National Grid's Initial Forecast of Incentivised Balancing Costs for Great Britain in 2008/9

1. Summary

This Appendix presents our forecast for National Grid's 2008/09 balancing costs. Note this appendix summates the forecast figures in the form used within our incentive schemes calculation.

The forecast is split into its component parts. Where possible, areas with a significant cost risk have a range included to indicate the level of uncertainty with the forecast. The detailed information is focused on the areas where there is significant changes in costs from our 2007/8 forecast.

In summary, for 2008/09 we forecast only minor changes to our underlying level of balancing costs. Excluding the three major change areas discussed below, our forecast for 2008/09 is £399m, the comparable figure for 2007/08 is £400m. Therefore, our forecast is a slight decline on underlying balancing costs year on year. This decline is more significant if one takes inflation and the higher power prices in 2008/09 into account.

At the time of forecast, the wholesale market forward price for electricity was £48/MWh for 2008/09, compared to a currently expected outturn of £41/MWh for 2007/08. Against this forward price, our forecast for 2008/09 increases by approximately £14m when compared to the same forecast referenced to 2007/08 wholesale prices.

In addition to this underlying trend, and wholesale market effects, there are three drivers for cost changes in 2008/09 when compared to 2007/08. These drivers are linked to work for environmental legislation and other work within the industry to reduce or facilitate the reduction in carbon output from the electricity sector. The three drivers are:

- A rise in Transmission Network outages in Scotland and the north of England, to allow the construction of increased transmission capacity for renewable generation. The cost effect of this increase is forecast to be £49m when compared with the latest 2007/8 forecast.
- The effect of introducing the Large Combustion Plants Directive. The cost effect of this remains more uncertain, but is forecast to be in the range £5m to £30m, with a central estimate of £15m. However, this is our initial forecast and we particularly seek participants views on likely behaviour of opted out plant to better inform this forecast.
- A continuing increase in wind generation. The cost effect of this increase is forecast to be £10m

In total our forecast for 2008/09 is as follows,

- Underlying costs decrease from £400m to £399m
- Wholesale prices have caused incentive costs to increase by approximately £14m
- Three additional drivers have a significant impact on increasing costs and are dealt with separately later in this document. The three drivers increase costs by £74m.
- Total forecast costs for 2008/9 are £50m above our latest 2007/8 forecast

Changes in Forecast Assumptions

There are a number of risks associated with fixing assumptions. We expect some of these drivers to change prior to final scheme proposals in late February. In particular:

- network outages will become more certain as works programmes are finalised early in the new year;
- whilst always fluctuating, we will have further information on the wholesale price through the current winter;
- we will have a clearer view of STOR costs for 08/09;
- we will have further data on reserve and response costs for the current winter;
- we hope to receive additional information on the effects of the introduction of the LCPD through this consultation and through other channels such as Grid Code data submission and routine liaison.

Forecast Volatility

The forecast is not a single number. We have endeavoured to discuss the likely range of balancing costs clearly within this document and we would encourage participants to also take into account this range when considering our scheme proposals. To better illustrate the range, we have tried to include illustrative 'scenarios' and we would welcome feedback on our assumptions within these.

This forecast represents our best view of next year's incentive balancing costs. There are many assumptions required to build such a forecast and these assumptions can and will change prior to the scheme being implemented and the drivers will continue to change costs through the scheme year. We have developed a forecast range to identify where we believe these assumptions changes will have an impact on the forecast. Therefore when considering the forecast, the range of potential costs and the corresponding risks need to be considered in conjunction with the central forecast.

There are a number of significant developments that will affect system operation costs over the next 5 years. The increased connection of wind and subsequent development of the transmission system, especially in Scotland will increase constraint and reserve costs. There is also significant uncertainty when considering the impact of LCPD on the running regime of the affected generators. These three drivers directly affect the costs for 2008/9.

2. Introduction and Assumptions

This appendix presents our forecast of balancing costs for 2008/09. Section 3 outlines the forecast method and considers the drivers of incentivised costs. Section 4, 5 and 6 discusses each forecast element before presenting the overall forecast within section 8.

In preparing this forecast, we have had to make three basic assumptions:

- In line with the scheme proposals put forward elsewhere in this document, our forecast assumes that NGET's role and responsibilities to balance the system remains the same for 2008/9 as in 2007/8;
- The impact of BSC modifications or CUSC amendments to be introduced after 1 October 2007 have not been considered;
- In particular, for this forecast we have had to assume the current arrangements for Cashout and Transmission Access, both subject to ongoing reviews.

3. Construction of Forecast

The aim of this forecast is to predict the likely range and central figure for balancing costs incurred in 2008/09. Incentivised balancing costs (IBC) are defined in NGET's transmission licence[1].

IBC covers National Grid's External System Operator costs, i.e. the net costs incurred on procuring services to balance the GB system. The majority of our forecast is undertaken by extrapolation, i.e. forecasting the trend for next year based on current and historic trends. This is the case for all areas except for:

- Transmission Network constraints, as these are dependent on the outages that will be undertaken during the year in question, and also dependent on forecast generation output and prices;
- The introduction of the Large Combustion Plant Directive. This is a change to the existing arrangements and hence we have no experience of what effect this will have.
- Our forecast costs increase due to the additional connection of wind generation is an extrapolation of existing experience of wind generation. As the level of wind generation is increasing over the next 5 – 10 years, we have prepared a more detailed forecast of this effect.

For the 2008/9 forecast, we have considered the following key drivers to have the greatest effect on overall balancing cost:

- Wholesale electricity prices
- Balancing Mechanism Prices
- Scottish generation output levels
- Transfers to / from Scotland
- Volume of wind generation
- LCPD
- Level of NIV
- Price trends in the procurement of balancing services
    - Reserve
    - Frequency Response
    - Reactive

There are many other cost drivers that influence GB IBC but are not explicitly included in this forecast as one of the key cost drivers. For example, the effect of fuel prices feeds into IBC through their effect on forward electricity and submitted BM Bid/Offer prices. This behaviour is reflected within the drivers above.

Different drivers impact on balancing costs in different ways. For example, forward wholesale electricity prices reflect the underlying costs of generation, which also feed through into our balancing services costs, such as BM costs and also through ancillary prices such as Reactive, which is index-linked to wholesale prices. BM prices clearly affect our balancing costs but our forecast of BM prices more closely reflects our view of competitiveness in the balancing mechanism.

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[1] For a full explanation of IBC, BSUoS please see our BSIS Seminar presentation of 10th January 2007, which formed part of last year's consultation process. This is available in the Ops Forum area of our industry information website here: http://www.nationalgrid.com/NR/rdonlyres/9065C6F7-BDEE-419E-8033-9D4BDE01442F/14305/BSIS_Seminar10_1_07.pdf

The historical trend and forecast future performance of the above key cost drivers are described below.

3.1 Balancing Cost Drivers

3.1.1 Electricity Forward Price

The electricity forward price impacts on IBC in several ways, including the costs of our pre-Gate trades and BM actions, the volume and direction of flows across the Anglo-French interconnector and the price of reactive power.

The average price this calendar year to date has been £27/MWh for baseload and £33/MWh for peak, in a large part these prices are a product of low gas prices in the early months of the year. Looking at current trends and future prices, we forecast an outturn power price of £41/MWh for 2007/8.

The following table outlines our power price assumptions for the forecast.

£/MWh	Summer	Winter
Baseload Power Price	£45.2/MWh	£50.7/MWh
Annual	£48/MWh	

3.1.2 Balancing Mechanism Prices

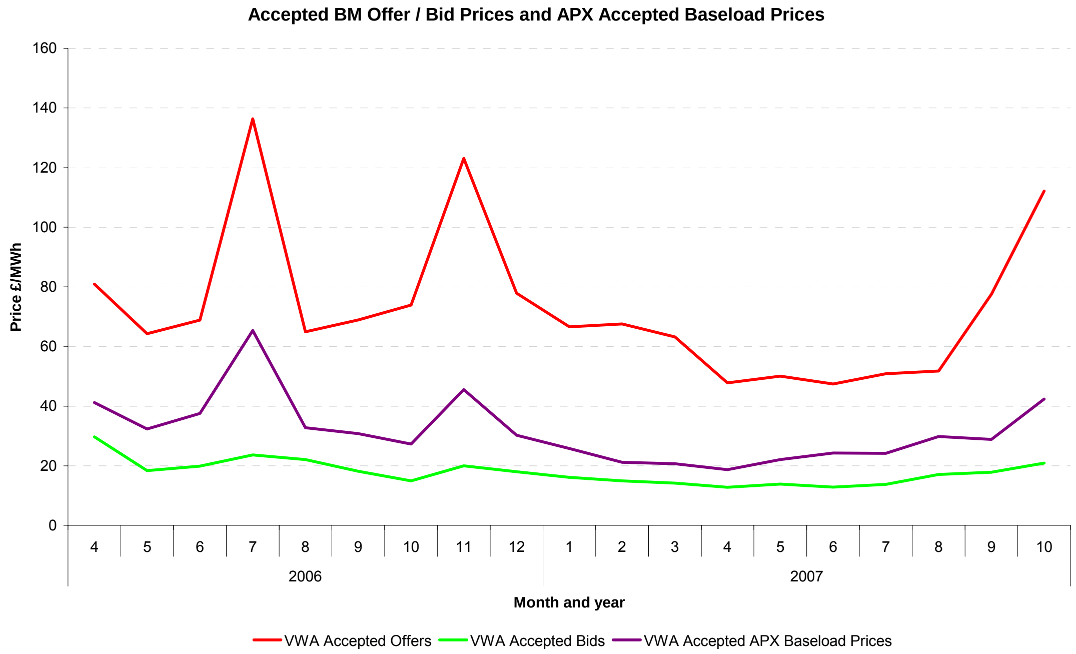
Prices in the Balancing Mechanism (BM) directly impact on the costs of balancing actions taken in the BM and (indirectly) pre-Gate.

The average Bid and Offer prices accepted in the BM depend upon

- the Bid and Offer prices submitted (which reflects the degree of competition in the BM as well as generators' behaviour); and
- degree of competition for locational services; and
- the volume of actions taken to balance the system.

The BM Bid market is competitive with a relatively stable average price, with a large volume of bids accepted principally for energy balancing purposes. In contrast, the average accepted BM Offer price is more volatile from month to month. Our analysis suggests this is because the volume of offers taken is smaller than the volume of bids and is more closely associated with balancing actions taken to create Operating margin or to resolve system constraints and is therefore more volatile than the more, 'liquid' average bid price.

The graph below shows the accepted BM Offer and Bid prices for 2006 and 2007 against the accepted APX baseload power price.



The graph shows a reasonable correlation between power prices and Offer prices with Bid prices showing a reduced correlation.

3.1.3 Scottish Generation Output Levels

With the current Scottish demand levels, Scottish generation profile and Scottish transmission topology, there are a number of intact and outage-related transmission constraints. These can vary significantly over the year, with the Scottish system being both an import and export constrained group within the year.

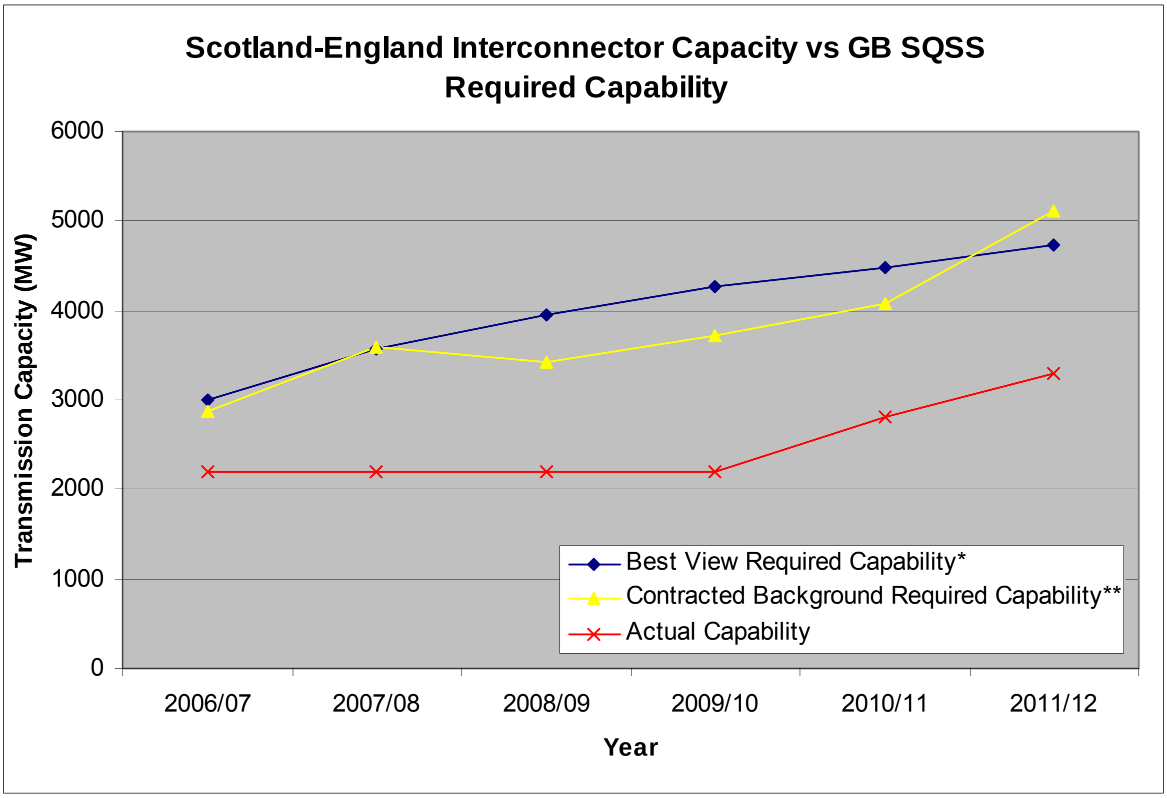
With a relatively predictable demand profile and the majority of significant system outages being known at the year ahead timescale, the greatest risk results mainly from the generation profile and price.

3.1.4 Transfers to and from Scotland

The Scotland to England flow boundary, commonly known as the 'Cheviot' boundary is derogated against SQSS standards because the boundary has insufficient capacity to meet SQSS standards. There are a number of planned system developments to increase the Cheviot boundary capacity. These works are planned over the next 5 years. These construction works require long outages that reduce the transfer capacity, and therefore increase constraints, in the short term.

The following graph shows the required intact system capability of the Scotland-England boundary based on the Contracted and a 'Best View'[2] generation backgrounds plotted against the boundary capability following sanctioned network reinforcements.

