

Sonia Brown
Director, Wholesale Markets
Ofgem
9 Millbank
London
SW1P 3GE

Chris Bennett
Transmission Regulation
Manager

chris.bennett@uk.ngrid.com
Direct tel +44 (0)1926 65 5949
Direct fax +44 (0)1926 65 6520
Mobile +44 (0)7767 298985

www.nationalgrid.com

1st September 2006

Dear Sonia

Potential income adjusting events under NGET's 2005/06 system operator incentive scheme

We welcome the opportunity to respond to the above consultation in relation to our system operator incentive scheme for the first year of BETTA¹ 2005/06.

At the time the incentive arrangements were put in place by Ofgem, there was significant uncertainty as to the likely effect on Incentivised Balancing Costs (IBC) of Scottish constraints and the introduction of CAP047. As a result, Ofgem proposed and NGET agreed to specific allowances in these areas with the provision that any material deviation in outturn costs from the allowances would be subject to consideration under the IAE mechanism associated with the Balancing Services activity revenue restriction on external costs in NGET's Transmission Licence.

Following our submission of the original IAE notices to Ofgem on 30 June 2006, and in addition to the information contained therein, we have provided significant additional information to Ofgem in support of the claims.

In relation to the consultation document we have responded to the questions posed by Ofgem and have added additional comment on points raised by the document within these replies. These detailed replies are appended to this letter. In summary, our main comments are:

Efficiency of NGET actions

1. We do not agree with Ofgem's analysis suggesting that, based on the data available in April 2005, we could have forecast, with a high degree of certainty, that insufficient generation would run local to the NLOANSSE constraint.

¹ The commencement of the 2005/06 incentive scheme period coincided with the introduction of the British Electricity Transmission and Trading Arrangements, BETTA, on the 1st April 2005

Therefore we do not agree that it would have been appropriate to contract in advance for what we considered to be a low probability constraint. With the benefit of hindsight, Ofgem's consultation analysis focuses on the management of the NLOANSSE constraint. Our efficient and economic decision not to pursue a firm contract for this constraint must be considered in the wider context of the uncertainties associated with BETTA.

In April 2005, and throughout the year, the NLOANSSE constraint risk was one of many low probability constraint risks managed by NGET across the GB Transmission system. Many of these, particularly within Scotland, involved localised constraints relying on a single generator or single generating company. To have adopted a firm contract approach to the management of these low probability constraints would have resulted in NGET inefficiently incurring large constraint contract costs to manage the risk of a large number of constraints including NLOANSSE, the majority of which, in outturn, resulted in little or no cost due to their low probability of occurrence.

If Ofgem are to assess our efficient IAE costs on the basis that NGET should have, ahead of time, entered into a firm contract to manage the risk of NLOANSSE, then this calculation should also include the expected cost for a number of other firm contracts that would have been entered into had this approach been followed. Overall we would expect such a calculation, based on the use of firm contracts in cases such as NLOANSSE, to reveal a higher net constraint cost than that actually incurred by NGET.

With regard to CAP047, we support Ofgem's comments that the reduction in dynamic response volume reflects NGET's actions to efficiently and economically manage the risk presented by CAP047 related cost increases.

2. We do not agree that the presence of the cost allowance may have removed NGET's incentive to manage these costs efficiently. In reference to Ofgem's discussion of CAP107, we do not believe that the consideration of CAP107 is appropriate within the assessment of CAP047 costs. Even if NGET or another party had raised such a CUSC modification once CAP047 price rises became clear in November 2005, such a modification would not have been implemented before the end of the IAE period, March 2006.

Costing Methodologies

3. With regard to the costing methodologies used, we have provided additional analysis in reference to Ofgem's comments in relation to:
 - a. CAP047 – Ofgem's proposed alternative costing methodology. We suggest a third alternative methodology reflecting Ofgem's use of summer 2005 prices in the calculation of the alternative price at which response could have been procured had CAP047 not been introduced. This methodology adjusts the overall IAE level by £200k.
 - b. Internal Scotland constraints – the possible inclusion of Scottish Bids and Offers in the calculation of the energy reference price. This alternative approach would increase the calculated IAE cost by £2.5k.

Summary

Overall, we would reinforce that the underlying reason for the establishment of cost allowances and associated IAE mechanisms within our incentive scheme was the considerable uncertainty faced by NGET in managing these costs. In the context of this uncertainty, we consider that our evidence provided to Ofgem demonstrates NGET's strong focus on managing these uncertainties in the most economic and efficient manner, to the benefit of consumers.

Please do not hesitate to contact either myself or Duncan Burt if you have any questions related to the points made within our response, or if we can provide additional information in any of these areas.

Yours sincerely

By E-mail

Chris Bennett
Transmission Regulation Manager

Appendix 1 (Detailed points) attached

Appendix 1

Detailed response to Ofgem's IAE consultation

Confidential text has been and blacked out (e.g. [REDACTED]) within this public version of our response.

