nationalgrid

Electricity System Operator Incentives

1. Overview

This appendix has been prepared following a request from Ofgem for NGET to provide information on incentives to support Ofgem's review of the System Operator role and incentives. This appendix is primarily focussed on the likely future trends in the Electricity Market relevant to the costs and role of the system operator.

We identify the growth of renewables and the affect these will have on system operation and management of system access as the key factors for consideration. In addition, we identify the main cost areas of operation: procurement of Reserve and Frequency Response services, and the management of constraints. At present we expect these to continue to be major SO cost areas going forward and are therefore pertinent when considering future incentive arrangements that aim to manage these cost risks.

2. Contents

3. Principles of incentivisation

NGET is incentivised to reduce the internal and external costs of its Transmission Owner and System Operator activities.

The principle of incentivisation of the SO aligns our financial incentives with our licence obligations to operate the system in an efficient, economic and co-ordinated manner, to the benefit of consumers who, through reduced Balancing and Use-of-System Charges (BSUoS), share the benefit of cost reductions.

Incentivisation of the SO also aims to balance the incentives on TO and SO. This balance is important in ensuring that any additional costs caused by TO activities, such as transmission system outages are assessed against the alternative TO cost, such as cancelling or accelerating an outage. Likewise, any additional costs placed on the TO to reduce the constraint costs of the SO can notionally be recovered through out-performance against the SO cost target.

4. History

Financial incentives on the SO activity were first introduced in 1994, following agreement between National Grid and the Suppliers under the then Pool. By 1997, the incentive arrangements had been refined and these early incentives were broken down by categories as follows:

1. Energy Uplift (the costs of energy balancing under the pool);
2. Transmission Losses (based upon a target volume of losses at a fixed price);
3. Transmission Services Uplift (covering the costs of securing the system including procuring Reserve, Frequency Response and system constraints);
4. Reactive Power Uplift (the costs of Reactive power).

The aim of the schemes was in each case to encourage National Grid to efficiently minimise 'Uplift' I.e. the additional uplift in costs compared to the 'unconstrained schedule'. The schemes for Energy Uplift and Transmission Losses were agreed with Suppliers under the pool. Those for Transmission Services Uplift and Reactive Power Uplift were agreed with Ofgem.[1]

The introduction of the New Electricity Trading Arrangements (NETA) changed the structure of the market and, with it, the role of NGET. NETA changed the way in which electricity was traded. Rather than the 'pool' system, one of the principles of NETA was that those wishing to buy or sell electricity should be able to enter freely into negotiated contracts to do so.

The expectation was that electricity would be traded through bilaterally negotiated contracts and power exchanges. With the majority of electricity being traded between participants, National Grid's role became that of residual balancer, responsible for real time balancing of the system to ensure standards for the security and quality of supply[2].

For the introduction of NETA, National Grid's System Operator Incentives were changed to reflect this new role and merged into a single scheme as this would allow National Grid 'to take appropriate balancing actions across all of its incentives'[3].

This single scheme structure has prevailed in this form to the current time, although Ofgem and National Grid failed to agree a scheme target for the year 2006/07.

For the incentive year 2005/6 the principles of the incentive scheme remained substantially unchanged. The target was increased to reflect known cost drivers and National Grid's extended role as Great Britain System Operator (GBSO) under the British Electricity Transmission and Trading Arrangements (BETTA). The main changes to the incentive scheme for BETTA were:

i. The conversion of the Transmission Losses adjustment from a Gross figure within the Scheme total to a Net figure, and;

[1] See, for example, 'Initial proposals for NGC's System Operator Incentive Scheme under NETA: A consultation Document and Proposed Licence Modifications' Ofgem, August 200.
[2] Ibid. Page 10, 1.10
[3] Ibid. Page 12, 1.17

ii. The introduction of Outage Management payments within the Internal SO cost to allow National Grid to refund the Scottish TOs for the costs of SO-initiated within-year changes to their transmission outage programmes.

The most marked effect of BETTA on SO incentives was the sharp increase in costs caused by the high level of constraint costs seen in Scotland when compared to the contemporaneous cost level in England and Wales. Prior to BETTA constraint costs within Scotland had been internalised within the Scottish companies, Scottish Power and Scottish Hydro Electric.

There have also been numerous changes to the Commercial framework and the wider electricity market over the period since NETA Go-live which have had a marked affect on the System Operation costs. In particular, we have seen:

- Reduction from 3½-hour to 1-hour Gate Closure in July 2002;
- Changes to Ancillary Services procurement, such as the introduction of Fast Reserve tenders from October 2001, and most notably CAP045 for Reactive Power and CAP047 for Frequency Response;
- Changes to the Imbalance price calculation, P78 and P201/P205 amongst many others;
- A gradual decline in the market length and levels of headroom within submitted Generator Physical Notifications, as seen since NETA Go-Live in 2001;
- An initial marked decline in Power prices to 2003, which then reversed as the Gas market tightened, and movements in plant margin that broadly mirrored this trend (though did not necessarily drive it);
- Changes in generation fuel costs which have seen the marginal fuel move from Coal to Gas and back to Coal again;
- The implementation of BETTA and the subsequent inclusion of Scottish constraints.

5. Current status

SO Incentive target and parameters have again been agreed between Ofgem and National Grid for the year 2007/08. This follows a year without a financial incentive on external Electricity System Operator costs for 2006/07 when Ofgem and National Grid failed to agree on an appropriate target.