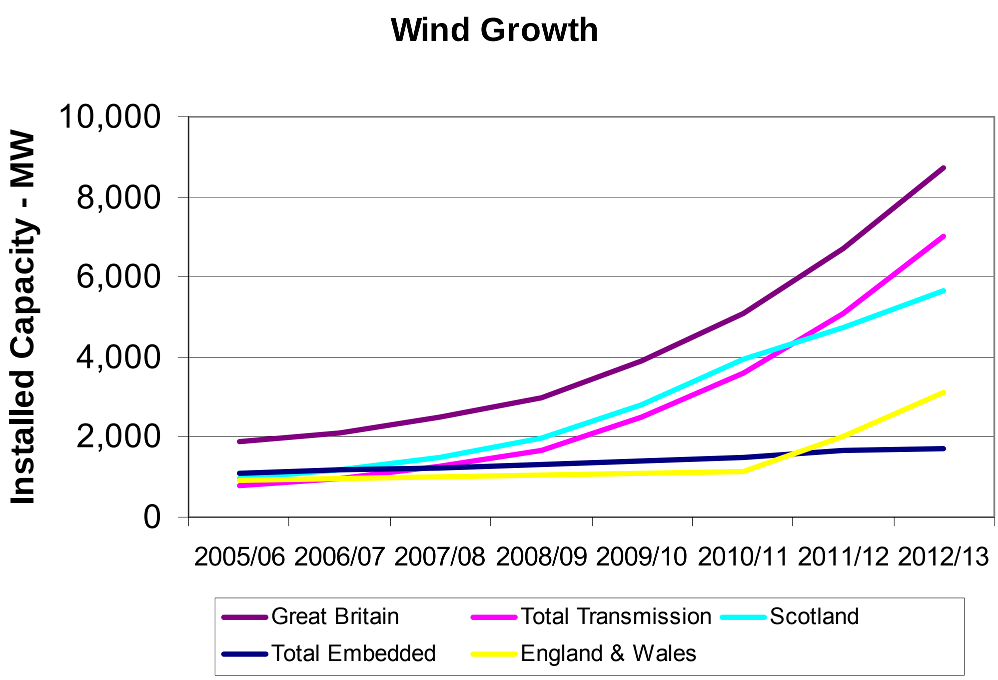
[2] This 'Best view' is lower than the SYS 'contracted level', being based on a wider set of data. We believe this 'best view' is consistent with BWEA expectations for future wind generation growth in Scotland.



As can be seen, for an intact system, there are transfer limitations. These limitations are significantly increased by taking system outages.

3.1.5 Increase in the Volume of Wind Generation

The table below shows our projected growth of wind power up to 2013 and beyond.



In forecasting the effect of increasing wind output on system operation, we can look to a number of sources:

1. Our experience of current levels of wind generating in Great Britain;
2. Forecasts of future wind output patterns based on known inputs such as weather variance and distribution of wind generation across GB;
3. Where relevant, the experience of other systems across Europe and around the world.

Increased wind output and the corresponding greater generation intermittency will place greater balancing burdens on both market participants and the SO. How this burden falls between the SO and the market will depend on the incentives (efficient avoidance of imbalance charges) to do so and the market's ability to forecast wind output and balance its own position.

Higher densities of wind generation, particularly in Scotland will lead to an increased volatility for forecasts of plant output at all lead times. This increased unpredictability of plant output, and hence power flows will impact on most of the activities the SO undertake to balance the system.

The two cost areas that will see the greatest immediate impact at the current relatively low levels of wind penetration are reserve and constraint management.

3.1.6 Large Combustion Plant Directive – LCPD

We are developing our understanding of the likely impact on the behaviour of plant directly affected by the introduction of the Large Combustion Plants Directive that comes into force on 1 January 2008. The main impact on the economics of operation will be the limitation of the operating hours of each stack for all opted out plant. 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 across the 8 year period, by optimising running and by operating multiple BM Units as a single block.

The rationing of hours of operation for two or more BMUs as a single block may affect the price and availability of these units for reserve and balancing by NGET, thereby leading to an increase in the cost of some system balancing. Also, the operation of a number of BMUs as a single block may also affect constraint costs as opted out generating stations are expected to operate with either all or no units running rather than, for example, with an average of one unit off across the summer outage season.

The following stations have opted out of the LCPD.

Cockenzie	Didcot A	Ferrybridge (one of two stacks)
Kingsnorth	Ironbridge	Tilbury (both stacks)
Grain	Fawley	Littlebrook

The bottom row of stations in the table above are all oil-fired and typically do not run for >1000hours pa; therefore we have assumed that the LCPD will have little or no impact on their operation or pricing.

For the remaining stations, there are two potential running regimes that we envisage the generators operating:

- Winter running regime - run the units over the Winter and moth ball them over the Summer
- Year round running regime - the generation will focus their running hours on the peak yearly power price periods, irrespective of season

These issues have been discussed with generators bilaterally and at the Grid Code Panel. At present there remains significant uncertainty (both for National Grid and from the Generators themselves) over the strategy that stations will adopt and therefore uncertainty over the anticipated impact. We will continue to review the impact of LCPD in conjunction with the industry and suggest that further questions on likely behaviour are asked within the consultation.

For full detail of the forecast effects of the introduction LCPD, please refer to our separate note.

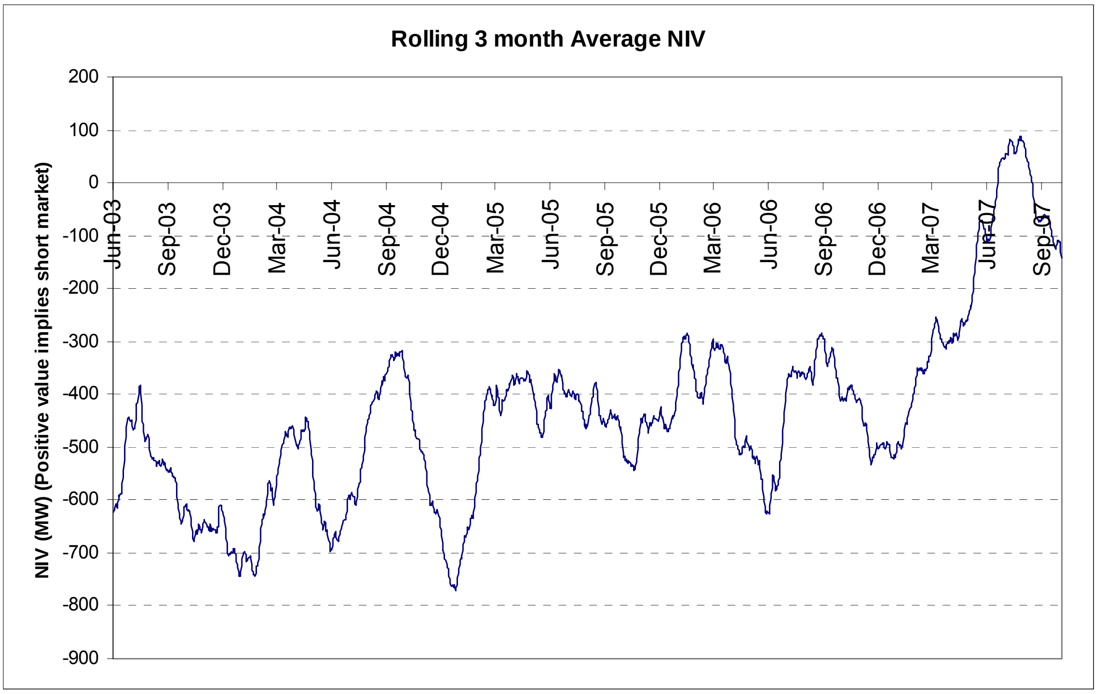
3.1.7 Level of NIV

NIV is the measure of market length, or the net energy imbalance position of the market. It is calculated as the net volume of balancing actions taken in the Balancing Mechanism and pre-Gate Closure.

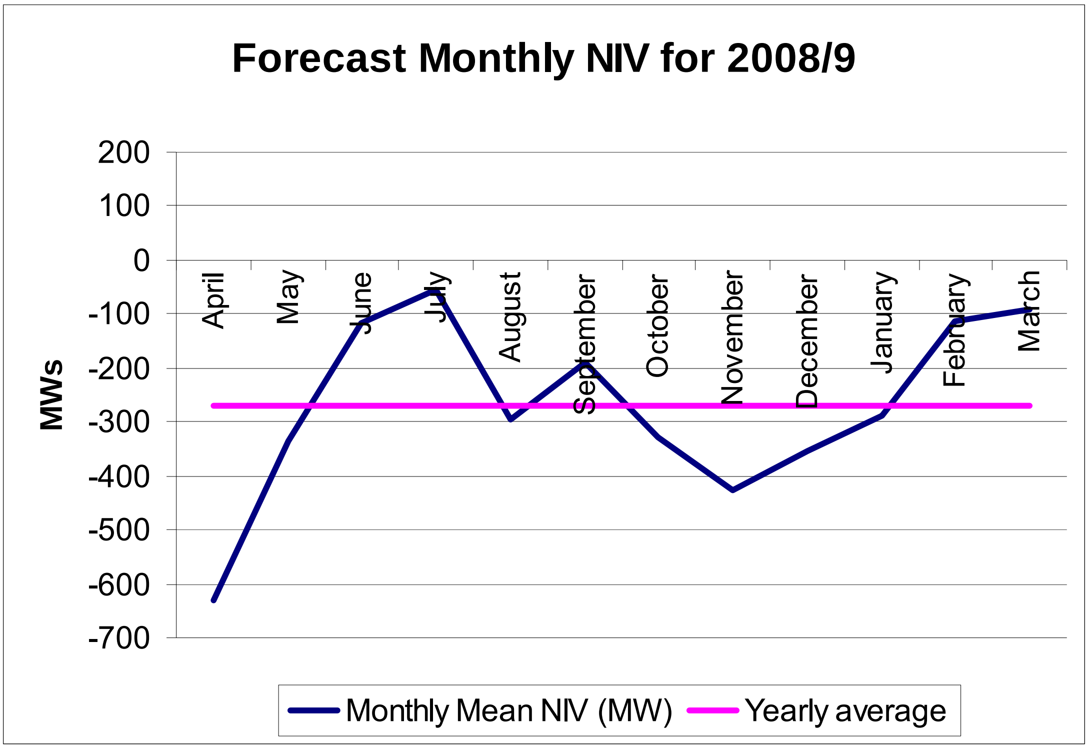
NIV directly determines the volume, and hence the costs, of Bids and Offers which we have to take to balance the market. It also affects the amount of operating margin available to us from the market at Gate Closure because any headroom provided by a long market (negative NIV) provides Reserve that can be used by us to balance the system. Likewise, a short market, as is often seen over the peak of the day, means that we must take additional actions to meet demand and Operating Margin.

In the majority of Settlement Periods NIV is negative, indicating a long market that we must resolve by taking Bids in the BM.

Average NIV has become slightly less negative (more balanced) over the last three financial years and we forecast this trend will continue in 2008/09, although not as severely as in the summer of 2007. The graph below is a 3 month rolling average of NIV.



The graph below outlines our forecast view of NIV for next year on a month by month basis:



3.1.8 Price Trends

There are a number of services that are influenced by certain market trends. Reactive power prices are affected by both volumes and prices where price is indexed power price and RPI. Reserve and response costs are linked to market behaviour of providers and their strategies. There is significant risk on the costs of providing these services if market conditions change from those forecast e.g. winter colder than forecast, markets become shorter than assumed, gas price increases /decreases.

We have developed a range of costs to cover the potential variation in cost drivers.

4. Balancing Service Forecast Costs

Methodology

Historical costs and volumes of Balancing Service contracts are reported in our Monthly Balancing Services Statements and to Ofgem. Our forecast model follows a similar reporting methodology but with the addition the BM costs associated with the procurement of each service.

The derived BM cost of each service is developed using the following formula:

Allocated cost of action = Volume x (Price of action – Energy Reference Price[3])

The Energy Reference Price is the volume weighted average of the submitted bids or offers available to resolve NIV ignoring plant dynamics (i.e. ERP = Energy Imbalance Cost / NIV). This does not include non-BM standing reserve prices, trades, PGBTs or SO-SO trades.

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[3] Energy Reference Price is calculated per settlement period. Annex B provides more detail.

Within this document there are a number of tables outlining our forecast costs for each component. The numbers are rounded to the nearest million. This can result in component numbers summating to different total values.

4.1 Baseline Forecast Summary

Our central forecast for baseline Balancing services costs is summarised in the table below. The table indicates that the baseline costs for 2008/9 are comparable with the latest forecast for 2007/8 baseline costs.

The table shows the latest forecast costs for 2007/8, and our forecast for 2008/9.

All Categories £m	Latest 07/08 Forecast	08/09 Forecast	Difference
Constraints England & Wales	33	19	-14
STOR	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

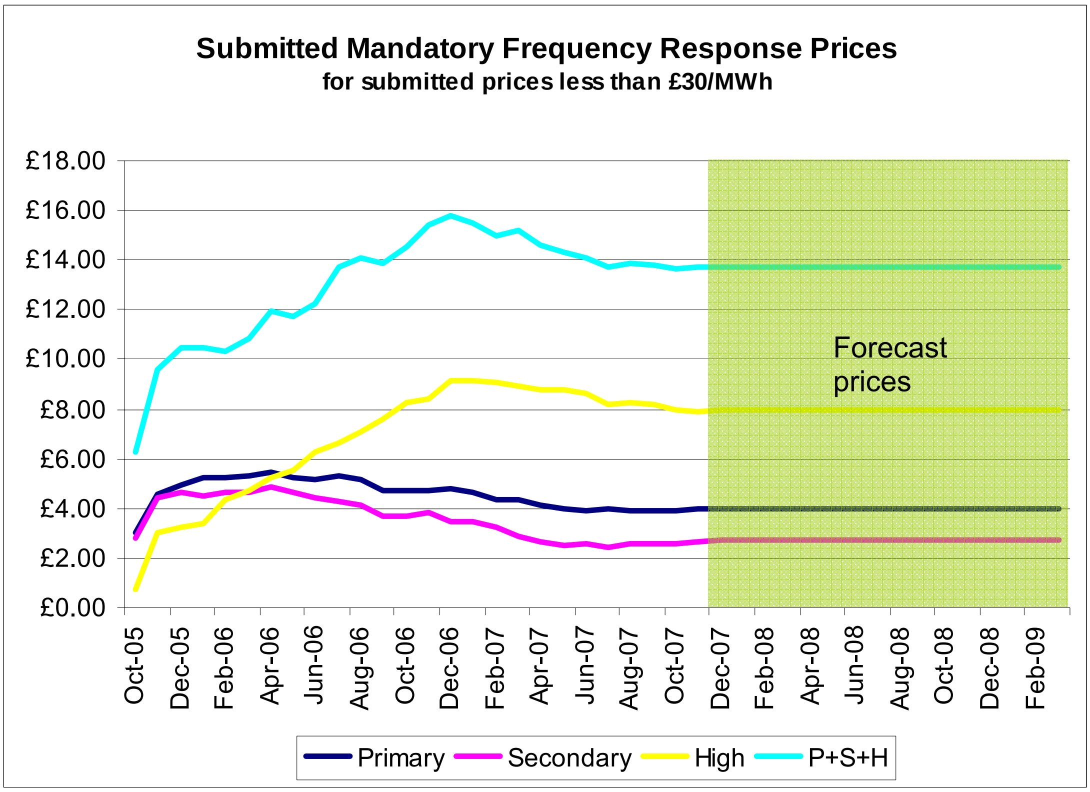
It can be seen that the main cost change from 2007/8 to 2008/9 is associated with contract costs of reserve services and reactive power cost increases. The reactive forecast increase is as a direct result of power price increases as there are no changes in forecast volumes.

The reasons for each elements changes are explained in more detail below.

4.2 Frequency Response

The key driver of frequency response costs is expected to be the market pricing behaviour for mandatory frequency response. Mandatory frequency response makes up approximately 60% of the response volume procured by us and is the prevailing price against which other dynamic and non-dynamic response services are valued. Our forecast cost of frequency response is therefore based on our view of price trends in mandatory frequency response. The forecast prices drive our view of the cost of mandatory response and the likely cost of alternative sources of frequency response.

Mandatory prices have been submitted monthly under the current pricing arrangements since November 2005. Average submitted prices for mandatory Frequency Response are shown in the graph below. The latest response price and utilisation data can be found on our Industry Information website, within the balancing services section.



For BMUs submitting combined prices (Primary plus Secondary plus High) below £30/MW/h, the mandatory market has seen prices stabilise over the last 8 months. Providers are maintaining their prices on the high service with primary and secondary prices moving towards pre-CAP047 levels.

