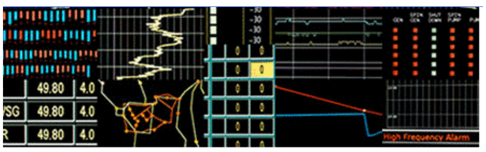
National Grid
Gas and Electricity System Operator Incentives

Initial Proposals Consultation

Issued 7th December 2007

Responses requested by 25th January 2008



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Executive Summary

National Grid operates the Electricity and Gas Transmission Systems in Great Britain. We are subject to a number of financial incentive arrangements which encourage us to minimise the overall cost of balancing to consumers and to support the efficient operation of the wholesale gas and electricity markets.

A number of these incentives expire on 31st March 2008, and in August 2007 Ofgem initiated a process for reviewing these incentives by issuing an Initial Thoughts consultation in respect of both Electricity and Gas System Operation.

In a change to previous approaches to setting incentives, Ofgem, in an open letter dated 1st November 2007, asked National Grid to take the lead in the next part of the process by providing and consulting upon its own set of 'Initial Proposals' for incentive arrangements to apply from April 2008. Ofgem will review the responses to this consultation ahead of bringing forward its Final Proposals and proposed modifications to National Grid's Electricity and Gas Licences in early 2008.

As part of this consultation process we have arranged an industry workshop on 10th January 2008 and are happy to engage with parties on a 1:1 basis in order to assist industry members in understanding our forecasts, informing their responses to this Initial Proposals consultation.

This document sets out our initial proposals for Electricity and Gas incentive arrangements upon which we invite industry views and preferences. A summary of the incentive proposals and the consultation questions can be found in Section 4.

The key themes in the consultation are summarised below:

In Electricity

- **Investment for renewable generation** - During 2008/09 major construction works will begin on the Scotland-England border to increase the capacity of the system, to connect renewable generation in Scotland, putting additional pressure on network constraints at this boundary. The costs of system operation are forecast to rise, during this investment in the transmission system, in the short term to help move towards a lower-carbon electricity sector.

- **Reducing carbon emissions** - The Large Combustion Plants Directive comes into effect on 1st January 2008. As a result some power stations may choose to change their operating regime and limit their output and/or availability. We will also see continued growth in renewable generation during 2008/09. These two effects lead to upward pressure on the costs of system operation.

- **Customer choice -** We have provided a range of options to allow customers to express preferences as to the way we should manage balancing costs. We have developed a range of options that offer choices as to whether we should aggressively pursue cost reductions or act conservatively to manage the system. To help customers understand the impact of these choices we have provided forecast ranges for balancing costs and likely BSUoS prices.

- **Targeted incentives** – Our scheme proposals are for one year and centre on our forecast mean incentivised balancing cost for 2008/09 of £530m, but there remains a wide range of uncertainties within this. In response to this we are seeking views on two possible indexation mechanisms, which would allow incentive targets to move with prevailing market and system conditions, keeping incentives more focussed on costs within our control.

In Gas

- **Lower overall requirements** - NTS Shrinkage and Operating Margins requirements are forecast to reduce from current levels primarily due to the anticipated commissioning of new supplies at Milford Haven, expansion at the Isle of Grain importation facility and increased flows at the NTS entry point at Easington.

- **Longer duration incentives** – The drivers of the majority of shrinkage costs are well understood and we propose to link the shrinkage target to cost drivers and remove links to cost elements that are outside of National Grid's control. This paves the way for the option of longer term incentives in this area, potentially unlocking value from innovations to further reduce shrinkage costs to consumers. We also propose enduring methodologies for reference prices associated with of shrinkage procurement to minimise uncertainty in this area going forward.

- **Customer choice** – We have provided a range of options to allow customers to express preferences in a number of areas. In relation to shrinkage, we describe options around duration and strength of incentive. In relation to Operating Margins we present options around the management of utilisation costs. In relation to residual balancing we offer choices around the removal of the linepack incentive, and in relation to information publication we offer choices around levels of service improvement and scheme duration.

- **Further review** – We believe there are areas of the SO activity, in particular Operating Margins, Residual Balancing and Demand Forecasting which could be reviewed more fundamentally in the longer term and therefore we propose to retain the existing form of these incentives for 2008/09.

We have provided summary information underpinning our forecasts in the main document and where appropriate further detail is provided within the appendices and in electronic format via our website. We believe the information provided, coupled with the planned Incentives workshop, should put customers in a better position to understand the drivers of costs and assist them in making informed representations in response to this consultation.

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

by 5pm on 25th January 2008

Contacts

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Section 1
Introduction

Introduction

1. National Grid operates the Electricity and Gas Transmission Systems in Great Britain. We are subject to a number of financial incentive arrangements which encourage us to minimise the overall cost of balancing to consumers and to support the efficient operation of the wholesale gas and electricity markets.

2. A number of these incentives expire on 31st March 2008, and in August 2007 Ofgem initiated a process for reviewing these incentives by issuing an Initial Thoughts consultation in respect of both Electricity and Gas System Operation.

3. In a change to previous approaches to setting incentives, Ofgem, in an open letter dated 1st November 2007, asked National Grid to take the lead in the next part of the process by providing and consulting upon its own set of 'Initial Proposals' for incentive arrangements to apply from April 2008. Ofgem will review the responses to this consultation ahead of bringing forward its Final Proposals and proposed modifications to National Grid's Electricity and Gas Licences in early 2008.

4. As part of this consultation process we have arranged an industry workshop which will cover both the electricity and gas proposals and provide opportunity for interested parties to ask questions and to understand better our forecasts and assumptions in relation to key cost drivers, in order to inform their responses to this Initial Proposals consultation. The workshop will be held on 10th January 2008 at the Stratford Manor Hotel, Stratford Upon Avon, Warwickshire. To register to attend this workshop please email Bea.ennim@uk.ngrid.com. More details will be circulated to registered attendees near the time.

5. In addition to the workshop, we are happy to meet with Market Participants to discuss specific issues in more detail. Please contact Duncan Burt or Mark Brackley (details below) if you are interested in this.

6. This consultation document sets out our initial proposals for Electricity and Gas incentive arrangements to apply from April 2008 upon which we invite industry views and preferences. The document is structured as follows:

   - Section 2 sets out the proposals which apply to National Grid Electricity Transmission (NGET) in respect of GB electricity system operation. It explains our forecasts for incentivised balancing costs and highlights key cost drivers and areas of uncertainty, and presents a number of incentive scheme options.

- Section 3 sets out proposals which apply to National Grid Gas (NGG) in respect of GB gas system operation. It explains our forecasts for Shrinkage and Operating Margins requirements and presents a number of proposals and incentive scheme options across the range of incentivised activities in the scope of this consultation.

- Section 4 summarises the incentive scheme proposals and consultation questions for both electricity and gas.

7. Further supporting information to this consultation can be found on National Grid's website at http://www.nationalgrid.com/uk/Electricity/SoIncentive/ in the analysts' area. Ofgem's initial thoughts consultation also contains information regarding historic outturns and performance under previous incentives and can be found here.

8. 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 should be sent to
soincentives@uk.ngrid.com

by 5pm on 25th January 2008

Contacts

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Section 2
Electricity System Operator Incentives

This section sets out National Grid's forecast for Electricity System Operator (ESO) balancing costs and initial proposals options for incentive scheme structures for 2008/09. The section is structured as follows:

-Background
-Cost Forecasts for 2007/08 and 2008/09
-Initial Scheme Proposals
-Forecast BSUoS prices 2007/08 and 2008/09

Supporting information for this section is provided in a separate electricity appendix available on the SO Incentives section of our website.

2.1 Background

9. National Grid is incentivised to balance the system in an efficient, economic and co-ordinated manner. The application of financial incentives to National Grid serves to ensure that we act and invest innovatively to ensure balancing costs and risks are efficiently minimised.

10. In the development of incentives proposals, our aim is to ensure that our forecast and the reasoning behind our initial proposals is:

    - clear and transparent;
    - that we offer a range of choices to seek customers' views on the appropriate incentive framework for NGET; and
    - that it is clear how the incentivised cost level, which sets the risk/ reward framework for NGET, relates to the level of cost borne by participants through BSUoS costs.

11. Any forecast of balancing costs contains a number of uncertainties and hence the forecast is presented as a likely range of balancing costs. Any reference to the 'forecast' refers to the forecast range of costs and not simply the 'mean' value derived thereof.

    Our forecast is structured as follows:

    1. For the majority of costs, forecast is by means of extrapolation of volumes, prices and costs based on historic and current trends and known drivers. Known drivers are variables such as Power price, Market Imbalance (NIV) and the volume of transmission network outages.
    2. For new, or more uncertain costs, forecasts have been developed based on the information available but are in general more uncertain.

In particular this applies to the likely impact of the Large Combustion Plants Directive on system operation.

3. As part of the forecast, we have also identified areas where we hope to make savings against these forecast costs through investments in the System Operator function. In line with the principle of incentivisation, the cost of these investments will only be funded through NGET sharing in any out-performance against the incentive scheme target.
4. We have received industry feedback to improve the clarity over the link between our forecast and likely BSUoS costs. Therefore, based on our balancing cost forecast we have produced two sets of outputs:

    i. the range of incentivised balancing costs used for setting incentive targets and parameters;
    ii. based on the same forecast, the corresponding range of BSUoS charges.

For a detailed background explanation of incentivised balancing costs and BSUoS costs please refer to our BSIS Seminar presentation of 10 January 2007, available on the Operational Forum section of our website and here.

2.2 Forecast balancing costs for 2007/08

As described above, our forecast for 2008/09 incentivised balancing costs is built up largely by extrapolating existing cost levels in line with drivers. Therefore, our forecast of 2007/08 costs forms the basis of our 2008/09 forecast. This section therefore describes our 2007/08 forecast. This is then followed by the explanation of our 2008/09 forecast in the following sections.

Summary

12. Our forecast for incentivised balancing costs for 2007/08 has been presented through the year at Operational Forums. The evolution of these forecasts and our latest forecast is shown on the diagram below.

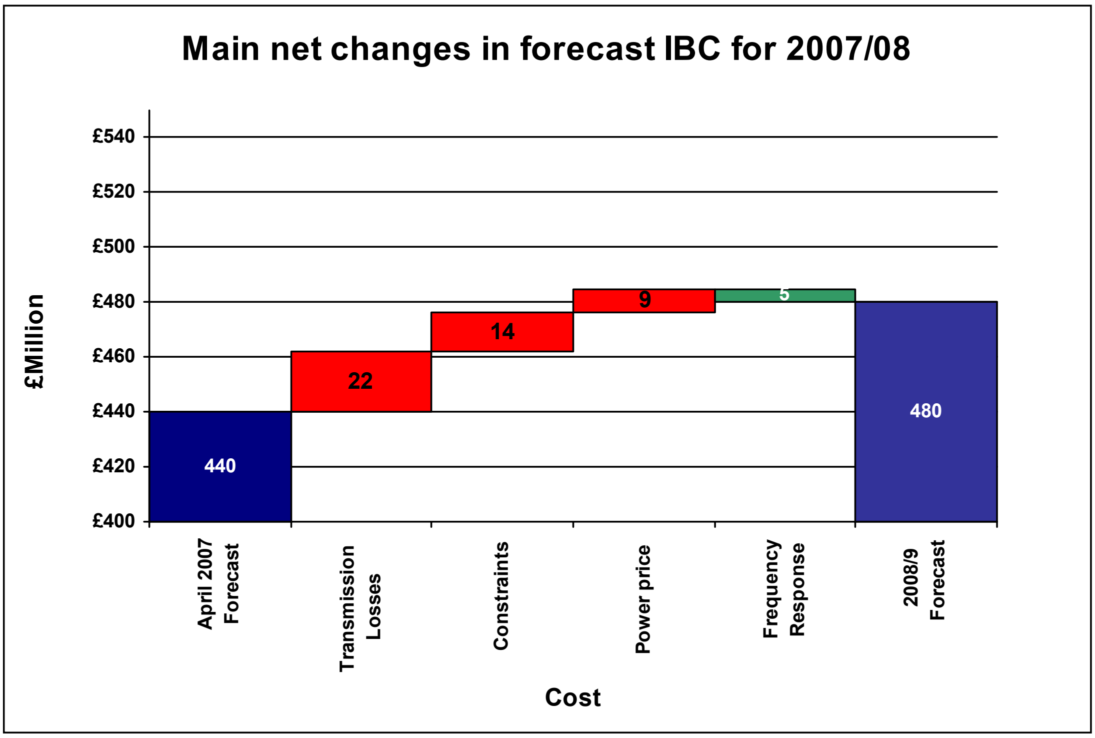

Figure 2.1: Main net changes to our 2007/08 forecast between our April 2007 forecast and our latest, December 2007, forecast

13. There have been a number of revisions to our forecast within year. These changes have arisen as market conditions, costs incurred and future indicators have changed and unfolded. As shown in the diagram the key factors that have driven revisions to our view of 2007/08 incentivised costs within-year have been:

- as yet not fully explained increases in transmission losses throughout the year;
- revised constraint costs based on outturn prices and volumes;
- a rise in forward winter wholesale electricity prices;

- reduction in market length, NIV, compared to previous years (this effect nets to zero hence is not discernible on the graph above);
- a reduction in frequency response costs.

14. The most significant of these effects in terms of incentivised costs *and* BSUoS costs for 2007/08 is the rise in wholesale prices seen ahead of the winter. The evolution in winter power prices for Q1 2006 through to 2009 is shown in the graph below.

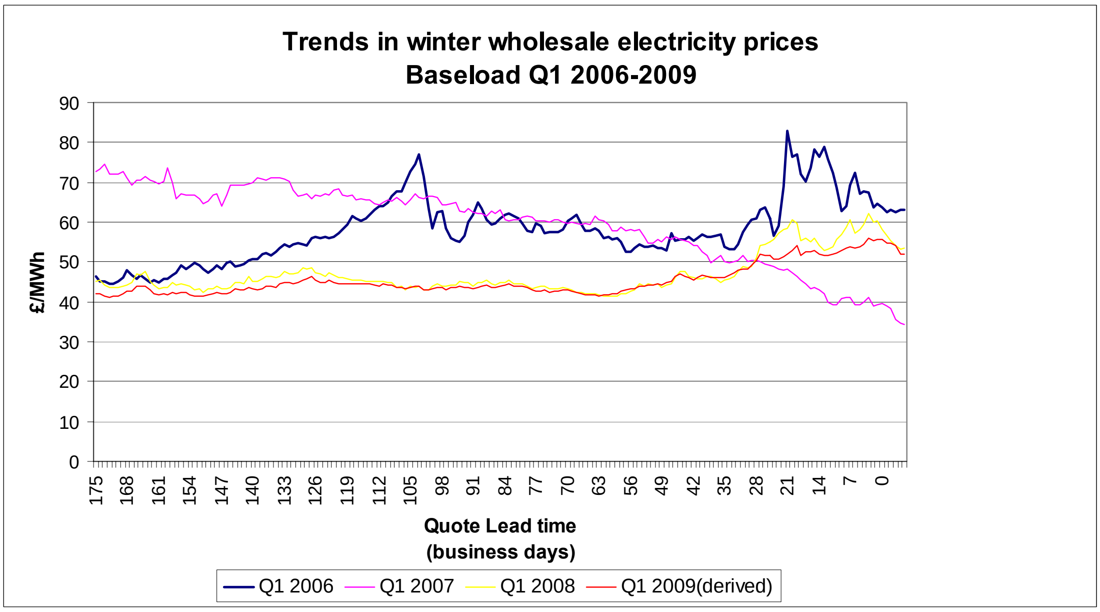

Figure 2.2: Trends in wholesale electricity forward prices (winter, Q1), 2006 to 2009

15. The trend in forward wholesale prices for this winter (Q1 prices used in the graph) repeats that seen in 2005/06 and is mirrored in the forward prices for Q1 2009. Also clear is the different trend followed by prices for Q1 2007, which tracked down through the year. The graph illustrates the high level of uncertainty in the forward price and the likelihood of change in prices through the year.

16. For comparison, the chart below shows National Grid's actual daily cumulative incentivised balancing costs for 2007/08, with an extrapolation to a forecast outturn of £480m, compared to the costs for 2006/07 which outturned at£495m.

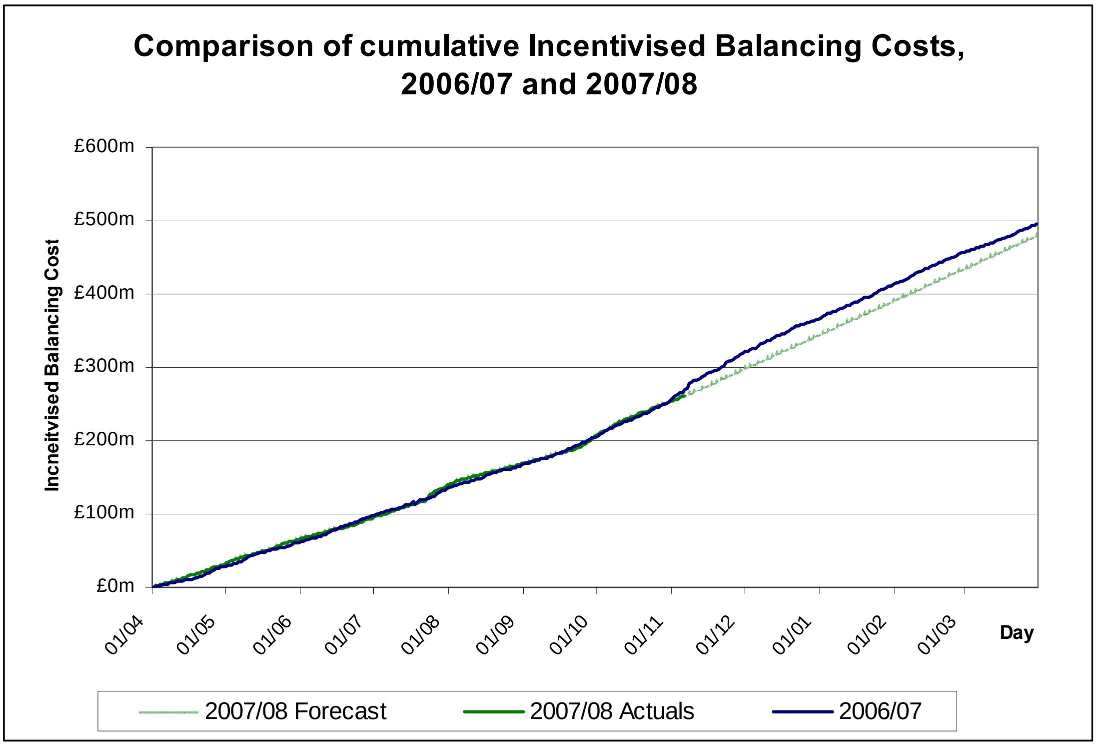

Figure 2.3: Comparison of cumulative daily IBC, 2006/07 actual and 2007/08 actual and forecast

17. As can be seen, year on year costs to date are very closely aligned to last year's and to achieve £480m we are forecasting a lower level of costs this winter than last. This is largely due to a lower constraint cost forecast for this winter.

18. A detailed component-level breakdown of our forecast for £480m is provided in our appendix and in comparison with the 2008/09 forecast in the next section.

Range of Forecast Costs 2007/08

19. There are a number of uncertainties that remain for 2007/08 balancing costs. With approximately four months of the incentive year remaining at the time of writing, the range of likely balancing costs for 2007/08 remains large at between approximately £460m and £510m. This corresponds to a range of likely BSUoS costs of £690m to £740m, or an annual average price of £1.00/MWh to £1.08. This range is due to uncertainties over a number of factors, including:

- wholesale market prices for gas and electricity;
- market length, NIV;
- generation availability and plant margin;
- winter weather and demand levels; and/or,
- market shocks, such as a cold snap or plant or infrastructure failure

20. The table below shows the forecast range for 2007/08 costs and gives illustrative scenarios that would see costs outturning at that point in the range for IBC and BSUoS:

Scenario	Conditions	IBC	BSUoS	Average BSUoS price
Low	-Milder winter - Reduction in wholesale gas and electricity prices - increase from current expected plant availability - Increase in market length -No major network shocks	£460m	£690m	£1.00/MWh
Central	-Winter in line with Met office forecast -Current lower expected plant availability prevails -Wholesale prices remain close to current forward levels -Network constraints in line with forecast	£480m	£710m	£1.03/MWh
High	-Colder winter and/or market shock -Rise in Wholesale prices -Plant availability in line with forecast or tighter -above forecast network constraints	£510m	£740m	£1.08/MWh

Market Drivers of Balancing Costs

21. Full detail on our forecast trends for cost drivers is provided in the appendix. We provide a summary of our forecast for the two market drivers, Wholesale Power Price and NIV, below.

Wholesale Power Price

22. Wholesale power price reflects a number of market conditions and links to different categories of balancing costs in different ways.

23. To illustrate the effect of this driver in more detail, the costs variances associate with variances in Wholesale Power price are divided into the three categories:

    1. Balancing costs driven directly by wholesale power price:
        a. Reactive Power default prices are indexed to wholesale power prices.
    2. Balancing costs variances that are likely to be associated by proxy with wholesale power price variances:
        a. The price of certain Bids and Offers in the Balancing Mechanism: Where the cost of provision is the primary driver of pricing, the prices are associated with the underlying cost of fuel and supply capacity.
    3. Balancing costs driven by market conditions which may also be reflected in the wholesale power prices:
        a. The costs of procurement of Reserve are linked both to the cost of provision (fuel cost) but also to market supply conditions, I.e. when supply conditions are tighter the price of additional Reserve increases.

24. In 2007, as in previous years, we have seen marked variations in the current year's prices and also to the forward price for 2008/09, as can be seen in fig 2.2. As in previous years, such variation in forward prices makes forecasting difficult as it is necessary to update continually the forecast for movements in the wholesale electricity price.