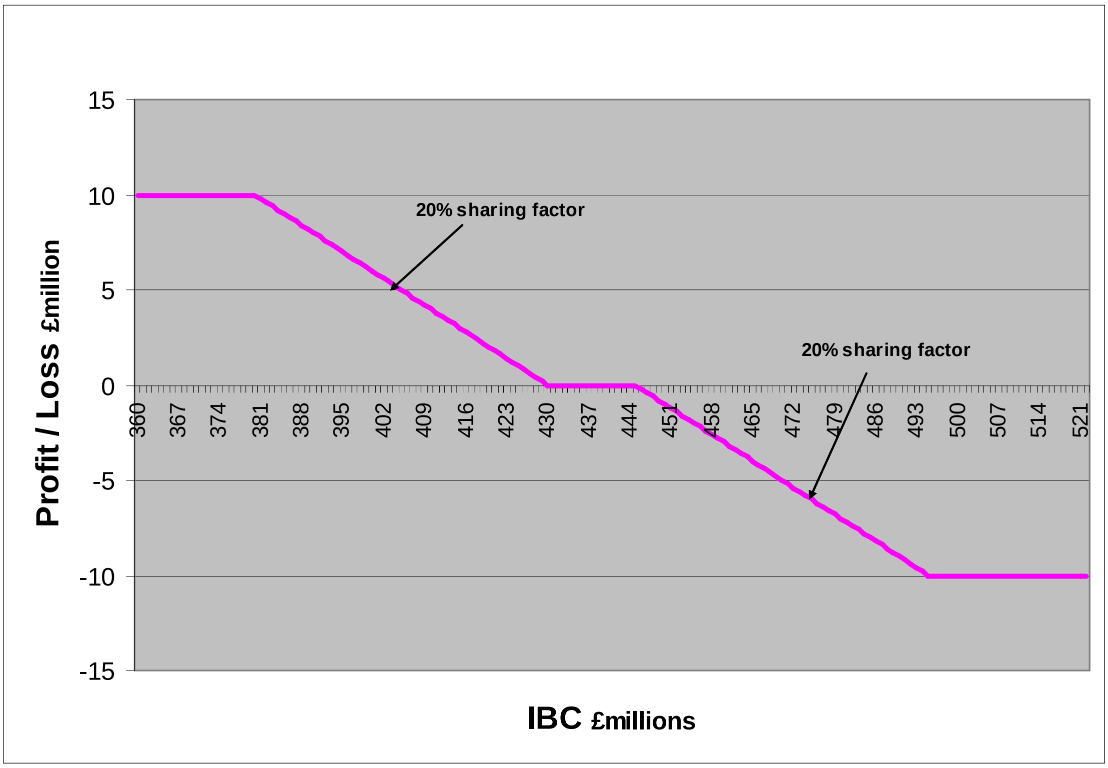
Failure to agree targets for 2006/07 came at a time of significant changes in the underlying costs of system operation[4] resulting from changes in costs due to:

- The introduction of CAP047, leading to a sharp increase in the costs of Frequency Response procurement;
- The high level of Scottish constraint costs, and;
- Increases in gas prices, resulting in rises in electricity prices and the cost of some balancing services.

[4] More detail on these changes and their effect can be found in material presented at a National Grid seminar on BSUoS costs on 10th January 2007. The slides can be found on the Operational Forum section of our industry website, here: http://www.nationalgrid.com/NR/rdonlyres/9065C6F7-BDEE-419E-8033-9D4BDE01442F/14305/BSIS_Seminar10_1_07.pdf

Against the targets proposed by Ofgem for 2006/07 National Grid would have made a £10 million or £40 million loss depending on the scheme option selected.

For 2007/08, Ofgem and National Grid have agreed a target of £430m to £445m for Incentivised Balancing Costs. For outturn costs above or below this, National Grid will share 20% of the gain or loss, subject to a cap of £10m.



Looking Forward
Looking forward, a number of factors that are likely to affect the role and costs of the SO are already apparent. The following sections set out each factor and its possible impact on the operation of the system, the aim being to identify and initiate discussion on areas which may need to be considered further as part of this review.

The next three sections cover areas relevant to the future of System Operation as follows:

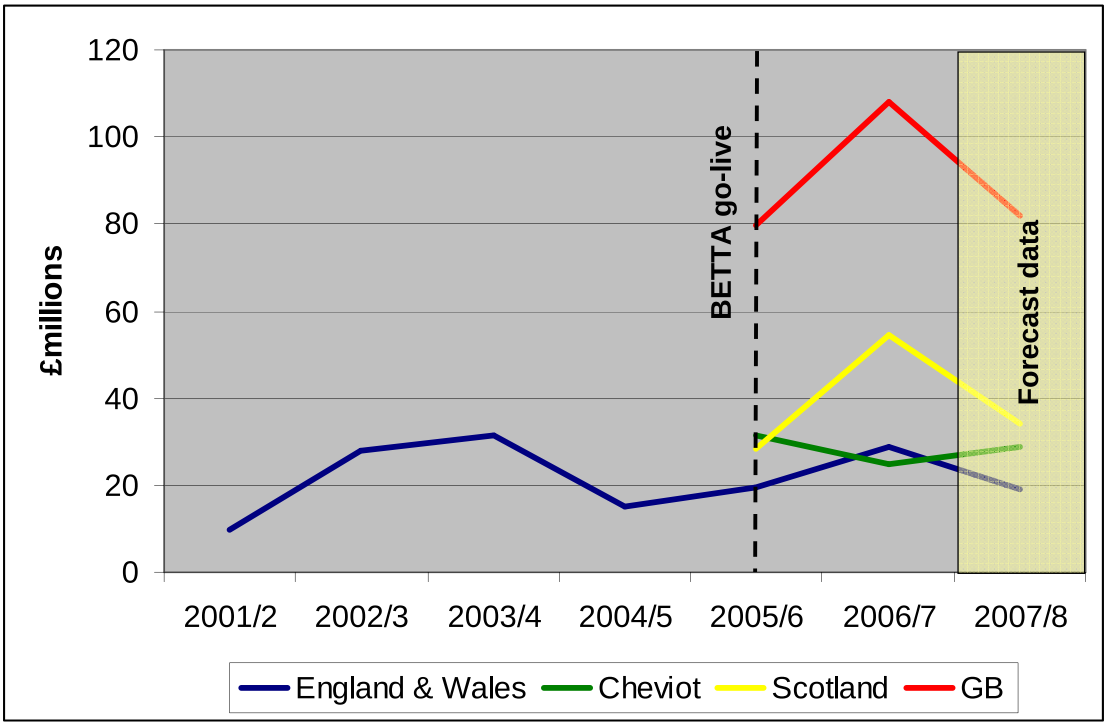
1. Current high cost areas
2. Upcoming challenges
3. Interacting Industry change

6. Current high cost areas

The top three areas for current costs are: Transmission constraints, Frequency response and Reserve procurement. Together these three activities make up over 60% of the initial 2007/08 incentivised cost forecast, over £300m compared to a forecast of £440m. In addition, costs for all three have been rising over recent years. As such, they are an obvious focus for the SO Review.