There are a number of potential drivers that we have considered as potential cost drivers for mandatory frequency response:

- Fuel costs
- Risk of energy price exposure
- Seasonal affects on submitted prices

Our analysis has not found any clear drivers behind submitted price changes. For our forecast, we have assumed that prices remain stable for the following year.

4.2.1 Price Assumptions

These assumptions are our central forecast. There are some risks associated with these assumptions. These are covered in more detail in 4.2.4.

- Forward mandatory prices are derived by extrapolating prices from post-CAP047 levels
- Prices for alternative response procurement are consistent with the mandatory price forecast
- Response energy costs to remain stable
- BOA costs will decrease by 8% as compared with the 2007/8 costs due to a change in the allocation of costs associated with the energy reference price

4.2.2 Volume Assumptions

The forecast assumption is that there is no change in the volume of frequency response for 2008/9 as compared with the last three years.

4.2.3 Forecast Frequency Response Costs

£m	2001/2	2002/3	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9
Mandatory Costs	28	27	25	24	37	76	69	69
BM Costs	15	16	11	12	17	36	26	24
Contract Costs (including response energy)	45	42	28	20	29	48	55	52
Total	88	85	64	56	83	160	150	145

The above table outlines the central forecast for frequency response costs for 2008/9. There is a risk associated with each element of the above costs. The table below indicates our risk range for frequency response costs.

4.2.4 Forecast Frequency Response Costs

There are a number of risks associated with the above forecast. The table below outlines the cost range for frequency response costs and the assumptions associated with that range.

£m	Mandatory Costs	BM Costs	Contract Costs (including response energy)	Total	Assumption
High	78	34	58	170	Mandatory costs increase by 10-15% Increase in commercial costs by 10-15% BOA costs increase by 40%
Medium	69	24	52	145	Assumptions outlined in 4.2.1 & 4.2.2 above
Low	65.5	24	52	141.5	Mandatory costs decrease by 5%

The above assumptions indicate that we believe that there is a higher risk of prices increasing than decreasing. This is mainly associated with the risk of mandatory prices increasing as compared with decreasing.

Considering the potential risks, we believe the overall range of costs is estimated to be £141.5m - £170m. This compares to an outturn of £160 million in 2006/7 and a forecast of £150 million in 2007/8.

4.2.4 Effect of Wind on Response Costs

With the predicted increase in wind generation for next year, we do not think that dynamic response levels will have to increase in all timescales. However there may be a number of days across the year where the variability of wind results in frequency control becoming more difficult. Under these conditions it would be prudent to increase the dynamic response holding.

Our forecast assumes that we require additional response on high wind output days, approximately 20 days across the year. This results in a total cost for additional response of approximately £1m.

4.3 Reactive Power

Reactive power is split into mandatory and commercial. The majority of costs are associated with mandatory service. The price paid to providers for reactive power is outlined in the CUSC. The price is linked to the power price and RPI. Therefore our forecast for Reactive Power costs is based on a straight calculation of prices based on projected power prices and an estimated RPI.

Tenders seeking reactive market contracts factor in the full default price into their tendered prices, and therefore our forecast is not sensitive to assumptions of the number of tenders accepted.

4.3.1 Assumptions

- The volume of reactive power forecast for 2007/8 is 24.0TVarh. We forecast no change in the total volume of reactive for 2008/9.
- Future power prices as outlined earlier have been used to determine the price of reactive power
- RPI estimated at being 3% for 2008/9
- Accepted tenders include the full default price and are therefore not sensitive the number of tenders accepted.

The change in reactive costs from 2007/8 and 2008/9 is directly associated with change in power price. This results in our forecast of reactive costs moving from a forecast of £50m for 2007/8 to £57m for 2008/9.

4.4 Short Term Operating Reserve (STOR)

STOR is a contracted Balancing Service, whereby the service provider delivers a contracted level of power when instructed. The service can be provided by both BM and non-BM participants. Utilisation of the service from BM participants is via the Balancing Mechanism. For non-BM service providers, a bespoke monitoring and despatch system (STOR despatch) is used.

The service falls into two main forms:

1. Committed service and
2. Flexible service

For the committed service, the provider must make the service available for all contracted windows. The flexible service is only open to non-BM service providers. The flexible service providers have greater freedom in nominating their availability windows.

The STOR forecast costs include the BM and non-BM costs.

4.4.1 STOR Forecast

The market day for the STOR tender round with the service starting April 2008 is 25 January 2008. We believe that it would be inappropriate to publish information that may influence the tender submissions and so this forecast for STOR provides a high level summary of forecast costs.

In summary, considering historic volumes and prices and projected future requirements, the STOR forecast for 2008/9 is £65.5 million. As compared with the latest forecast of £63.5 million for 2007/08.

4.5 Fast Reserve

Fast reserve provides rapid delivery of active power through an increased output from generation or the reduction in demand following a despatch instruction. Fast Reserve is procured either via a monthly tender process by issuing a Bid Offer Acceptance in the Balancing Mechanism on a generator with suitable Dynamics.

The main factors driving the costs of fast reserve are the number of providers and contracts terms and conditions.

4.5.1 2008/9 Assumptions

There are a number of changes from the 2007/8 forecast assumptions

- An additional £2.5m for forecast contract costs.
- An additional £1.0m to neutralise the effects of abnormal weather in early 2007/8 which saw the markets become short and some fast reserve costs were subsumed into reported energy balancing costs. This has also been offset in our energy balancing forecast.

Historical costs are shown below with the 2008/9 forecast.

(£m)	2005/6	2006/7	2007/8	2008/9
Total	51.0	58.5	56.1	59.8

4.5.2 Effect of Wind on Fast Reserve costs

With increasing wind generation the variability of generation will lead to other forms of reserve being required to cover shortfalls. Fast Reserve provides the bridge between noticing that there is a generation / demand mismatch and calling on other forms of longer notice reserve e.g. STOR.

To cover the risk of additional generation short fall due to wind, we have assumed additional fast reserve requirements for on average an extra 1 hour a day. This leads to additional Fast Reserve forecast costs due to the increase in wind of £1m.

4.6 Other Reserve

Other Reserve includes the costs of other BM intra half hour energy trimming actions that do not fall into the fast reserve category. For 2008/9, we are forecasting costs in line with those for 2007/08 at £2m.

4.7 Black Start

Costs for Black Start services for 2008/9 are projected to be £17m. Existing Black Start contracts are forecast to cost £15.2m for the year (assuming no closures or delays to new services commissioning). In addition to this we anticipate spending approximately £1.2m on service testing activities, and £0.6m investment towards retention of essential Black Start equipment.

Our forecast follows the current practice of four stations tested for Black Start each year, and we have assumed no changes in testing frequency that may result from current initiatives on Black Start preparedness

Our 2008/9 forecast accounts for the delayed commissioning of a new Black Start service which has lead to a lower cost outturn in 2007/8 than previously anticipated.

4.8 Other

Each year, we incur miscellaneous other balancing costs, which include Trading fees, and liabilities for services used which we do not manage to settle within-year. In addition, there are actions taken in the BM that do not simply fall into one of the balancing services categories used in our reporting. In total costs in this area are currently forecast at some £13m in 2007/08 and are not expected to vary significantly from this level in 2008/09.

4.9 England and Wales Constraints

Constraint forecast is covered in Section 5

4.10 Baseline plus Energy and Margin Forecast

The previous section outlines the baseline costs for the 2008/9 forecast. This section considers the energy and margin costs for the 2008/9 forecast.

The following table outlines the cost breakdown including energy balancing, reserve and Net Imbalance Adjustment costs.

All Categories £m	Latest 07/08 Forecast	08/09 Forecast	Difference
Constraints England & Wales	33	19	-14
STOR	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 baseline	383	380	-3
Energy Imbalance	34	26	-8
Negative NIA	-141	-162	-21
Margin	124	155	31
BM Start Up	17	15	-2
Reserve	107	140	33
Sub-total Energy + Margin	17	19	2
Total	400	399	-1

Changes are a direct result of NIV and power prices

The energy, reserve and NIA forecast are heavily influenced by NIV and power price. The table shows that the forecast for 2008/9 shows a change in energy, margin and NIA. For incentivised costs, there is little change in the overall forecast. However, this forecast will interact with the forecast for BSUoS.

The forecast for energy, NIA and reserve are covered in more detail below.

4.11 Energy Forecast

The energy forecast includes the forecast of energy balancing costs and our prediction of Net Imbalance Adjustment taking into account historic NIV and future pricing. The forecast detail is described in Annex B.

4.12 Margin

The margin forecast covers the cost of procuring adequate supplies to cover the potential short fall of generation and demand forecast errors. This is made up of two main components, BM start up and reserve. The forecast for these two components are detailed below.

4.12.1 BM Start-Up costs

The BM start-up service is a mechanism for us to access generation in the BM which is not otherwise planning to run. The service contains two elements; BM start-up and hot standby.

BM start-up is associated with bringing a BM Unit to a state where it can synchronise within BM timescales. Hot standby is associated with holding the BM Unit in such a state of readiness.

The BM start-up service was initiated in late 2006. A similar service in place prior to 2006 was Warming. The cost table below compares the historic warming costs with the forecast BM start-up costs.

£/Million	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
BM Start Up	9.4	30.4	21.1	16.2	7.4	11.9	17.0	15.0

The increase from 2006/7 to 2007/8 is due to number of factors:

- Introduction of the BM start up contract. This changed the contract terms from the previous warming contract
- Market behaviour

Our forecast of BM Start Up costs for 2008/09 extrapolates from the levels forecast for 2007/08. The forecasted BM Start-Up costs for Financial Year 2008-09 are £15m. The decrease is mainly associated with the forecast change in market behaviour.

4.12.2 Reserve Forecast

The reserve forecast is the cost of providing adequate margin from day ahead and on the day actions. These costs are exclusive from STOR, BM start up contract costs, fast reserve and fast start costs.

We forecast the cost of margin over the year by splitting the year into 84 separate sections (one per month (12), fuel type (7) in combination). For each section, we forecast the expected offer price, volume requirement, and value of energy. From these three components we generate the reserve cost forecast:

$$\text{Margin cost for section} = \text{Volume} \times (\text{Offer Price} - \text{Energy Reference Price})$$

The total margin cost over the year is the sum of the 84 values.

The fuel types used are Coal, Gas, Oil, Hydro, Forward GB Trades, SO-SO Trades and Forward French Trades. The volume forecast is an average of the appropriate outturn data since April 2005. A detailed derivation of the (per fuel) reserve price forecast is included in Annex A. Finally, the energy reference price is derived from the Energy forecast above.

The total forecast spend for Reserve is £139.6m, a break down (per fuel-type and month) is included in Annex A.

4.12.2.1 Effect of LCPD on Reserve Costs

The change in running regime of LCPD generation will have an effect on the procurement of reserve services. Currently, there is up 8 GW of opted out coal plant that may significantly change its operating regime.

The change in operation of a portion the 8GW of opted-out coal plant capacity will increase the cost of marginal energy actions. The introduction of LCPD is forecast to increase energy costs by £10m over 2008/9.

See Annex C for more information.

4.12.2.2 Effect of Wind on Reserve Costs

In operating the system in real time, we procure energy to ensure that it can secure the system for the loss of generation or for demand forecast errors. The expected increase in intermittent generation is likely to increase the volatility of generation and hence increase the reserve requirements.

Our initial assessment indicates that for the additional volumes of wind generation connecting in 2008/9 there will be an increase of £5.5m - £9.5m with a central forecast of £8m.

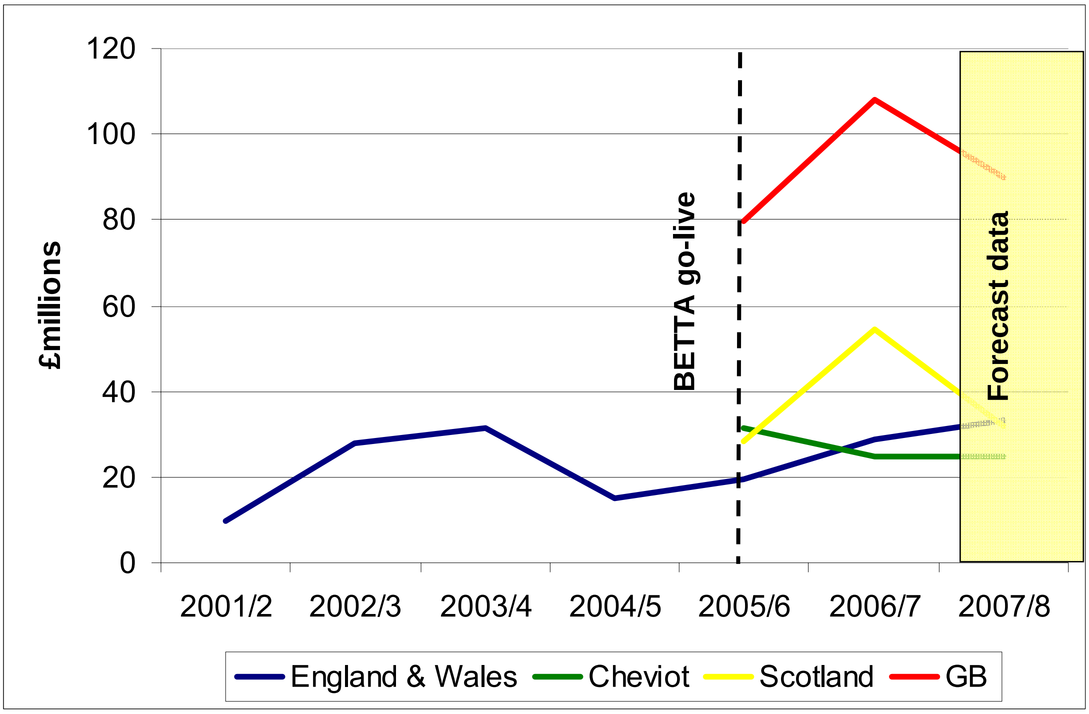
It should be noted:

- That the analysis implicitly assumes that the market will self balance up to Gate Closure, and that NGET will balance post Gate Closure.
- That the analysis is using the wind error on the metered wind farms and extrapolating across all GB wind farms. It is noted that going forward there are projects in the pipeline to improve metering.

Although it is anticipated that other generation plant (thermal and hydro) will vary its output to compensate for variations in wind output, the magnitude of any impact on our energy requirements will depend on the ability of the market to compensate for variations in wind output through short-notice changes.

5. Constraint Costs

The graph below shows constraint costs since the start of NETA:



Constraint costs for the GB transmission system were £108 million in 2006/7 and are forecast to be £89 million for 2007/8. A significant proportion of these costs are incurred as a result of constraints on the Scottish transmission system or on the Cheviot (Scotland to England) boundary: £80 million in 2006/7, and forecast to be around £57 million for 2007/8.

Forecast Summary for 2008/9

Network constraint costs are forecast to total £125 million for 2008/9. The breakdown of these costs is shown in the table below.

£m	England & Wales	Cheviot	Scotland	LCPD	GB
2007/8 forecast	33	35	22	0	89
2008/9 forecast	19	67	39	5	130

The following sections describe in more detail the forecasts for the three elements.

5.1 Constraint Forecasting Approach

Due to the GB transmission network topology and the nature of constraints identified, we divide the GB transmission system into three parts and forecast their constraint costs separately, namely:

- Within Scotland;
- Cheviot boundary (between Scotland and England);
- England & Wales

For the Cheviot boundary, we use a probabilistic model, which convolves distributions of Scottish generation against demand level and Cheviot boundary flows against the boundary's capability.

