA result of 73.3%.

Model 5

From the analysis of the four previous models, it became evident that regressing on the data in terms of separate offers and bids gave the best fit. However, TQEI is not only made up of offers and bids, so TQEI was included as a separate variable in the regression. Model five therefore looks at all components of market length, not just bids and offers.

When model five was initially regressed (without any of the considerations) the adjusted R^2 was 83.2%. This result showed that including TQEI in the regression with the offers and bids made a significant improvement when compared the initial regressions on previous models.

The variables included were:

- SPNIRP
- Accepted Offers (TQAO)
- Accepted Bids (TQAB)
- SPNIRP * Accepted Offers
- SPNIRP * Accepted Bids
- TQEI
- TQEI * SPNIRP

The following equation describes the initial regression model:

$$\begin{aligned} TARGET = {} & 33.4*SPNIRP + 33.1*TQAO + 30.3*TQAB + 8.72*TQEI \\ & - 0.0513*SPNIRP*TQAO - 1.20*SPNIRP*TQAB \\ & - 1.39*SPNIRP*TQEI + C \end{aligned}$$

Seasonal Analysis

The data was then analysed seasonally according to the GMT/BST and summer/winter splits. The results from this analysis are shown in Figure AP. 10 below:

	GMT	BST	Average	St Dev
Adjusted R^2	83.4%	83.8%	**83.6%**	0.283

	Summer	Winter	Average	St Dev
Adjusted R^2	85.3%	82.7%	**84.0%**	1.84

Figure AP. 10

The equations which represent the BST/GMT model are:

In **BST**:

$$\begin{aligned} TARGET = {} & 39.8*SPNIRP + 29.6*TQAO + 23.5*TQAB + 6.00*TQEI \\ & + 0.0497*SPNIRP*TQAO - 0.964*SPNIRP*TQAB \\ & - 1.27*SPNIRP*TQEI + C \end{aligned}$$

In **GMT**:

TARGET = 81.5*SPNIRP + 36.1*TQAO + 32.7*TQAB + 7.31*TQEI
– 0.0814*SPNIRP*TQAO – 1.28*SPNIRP*TQAB
– 1.38*SPNIRP*TQEI + C

The equations which describe the summer/winter model are:

In **summer**:
TARGET = 77.5*SPNIRP + 31.5*TQAO + 21.1*TQAB + 6.63*TQEI
+*0*SPNIRP*TQAO* – 0.870*SPNIRP*TQAB
– 1.27*SPNIRP*TQEI + C

In **winter**:
TARGET = 59.0*SPNIRP + 32.0*TQAO + 30.8*TQAB + 5.98*TQEI
+*0*SPNIRP*TQAO* – 1.23*SPNIRP*TQAB
– 1.36*SPNIRP*TQEI + C

The results in Figure AP. 11 show that there is a significant improvement on the average adjusted R^2 when compared to the seasonal values for all previous models. As with all the other models, the summer/winter results come out slightly higher than the GMT/BST results, but also have a wide range and poor standard deviation.

Quarterly Analysis

The results for quarterly analysis for model 5 are given in Figure AP. 11:

	Q1	Q2	Q3	Q4	Average	St Dev
Adjusted R^2	86.2%	84.5%	86.1%	81.6%	**84.6%**	2.15

Figure AP. 11

The quarterly model consists of the following equations:

Quarter 1
TARGET = 46.9*SPNIRP + 27.4*TQAO + 24.1*TQAB + 4.22*TQEI
+*0*SPNIRP*TQAO* – 1.04*SPNIRP*TQAB
– 1.34*SPNIRP*TQEI + C

Quarter 2
TARGET = *0*SPNIRP* + 37.7*TQAO + 31.1*TQAB + 19.6*TQEI
– 0.101*SPNIRP*TQAO – 1.09*SPNIRP*TQAB
– 1.57*SPNIRP*TQEI + C

Quarter 3
TARGET = 127*SPNIRP + 24.3*TQAO + 12.5*TQAB – 3.93*TQEI
+0.0628*SPNIRP*TQAO – 0.761*SPNIRP*TQAB
– 1.13*SPNIRP*TQEI + C

Quarter 4
TARGET = -23.2*SPNIRP + 22.8*TQAO + 29.0*TQAB + *0*TQEI*
+0.321*SPNIRP*TQAO – 1.25*SPNIRP*TQAB

– 1.24*SPNIRP*TQEI + C

These results show a significant improvement in all of the quarters; however quarter four is still lower and so decreases the average.

Summary
Overall, this model was the best in terms of fit as it built on the advantages from the previous models and gave an end average adjusted R^2 of 84.6% when the data was analysed in terms of quarters. However, the BST/GMT model produces an average adjusted R^2 value of 83.6% and the data is less varied than all of the other regressions for this model.

Cumulative Data

One of the hypothesis of the present analysis is whether summing the half hourly data over different time periods would lead to a better relationship between cost of balancing and the variables involved. By performing averaging and summing to aggregate the data, any outliers in the dataset can effectively brought closer in to the best fit line. An example of this could be the summation of the data for 48 half hourly periods to give daily data.