6.1. Transmission Constraints

The cost of constraints since 2001/02 is shown in the graph below:



Constraint costs for the GB transmission system were £108 million in 2006/7 and are forecast to be £82 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 Scotland to England Boundary: £80 million in 2006/7, and forecast to be around £63 million for 2007/8.

Looking forward, a number of factors will affect system constraints in areas of GB:

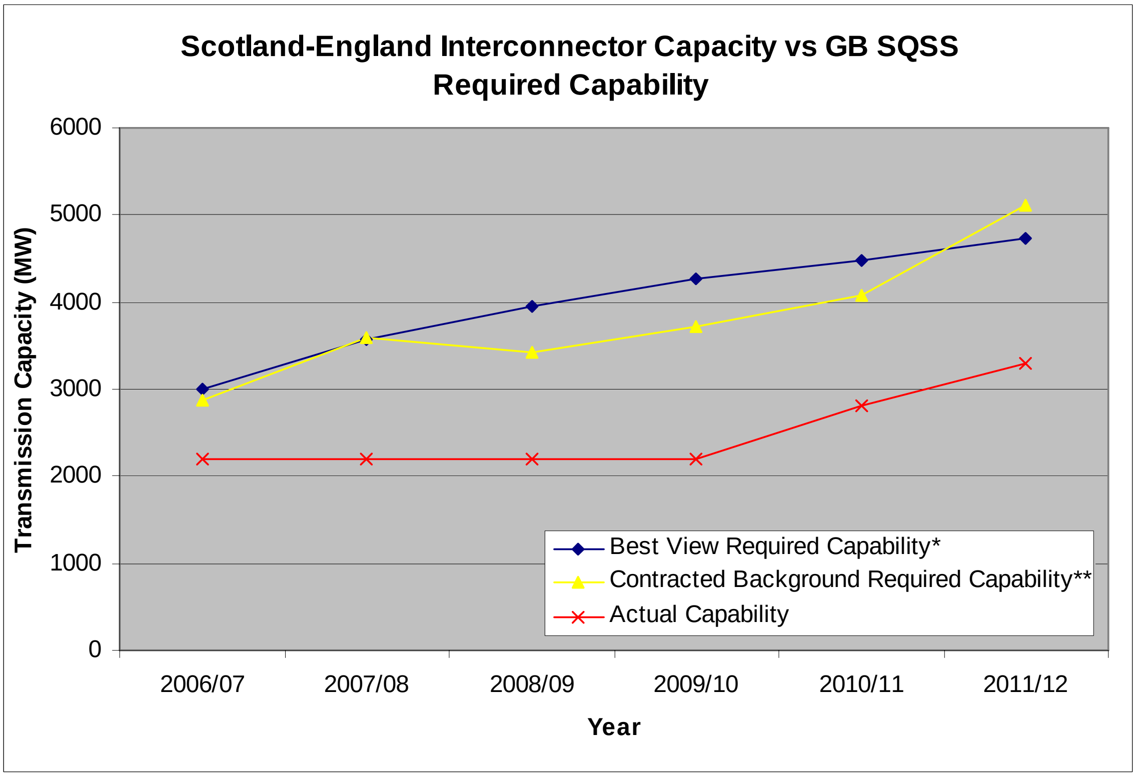
Impact of increasing Transmission Owner capital investment plan, 2007 – 2012: With the agreed increase in capital spend over the next five years and the construction work associated with the connection of a large volume of renewable generation in Scotland (TIRG), there is increasing pressure on the System Operator to allow system outages to facilitate the TO work that delivers this capital investment. This increase in the volume of investment, and thereby system outages, reduces system capacity and thereby increases the risk of constraints. Moreover, a more closely packed outage plan reduces the ability of the SO to manage constraint costs down through changes to the outage plan because there is less ‘space’ or flexibility in the programme of system outages. In addition, the increase in construction work is resulting in greater exposure to constraint cost risk for the SO, in particular as a result of the progressive elongation of the outage ‘window’ (traditionally the ‘summer time’ months (BST), when demand is lower) into the higher demand months i.e. extending into and beyond the clock change months.

Scotland-England interconnector capacity deficit

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. The system developments are programmed to be completed during the current price control period, i.e. prior to 2012. Whilst these developments will increase the capacity of the flow boundary the excess level of generation capacity connected in Scotland above expected demand levels will also grow at a similar or greater rate. This means that, if generation growth in Scotland is in line with expectations then the capacity deficit on this boundary will also increase. This is likely to result in increased constraints however the level of future constraint costs will depend on the output of generation in Scotland and the transmission outage programme.

The following graph shows the required capability of the Scotland-England boundary based on the Contracted and a ‘Best View’[5] generation backgrounds plotted against the boundary capability following sanctioned network reinforcements.

[5] 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.



The graph shows a significant increased in capacity between 2009/10 and 2011/12, when the works to increase the boundary capacity start to come on line. The graph also shows that the 'required level' of capacity, I.e. the level of transmission capacity National Grid believes is required to efficiently minimise constraints on the boundary grows at a faster rate over the six years 2006/07 to 2011/2012. The deficit in actual capacity against our best view of required capacity increases from 800MW to a maximum deficit of 2GW in 2009/10 before falling back to 1.2GW, still above the 2006/07 level, in 2012. Against an 800MW deficit in 2006/07, constraint costs on the Cheviot boundary were £25m.

As can be seen above, there is considerable construction work occurring over the next four to five years. The benefits in capacity increases resulting from the construction work are visible in the above graph. However, the growth in generation capacity is expected to outpace the growth in interconnector capacity. In addition, there will be increased constraint risk during the construction work where capacity will be reduced during the construction outages.

Market interaction with Europe

Whilst the level of constraint costs in England and Wales have been maintained at historically low levels, there remain a number of constraint risk areas within the England and Wales transmission system. One significant risk areas historically and looking forward is constraint in South East England that are mainly driven by flows n the French interconnector. This constraint risk is largely driven by the interaction of the GB and European markets, which, through interconnector trading, directly affects the transfers between England and France. Large swings in flows on the interconnector can significantly increase constraint costs for outages in England and Wales and uncertainty of the GB/continental spread adds significant risk when making assumptions during the transmission outage planning phase. Recent operational experience has seen large changes in flows across the interconnector over a relatively short timescale and these have led to increased constraint costs being incurred in operational timescales.