25. To mitigate this uncertainty within the incentive scheme structure, we have proposed indexation of the scheme target as an option in the menu of possible schemes for 2008. Further detail on proposed indexes can be found in the scheme proposals section.

26. For our forecast described in this document we have used the wholesale price for 2008/09 as of late November. These are shown in more detail, with current year prices (outturn and balance of year), below.

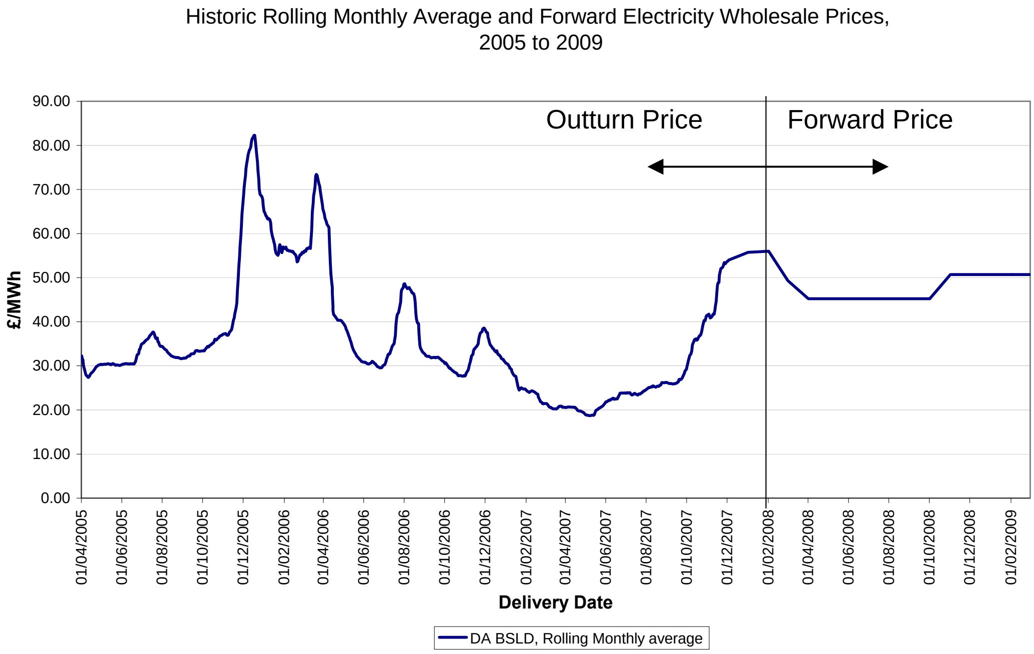

Figure 2.4: Historic (monthly rolling average) and forward wholesale electricity prices, April 2005 to March 2009

Net Imbalance Volume (NIV)

27. During the past 12 months to November 2007 the average market length, NIV has become less long, as shown in the figure below

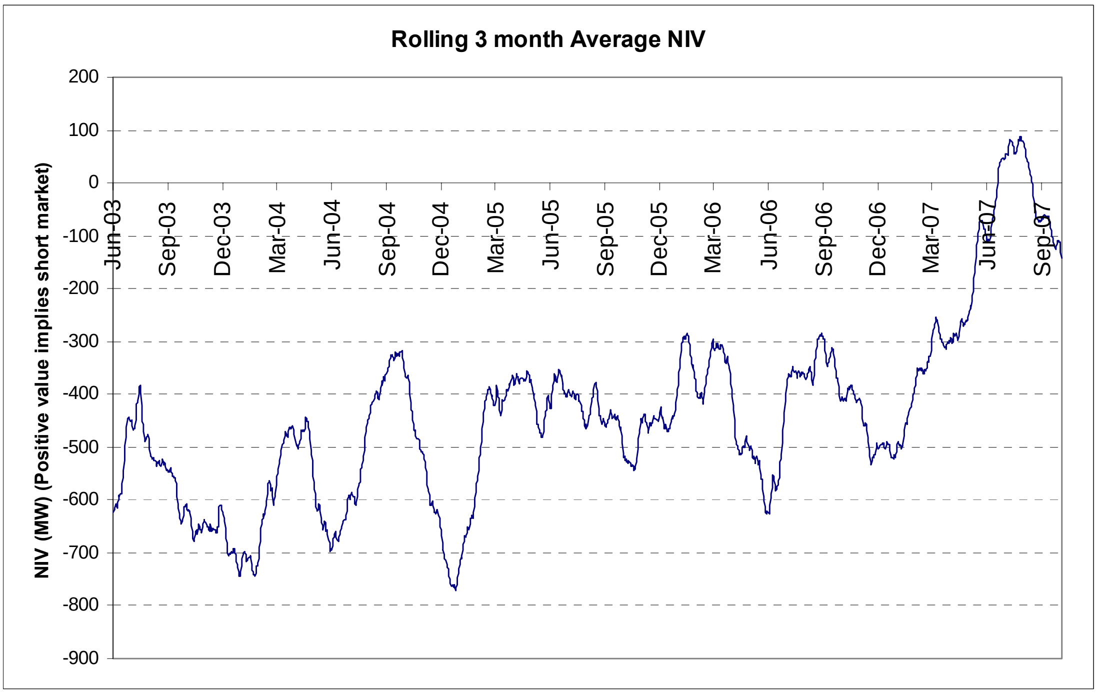

Figure 2.5: Historic (3 month rolling average) Net Imbalance Volume (NIV) 2003 to present

28. The reasons for this decline are not clear to National Grid at this time and we would welcome respondents' views on the causes of this effect. Analysis of historical changes in NIV has shown that previous changes were likely to be the result of:

- changes to imbalance price calculation methodologies, such as the introduction of P78[1], which would be expected to adjust participants view of risk;
- changes to wholesale price, which could also be expected to adjust the economic risk position adopted by participants;
- short and medium term weather conditions (such as a cold snap)

29. Over the past 12 months there have been some variance in these same factors which may have resulted in the observed reduction in the average level of NIV during 2007:

- the implementation of P205 in November 2006, moving the main price from an volume weighted average price of the cheapest volume of actions that make up NIV to a 'chunky marginal' price, produced from the volume weighted average price for the marginal 500MWh that make up NIV;
- the inclusion of BM Start Up costs in within cashout from 1 October 2006;
- variations in power price, in particular a moderation of prices during summer 2007 relative to summer 2006, and to the current level of forward prices for summer 2008;
- Wetter weather during summer 2007 in comparison to recent years.

30. At present no single driver appears to have caused the change in average NIV but nevertheless NIV does appear to have stabilised at a new, more balanced level during 2007. Our forecast for NIV during 2008/09 is weighted between the less long level seen in 2007/08 and that of the previous year 2006/07. This weighting is described in more detail in the appendix.

31. This more balanced outcome reduces the costs borne by participants as it indicates that the market is perhaps over-contracting by a lesser amount, and results in a reduction in procurement costs for the equivalent forecast level of requirement compared to previous years. This effect is discussed further in our BSUoS forecast discussion, section 2.6.

[1] The introduction of P78 in February 2002 changed the calculation of the Reverse imbalance pries. Soon after the introduction of P78 a systematic shift in average NIV to a less long position can be observed but is not shown or discussed further here.

2.3 Forecast balancing costs for 2008/09

Summary

32. Our forecast for incentivised balancing costs for 2008/09 is that the underlying incentivised cost of balancing services will decline in real terms for 2008/09 compared to the current year 2007/08.

33. On a like for like basis, our forecast of underlying incentivised balancing costs will fall from £400m in 2007/08 to £399m in 2008/09. The reduction is more significant if one considers that these figures are not corrected for RPI. The overall reduction is driven by:

- forecast reduction in the costs of frequency response. These are forecast to result from the implementation of efficiency measures by National Grid, in particular new developments to the dispatch optimisation algorithm developed over the past 18 months and introduced in July 2007.
- we have discounted our forecast for 2008/09 England and Wales network constraint costs compared to our current year forecast. This is because we do not forecast a repeat of several ‘one-off’ events that occurred during 2007, in particular the summer floods.

34. This underlying reduction will be more than offset by three factors:

- commencement of a significant programme of network outages in Scotland and the north of England associated with work to connect new renewable generation;
- the introduction of the Large Combustion Plants Directive on 1st January 2008; and,
- increasing costs of system operation due to rising levels of wind generation.

35. The range of likely total incentivised balancing costs for 2008/09 is £471m to £603m, with a mean forecast value of £530m. The main uncertainties within the forecast are:

- the network outage programme in the north of England and Scotland;
- variations in the wholesale power price and underlying generation fuel prices, such as gas and coal;
- the impact of LCPD on power station availability and operation;
- the underlying drivers of Reserve procurement costs, in particular on-the-day plant margin and the price of reserve services;
- pricing behaviour in other ancillary markets, in particular frequency response.

36. The remainder of this section provides an overview of our forecast of balancing costs, and provides additional detail on the three key cost increases for network constraints in Scotland and on the Scotland-England boundary, wind and LCPD.

Underlying Balancing Costs

37. Our forecast mean level of underlying incentivised balancing costs for 2008/09 remains in line with costs seen in 2006/07 and 2007/08. The variances are as a result of the following of factors:

- a decline in England and Wales constraint costs due to 'one-off' costs occurring in 2007/08;
- changes in the wholesale power price and NIV (predominantly affecting Reactive, STOR, Fast Reserve and Energy + Margin);
- achievement of cost reductions in frequency response procurement and a forecast stabilisation of frequency response holding prices.

38. The summary of mean forecast costs for each category of underlying costs is shown below. The full detail of our 2008/09 forecast can be found in the appendix.

All Categories £m	Latest 2007/08 Forecast, £m	2008/09 Forecast, £m	Difference, £m
Constraints England & Wales	33	19	-14
STOR[2]	63	65	2
Footroom	4	4	0
Fast Reserve	57	60	3
Response	150	145	-5
Reactive	50	57	7
Blackstart	14	17	3
Unclassified BM	10	9	-1
BM+AS General	3	4	1
Reconciliation	-1	0	1
Sub-total system	383	380	-3
Energy Imbalance	34	26	-8
Negative NIA	-141	-162	-21
Margin	124	155	31
Sub-total Energy + Margin	17	19	2
Total	**400**	**399**	**-1**

Reduction as events not forecast to re-occur in 2008/09

Reactive cost increase is linked to the power price rise

Changes are a direct result of NIV and power prices assumptions

39. It can be seen that the main changes to costs are in the areas of England and Wales constraints, Response, Reactive and the sub-total for 'Energy + Margin'. The reasons for these changes are described in the boxes adjacent to the table.

[2] Short Term Operating Reserve, STOR

New Factors Driving Changes to Balancing Costs in 2008/09

Network Investment

40. The forecast year, 2008/09, sees the commencement of major works to construct or rebuild major new sections of the transmission system in Scotland and the North of England, to deliver additional transmission capacity to transport energy from new renewable generation (wind) in Scotland and the North of England, as part of the Transmission Investment for Renewable Generation (TIRG) works.

41. The network outages to undertake the work will reduce the available transmission system capacity on these boundaries and require National Grid to constrain plant output down to keep the system operating safely and securely. Within our forecast, these projects will impact on our constraint costs on the Cheviot boundary (Scotland-England boundary) and also major flow boundaries within Scotland.

Cheviot Boundary

42. As part of this project, major outages are required to upgrade the capacity of the transmission circuits that cross the Cheviot boundary. This is the first year of a three year project to upgrade the transmission capacity of the circuits crossing this boundary from 2.2 GW to 3.2 GW by 2011/12.

43. In 2008/09 there are 30 weeks of programmed outage on one or other of the two boundary circuits themselves, this compares to 8 weeks 2007/08, which is in line with the historic level. An outage on one of the two double circuits reduces the boundary transmission capacity from an average of 2.2 GW to between 0.9 GW and 1.5 GW, depending on the precise nature of the outage.

44. This scale of works, at 30 weeks in a single year, is without precedent in recent history and the resultant reduction in transmission capacity is expected to lead to a significant increase in constraint volumes, cost and risk on the Cheviot boundary for the period of the works, starting in 2008/09.

45. Forecasting Cheviot constraint volume and cost is complex as it is influenced by the output of plant across Scotland. For the forecast we use a probabilistic model, which convolves distributions of generation output in Scotland against demand level and Cheviot boundary flows against the boundary's capability, and applies forecast Bid prices in Scotland and replacement energy prices in England and Wales.

46. Our model forecasts a central Cheviot constraint cost of £67m. The 90% probability range of the overall cost is from £42m to £99m. The distribution is shown below.

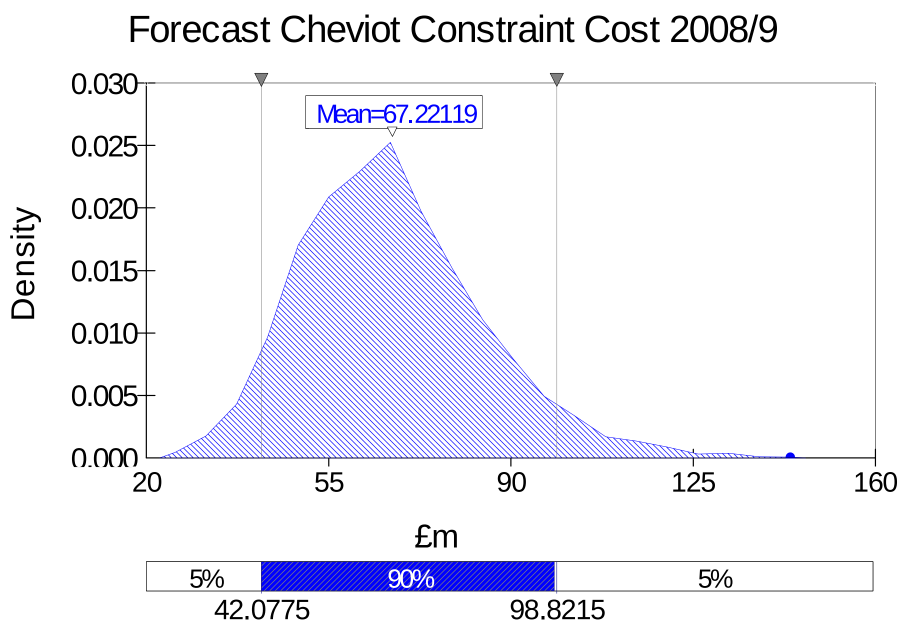

Figure 2.6: Forecast Cheviot constraint cost, 2008/09

47. The range of this forecast is predominantly driven by uncertainty as to the likely output of generation in Scotland during the year (in particular during the period of outages) and the pricing of Bids in Scotland and replacement plant in England and Wales:

- At the P95 level of £98m, this would be the result of an increase in Scottish generation output and/or the cost of resolution of the constraint.
- At the low end, the P5 figure would be the result of a decrease in Scottish generation output and/or the cost of resolution of the constraint.

48. The key driver of cost changes year on year is the increase in outage works. To show the effect of the increase in outage works for 2008/09, we have run our forecast model for 2008/09 Cheviot costs against two scenarios. The first is using the outage programme for the current year, 2007/08 of 8 weeks of outages. The second scenario includes the full programme of 30 weeks for 2008/09.

49. The table below provides a breakdown of the mean costs, volumes and prices.

Forecast Basis	Description	Forecast constraint balancing actions		
		Volume	Mean Price	Cost
2008/09 with 2007/08 outage programme of 8 weeks	The 2008/09 forecast but with only 8 weeks of boundary outages, the level seen in summer 2007/08	0.62TWh	£52.58 /MWh	£32.6m
2008/09 forecast with 30 week outage programme	30 weeks of boundary outages, our actual forecast (26 weeks summer + 4 weeks winter)	1.29TWh	£52.90 /MWh	£67.2m

50. Running the 2008/09 Cheviot boundary cost forecast with the 2007/08 outage pattern gives a forecast cost of £32.6m, this is consistent with our 2007/08 forecast level of £35m. This demonstrates that the main driver of increased costs during 2008/09 is the sharp increase in volume of constraint actions caused by the greater number of outage weeks.

51. Comparing the costs of the two outputs gives a £34.6m increase in cost for an additional 22 weeks of outages across the year. This gives an average net weekly cost for the additional outages programmed for 2008/09 of £1.57m/week.

52. The table below shows the mean forecast cost for each season, with summer broken down into outage and intact conditions due to the high number of outages:.

Forecast Basis	Description	Constraint costs during period, £m			
		Summer (Network outages)	Summer (Intact network)	Winter	Total
2008/09 with 2007/08 outage programme	The 2008/09 forecast but with only 8 weeks of boundary outages, the level seen in summer 2007/08	£9.2m (8 weeks)	£10.3m (22 weeks	£13.0m (22 weeks)	£32.6m
2008/09 forecast	30 weeks of boundary outages, our actual forecast (26 weeks summer + 4 weeks winter)	£49m (26 weeks)	£1.9m (4 weeks)	£16.4m (22 weeks incl. 4 week Outage March 09)	£67.2m

53. As the table shows, our cost assumptions for winter costs, when there are only 4 weeks of outage, vary by a lesser amount but still close to the average value of £1.57m per week.

54. The Cheviot boundary outages represent the single largest change in our costs year-on-year. These costs relate directly to the construction programmes of the two Transmission Owners (TO): National Grid and Scottish Power Transmission. As with any construction project there are uncertainties around the actual time the construction works will take place during 2008/09.

55. Considering these construction uncertainties in more detail:

- Small variations are likely to be driven by change to the programme or acceleration or delays to works by the Transmission Owners;
- More major changes to the programme are likely to be driven by events such as weather or other factors which may interrupt the progress of works; and,
- In severe circumstances this could, for example, be events (such as an outbreak of foot and mouth) which would prevent access to land to carry out the work.

56. To manage this uncertainty within the incentives framework, we have proposed an index in two of the proposed scheme options to adjust the target based on the number of outage weeks that actually occur during 2008/09. As shown in the table above, the average weekly cost of these outages is forecast as £1.57m. Therefore we have proposed an index to adjust the target by £1.57m for every week of outage that varies from the 2007/08 baseline of 8 weeks.

57. Finally, during the Cheviot circuit outages, for the loss of the other double circuit (e.g. as a result of equipment failure, weather or some other force majeur event) it may be necessary to separate the Scottish system from the England and Wales system and operate them as two distinct systems until one of the two double circuits can be returned.

58. The costs of operating the systems during such a scenario are expected to be high and the risk of such a low probability, high cost event has not been included within our forecast. We believe it is inappropriate to include the risk of costs in our forecast. Therefore we believe it is correct that such an event to constitute an Income Adjusting Event and would welcome respondents views on our proposal to treat this as an IAE rather than reflecting this low probability, high cost event within our forecast.

Network Constraints within Scotland

59. The within-Scotland outage program for 2008/9 affects a number of critical constraint boundaries across the Scottish network. This is the main driver behind the cost forecast for within Scotland constraints of £39m. This compares with an outturn of £54.6m for 2006/7 and a forecast of £22m for 2007/08.

60. As with the Cheviot boundary constraints, these risks are associated with generation output and prices. The within-Scotland forecast involves constraints on a number of boundaries within-Scotland and hence a more diverse set of risks are associated with this forecast. The graph below shows our forecast of the cost risk profile for internal Scottish constraints.

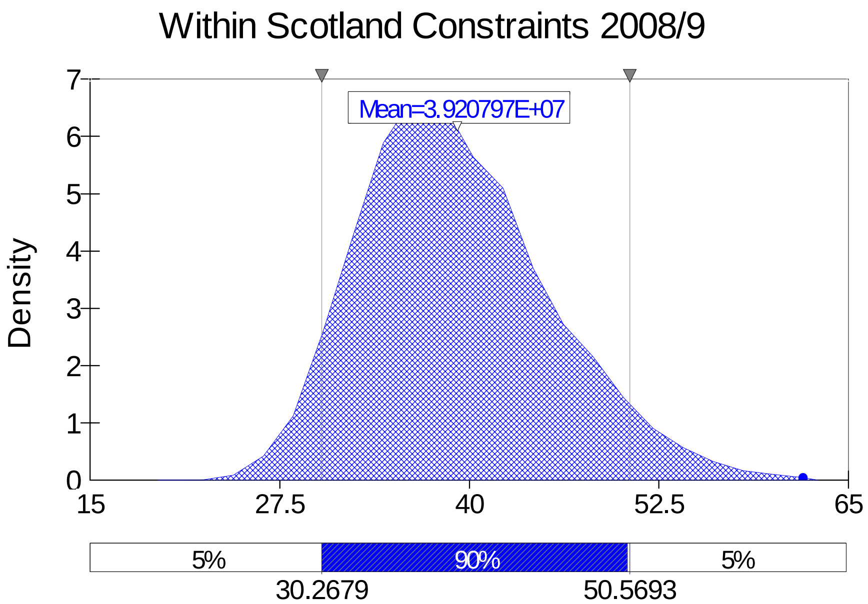

Figure 2.7: Forecast Within-Scotland constraint cost, 2008/09

The graph shows a range from £30m - £51m, with a mean of £39m.

Summary of Scottish and Cheviot constraint forecast

61. The forecast mean figures for the two categories of constraint costs for 2008/09 are shown below, totalling £106m.

Year	Cheviot	Scotland	Total
2007/08	£35m	£22m	£57m
2008/09	£67m	£39m	£106m

Large Combustion Plants Directive (LCPD)

62. The Large Combustion Plants Directive comes into force on 1 January 2008. Approximately 12 GW of generation capacity has opted out of the Directive and for this capacity its running hours will be limited on a stack basis to 20,000 hours across the 8 year period to 2015.

63. Due to the limitation on operating hours on a stack basis and not on a unit basis, we expect operators will look to maximise earnings from the remaining 20,000 hours, by optimising running and by operating multiple BM Units as a single block at the same time. Full details of this can be found in our appendix.