Responses to Questions raised by Ofgem in Chapter 3 (IAE in respect of transmission constraints)

Question 1:

Do you consider that, prior to the start of the 2005/06 SO Incentive period and based on available information at the time, NGET acted economically and efficiently in deciding to manage internal to Scotland and Cheviot constraints in the BM?

We note within the consultation document that Ofgem provide analysis that leads it to suggest that NGET might have been able to contract forward for certain constraints on an economically efficient basis in early 2005. Ofgem's analysis suggests that NGET should have been able to form very precise and robust forecasts as to likely output of individual Scottish units and, on the basis of this forecast NGET could then have contracted forward. We strongly disagree that such a forecast could have been developed to form a robust basis on which to efficiently procure a firm contract.

As laid out in March 2005 Ofgem's final incentive scheme proposals and as described within our original notice, the purpose of the cost allowances and the availability of the IAE mechanism within the scheme was to reflect the fact that the likely level of Scottish constraint costs for 2005/06 were not certain in early 2005, at the stage that targets were set.

Our original notice provides considerable detail on our risk analysis and actions taken by NGET to efficiently manage the cost of Scottish constraints. We consider that we acted economically and efficiently in choosing not to procure firm contracts to manage Cheviot and Internal Scotland constraints ahead of the start of the SO Incentive period and prior to November 2005.

In response to this question, a summary of our general risk management approach to constraints, as described in our notice, is given below. This is followed by additional material prepared in response to points raised by Ofgem in the consultation document regarding Cheviot and Internal Scotland constraints.

General risk management approach

By choosing to manage a constraint in the short term, e.g. in the balancing mechanism, costs are only incurred if a set of conditions combine to mean the constraint is active. If the constraint has a low probability of occurrence (as is normally the case), then it is more efficient to manage the constraint in this manner, as costs are only incurred on the few occasions when a low probability event occurs.

When costs are incurred in managing a constraint in the short term, it is often the case that if those costs are compared directly with a hindsight estimation costs of securing the constraint through a firm contract arranged in advance, then the firm contract can appear to have a lower cost. However, as most constraints have a low probability of occurrence and, therefore, do not materialise (the specific conditions that cause the constraint did not arise), it would be inefficient and uneconomic to incur firm costs to manage the risk presented by most constraints.

Firm contracts are used ahead of time to manage a constraint risk where the trade off between uncertainty of constraint occurrence and the lower cost of a firm contract make it efficient to procure services firm. Examples where this trade off may result in a firm contract approach being favoured are:

- Where resolution in shorter timescales poses a very large financial risk relative to the likely firm cost (such as likely exposure to £99,999/MWh Bids and/or Offers); or
- Where the constraint is certain to occur and no more economic alternative (such as outage movement to a lower risk time slot or system re-configuration) is available.

Summary of our risk management approach to Cheviot and Internal Scotland constraints

The decision not to contract in advance to manage these constraints can be summarised as follows:

- Although the **Cheviot constraint** was certain to occur during the period, the total volume of actions that would need to be taken by NGET was dependent on real-time total Scottish generation output, which could not be known with great certainty in advance.

On most occasions, resolution of the constraint would be available through the competitive use of Bids in the Balancing Mechanism. A firm contract approach would have required NGET to agree contracts that managed the output of the majority of major generators in Scotland.

Given our forecasts indicated a very wide range of possible volume requirements and that competition would exist for services to resolve the constraint in the BM, a firm contracting approach was considered inappropriate.

- Our actions with regard to **Internal Scotland** constraints were also taken in line with the general strategy laid out above. Our points in response to the question one, above, relate primarily to the NLOANSSE constraint, as this was the subject of detailed analysis within the consultation document.

In summary, in spring and summer 2005 it was considered a low probability that insufficient plant local to the NLOANSSE constraint would run. With only a low probability of occurrence, based on the information available at the time it would have been inefficient and uneconomic to contract in advance for the constraint. We provide further detail on this assessment below.

In addition, without first gaining experience of operating the relevant area of the transmission system, it was not clear that NGET would not find alternative transmission system configurations to resolve the constraint without cost.

Given the low probability of constraint occurrence, and the possibility that operational experience following BETTA go-live may reveal a zero-cost transmission solution to the constraint, based on the information available at the time it would have been inefficient and uneconomic to have contracted firm to secure against such a low probability event.

In both of these cases, the constraint risk was heavily dependent on the level of Scottish plant that self despatched in line with commercial drivers faced by their owners. [REDACTED]

[REDACTED]

A firm contracting approach would have meant intervening to control the output of a significant portion of the Scottish generation fleet, without first giving the market time to work and thereby obviate the need for the majority of balancing actions. If we had taken such firm contracting actions without first allowing the market to work, we would have had little basis against which to have assessed the efficiency of any contract expenditure. Furthermore, without previous experience of Scottish constraint costs, such a firm contract could have been expected to set the enduring cost level for these constraints without first allowing the possibility that the consumer could benefit from lower costs achieved through management of the constraint in the short term, within the BM and elsewhere.

Therefore we do not agree that it would have been appropriate to contract in advance for what we considered to be a low probability constraint. With the benefit of hindsight, Ofgem's consultation analysis focuses on the management of the NLOANSSE constraint. Our efficient and economic decision not to pursue a firm contract for this constraint must be considered in the wider context of the uncertainties associated with BETTA.