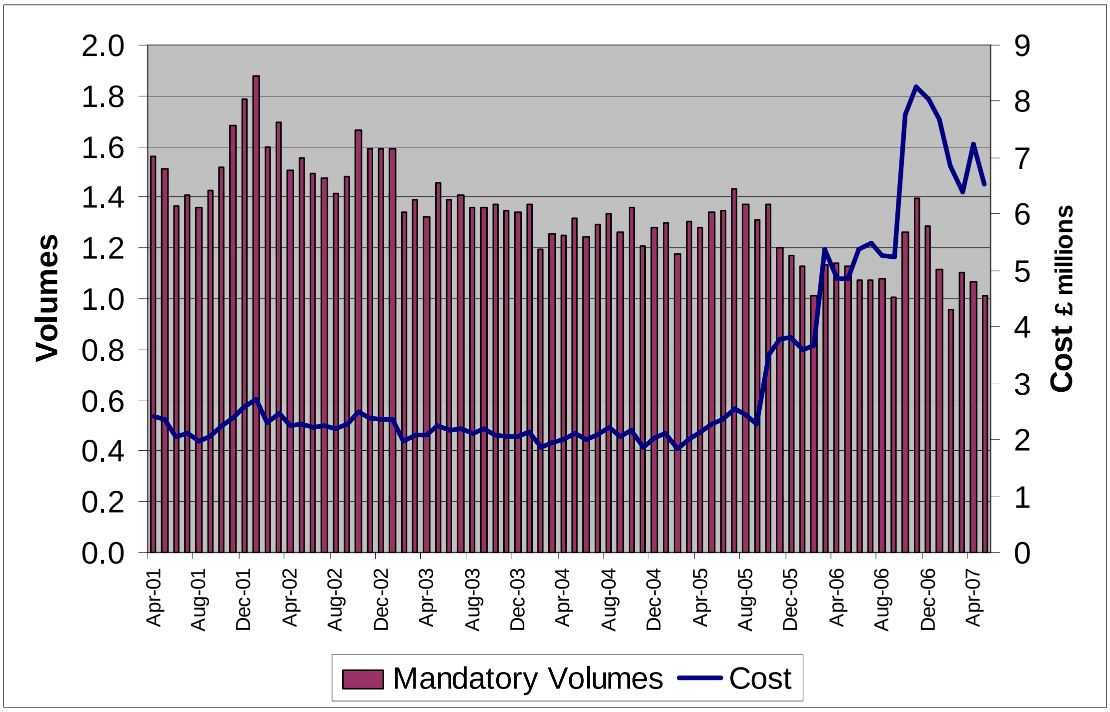
Scottish TO outage change costs
National Grid has developed a number of tools for constraint risk management and cost reduction. Since the introduction of incentivisation in 1994 we have seen a significant reduction in constraint costs within England and Wales, partly driven by the development of these tools. Over time we would expect to see incentives help to drive a similar reduction in constraint costs within Scotland and on the Scottish Boundary. National Grid is already working with the Scottish TOs to examine additional mechanisms that may increase the capacity and flexibility of the network, thereby helping to manage constraint costs.

At present National Grid is able to pay the Scottish TOs for the additional costs they incur to manage outages through Outage management payments. We anticipate that a number of new tools under consideration may also be able to be paid for through this mechanism and any expect development of these tools to be progressed through changes to the SO-TO Code. However, the use of these payments is limited to within-year changes to the outage plan. As such, there is currently no broader financial compensation or incentive framework on the Scottish TOs to fund actions or investment to minimise constraint costs throughout the system investment and planning timeline.

England and Wales TO outage change costs
At present, there is no compensation mechanism for the additional costs incurred by NGET as TO in England and Wales for actions requested by NGET as GBSO. Over the course of a year, these costs can be considerable. Implicitly, the potential benefit to NGET of incurring additional TO costs is the result in a potential increased profit from the SO incentive scheme. I.e. Additional NGET TO costs should be funded through the expected increase in return from the SO incentive. However, we are concerned that under recent incentive arrangements, the SO incentive scheme profit is or has been insufficient to compensate for additional TO costs and risks.

6.2. Frequency Response Services

The monthly cost of frequency response procurement since 2001 is shown in the graph below.

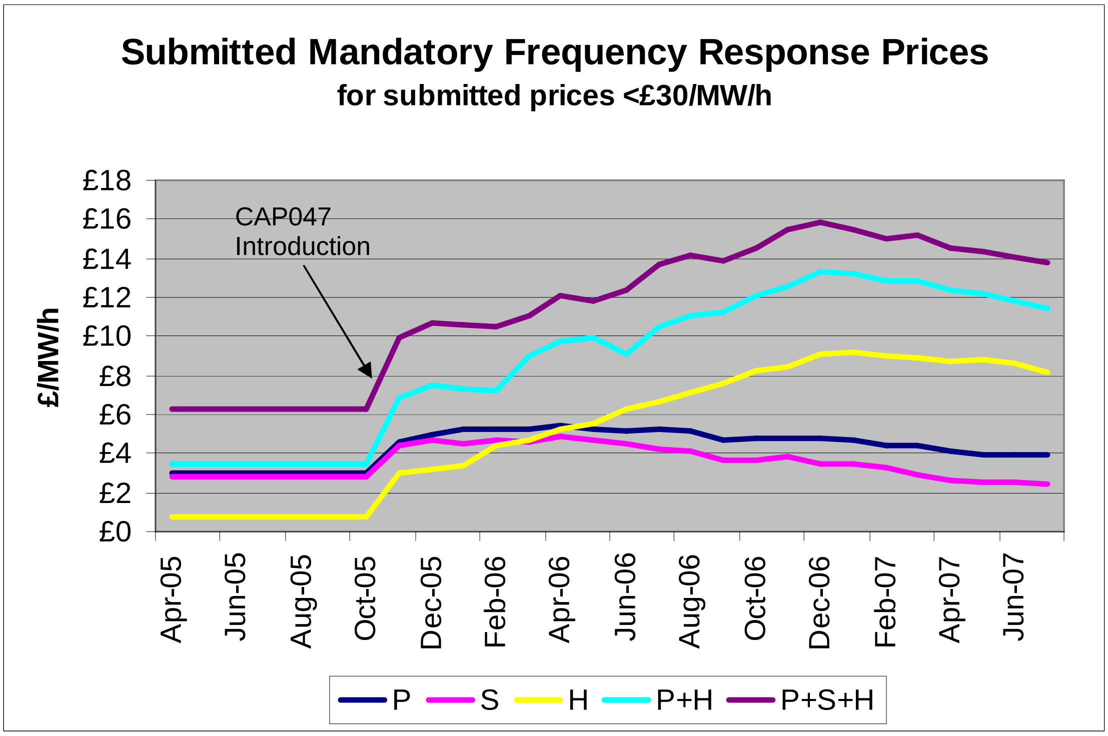


Since the removal of cost-reflective pricing for mandatory frequency response as a result of the changes introduced by CAP047 in November 2005, the average price paid for mandatory response have more than tripled, driven by similar increases in the prices submitted by generators. The costs of frequency response procurement have increased markedly, nearly doubling over the same timeframe. The cost of mandatory response procurement has increased from £38m on 2004/05 to £70m in 2006/07.