64. As part of this forecast we have undertaken initial economic analysis as to how the 20,000 hour constraint will affect operating behaviour. We expect the economic drivers and hence the precise behaviour to vary for each station. Based on our analysis our initial views are:

- We do not expect the low-load factor Oil units, totalling 3.7GW of opted out capacity, to change behaviour as the 20,000 hour limit is above what these stations would expect to achieve over the 8 years at their typical historic running level.
- For opted out coal units, the 20,000 hour limit is likely to act as a constraint on output. For these stations we anticipate two possible scenarios:
    - *Summer-cold regime* - run the units over the winter and are then unavailable over the summer, either on maintenance or moth balled.
    - *Year-round running regime* - the generation will focus their running hours on the peak power price periods across the year, irrespective of season.

- We expect opted-out coal units on the same stack to act as a single block, synchronising and desynchronising at the same time.
- The operation of a number of BMUs as a single block is also expected to mean that these units take outages at the same time. If this occurs then this will lead to:
  - o tighter plant margins during the lower value summer period; and/or,
  - o lower diversity of plant output (I.e. all on or all off, rather than averaging one unit on maintenance during the summer outage season) which will increase the risk of network constraints that are sensitive to extremes of generation, such as constraints local to opted-out generation.

We would welcome views on our scenario assumptions and on how LCPD opted-out stations will operate in 2008/09.

Effect of LCPD on Reserve

65. If the opted-out coal plant capacity regimes off at low value periods (year-round running regime) or is shut down for the summer (summer-cold regime) this will create tighter plant margins at low value periods. This will increase our reserve costs as we will procure reserve from more expensive sources. Please see the appendix annex on the impact of LCPD for full detail. Based on our economic analysis we forecast that reserve procurement costs could increase by between £5m and £15m with a mean forecast of £10m.

Effect of LCPD on Constraints

66. The impact of LCPD opted out plant running behaviour on network constraint costs is more uncertain because of the, in the main, highly localised effect each individual station's operation may have on constraints in that area.

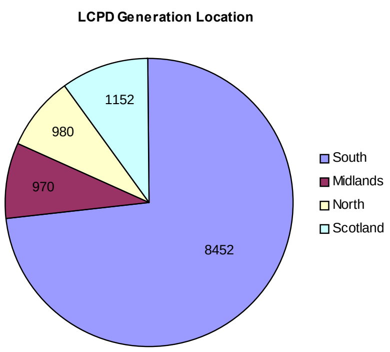

Figure 2.7: LCPD opted-out plant capacity, by location, 2008/09

67. The impact on national-level constraints is the result of the high volume of LCPD plant in the Southern part of the system. This will increase pressure on all our major North–South network constraints for an intact and outage constrained system. Our mean forecast of the impact on constraint costs

resulting from reductions in summer or low value period output on southern LCPD opted out plant is £5m with a range of £1m to £20m.

68. The localised constraint cost effect that will result from the introduction of LCPD is dependent on individual plant behaviour and is very uncertain. With the opted out gensets operating as either all on or all off, there is an increased risk of localised constraints being activated which would need to be secured through additional balancing actions by National Grid. This could be within the Balancing Mechanism or via contracts to secure or reduce output during a local transmission outage. The range of our forecast for these localised costs reflects this uncertainty, with a range of £6m to £30m and a central figure of £15m.

Summary of LCPD impact

69. The range of possible scenarios and costs is set out in the table below:

Scenario	Assumptions	Impact on balancing	Cost
Low	All or vast majority of opted-out units continue to operate in line with pre LCPD behaviour, resulting in hours limitations being hit within a few years and most stations closing by 2012, well ahead of final deadline.	Slight or no increase in costs, primarily driven by slight reduction in plant margins or higher prices for additional units at opted out stations occasionally during year	Low end of range, £6m - £10m
Central	Around half opted out coal stations show some change in behaviour due to LCPD constraint. Some show significant change, either mothballing for the summer or not running but available to NGET at higher prices during lower wholesale price period	Impact on reserve costs as plant margins for periods in the summer become tighter and/or also BM prices for opted out plant increase. Some rise in flow south levels during low value periods due to lower southern opted out station output and potential for occasional small local constraints	Mid range, £10m - £20m
High	Most or all opted out coal stations show a change in behaviour. Several stations a show a significant change either mothballing for the summer or lower value periods. Others are not running but available to NGET at higher prices.	Impact on reserve costs as plant margins through the summer become tighter and/or also BM prices for opted out plant increase. Flow south levels rise during low value periods and at actions required to secure some small local constraints, including at least one major local constraint issue.	Upper end - £20m to £30m

70. Under all scenarios we assume that opted out Oil fired units will continue to operate in line with pre-LCPD patterns as their normal operation will not be constrained by the running hours limitation.

71. Based on the above assumptions, our initial central forecast of the impact of LCPD plant behaviour on balancing costs is a range from £6m to £30m, with a central forecast of £15m. Once again, we would welcome respondents' views on our forecast assumptions used to develop this forecast.

Wind

The graph below shows National Grid's best view on the projected growth of wind power up to 2012/13.

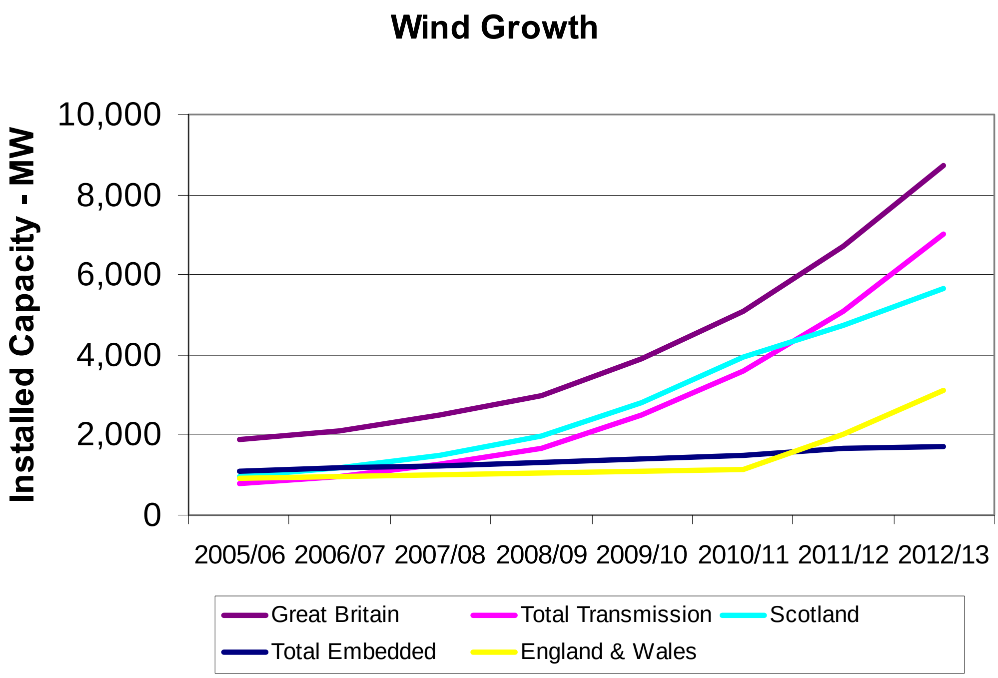

Figure 2.8: Growth in wind generation capacity, 2005/06 to 20012/13

72. The capacity and output of wind generation on the GB transmission system has been growing gradually over recent years. For 2008/09 our best view is a 500MW increase in wind capacity across the GB system. These best view figures are those used for National Grid's Transporting Britain's Energy and Winter Outlook reports.

73. Increased variable output from wind sources places greater burdens on both market participants and the SO to ensure the system remains secure and in balance. How this burden falls between the SO and the market will depend on the market's ability to forecast wind output and balance its own position and the incentives (efficient avoidance of imbalance charges) to do so.

74. At present, wind output in Great Britain remains low compared to some European countries such as Denmark, Germany and Spain. However, the effect of wind output is now becoming noticeable in terms of its cost impact on energy balancing and our procurement and dispatch of reserve. Separately, the higher proportion of wind output in Scotland is impacting on constraint management.

75. Our wind growth assumptions have been factored into our constraint forecasts. This section summarises the impact of wind on Reserve costs to date and forecast for 2008/09.

Effect of Wind on Reserve

76. The main cost of increasing wind is associated with the additional reserve required to meet National Grid's reserve requirements. Fig2.9 below shows the increasing impact of wind error relative to conventional generation output error on our reserve requirements. The growth in total error of wind and conventional generation, driven by wind, results in an increase in our minimum requirements for reserve.

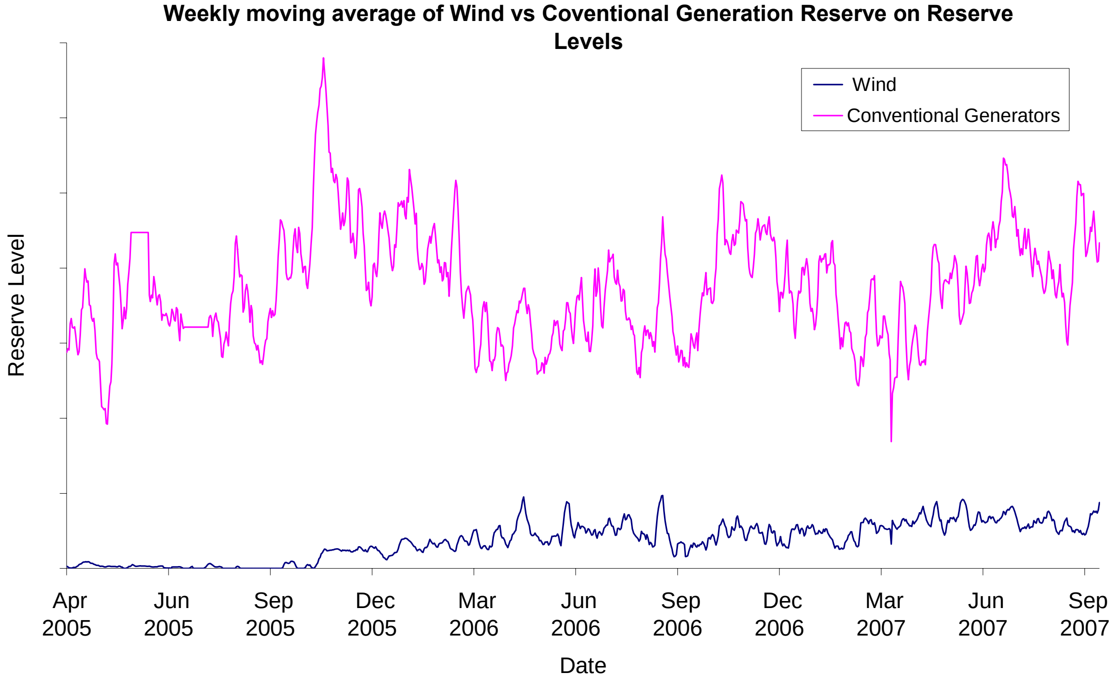

Figure 2.9: Proportional Contribution to reserve requirements, wind and conventional generation, April 2005 to present

77. At present wind contributes approximately 10% of total plant output error. The variation or error in wind output from forecast is much larger in proportion to

output than that of conventional generation. This larger error requires us to increase our reserve requirements at times of higher wind output relative to what our requirement would have been had the output been from conventional generation.

78. Against current wind installed capacity and output, this proportionally large error results in increased reserve costs of £17m during 2007/08. For 2008/09, the net impact of the higher installed capacity and expected output is a net cost increase in the range of £5.6m to £9.6m, with a central forecast of £8m.

Effect on real-time frequency control

79. In addition to increase Reserve holding, the management of minute by minute variation is forecast to result in increases in our dynamic response and Fast reserve holding on occasion (such as during higher wind generation output).

80. Experience to date indicates the rise of 500MW for 2008/09 can be expected to cause a £2m rise in costs across Fast Reserve and Frequency Response holding. This figure represents less than 1% of total forecast costs for Response and Fast Reserve. This gives a total mean forecast cost resulting from wind growth of £10m. Further detail on this is available in the appendix wind annex.

Summary

81. Based on the above assumptions, our central forecast of the impact of 500MW increased installed wind capacity in 2008/09 on balancing costs is £10m, in a range £7m to £12m.

Range of Forecast Costs 2008/09

82. Our forecast range of balancing costs for 2008/09 is greater than the residual remainder for 2007/08 and is shown in the graph below.

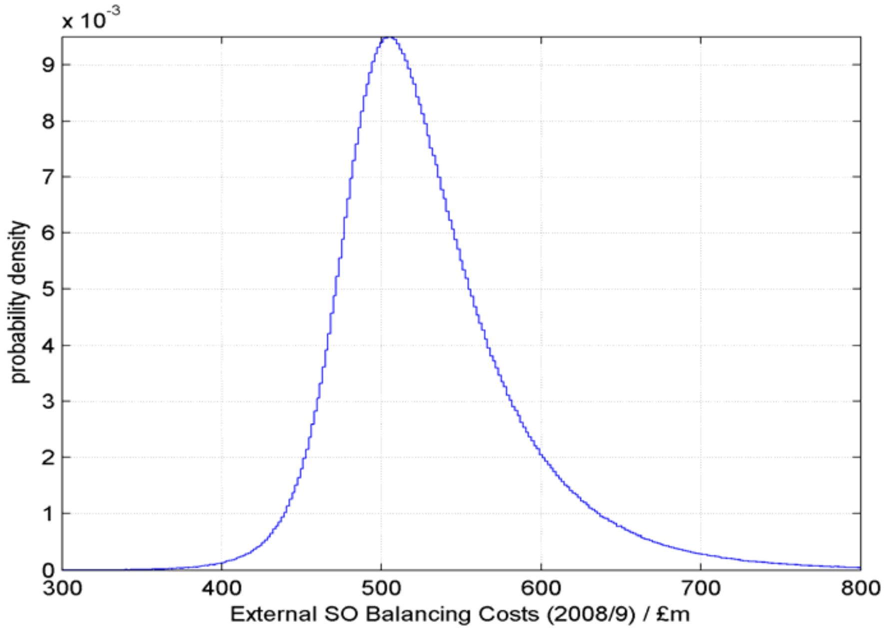

Figure 2.10: Forecast range of IBC, 2008/09

83. Our range of costs for 2008/09 has a mean of £530m and the other properties shown in the table below.

P10	P50	P90	Mean
£471m	£519m	£603m	£530m

84. This range is derived using the variation in drivers as described in more detail in the appendix.

85. The build up of the component costs to the forecast mean cost of £530m is shown in the table below.

Cost Category	2008/09 Forecast
Underlying balancing cost	£399m
Cheviot and within Scotland constraints	£106m
LCPD	£15m
Wind Growth	£10m
Mean forecast	**£530m**

86. The table below illustrates the range using typical ‘scenarios’, to indicate what market conditions and the main cost drivers would be for the costs to outturn

at different points within the range. The table below shows the range and gives illustrative scenarios that would see costs outturning at that point in the range for IBC and BSUoS:

Scenario	Conditions	IBC	BSUoS	Average BSUoS price
Low	-Milder winter - Reduction in wholesale gas and electricity prices from current forward levels - increase from current expected plant availability - Increase in market length -No major network shocks	£471m	£729m	£1.06/MWh
Central	-Winter in line with Met office forecast -Current lower expected plant availability prevails -Wholesale prices remain close to current forward levels -Network constraints in line with forecast	£530m	£788m	£1.15/MWh
High	-Colder winter and/or market shock -Rise in Wholesale prices -Plant availability in line with forecast or tighter and/or -Above-forecast levels of network constraints	£603m	£861m	£1.25/MWh

87. The table gives a low end range of £471m and a high end range of £603m (corresponding to the P10 and P90 values respectively). These correspond to a range of likely BSUoS costs of £729m to £861m, or an annual average price of £1.06/MWh to £1.25/MWh and a central value of £1.15/MWh. As with 2007/08, this range is due to a number of factors, including:

- Wholesale market conditions for gas and electricity;
- Generating Plant availability;
- Outturn levels of network constraints and local plant output;
- Winter weather and demand levels;

- Market shocks, such as a cold snap, plant or infrastructure failure.

Sensitivity to Wholesale Power price – indexation level

88. As reported through this document, changes in wholesale power prices have led to revisions to our within-year forecast of balancing cost for the past two years and the current year. This section considers the appropriate level of indexation for use within the proposed incentive scheme options.

89. The cost variances associated with variances in wholesale power price can be considered as being divided into the three categories:

    1. Balancing costs driven directly by wholesale power price:
        a. Reactive Power default prices are indexed to wholesale power prices in accordance with the CUSC.
    2. Balancing costs variances that are likely to be associated by proxy with wholesale power price variances:
        a. The price of certain Bids and Offers in the Balancing Mechanism: Where the cost of provision is the primary driver of pricing, the prices are associated with the underlying cost of fuel and supply capacity.
    3. Balancing costs driven by market conditions which may also be reflected in the wholesale power prices:
        a. The costs of procurement of Reserve are linked both to the cost of provision (fuel cost) but also to market supply conditions, i.e. when supply conditions are tighter the price of additional Reserve increases.

90. Reactive Power, the only category 1 cost, sets a lower bound for the possible level of indexation:

91. The annual volume of Reactive Power dispatch multiplied by the index described in the CUSC gives a figure of +£0.8m of IBC for each +£1/MWh change in outturn power price, and vice versa, across the year as an average.

92. The addition of other costs is more subjective and is sensitive to multiple factors such as the way other market variables, such as NIV and plant margin may vary with power price.

93. We have assessed this variance at a global level by plotting daily incentivised balancing costs (excluding the adjustment for transmission losses) against the relevant day ahead wholesale baseload power price.

94. The graph below shows the scatter of these daily values for April 2006 to date.

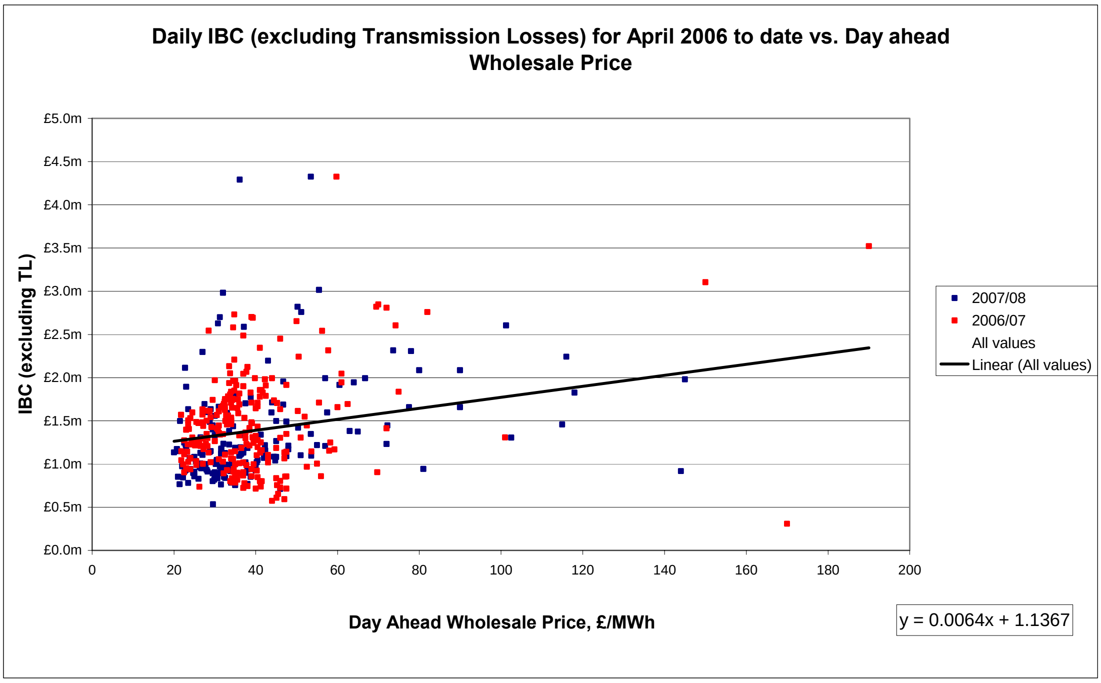

Figure 2.11: Relationship of daily IBC to day ahead wholesale price, April 2006 to present

95. The relationship between daily wholesale pries and daily IBC is not clear or stable. Our current analysis implies a slope of £6.4k/day per £1/MWh, but there is ongoing analysis in this area to understand better this relationship.

96. At an annual average level, £6.4/k/day per £1/MWh corresponds to an index value of £2.3m/ per £1/MWh. The slopes, index level and correlations for the subsets of this data are shown in the table below.

Period	Slope	Average Annual price index value
Reactive Power base level	-	£0.8m per £1/MWh
2006/07	£46k per £1/MWh	£1.7m per £1/MWh
2007/08 to date	£85k per £1/MWh	£3.1m per £1/MWh
All values, April 2006 to date	£64k per £1/MWh	£2.3m per £1/MWh

97. The results show a range of possible values for an index that links the scheme target to the average annual wholesale price, based on day-ahead prices. It is our view that this reflects the variations in other drivers that are also causing daily costs to vary significantly.

98. As a result of this range we propose to use a conservative value for this index. A conservative value will mean that the scheme offers only partial protection against wholesale price movements and the market changes that cause these. Therefore our initial proposal is an indexation level of +£2m change in

target for each +£1/MWh change in outturn average annual wholesale price, and vice versa. This indexation level is below the outturn value based on data from April 2006 to date but is above the base level set by Reactive Power indexation.

99. We would welcome views on the assumptions we have made to arrive at this figure and the appropriateness of the index.