Due to the multiplicity of possible constraint boundaries in England & Wales and within-Scotland, using a probabilistic model to forecast constraint costs is not feasible. The approach involves:

- Detailed studies of the transmission network, based on planned transmission and generator outages, and on utilisation of short term circuit ratings and operational measures;
- Uncertainties in market behaviour, such as French interconnector flows, are studied and the impact estimated;
- Key outages and/or transmission boundaries that cause significant constraint costs are identified

5.2 Within Scotland

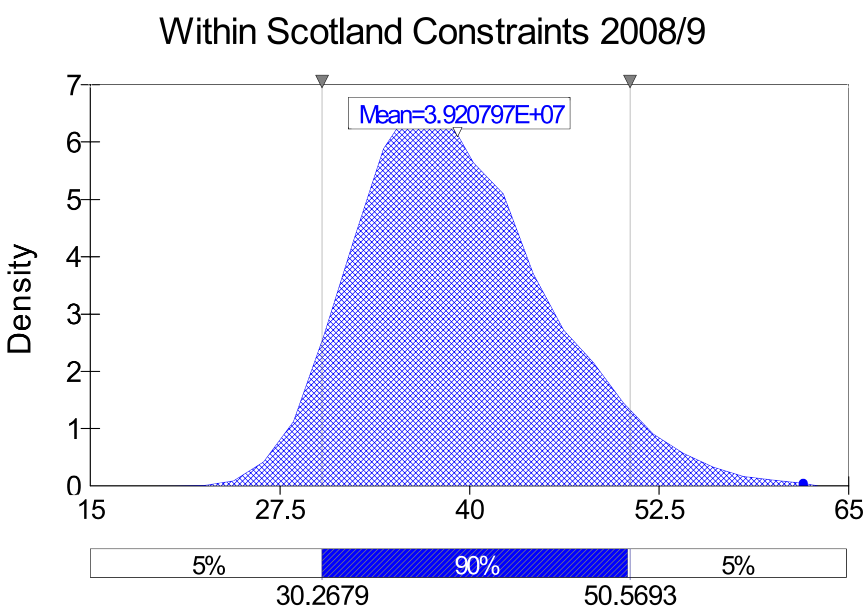
In 2008/9, as last year, we have experienced a number of constraints within the Scottish Hydro Electric Transmission Limited, SHETL and the Scottish Power Transmission Limited, SPTL transmission systems that impact both import and export constraints. We have identified at least eight distinct constraint boundaries as causing costs. Mainly these constraints occur under conditions of transmission outage, but some occur for an intact network.

Forecast Assumptions

- Increase in critical outages from 8 weeks in 2007/8 to 30 weeks in 2008/9.
- High declared generation availability against historic expectations

The outage program for 2008/9 affects a number of critical constraint boundaries across the Scottish network. There are considerable Transmission Investment for Renewable Generation (TIRG) and B5 (Scottish internal Seven Year Statement defined boundary) construction works being undertaken during 2008/9. The associated outages increase the risk on constraint volumes and prices.

The graph below represents the cost risk profile for internal Scottish constraints.



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The central cost forecast for within Scotland constraints is £39.0m. This compares with an outturn of £54.6m for 2006/7 and a forecast of £22m for 2007/8. The graph shows a range of costs from £30m - £51m, indicating the extent of the uncertainty surrounding the forecast.

The range outlines the risk with volumes and prices. Generation and demand patterns can change from those forecast depending on many factors e.g. generation planned maintenance, market conditions.

5.3 Cheviot Boundary

The Cheviot boundary is a critical constraint boundary located between Scotland and England. For intact conditions there is a limitation on the power that can flow across the boundary due to thermal, system stability and voltage issues. For outage conditions, this limitation is significantly exacerbated.

Over the next 5 years, there is considerable construction works planned to upgrade the capability of the Cheviot boundary. These outages are mainly associated with TIRG construction works and will be more onerous in terms of duration and restriction than a typical maintenance plan would necessitate. During 2008/9 there are a number of TIRG outages that will limit the export capability of the Scottish system, hence increasing the constraint costs.

5.3.1 Forecast

For the 2008/9 Cheviot boundary cost forecast, we have used our Cheviot forecast model.

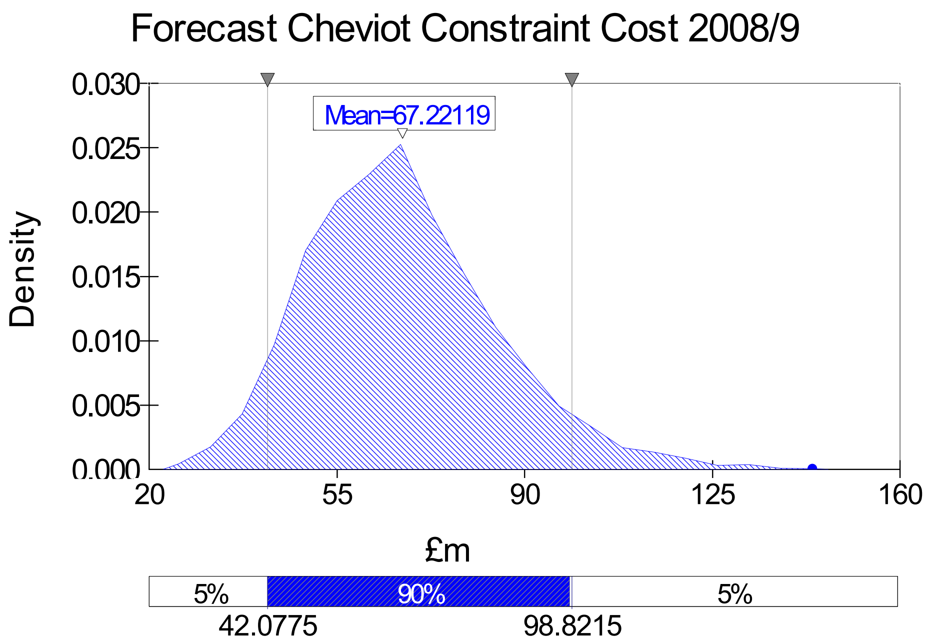
For 2008/9, the key forecast assumptions are:

- The model uses probabilistic Scottish generation profiles that reflect historical trends and anticipated plant outages;
- An increase in boundary circuit outages from 8 weeks in 2007/8 to 30 weeks in 2008/9
- Range of bid / offer prices are stated in the table below

Forecast year: 2008/9	Scenario Number, Description and Probability			Mean
	1	2	3	
	Low	Central	High	
	20%	60%	20%	
Winter				**Weighted Avg**
Avg Scottish Bid Price	14.9	15.7	17.8	**15.9**
Replacement Price GB	75.0	83.9	92.8	**83.9**
Constraint Price	**60.1**	**68.3**	**75.0**	**68.0**
Summer				**Weighted Avg**
Avg Scottish Bid Price	13.0	13.8	14.5	**13.8**
Replacement Price GB	57.3	65.0	76.4	**65.7**
Constraint Price	**44.3**	**51.2**	**61.9**	**52.0**

- Average Scottish wind capacity during summer is 1352MW with a load factor of 25% and winter of 1557MW with a load factor of 30%. Invisible / embedded wind capacity is assumed to offset demand growth.
- Utilised the average capability of intertrips so far experienced during 2007/8 and at the current pricing level.

Against these assumptions, our model forecasts a total Cheviot cost of £67m. The 90% probability range of the overall cost is from £42m to £99m. The cost distribution is shown below.



The above graph indicates the range of potential costs associated with the Cheviot boundary constraint and the corresponding risk. The risks are mainly associated with the constraint volumes and prices. These are affected by plant availability and market conditions.

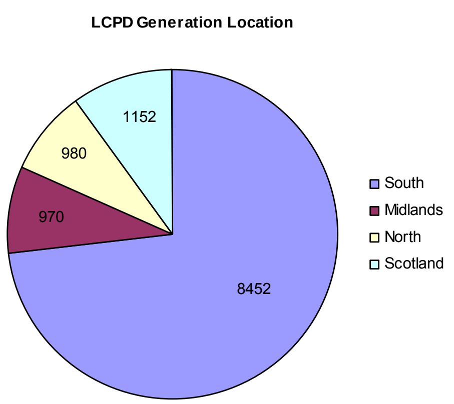
5.4 England & Wales

Our initial assessment of the indicative outage plan in England and Wales indicates a reduction in costs of £14m for 2008/9 when compared with 2007/8. The reduction is associated with the removal of one-off events that have caused current year costs to increase to £33m.

Our forecast estimates total England and Wales constraint costs of £19m as compared to a forecast of £33m for 2007/8 and £28.6m in 2006/7.

5.4.1 LCPD Effect on Constraints

The impact of LCPD opted out plant running behaviour on network constraint costs is uncertain.



Assessment of the impact on national-level constraints is due to the fact that, of the 11.5GW of opted plant, 8.5GW is located in the Southern part of the system. During the periods where there is an active constraint with opted out units choosing not to run, the generation that will replace this energy will be spread throughout the country. This will increase pressure on all our major North–South network constraints with the system both intact and under outage conditions.

There is also a more unpredictable localised constraint cost effect that will result from the introduction of LCPD. With the units at opted out generation stations operating as either all on or all off, as described above, there is an increased risk of localised constraints being activated which would need to be secured through additional balancing.

Our initial view of the cost risk for the impact of LCPD plant behaviour on constraint costs is a range from £1m to £20m, with a central forecast of £5m.

Summary of GB Constraint Forecast

The below summarises the total forecast of GB constraint costs.

£m	England & Wales	Cheviot	Scotland	LCPD	GB
2001/2	9.9				
2002/3	28				
2003/4	31.6				
2004/5	15.1				
2005/6	19.6	31.6	28.5		79.7
2006/7	28.6	24.9	54.6		108.1
2007/8 forecast	***33***	***35***	***22***		***89***
2008/9 forecast	***19***	***67***	***39***	***5***	***130***

In summary, we forecast a mean GB constraint cost of £130.0 with a range [£94m - £162m]. The increase in costs is associated with an increase in outages on critical circuits plus additional wind generation in Scotland.

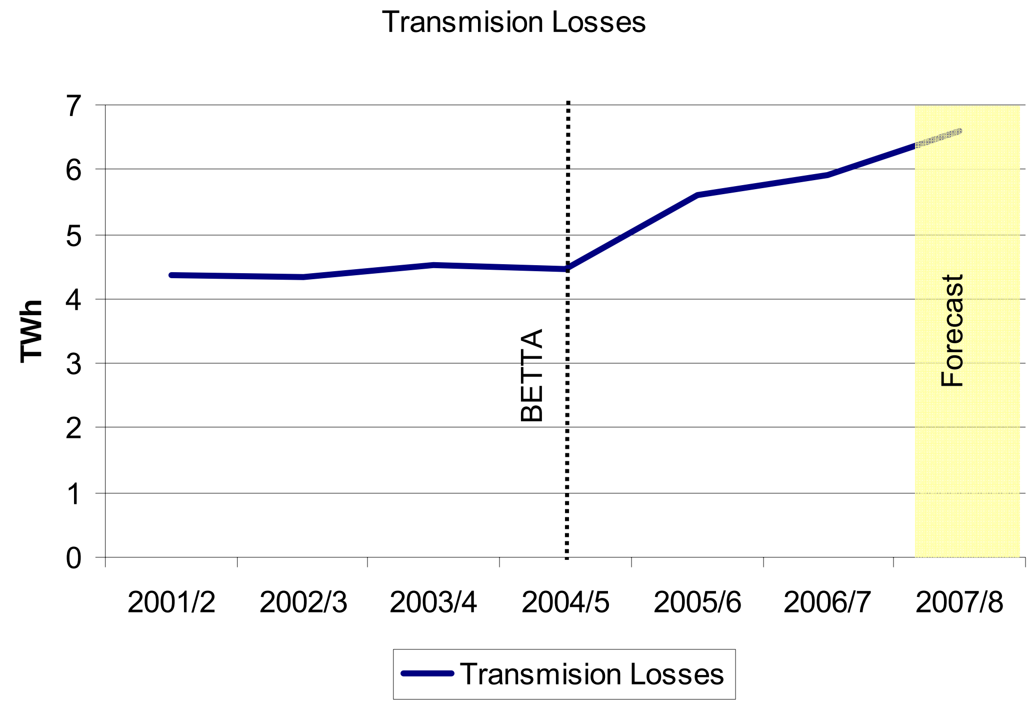
6. Transmission Losses Forecast

Transmission losses occur when power is transmitted across the transmission system. The main element of transmission losses is associated with heating losses in transmission equipment caused when current passes through the equipment. There are many elements that affect the volume of transmission losses; transmission equipment design, transmission topology, generation location and demand. By far the main element of transmission losses is the generation location.

Transmission Losses Forecast

As in previous years, our transmission losses (TL) forecast model is based upon forecast changes in the zonal disposition of generation. The difference between historical and forecast station output for each zone is multiplied by the Transmission Loss Factor to give the forecast change in zonal TL. Thus, forecast TL is calculated as base period TL plus the sum of forecast zonal TL changes.

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 understood. This increase in recent years is shown in the graph below.



We are at present engaged in detailed analysis to understand whether this rise is driver by:

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

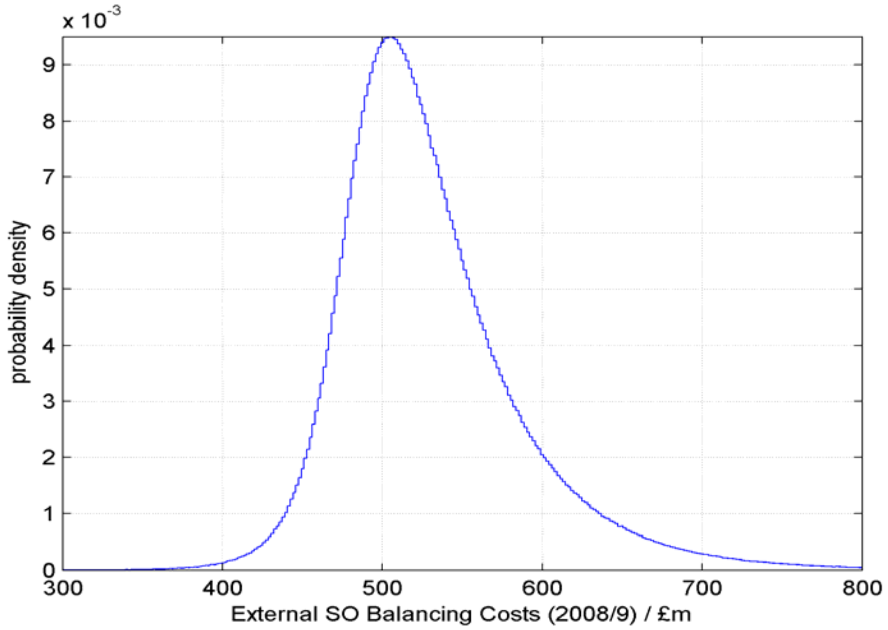
We hope to conclude this work during December and will report to the industry on our findings and industry meetings including the SO Incentives workshop. As a result of this ongoing uncertainty, we are no in position to be able to forecast or propose an appropriate target level for losses in 2008/09.

Our forecast therefore does not include a figure for the Transmission Losses element of the scheme. However, as this is a net scheme, the headline costs within the forecast is zero at commencement of the year, so the lack of a forecast has no effect on the headline target of £530m.

7. Incentive cost Range

As described in the forecast sections above, there are a number of uncertainties when considering the forecast for each incentive component and for the complete incentive costs.

The graph below indicates incentive cost risk / uncertainty profile.