Price Drivers
In addition to mandatory response, National Grid also procures frequency response through bilateral contracts and via the Firm Frequency Response tender. However the majority of response is still procured through the mandatory service.

Mandatory response prices appear to have reached a plateau in the first half of 2007. However, given the paradigm shift in prices and costs since November 2005, there are a number of uncertainties with the current arrangements:

- What are the underlying drivers of prices for frequency response that might affect prices going forward?
- What is the potential for new entrants and increased competition in the provision of frequency response?

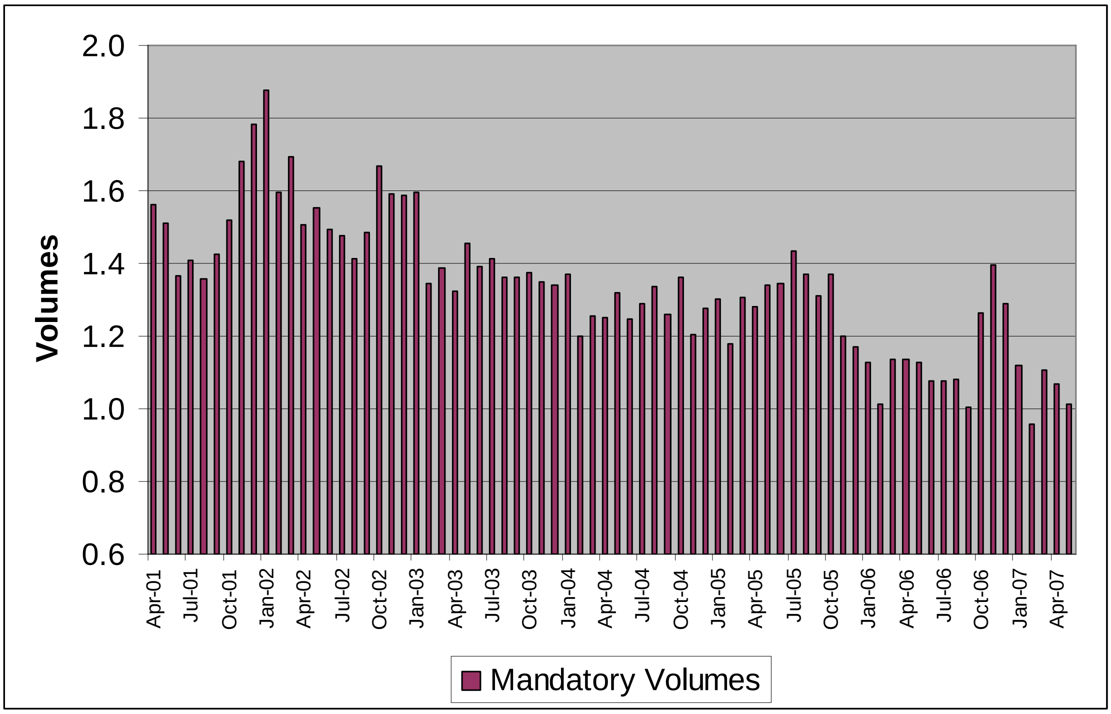


Volume Drivers
The volume of frequency response procured by National Grid is mainly driven by system demand levels and the largest power infeed loss that needs to be secured in line with the SQSS. Historic volumes procured since 2001 are shown in the graph below

There are a number of factors that directly or indirectly affect the volume of reserve required. Increased levels of intermittent wind generation are likely to affect dynamic frequency and cause an increase in the level of dynamic response required to maintain steady state frequency performance due to the variability of the generation output.

With the current system conditions, National Grid does not expect any other significant changes in the volumes of response procured. However, over the next 5 years the following factors would change our response volume requirements:

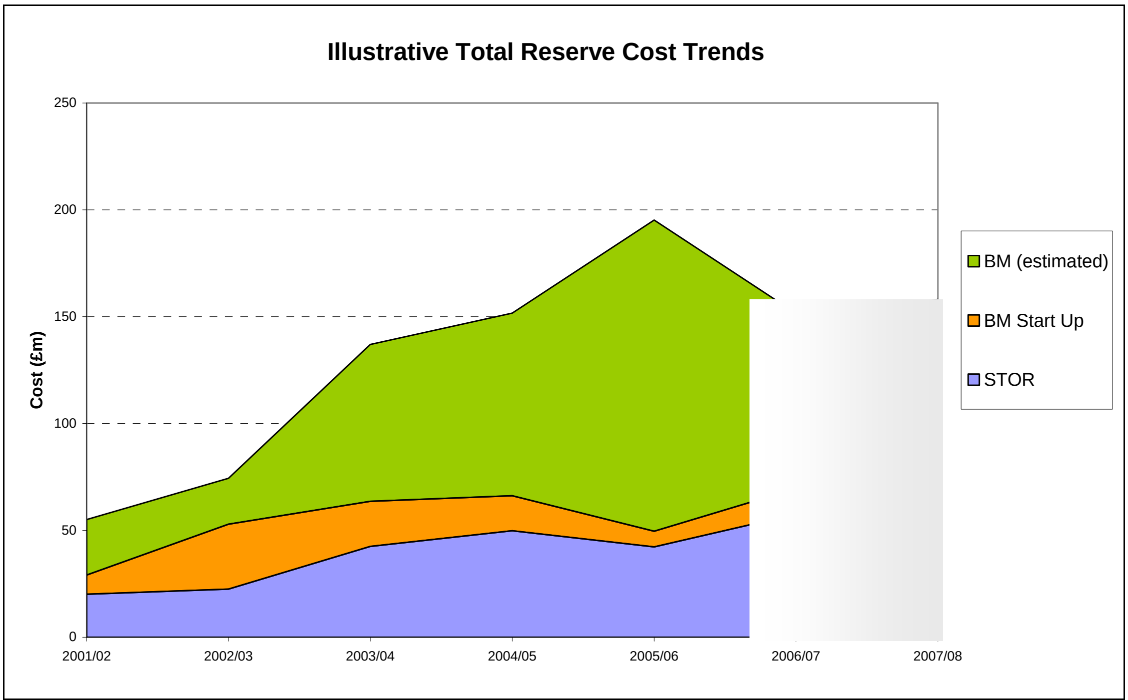
- A change (increase) in the Maximum loss of generation infeed to the system for a securable fault. This is currently set in the SQSS at 1320MW. We do not currently expect this figure to change in the next few years, up to 2011.
- A change to the typical maximum largest demand loss on the system. Again, this is set in the SQSS and we do not expect it to change (increase) in the next few years.
- Increased levels of constraints, as described above, may lead to some additional response procurement if maximum losses are present for a greater period of time, however we expect this effect to be negligible.