Transmission Losses

100. As we have reported at Operational Forums during 2007, the level of transmission losses recorded during 2007 has continued to rise for reasons that are not yet fully explained by our modelling of losses based on the outturn pattern of generation and demand across Great Britain. We are at present engaged in detailed analysis to understand whether there are other drivers behind this increase such as:

- Metering or calculation error(s);or
- Physical effects that are not accurately replicated within our current model.

101. We hope to conclude this work during December and will report to the industry on our findings and industry meetings including the SO Incentives workshop.

102. As a result of this ongoing uncertainty, we are not in position to be able to forecast or propose an appropriate target level for losses in 2008/09.

2.4 Forecast Performance

103. Since 2004/05, our view is that balancing costs have become more volatile, both day on day, month on month and year on year. As such, the range of likely costs has increased and forecasting costs has become more challenging. This is due to a number of factors:

1. greater variation in underlying generation fuel costs, particularly gas due to greater variations in wholesale gas price;
2. an increase in the volumes of reserve procured by National Grid as a result of a more balanced market and lower headroom on plant. With greater volumes being procured our costs are more sensitive to fluctuations in the price of reserve services, particularly at times of lower plant availability;
3. larger and more volatile network constraint volumes, and hence costs, due to the inclusion of Scottish and Cheviot constraint costs in our incentivised costs.; and
4. for 2005/06, the one-off impact of the introduction of CAP047 in November 2005.

104. In particular, in each of the last two years, and now in this year, National Grid has, at the time of scheme agreement, under-forecast the outturn level of

balancing costs due primarily to the factors above. This is illustrated in the graph below:

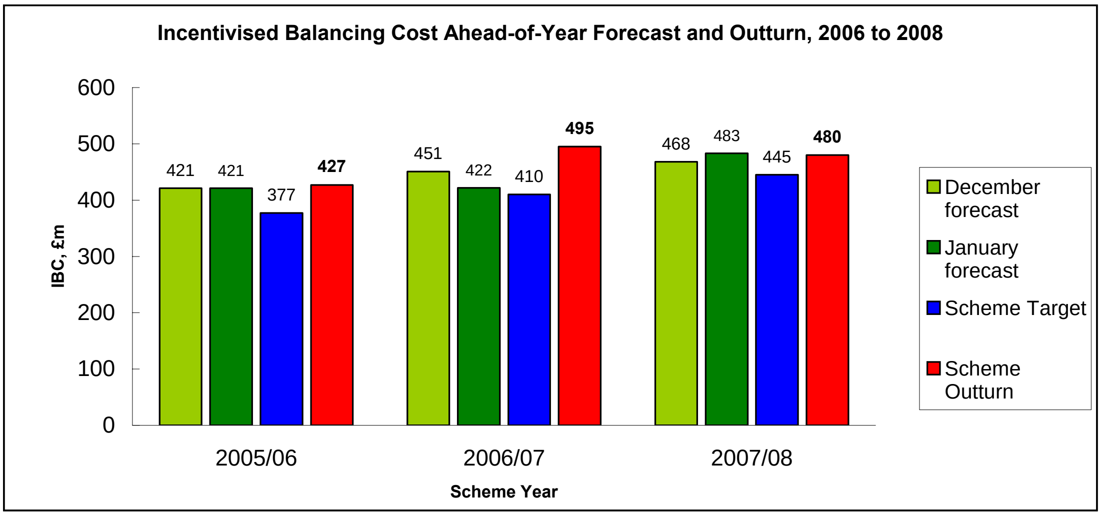

Figure 2.12: IBC ahead-of-year forecast and outturn performance, 2005/06 to 2007/08

105. The graph shows that for each year outturn costs have been:
- above our forecasts made prior to the commencement of the year; and
- even further above the scheme target (or proposed target for 2006/07).

106. As with the wholesale market, National Grid's balancing activity and costs are exposed to variations in market conditions. The table below shows our winter forecast of outturn costs for each year and actual outturn costs for 2005/06 and 2006/07.

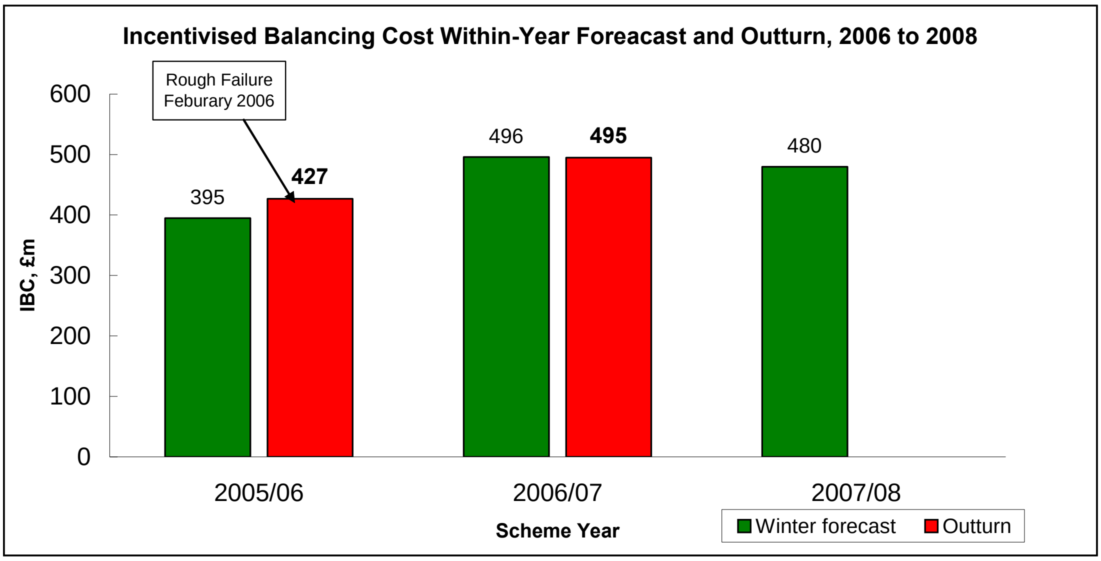

Figure 2.13: IBC winter (within-year) forecast and outturn performance, 2005/06 to 2007/08

107. The above discussion and graph illustrates the increased variability of costs since BETTA go-live and the issues that this has caused with regard to

scheme targets and outturn cost levels. For all years post-BETTA this variation has or will result in costs outturning above the agreed or proposed scheme target level, resulting in National Grid making a loss on the incentive scheme in 2005/06, a significant loss had we accepted the proposals in 2006/07, and an expected loss for 2007/08.

108. Our historic forecast performance also highlights that our revisions to forecasts, made each year in early winter in response to the change in market indicators, have proved to be reliable and accurate indicators of final outturn costs. This historic performance should provide additional confidence to readers that our mean forecasts of £480m for 2007/08 and our forecast of £530m for 2008/09 can be considered accurate central forecasts for their relevant years.

2.5 Initial Proposals

109. As part of its wider SO Review, Ofgem is developing possible changes to the format of incentives for the Electricity SO schemes commencing April 2009. As outlined in our letter of 7 November, for Electricity SO schemes commencing 1 April 2008 we have only considered one year schemes. In addition, given the time available for the development of proposals we have not prepared the full detail behind those schemes that offer a significant departure form the historic scheme arrangements.

110. As described above, our forecast mean incentivised balancing costs is £530m. The forecast likely range of incentivised balancing costs is shown in the figure below:

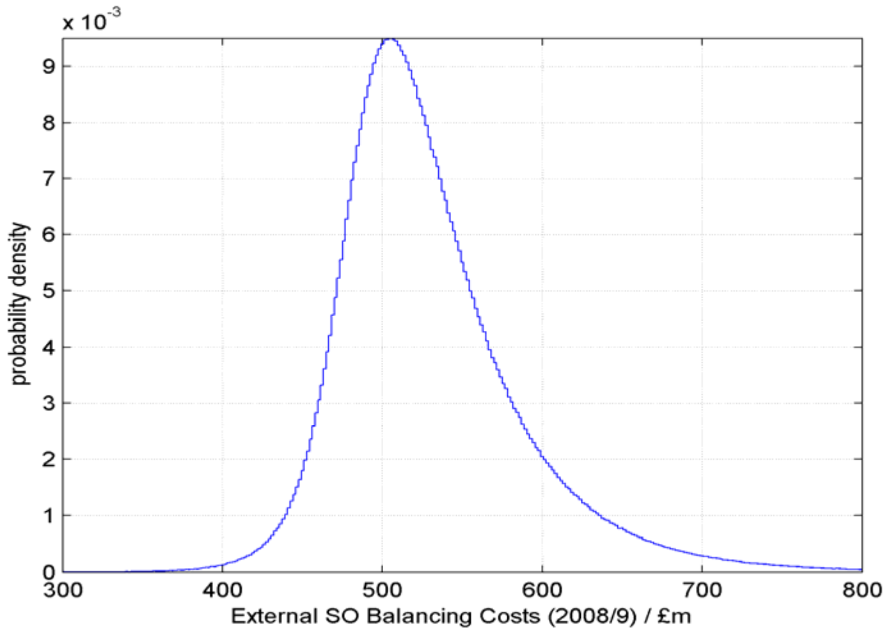

Figure 2.14: Forecast range of IBC, 2008/09

111. This range is derived by considering the range of possible outturn cost drivers during 2008/09. These drivers will affect both the volume of balancing services National Grid buys and/or the price it pays for these services. As such, the distribution of costs in the figure above can be considered to consist of:

- a mean cost value that represents our view of the central case for balancing costs; and
- the range of costs around this that will result from the actions of cost drivers on balancing costs.

112. This forecast mean and range assume a continuation of efficient and economic operation and current efficiency measures. It is from this ‘base’ that further efficiency measures are built.

113. The aim of the incentives is to encourage National Grid to invest in innovations to achieve reductions in balancing costs. Such reductions should result both in a reduction of the likely mean balancing cost and also in a contraction of the likely upper end range of balancing cost.

114. In this section we propose a menu of scheme proposals that allow participants to chose the level of risk and reward that they believe is appropriate for National Grid, as SO, should face, given the likely range, risk and uncertainty of costs and possible investment in savings identified.

115. In section 2.5 we have outlined a number of areas in which we are or we hope to undertake investments in further efficiencies to reduce balancing costs for 2008/09. In section 2.3 and the appendix we have outlined our view as to the range balancing costs for 2008/09 and the main risks and uncertainties.

116. In proposing the menu below we have endeavoured to provide options so that participants can provide views on:

    1. the central target or target range of costs;
    2. whether this target should be indexed to one or more variables;
    3. the sharing factors that should apply to set the level of upside or downside performance around the target borne by National Grid; and,
    4. the cap and collar that should apply to any share of upside or downside.

117. We have developed the options to show the range of possibilities but the individual parameters can be used in other combinations to provide different incentives

118. Our options forming our initial proposals for incentive scheme parameters for 2008/09 are shown in the table below:

Scheme	1	2	3	4	5	6
Target, £m	481	495	530	520 to 540	530	540
Upside sharing factor, %	35%	35%	15% from £530 to £520m 40% below £520m	40	35	15
Cap, £m	20	20	10	10	10	7
Downside Sharing factor, %	27%	27%	15% from £530m to £540m 20% above £540m	15	27	15
Collar, £m	20	20	10	15	10	7
Indexes	1. Cheviot Outage weeks 2. Power price option (a)	1.Cheviot Outage weeks	None, but could be added	None, but could be added	None, but could be added	None, but could be added

Scheme proposals commentary

119. **Scheme 1** provides some indexation of the target for factors outside our control. In doing so it will facilitate our taking a more aggressive approach to pursuing cost savings whilst maintaining strong, balanced sharing factors on each side of the target. This is because we would be able to make investments in additional efficiencies against a greater certainty that factors outside our control will not undermine any expectation of out performance resulting from the efficiency. In effect, if investments do deliver savings we would have greater certainty that the result would be a performance payment from the incentive. The sharing factor levels are set to give a balanced profit and loss probability over the range of the sharing factors.

120. The Scheme 1 indexes only remove some market-driven risk from the scheme and leave most balancing risks within the target. The removal of some factors outside our control reduces the risk of windfall gain or loss and therefore the caps and collars on the scheme can be increased, meaning that the scheme continues to incentivise performance over a greater range of costs.

121. Please note that the description of Scheme 1 above applies to the option (a) power price index, which is indexation of the target using outturn power prices through the year. Option (b) power price indexation does not have these properties and will simply adjust the start of year target based on the average forward price over the preceding three months. In this respect, Option (b) power price indexation offers a scheme that delivers the same behaviour as Scheme 2 but sets the target based on the latest power price data.

122. **Scheme 2** is designed as per Scheme 1 but the removal of power price indexation places greater risk on our performance against the scheme target. The retention of higher balanced sharing factors as described in scheme 1 mean that we will act in a more conservative manner, looking to contain overall cost levels but not pursuing additional investments to deliver savings in such an aggressive manner as would be the case under Scheme 1. The only indexation is for Scottish Outage weeks which would ensure that we are not exposed to windfall losses or gains as a result of changes in the Cheviot outage programme.

123. **Scheme 3** is designed to provide a more uniform financial incentive by increasing our sharing factor for lower probability cost outcomes above and below the target. The low central value sharing factor of 15% means that we are more weakly incentivised against more probable cost outturns close to the mean forecast.

124. The increase in sharing factor further away from the target means that we will pursue investments in efficiencies or risk mitigation that aim for or guard against lower probability events. These investments become more attractive as they will deliver a higher average level of potential return than would be case for smaller investments. However, the low sharing factor in the central band around the target means that the average sharing factor remains low for most outcomes and therefore we would not pursue savings as aggressively as would be the case under Scheme1, 2 or 4.

125. **Scheme 4** is designed to focus efforts on achieving efficiency savings by offering a strong sharing factor for costs outturns that are more than £10m below the mean forecast. Consistent with this incentive to achieve savings the scheme also has a lower sharing actor for outturn costs more than £10m above the mean forecast. This lower sharing factor is balanced by having a larger collar to ensure we continue to mitigate risks that could cause costs to increase significantly. Overall this scheme will encourage a more aggressive attitude to achieving savings but will ensure that major cost risks are mitigated.

126. **Scheme 5** provides a sharing factor that delivers a balance probability of gain or loss across the range of the sharing factors. In doing so it provides a balanced incentive to pursue investments that deliver savings and mitigate risks. As the scheme does not offer indexation protection it places greater risk against the target and makes investments more uncertain. Therefore we would act more conservatively in making investments under this scheme than we would under either of the indexed scheme 1 or 2.

127. **Scheme 6** provides a lower sharing factor that will result in a more conservative attitude to making investments. It will mean that we make lower cost (or higher payback) investments to mitigate risk or deliver savings but will not aggressively pursue investments that have less certain benefits. The equal sharing factors are ‘balanced’ to give even probability of gain or loss across the range by offsetting the scheme target to £10m above the mean forecast cost.

Summary

128. In summary, the six schemes provide a range of options that offer varying degrees of targeting and risk. We would welcome views on the individual schemes and the spread of scheme options. Please note that although we have only included indexation options on Scheme 1 and 2 these indexes could equally be applied to other schemes to provide different incentive properties. We would therefore welcome views on whether indexation should be considered for schemes 3 to 6.

Indexes

Cheviot Outage Weeks Index

129. This proposed index is designed to adjust the scheme target based on the number of weeks of outage that actually occur on the two Cheviot boundary circuits during the scheme year. As described in section 2.3, the forecast cost for these outages averages at £1.57m per week evenly across the year for the 30 weeks of outage, including those outages occurring during the winter months (in March).

130. This index proposes to base the level of outage weeks at 8 weeks, in line with the level in 2007/08 and also the typical annual level of outages on the boundary. It would adjust the scheme target up by £1.57m for each additional week of outage that occurs, and vice versa.

131. Re-basing the £530m forecast (at 30 weeks) down to the index base (of 8 weeks) reduces the scheme targets for Schemes 1 and 2 by £34.6m each. As this is the only index on Scheme 2, this results in a Scheme 2 target of £495m.

Power price

132. This proposed index is designed to adjust the scheme target based on power price. The sensitivity of forecast costs to power price is discussed in more detail in section 2.3. This analysis concludes with a proposed indexation level of +£2m of target IBC for each +£1/MWh change in average annual wholesale prices, and vice versa. Based on this figure we are putting forward two alternatives for the structure of this mechanism. Scheme 1 is proposed with Option (a). We would welcome respondents views as to their preference to Option (a) or (b).

Option (a)

133. Option (a) indexes the scheme target to outturn wholesale prices during the scheme year. This would be a full index and would adjust the target for rises and falls in price seen during the year. In doing so this index would offer protection against changes in market conditions during the year, thereby focussing the incentive scheme on areas more closely under our control.

134. Under option (a) the average outturn wholesale price for the year would not be know until the end of the year. For this reasons we have proposed to set the index base as current level of wholesale prices for 2007/08.

135. Based on outturn to date and forward prices for the remainder of the year, we have used a base figure for 2007/08 average prices of £41/MWh. This compares to the annual forward price for 2008/09 of £48/MWh (based on the latest available data at time of forecast). Re-basing the Scheme 1 target to the 2007/08 outturn power price gives a reduction in the target for Scheme 1 of £14m relative to £530m. This £14m reduction is based on a £7/MWh 2007/08 to 2008/09 annual wholesale price differential multiplied by the index factor of £2m per £1/MWh.

136. Scheme 1 therefore has two adjustments to its headline target:

- £34.6m reduction in target for Cheviot outage indexation;
- £14m reduction in target due to power price indexation

This gives a total reduction in the Scheme 1 headline target of £49m relative to our £530m forecast.

Option (b)

137. Option (b) is not a full within-year index. Instead this option would set a fixed target at the start of the year but the target would be based on the average annual forward price for 2008/09 seen over the months of January 2008 to March 2008. This would mean that the index did not offer any protection for within-year variations and would therefore not focus incentives on areas more under our control. However, in using the latest data available it would offer a clear and transparent way to revise the scheme target based on the prevailing conditions just prior to the start of the year. Again, the indexation level would be at +£2m change in target IBC per +£1/MWh, and vice versa.

Scheme Actions

138. In order to establish appropriate incentives, it is also important to understand those measures we are taking or developing to achieve reductions and perform against the incentive.

139. Frequency Response:
    - Reductions in our required levels of dynamic response.
    - Development and improvement of the response optimisation component of our complex system optimisation and dispatch advice tool. After approximately 18 months of development work we implemented the first stage in this development in July 2007.
    - Development work with the Balancing Services Standing Group (established under the CUSC) and through wider consultation with the industry.

140. Reserve:

- Reductions in the volume of Reserve:
    - Over the past year we have initiated a major piece of analysis to examine how we should develop our reserve requirements over the coming years, in particular looking at ways to feed more information into reserve levels, such as on-the-day conditions. This work is aligned with our work on wind forecasting to help optimise our forecasting of wind output and management of the risk of variations in this output in real time.

141. Scottish Constraints:
    - Development of new tendered product
        - As a response to the increased forecast costs for 2008/09 we are looking to work with the industry and potential providers to develop a tendered service for the availability and price of Bids in Scotland. If successful this should have a number of benefits:
            - Price discovery and cost reduction through competitive tender process
            - Reduced potential impact of Bids on cashout prices

Longer Term Investment in Balancing Cost Reductions

142. As System Operator, National Grid has been approached by a number of organisations that are developing new technologies that, if implemented, would help to reduce the costs of operating the system.

143. These systems can be generalised into two forms:

- **Passive systems** are, for example, frequency responsive appliance controllers that adjust the power used by an appliance in real time to assist in the management of system frequency. As the frequency rises the controller allows more power to be used and vice versa.
- **Active systems** would facilitate SO control of the power used by a large number of small consumption units (such as industrial or domestic appliances).

144. Development of such technologies may in future help to balance the system more efficiently and cause less carbon to be emitted. As such, the development of these systems is in the interest of parties paying BSUoS.

145. National Grid has been approached to assist financially in the development and trialling of such technologies. We are not yet at a stage at which we can provide full details of potential costs but at this time we anticipate total annual funding requests could be up to several hundred thousand pounds. We would like interested parties views on whether they consider funding of such projects by electricity consumers to be appropriate and, if so, how these costs should be funded. We see three potential ways in which this could occur:

1. Funding by National Grid and recovery of costs through BSUoS in the year of funding.

2. Funding by National Grid with payments and cost recovery occurring through an alternative mechanism developed with the industry and Ofgem.
3. Funding via an alternative party, such as public sector funding, industry and/or non-governmental organisation.

146. We would welcome interested parties views on the most appropriate funding mechanism.

2.6 BSUoS Forecast and Wider Cost Impact

147. The comparison of year on year total balancing costs, which feed into BSUoS, is shown in the table below:

	06/07	07/08 Forecast	08/09 Forecast
BSUoS cost (£m)	657	710	788
BSUoS (£/MWh)	0.99	1.03	1.15

148. As can be seen, the level of BSUoS costs is forecast to rise year on year. The reasons for this is not only that total incentivised balancing costs are forecast to rise, in line with the forecast described in this document, but that we forecast a continuation of the current shorter level of NIV. The level of NIV has become more balanced (i.e. closer to balance, or zero) during 2007 compared to the longer position seen in 2006/07.

149. The reasons for this apparent shift in NIV are not yet clear but the result of this is that Bid receipts to National Grid have reduced and Offer payments have increased, as on average we now need to resolve less length in the market and the market is short more often.

150. Overall, the less-long average NIV reflects a market that is more balanced in each half hour and we would expect this to be a good indicator of a more efficient market, resulting in a reduction in overall costs to the industry.

151. In this regard, whilst the reduction in NIV has resulted in a rise in BSUoS costs, the rise in BSUoS costs to the industry cannot be considered in isolation. In particular, the rise in BSUoS due to less long NIV will be offset to some extent by the increase in residual cashflow reallocation cashflow (RCRC) receipts.