By choosing to model data consolidated over a time interval longer than the standard half hour period, it helps to alleviate the problem of balancing actions leaking into adjacent data periods. For example, if the control room takes action in period 12, it may impact on periods 13, 14, 15, etc. For this reason, it was decided not only to investigate the effect of changing variables, but also to investigate the effect of using cumulative data over the following time periods:

- EFA Block
- Peak/Trough
- Daily

Analysis began by modelling a simple relationship between total cost, power price and market length – the variables considered in the NIA of previous years – as it is reasonably conclusive that balancing costs are impacted upon by these factors.

This following model is used purely as an example to demonstrate that the usage of daily summed data provides the highest R^2 (this model is analysed under the heading “Model 6”).

This was achieved by performing a regression where the cost of balancing was the dependant variable, with power price (SPNIRP) and power price multiplied by energy imbalance (TQEI) in both long and short market situations the independent variables. Finally, a constant variable C was included so as not to force the line of best fit through the origin.

This gave the following regression:

- Sum of SPNIRP
- Sum of (SPNIRP * TQEI) in a long Market
- Sum of (SPNIRP * TQEI) in a short Market

The results showed an adjusted R^2 value of 87.7%.

Whilst it was suspected that using the daily summed data would give the best results (due to the longer time period) in order to prove this theory it was necessary to carry out the same regression using EFA blocks and peak/trough summations. A summary of the resulting adjusted R^2 values is shown below:

EFA Block	1	2	3	4	5	6	Average	Std. Dev.
Adjusted R^2	71.9%	60.6%	84.4%	88.0%	81.0%	77.8%	77.3%	9.87

	Peak	Trough	Average	Std. Dev.
Adjusted R^2	87.2%	77.2%	82.2%	7.07

	Daily
Adjusted R^2	87.7%

Figure AP. 12

This is an important set of results as from these, it can be seen that summing the half hourly data into daily periods (subsequent to any calculations) gives the most improved R^2 values.

Whilst performing the regressions for the models that follow in this document the daily summation consistently provided the best results and as such the figures from this point in the document onwards refer only to the daily data set.

Model 6

Returning to this model to for a more in depth analysis - it was created on the hypothesis that by breaking down the energy imbalance into the daily sums of half hourly periods where the market is both long and short, it may be possible to achieve a more accurate model. This accounts for the differences in costs of balancing either a short or a long market. In this case the following variables were regressed on TARGET:

- Sum of SPNIRP
- Sum of (SPNIRP * TQEI) in a long market

- Sum of (SPNIRP * TQEI) in a short market

As suspected, this resulted in a much improved adjusted R^2 value of 87.7%

Target = 427 * Sum of SPNIRP
– 0.99 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.61 * Sum of (SPNIRP * TQEI) in a Short Market + C

This gives in excess of a 9% improvement on a similar model using half-hourly data (74.5%) and verifies that daily summed data gives far superior results in terms of R^2 values than half hourly data.

By breaking down this model into several sections according to the time of year, it was theorised that an improved adjusted R^2 could be achieved. Obviously usage habits vary according to time of year, and as such having several models to reflect these different periods seems to result in a better fit for each.

The same regression was carried out for each data set below (i.e. the data set 'quarter 1' uses only data from the first quarter of each of the years covered by the full dataset):

	British Summer Time	Greenwich Mean Time	Average	Std. Dev.
Adjusted R^2	89.5%	86.8%	88.2%	1.91

Figure AP. 13

BST:
Target = 435 * Sum of SPNIRP
– 1.04 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.42 * Sum of (SPNIRP * TQEI) in a Short Market + C

GMT:
Target = 422 * Sum of SPNIRP
– 0.887 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.87 * Sum of (SPNIRP * TQEI) in a Short Market + C

	Summer	Winter	Average	Std. Dev.
Adjusted R^2	90.6%	86.4%	88.5%	2.97

Figure AP. 14

Summer:
Target = 442 * Sum of SPNIRP
– 1.18 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.37 * Sum of (SPNIRP * TQEI) in a Short Market + C

Winter:
Target = 427 * Sum of SPNIRP
– 0.887 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.85 * Sum of (SPNIRP * TQEI) in a Short Market + C

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Average	Std. Dev.
Adjusted R^2	88.1%	88.7%	92.6%	88.0%	89.4%	2.19

Figure AP. 15

The equations are as follows:

Quarter 1:
Target = 270 * Sum of SPNIRP
– 0.727 * Sum of (SPNIRP * TQEI) in a Long Market
– 2.01 * Sum of (SPNIRP * TQEI) in a Short Market + C

Quarter 2:
Target = 360 * Sum of SPNIRP
– 1.18 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.57 * Sum of (SPNIRP * TQEI) in a Short Market + C

Quarter 3:
Target = 483 * Sum of SPNIRP
– 1.12 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.27 * Sum of (SPNIRP * TQEI) in a Short Market + C

Quarter 4:
Target = 555 * Sum of SPNIRP
– 1.08 * Sum of (SPNIRP * TQEI) in a Long Market
– 1.74 * Sum of (SPNIRP * TQEI) in a Short Market + C

It can be seen that the quarterly splitting of the model results in the greatest overall improvement in adjusted R^2 values; with a reasonably low standard deviation in results (i.e. the adjusted R^2 values are consistently high between quarters).

Model 7

Model 7 includes the sum of energy imbalance during the daily period as a standalone variable in order to see if this has a direct effect on cost.

The variables in the analysis were:

- Sum of SPNIRP
- Sum of TQEI
- Sum of (SPNIRP * TQEI) in a long market
- Sum of (SPNIRP * TQEI) in a short market

This gave an overall adjusted R^2 of 87.8%.