The balancing services standing group, which sits under the CUSC, are currently considering if there are any changes that can be made to the mandatory procurement mechanism to improve the efficiency of the market.

6.3. *Procurement of Reserve services*

The costs of Reserve procurement since 2001/02 are shown in the graph below[6].



Since 2001/02 there has been a steady and significant increase in the cost of procuring reserve[7]. This increase has been driven by market trends in a number of areas including:

Volume drivers:

- A reduction (shortening) in average net imbalance volume, NIV, over the peak demand periods for which Reserve is procured.
- A reduction in "free" headroom over peak demand periods.

Price drivers:

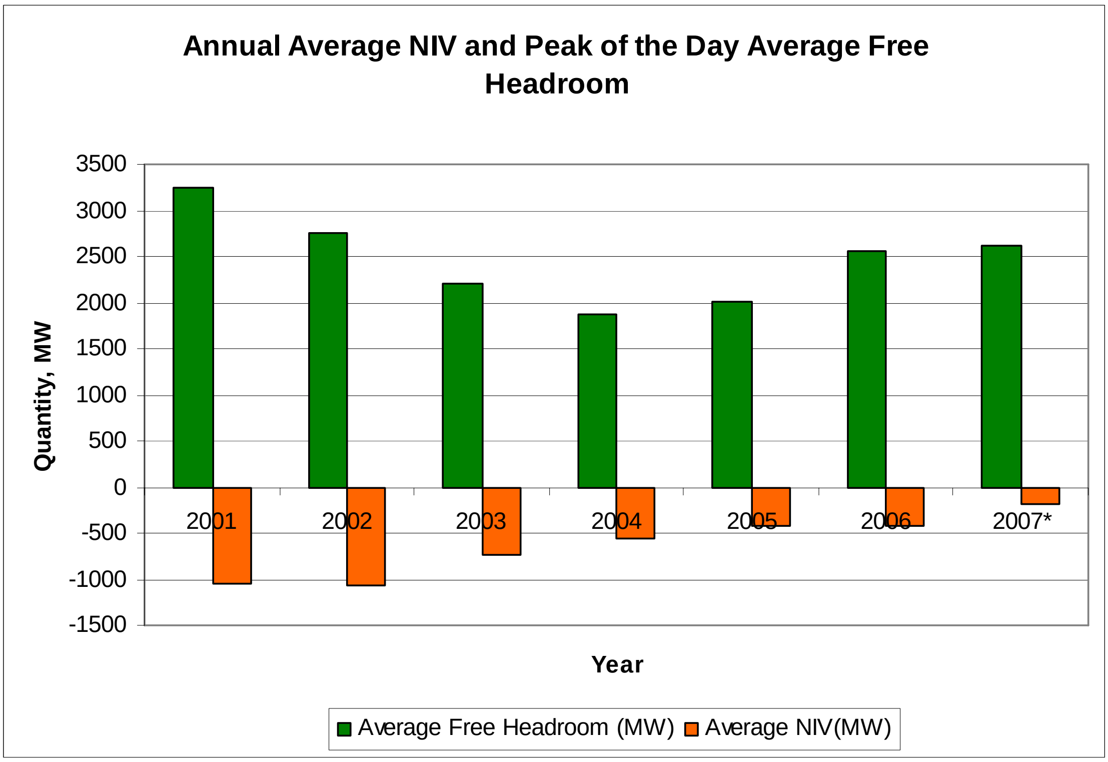
- General increase in wholesale energy prices and generation fuel costs
- A changing plant mix among reserve providers
- Prices offered by reserve providers

[6] These costs are identified as illustrative because the costs of reserve procurement within the Balancing Mechanism can only be estimated. This is an 'estimate' because the identification of certain BM costs as specifically reserve costs is an approximation due to the fact that many BM actions are taken for more than one reason. In addition, these BM Offer costs have been corrected to reflect the fact that there are balancing Bid costs which reduce the total cost of the action to National Grid.

[7] The above-trend rise in 2005/06 is related to the market conditions and associated higher power prices seen in that winter. 2007/08 is forecast data.

When viewed in the context of market trends it would seem that, generally, the increase in reserve costs can be seen as a transfer of costs from the market onto National Grid. I.e. as the market has reduced market length (become less long) and free headroom has declined (synchronised plant is more fully utilised by the market), some of the costs of holding additional reserves have been transferred onto National Grid. As the volume of reserve procured by National Grid has increased, so have the average prices paid.

The following chart shows the trend in average Net Imbalance Volume and 'free' headroom over the peak since 2001/02. It can be seen that NIV has continued to decline whilst the trend in declining free headroom reversed in 2005, in line with the introduction of BETTA.



In response to the increasing costs of reserve procurement, driven by both volume and price, NGET carried out a Review of Reserve in consultation with the industry. As a result of the Reserve Review initiative, two developments have been introduce, these are: BM Start-Up and; STOR (Short Term Operating Reserve)[8]. They offer a number of benefits over the previous arrangements. These include

- Reduced Complexity
- Closer alignment of product with our current dispatch requirements
- Expected Increase in Participation, attraction of new providers
- Improved Information Provision

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[8] BM Start-Up was introduced in November 2006 and replaced the Warming service. The new STOR service replaces Standing Reserve and supplemental Standing Reserve and went live on 1st April 2007 following the first tender round held in late 2006 and early 2007.