152. Overall, we would expect the net increase in costs to the industry to be in line with the increase in incentivised costs, excluding the effect of our transmission losses incentive. The change in incentivised costs from 2007/08 to 2008/09, excluding transmission losses, is approximately £70m[3]. We would therefore

[3] Excluding the £22m of transmission losses underperformance from our forecast for 2007/08 gives a balancing cost figure of £458m. Comparing this figure to the 2008/09 forecast of £530m gives a net cost increase of £70m.

expect the net increase in costs to the industry to be approximately £70m, rather than the £90m increase in BSUoS charges.

2.7 Consultation Questions

1	Do you agree with the assumptions (described in detail in the appendix) used to forecast the various elements that make up underlying balancing costs?
2	In particular, do you have any comments on views on National Grid's forecast assumptions for cost drivers: i. The behaviour of NIV during 2008/09 can be expected to be broadly in line with that seen during the current year, 2007/08. ii. That the forward price is the most appropriate figure to represent the likely outturn wholesale price during 2008/09. iii. That wholesale power price either directly drive or act as an appropriate proxy to index certain balancing costs.
3	Do you agree with the assumptions used to forecast Cheviot and Scottish constraint costs, and the costs associated with the forecast rise in Wind output in 2008/09?
4	Do you have any comments on our initial analysis of the likely impact of the introduction of the Large Combustion Plants Directive, in particular on the likely operation of opted-out plant?
5	Do you have any comments on the forecast range of incentivised balancing costs and BSUoS costs for 2008/09?
6	Do you agree with the main areas for efficiency identified by National Grid?
7	Do you agree with the range of proposed scheme options? Are there alternative scheme structures that should be considered for 2008/09?
8	Do you support the use of indexes for the 2008/09 incentive scheme - Do you agree with the proposed level of scheme target indexation for wholesale power price? - Do you prefer wholesale power price index option (a) or (b)? - Do you agree with the proposed level of scheme target indexation for Cheviot outage weeks?
9	Which is (are) your preferred scheme(s)? (please provide reasons) If your preferred scheme is scheme 3 or 4 do you consider these should have a target indexed to power price and/or Scottish outage weeks or not?

10	Do you agree that longer term development of systems that will reduce the cost and carbon impact of operating the system be supported? Which manner of funding do you consider to be the most appropriate?
11	Did you find the level of information within this consultation, and associated documentation and workshop, on our balancing and BSUoS costs forecasts for the current year and 2008/09 informative. - What additional information should National Grid provide to explain better the costs and cost drivers?
12	Do you have any further comments on the analysis and information provided within the appendices to this consultation or in the further documentation available on our website?
13	Do you have any further comments on any aspect of this consultation in relation to the Electricity SO?

Section 3
Gas System Operator Incentives

This section sets out National Grid's forecasts and initial proposals for SO incentive schemes from 1st April 2008 in relation to System Balancing, Residual Balancing and Quality of Information.

Supporting information for this section is provided in a separate gas appendix available on the SO Incentives section of our website.

3.1 Background

Current Incentives

153. National Grid is subject to a set of System Operator (SO) incentives which encourage it to efficiently manage the costs associated with the day to day management of its gas transportation system, and improve the performance and quality of its information provision services. It is also subject to a set of capacity investment related incentives which encourage efficient investment in the NTS in response to the changing needs of customers. A number of these incentives have already been agreed as part of National Grid Gas's NTS Price Control. Those that are outstanding from April 2008, and are therefore part of this Initial Proposals consultation, are:

- System Balancing Incentives
- Residual Gas Balancing Incentives
- Quality of Information Incentives

System Balancing

154. The System Balancing incentive comprises two separate incentives (i) NTS Shrinkage and (ii) System Reserve (known as Operating Margins)

(i) NTS Shrinkage

155. National Grid undertakes the role of NTS Shrinkage Provider on behalf of the community and procures gas and electricity for this purpose. NTS Shrinkage covers the gas and electrical energy which is used for compression and to cater for gas that cannot be accounted for and billed in the measurement and allocation process. The shrinkage incentive encourages National Grid to minimise the overall cost of procuring gas and electricity to cover the three shrinkage components:

- Compression Energy - that energy used to run compressors to transport gas through the NTS

- Calorific Value Shrinkage (CV Shrinkage) – that energy which cannot be billed due to CV capping under application of the Gas (Calculation of Thermal Energy) Regulations 1996, subsequently amended in 1997.
- Unaccounted For Gas (UAG) – that gas which remains unaccounted for after taking into account all measured inputs and outputs from the system, own use gas consumption, CV Shrinkage and the daily change in NTS linepack. This is primarily due to inherent metering tolerances.

(ii) System Reserve (Operating Margins)

156. Operating Margins (OM) services are purchased by National Grid on an annual basis in line with both the requirements of the UNC and obligations placed on it through its safety case. Primarily, OM gas is used during periods of operational stress providing within-day support to maintain system pressures while other remedial actions are taken to avoid entering into an emergency. Operational stress may be caused by events such as significant unanticipated changes in supply/demand patterns, minor or major offshore supply failures, unexpected pipeline and/or plant unavailability. There is also a need to procure an amount of OM gas to cover the safe and orderly rundown of the distribution networks whilst maintaining safe pressures on the NTS in the event of a network emergency.

157. The system reserve incentive encourages National Grid to minimise the OM service provision costs. The gas commodity costs are not part of the incentive and are recovered from shippers through Network Code energy balancing neutrality arrangements.

Residual Gas Balancing

158. Shippers are incentivised, via cash-out arrangements, to ensure that the volume of gas that they supply onto the system matches the volume of gas that they take from the system on a daily basis. However shippers (in aggregate) do not always maintain balance, and it falls to National Grid as residual balancer to buy and sell gas via the on-the-day commodity market (OCM) to balance the system by end of day and keep system pressures within operational limits at all times.

159. This incentive comprises the Daily Price Incentive and the Daily Linepack Incentive.

(i) Daily Price Incentive

160. In performing its role as residual balancer on any particular day, National Grid may need to take balancing actions on the OCM where it believes it is necessary in order to resolve the energy imbalance. National Grid is not directly incentivised to minimise the total cost of its actions but instead is

incentivised to trade close to the System Average Price (SAP), to minimise the impact that its trades may otherwise have on market prices.

(ii) Daily Linepack Incentive

161. NTS linepack is the volume of gas contained within the NTS at any one time. The daily linepack incentive encourages National Grid to balance the system such that the change in linepack between the start and end of the gas day is kept within a tight tolerance, to minimise imbalances being transferred from one day to the next through linepack.

Quality of Information Incentive

162. The quality of information incentive was introduced in October 2006 to improve the quality of certain information published to market participants and reduce the overall cost of gas to consumers through enhancing the efficiency of the wholesale market. Two specific performance aspects were subject to individual incentives; (i) demand forecast accuracy, and (ii) the availability and timeliness of certain key market data published via National Grid’s website.

(i) Accuracy of day-ahead demand forecast

163. This incentive encourages National Grid to invest in systems and processes to increase the accuracy of its day-ahead demand forecast published to market participants

(ii) Website performance

164. This incentive encourages National Grid to invest in new processes, IT hardware, software, and infrastructure upgrades and appropriate support arrangements to improve the availability and timeliness of key market information that it publishes via its website.

Forecasts and Incentive Scheme Options

3.2 System Balancing Incentive – Shrinkage

Context

165. The nature and location of gas supplies into the UK has a very significant effect on a number of system operation activities, and is the greatest source of uncertainty going forward. With UKCS production now in sharp decline, the UK is increasingly dependant on imports to meet its demand for gas. With many new import projects now coming on stream, and with further projects expected next year and beyond, it is expected that there will be a surplus of import capacity to the UK. However the timing of these projects, and whether there is gas behind the capacity, remains highly uncertain.

166. Historically flows from UKCS have been relatively stable, but going forward flows through import infrastructure are likely to be much more price sensitive as the UK will compete for gas with continental Europe and, in the case of LNG, the global market. From an SO perspective, the source, pricing and location of a range of gas supplies creates a much more uncertain day to day operating environment and has the potential to cause a fundamental change to supply patterns and associated flows on the NTS. This is relevant for Shrinkage as the shifting of supplies away from UKCS affects the requirement for NTS compression, and different sources of gas coupled with Transmission and Distribution network topology may affect levels of CV Shrinkage (described more fully below) going forward.

Volume Forecasts

167. Shrinkage comprises three components which are forecast separately as they are independent of each other with different underlying drivers:

- **Compression Energy** - that energy used to run gas and electric compressors to transport gas through the NTS
- **Calorific Value (CV) shrinkage** – that energy which cannot be billed due to CV capping under application of the Gas (Calculation of Thermal Energy) Regulations 1996.
- **Unaccounted For Gas (UAG)** – that gas that remains to be accounted for after taking into account all measured inputs and outputs from the system, own use gas consumption, CV Shrinkage and the daily change in NTS linepack. This is primarily due to inherent metering tolerances.

Compression Energy Forecast

168. Our forecast of compression energy requirements is based upon the 'Base Case' supply scenario developed in conjunction with the industry using information provided from UKCS producers, gas importers and project developers through our annual Transporting Britain's Energy (TBE) consultation process. For further information on this process click here.

169. Due to the distances involved in physically moving gas from point of NTS entry to point of exit, the operation of a significant proportion of the compression fleet is predominantly dependent on supplies at the St. Fergus entry point. We have therefore 'stressed' the Base Case flow assumptions to examine the range of compression requirements with St. Fergus at very high average flows and very low average flows (rebalancing supply proportionally on other major entry terminals). Further detail is provided in the appendix. The resulting range of requirements is described in figure 3.1.

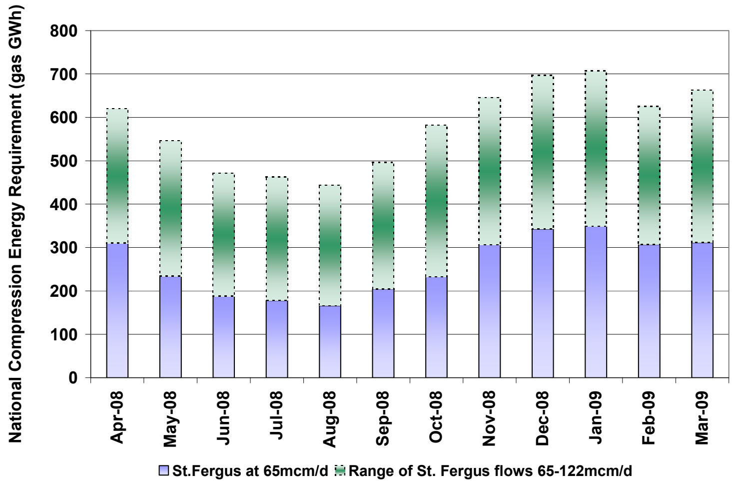

Figure 3.1: Variation in Compression requirements with potential range of Entry flows at St. Fergus Terminal

170. As can be seen, the overall national compression requirement can vary hugely depending on average flows at St. Fergus. Given the uncertainty over how new supplies will affect actual flows at St. Fergus going forward, we have further analysed this key driver to establish the relationship between total compressor fuel usage and entry flows at St. Fergus. This is shown in figure 3.2 below:

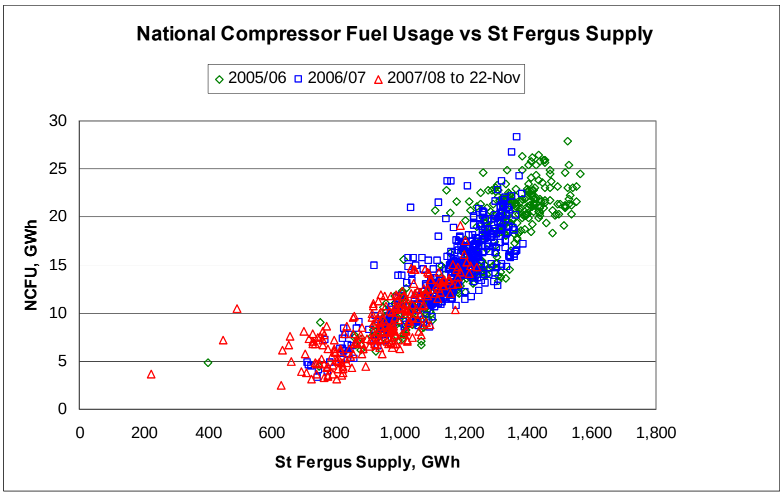

Figure 3.2: Correlation of National Compressor Fuel Usage with flows from St. Fergus Entry Terminal

171. This shows a strong correlation between supply levels at St. Fergus and national compressor fuel usage, demonstrating a broadly linear relationship through credible ranges. This supports the approach used in the current incentive arrangements where the target shrinkage volumes vary with annual average entry flows at St. Fergus through the use of three ‘bands’.

172. Hence we believe a similar approach should be used for incentives from 08/09 where the target volumes are linked to St. Fergus entry flows. We propose to continue with the banding approach employed in the current incentive as we believe this is pragmatic, but propose to create additional bands to provide greater resolution. More detailed information on this analysis and forecast is contained within the appendix, but in summary our aggregated forecast of compression requirements from 2008/09 expressed in gas GWh is:

X = Average annual volumetric flow through St. Fergus terminal (mcm/d)	Total Compression Requirement (gas GWh)
X<85	3777
85<= X <90	4627
90<= X <95	4967
95<= X <100	5308
100<= X <105	5648
X>105	6396

Gas and Electricity Compressors

173. In response to environmental legislation (IPPC) National Grid has assessed compressor sites against the Best Available Technique test. As a consequence, we are presently implementing a program to install electric drives at certain compressor sites, replacing gas fuelled turbines. Currently there are only two small electric drives on the NTS, accounting for less than 1% of the costs of Shrinkage. Over the next few years, the changeover program will mean that a much more significant proportion of the energy required for operating NTS compressors will be electrical, rather than own use gas. In the year 2008/09, electric drives are scheduled to commission at the following sites:

Site	Commissioning Target date
Wormington	Feb 08
Churchover	May 08
Kirriemuir	April 08
Felindre	May 08
St. Fergus	Jan 09

174. Unlike own use gas, which is taken from the NTS at these sites to fuel gas compressors and procured on the wholesale market, no equivalent electricity supply exists at these sites. Therefore National Grid has to purchase its electricity requirements for the electric compressor drives as an end consumer, paying supplier charges for connection and supply at retail rates.

175. As the electricity requirements are much more significant going forward than at present, we believe it is essential to explicitly reflect this in the incentive design. We believe that the shrinkage incentive arrangements should be designed to encourage National Grid to manage the costs and risks of electricity procurement in a similar way to its gas procurement. This will be expanded later in the reference price section. Given this, there is a need to split the overall compression volumes into forecasts for Electric Compressor Energy (ECE) and Own Use Gas (OUG) requirements. Note the overall compression load remains unaltered, only the fuel type changes. This split has been calculated using a gas to electricity ratio of 3:1 which reflects the average relative efficiencies of gas and electricity driven compressors across their operating ranges. Thus for each three units of OUG saved, one unit of electrical energy will be required to transport the same volume of gas through the NTS. Therefore our aggregated forecast of compression requirements from 2008/09 by fuel type is:

X = Average annual volumetric flow through St. Fergus terminal (mcm/d)	*TOTAL energy requirement (gas GWh)*	OUG component (gas GWh)	ECE component (elec GWh)
X<85	**3777**	*3000*	*259*
85<= X <90	**4627**	*3682*	*315*
90<= X <95	**4967**	*3953*	*338*
95<= X <100	**5308**	*4228*	*360*
100<= X <105	**5648**	*4499*	*383*
X>105	**6396**	*5097*	*433*

CV Shrinkage Forecast

176. The CV of natural gas determines the amount of energy transported. CV information is provided daily to gas shippers and suppliers, and is used to bill gas consumers for the energy they use. The methodology for calculating the daily CV within a charging zone is designed to ensure that customers within a zone are not at material risk of being charged for energy not supplied due to local variations in the CV of gas. This therefore gives rise to the possibility of energy being delivered that cannot be billed, which is termed CV Shrinkage.

177. Determination of the daily CV is enshrined within the Gas (Calculation of Thermal Energy) Regulations 1996 (Amended 1997). In summary, the methodology detailed in paragraph 4(A) of the Regulations says that the daily CV for a charging zone shall be the lowest of:

- the flow weighted average CV calculated across the charging zone; or

- the average CV measured at any of the input or output points to the charging zone, plus 1MJ/m^3.

178. This means that the CV used to calculate shrinkage is capped at 1MJ/m^3 above the lowest average CV entering or leaving that charging zone from a single point, *no matter how small the volume.*

179. Historically, UKCS production has been high and stable and has meant that CV Shrinkage has been at relatively small levels. However going forward, as UKCS production falls, the importation of gas is increasing significant and this will almost certainly mean a greater difference in CV between different sources of gas imported from different countries. Also, with the approval and implementation of UNC modification 154 "Enduring provisions for LDZ entry points", the possibility of CV shrinkage caused by the direct entry of gas with different CVs into Distribution Networks increases significantly.

180. We have conducted network analysis for 2008/09 and our base forecast of the underlying CV Shrinkage risk remains close to last year at 150GWh, compared with 152GWh in 2007/08. However, this underlying forecast excludes an increasingly important effect, which is that the location of supply points and offtakes and associated network topology may mean that the System Operator has no economic means of mitigating CV shrinkage in certain parts of the network.

181. In 2008/09, specific risks arise due to the commissioning of the new Entry Point at Milford Haven and the associated uncertainty over the CV of gas that will enter the NTS. Figure 3.3 show examples of how CV capping can occur due to the combination of supply, local NTS topology, offtakes and boundaries of the Distribution Networks, which cannot be mitigated by the SO:

Case 1 – Low CV (37 MJ/m^3) **Case 2 – High CV (42 MJ/m^3)**

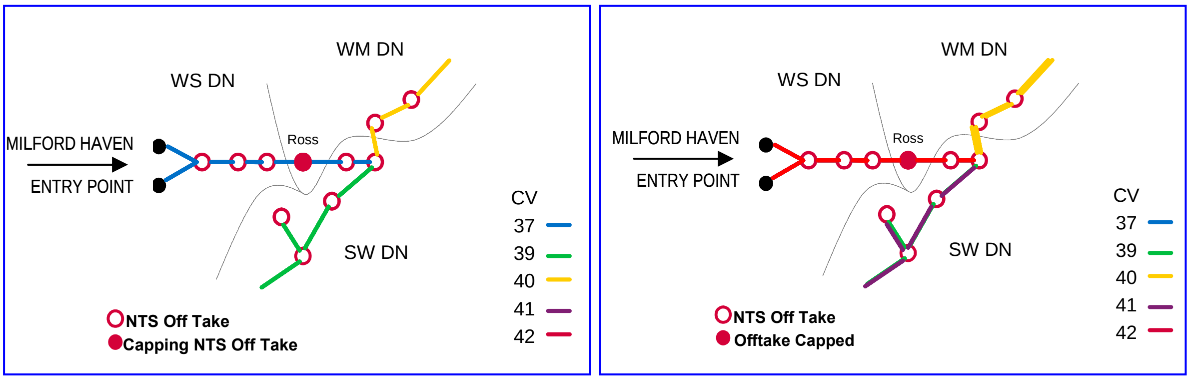

Figure 3.3: CV capping caused by gas of varying CV entering at Milford Haven

182. In case 1, if gas at CV of 37MJ/m^3 gas enters at Milford Haven, then the capping rules will mean that gas exiting at Ross in the West Midlands DN is highly likely to cap the calculation of energy for gas exiting at all other offtakes in the West Midlands DN. We have conducted network analysis which demonstrates this case could create CV shrinkage of up to 707GWh per year.

183. In case 2, if gas at CV of 42MJ/m^3 enters at Milford Haven, then the capping rules are highly likely to result in one of the other offtakes in the West Midlands DN capping the calculation of energy for gas offtaken at Ross. Our analysis shows that this case could create CV shrinkage of up to 352GWh per year.

184. In both cases it can be seen that there are no mitigation options for the System Operator as the gas from Milford Haven hits the Ross offtake before any possibility of diverting or mixing with other gas can occur on the NTS.

185. The same issue exists at the Cowpen Bewley offtake in the Northern Distribution Network, which is close to the Teesside Entry point. If the CV of gas entering at Teesside were to be between 36.9 – 38MJ/m^3 then analysis suggests a potential CV shrinkage exposure of up to 858GWh per year. Again, no mitigation options exist for the SO due to network topology and the proximity of the offtake to the entry terminal.

186. The two specific circumstances highlighted above are low probability, but high impact risks. However with the shift to new and diverse sources of gas, including that entering directly into Distribution Networks, we believe CV Shrinkage will become a much more significant issue going forward, with National Grid NTS having little or no control over its management. This leads us to reach the following conclusions:

    1. We propose to exclude CV shrinkage volumes associated with Ross, Dyffryn Clydach and Cowpen Bewley offtakes, (i.e. caused by Milford Haven and Teesside entry flows) and CV shrinkage volumes caused by direct DN entry, from the SO incentive arrangements from 2008/09.
    2. With the changing nature and entry location of gas supplies, it may be timely to review the CV capping rules contained within the Gas (calculation of thermal energy) Regulations, which is under the governance of BERR (formally DTI).
    3. As shippers pay for the resultant CV shrinkage costs, we believe it is up to Shippers to indicate to Ofgem and BERR through their response to this consultation how strongly they feel about the continuing appropriateness of the current capping arrangements.

187. In summary, our forecast requirement for underlying CV shrinkage for 2008/09 is 150GWh, which excludes any effects of CV capping from supplies from Milford Haven, Teesside or Direct DN Entry. We propose to exclude CV shrinkage volumes associated with Ross, Dyffryn Clydach and Cowpen Bewley offtakes, (i.e. caused by Milford Haven and Teesside entry flows) and CV shrinkage volumes caused by direct DN entry from the incentive arrangements, due to the cause being outside of the control of the SO, and there being no economic mitigating actions available to the SO. This could be effected through Ofgem's monthly CV audit process.