In April 2005, and throughout the year, the NLOANSSE constraint risk was one of many low probability constraint risks managed by NGET across the GB Transmission system. Many of these, particularly within Scotland, involved localised constraints relying on a single generator or single generating company. To have adopted a firm contract approach to the management of these low probability constraints would have resulted in NGET inefficiently incurring large constraint contract costs to manage the risk of a large number of constraints including NLOANSSE, the majority of which, in outturn, resulted in little or no cost due to their low probability of occurrence.

If Ofgem are to assess our efficient IAE costs on the basis that NGET should have, ahead of time, entered into a firm contract to manage the risk of NLOANSSE, then this calculation should also include an expected cost of a number of other firm contracts that would have been entered into had this approach been followed. Overall we would

expect such a calculation, based on the use of firm contracts in cases such as NLOANSSE, to reveal a higher net constraint cost than that actually incurred by NGET.

Detailed points in response to question 1 and related issues identified by the consultation document

The remainder of the response to this question addresses separately the points raised by Ofgem within the consultation document relating to the management of Cheviot constraints and to Internal Scotland Constraints.

Cheviot constraint

Within sections 3.57 and 3.58, Ofgem requests views as to whether NGET's approach of managing the Cheviot constraint through the BM was appropriate. In addition to the detail provided in our notice, we make the following comments in regard to this point:

The Cheviot constraint was certain to occur, given the excess plant capacity in Scotland above demand and the known capacity of the export circuits to England and Wales. However, the total volume of actions that would be required across the year was uncertain.

This uncertainty resulted in a wide range forecast cost range for the management of the Cheviot constraint and contributed to the eventual decision to establish IAE allowances within the incentive scheme. The volume of actions required to manage the constraint had a wide range of possible outcomes because the volume of actions required is dependent on the total output of the Scottish generation fleet at any time.

It was likely that a competitive excess of Bids would be available in the BM across the Scottish generation fleet to manage the Cheviot constraint. With competitive procurement available on most occasions in shorter timescales (when the volume required would be known) within the BM or short-term trading, there was no price advantage in procuring firm in advance. Therefore, the most efficient route to manage the constraint was assessed to be through the use of shorter-term tools such as the BM, PGBTs etc.

Broadly this expectation has proved to be the case and sufficient volumes of competitive Bids have been available to allow NGET to secure the constraint at what we judge to be very close to the real cost. [REDACTED]

[REDACTED]. On a number of occasions when it was economic to do so, [REDACTED] NGET has used traded products [REDACTED] to efficiently manage the costs associated with the constraint.

Internal to Scotland Constraints – management of the NLOANSSE constraint

As described above, we note within the consultation document that Ofgem provide analysis that leads it to suggest that NGET might have contracted forward to manage the risk presented by the NLOANSSE constraint. Ofgem's analysis suggests that NGET should have been able to form very precise and robust forecasts as to the likely output of plant local to NLOANSSE and, based on this forecast, NGET could then have contracted forward. We strongly disagree that such a forecast could have been developed to form a robust basis on which to efficiently procure a firm contract.

In summary, we do not agree with Ofgem's analysis that, before mid-November 2005 and/or prior to the start of the 2005/06 SO Incentive period, it could have been forecast with any certainty that insufficient plant would run local to NLOANSSE and that the constraint would therefore occur. Overall we would only contract firm if we had a very high degree of certainty we would spend higher sums of money in the BM to secure the constraint.

The following points highlight why our forecast indicated a low probability of the constraint and explain why we could never have justified an assessment that there was a 'significant risk' that insufficient local plant would run thereby leading to a constraint, as suggested by Ofgem in the consultation document: The following points are divided in to points related to:

1. Gas and electricity market uncertainty in early 2005 and market shifts in the run up to winter 2005/06.
2. Uncertainty regarding possible changes in the behaviour of gas-fired generation during winter 2005/06 in the expectation that the winter could see high gas prices.
3. Specific expectations relating to the winter output of generation local to the NLOANSSE constraint.

Gas and electricity market uncertainty in early 2005 and market shifts in the run up to winter 2005.

In early 2005/06 the likely situation for winter 2005/06 was still very uncertain. To illustrate this, we note that in setting our SO target for 2005/06 Ofgem had concluded that power prices were likely to decline from their then high of £30/MWh¹. Against a forecast level of £30/MWh, gas plant behaviour during the winter would have been similar to that seen in winter 2004/05, when more than adequate levels of gas plant running were seen.

Prices in the market were then driven by gas market uncertainty building through the year. This was influenced by a number of factors including:

- Data on UKCS decline and analysis within the winter outlook report

¹ Section 5.39, NGC System Operator scheme from April 2005, initial proposals Ofgem, December 2004.

- After initial LNG deliveries to Grain in late summer – no further supplies arrived in the UK, tightening the gas situation further. This was linked to the international situation in the gas market including:
 - US hurricanes meant that LNG supplies that could have come to the UK were instead diverted to the US.
 - In late 2005 Spain changed the calculation of gas imbalance prices to mean that Spain's imbalance price would always be higher than GB's, further reducing the likelihood of supplies of LNG to GB.