Looking forward, it is likely that the market trends that have historically led to an increase in reserve procurement are likely to remain and that reserve costs will remain a significant proportion of balancing costs. In addition, the increase in intermittent generation is likely to lead to increase holding of reserve by National Grid. This issue is discussed in more detail below.

7. Upcoming challenges

7.1. Growth in Wind Power and other Intermittent Generation

The volume of wind power and other intermittent generation sources is expected to grow over the coming years. The table below shows our projected growth of wind power up to 2011 and beyond[9].

Wind Generation Capacity (MW)

		2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
SYS Tx Connected	*E & W*	*140*	*140*	*640*	*939*	*2,389*	*2,389*
	Scotland	*921*	*1,597*	*2,473*	*4,406*	*5,689*	*6,262*
	Total	*1,061*	*1,737*	*3,113*	*5,345*	*8,078*	*8,651*
Best View Transmission Connected	E & W	0	0	0	0	200	1,090
	Scotland	944	1,282	2,185	3,757	4,880	5,591
	Total	944	1,282	2,185	3,757	5,080	6,681
Best View Distribution Connected	E & W	945	992	1,042	1,094	1,149	1,306
	Scotland	234	255	293	308	323	340
	Total	1,179	1,247	1,335	1,402	1,472	1,645
Total 'Best View' wind capacity		2,123	2,529	3,520	5,159	6,552	8,326

Wind is likely to run in preference to other forms of generation when available. In forecasting the effect of increasing wind output on system operation, we can look to a number of sources:

1. Our experience of current (lower) levels of wind currently generating in Great Britain.
2. Forecasts of future wind output based on know inputs such as weather variance and distribution of wind generation across GB.
3. The experience of other systems across Europe and around the world.

[9] The table presents a comparison of the contracted level of Transmission-connected wind generation, as quoted in the Seven Year Statement, SYS, and our 'Best View' of Transmission connected wind generation. Our best view adjusts SYS data based on the latest construction information and expected or known delays. For Distribution connected generation our best view is based on data form the DTI and the British Wind Energy Association, BWEA. We anticipate that wind generation will make a significant contribution to growth in overall quantity of renewable electricity delivered over this period. Based upon our view of capacity renewable sources will account for around 8% of power supplied in 2010/11, this is equivalent to DTI forecasts in their 'as is' view of Renewable Obligation development.

Generally, it is expected that increased wind output and its intermittency will place greater burdens on both market participants and the SO to balance the system. How this burden falls between the SO and the market will depend on the market's ability to forecast wind output and balance its own position and the incentives (efficient avoidance of imbalance charges) to do so.

Taking a broad summary of the published work in the field, and our own experience of operation of higher densities of wind generation, particularly in Scotland, it is likely that increases in wind power penetration will lead to increase volatility for forecasts of plant output at all lead times for both wind and thermal plant. Thermal plant will act as the swing producer, counteracting variations in wind output:

This increased unpredictability of plant output, and hence power flows will impact on most of the activities we undertake to balance the system, from voltage management and constraints through to energy balancing (demand/supply balance) and frequency management.

However, it is expected that the two areas that will suffer the greatest immediate impact are energy balancing (including the procurement of reserve and response) and constraint management. In addition we also expect that response holding and demand forecast accuracy may be affected by increased wind output. These four points are discussed in more detail below:

Energy Balancing and Reserve procurement
In operating the system in real time, National Grid procures reserve 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 National Grid reserve requirements.

It is expected that other generation plant (thermal and hydro) will vary its output to compensate for variations in wind output. The magnitude of any impact on NGET reserve requirements will depend on the ability of the market to compensate for variations in wind output through short-notice changes to the output of other plant. However, we do expect our reserve requirements to increase given the already observed levels of short-term fluctuations in wind output. We will be undertaking further analysis on the impact of wind on reserve requirements through this summer. Broadly speaking, we expect that, as with thermal plant, market participants will be more able to replace within-day shortfalls at longer timescales, greater than 6 hours ahead, but that this ability will reduce at lead times less than this.

Constraint Management
Increased variability of output will lead to greater uncertainty of power flows, which will impact on the management of constraints and constraint cost risk in the ahead of day in question and in real time.

At present it is possible for National Grid to assess generator related constraint risk by forecasting the likely output of an individual generator or group of generators based on:

i. Historic running behaviour;
ii. Known fuel costs;
iii. Notified generator outages, and;

iv. In a system with high wind generation penetration, likely wind generation output.

The first three variables tend to change only slowly with time and therefore it is possible to plan transmission system outages ahead of time to fit with forecast generator running and, if these drivers change an outages can often be re-planned at longer lead times and minimal cost, thereby minimising constraint risk and cost.

The result of more variability of plant output, driven by wind generation levels, adds an additional, much more volatile short term factor into the forecast of marginal plant running. I.e. any forecast would need to assess what the likely level of wind output would be and hence the likely running of thermal plant. At the longer lead times (day ahead, week ahead, month ahead and longer), forecasting likely wind output becomes increasingly uncertain and hence increases the uncertainty of plant running. This increase in uncertainty will not prevent system outages being planned but the increased uncertainty will result in additional costs to manage constraints. In addition, for longer duration outages, marginal plant is more likely to cycle in response to wind output, thereby increasing the risks that constraint costs will be incurred at some point during the outage.

Within-day, variability of power flows will also result in additional measures being taken to manage constraints. This is already the case in Scotland, which has a greater proportion of wind generation relative to network capacity. In particular, the variability of wind has caused two effects:

1. For import constraints, additional actions are taken to ensure that the system will remain secure following a fall in wind output.
2. For export constraints, an additional safety margin is put in place to reduce the flow across a constraint boundary to ensure that the actual flow does not exceed the constraint limit as a result of minute-to-minute changes in wind output.

Overall, the impact of increased variability due to wind in all timescales will be driven by the maximum swing in wind output that could be seen. Data from GB and other systems suggest that significant swings in total wind output (i.e. greater than 50% of installed capacity can be expected over a few hours).

As an example, in the Christmas week of 2004 E.ON Netz in Germany reported a major rise and fall of in power from their wind fleet of 85%[10].

The model used to predict wind generation in the UK, estimates that during the same period, the UK would have experienced the same percentage change in wind output.