188. For the avoidance of doubt, National Grid would still have to procure gas to cover CV shrinkage from these sources, and the GCRP methodology would still provide us with an incentive to procure these volumes efficiently in the

market, and expose us to the risk of inaccurately forecasting these volumes or mis-timing their procurement.

Unaccounted for Gas Forecast

189. Unaccounted for gas (UAG) is that volume which remains unaccounted for after taking into account all measured inputs and outputs from the NTS, own use gas consumption, CV Shrinkage and the daily change in NTS linepack. It is primarily due to inherent tolerances in metering equipment and metering error due to contamination. The small amounts of natural gas vented during the commissioning and maintenance of NTS pipeline and associated equipment also contribute to UAG, though these are minimal.

190. National Grid continuously monitors and analyses UAG. Outturn UAG is extremely volatile and there appears to be no statistically robust driver to explain its behaviour. In the management of shrinkage we employ a forecast technique based upon analysing historic outturn data, using a statistical process to adjust for outliers, in order to inform our day to day forecasting and procurement of shrinkage requirements.

191. The annual forecast for 2008/09 is based on this technique using historic outturn averages adjusted for outliers which fall outside two standard deviations of the rolling average.

Period	Normalised UAG Volume (GWh)
Oct01 - Mar 02	457
02/03	1535
03/04	707
04/05	971
05/06	1260
06/07	1361
Apr 07 – Sep 07	679
Annual Average	**1161GWh**

Aggregated Shrinkage Forecast for 2008/09

192. The following table summarises the forecast for 2008/09 by shrinkage components.

X = Average annual volumetric flow through St. Fergus terminal (mcm/d)	Compression OUG component (gas GWh)	Compression ECE component (elec GWh)	CV Shrinkage (gas GWh)	UAG (gas GWh)
X<85	**3000**	***259***	**150**	**1161**
85<= X <90	**3682**	***315***	**150**	**1161**
90<= X <95	**3953**	***338***	**150**	**1161**
95<= X <100	**4228**	***360***	**150**	**1161**
100<= X <105	**4499**	***383***	**150**	**1161**
X>105	**5097**	***433***	**150**	**1161**

193. The following table summarises the forecast by fuel and draws a comparison with 2007/08. Note that the comparison with 2007/08 assumes the electricity component is converted to its gas GWh equivalent.

X = Average annual volumetric flow through St. Fergus terminal (mcm/d)	TOTAL 2008/09 Gas requirement (gas GWh)	TOTAL 2008/09 Electricity Requirement (elec GWh)	2007/08 Requirement (GWh)	% change 2007/08 to 2008/09
X<85	4311	259	*6393*	↓ 21%
85<= X <90	4993	315		
90<= X <95	5264	338	*7129*	↓ 12%
95<= X <100	5539	360		
100<= X <105	5810	383	*8312*	↓ 17%
X>105	6408	433		

194. This significant reduction is due to the increase in geographic spread of supply sources, in particular the anticipated commissioning of LNG importation terminals at Milford Haven, Grain phase II and increased flows at Easington.

Reference Price Methodologies

195. A Gas Cost Reference Price (GCRP) methodology has been used in the calculation of an overall cost target for Shrinkage gas since 2002 and is designed to provide a benchmark against which National Grid's procurement activity in the market is measured. The principle being that if we can procure energy at prices which are better than the average market price over the GCRP period, then we share the savings with consumers. If our procurement price exceeds the average market price then we bear a share of those additional costs.

196. As the volume of electricity required to run electrical drives is much more significant going forward, we believe it is essential to adopt a similar electricity cost reference price (ECRP) methodology to incentivise the costs of procuring electricity, whilst retaining a single overall cost incentive for NTS shrinkage.

Enduring GCRP Methodology

197. The existing GCRP methodology has been prevalent for a number of years and has driven National Grid to adopt forward procurement and risk management strategies which have delivered significant savings over market prices, whilst protecting consumers from the volatility of prompt market prices. We continue to believe that the existing GCRP methodology is in the best interests of consumers, as it

- leads to procurement strategies in the forward markets that provide relative price stability over alternative methodologies that reference prompt market activity;

- provides opportunity for risk management strategies to be employed; and
- facilitates volumes being procured over a period of time without adversely influencing market prices.

198. We therefore propose that the existing GCRP methodology be retained and that the referencing period be clarified in National Grid's GT Licence in respect of the NTS for incentive years up to 2012/13 (the year after the expiry of the current NTS price control) enabling the next price control to proceed as normal without introducing uncertainty and potential for inefficiencies into shrinkage procurement that are described below.

Interim GCRP Methodology for 2008/09

199. For the past few years we have had certainty over the GCRP methodology applying to relevant years as it has been set out within National Grid's Gas Transporter Licence in respect of the NTS. For 2008/09 onwards this was not the case and with the SO review considering arrangements for the incentive year 2008/09 and beyond, we have had no certainty over whether the current GCRP methodology will continue to apply or a new one be adopted. As this is directly linked to the recovery of costs incurred (as well as any incentive arrangement), we have not yet purchased gas for NTS Shrinkage purposes for delivery from 1st April 2008. Previously the GCRP methodology would have driven a strategy where procurement for 2008/09 is likely to have started around April 2007.

200. Given the significant volumes of gas required for NTS Shrinkage purposes, we believe that the existing GCRP methodology is an appropriate enduring methodology to reference the cost of NTS Shrinkage gas. Whilst we believe this should be applied for years 09/10 onwards, an interim methodology is required for 2008/09 as we are already over half way through the annual GCRP period if the enduring methodology was to apply. The inherent timescales associated with the process of Initial Proposals and Final Proposals for arrangements to apply for gas delivered from 1st April 2008 will mean that a methodology is unlikely to be agreed and encoded in National Grid's GT Licence until just prior to 1st April 2008.

201. We strongly believe it is in the interest of consumers for our procurement of shrinkage gas, for delivery from 1st April 2008, to begin as soon as possible. Delaying procurement further diminishes the effectiveness of our risk management strategies and could expose consumers to the price volatility associated with prompt markets. In addition, given the significant volumes of gas we procure to cover NTS shrinkage, there is a risk that heavy procurement over a short period will influence market prices.

202. We therefore intend to propose a pragmatic change to the existing/proposed enduring GCRP methodology to create an interim methodology for 2008/09 only. Importantly, we intend to start the procurement of gas assuming that this proposed interim methodology (which will inherently provide cost recovery as well as incentive arrangements for National Grid) will be in place on 1st

April 08. If there are strong objections to the proposed interim methodology, we would ask market participants to express them in response to this consultation, and we will then review our procurement position with Ofgem.

203. We propose an interim GCRP methodology for 2008/09 which is the same as the existing GCRP, but rather than using a reference period from 1st April 07 – 31st March 08, use the following periods:

    1. For 'summer' quarters (Q2-08 and Q3-08) the reference period becomes 1st Jan 2008 to 31st Mar 2008 inclusive.
    2. For 'winter' quarters (Q4-08 and Q1-09) the reference period becomes 1st Jan 2008 to 30th June 2008 inclusive.

204. For years beyond 2008/09 the existing/proposed enduring methodology would apply.

Enduring (ECRP) Methodology

205. We believe that developing an ECRP on a similar basis to GCRP is an appropriate enduring way to benchmark the cost of procuring electric compression energy for incentive purposes. The methodology will need to reflect the fact that unlike our procurement of shrinkage gas from the wholesale market, the electric compressor energy will be purchased through a flexible retail contract which includes additional cost elements to cover supplier charges and delivery (use of system) charges.

206. We have considered a number of readily available retail power price indices, but due to the individual nature of large industrial retail power pricing, and the NTS compressor load profile, these indices are not sufficiently reflective of the electric compressor energy profile to provide a reasonable benchmark. We believe that the closest proxy would be achieved by using a seasonal wholesale power price index, appropriately uplifted for additional retail and load profile costs.

207. We therefore propose an enduring ECRP methodology that calculates a reference price from independently (e.g. Heren) reported forward seasonal baseload wholesale electricity prices, appropriately uplifted to cover additional retail and load profile costs, weighted for seasonality (summer/winter) in a similar way to GCRP. The reference period over which these prices are taken is proposed to mirror the GCRP reference period (year -1). The uplift is explained for fully in the next section (interim ECRP arrangements for 2008/09).

208. This reference price would then be multiplied by the appropriate ECE volume and, with inclusion of forecast electricity Use of System charges, would be aggregated with the total gas incentivised cost (resulting from the equivalent GCRP process) to derive the overall total cost incentive target.

209. For the reasons described above, we believe both the ECRP and GCRP arrangements should apply on an enduring basis in National Grid's GT

Licence irrespective of the duration of any incentive scheme that may be agreed. We also believe it is necessary to establish a simple update mechanism to ensure that proper account is taken of variables that are not directly related to controllable shrinkage costs and therefore not the primary focus of the incentive, being:

- retail uplift and delivery charges; and
- In the case of multi-year incentives, the allocation of compressor requirement volumes between electricity and gas fuels as the electric drive changeout program progresses.

210. Currently National Grid's GT Licence contains provision for the annual notification to the Authority of the published index to be used for the calculation of GCRP, over which the Authority has right of veto. It is proposed that this type of mechanism be used for these updates.

Interim ECRP Methodology for 2008/09

211. As discussed in the previous section, an annual reference price period relating to 2008/09 delivery year has already partially elapsed and an interim arrangement is required for deriving an ECRP for 2008/09.

212. We propose that for 2008/09 the ECRP be derived from published forward seasonal reference prices taken over the period 1st March 2008 – 31st March 2008 inclusive, with appropriate seasonal weightings. This facilitates National Grid bringing the new compressors under its existing retail contract and effectively benchmarks the prices that the contract is based upon. It will then be up to National Grid to use the flexibility within the contract to manage the energy costs as the wholesale market moves, sharing any benefits (or losses) with consumers.

213. We have worked closely with our supplier to understand the retail uplift and the delivery charges (over which National Grid has limited or no influence) that are levied in addition to the wholesale price of electricity. More detail on this is contained within the appendix.

214. In summary, our analysis shows that the retail uplift over wholesale prices for the NTS compressor load is £8.50/MWh. We therefore propose that the wholesale ECRP be uplifted by this amount for 2008/09. In addition to the retail uplift, the delivery charges for 2008/09 are forecast to be £3.2m. These are expected to change when new Transmission and Distribution Use of System Charges are published. We propose that delivery charges be reforecast prior to Final Proposals to capture any change, and are added to the final overall target for this incentive.

Incentive Scheme Design

215. The forecast gas and electricity volumes and respective references price methodologies combine to derive an overall £m target for shrinkage costs. At current market prices, these volume forecasts would equate to approximately £116m for the volume target band 95<= X <100.

216. The current shrinkage incentive scheme arrangement has the following parameters, noting that this was a one year rollover of the previous scheme which had been agreed for five years as part of Transco's price control in 2002.

Scheme	Duration	Annual Cap	Upside Sharing Factor	Annual Collar	Downside Sharing Factor
Current	*1 year*	*£4m*	*25%*	*£-3m*	*20%*

217. We have developed a number of incentive scheme options, to apply from 1st April 2008, with varying risk/reward profiles and varying durations. We feel that longer term options should be strongly considered as the greatest uncertainties are mitigated through the volume target being driven by the primary cost driver and the unmanageable risk of CV shrinkage being removed from the incentivised arrangements.

218. We are interested in views on how Market Participants believe we should be incentivised in respect of shrinkage management and procurement activities.

Scheme	Duration	Annual Cap	Upside Sharing Factor	Annual Collar	Downside Sharing Factor
A	**1 year**	**£10m**	**40%**	**£-6m**	**35%**
B	**1 year**	**£5m**	**25%**	**£-3m**	**20%**
C	**2 years**	**£8m**	**30%**	**£-5m**	**25%**
D	**4 years**	**£10m**	**40%**	**£-6m**	**30%**
E	**4 years**	**£6m**	**25%**	**£-4m**	**20%**

219. **Scheme A** is a short-term strong incentive signalling that we should chase efficiencies aggressively in this area, which may involve adopting riskier procurement strategies and concentrating resources over the short-term. Any resulting benefits continue to be shared with consumers through sharing factors with National Grid taking on a higher risk on the downside, but a higher reward on the upside.

220. **Scheme B** is a short-term weaker incentive signalling that National Grid should continue with its current relatively risk adverse strategy. Benefits

continue to be shared with consumers through sharing factors with National Grid taking on a lower risk on the downside, but a lower reward on the upside.

221. **Scheme C** is a medium term, medium strength incentive signalling that National Grid should look to take on some more risk, potentially seeking new opportunities for improvements which will be limited as a result of the maximum 2 year payback period.

222. **Scheme D** is a long term aggressive incentive and signals that National Grid should consider identifying and making significant new investments in the reduction of shrinkage costs through a variety of means in order to earn higher rewards. The downside sharing factor and collar reflects the risk that a 4 year incentive represents given the pace of change in the gas regime in relation to new supplies, exit reform etc.

223. **Scheme E** is a long term weaker incentive that signals National Grid should investigate some longer term investments in the reduction of shrinkage costs as the result of the longer payback period, but generally adopt a similar risk adverse strategy to now.

224. Going forward as environmental considerations become increasing important, we believe longer term incentives in relation to shrinkage potentially provide opportunity to deliver wider environmental benefits as well as reduced shrinkage costs, through more efficient use of compression. A longer term aggressive incentive would open the potential to consider novel investments in the NTS to increase the flexibility and availability of compression, strategic placement of pipework to enhance operating ranges, new technologies to improve fuel and emission efficiencies and installing different compression components depending on how new flow patterns develop across the year. There are also potential developments in relation metering and better understanding the drivers of UAG which could be progressed under more aggressive incentives.

Consultation Questions

13	Do you agree with the approaches used in forecasting the various elements that make up NTS shrinkage?
14	Do you support the continued linking of shrinkage target volumes with flows at the St. Fergus entry point, and do you support the move to an increased number of bands?
15	Do you agree that the SO should not be incentivised on CV shrinkage that is outside of its control? Please comment on whether you believe it is necessary for Ofgem and BERR to review the continuing appropriateness of the CV capping rules in the Gas (Calculation of Thermal Energy) Regulations.
16	Do you have an objection to the proposed interim GCRP and ECRP methodologies for 2008/09? If so please explain why and outline

	your suggested alternative.
17	Do you support the proposal to establish the proposed enduring GCRP and ECRP methodology arrangements into the National Grid’s GT Licence for an extended period, (to avoid the need for interim arrangements in the future) regardless of the duration of any incentive scheme?
18	Which of the scheme options do you believe provides the most appropriate incentive arrangements for the management of NTS Shrinkage?

3.3 System Balancing Incentive – Operating Margins

Context

225. Operating Margins (OM) services are purchased by National Grid on an annual basis in line with both the requirements of the UNC and obligations placed on it through its safety case. To date, OM services have been provided by storage facilities due to their strategic location on the extremities of the network, implicit availability and the high deliverability rates which are necessary for OM purposes.

226. At its recent Transmission Price Control, National Grid Gas accepted an obligation in Special Condition C25 of its Gas Transporter Licence to use reasonable endeavours to promote competition in the provision of OM by 1 April 2009.

227. As a step towards this, National Grid held a competitive tender in September 2007 for the provision of OM Services against its locational requirement in the South-East. The tender was open to any potential providers in the South-East, although the main interested parties were those Shippers with capacity in Grain Phase 2. Providers were generally reluctant to offer services ahead of gaining some operational experience following the commissioning of Grain phase 2, although one new potential provider participated in the tender, offering a 1 year service from 2009. This tender has recently been assessed as uneconomic against current service provision.

228. National Grid also intends to hold a competitive tender for its entire 2008/09 requirement from storage facilities in January 2008.

229. We are currently undertaking a review of OM with a view to increasing the types of service providers able to meet the service requirements. Following some preliminary investigation with the Health and Safety Executive (HSE), we hope to engage with the industry on this topic within the next 6 months.

230. During the 2008/09 incentive period we anticipate that the current pool of service providers of OM services will remain unchanged. This pool includes a number of commercial storage operators as well as National Grid LNG storage business, which has regulatory and financial separation from National Grid Gas. NG LNG services are procured through pre-emption rights in accordance with UNC at prices administered through National Grid's GT Licence. These regulated prices, to apply from April 2008, are currently the subject of an Ofgem price review.

Forecast Operating Margins Requirements for 2008/09

231. Requirements for Operating Margins gas are determined through network simulation analysis. The requirement is for the physical delivery of additional gas to maintain safe pressures within the NTS during a System Event, until other measures take effect.

232. Potential System Events are split into three categories:

- Group 1 (Major events) e.g. loss of supply infrastructure, loss of largest sub-terminal
- Group 2 (Multiple events) e.g. compressor failures, pipe breaks
- Group 3 (Orderly rundown) maintain pressures in the event of a national gas supply emergency

233. The topology of the NTS dictates that these events have varying locational impacts and therefore the proximity of OM held in reserve against these events is a significant factor. For some events a proportion of OM is required to be held in close proximity as network pressures cannot be maintained for sufficient time to transport OM services located further away, due to the transit time of pressure changes across the network. Therefore OM requirements are presented as two 'types':

- **Minimum locational requirement** is where a minimum volume/ deliverability of OM must be held in a specific area of the network to cater for certain specific events.
- **Non-locational requirement** can be spread between OM providers on the network, subject to a number of important criteria, to cater for all other events.

Minimum Locational Requirements

Events dictating requirement	Current Facility	Min. Locational Requirement 2008/09 (GWh)
Feeder 10 loss, compressor trips in Scotland	**Glenmavis**	**78**
Compressor trips (Carnforth / Nether Kellet / Warrington)	**Partington**	**10**
Feeder 14 loss, compressor trips (Alrewas / Churchover/ Wormington / Aylesbury / Lockerley)	**Avonmouth**	**115**
Compressor trips (Peterstow)	**Dynevor Arms**	**27**
Feeder 5 loss north of Thames	**Isle of Grain facility**	**94**
	TOTAL	**324 GWh**

Non-locational Requirements

Requirement Category	Key Requirement Criteria	Non-locational Requirement for 2008/09 (GWh)
Category 1 (Single Large Supply Loss e.g. Easington or St. Fergus s/t)	Deliverability rate	**384**
Category 2 (pipe breaks, compressor failures not tied to a specific location)	Limited to an extent by proximity	**98**
Category 3 (Orderly Rundown)	Volume	**455**
	TOTAL	**937 GWh**

234. The column ‘key requirement criteria’ shows the primary driver that sits behind the volume required. To cater for a category 1 loss, it is the rate at which gas can be delivered which is of primary importance. For a category 2 event, where more than one facility can meet all or part of a requirement then the requirement is a “non-locational” requirement but the choice of where this can be procured may still be limited to an extent by proximity. For the orderly rundown component, there are no locational restrictions, but it is important that there is physical capacity to accept the additional gas onto the NTS given that it is likely that all available supplies will be at maximum.

Summary of Total Requirements

Aggregating the minimal locational requirements with the non-locational requirements gives the following forecast requirement for 2008/09.

Requirement	Forecast 2008/09 (GWh)
Minimum Locational	324
Non-Locational	937
Total	**1261**
↓ Reduction of 15% on 2007/08	

235. The significant reduction in OM requirements from 2007/08 levels is due to new NTS infrastructure being in place and a forecast increase in supply diversity, particularly the anticipated commissioning of the importation terminals at Milford Haven. This new infrastructure has also meant that a greater proportion of the overall OM requirement can potentially be sourced from a wider set of providers.

236. The presence of flows from Milford Haven is a key driver in the reduction of OM requirements for 2008/09 and whilst there remains uncertainty over the timing of the commissioning and operation of this facility, we will keep the requirements for OM for 2008/09 under review.

Indicative Operating Margins Holding Costs for 2008/09

237. In order to show how we anticipate the requirements detailed in the previous section will be met by OM providers, we have assumed that all current providers of services will continue for 2008/09.

Facility	Expected Bookings 08/09 (GWh)	Proportion of Total OM Requirement
Glenmavis LNG	210	17%
Partington LNG	156	12%
Avonmouth LNG	228	18%
Dynevor Arms LNG	50	4%
All other providers	617	49%
TOTAL	**1261**	**100%**

238. However, the actual proportions of bookings may be different to this depending on the number of service providers, relative economics and nature of services offered in the January 08 tender.

239. Ofgem is currently undertaking a review of the regulated prices “C3 prices”, in respect of National Grid’s LNG storage facilities, contained with Special Condition C3 of National Grid’s GT Licence. The outcome of this review will directly affect the cost of procuring OM from these LNG facilities (Glenmavis, Avonmouth, Dynevor Arms, Partington). We are not in a position to be able to forecast the outcome of the review (nor is it appropriate to) and as a result have provided an indication of costs using 2007/08 prices inflated by an estimate of RPI at 3.8%. However it should be noted that this assumption is entirely independent of the LNG price review and may bear no relation to the outcome. Following this review we would expect the new C3 prices to be used for system balancing incentive purposes, as is currently the case.

240. Using the above price assumption, and assuming we book a storage product that does not include deliverability rights (explained further in the next section), an indication of the costs of OM services from the regulated LNG facilities is provided below.

Facility	Expected Bookings 08/09 (GWh) * [07/08 price + 3.8% p/kWh]	Indicative Costs (£m)
Glenmavis LNG	(210) * [1.76]	3.6
Partington LNG	(156) * [1.88]	3.1
Avonmouth LNG	(228) * [2.16]	4.8
Dynevor Arms LNG	(50) * [2.94]	1.7
TOTAL	**644GWh**	**£13.2m**

241. For services provided from other commercial facilities, as we intend to run a competitive tender in January 2008, and there are relatively few providers, we are unable to give a more detailed breakdown in this consultation, as this could prejudice prices submitted. However, a full breakdown of our forecasts

for other commercial service provision has been provided to and scrutinised by Ofgem.