These events during 2005 pushed up prices and costs and exaggerated the marginal position of gas thereby tightening the situation for all gas plant.

Uncertainty regarding possible changes in the behaviour of gas-fired generation during winter 2005/06 in the expectation that the winter could see high gas prices

Our Winter Outlook analysis undertaken for the May 2005 consultation document forecast significant possible reductions in gas plant output (to minimise gas consumption) but that we would still require nearly all gas stations to run to meet demand on winter days.

Our assumptions as to the flexibility of gas plant to deliver this much gas demand response were questioned by the industry who highlighted two points that suggested gas plant may continue to run more often:

- Concerns over the gas plant flexibility suggested that gas plant would not be able to two-shift and would instead continue to run inflexibly
- Concern that Coal and Oil plant would not be able to run at full output for the entire winter due to limitations on their emissions bubbles.
- Both of these points suggested that gas would continue to form a large part of the generation mix, particularly less flexible gas plant that would still be required to meet demand, would therefore run for longer periods.
- These points, made by industry respondents to our winter outlook consultation, illustrate that even through the spring and into summer 2005 there was a great deal of uncertainty as to how gas station output would vary compared to previous winters, given the increase in winter 2005/06 forward gas prices. The general message was that gas might not be able to flex as much as our forecast (which still indicated all gas stations would be required to run) and that gas plant would instead run for longer periods, more in line with historic experience.
- These forecast assumptions were confirmed by experience during winter 2005/06. Graph 2², at the end of our response to this question, shows that the gas-fired generation continued to run for the majority of days, [REDACTED].

² Graph 2 is confidential

Specific expectations relating to the winter output of generation local to the NLOANSSE constraint.

In addition to analysis indicating that gas plant would still be required to run, the quantity and diversity of generation plant local to NLOANSSE, only a proportion of which required gas burn, suggested a low probability that insufficient portion of this would generate.

- Our winter outlook merit order analysis indicated that only a small minority of gas-fired generation would not run during the winter period.
- Both Peterhead and Fife CCGT units were commissioned from the year 2000 onwards and are [REDACTED]

As such, with only a limited level of generation required to meet the constraint from Fife, Foyers, the CCGT unit at Peterhead and occasional Peterhead Unit 2 running on Miller Gas we believed there was significant generation diversity to allow the system to be secured without NGET intervention.

In addition, our analysis (including winter outlook merit orders) suggested that on tight days oil fired generation may run in preference to some gas fired generation, due to high gas prices: under a possible high gas price scenario, as modelled within Winter Outlook analysis, we anticipated that gas plant deciding not to run would be replaced by oil and distillate running plant in order to meet demand. Therefore, if the CCGT at Peterhead did not run for economic reasons, our analysis suggested it was likely that Peterhead units would run on oil, providing even more confidence that sufficient local generation would run of its own accord.

This expectation was reinforced by the large capacity of the two oil-fired units at Peterhead and [REDACTED]. This expectation of a switch to oil is supported by outturn data for winter 2005/06, which saw higher levels of self-despatch for other oil-fired generation [REDACTED].

The large number of variables listed above highlight that, prior to November 2005, indications were that there was a low probability of the constraint occurring. Prior to winter 2005/06 NGET, Ofgem and the industry as whole faced significant uncertainties as to the likely running behaviour of the fleet of gas stations and of particular gas units. However, it was known that gas stations would still be required to run to meet peak demand. In particular we considered there to be a low probability that generation local to NLOANSSE would not run for a significant majority of the winter period, given the number of possible factors described above, any one of which could have resulted in sufficient generation local to NLOANSSE.

Furthermore, prior to BETTA NGET had no experience of operation of the Scottish system and therefore did not know whether transmission system solutions could be

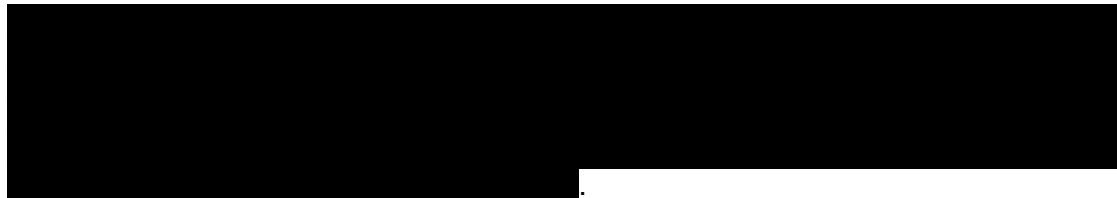
developed in order to remove constraints. Within England and Wales NGET regularly resolves transmission constraints using innovative system configurations and running arrangements. It was possible that once NGET began to operate the Scottish system it would develop transmission solutions which would resolve the NLOANSSE constraint and obviate the need for firm running.