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

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 range is due to uncertainties for 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;
- market shocks, such as a cold snap, plant or infrastructure failure

The table below shows the range and gives illustrative scenarios that would see costs outturning at that point in the range

Scenario	Conditions	IBC
Low	- Milder winter - Reduction in wholesale gas and electricity prices - increase from current expected plant availability - Increase in market length - No major network shocks	£471m
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
High	- Colder winter and/or market shock - Rise in Wholesale prices - Plant availability in line with forecast or tighter and/or - Above forecast network constraints	£603m

We would expect this distribution to become narrower as the uncertainty in the various forecast components decreases (for example after the STOR tender round).

8. Comparison with 2006/7 and Current Year

The table below compares the baseline forecast incentive costs for 2008/9 with the baseline costs for 2007/8. The baseline cost comparison shows very little difference in the year on year forecast costs.

All Categories £m	Latest 07/08 Forecast	08/09 Forecast	Difference
Constraints England & Wales	33	19	-14
STOR	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

The main changes in costs for 2008/9 are associated with a decrease in constraint costs across England and Wales, an increase in contract costs for reserve services, the increase in reactive costs and the decrease in frequency response costs.

The increase in costs for reactive can be mainly attributed to an increase in forecast power price. This accounts for approximately £5m in increased costs.

The main increase in costs for 2008/9 is associated with three main drivers;

- A rise in Transmission Network outages in Scotland and the north of England.
- A continuing increase in wind generation.
- The effect of introducing the Large Combustion Plants Directive.

These three drivers account for the majority of cost increases for next year. The table below outlines the forecast costs for these three drivers.

£m	Latest 07/08 Forecast	08/09 Forecast	Difference
Cheviot	35	67	32
Internal Scotland	22	39	17
LCPD	0	15	15
WIND	0	10	10
Total	**57**	**131**	**74**

The table shows a considerable increase in Cheviot and internal Scottish constraints, additional costs for LCPD and wind.

The following table below highlights all the forecast components.

All Categories £m	2006-7 Outturn	Latest 07/08 Forecast	08/09 Forecast	Difference for 08/09 - 07/08
Net Energy + Margin + STOR	60	81	84	4
Energy Imbalance	-28	34	26	-8
Negative NIA	-65	-141	-162	-21
Net Energy	-92	-107	-136	-29
Constraints	108	89	125	36
Cheviot	25	35	67	32
Internal Scotland	55	22	39	17
England & Wales	28	33	19	-14
Margin + STOR	152	187	220	33
Margin	119	124	155	30
STOR	63	63	65	2
Footroom	9	4	4	0
Fast Reserve	58	56	60	2
Response	160	150	145	-5
Reactive	53	50	57	7
Blackstart	15	14	17	3
Unclassified BM	10	10	9	-1
Transmission Losses Adjustment	9	22	0	-22
BM + Ancillary Services General	4	3	4	1
Reconciliation	7	-1	0	1
LCPD	0	0	15	15
WIND	0	0	10	10
Total	**495**	**480**	**530**	**50**

Our forecast of £530m for 2008/9 is £50m above our latest forecast of £480m for 2007/8 and £35m above the 2006/7 outturn.

The main areas where costs have increased are:

- Constraints
  The main cause for the increase in forecast costs is within Scotland and Cheviot constraint costs, with a combined effect of increasing costs by £49m. The main cause for the increase in constraint costs is an increase in outages across critical boundaries:
  - Cheviot increase in outages from 8 weeks in 2007/8 to 30 weeks in 2008/9. This provides an increase of approximately £32m.
  - Within Scotland constraints increased by £17m due to an increased volume of outages. Also, current information suggests an increase in generation as there are a limited number of generation outages currently planned.
- LCPD
  The overall effect of LCPD is currently unknown. Our initial assessment has predicted two operational scenarios that generators are likely to adopt. Both these scenarios will increase costs of reserve and constraints. There is significant uncertainty about the potential effect of the introduction of LCPD.
- Wind
  The planned increase wind generation will increase the cost of reserve and constraints due to the location of the new connections.

The incentive cost range has been developed to indicate the risk of outturn costs for the scheme. The central target provides an indication of the central cost whereas the range indicates the potential for higher or lower costs.

The main cost sensitivities are associated with current unknowns, e.g. power price.

9. Conclusion

Our overall central forecast for incentive scheme costs for 2008/9 is £530m, an additional £50m on the 2007/8 forecast and £35m above 2006/7 outturn costs.

The underlying costs for 2008/9 are comparable with the costs for 2007/8 with some increases and decreases in component elements.

The majority of cost increases are focused on three main areas:

- Constraint costs
- LCPD
- Additional wind

These costs are associated with the development of the system to connect additional renewable generation and cut emissions from existing fossil fuelled generation.

The continuing trend for reducing market length and the recent increase in power prices, impacts the energy and reserve forecasts. Although these changes are not significant for incentivised costs, there will be a change in BSUoS costs.

There is significant risk associated with the potential outturn costs. In producing the forecast, there are a number of assumptions that affect the forecast costs. These assumptions are likely to change prior to the start of the scheme for the scheme duration. One such assumption is power price. This directly affects a number of component costs (e.g. reactive) and interacts with others (e.g. reserve costs). In addition, the number of outage weeks across significant constraint boundaries will have an effect on the constraint costs. The current forecast outlines the best information that we have at this time. However, these assumptions are changing and we will have a more detailed understanding of the likely out come after the winter.

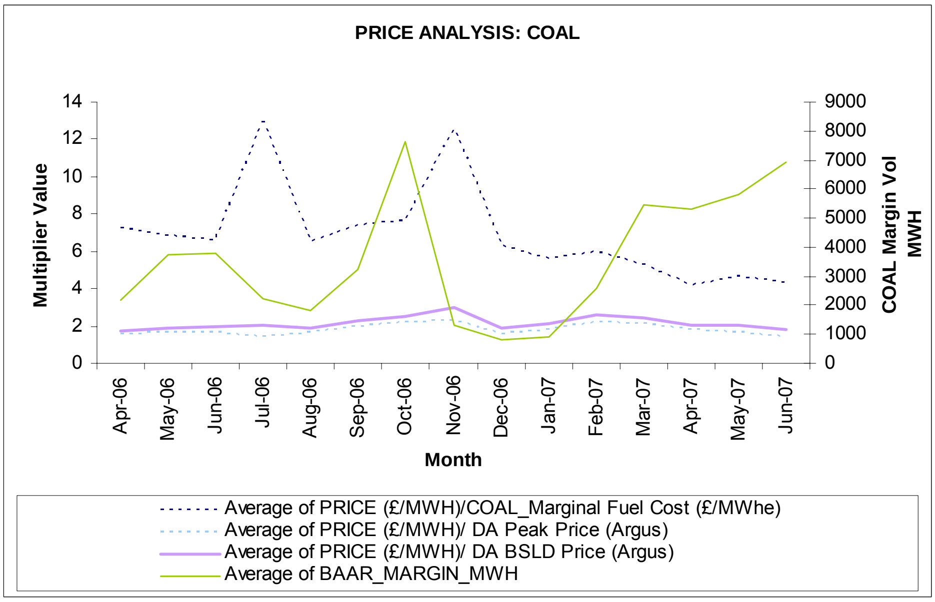
Annex A – Reserve Price Forecast Methodology

This annex provides further detail of our analysis of likely prices for Reserve plant for dispatch on the day. To do this, we analysed the ratio of the prevailing price of reserve actions. The three variables we analysed were: The underlying fuel cost, wholesale baseload price and peak prices. This analysis is shown in the graphs below for each fuel type, Coal, Oil and Gas. The price forecast is then based on the best correlation, being either:

1. Correlated with associated fuel price.
2. Correlated with wholesale electricity price (baseload and/or peak)
3. If no correlation with the above two variables then we assume a fixed price based on historic levels.

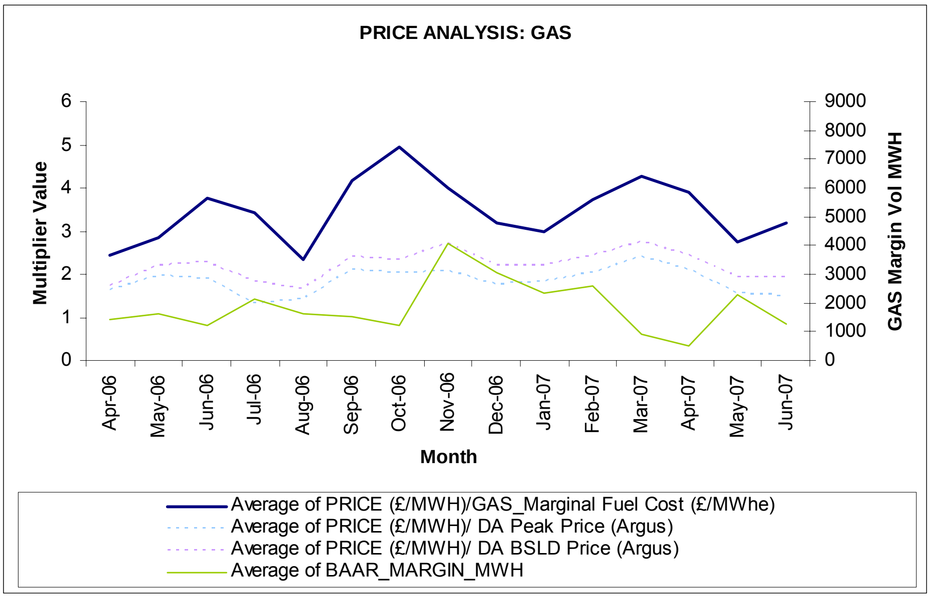
Note: In all graphs price is the Offer price of reserve actions which is then divided by one of the above variables to give a multiplier value, shown on the left hand scale. Volume is shown on the right hand scale.

Coal



- For coal, the most consistent relationship throughout the year is with wholesale price
- Coal Offer Price by month approximately equal to 2.2 multiplied by the baseload power price

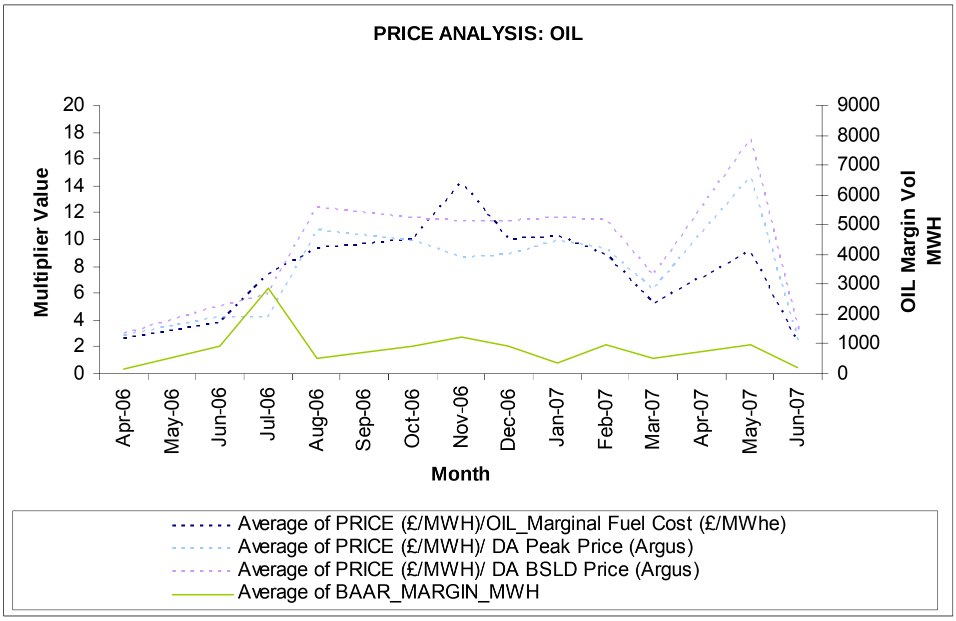
Gas

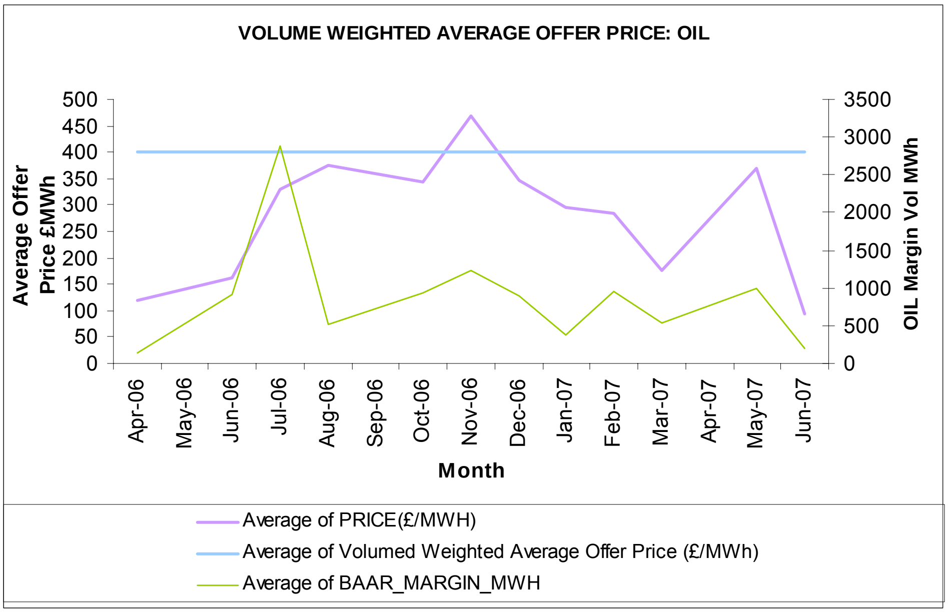


There is a good relationship between the gas reserve price and fuel price. The relationship derived is:

- In most months, gas generation reserve price is 2.5 to 3.5 multiplied by the gas marginal fuel cost.
- Therefore, for future reserve prices, we have used the forward fuel price (including Carbon) to forecast the marginal gas fuel price
- The reserve price multipliers have been used to calculate our forecast prices for gas plant supplying reserve.

Oil





- For Oil plant there is no correlation with underlying fuel costs or wholesale prices, therefore we have assumed a fixed price.
- Offer Price Value - £402 MWh

<u>Trades on the French Interconnector</u>

Historically the achieved trade price for purchasing reserve over the French Interconnector is 1.5 multiplied by the forward French power price. This factor reflects the fact that the days we purchase the power are correlated with the higher on-the-day French price.

Summary

The table below provides an overview to the price assumptions used in the forecast.

			Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	
Offer Price	Coal	Offer Price	97.6	97.6	97.6	97.6	97.6	97.6	109.4	109.4	109.4	109.4	109.4	109.4	
		Multiplier	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	*2.16*	
		Baseload Power Price	*45.2*	*45.2*	*45.2*	*45.2*	*45.2*	*45.2*	*50.7*	*50.7*	*50.7*	*50.7*	*50.7*	*50.7*	
	Gas	Offer Price	98.4	98.4	98.4	112.9	112.9	112.9	152.2	152.2	152.2	165.0	165.0	165.0	
		Multiplier	*2.55*	*2.55*	*2.55*	*3.08*	*3.08*	*3.08*	*3.57*	*3.57*	*3.57*	*3.57*	*3.57*	*3.57*	
		Forward Fuel Price converted to £/MWh	*38.6*	*38.6*	*38.6*	*36.7*	*36.7*	*36.7*	*42.6*	*42.6*	*42.6*	*46.2*	*46.2*	*46.2*	
	Oil	Fixed Value - Mean Offer Price 2006/07	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	
	Hydro	Fixed Value - Mean Offer Price 2006/07	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	
	UK_Trade (UTEV)	Peak Power Price (Forward)	54.4	54.4	54.4	54.4	54.4	54.4	63.5	63.5	63.5	63.5	63.5	63.5	
	French SOSO	Fixed Value - Mean Price 2006/07	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	
	French Trades	Trade Price	73.7	73.7	73.7	83.0	83.0	83.0	91.5	91.5	91.5	96.2	96.2	96.2	
		Multiplier	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	*1.49*	
		Peak Power Price (French price converted to £/MWh)	*49.4*	*49.4*	*49.4*	*55.7*	*55.7*	*55.7*	*61.4*	*61.4*	*61.4*	*64.5*	*64.5*	*64.5*	
Energy Balancing Price		Pseudo Price (£/MWh)	56.2	58.6	57.6	60.1	54.9	59.2	66.4	60.2	66.2	61.8	67.9	70.1	
Volume (Mwh)	Coal		77,676	98,943	109,296	119,685	80,875	87,912	102,443	52,936	46,838	33,184	40,691	63,415	
	Gas		32,339	41,194	45,504	49,829	33,671	36,601	42,650	108,959	96,407	68,302	83,754	130,528	
	Oil		4,225	5,382	5,945	6,510	4,399	4,782	5,572	8,691	7,690	5,448	6,681	10,411	
	Hydro		17,467	22,249	24,577	26,913	18,186	19,769	23,036	29,473	26,078	18,476	22,655	35,308	
	UK_Trade		17,542	22,345	24,683	27,029	18,265	19,854	23,135	23,404	20,708	14,671	17,990	28,037	
	French SOSO		3,540	4,509	4,981	5,454	3,686	4,006	4,669	5,309	4,697	3,328	4,081	6,359	
	French Trades		11,507	14,658	16,192	17,731	11,981	13,024	15,177	9,802	8,673	6,145	7,535	11,743	
Cost (£)	Coal		3,218,660	3,861,489	4,374,766	4,486,978	3,455,696	3,375,454	4,407,728	2,603,521	2,025,181	1,580,925	1,689,095	2,494,139	
	Gas		1,365,845	1,640,542	1,857,676	2,629,512	1,953,242	1,964,608	3,659,888	10,020,615	8,293,202	7,051,686	8,133,515	12,391,191	
	Oil		1,461,104	1,848,185	2,047,505	2,225,621	1,526,959	1,639,114	1,870,233	2,970,351	2,582,469	1,853,603	2,231,999	3,455,780	
	Hydro		835,002	1,010,008	1,140,252	1,180,363	892,885	884,918	866,670	1,290,280	986,627	780,364	818,002	1,197,851	
	UK_Trade		-32,363	-95,073	-80,349	-156,562	-10,099	-97,013	-66,577	76,721	-55,214	25,492	-79,047	-184,312	
	French SOSO		77,188	87,456	101,585	97,404	85,129	75,175	54,260	94,376	55,583	54,034	41,239	50,406	
	French Trades		201,042	220,764	260,047	404,902	336,377	309,210	381,056	306,466	219,605	211,394	213,019	306,382	
	Total		*7,126,479*	*8,573,370*	*9,701,482*	*10,868,217*	*8,240,188*	*8,151,466*	*11,173,259*	*17,362,331*	*14,107,453*	*11,557,499*	*13,047,822*	*19,711,437*	*139,621,004*

Annex B - 2008/9 Energy Balancing Forecast

The 2008/9 forecast of Energy Balancing costs consists of two elements:

- Volume Forecast
- Price Forecast

Volume (NIV) forecasts are created from historic outturn data with an "offset" applied to reflect the expected changes in market length. The use of historic data captures seasonal changes in length – for instance October/November lengthening and March shortening.

For NIV in 2008/9 certain assumptions have been made. These are:

- Mean NIV will continue the trend towards less long markets
- NIV will follow the same underlying distribution
- There is insufficient data to say if the exceptional shortening in market length over the summer of 2007 will continue into the 2007/8 winter and further in to 2008/9

This in turn leads us to forecast NIV under certain scenarios and then combine these in to a single central forecast. Different scenarios have been used for summer and winter. This is in part due to uncertainty over the behaviour in NIV in winter 2007/8 at the time the forecast was produced. This is particularly difficult to predict this year given the exceptional shortening seen over the summer of 2007 and the historic seasonal increases in length over October and November. Given these factors, we cannot determine if the market will return to 'normal' operation or continue being significantly less long than in the past until more data has become available.

The summer (April to September) scenarios used are:

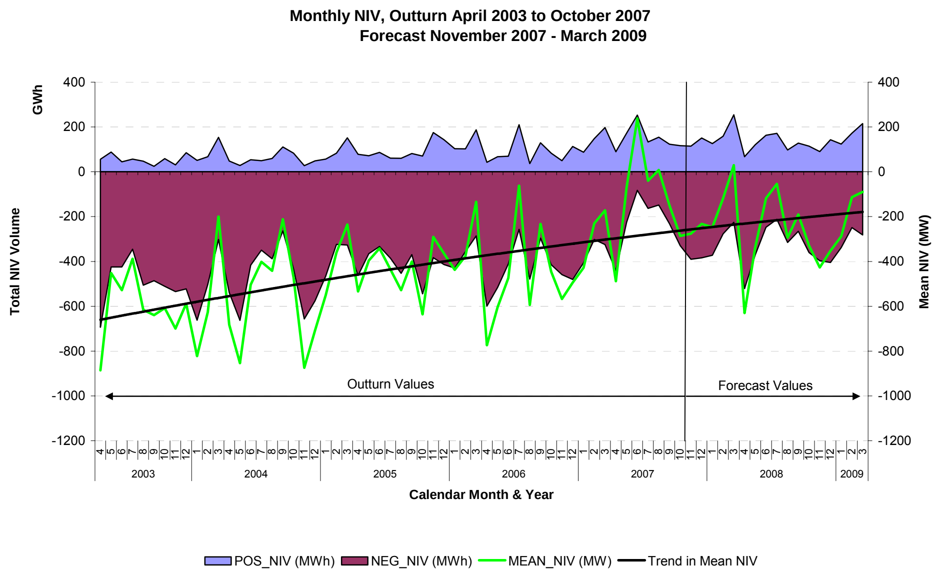
1. NIV same as 2006 (50% weighting) ['Norma']
2. NIV same as 2007 (50% weighting) [Much less long]

The choice of scenario here reflects the uncertainty as to if the shortening in NIV over summer 2007 will repeat in summer 2008 or if NIV will return to behaviour more in line with the historic norms.

The winter (October to March) scenarios used are more complex

1. 2006/7 NIV, shortened by 100MW/period (50% weighting)
2. 2003/4-2006/7 distributions, shortened by 50MW/period (25% weighting)
3. 2003/4-2006/7 distributions, shortened by 400MW/period (25% weighting)

The 3rd scenario here reflects a winter that experiences the changes seen in the summer of 2007. At the time of forecasting there is insufficient data from winter 2007/8 to say if the trend of the summer will continue into the winter. Scenarios 1 & 2 reflect a "business as usual" scenario with a small level of reduced length continuing. The chart below shows how the forecast NIV volumes from November 2007 onwards compared to the outturn from April 2003.



The second part of the Energy Balancing Cost forecast is the prices of energy balancing actions in the BM and SPNIRP, each of which varies with wholesale prices. As we do not believe we can forecast future market prices better than the market we use the forward Baseload and Peak prices to as inputs to the model. The forward prices used in the current 2008/9 forecast are as follows:

	Baseload	Peak
Summer	£ 45.20	£ 54.35
Winter	£ 50.65	£ 63.50

SPNIRP is defined within National Grid's Transmission Licence and is based on the four-hour and half-hour trade products on the APXUK power exchange for a given settlement period. As this uses market prices it is reasonable to expect this to be strongly correlated with underlying wholesale prices. A model of how SPNIRP relates to Baseload and Peak prices, and to varying market lengths, in each EFA block of each month was created and tuned on 2006/7 data. This relationship was then used to derive SPNIRP values for 2008/9 given the forecast NIV distribution.

As it is believed that energy balancing prices also vary with underlying wholesale prices it follows that these prices also relate to SPNIRP. Investigation showed that this gives relatively static results whereby energy balancing prices are 0.8 multiplied by SPNIRP in long markets and 1.6 multiplied by SPNIRP in short markets. Applying this to 2006/7 outturn data gives the following comparison of costs.

	Outturn			Forecast Model			
£m	BM Costs	-1*NIA	Net	BM Costs	-1*NIA	Net	Variance
Apr-06	-15.10	6.27	-8.83	-12.91	5.20	-7.70	1.12
May-06	-4.98	1.72	-3.27	-6.68	0.26	-6.41	-3.15
Jun-06	-4.88	-1.30	-6.18	-4.76	-1.59	-6.35	-0.17
Jul-06	16.81	-40.70	-23.89	14.71	-33.37	-18.66	5.23
Aug-06	-9.67	4.33	-5.34	-8.64	3.38	-5.25	0.09
Sep-06	0.61	-7.69	-7.08	1.95	-8.87	-6.92	0.16
Oct-06	-2.99	-3.14	-6.12	-3.04	-2.32	-5.36	0.77
Nov-06	-6.50	-0.02	-6.52	-9.78	2.31	-7.47	-0.95
Dec-06	-3.44	-3.00	-6.44	-2.17	-5.55	-7.71	-1.28
Jan-07	-3.71	-1.48	-5.19	-2.63	-2.54	-5.16	0.03
Feb-07	3.32	-8.17	-4.85	3.02	-8.98	-5.96	-1.10
Mar-07	2.93	-11.58	-8.65	4.37	-11.36	-6.99	1.66
Total	-27.59	-64.78	-92.37	-26.53	-63.41	-89.94	2.43

The overall model results for 2008/9 are shown on the next page.

Units	Category	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
MWh	Mean NIV	-315.1	-167.6	-59.1	-26.9	-146.9	-95.3	-165.0	-213.2	-176.2	-144.1	-56.9	-44.9	-134.3
GWh	NIV+	67.1	120.9	162.7	171.8	97.0	128.1	114.3	89.7	142.7	123.5	172.5	215.0	1605.4
GWh	NIV-	-520.8	-370.4	-247.9	-211.9	-315.6	-265.3	-360.2	-396.7	-404.9	-337.9	-249.1	-281.8	-3962.3
£/MWh	BSLD	45.2	45.2	45.2	45.2	45.2	45.2	50.7	50.7	50.7	50.7	50.7	50.7	47.9
£/MWh	PEAK	54.4	54.4	54.4	54.4	54.4	54.4	63.5	63.5	63.5	63.5	63.5	63.5	58.9
£/MWh	SPNIRP+	-53.0	-56.4	-53.4	-54.6	-48.6	-53.6	-63.1	-61.1	-67.9	-62.9	-68.3	-70.2	60.6
£/MWh	SPNIRP-	-37.4	-37.2	-37.8	-38.5	-39.3	-39.0	-43.4	-43.3	-42.8	-42.6	-43.7	-44.3	40.7
£/MWh	BM Offer	84.8	90.2	85.4	87.4	77.8	85.8	101.0	97.7	108.6	100.6	109.3	112.3	96.9
£/MWh	BM Bid	29.9	29.8	30.2	30.8	31.5	31.2	34.7	34.6	34.3	34.1	35.0	35.4	32.6
£m	Eng+	5.7	10.9	13.9	15.0	7.5	11.0	11.5	8.9	15.5	12.5	18.9	24.2	155.6
£m	Eng-	-15.6	-11.0	-7.5	-6.5	-9.9	-8.3	-12.5	-13.7	-13.9	-11.5	-8.7	-10.0	-129.1
£m	-NIA+	-8.9	-17.0	-21.7	-23.4	-11.8	-17.2	-18.0	-13.9	-24.2	-19.5	-29.5	-37.9	-243.1
£m	-NIA-	9.7	6.9	4.7	4.1	6.2	5.2	7.8	8.6	8.7	7.2	5.4	6.2	80.7
£m	**Net Energy**	**-9.0**	**-10.3**	**-10.6**	**-10.9**	**-8.0**	**-9.3**	**-11.2**	**-10.2**	**-13.9**	**-11.3**	**-13.9**	**-17.4**	**-135.9**
£m	Energy Balancing Costs	-9.9	-0.1	6.4	8.5	-2.4	2.7	-1.0	-4.8	1.6	1.0	10.2	14.3	26.5
£m	-NIA	0.8	-10.2	-17.0	-19.4	-5.6	-12.0	-10.2	-5.3	-15.5	-12.3	-24.0	-31.6	-162.4

In the table above, category names with a “+” suffix indicate the value in short markets (NIV>0) whereas a “-“ suffix indicates a value in long markets (NIV<0)

NIA is quoted as -1 * NIA such that Net Energy Balancing costs are “Energy Balancing” plus “-NIA”

Annex C- Impact of LCPD on Balancing Costs – detailed assumptions and analysis

Introduction
This paper describes our initial analysis into the likely impact of the LCPD on balancing costs, in particular arising as a result of changes in the operation, availability and pricing of opted out units.

Summary of LCP Directive
The Large Combustion Plants Directive (LCPD 2001/80/EC) is a European Union directive aimed at reducing pollutants from large combustion plants. The directive comes into effect on 1st January 2008.

The directive imposes emission limits on new plant i.e. licensed after 1st July 1987. Existing plant i.e. licensed before 1987 have 3 options:-

1. Meet new emission limits which will require retrofitting of flue gas treatment equipment
2. Opt out of the directive with a derogation that limited running to 20,000 hours of operation between 1st Jan 08 and 31st Dec 2015
3. Close before 1st Jan 2008

It is the units that have chosen option 2 whose operation we expect to affected following the introduction of LCPD on 1st January 2008.

The agreed definition of LCP is that a collection of plants whose waste gases are discharged through a common stack should be considered to be a single plant.

Start up and shut down hours will not be counted as operating hours i.e. LCPs will not expend operating hours whilst the output is below the minimum stable output.

The strategies that individual generation companies and stations will follow in utilising their 20 000 running hours have not been divulged and it is expected that they will vary during the 8 year period as market conditions change.

There are a number of running regimes that may be adopted due to the implementation of the LCPD. The potential increase in operational costs depends in some part on the running regime adopted.

Economic Drivers for Opted Out Plants
There are many factors that could influence the running regime that generators may adopt. Our view is that the key factors will be the current and forecast future level of each cost below:

- Fixed cost of keeping plant open
- Variable cost of running plant
- Cost of fuel
- Demand for electricity & electricity prices
  The price of electricity tends to be highest when demand is high or more broadly when there is scarcity of supply. To maximise income, generators would need to target accurately these peak price periods. The simplest method is to predict high demand periods but it is unlikely that this alone would result in running over all the peak price periods in any given year.
- Opportunity cost of developing land

The opportunity cost of developing the redundant generation site needs to be considered when looking at the future running regime. The cost of replanting the site may suggest that early closure of the existing station and building a new power station on the same land may be the favourable plan.

- Growth of alternative sources of generation, such as renewable sources
  The rate of growth of alternative replacement sources of generation will affect the market need for LCPD opted-out fossil fuel generation.
- Company strategy
  Each company will have its own strategy regarding LCPD, which will affect the running regime that each company adopts.
- Carbon emission costs

We would expect the above factors to vary in importance on a company and station basis. It is expected that the weighting of these factors will determine the most economic option for each station. For example, a station with high annual costs to keep it open may be more likely to utilise its LCPD allocated hours relatively quickly. Alternatively, if a company forecasts higher future electricity prices (driven by higher gas and carbon prices) then it may ration hours of running in early years to allow greater profit in later years.