242. In aggregate, the total indicative cost (using the LNG price assumptions stated above) and our forecasts of costs from other service providers for providing OM services 2008/09 is as follows:

Year	Total Indicative Cost of holding OM requirements
2008/09	**£23.3m**
2007/08 allowance	*£25.6m*

Costs associated with Operating Margins Utilisation

243. National Grid has a choice between two storage products when booking an OM service from current service providers.

- Space only product, with no deliverability rights
- Standard bundled product which includes space and deliverability rights

244. Due to the low probability of needing to use OM in response to an event, and the fact that National Grid does not need to own the gas, in more recent years OM has been procured as a space only product. This is more economic than securing a standard bundled product which includes deliverability rights. As an illustration of this we have calculated the cost of procuring the entire 2008/09 requirement through bundled products:

- Costs with space only product = £23.3m
- Costs with standard bundled product = £36.6m

245. Hence procuring standard bundled products would lock into an additional estimated £13.3m cost ex-ante, and we do not believe this is the economic choice for procuring the OM service.

246. However in choosing a ‘space only’ product additional charges will apply in order to flow gas, when there is a need to use operating margins gas in response to an event, comprising withdrawal and injection overrun charges. These additional service charges, together with the injection and withdrawal service charges are termed “Utilisation Charges” herein.

247. In the event that National Grid needs to use the operating margins service in response to a system event, then the weighted average cost of the gas is recovered through energy balancing neutrality in accordance with the arrangements contained within UNC section K. However the additional Utilisation Charges incurred are not recoverable through energy balancing neutrality or any other mechanism. These Utilisation Charges are incurred as a legitimate cost of using the OM service in response to a system event, to

maintain the integrity of the system for all users. The probability of these charges being incurred is relatively low and we believe, over time, any utilisation costs incurred are more than offset by the savings achieved through the procurement of space only (as opposed to a bundled) storage products.

248. The potential costs associated with utilisation charges can be very significant. The level of Utilisation Charges for NG LNG facilities are fixed and published in advance, but other OM providers relate elements of their charges to SMP buy on the day the gas is needed.

249. To illustrate the magnitude of this risk, we have analysed the potential utilisation charges associated with using all 1261GWh of OM for 2008/09. Taking a very conservative proxy for SMP buy, by using a forward market price for Q3 2008, the utilisation charges associated with using all 1261GWh of OM would be just over £20m. Clearly SMP could be much higher than this assumption, and to use all of the OM booked in a year would represent an improbable scenario, but it serves to illustrate the potential significance of these costs.

250. The magnitude (GWh) of a utilisation can be considered to be mutually exclusive from the probability of an event occurring. Since the start of the Network Code in 1996 the average number of days in each incentive year when OM has been required is 2.7, with magnitude in the range 1GWh to 54GWh per day, with a mean of 14.21GWh. This data is presented in Figure 3.4:

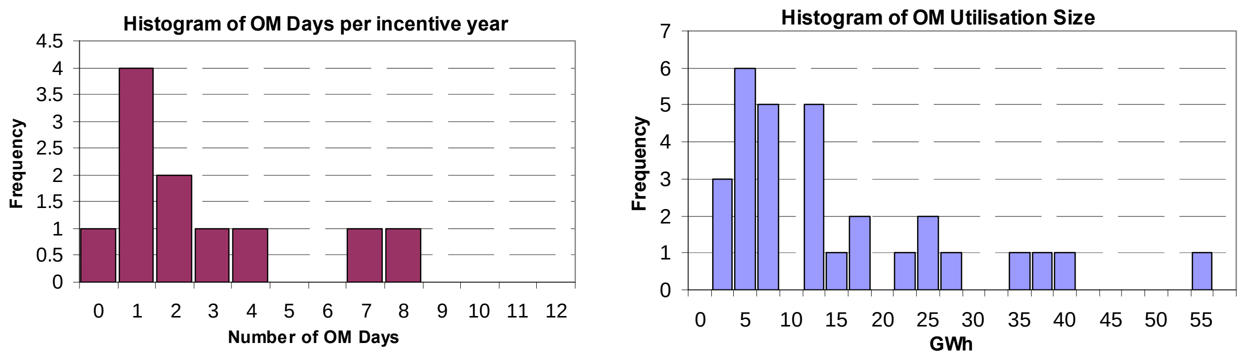

Figure 3.4: Histogram Analysis of OM Utilisation 1996 – Oct 2007.

251. To date, Operating Margins has only been required for relatively small events **such** as compressor failure and smaller supply side failures. An average utilisation of 38.65GWh per year (magnitude * probability) therefore represents an annual 'background' utilisation amount for these types of event.

252. If this background utilisation volume is multiplied by the current average utilisation prices of the NG LNG facilities + 3.4% RPI (£6973/GWh) then an average background utilisation cost can be derived which equals £0.27m per year.

253. It should be recognised that as well as variances around the number and size of smaller events seen historically, there is also the possibility of much more

significant events occurring such as major supply loss failures and, in extremis, orderly rundown.

254. As utilisation costs are necessarily incurred as a result of procuring overall more economic products, we believe it is entirely legitimate to recover these costs, in the event they were incurred, from all users post event through commodity charges. To provide market participants with choices around this, we have developed some incentive options based on the ex-ante estimate of background utilisation cost for 2008/09 described above.

Incentive Scheme Design

255. Ofgem has set the current incentive scheme with 100% sharing factors with no cap/collar due to National Grid's ownership of four of the LNG facilities that provide some of the OM services. Their previous argument has been that any other sharing factor creates a potential for perverse incentives on National Grid to favour its own LNG business over other providers. Whilst this would absolutely not be the case (and would probably constitute a beach of our NTS Licence) we believe Ofgem still holds this concern and therefore propose to retain 100% sharing factors for 2008/09.

256. We propose that the total costs of holding OM be based on our expected bookings (volumes) at the NG LNG facilities multiplied by the C3 prices resulting from Ofgem's LNG price review, plus our forecast for the remaining OM holding costs for 2008/09.

257. Incorporating choices with regard to treatment of utilisation costs, we therefore propose three incentive options for 2008/09 which effectively recognise the difference between the more probable 'background' utilisation amounts, and less probably large magnitude utilisation amounts. We are interested in views on how Market Participants believe we should be incentivised in respect of OM utilisation risks.

Scheme	Target (pending C3 prices)	Holding Cost Cap	Holding Cost Collar	Upside Sharing Factor	Downside Sharing Factor	Utilisation Cost Collar
A	£23.3m	none	none	100%	100%	£0
B	£23.57m	none	none	100%	100%	-£0.5m
C	£24.38m	none	none	100%	100%	none

258. **Scheme A** - The target is the indicative holding costs only, and should any utilisation costs be incurred, these would be recovered from Shippers post event.

259. **Scheme B** - The target comprises the indicative holding costs plus the average 'background' utilisation cost (£0.26m). The utilisation cost collar is based on a point on the utilisation distribution which would cover approximately 88% of historical utilisation. This option effectively leaves

National Grid exposed to the majority of ‘background’ utilisations but would allow National Grid to recover actual costs incurred over and above £0.5m post event, which may be caused by more significant OM utilisation events.

260. **Scheme C -** The target is based on the indicative holding costs plus four times the average ‘background’ utilisation cost, with no utilisation cost downside collar. This option puts all of the utilisation cost risk on National Grid and insulates market participants from any post event costs. Through the higher target National Grid has a bigger potential upside for having all of the utilisation cost risk.

261. Options A and B would require an additional term in the NTS Licence to allow National Grid to recover some or all utilisation costs from Shippers post event should they be incurred.

Consultation Questions

19	Do you agree that the incentive cost target should be constructed in the way proposed in this consultation?
20	Which of the scheme options do you believe is the most appropriate way to incentivise the costs of utilising OM?

3.4 Residual Balancing Incentive

Context

262. The residual balancing incentive was established in 1999, and updated in 2002 when it was set for five years as part of Transco's NTS price control. The current 2007/08 incentive was a one year roll-over of the five year scheme. As such the form and scope has not been thoroughly reviewed since 2002. Given the potential changing nature of the residual balancing role going forward, we believe that the residual balancing incentive is a good candidate for considering more fundamental review beyond 2008/09.

Incentive Scheme Design

The existing scheme has the following parameters:

Scheme	Price Incentive			Linepack Incentive			Overall Annual Cap / Collar
	Daily Cap	PIR	Daily Collar	Daily Cap	LIR	Daily Collar	
Current	**£+5k**	**10%**	**£-30k**	**£+5k**	**2.4mcm**	**£-30k**	**£+3.5m / £-3.5m**

263. **Where**:
- PIR is the target daily spread between the highest and lowest prices traded by the SO when undertaking eligible balancing actions as a %age of System Average Price (SAP).
- LIR is the target value for the change in linepack between the start of the gas day and the end of the gas day.

264. Our proposals for 2008/09 are based around the same form of scheme i.e. daily performance measures, and are proposed for one year only pending more fundamental review going forward. As a result of comments received to Ofgem's Initial Thoughts consultation, we have provided an option which removes the linepack incentive and are interested in the views of Market Participants in this regard.

Scheme	Duration	Price Incentive			Linepack Incentive			Overall Annual Cap / Collar
		Daily Cap	PIR	Daily Collar	Daily Cap	PIR	Daily Collar	
A	**1 year**	**£+6k**	**10%**	**£-35k**	**£+6k**	**3.1mcm**	**£-35k**	**£+3.5m / £-3.5m**
B	**1 year**	**£+10k**	**7%**	**£-60k**	**Remove**			**£+3.5m / £-3.5m**

265. **Scheme A** mirrors the current scheme but with updated parameters. The daily caps and collars which were revised in 2002 have been updated with RPI to bring them into today's price base. The Linepack Performance measure was originally set in 1999 at 1% of the total linepack in the system. By 2008 the size of the NTS will have increased such that total linepack is 30% greater than it was in 1999. Therefore we propose LPM increases accordingly.

266. **Scheme B** removes the linepack incentive altogether. The value contained within this part of the incentive has been transferred to the price incentive, and the performance measure made more challenging by reducing the target price spread as a proportion of SAP by 30%.

Consultation Questions

21	Do you agree that a one year scheme is appropriate pending a potentially more fundamental review of residual balancing incentive going forward?
22	Which of the scheme options do you believe provides the most appropriate incentive arrangements for the residual balancing activity for 2008/09, and what are your views on the potential removal of the linepack element of the incentive?

3.5 Quality of Information Incentive - Demand Forecasting

Context

267. The Demand Forecasting incentive was established in October 2006, and was updated for 2007/08. In its consultations with Market participants for establishing this incentive, Ofgem highlighted the potential market efficiencies that accurate demand forecasting could generate.

268. Using merit order analysis, to rank sources of gas supply in order of cost, Ofgem showed that errors in gas demand forecasts had the potential to distort the prices at which Market Participants contract for gas by approximately 8p/therm. As an upper bound, they estimated this could equate to a potential cost to customers on a tight day of up to **£10.6m per day**. They concluded that even marginal improvements in the accuracy of our demand forecast could produce large benefits to customers.

269. We believe the original rationale for establishing this incentive holds on an enduring basis, as accurate demand forecasts have been shown to have an overall benefit to the operation of the wholesale market and should reduce costs to consumers.

270. Given the potential changing nature of the residual balancing role going forward, and the intrinsic link between residual balancing, market balancing and demand forecasting, we believe that demand forecasting should be considered an integral part of a longer term review of the residual balancing activity and incentives. In the interim we believe the incentive should be retained for 2008/09 to continue delivering benefits to consumers.

271. The forecasting of total system demand needs to take account of Interconnector exports, storage injections and gas fired generation load as well as underlying industrial and domestic demand. We believe there are a number of factors which make forecasting gas demand more challenging during 2008/09 and beyond which include:

    1. The increasing interaction of the UK market with continental gas markets and world LNG markets presents new challenges for understanding the nature and drivers of interconnector flows.
    2. As new storage facilities are commissioned there is uncertainty over how the market will use these facilities from day to day. In addition, the is evidence to suggest that the use of existing storage facilities is changing with more opportunistic injections being made rather than the more predictable historic cycles of injection and withdrawal.
    3. The introduction of the Large Combustion Plants Directive on 1st January 2008 could have a significant effect on the power generation sector, potentially with a change in duty for gas fired generation. (This is discussed in more detail in the electricity section of this document.)

Incentive Scheme Design

272. The current scheme parameters derive a target of an absolute demand forecast error of 4%, with upside and downside gradients that give a profit or loss of £1.6m for a 5% increase or decrease (respectively) in performance around this target. There is a shallower upside gradient for performance increases above this, with potential losses for worse performance collared at £-1.6m.

273. We have identified areas where we can make further improvements to modelling, systems and processes to monitor and analyse the factors outlined above to keep pace with the changing market and its implications for demand forecasting. We therefore propose to roll the current scheme forward to 2008/09, pending the longer term review, with no change to the parameters as the forecasting environment is implicitly more challenging.

Consultation Questions

23	Do you agree that the current Demand Forecasting incentive should roll forward to 2008/09, pending a more fundamental review of the residual balancing activity and incentives?

3.6 Quality of Information Incentive – Data Publication

Relevant Background

274. The current information publication incentive was established in October 2006 to improve the publication performance of a number of key data items in respect of the timeliness of publication, and availability of publication systems. This incentive has been successful in improving the publication arrangements for a small number of key data items which benefits consumers through more efficient operation of the wholesale gas market, and therefore a lower overall cost of gas. We believe there is scope to build on this success and we have identified further opportunity to improve the delivery of market information through incentivisation from April 2008.

Proposed Improvements to Market Information Delivery

275. As well as the data items that are currently the subject of an incentive, there are a number of other data items which we believe Market Participants value in relation to making market based decisions. Improving the delivery of these data items should therefore lead to more efficient market operation. We propose a set of arrangements that will:

- Expand the scope of incentivised key data to include certain forecast data, real time data, within day data and post event data;
- Aim to reduce the delay between this data becoming available and its publication; and
- Aim to improve the availability of these new data items through monitoring an increased set of outputs (which map to systems not currently included in the incentive arrangements)

276. These proposals involve potential investments that are not covered by any existing projects. A more detailed explanation of the proposals is presented below.

Proposed Design of New Arrangements

277. We propose to retain the current incentive philosophy and structure which is based around measuring both the timeliness and availability of key market information published via our website, and incentivising National Grid to deliver real improvements in performance equally across both of these areas.

Scope of Incentivised Data

278. The choice of reports for incentivisation was previously based upon the most downloaded reports during the period 2005/6, but did not reflect the number of reports of each type that were published. We believe a better measure of the potential value of the report to users is to measure the downloads per publication, rather than just purely the number of downloads, as this reflects how many times each type of data is potentially used by Market Participants irrespective of the number of times it is published.

279. A graph showing downloads per publication across a range of published reports for the period Oct 2006 to Sep 2007 is shown in figure 3.5 below:

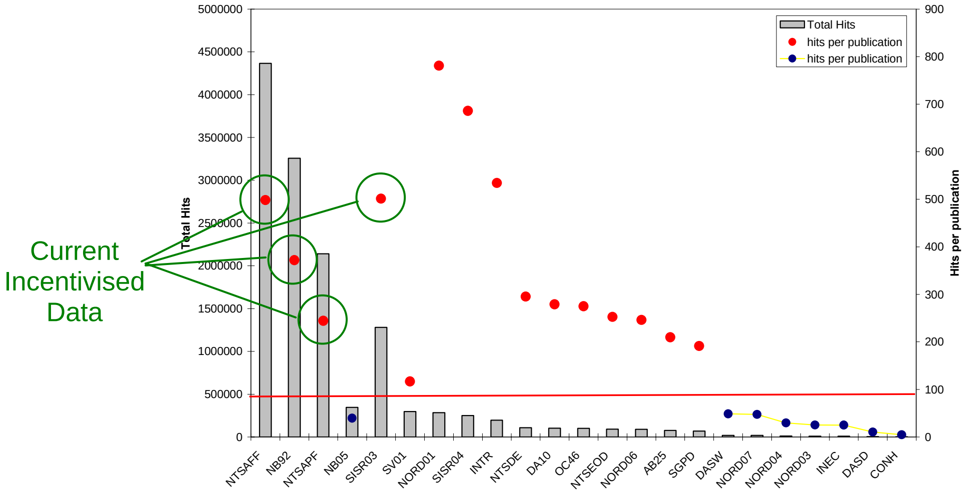

Figure 3.5: Data downloads per publication between October 2006 and September 2007

280. Based on this analysis we propose to extend the range of incentivised data to include all reports with a similar level of user downloads per publication as for the currently incentivised data as well as the ‘real time’ metered flow data at system entry points. This would result in the following data being included within the incentive:

Report	Frequency	Content
NTSAFF	hourly	Forecast flows onto the network - based on DFNs
NB92	hourly	Closing Linepack forecast
NTSAPF	hourly	Forecast flows onto the network - based on physical flowrates
SISR03	7 times / day (UNC defined)	Within day and day ahead demand forecasts
RTFD	every 12 minutes	Real Time metered Flow data at entry points
SV01	7 times / day (UNC defined)	Within day and day ahead LDZ shrinkage forecast
INTR	Daily forecast	Likelihood to interrupt forecast
NTSDE	Daily forecast	D-2 to D-5 demand forecasts
NORD01	Daily (after the day)	Balance information, Operational Information and Prices
SISR04	Daily (after the day)	Actual NTS and LDZ demands
DA10	Daily (after the day)	Weather Correction and Scaling factors
OC46	Daily (after the day)	Actual prices at an hourly resolution
NTSEOD	Daily (after the day)	Actual flows onto the network by site
NORD06	Daily (after the day)	Trading summary
AB25	Daily (after the day)	Actual NTS and LDZ Shrinkage
SGPD	Daily (after the day)	Shrinkage Procurement and Disposals

We welcome views from Market Participants as to whether this is the most valuable set of data items to bring into the incentive.

Timeliness Improvement Measure

281. Increasing the range of data published within the incentive results in significant variation of the publication frequencies of the incentivised data. As a result, we believe it is important to recognise what a valuable improvement in each area would actually be, and we have designed the target

improvements accordingly. In general we believe publishing information earlier should reduce uncertainty for Market Participants and therefore should result in more efficient market operation.

282. We propose the incentive be designed around the different ‘timescale’ categories with each having a proportional bearing upon the overall Timeliness element of the incentive. To establish a benchmark for current performance we have analysed the performance of data publication over the period October 2006 to September 2007.

- For ‘real time’ data which is published every 12 minutes, we will aim to reduce the number of publications which miss the publication slot. Over the benchmark period this accounts for 4.37% publications.
- For Within day data, the aim will be to reduce the latency of publication e.g. publish ‘hourly’ data nearer to the hour in question. Benchmark performance delivers hourly data with an average latency of 10 minutes each hour. For data linked to demand attribution runs, a publication slot is defined and therefore we will aim to reduce the number of publications missing the defined publication time (currently 0.55% of publications).
- For post event daily data, the aim will also be to reduce the latency of publication i.e. publish daily data earlier in the day. Current benchmark performance shows that data is published with an average latency of 4hr 47mins from the start of the gas day, i.e. data is published on average at 10:47 each day.

Availability Improvement Measure

283. This part of the incentive is about improving the availability of key market information. The proposed incentivised data is published across 6 pages, in two categories:

1) The Real Time Flow Data
   a. Instantaneous Flows Report
   b. Entry Zone Graphs
   c. User Defined Download

2) Operational Data Publication
   a. Prevailing view
   b. Data Item Explorer
   c. Report Explorer

284. We propose that the availability element of the incentive would monitor these six pages and operate as a straight average of availability of all of the pages,

thus the availability of each system has a proportionate bearing on the overall availability performance.

285. This significantly increases the scope of the availability monitoring within the incentive arrangements and effectively covers the systems providing access to all real time, within-day and daily information to users.

286. We propose the benchmark, against which improvements will be measured, should be the average unavailability of the proposed data over the last year (October 2006 to September 2007). During this period the average availability is 99.49% and therefore the unavailability is 0.51%. We therefore propose an overall unavailability benchmark of 0.51% for the new incentive.

287. The existing availability element of the incentive arrangements splits the year into quarterly measurement intervals. This limits the impact of a single availability issue to the period in which it occurred in order to retain incentive properties for National Grid to continue to make improvements. Going forward we believe moving to monthly measurement intervals better achieves this objective.

288. The current scheme does not allow for "legitimate unavailability" due to planned outages for maintenance and upgrades. This is somewhat counter-intuitive as the incentive is about delivering performance improvements which required outages to systems. Going forward we propose that a defined number of maintenance periods should be allowed within the incentive framework, designed around minimising the effect on end users of the data:

1) No more than 12 per year
2) Notified at least 2 days in advance
3) Maximum of 4 hours downtime
4) Outside of core business hours (7am to 7pm)

289. For monitoring of performance against the availability element of the incentive we propose to continue to use an external independent specialist website performance monitoring service provider.

Incentive Scheme Options

290. We have identified a set of potential investments with additional elements which could be progressed into a second year. Ofgem's original principles for designing the current incentive was to reward target improvements with 2 times the investment value and cap rewards at 3 times the investment value. We have continued with these principles in designing the following incentive options from 1st April 08. The timeliness and availability elements would have an equal weighting within each incentive option.

Scheme Option	Duration	Max Incentive Return	Incentive Return for Achieving Target Improvement	Target Improvement
A	1 year	£1.8m	£1.2m	Reduce Unavailability by 25% Improve Timeliness by 25%
B	2 years	£2.5m	£1.7m	Reduce Unavailability by 50% Improve Timeliness by 40%

291. Whilst there is no explicit additional downside to these incentives, there is an inherent downside in that if investments are made with no increase in performance then no revenue is generated to offset our investment costs.