In summary, to have established that a firm contract was the most efficient option, NGET would have needed to conclude that there was a significant (broadly speaking, greater than 50% chance) that insufficient generation out of the in excess of 2.5GW of generation local to NLOANSSE would not run. The following example considers this likelihood in terms of illustrative probabilities of a view before the experience of November 2005 to demonstrate the low probability that no generation would run:

Illustrative probabilities to explain our view of the low level of probability that insufficient generation effective on NLOANSSE would self despatch:

Probability that [REDACTED]	20%
Probability that [REDACTED]	25%
Probability that [REDACTED]	50%
Likelihood of no transmission solution being found (3 in 4)	75%
Probability that the constraint itself would be biting	50%
Illustrative resultant probability of constraint occurring	~1%

The above illustration shows that the cumulative result of a number of variables means that likelihood of the constraint occurring was in our view very low. This rarity means that for the few occasions the constraint does occur it is both economic and efficient to manage in the shorter term through the Balancing Mechanism rather than through a firm contract for the winter.



Overall, prior to November 2005 and before April 2005 it could not have been concluded with any certainty that sufficient generation local to NLOANSSE would not run. The number of different variables affecting the behaviour of local generation included:

- i. UK Gas market conditions
- ii. International events such as US hurricanes and changes to European Gas market arrangements
- iii. The unknown likely behaviour of gas units (including inflexible units) under high gas prices and the possibility of emissions limits limiting the ability of Coal and Oil to replace these units whilst meeting emissions limits
- iv. The known efficiency and historic load factor of Peterhead, in particular operating in the modern CCGT configuration relative to other units on the GB system



- v. The diversity of other local generation capacity, reducing the possibility that insufficient generation local to the group would run as a whole. Other generation included output of the CCGT at Fife, Peterhead running on Miller gas and the hydro station at Foyers
- vi. The likely commercial strategy of SSE [REDACTED]
- vii. The possibility that NGET would find alternative transmission system solutions that resolved (or partially resolved) the constraint and obviated (or reduced) the need for local generation.

Confidential Graphs 1 and 2, relating to this section of our response can be found at the end of this section. Additional background information on our own merit order analysis undertaken for the Winter Outlook consultation can be found at the end our response to question 2, below.

Question 2:

Do you have any comments on whether the analysis we present in relation to forecasting the level of self-dispatch of generation is appropriate in addressing this issue?

In line with our reply to question 1, above, we do not consider that Ofgem's analysis provides an appropriate basis for assessing the likely running of individual units. Moreover we consider that the conclusions drawn by Ofgem, that the analysis demonstrates a 'significant risk', could only be arrived at with the benefit of hindsight.

We do not consider that a robust case for a firm contract could have been made using the best merit order data available at the time, such as that used within the winter outlook consultation. In our reply to Question1, above we identify a number of variables and uncertainties which were relevant to the likely running of gas-fired generation generally and NLOANSSE generation in particular.

With regard to the specifics of Ofgem's analysis within the consultation document we would make the following points:

1. Ofgem's analysis asserts that the majority of plant within the NLOANSSE area as pre-1995 commissioned CCGTs and that, as a result if one assumes that the plant local to NLOANSSE is amongst the most inefficient of these pre-95 stations then there would be a significant risk that generation would not run. We do not agree that this assertion is appropriate because:
 - a. The main CCGT within the grouping is Peterhead. This unit was commissioned as a CCGT unit in 2000, not prior to 1995. Whilst we are aware of a number of unique engineering elements to the configuration of the unit, we consider that it is not appropriate to treat the unit as pre-95 and that, based on historic load factor, this unit can be considered [REDACTED]

- b. The other generation local to NLOANSSE includes Fife CCGT (123 MW), commissioned after 2000, and Foyers Pumped Storage station (300 MW). Again, neither of these units fall into the pre-95 CCGT category and could reasonably be expected to be running on a number of occasions. This diversity of generation adds to the low probability that insufficient generation would run and thereby trigger the constraint.
2. Ofgem's analysis covers the full 182 days of winter (October to March), whereas the constraint was only likely to be present on the higher demand days within the period November to March (the GMT clock-change time period), 151 days.
3. Following the publication of the consultation, Ofgem has confirmed to us that the demand forecast used within their analysis was lower than that used by NGET in early 2005 and available from the Seven Year Statement. Use of the correct higher demand figure increases the number of days on which the majority of pre-95 CCGTs are required to run.

In summary:

- We do not consider that it is appropriate for Ofgem to assume NLOANSSE plant is within Ofgem's pre-95 CCGT category and that the majority of plant within NLOANSSE can be considered to be more efficient or to be more likely to run than pre-1995 CCGTs.
- By understating the actual forecast demand figure and by using 180 days instead of the higher demand days of November to March, Ofgem's analysis understates the proportion of days that all plant can be expected to run and thereby significantly overstates the risk that plant would not self dispatch.
- Considering the two points above together, we consider that making these changes to Ofgem's analysis would confirm that NGET's original assessment of a low probability for the constraint was correct.
- Having reviewed Ofgem's analysis, we do not consider that a robust case could have been made for a decision to pursue a firm contract prior to November 2005 and that a case cannot be made for a contract within Ofgem's analysis without relying on hindsight.