Target = 404 * Sum of SPNIRP
- 5.77 * Sum of TQEI
- 0.85 * Sum of (SPNIRP * TQEI) in a long market
- 1.58 * Sum of (SPNIRP * TQEI) in a short market + C

This proves that inclusion of the sum of energy imbalance does not greatly impact upon our model for cost since the adjusted R^2 has improved by only 0.1%. This model can therefore be discarded as the addition of another variable (and therefore additional complexity to the model) is not justified by such a small increase.

<u>Model 8</u>

Model 8 deals with similar variables to model 7, but has included the factor of splitting Power Price and Energy Imbalance variables according to market length in order to represent the long and short market components. It was hoped this would provide a higher resolution of results.

The variables in the analysis were:

- Sum of SPNIRP in a Long Market
- Sum of SPNIRP in a Short Market
- Sum of TQEI in a Long Market
- Sum of TQEI in a Short Market
- Sum of (SPNIRP * TQEI) in a Long Market
- Sum of (SPNIRP * TQEI) in a Short Market

This gave an overall adjusted R^2 of 87.7%.

Target = 340 Sum of SPNIRP in a Long Market
+ 449 Sum of SPNIRP in a Short Market
- 7.65 * Sum of TQEI in a Long Market
*+ 0 * Sum of TQEI in a Short Market*
- 0.74* Sum of (SPNIRP * TQEI) in a long market
- 1.53* Sum of (SPNIRP * TQEI) in a short market + C

Again, the adjusted R^2 value has not increased with the addition of more variables, showing that splitting according to market length has little to no effect on our model.

<u>Model 9</u>

Model 9 focused on the inclusion of the total quantity of bids and offers on the system as a product of power price.

The variables included were:

- Sum of SPNIRP
- Sum of (SPNIRP * Total Quantity of Accepted Bids)
- Sum of (SPNIRP * Total Quantity of Accepted Offers)

This resulted in an overall adjusted R^2 of 83.2%

Target = 273* Sum of SPNIRP
+ 0.81* Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.60 Sum of (SPNIRP * Total Quantity of Accepted Offers) + C

Looking at this model in more detail (as this is the first model to include the variables of bids and offers), seasonal results are as follows:

	British Summer Time	Greenwich Mean Time	Average	Std. Dev.
Adjusted R^2	84.8%	82.7%	83.8	1.48

Figure AP. 16

BST:
Target = 275 * Sum of SPNIRP
+ 0.854 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.51 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

GMT:
Target = 338 * Sum of SPNIRP
+ 0.787 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.65 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

	Summer	Winter	Average	Std. Dev.
Adjusted R^2	86.4%	82.0%	84.2%	3.11

Figure AP. 17

Summer:
Target = 264 * Sum of SPNIRP
+ 0.906 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.55 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Winter:
Target = 333 * Sum of SPNIRP
+ 0.809 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.66 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Average	Std. Dev.
Adjusted	85.1%	86.5%	86.9%	82.4%	85.2%	2.04

R^2							

Figure AP. 18

The equations are as follows:

Quarter 1:
Target = 237 * Sum of SPNIRP
+ 0.810 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.61 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Quarter 2:
Target = 201 * Sum of SPNIRP
+ 1.00 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.69 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Quarter 3:
Target = 318 * Sum of SPNIRP
+ 0.841 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.43 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Quarter 4:
Target = 361 * Sum of SPNIRP
+ 0.848 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.89 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

This essentially shows there is a good correlation between power price and the quantity of accepted bids and offers. This relationship, however, is clearly not as strong as that between power price and market length as the adjusted R^2 value in this case is substantially lower.

Model 9.1

Model 9.1 is a modified version of model 9 that includes standalone variables for the total quantity of accepted bids and offers (as opposed to being included as a product of power price) in an attempt to increase the R^2 to a similar level as previous models.

The variables included were:

- Sum of SPNIRP
- Sum of Total Quantity of Accepted Bids
- Sum of Total Quantity of Accepted Offers
- Sum of (SPNIRP * Total Quantity of Accepted Bids)
- Sum of (SPNIRP * Total Quantity of Accepted Offers)

This gave an overall adjusted R^2 of 83.4%

Target = 165 * Sum of SPNIRP
- 13 * Sum of Total Quantity of Accepted Bids
*+ 0 * Sum of Total Quantity of Accepted Offers*

+ 0.56 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 1.6 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Whilst this model does provide an increase in the value of adjusted R^2, there is only a 0.2% increase from model 9. This is not really justified by the addition of 2 new variables and the associated complexity that these add to the model. As such it would seem unnecessary to analyse this model any further.

<u>Model 10</u>

The final model analysed was a combination of models 6 and 9. This means the model considers the relationship of cost with power price, energy imbalance, market length, accepted offers and accepted bids.

The variables included were:

- Sum of SPNIRP
- Sum of (SPNIRP * TQEI) in a long market
- Sum of (SPNIRP * TQEI) in a short market
- Sum of (SPNIRP * Total Quantity of Accepted Bids)
- Sum of (SPNIRP * Total Quantity of Accepted Offers)

This produced an initial R^2 of 91.1% - the highest yet achieved.