[10] E.ON Netz report a fall of 85% over two days, between 24th December 2004 and 26th December 2004. See E.ON Netz Wind Report 2005, Germany, 2005 http://www.eon-netz.com/Ressources/downloads/EON_Netz_Windreport2005_eng.pdf .

Response Requirements
An increase the volume of wind and the subsequent intermittency of the output is likely to have an affect on the volumes of dynamic response required to maintain frequency response standards and to maintain steady state frequency performance.

To ensure frequency response standards are maintained during all credible instances, adequate dynamic response[11] is required to maintain response perturbations within operational limits. Increased volatility of demand and generation could increase the requirement for dynamic frequency response may increase to ensure that steady state, second by second, performance is maintained. Increasing the dynamic response requirement has an impact on cost as more response is held on dynamic generation rather than generally cheaper static (relay initiated) frequency response sources.

Similar issues regarding variability of generation output and dynamic response arose at NETA Go-Live, as generation moved from being central dispatched to self-dispatched. The increase in variability of output from each unit[12] resulted in a need to increase the minimum level of dynamic response from a typical level of 350MW pre-NETA to typically 550MW post-NETA. NGET has worked to reduce the minimum dynamic level back down whilst maintaining frequency performance and we now have a requirement that varies through the day.

Demand Forecasting
An increase in embedded wind generation will result in increased inaccuracies of demand forecast. Small embedded wind generators can connect onto the distribution system without notifying National Grid. An increase in small embedded wind connections may reduce our demand forecasting accuracy due to the unknown volume and location of the generation. This could affect the levels of reserve required to cover the unknown risk.

7.2. Developments within the Gas Market

GB gas and electricity market are now closely linked as a result of the high level of gas-fired electricity generation within the electricity market. We expect this coupling to be maintained and indeed grow stronger in the medium term as a result of large number of new generators connecting or planning to connect to the electricity system with gas as their primary fuel. NGET's seven year statement, based on contracted connections, sees an increase of 12.9GW of CCGT over current capacity by 2013/14.

One effect of the close linkage of gas and electricity markets is that electricity prices are often driven by underlying gas prices. In recent years gas market prices have been more volatile (compared to the historic levels of other major electricity generation fuels coal and nuclear). This has resulted in large variations in electricity wholesale prices, linked to gas prices and has also resulted in large swings in NGET's balancing costs.

[11] Response delivered within the normal operational range 50Hz +/- 0.2Hz.
[12] Under self-dispatch arrangements units change output in line with Physical Notifications (PNs), following their own contracted positions. Post-NETA this led to a greater number of units moving and changing load point on a regular basis. This increase volatility, or variability, of output across units led to an increase in dynamic response holding to help to 'smooth' the affect of these changes and maintain frequency control.

Going forward, it will be important to consider the future level of gas prices, and likely range of gas wholesale prices when considering the likely range of electricity wholesale prices and SO balancing costs.

7.3. Impact of the Large Combustion Plant Directive

NGET is working with the industry to understand the impacts on operation that will result from the Large Combustion plant Directive, which will come into force on 1 January 2008. The main impact on operation of large plants will be the limitation of the operating hours of each stack for all opted out plant, of which there are a number of older coal and oil fired stations in GB. Due to the limitation on operating hours on a stack basis, we understand that it is likely that operators will look to maximise plant use by operating multiple BM Units as a single block.

We do not anticipate that operation of two or more BMUs as a single block will affect our ability to operate the system. However it may affect our ability to access individual units for balancing and the price at which the units are made available to NGET, thereby leading to an increase in the cost of some balancing actions. The operation of a number of BMUs as a single block may also affect constraint costs as some 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.

We will continue to review the impact of LCPD in conjunction with the industry, under the Grid Code Review Panel.

7.4. Consumer Behaviour and Awareness

There are many social and political initiatives that are aimed at driving consumer behaviour. ‘Lights out London’ and many other initiatives have been initiated to highlight the changes peoples’ behaviour can have on the environment and these individual events directly affect our ability to operate the system securely and may result in additional balancing costs. Consumers are becoming much more aware of their carbon footprint, energy efficiency being a major factor with manufactures continuing to develop products that are more efficient.

These developments are expected to have an effect on electricity demand, although it is not possible to accurately forecast the magnitude of any impact. However, we anticipate that the scale of any change over the next few years, whilst impacting the wholesale market, will not significantly impact our balancing costs in the short term.

8. Interacting industry change

There are a number of areas of work running in parallel with Ofgem's SO Review, the results of which may interact with the work and conclusions of the SO Review. We have listed those we believe relevant below:

8.1. Developments to Transmission Access

As CUSC Amendments and under the CUSC Transmission Access Standing Group a number of proposals and issues are being discussed that are expected to result in changes to the transmission access framework. A number of these initiatives are focused on facilitating the connection of renewable generation prior to the completion of the required (to meet current security standards) transmission upgrades.

The implementation of the proposed initiatives will, in the main, allow the earlier connection of renewable generation. However, the effect of commissioning generation prior to the completion of the relevant infrastructure works will be to increase balancing costs as a result of the system constraint that will arise. In addition, some proposals see a greater role for the SO in managing short term access to the system in order to facilitate access for renewables. Therefore the developments to transmission access that do arise need to be included within the SO Review.

8.2. Cashout Programme

Since the introduction of NETA in 2001, there have been a number of modifications to cashout, the methodology to calculate imbalance prices. These modifications have had a number of effects on the market, on the operation of the system and balancing costs.

Any change to the cashout methodology has the potential to affect NGET's balancing activity. Therefore any changes to the cashout methodology will need to be assessed for potential effects on the NGET's balancing activity and balancing costs.

8.3. Delivery of Market Information

There are a number of ongoing Market information initiatives. In particular NGET has been working with participants to review the level of information provision and identify any gaps potential improvements. This work is ongoing and information is available on National Grid's website http://www.nationalgrid.com/uk/Electricity/Data/electricitymarketinfo/. At this time the conclusions of this work are not expected to suggest changes in the SO role or SO costs.

8.4. European Cross-Border Regional Initiatives

There are a number of potential impacts on SO activity, both from the operation of Interconnectors and delivery of information that arise out of ongoing work at a European level to bring European Electricity markets closer together. The GB system forms part of a region that also includes France and Ireland. When changes are agreed, NGET will look to feed these into the SO Review.