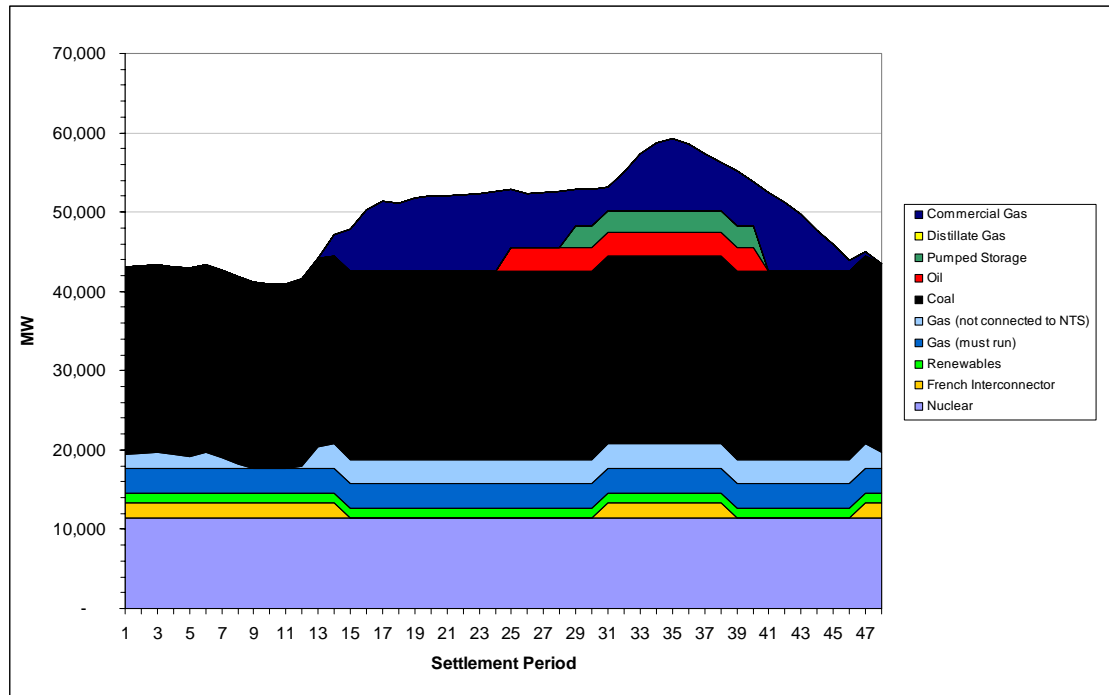
Further information - Winter Outlook report merit orders and gas running

National Grid undertook detailed gas station merit order analysis in consultation with the industry as part of its analysis for the Winter Outlook Report. This analysis identified significant opportunities for reduced gas-fired power station demand which would provide relief to the gas NTS. However, this detailed ½ hourly merit order analysis still identifies that, even with Oil assumed to be running ahead of commercial gas units³, including [REDACTED], we still forecast a requirement that by mid-November over 90% of the 'commercial' gas output forecast to be available is required under average demand conditions at some point during the day.

³ Please see the Winter Outlook consultation for further details. The commercial gas category represents marginal gas units that take NTS gas and can choose not to run.

Our forecast requirement for gas running was greater than this for higher demand conditions such as those seen, on average, in December, January and February or under colder conditions, such as actually seen in late November 2005.

Our May 2005 Winter Outlook Report forecast merit order (forecast for early January 2006) running is shown in graph 3, below:



This graph shows that significant commercial gas running is required to meet demand at several points during the day, even assuming maximum possible peak running from Oil and hydro.

Question 3:

Do you consider that, in November 2005, NGET acted economically and efficiently in managing internal to Scotland constraints through a commercial contract?

Yes. By early December, prevailing forward market prices and the trend in balancing costs since mid-November indicated that the ongoing cost of management of the constraint was in the region of £5m per month. As such, the agreement of a firm contract covering the period December to March for approximately [REDACTED] provided a more economic solution.

As described in Appendix 6 of our notice, NGET acted to secure a more economic firm service as soon as an enduring requirement for NGET to procure generation became clear. In total, final contract sums for the three and a half month period, mid-December to end-March, totalled some [REDACTED]. Based on prevailing costs of alternative procurement through weekly trades, the alternative cost of provision would have been at a monthly net cost of approximately £5m. This would have resulted in net costs of approximately

£17m had the trades needed to be undertaken for the whole of the firm contract period, mid-December to end-March.

Question 4:

Do you consider that NGET acted economically and efficiently in negotiating this contract?

Yes. In negotiating the contract NGET sought to minimise the firm cost and include arrangements in the contract that would cover the costs of generation on those occasions when the unit would otherwise not have run. In this way NGET would only incur costs when the generation did not run for economic reasons, i.e. 'in merit'.

NGET required a minimum level of local generation from a group of generating units, all owned by SSE Generation, in order to secure the constraint. NGET proposed a number of contract forms, each of which was designed to pay for the unit only when it would not otherwise have run of its own accord (through self despatch).