Target = 136 * Sum of SPNIRP
– 1.42 * Sum of (SPNIRP * TQEI) in a long market
– 1.54 * Sum of (SPNIRP * TQEI) in a short market
– 0.69 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.19 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Dividing the data up seasonally produced the following results:

	British Summer Time	Greenwich Mean Time	Average	Std. Dev.
Adjusted R^2	91.4%	91.6%	91.5	0.141

Figure AP. 19

BST:
Target = 197 * Sum of SPNIRP
– 1.31 * Sum of (SPNIRP * TQEI) in a long market
– 1.34 * Sum of (SPNIRP * TQEI) in a short market
– 0.485 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.223 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

GMT:
Target = 88.2 * Sum of SPNIRP
– 1.67 * Sum of (SPNIRP * TQEI) in a long market

– 1.89 * Sum of (SPNIRP * TQEI) in a short market
– 1.01 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ *0 * Sum of (SPNIRP * Total Quantity of Accepted Offers)*+ C

	Summer	Winter	Average	Std. Dev.
Adjusted R^2	92.5%	91.0%	91.8%	1.06

Figure AP. 20

Summer:
Target = 189 * Sum of SPNIRP
– 1.44 * Sum of (SPNIRP * TQEI) in a long market
– 1.29 * Sum of (SPNIRP * TQEI) in a short market
– 0.506 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.223 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Winter:
Target = 133 * Sum of SPNIRP
– 1.48 * Sum of (SPNIRP * TQEI) in a long market
– 1.71 * Sum of (SPNIRP * TQEI) in a short market
– 0.803 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.176 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Average	Std. Dev.
Adjusted R^2	93.6%	91.4%	93.9%	91.7%	92.7%	1.28

Figure AP. 21

The equations are as follows:

Quarter 1:
Target = *0 * Sum of SPNIRP*
– 1.42 * Sum of (SPNIRP * TQEI) in a long market
– 1.76 * Sum of (SPNIRP * TQEI) in a short market
– 0.760 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.176 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Quarter 2:
Target = 116 * Sum of SPNIRP
– 1.30 * Sum of (SPNIRP * TQEI) in a long market
– 1.31 * Sum of (SPNIRP * TQEI) in a short market
– 0.360 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.429 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

Quarter 3:
Target = 259 * Sum of SPNIRP
– 1.53 * Sum of (SPNIRP * TQEI) in a long market
– 1.36 * Sum of (SPNIRP * TQEI) in a short market

– 0.617 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ *0 * Sum of (SPNIRP * Total Quantity of Accepted Offers)*+ C

Quarter 4:
Target = 194 * Sum of SPNIRP
– 1.52 * Sum of (SPNIRP * TQEI) in a long market
– 1.58 * Sum of (SPNIRP * TQEI) in a short market
– 0.767 * Sum of (SPNIRP * Total Quantity of Accepted Bids)
+ 0.396 * Sum of (SPNIRP * Total Quantity of Accepted Offers)+ C

These results show that by combining two previous models each with good correlations using different variables it is possible to achieve a single model using the full range of variables to achieve a superior R^2 value.

Appendix B

B.1 Managing the system frequency

1. Great Britain's nominal operating frequency is 50 Hz and National Grid have a statutory duty to maintain system frequency within 49.5 and 50.5 Hz; operationally, National Grid set a more restrictive range of 49.8 to 50.2 Hz.

2. In order to maintain frequency within such limits, generation and demand have to be balanced in the system second-by-second, otherwise excessive generation causes frequency to raise and excessive demand causes frequency to reduce.

B.1.1 What is Energy Imbalance

3. National Grid balance the system in a steady state condition through:
   - buying and selling power in the Balancing Mechanism (otherwise known as offers and bids);
   - pre-gate closure balancing transactions (PGBTs); and
   - trading, either through over the counter negotiations or through the energy exchange market, APX.
4. The costs (and incomes) caused by such transactions are the so-called Energy Imbalance actions.

5. Additional information can be found at http://www.nationalgrid.com/uk/Electricity/Balancing/services/energyrelated/

B.1.2 What is Margin

6. An important driver in National Grid's ability to take the aforementioned actions is the amount of available and connected (synchronised) generation in the system. As such, National Grid defines a Short Term Operating Reserve Requirement (STORR), which is the minimum acceptable difference between the sum of the synchronised generation capacity and the forecast demand.

7. The STORR is set such that there is a risk of only 1 in 365 days that total demand won't be able to be met. Setting STORR is a fine balance: demanding a lower risk implies a more expensive system operation; achieving cost reduction through the reduction of this requirement implies an acceptance of higher risk of demand disconnection.

8. Operationally, costs related to meeting STORR are called Margin actions. There are two basic mechanisms to achieve STORR: Operating Reserve actions and contracting of Short Term Operating Reserve (STOR) units.

9. The first mechanism is acted by the purchase of power from units not scheduled to be connected in the system at the required time. These actions are expected to cause either the additional synchronisation of such units or the advancing of synchronisation time of units that were

already planned to connect, or the delaying of the de-synchronisation time of units already connected in the system. These Operating Reserve actions can be operated either in the form of offers in the balancing mechanism or as PGBTs and Trades.

10. The second mechanism is the contracting of relatively fast acting standby generation through STOR tenders. STOR units can be either BM participants or not. Such units are paid availability fees and utilisation fees.

11. Two additional items fall within the “Margin” cost group: BM Start Up and Constrained Margin Management actions.

12. BM Start Up relates to actions taken by National Grid to position generation units with longer notice times into a state of readiness through “warming” the units.