292. **Scheme A** is a one year scheme and is based around a set of potential investments (up to £600k) which could enhance timeliness by modifications to source systems, data transfer protocols and configuration arrangements, and to enhance availability by improvements to the web interfaces and load management from the publication systems. Under this option we would aim to reduce unavailability against benchmark by 25%, and would aim to deliver a 25% improvement against the timeliness benchmark.

293. **Scheme B** runs across 2 years (not annually) and is based around an extended set of potential investments (up to £850k) which could enhance timeliness by modifications to source systems and re-routing key data transfers to provide direct interfaces, and to enhance availability by improvements to the web interfaces, API functionality, bandwidth availability and load management from the publication systems. Under this option we would aim to reduce unavailability against benchmark by 50%, and would aim to deliver a 40% improvement against the timeliness benchmark.

Consultation Questions

24	Do you think it is appropriate to widen the data items that are subject to incentivisation to include the additional data items outlined in the proposal?
25	Do you agree with the proposed scheme design in terms of timeliness and availability elements, and the provisions for planned upgrades / monthly measurement intervals?
26	Which of the proposed performance improvements and associated incentive schemes do you believe is most appropriate?

4.1 Summary of Electricity Scheme Proposals

294. We have developed a number of options for our initial proposals for the incentive scheme commencing 1st April 2008 to provide options so that participants can provide views on:

1. the central target or target range of costs;
2. whether this target should be indexed to one or more variables;
3. the sharing factors that should apply to set the level of upside or downside performance around the target borne by National Grid; and,
4. the cap and collar that should apply to any share of upside or downside.

295. We have developed the options to show the range of possibilities but the individual parameters can be used in other combinations to provide different incentives

296. The options forming our initial proposals for incentive scheme parameters for 2008/09 are shown in the table below:

Scheme	1	2	3	4	5	6
Target, £m	481	495	530	520 to 540	530	540
Upside sharing factor, %	35%	35%	15% from £530 to £520m 40% below £520m	40	35	15
Cap, £m	20	20	10	10	10	7
Downside Sharing factor, %	27%	27%	15% from £530m to £540m 20% above £540m	15	27	15
Collar, £m	20	20	10	15	10	7
Indexes	1. Cheviot Outage weeks 2. Power price option (a)	1.Cheviot Outage weeks	None, but could be added	None, but could be added	None, but could be added	None, but could be added

Scheme proposals commentary

297. **Scheme 1** provides some indexation of the target for factors outside our control. In doing so it will facilitate our taking a more aggressive approach to pursuing cost savings whilst maintaining strong sharing, balanced, sharing factors on each side of the target. This is because we would be able to make investments in additional efficiencies against a greater certainty that factors outside our control will not undermine any expectation of out performance resulting from the efficiency. In effect, if investments do deliver savings we would have greater certainty that the result would be a performance payment from the incentive. The sharing factor levels are set to give a balanced profit and loss probability over the range of the sharing factors.

298. The Scheme 1 indexes only remove some market-driven risk from the scheme and leave most balancing risks within the target. The removal of some factors outside our control reduces the risk of windfall gain or loss and therefore the caps and collars on the scheme can be increased, meaning that the scheme continues to incentivise performance over a greater range of costs.

299. Please note that the description of Scheme 1 above applies to the option (a) power price index, which is indexation if the target against outturn power prices through the year. Option b power price indexation does not have these properties and will simply adjust the start of year target based on the average forward price over the preceding three months. In this respect, Option (b) power price indexation offers a scheme that delivers the same behaviour as Scheme 2 but sets the target based on the latest power price data.

300. **Scheme 2** is designed as per Scheme 1 but the removal of power price indexation places greater risk on our performance against the scheme target. The retention of higher balanced sharing factors as described in scheme 1 mean that we will act in a more conservative manner, looking to contain overall cost levels but not pursuing additional investments to deliver savings in such an aggressive manner as would be the case under Scheme 1. The only indexation is for Scottish Outage weeks which would ensure that we are not exposed to windfall losses or gains as a result of changes in the Cheviot outage programme.

301. **Scheme 3** is designed to provide a more uniform financial incentive by increasing our sharing factor for lower probability cost outcomes above and below the target. The low central value sharing factor of 15% means that we are more weakly incentivised against more probable cost outturns close to the mean forecast.

302. The increase in sharing factor further away from the target means that we will pursue investments in efficiencies or risk mitigation that aim for or guard against lower probability events. These investments become more attractive as they will deliver a higher average level of potential return than would be case for smaller investments. However, the low sharing factor in the central band around the target mean that the average sharing factor remains low for

most outcomes and therefore we would not pursue savings as aggressively as would be the case under Scheme1, 2 or 4.

303. **Scheme 4** is designed to focus efforts on achieving efficiency savings by offering a strong sharing factor for costs outturns that are more than £10m below the mean forecast. Consistent with this incentive to achieve savings the scheme also has a lower sharing actor for outturn costs more than £10m above the mean forecast. This lower sharing factor is balanced by having a larger collar to ensure we continue to mitigate risks that could cause costs to increase significantly. Overall this scheme will encourage a more aggressive attitude to achieving savings but will ensure that major cost risks are mitigated.

304. **Scheme 5** provides a sharing factor that delivers a balance probability of gain or loss across the range of the sharing factors. In doing so it provides a balanced incentive to pursue investments that deliver savings and mitigate risks. As the scheme does not offer indexation protection it places greater risk against the target and makes investments more uncertain. Therefore we would act more conservatively in making investments under this scheme than we would under either of the indexed scheme 1 or 2.

305. **Scheme 6** provides a lower sharing factor that will result in a more conservative attitude to making investments. It will mean that we make lower cost (or higher payback) investments to mitigate risk or deliver savings but will not aggressively pursue investments that have less certain benefits. The equal sharing factors are ‘balanced’ to give even probability of gain or loss across the range by offsetting the scheme target to £10m above the mean forecast cost.

Summary

306. In summary, the six schemes provide a range of options that offer varying degrees of targeting and risk. We would welcome views on the individual schemes and the spread of scheme options. Please note that although we have only included indexation options on Scheme 1 and 2 these indexes could equally be applied to other schemes to provide different incentive properties. We would therefore welcome views on whether indexation should be considered for schemes 3 to 6.

Indexes

Cheviot Outage Weeks Index

307. This proposed index is designed to adjust the scheme target based on the number of weeks of outage that actually occur on the two Cheviot boundary circuits during the scheme year. As described in section 2.3, the forecast cost for these outages averages at £1.57m per week evenly across the year for the 30 weeks of outage, including those outages occurring during the winter months (in March).

308. This index proposes to base the level of outage weeks at 8 weeks, in line with the level in 2007/08 and also the typical annual level of outages on the boundary. It would adjust the scheme target up by £1.57m for each additional week of outage that occurs, and vice versa.

309. Re-basing the £530m forecast (at 30 weeks) down to the index base (of 8 weeks) reduces the scheme targets for Schemes 1 and 2 by £34.6m each. As this is the only index on Scheme 2, this results in a Scheme 2 target of £495m.

Power price

310. This proposed index is designed to adjust the scheme target based on power price. The sensitivity of forecast costs to power price is discussed in more detail in section 2.3. This analysis concludes with a proposed indexation level of +£2m of target IBC for each +£1/MWh change in average annual wholesale prices, and vice versa. Based on this figure we are putting forward two alternatives for the structure of this mechanism. Scheme 1 is proposed with Option (a), with Option (b) and alternative option.

Option (a)

311. Option (a) indexes the scheme target to outturn wholesale prices during the scheme year. This would be a full index and would adjust the target for rises and falls in price seen during the year. In doing so this index would offer protection against changes in market conditions during the year, thereby focussing the incentive scheme on areas more closely under our control.

312. Under option (a) the average outturn wholesale price for the year would not be finally know until the end of the year. For this reasons we have proposed to set the scheme target based on the current level of wholesale prices for 2007/08.

313. Based on outturn to date and forward prices for the remainder of the year, we have used a base figure for 2007/08 average prices of £41/MWh. This compares to the annual forward price for 2008/09 of £48/MWh (based on the latest available data at time of forecast). Re-basing the Scheme 1 target to the 2007/08 outturn power price gives a reduction in the target for Scheme 1 of £14m relative to £530m. This £14m reduction is based on a £7/MWh 2007/08 to 2008/09 annual wholesale price differential multiplied by the index factor of £2m per £1/MWh.

314. Scheme 1 therefore has two adjustments to its headline target:

- £34.6m reduction in target for Cheviot outage indexation;
- £14m reduction in target due to power price indexation

This gives a total reduction the Scheme 1 headline target of £49m relative to our £530m forecast.

Option (b)

315. Option (b) is not a full within-year index. Instead this option would set a fixed target at the start of the year but the target would be based on the average annual forward price for 2008/09 seen over the months of January 2008 to March 2008. This would mean that the index did not offer any protection for within-year variations and would therefore not focus incentives on areas more under our control. However, in using the latest data available it would offer a clear and transparent way to revise the scheme target based on the prevailing conditions just prior to the start of the year. Again, the indexation level would be at +£2m change in target IBC per +£1/MWh, and vice versa.

4.2 Summary of Gas Scheme Proposals

System Balancing – Shrinkage

316. We have developed a number of incentive scheme options, to apply from 1st April 2008, with varying risk/reward profiles and varying durations. We feel that longer term options should be strongly considered as the greatest uncertainties are mitigated through the volume target being driven by the primary cost driver and the unmanageable risk of CV shrinkage being removed from the incentivised arrangements.

Scheme	Duration	Annual Cap	Upside Sharing Factor	Annual Collar	Downside Sharing Factor
A	1 year	£10m	40%	£-6m	35%
B	1 year	£5m	25%	£-3m	20%
C	2 years	£8m	30%	£-5m	25%
D	4 years	£10m	40%	£-6m	30%
E	4 years	£6m	25%	£-4m	20%

317. **Scheme A** is a short-term strong incentive signalling that we should chase efficiencies aggressively in this area, which may involve adopting riskier procurement strategies and concentrating resources over the short-term. Any resulting benefits continue to be shared with consumers through sharing factors with National Grid taking on a higher risk on the downside, but a higher reward on the upside.

318. **Scheme B** is a short-term weaker incentive signalling that National Grid should continue with its current relatively risk adverse strategy. Benefits continue to be shared with consumers through sharing factors with National Grid taking on a lower risk on the downside, but a lower reward on the upside.

319. **Scheme C** is a medium term, medium strength incentive signalling that National Grid should look to take on some more risk, potentially seeking new opportunities for improvements which will be limited as a result of the maximum 2 year payback period.

320. **Scheme D** is a long term aggressive incentive and signals that National Grid should consider identifying and making significant new investments in the reduction of shrinkage costs through a variety of means in order to earn higher rewards. The downside sharing factor and collar reflects the risk that a 4 year incentive represents given the pace of change in the gas regime in relation to new supplies, exit reform etc.

321. **Scheme E** is a long term weaker incentive that signals National Grid should investigate some longer term investments in the reduction of shrinkage costs

as the result of the longer payback period, but generally adopt a similar risk adverse strategy to now.

322. Going forward as environmental considerations become increasing important, we believe longer term incentives in relation to shrinkage potentially provide opportunity to deliver wider environmental benefits as well as reduced shrinkage costs, through more efficient use of compression. A longer term aggressive incentive would open the potential to consider novel investments in the NTS to increase the flexibility and availability of compression, strategic placement of pipework to enhance operating ranges, new technologies to improve fuel and emission efficiencies and installing different compression components depending on how new flow patterns develop across the year. There are also potential developments in relation metering and better understanding the drivers of UAG which could be progressed under more aggressive incentives.

System Balancing – Operating Margins

323. Ofgem has set the current incentive scheme with 100% sharing factors with no cap/collar due to National Grid's ownership of four of the LNG facilities that provide some of the OM services. We believe Ofgem still holds this concern and therefore propose to retain 100% sharing factors for 2008/09.

324. We propose that the total costs of holding OM be based on our expected bookings (volumes) at the NG LNG facilities multiplied by the C3 prices resulting from Ofgem's LNG price review, plus our forecast for the remaining OM holding costs for 2008/09.

325. Incorporating choices with regard to treatment of utilisation costs, we therefore propose three incentive options for 2008/09 which effectively recognise the difference between the more probable 'background' utilisation amounts, and less probably large magnitude utilisation amounts. We are interested in views on how Market Participants believe we should be incentivised in respect of OM utilisation risks.

Scheme	Target (pending C3 prices)	Holding Cost Cap	Holding Cost Collar	Upside Sharing Factor	Downside Sharing Factor	Utilisation Cost Collar
A	£23.3m	none	none	100%	100%	£0
B	£23.57m	none	none	100%	100%	-£0.5m
C	£24.38m	none	none	100%	100%	none

326. **Scheme A** - The target is the indicative holding costs only, and should any utilisation costs be incurred, these would be recovered from Shippers post event.

327. **Scheme B** - The target comprises the indicative holding costs plus the average 'background' utilisation cost (£0.26m). The utilisation cost collar is

based on a point on the utilisation distribution which would cover approximately 88% of historical utilisation. This option effectively leaves National Grid exposed to the majority of ‘background’ utilisations but would allow National Grid to recover actual costs incurred over and above £0.5m post event, which may be caused by more significant OM utilisation events.

328. **Scheme C** - The target is based on the indicative holding costs plus four times the average ‘background’ utilisation cost, with no utilisation cost downside collar. This option puts all of the utilisation cost risk on National Grid and insulates market participants from any post event costs. Through the higher target National Grid has a bigger potential upside for having all of the utilisation cost risk.

Residual Balancing

329. Our proposals for 2008/09 are based around the same form of scheme i.e. daily performance measures, and are proposed for one year only pending more fundamental review going forward. As a result of comments received to Ofgem’s Initial Thoughts consultation, we have provided an option which removes the linepack incentive and are interested in the views of Market Participants in this regard.

Scheme	Duration	Price Incentive			Linepack Incentive			Overall Annual Cap / Collar
		Daily Cap	PIR	Daily Collar	Daily Cap	PIR	Daily Collar	
A	1 year	£+6k	10%	£-35k	£+6k	3.1mcm	£-35k	£+3.5m / £-3.5m
B	1 year	£+10k	7%	£-60k	Remove			£+3.5m / £-3.5m

Where:

- PIR is the target daily spread between the highest and lowest prices traded by the SO when undertaking eligible balancing actions as a %age of System Average Price (SAP).
- LIR is the target value for the change in linepack between the start of the gas day and the end of the gas day.

330. **Scheme A** mirrors the current scheme but with updated parameters. The daily caps and collars which were revised in 2002 have been updated with RPI to bring them into today’s price base. The Linepack Performance measure was originally set in 1999 at 1% of the total linepack in the system. By 2008 the size of the NTS will have increased such that total linepack is 30% greater than it was in 1999. Therefore we propose LPM increases accordingly.

331. **Scheme B** removes the linepack incentive altogether. The value contained within this part of the incentive has been transferred to the price incentive, and the performance measure made more challenging by reducing the target price spread as a proportion of SAP by 30%.

Quality of Information – Demand Forecasting

332. We have identified areas where we can make further improvements to modelling, systems and processes to monitor and analyse the factors outlined above to keep pace with the changing market and its implications for demand forecasting. We therefore propose to roll the current scheme forward to 2008/09, pending the longer term review, with no change to the parameters as the forecasting environment is implicitly more challenging.

333. The proposed scheme therefore has a target of an absolute demand forecast error of 4%, with upside and downside gradients that give a profit or loss of £1.6m for a 5% increase or decrease (respectively) in performance around this target. There is a shallower upside gradient for performance increases above this, with potential losses for decreased performance collared at £-1.6m.

Quality of Information – Publication systems

334. As well as the data items that are the subject of the current incentive, there are a number of other data items which we believe Market Participants value in relation to making market based decisions. Improving the delivery of these data items should therefore lead to more efficient market operation. We propose a set of arrangements that will:

- Expand the scope of incentivised key data to include certain forecast data, real time data, within day data and post event data;
- Aim to reduce the delay between this data becoming available and its publication; and
- Aim to improve the availability of these new data items through monitoring an increased set of outputs (which map to systems not currently included in the incentive arrangements)

335. We have identified a set of potential investments with additional elements which could be progressed into a second year. Ofgem's original principles for designing the current incentive was to reward target improvements with 2 times the investment value and cap rewards at 3 times the investment value. We have continued with these principles in designing the following incentive options from 1st April 08. The timeliness and availability elements would have an equal weighting within each incentive option.

Scheme Option	Duration	Max Incentive Return	Incentive Return for Achieving Target Improvement	Target Improvement
A	1 year	£1.8m	£1.2m	Reduce Unavailability by 25% Improve Timeliness by 25%
B	2 years	£2.5m	£1.7m	Reduce Unavailability by 50% Improve Timeliness by 40%

336. Whilst there is no explicit additional downside to these incentives, there is an inherent downside in that if investments are made with no increase in performance then no revenue is generated to offset our investment costs.

337. **Scheme A** is a one year scheme and is based around a set of potential investments (up to £600k) which could enhance timeliness by modifications to source systems, data transfer protocols and configuration arrangements, and to enhance availability by improvements to the web interfaces and load management from the publication systems. Under this option we would aim to reduce unavailability against benchmark by 25%, and would aim to deliver a 25% improvement against the timeliness benchmark.

338. **Scheme B** runs across 2 years (not annually) and is based around an extended set of potential investments (up to £850k) which could enhance timeliness by modifications to source systems and re-routing key data transfers to provide direct interfaces, and to enhance availability by improvements to the web interfaces, API functionality, bandwidth availability and load management from the publication systems. Under this option we would aim to reduce unavailability against benchmark by 50%, and would aim to deliver a 40% improvement against the timeliness benchmark.

4.3 Summary of Consultation Questions

Electricity Related Questions	
1	Do you agree with the assumptions (described in detail the appendix) used to forecast the various elements that make up underlying balancing costs?
2	In particular, do you have any comments on views on National Grid's forecast assumptions for cost drivers: i. The behaviour of NIV during 2008/09 can be expected to be broadly in line with that seen during the current year, 2007/08. ii. That the forward price is the most appropriate figure to represent the likely outturn wholesale price during 2008/09. iii. That wholesale power price either directly drive or act as an appropriate proxy to index certain balancing costs.
3	Do you agree with the assumptions used to forecast Cheviot and Scottish constraint costs, and the costs associated with the forecast rise in Wind output in 2008/09?
4	Do you have any comments on our initial analysis of the likely impact of the introduction of the Large Combustion Plants Directive, in particular on the likely operation of opted-out plant?
5	Do you have any comments on the forecast range of incentivised balancing costs and BSUoS costs for 2008/09?
6	Do you agree with the main areas for efficiency identified by National Grid?
7	Do you agree with the range of proposed scheme options? Are there alternative scheme structures that should be considered fro 2008/09?
8	Do you support the use of indexes for the 2008/09 incentive scheme - Do you agree with the proposed level of scheme target indexation for wholesale power price? - Do you prefer wholesale power price index option (a) or (b)? - Do you agree with the proposed level of scheme target indexation for Cheviot outage weeks?
9	Which is (are) your preferred scheme(s)? (please provide reasons) - If your preferred scheme is scheme 3 or 4 do you consider

	these should have a target indexed to power price and/or Scottish outage weeks or not?
10	Do you agree that longer term development of systems that will reduce the cost and carbon impact of operating the system be supported? Which manner of funding do you consider to be the most appropriate?
11	Did you find the level of information within this consultation, and associated documentation and workshop, on our balancing and BSUoS costs forecasts for the current year and 2008/09 informative. - What additional information should National Grid provide to explain better the costs and cost drivers?
12	Do you have any further comments on analysis and information provided within the appendices to this consultation or in the further documentation available on our website? Do you have any further comments on any aspect of this consultation in relation to the Electricity SO?

Gas Related Questions	
13	Do you agree with the approaches used in forecasting the various elements that make up NTS shrinkage?
14	Do you support the continued linking of shrinkage target volumes with flows at the St. Fergus entry point, and do you support the move to an increased number of bands?
15	Do you agree that the SO should not be incentivised on CV shrinkage that is outside of its control? Please comment on whether you believe it is necessary for Ofgem and BERR to review the continuing appropriateness of the CV capping rules in the Gas (Calculation of Thermal Energy) Regulations.
16	Do you have an objection to the proposed interim GCRP and ECRP methodologies for 2008/09? If so please explain why and outline your suggested alternative.
17	Do you support the proposal to establish the proposed enduring GCRP and ECRP methodology arrangements into the National Grid's GT Licence for an extended period, (to avoid the need for interim arrangements in the future) regardless of the duration of any incentive scheme?
18	Do you agree that the incentive cost target should be constructed in

	the way proposed in this consultation?
19	Which of the scheme options do you believe is the most appropriate way to incentivise the costs of utilising OM?
20	Do you agree that a one year scheme is appropriate pending a potentially more fundamental review of residual balancing incentive going forward?
21	Which of the scheme options do you believe provides the most appropriate incentive arrangements for the residual balancing activity for 2008/09, and what are your views on the potential removal of the linepack element of the incentive?
22	Do you agree that the current Demand Forecasting incentive should roll forward to 2008/09, pending a more fundamental review of the residual balancing activity and incentives?
23	Do you think it is appropriate to widen the data items that are subject to incentivisation to include the additional data items outlined in the proposal?
24	Do you agree with the proposed scheme design in terms of timeliness and availability elements, and the provisions for planned upgrades / monthly measurement intervals?
25	Which of the proposed performance improvements and associated incentive schemes do you believe is most appropriate?
26	Are there any other points that you would like to raise in relation to the setting of the Gas SO incentives from April 2008?

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

by 5pm on 25th January 2008