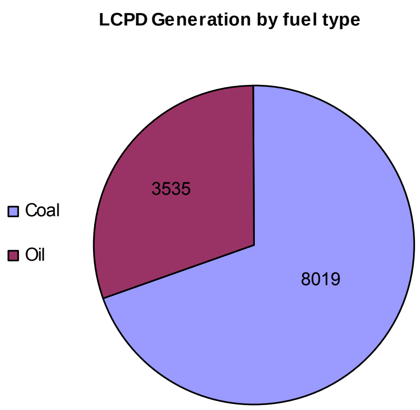
The next section describes in more detail the potential running regimes that opted out generation units may adopt.

Potential Running Regime of Opted Out Plant

There is 11,550 MW of opted out generation whose future running hours will be limited by the introduction of LCPD. These stations are shown below:

Station	**MW**
Didcot A	1940
Ferrybridge	980 (half)
Kingsnorth	1940
Ironbridge	970
Tilbury	1037 (both stacks)
Littlebrook	1245
Fawley	990
Grain	1300
Cockenzie	1152

As the Directive imposes a limit on operating hours rather than the volume of energy generated, then any station that expects to be constrained by the limitation on hours will endeavor to maximise their income over the limited hours by maximising their generation output in each hour. Therefore, for each generation stack, in all scenarios, it is assumed that constrained generators will run all or none of their units e.g. at Kingsnorth, we would expect all 1940MWs of potential output to either run or not run, meaning output at the station can be expected to operate either at 1940MW or 0MW.



In all scenarios that we see as feasible, a change in the running regime of oil-fired generation is not envisaged. In the list above, there are three stations (Grain, Fawley and Littlebrook) that are oil-fired, totalling 3,535MW. Typically these stations have not run for more than 1000 hours/annum since 1985. Therefore we are assuming that the implementation of the LCPD has zero impact on their operation.

The other affected stations are coal-fired, totalling 8019MW, and have operated at 30%-50% or greater load factor (2600-5000 hours/annum) in recent years. As described above, it is likely that the LCPD running hours restriction will result in some of these units rationing their annual running hours, whereas others may continue to operate broadly in line with current levels. If these stations were to smooth their hours over the remaining 8 years, this running level would need to halve to 2500 hours/annum.

Any station that does move to a more limited hours regime is expected to attempt to maximise income through minimising operational costs when not running and maximising income from electricity sales when it does run. In this trade-off, it is possible that stations could choose either:

- to go summer cold, to minimise station operating costs, and only generate during the higher-priced winter months, or;
- to run during the peak priced hours of the year, remaining available throughout the year, thereby maximising income but at the expense of greater station operating costs.

These two scenarios are described further below with fuller analysis outlined in the appendices.

It should be noted that these scenarios have been developed based on the assumptions described in this paper. At present it is not clear from the limited information available how many stations will not chose to ration annual hours, and for those that do, what strategy they will adopt.

Scenario 1 – Summer-cold Regime
In this scenario, the generator would focus the running hours on the winter months when the power prices were at their highest and would mothball the generation over the summer months. The bulk of the peak prices would be winter weekdays, and equinox peaks. Summer mothballing would allow the station to limit operating costs but still allow the majority of high priced periods to be captured. A more detailed regime explanation is contained in Annex 2.

This running regime will impact on balancing costs:

- The costs of reserve, through tighter summer plant margins which will push up the reserve procurement price slope, and;
- Constraint costs, where additional actions may be required to secure local areas of the transmission system which were not planned for extreme whole station on or off summer running, thereby increasing the volume of local

constraints and, more generally, flow south constraint volumes (see appendices for more detail).

Scenario 2 – Year-round running regime

All year availability with running to maximise income from electricity sales by targeting peak power price periods, irrespective of season.

Historical analysis undertaken for this paper indicates that under flat coal prices (i.e. no seasonal effects) the difference in income of 2500[4] hours running over the peak price periods throughout the year provides an additional 15% - 20% income over running for 2500 hours in the winter, for a 1GW station in a single year. However, there are additional costs in this adopted regime that may offset the increased income e.g. additional number of start ups and manpower costs, which we would expect to vary for each station. Offsetting these additional costs, there is an additional potential profit to be made from adopting this regime but also a potential increase in risk if the high priced periods cannot be accurately targeted.

A more detailed regime explanation is in Annex C3.

Impact on the costs of system operation

Currently the coal stations opted out of LCPD are active in the reserve market, offering additional units at relatively low prices for dispatch on the day. In addition, the majority of these units are in the south of England and are in areas of the system which are at risk to localised constraints.

Within both scenarios opted-out coal units will run in more concentrated bursts and when not running are expected either to be unavailable for dispatch or available but at a higher price:

- Under scenario 1, the summer cold scenario, the former is more likely, and the units will not be available, leading to tighter summer plant margins;
- Under scenario 2, year-round running with peak price targeting, the station units may be available when they are not running but the price of the units will be higher than at present due to the lost opportunity cost of eroding the rationed available running hours (we would expect this lost opportunity will be valued against the future profit that could be made from each hour's running).

Under each scenario:

- The station will either be running at full output or not running, reducing diversity of local output.

Reserve On-Cost

The change in running regime of some of the 8GW of opted-out coal plant capacity is expected to reduce the available plant margin and/or increase the price of those units that remain available when not running of their own accord. Each of these factors is expected to increase the price at which we procure reserve. Alternative generation is expected to replace the energy that this tranche of plant would have generated, and so the volume of reserve actions is not expected to increase.

Therefore, we see the impact of LCPD on reserve procurement to be a price effect:

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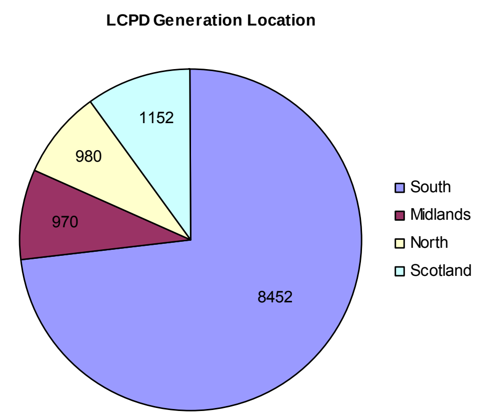
[4] For this initial analysis we have assumed a smooth average of 2500 hours each year of the 8 year LCPD period, totalling 20,000hours.

- When these units are not running, the cost of procuring additional units for Reserve will be higher because either one of, or a combination of, the two factors:
  - The opted out units will not be available and plant margins will be tighter, resulting in a higher offer price;
  - If the unit is available then an additional lost opportunity premium will be added to the offer price.

Put another way, the stack of out-of-merit plant, available to synchronise for Reserve will either be significantly depleted, or the units at the cheaper end of the price stack will be charging more, and so the price of reserve actions will, all other things being equal, increase. We have assumed that this price effect will occur during periods with lower expected power prices as under both scenarios we assume coal plant continues to run in merit during the winter or under higher price periods.

For this initial analysis we have estimated that the average price of reserve actions during the summer will increase by a central figure of £10/MWh. The resultant increase in the prices paid for reserve procurement leads to an estimate of the additional reserve cost at £10m, with an initial view of the range being £5m to £15m. The detail of this calculation is described in Annex C1.

Constraint on-cost for both scenarios
The impact of LCPD opted out plant running behaviour on network constraint costs is more uncertain.



Assessment of the impact on national-level constraints indicates one major driver: the fact that, of the 11.5GW of opted plant, 8.5GWs is located in the Southern part of the system. During the periods where there is an active constraint with opted out units choosing not to run, the generation that will replace this energy will be spread throughout the country. This will increase pressure on all our major North–South network constraints with the system both intact and under outage conditions. This is expected to occur during the summer period under Scenario 1 and low value periods in Scenario 2.

There is also a more unpredictable localised constraint cost effect that will result from the introduction of LCPD. With an opted out plant operating as with units 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.

Our initial view of the cost risk for the impact of LCPD plant behaviour on constraint costs is a range from £1m to £20m, with a central forecast of £5m. Further detail on this costing is provided in Annex 1.

Summary
There are a considerable number of uncertainties that surround the potential change in running regime for opted out LCP. In our view, the scenarios above illustrate the two most likely behaviour patterns for opted-out stations. We would ask the

respondents to the Initial Proposals consultation include any comments they have on these scenarios within their response to the consultation.

The assessment of both scenarios focuses on the potential increase in reserve and constraint costs. There is the potential for reserve costs to increase when the generation is not available due to changes in operating strategies and also for price increase to recover the lost opportunity costs when generation is made available to the SO. With constraint costs, the main risk is associated with the all on / all off scenario and the potential constraints that this may cause.

The range for the potential cost increases reflects the uncertainty that exists with predicting the potential impact. The costs are estimated to be:

- Additional £10m on Reserve costs, with a range of £5m to £15m;
- Additional £5m constraint costs, with a range of £1m to £20m;
- Combining these two individual elements, we forecast a total central figure of a £15m increase in costs, with a range of £6m to £30m.

Annex C1 - Detailed Cost Discussion

Reserve Cost Calculation

The price stack for Reserve actions varies from day to day and is very sensitive to plant margin and to our overall requirement for reserve (prices do rise and fall with scarcity).
Typical prices for Reserve units in the summer can reach in excess of £500/MWh but are more typically of the value £80/MWh to £120/MWh.

On any day the additional unavailability of 2 to 4 LCPD units at an opted out station will significantly tighten plant margin, moving procurement decisions up the reserve price stack and also increasing scarcity, placing further pressure on prices.

Forecast assumptions:

- Forecast volumes of margin actions over the summer is 1000GWh
- For 2008, the depletion of the Offer stack will lead to an increase in average Margin price of between £5/MWh and £15/MWh, centred on £10/MWh.

Thus the consequence of the LCPD depletion of the Offer stack:
= 10 £/MWh x 1000GWh
= +£10m increase, with a range of +£5m to +£15m

Constraint Cost Calculation

North-South flow constraint

We forecast some £5m of the North-South constraint costs across the summer. Our assumption is that the potential removal of up to 8.5 GW of capacity of Southern LCPD opted out plant, of which 4.9GW is coal, will increase this cost by 50%, namely +£2½m.

Localised constraints

There is also a local constraint risk impact arising from LCPD. The LCPD restriction is per hour of operation of all units within the chimney stack; all opted out stations (except Ferrybridge and Tilbury) only have one chimney stack. This could take the form of additional BM actions, forward trades or contracts. It may be necessary to agree contracts with some opted-out stations to secure the network for certain network outages. N.B. The worst case scenario for all local or regional import constraints is with no units operating at the local station.

In each case we would expect the price of these actions to be broadly in line with current prices. However the all on or all off nature of opted-out station output is expected to result in us taking a greater volume of actions to secure the system. At the upper end of this risk, we may need to agree a contract with more than one station during the year to control output during the summer outage season. Under such scenarios total costs would be uncertain but could be expected to reach £20m or above to constrain output. At the lower end of our estimation, the impacts may not materialise if station running 'fits' with transmission system outages and/or may be able to be mitigated by re-planning outage work. We estimate a +£2½m central cost impact on local constraints.

Overall our initial view of the cost risk for the impact of LCPD plant behaviour on constraint costs is a range from £1m to £20m, with a central forecast of £5m.

Annex C2 Summer-cold regime – More detailed regime assumptions

Our detailed view of forecast load factor makes the following central assumptions:

- 6GW target the 2500 hour limit fairly precisely, and opt to regime station cold for 4 of the 5 summer months May to September. Summer weekday times have a long flat 12 hour daily plateau, 0800–2000, and so any station that runs during these times is going to use 1500 hours of running just to cover summer weekday time peaks.
- 2GW target running near 4000hours/annum, near current levels. We assume that the medium-term intention of the owners is that these stations exhaust their 20,000 hours by 2011–2013, and close early.

The important consequence of this regime's assumptions is that a proportion of the 8GW of opted-out coal is unavailable over summer (May–September). Our assumption is that this will not cause a supply security problems because in the event of Margin tightness, we would expect the generation to become available at a price.

Annex C3 Year-round running regime – More detailed regime assumptions

Our detailed view of forecast load factor makes the following assumptions for the 8GW of opted-out coal station capacity:

- We assume that 2GW target running near 4000hours/annum, near current levels. The medium-term intention of the owners is that these stations exhaust their 20,000 hours by 2011–2013, and close early. We have chosen this level to represent a station or stations where the per MW station overheads are high, thus yielding the greater savings on closing early.
- We assume that 6GW will target a longer station life and assume restricted annual running hours of 2500 hours. Our assumptions on running behaviour will therefore have to be based on current market prices.

Justification for Year Running Regime
If we assume that a 1GW station targets a longer station life it is possible to estimate the income from both the winter running and the all-year running regimes.

More precisely, we need to assume restricted annual running hours of 2500 hours and the following prices:

	Baseload	**Peak**
Summer	45.20	54.35
Winter	50.65	63.50
Year round	47.93	58.93

If we look at the income (before application of fuel costs (assumed constant) & running costs for a winter running vs peak running scenario we get the following:

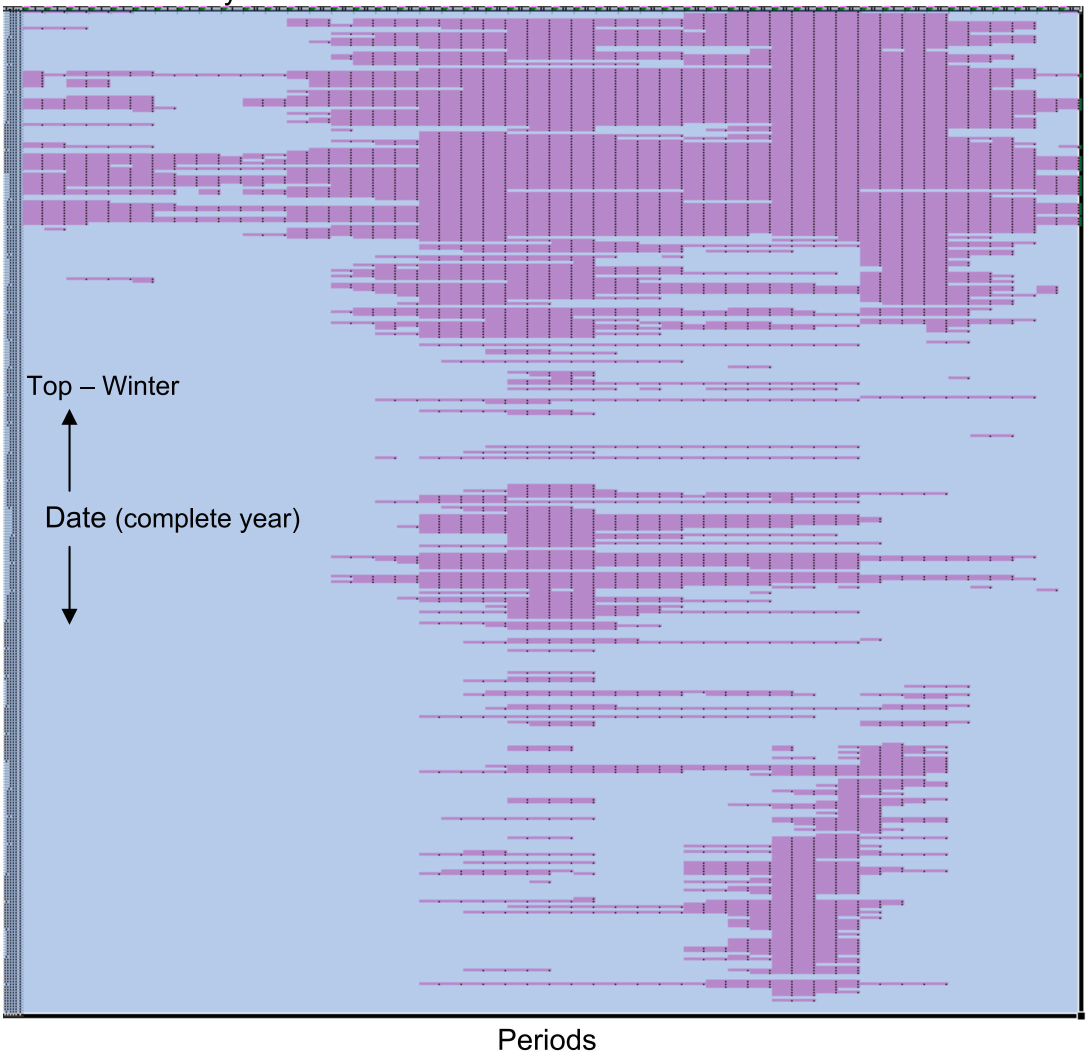
<u>Winter running scenario</u>
Assuming that a 1 GW station runs for 2460 hours over the year we can calculate the income:

- 14 weeks winter baseload:
  hours = 24 (hours per day) * 7 (days per week) * 14 (weeks) = 2352
  income = 2352 (hours) * 50.65 (price) * 1000MW (capacity) = £119.1m
- 9 days winter peak:
  hours = 12 (hours per day) * 9 (days) = 108
  income = 108 (hours) * 63.50 (price)* 1000MW (capacity) = £6.9m
- Total:
  2460 hours with an income of £126.0m

<u>All Year running scenario</u>

The graph below is an extract from 2006 power prices. The pink colour represents the peak 5000 price periods during the year. As can be seen, the peak prices mainly occur in the winter. However there are a considerable number of periods throughout the year where there are high price periods.