The final contract structure reflected NGET's aims. [REDACTED]

Discussions regarding alternative contract structures linked to prevailing gas prices did not succeed due to complexities associated [REDACTED]

Overall, at [REDACTED], the contract provided a significant saving to the traded and/or BM alternative (see reply to question 3, above). The contract rate is also comparable with similar 'must-run' constraint contracts agreed with [REDACTED]

Question 5:

Do you have any comments on the methodology used by NGET in estimating the total cost of managing internal to Scotland and Cheviot constraints following the start of BETTA, and the amount of the proposed income adjustment?

As described in detail within our original notice, we believe our methodology accurately represents the costs incurred and, where necessary, makes assumptions that are reasonable and balanced.

In response to Ofgem's specific point regarding the inclusion of available Scottish Bids and Offers within the energy reference price (paragraph 3.60 of the consultation document).

We can confirm that the reason we did this was to simplify the calculation and ensure consistency on the few occasions where a half hourly constraint cost was divided between Cheviot and Internal Scotland categories.

We have repeated the analysis for internal Scotland constraints with the addition of Scottish Bids and Offers within the energy reference price. The result is that the inclusion of Scottish Bids and Offers is negligible and results in an increase in the calculated constraint cost of £2.5k. This increase is due to the fact that inclusion of a small volume of attractive Scottish Offers increases the attractiveness of the reference price and therefore increases the sub-optimality and therefore cost of a few constraint actions. We will supply the spreadsheet detailing this analysis to Ofgem separately to this response.

Question 6:

Do you have a view of the appropriateness of having separate cost allowances within the overall SO incentive cost target?

Although the calculation of constraint costs has proved to be relatively complex, we consider that a separate cost allowance for constraints with associated IAE provisions was an appropriate mechanism to manage the significant constraint cost uncertainty surrounding the introduction of BETTA.

Considering possible further possible applications of the mechanism, we do not consider that a cost allowance presents an ideal solution and, if possible, an appropriate forecast of costs should instead be included within the scheme target.

However, we believe that an allowance remains an appropriate tool to reach agreement on the wider scheme target, particularly where:

- Agreement cannot be reached on an appropriate forecast cost for one element within the overall target; or
- If the possible range of costs for one element is very volatile, relative to other balancing costs, and inclusion of these extremely volatile or uncertain costs within the overall incentive target could dampen the incentive to manage balancing costs in other areas.

Graphs and further background data relating to Chapter 3, Question 1

***Graph 1 – Historic Station running
[confidential]***

***Graph 2 – Winter 2005/06, gas-fired generation daytime output by unit
[confidential]***

Responses to questions related Chapter 4 (IAE in respect of costs associated with CAP047)

Question 1:

Do you consider that NGET has acted economically and efficiently in procuring frequency response to minimise costs?

We have worked hard to minimise the costs of procuring frequency response and have taken efficiency measures that have resulted in a reduction in the volume of dynamic response procured. The reduction in our procurement of Dynamic Response is a result of:

- Increases in the available volumes and efficient procurement of Non-Dynamic Response across 2005/06, partially offsetting the increase in requirement resulting from BETTA
- Ongoing efficiency gains through reductions in our minimum Dynamic requirements
- Continuing efficiency gains through optimisation in procurement and dispatch of Dynamic Response

We welcome and support Ofgem's view that, as shown in the consultation document, figure 4.4, our reduction in dynamic response volumes shows the ongoing efficiency of National Grid's dynamic response procurement.

We do not agree that the presence of the allowance may have removed NGET's incentive to manage these costs efficiently. In reference to Ofgem's discussion of CAP107, we do not believe that the consideration of CAP107 is appropriate within the assessment of CAP047 costs. The income adjusting event cost calculation relates to those cost increases directly related to CAP047-related price rises. Notwithstanding this point, if NGET or another party had raised such a CUSC modification once CAP047 price rises became clear in November 2005, such a modification would not have been implemented before the end of the IAE period, March 2006.

Question 2:

Do you have any comments on the methodology used by NGET in estimating the total cost of frequency response following the implementation of CAP047, and the amount of the proposed income adjustment?

Given the relatively straightforward nature of the main impact of CAP047, in that the modification has led to an increase in the holding prices available to NGET for the dispatch of response, we considered a simple approach to the calculation to be appropriate.

As described in our notice, in developing the cost calculation we chose not to include the smaller but more complex estimated cost increases in BM optimisation costs that have resulted from increases in response holding prices. Our calculation, therefore, represents a conservative approach to estimating the additional incentivised balancing costs resulting from CAP047.