13. Constrained Margin Management (CMM) relates to additional operating reserve actions taken only partially due to the sterilisation of operating reserve (headroom) caused by active transmission constraints. Therefore, if an operating reserve action taken in a given generation unit is deemed to be completely for the replacement of sterilised headroom behind a constrained boundary, then it is assigned as a constraint cost; otherwise, if only part of the created headroom is deemed to have been necessary for sterilised headroom replacement, then the cost is assigned as CMM, as illustrated below:

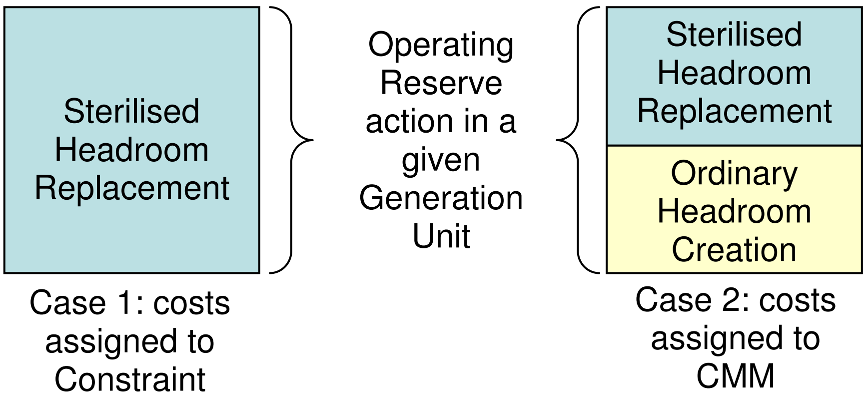


Figure AP.22 - Operating Reserve actions assigned to Constraints or to CMM

14. Additional information can be found at http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/

B.1.3 What is Footroom (Downward Regulation)

15. If Margin actions are those that enable National Grid to increase generation to higher than expected demand levels, Footroom (or Downward Regulation) actions are those taken to reduce the amount of

generation connected in the system so that frequency can be safely managed in periods of lower than expected demand.

B.1.4 What is Response

16. Transient frequency control is managed by positioning a certain number of generation units in an automatic frequency responsive mode, so that such generation units can automatically change their output according to the metered frequency.

17. The amount of generation held in this frequency responsive mode is a function of the largest possible immediate loss of generation and demand and the maximum acceptable frequency excursion in such event.

18. National Grid incurs two main costs by performing such actions: the cost of positioning the units in the responsive mode (bids and offers in the Balancing Mechanism) and the usage fee charged by the generators to act in such mode (tendered).

19. Special contracts exist to minimise National Grid's cost of positioning the units in frequency response mode, namely the Firm Frequency Response (FFR) and Part Loaded Response (PLR) contracts.

20. The above described mechanism is provided by dynamic response providers. A certain proportion of frequency response can also be achieved with the immediate disconnection of large demand units, the so called static response providers.

21. Additional information can be found at http://www.nationalgrid.com/uk/Electricity/Balancing/services/frequencyresponse/

B.1.5 What is Fast Reserve

22. In the event of an incident involving generation disconnection, frequency response units will act immediately to stabilise frequency within acceptable limits. Control engineers will issue instructions to re-despatch generation so that a new steady state balance can be achieved; however, those actions have a natural delay time, dependant of the dynamics of the available generation at the time of the incident. In order to achieve a more promptly re-establishing of frequency and restore the system frequency response capability, National Grid need to use units with enhanced dynamic characteristics.

23. Additionally, in the event of rapid demand changes, such as those experienced during "TV pickups", National Grid will utilise the enhanced capabilities of fast acting units.

24. Such units, capable of providing ramp rates of at least 25 MW/min and holding such output for at least 15 minutes, are contracted under the Fast Reserve terms.

25. Additional information can be found at http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/fastreserve/

B.2 Inter-dependency of components

26. As can be seen, the above components (Energy Imbalance, Margin, Response and Fast Reserve) are all products used by National Grid to maintain frequency within defined limits. As such, it makes sense to have a bundled incentive scheme with those components.

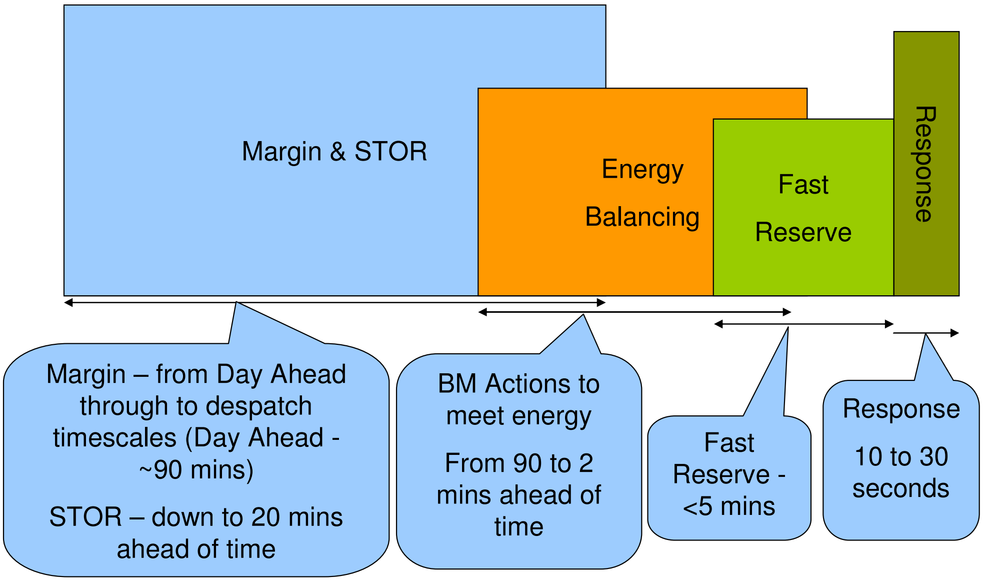


Figure AP.23 - Actions taken in different timescales for managing system frequency