The 48 daily periods are represented along the x-axis and the date is represented top to bottom on the y-axis.



- 205 days weekdays peaks:
  hours = 12 (hours per day) * 205 (days) = 2460
  income = 2460 (hours) * 58.93 (price) * 1000MW (capacity) = £145.0m

Comparison

So a 1GW generator can achieve a £19m increase in income simply by targeting the best 205 days in the year vs. shutting over the summer.

Historical analysis has shown under flat coal prices (i.e. no seasonal effects) difference in income for a 1GW station is:

- 2004: £12m
- 2005: £19m
- 2006: £19m

Annex D - Impact of Additional Wind Capacity on Balancing Costs

Introduction

This note describes in more detail our forecast of balancing costs associated with wind generation for 2008/09. We have identified the growth in wind generation as a cost driver as part of its review of the longer term drivers of balancing costs. There is a significant volume of wind generation planned to connect to the system over the next 5 years. The level of cost impact on our residual balancing activity that will result from this growth is uncertain and will depend on the level to which market participants are able to manage their own positions.

This note provides details of the impact of the increase in wind generation on the system operating costs for 2008/09 associated with Reserve and Dynamic Frequency Response, comparing this to the current costs and predicted costs in future years.

Summary

Our central forecast cost increase for the forecast extra wind generation for 2008/09 is £10m. This consists of the following breakdown:

- An increase in the volume of reserve required at 4-hour ahead £8m
- Increase in the volume of dynamic response £1m
- Increase in Fast Reserve costs of £1m
- We assume participants will manage all variations in output beyond the four hour stage, therefore we forecast no immediate increase in reserve beyond the 4-hour ahead timeframe.
- Increase in Downward Regulation costs £70k

Analysis of Intermittency of Wind

There are significant daily and seasonal factors that affect wind load factor. Figures 1 & 2 below show the mean load factor and Standard deviation for the wind generation that we currently meters. Wind generation outages are included in the data. Numbers quoted are percentage of installed capacity.

Figure 1: Mean Load Factor of GB wind

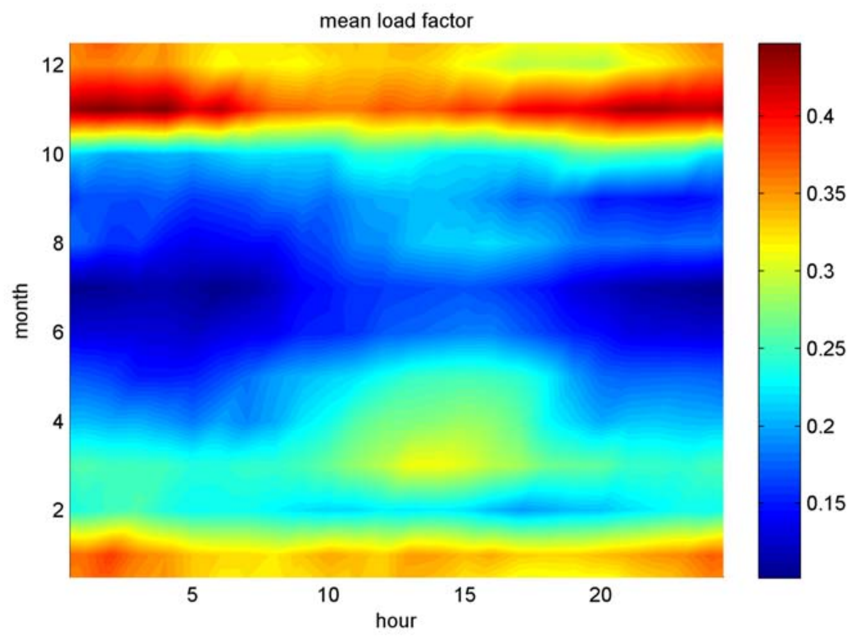
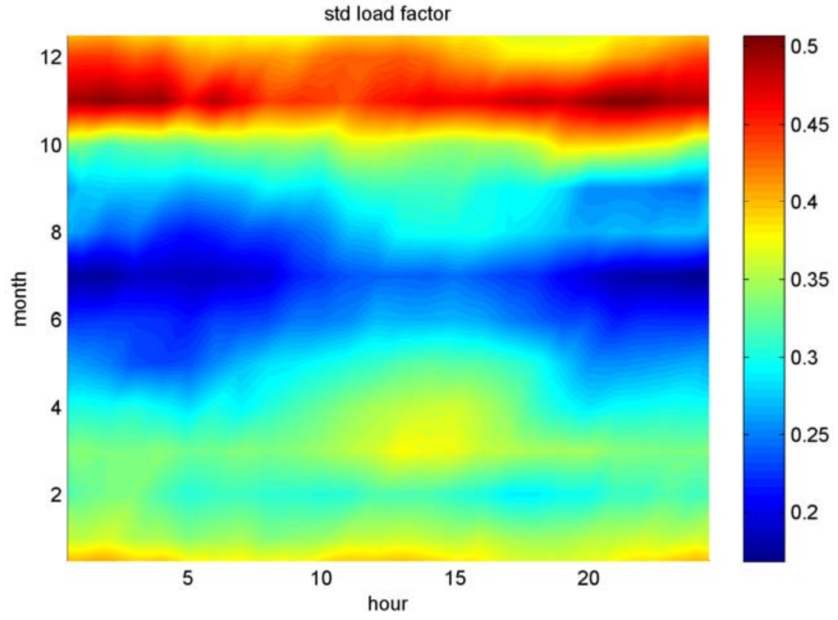


Figure 2: Standard Deviation of GB wind



Main points from Figures 1 & 2 are:

Across the winter

- Average load factor is around 35% (November to March inclusive)
- Wind load factors are higher than during the summer due to more wind and less outages.
- Off-peak load factors can be higher than across the peak of the day

Across the summer

- Average load factor is around 19%
- Average load factors drop to around 15% overnight
- Outages are mainly taken in the Summer and hence effect the load factor calculation

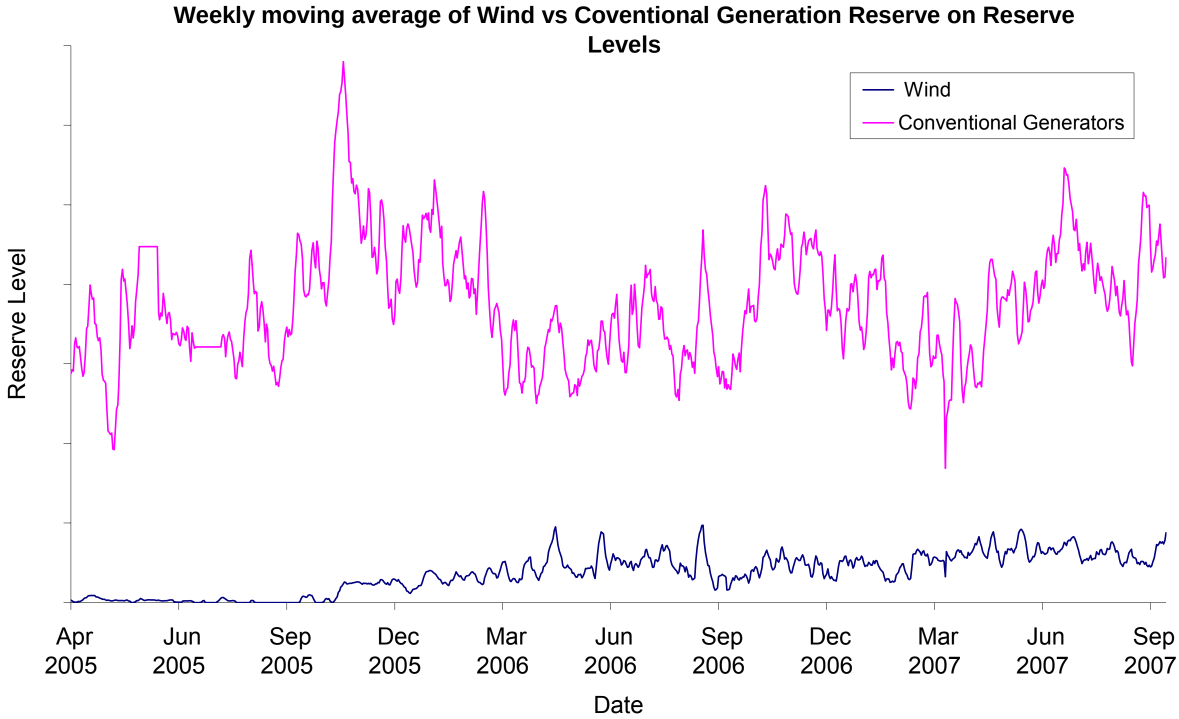
Impact on Reserve Requirements

Our Reserve requirements are set such that the loss of load expectation is set to 1 in 365, or one event per year. Our reserve requirements are calculated using the historic level of demand forecast error and generation plant reliability, which approximate to a normal distribution.

We have analysed the impact of wind on reserve. Figure 3 below shows the effect of wind in relation to overall reserve levels by plotting a weekly moving average of Wind Error and Conventional Generation Error on overall Short Term Reserve Levels.

It is possible calculate the extra cost of wind on Reserve by calculating Short Term Operating Reserve Levels with and without wind, subtracting one from the other to get the net effect.

Figure 3 The growing effect of wind on Short Term Operating Reserve



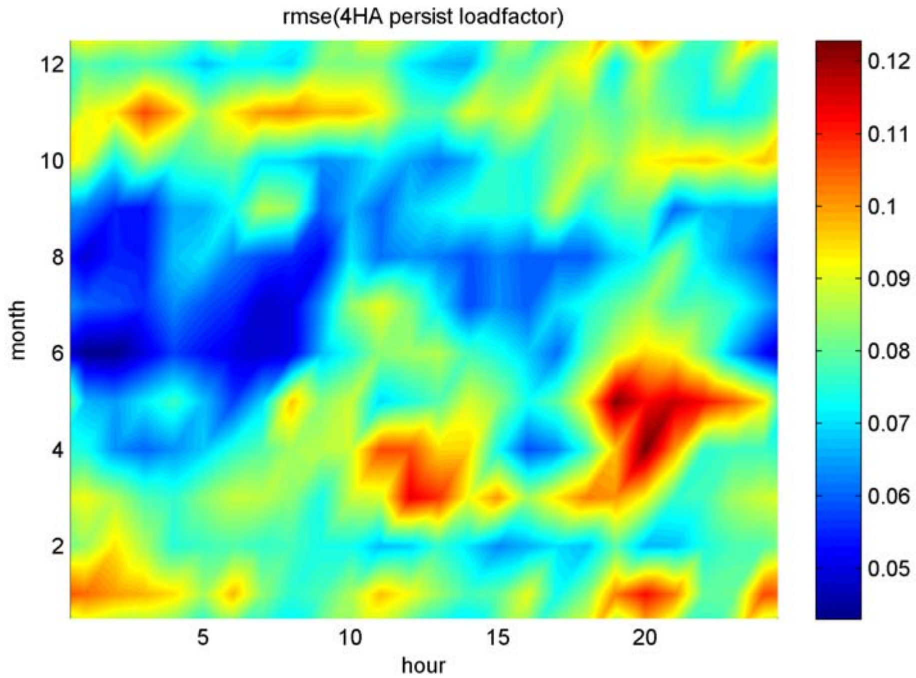
There are a number of points that can be derived from the above graph:

- The influence of conventional Generators (e.g. gas, coal etc) on reserve levels is remaining stable when averaged over annual timescales.
- Wind has only recently become material in terms of its impact on reserve levels and is generally increasing over time.
- As more and more wind connects we expect this rising trend to continue.
- For the start of 2007/08 GMT, we introduced a variable 4-hour ahead reserve level dependent on forecast wind. This has the effect of increasing the 4-hour reserve level dependent on forecast wind output.

Considering the potential increase in reserve requirements and the cost of reserve procurement, we forecast a range of costs from £5.6m to £9.6m in 2008/09. This leads to a central assumption of around a £8m increase on 2007/8.

Frequency Response and Fast Reserve Costs
The RMSE error is not constant across the year and the picture below shows where the greatest errors reside using a persistence based modelling technique.

Figure 4: RMSE of GB wind



The above has implications on costs:

- The greatest errors occur around sunrise / sunset across the spring / summer. These errors correspond to where the Reserve Requirement, Fast Reserve Requirement and Dynamic Response Requirement are at their highest.

Additional Response costs forecast

At this stage and level of wind generation we do not think that dynamic response levels will have to increase at all times of the day. However there may be a number of days across the year where the variability of wind, under high wind output conditions, results in frequency control becoming more difficult to control. When these conditions arise we increase the level of dynamic frequency response held to assist in managing the frequency variation to within limits.

Our forecast assumes that we require additional response on high wind output days, approximately 12 days across the year, (i.e. one day a month) for 8 hours per day with an additional 100MW of response. This results in a total cost for additional response of approximately £1m.

Fast Reserve costs

With increasing wind the variability of generation will lead to other forms of reserve being required to cover shortfalls. Fast Reserve provides the bridge between noticing that there is a mismatch and calling on other forms of longer notice reserve e.g. STOR.

Our forecast assumes that we require additional response on high wind output days, approximately 20 days across the year. This results in a total cost for additional response of approximately £1m.

Downward Regulation costs

As a result of ROC incentives to maximise output, wind-powered generation is expected to submit unattractive negative Bid prices. Therefore during the summer low demand periods, wind generation output will increase the costs of maintaining our downward reserve requirement either directly through pricing or more likely indirectly through the displacement of alternative generation with more attractive bid prices.

Figure 1 shows that overnight during the summer, the average load factor of wind generation is around 15%. Therefore with an additional 500MW of wind capacity for 2008/9 will on average result in an additional 75MWs of inflexible generation.

The downward regulation cost estimate is £70k. This low figure confirms our view that levels of wind generation are not significant enough to impact on downward regulation requirements. However, it should be noted that this issue may become more prevalent in future years as the level of wind output rises and will be kept under review.