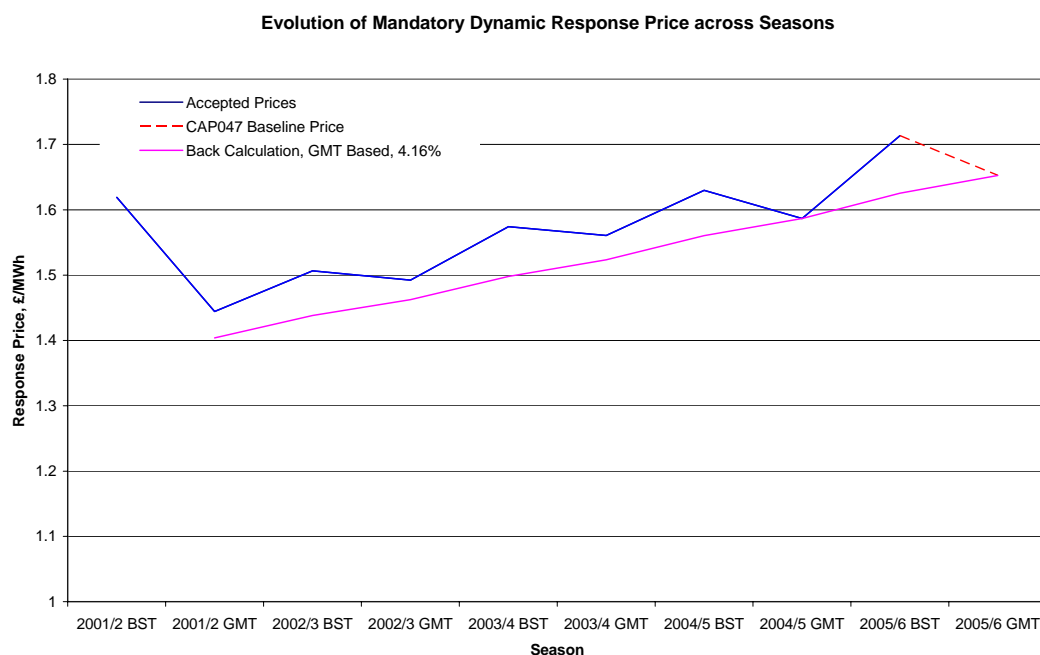
Question 3:

Do you have any comments on our proposed alternative methodology, and the amount of the income adjustment that may result should we determine that the events or circumstances surrounding the increase in frequency response costs incurred by NGET is an IAE?

Although the effect on the overall additional CAP047 cost is small, we do not consider that Ofgem's proposed alternative methodology provides a more appropriate level of calculated cost increase. Ofgem's calculation of an alternative holding prices based on forward extrapolation of October 2005 prices through the CAP047 period, table 4.1 in the consultation document, ignores the seasonal trend in Response prices. Response prices are typically lower in winter (GMT period, November to March) than in summer (BST period, April to October). Therefore, by extrapolating forward through the winter from October's price, Ofgem are over-estimating the alternative prevailing price and thereby under-estimating the additional cost of CAP047.

Average accepted response holding prices tend to be lower in the winter because we procure a smaller volume of response during the winter months. Lower volumes of response are required because response requirements fall as demand levels increase and therefore, higher average winter demand levels result in lower average levels of response procurement and lower average accepted prices.

The seasonal variation in response prices is shown in graph 4, below:



The summer/winter variation can be seen in the graph above with average winter prices always out turning lower than the preceding summer period⁴. Excluding the 2001/02

⁴ Note that for the calculation of 2005/06 BST prices, i.e. summer 2005 prices, October 2005 prices have been corrected as per footnote 37 of Ofgem's consultation document.

transition, which saw a large decline between 2001/02 BST and 2001/02 GMT prices, the winter prices have averaged between 97% and 99% of the preceding summer prices. Assuming a central figure of 98% for GMT 2005/06 prices relative to BST 2005 would give an average alternative GMT 2005/06 response holding price of £1.68.

In line with table 4.1 in the consultation document, using a seasonally corrected 'flat' average price of £1.68/MW/h gives an additional mandatory response cost resulting from CAP047 of £10.84m. This calculation is shown in the table below:

	Baseline, £/MWh	Differential, £/MWh	Mandatory & Commercial Volume, GWh	On Cost, £m
November	1.68	1.46	1204	1.76
December	1.68	1.55	1140	1.77
January	1.68	1.54	1104	1.71
February	1.68	2.08	1005	2.09
March	1.68	3.08	1139	3.51
Total				10.84

This above calculation relates to mandatory response costs only. Using the same methodology, we estimate that the firm frequency response costs increased by £1.93m, giving a total estimated additional cost resulting from CAP047 of £12.77m.

Question 4:

Do you have a view on the appropriateness of having separate cost allowances within the overall SO incentive scheme cost target?

We consider that the application of a separate cost allowance for the additional costs associated with the introduction of CAP047 was an appropriate mechanism to manage significant balancing cost uncertainty surrounding the introduction of CAP047.

Considering possible further possible applications of the mechanism, we do not consider that a cost allowance presents an ideal solution and, if possible, an appropriate forecast of costs should instead be included within the scheme target.

However, we believe that an allowance remains an appropriate tool to reach agreement on the wider scheme target, particularly where:

- Agreement cannot be reached on an appropriate forecast cost for one element within the overall target; or
- If the possible range of costs is very volatile relative to other balancing costs and inclusion of these extremely volatile or uncertain costs within the overall incentive target could dampen the incentive to manage balancing costs in other areas.