B.3 Current Incentive Arrangements

27. The cost for managing system frequency through the usage of each of the described products is currently incentivised with the other balancing cost components as part of the Balancing Services Incentive Scheme (BSIS).

28. Changes in procurement costs of those energy related products feed into the overall BSIS incentive cost pot. Figure 3 shows the relative cost of energy related components when compared to other BSIS components

B.4 Components Volumes and Costs

29. Figure AP.24 shows the cost incurred for each energy-related product. As can be seen, costs can be incurred as bid/offers in the Balancing Mechanism (BM), as bilateral over the counter (OTC), energy exchange (APX) and System Operator to System Operator (SO-SO) trades, and as a result of Ancillary Services (AS) contracts.

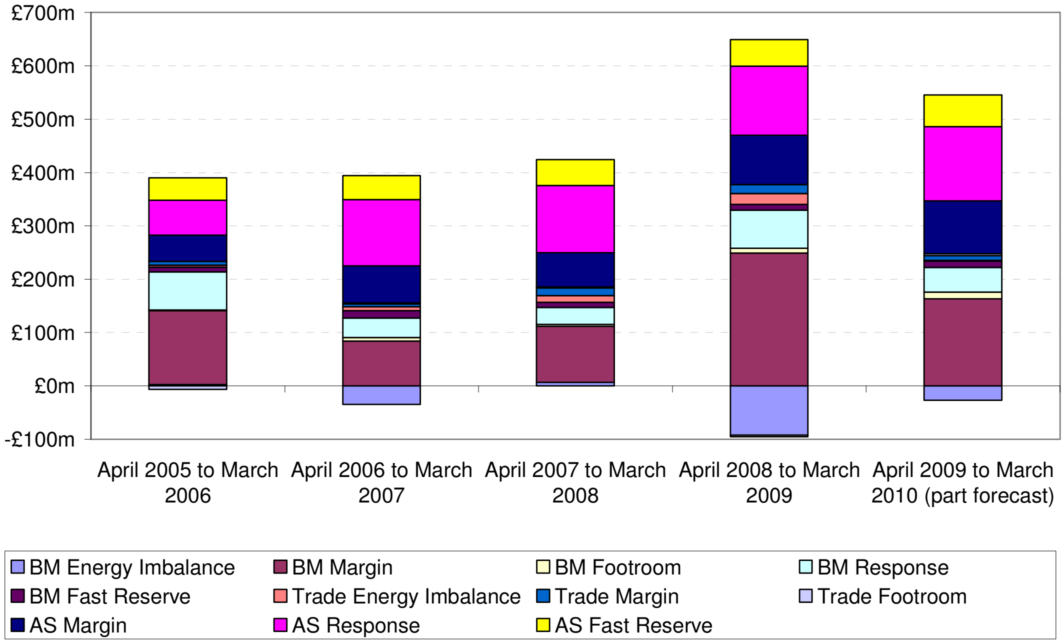


Figure AP.24 - Energy Related Components since BETTA Go-live

30. Each component has a different proportion of costs in the Balancing Mechanism, Trades and Ancillary Services, as can be seen in the following charts:

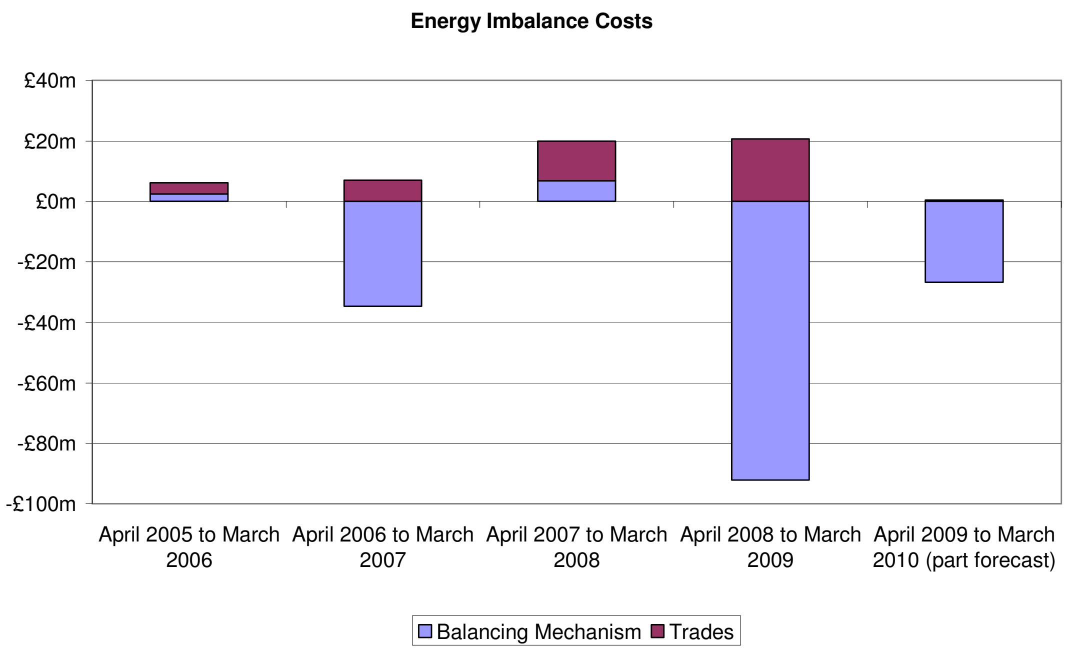


Figure AP.25 - Energy Imbalance split in BM and Trades

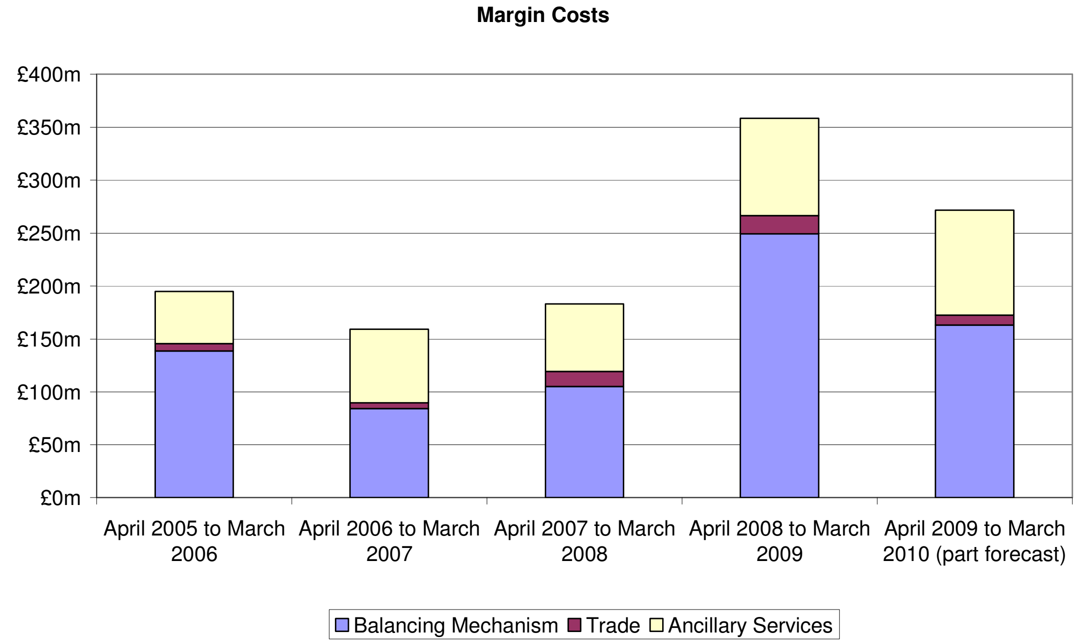


Figure AP.26 - Margin split in BM, Trades and AS

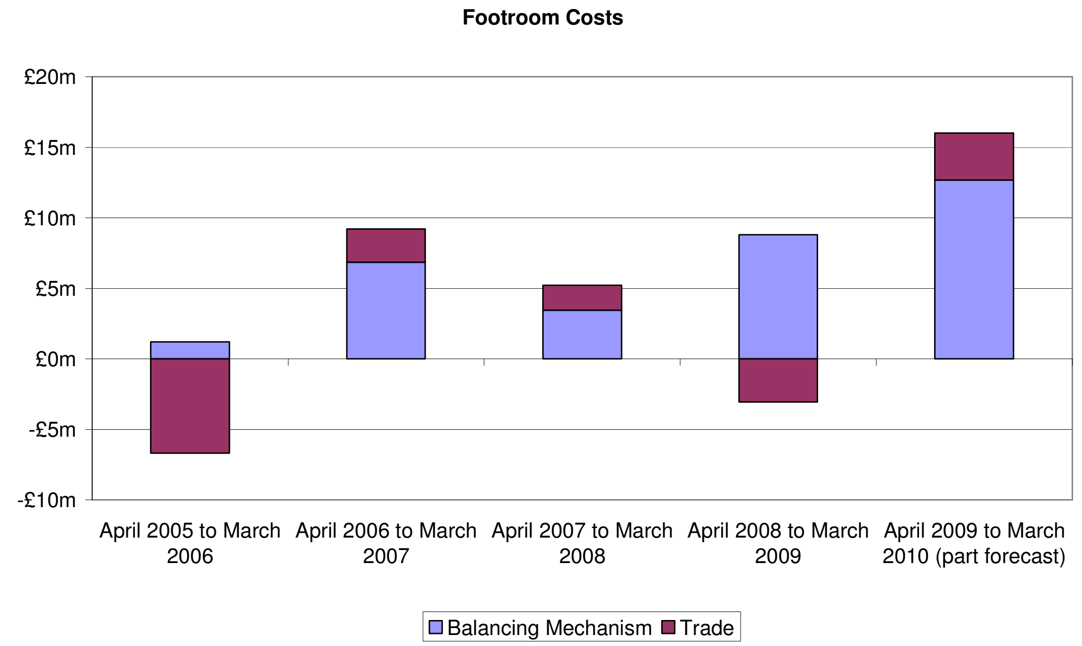


Figure AP.27 - Footroom split in BM and Trades

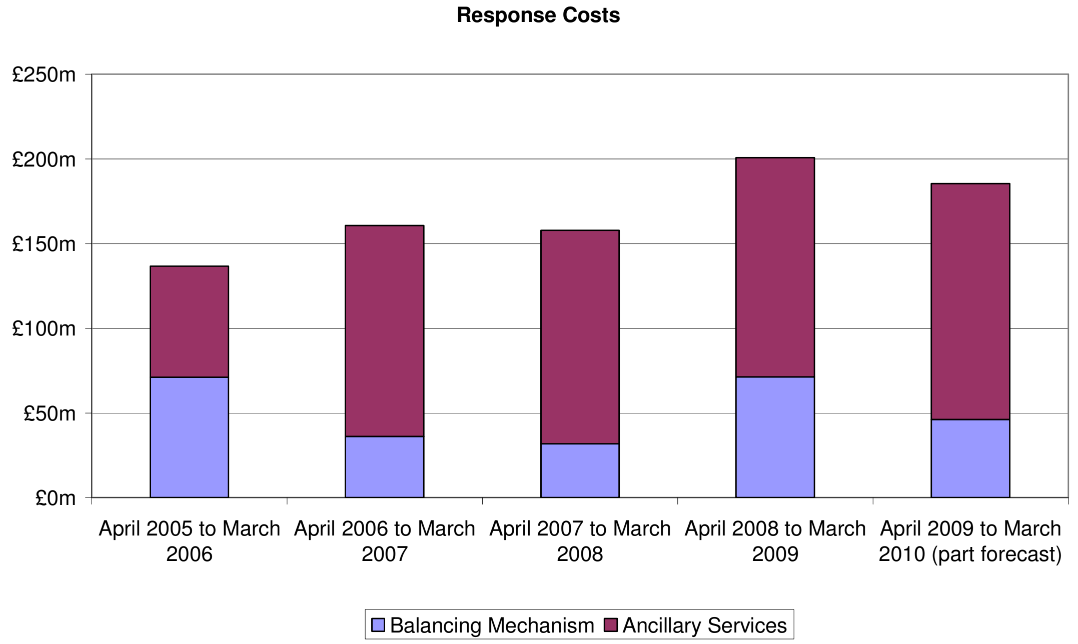


Figure AP.28 - Response split in BM and AS

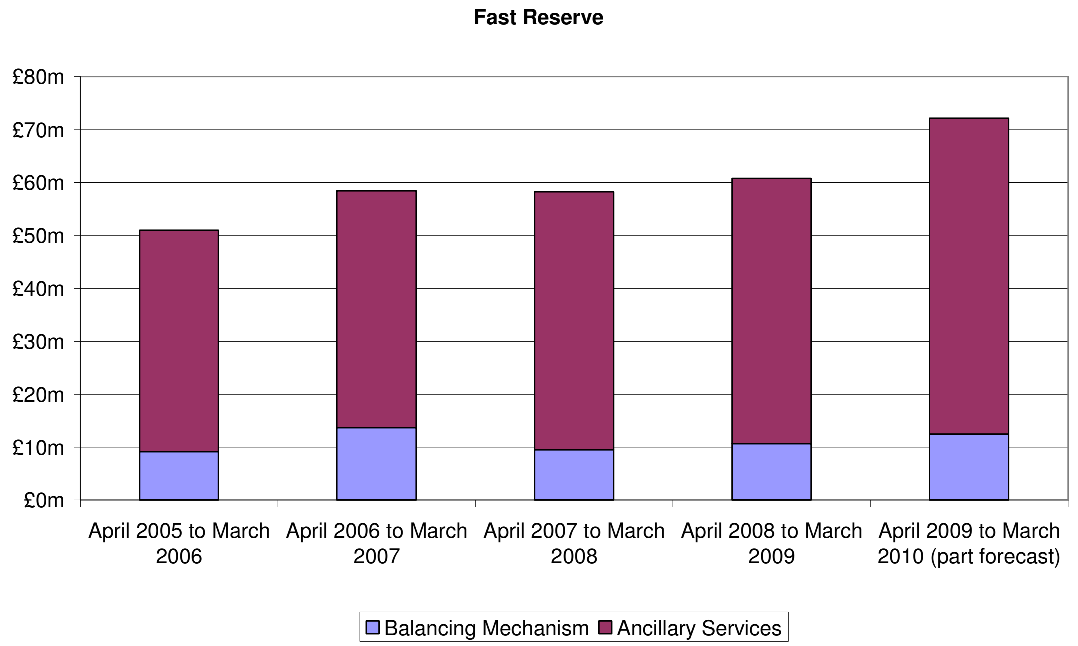


Figure AP.29 - Fast Reserve split in BM and AS

Section 7
Contact details

If you would like to discuss any issue on SO Incentives, please contact us via the contact details below.

To register your interest in receiving future communications on this consultation process please email: SOIncentives@uk.ngrid.com

On the web:
New dedicated web pages for this process are available at the following addresses:

Electricity SO Incentives:	http://www.nationalgrid.com/uk/Electricity/
Gas SO Incentives:	http://www.nationalgrid.com/uk/gas/

Talk to us:

Gas

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Electricity

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