Annex A - Demand Forecasting Methodology

This Annex explains the basis for our revised demand forecasts. It sets out the underlying assumptions, explains the developments made to the methodology, describes the validation that we have undertaken of the forecasts and highlights the associated issues.

1. Background

In addition to the weather, gas demand is influenced by a number of factors, each having a varying impact on the sensitivity of the forecast. The level of exports, amount of CHP capacity installed, CCGT developments, gas price and the strength of the economy are examples of some of the key factors considered when producing our forecast.

The process that is employed to develop the annual gas demand forecasts is based upon a combination of different techniques, including econometric modelling, monitoring of information from the enquiries for new load and analysis of the consumption history of existing large demands. Detailed analysis of certain sectors of the market, such as power generation, is also carried out. Each forecast is developed from a set of planning assumptions, which, if necessary, can be flexed to create alternative scenarios. In the case of gas demand, these assumptions will take account of economic and fuel price factors, environmental legislation and Government energy policy.

Some of the data used to support the forecasts is obtained from independent organisations and we also use the Transporting Britain's Energy (TBE) consultation to validate our assumptions. The TBE consultation process incorporates data-gathering questionnaires aimed at specific sectors of the industry (including consumers), and meetings with major industry demand-side stakeholders, such as the power generators and shippers.

These annual demand forecasts are then converted into daily demand forecast profiles and load duration curves for average and severe conditions using a range of statistical techniques including regression and simulation. A detailed description of this process is given in the Gas Demand Forecasting Methodology paper on our website; Gas Demand Forecasting Methodology[1]

2. Frontier Economics' review of methodology

National Grid's gas demand forecasting process has been audited on several occasions in the past by consultants commissioned by Ofgem, as part of various regulatory reviews. On all such occasions the reviews have concluded that the process was comprehensive and soundly based. The latest review of the process, undertaken by Frontier Economics in April 2006 (and published alongside this consultation document), concluded that:

[1] http://www.nationalgrid.com/NR/rdonlyres/71CFD0F6-3607-474B-9F37-0952404976FB/4153/1104_Gas_Demand_forecasting_methodology.pdf

"The weather-correction and daily demand forecasting process appears to have worked satisfactorily in the past, and continues to do so for non-price sensitive customers……Our principal recommendation, therefore, relates to augmenting the daily demand forecasts produced as part of this process, with analysis of demand response to particular price levels."

Frontier Economics' recommendation reflects the fact that, until this year, our approach has been to produce 'unrestricted' demand forecasts, which take account of underlying economic trends but do not seek to incorporate allowances for demand-side response by large consumers to high spot prices.

We recognise that with current price levels sufficiently high that demand-side response is observed systematically (as has been the case in the power sector for example), unrestricted demand forecasts may appear unrealistic. We have therefore augmented our forecasting process this year by producing an alternative forecast along the lines that Frontier Economics suggest. To do this we have adjusted the assumptions and individual load profiles utilised within the existing process to better reflect the recently seen impact of high and volatile spot prices on the price sensitive sectors of power generation and large industrial sectors. These adjustments to the process are described in Section 4 below.

Frontier Economics also make a recommendation in relation to the modelling of net export flows, suggesting that scenario analysis is undertaken in this area. We would note, however, that our analysis of long-term supply and demand does incorporate the assessment of alternative scenarios, which we consult on through the TBE process. In addition, we view this winter consultation as key in informing the question of potential winter flow patterns through the various importation routes.

3. Fuel price forecasts

To facilitate the production of the gas demand forecasts it is necessary to develop a set of assumptions about the likely level of energy prices, particularly those paid by end-users. In developing these assumptions we consider historical price trends, forward market prices, the forecasts of specialist consultancies and feedback from the TBE consultation process. The following information provides a brief overview of recent prices, current forward market prices and, where applicable, our latest forecast of movements over the next two years. All price information in the following tables is quoted on a nominal basis with any outturn data shown in italics. Our view of price is presented on a calendar year basis as this is consistent with the approach taken to the production of annual demand forecasts.

Table A.1 – Quarterly NBP gas prices

	Quarter	2005	2006	2007
NBP Price (p/therm)	1	*37.5*	*67.6*	91.9
	2	*29.8*	33.9	51.5
	3	*28.8*	40.9	47.1
	4	*45.6*	78.4	68.3
Change on previous year (%)	1	*55%*	*80%*	36%
	2	*46%*	14%	52%
	3	*25%*	42%	15%
	4	*63%*	72%	-13%

Source: Heren

Table A.1 reveals the extent of wholesale price movements experienced during 2005 and suggests that this is a trend that will extend through to the summer of 2007. Only at the beginning of winter 2007/08 is there an indication of quarterly prices being lower than they were in the previous year. Throughout the forward period the market remains well above recent outturns.

The projection of end-user gas prices is an important part of the demand forecasting process and is supported by a long-term view of wholesale price movements. The following table presents actual prices in 2005 together with our forecast for 2006 and 2007, and percentage changes from the previous year. For information, our view of annual NBP prices is also included.

Table A.2- Annual wholesale & end-user gas prices (actual & forecast)

Sector	Units	2005	2006	2007
NBP	p/therm	*39.6*	54.9	55.9
Domestic		*60.7*	75.6	87.7
Commercial		*49.6*	70.8	83.4
Industrial - Firm		*42.6*	64.4	76.8
Interruptible		*39.1*	58.3	66.5
Power		*29.7*	45.2	51.9
NBP	%	*66%*	39%	2%
Domestic		*15%*	25%	16%
Commercial		*25%*	43%	18%
Industrial - Firm		*43%*	51%	19%
Interruptible		*46%*	49%	14%
Power		*33%*	52%	15%

Sources: Heren & DTI historical data and National Grid forecasts

The data in Table A.2 reveals that, in 2005, end-users in all sectors experienced material price increases. Our forecast of prices suggests that significant price increases will also occur in all sectors during 2006. In 2007, prices are forecast to continue rising, but at a slower rate and with less of a variation between categories.

Year-to-date validation of our forecast of the NBP price during 2006, based upon current outturns and quoted forward prices, indicates a market average of 53.8 p/therm, against a projection of 54.9 p/therm. This close correlation suggests that, with the market in its current position, our latest view of the wholesale price is robust. Recent announcements concerning gas prices in the domestic sector are consistent with our view of a continued increase in the cost to end-users.

4. Development of alternative approaches for power generation & DM loads

This section concentrates on the approaches used to forecast the sectors that are affected by daily fluctuations, most notably the power and large industrial sectors.

Forecasts of demand from the power generation and large industrial sectors have been developed to not only reflect the underlying price changes but also their response at times of high winter spot prices. As outlined above, we have developed two alternative forecasts, as follows:

- "Unrestricted" demand is the level of demand expected in response to underlying econometric variables including the economy and price. These forecasts allow for the underlying consumers' response to increases in prices rather than the high spot prices seen on certain days, and follow the traditional approach utilised in previous forecasts.
- "Restricted" demand is the level of demand expected when additional demand-side response is incorporated to allow for high spot prices and subsequent fuel-switching in the power generation and industrial sectors.

In addition, we have re-run our modelling of the interactions between the gas and electricity markets in order to establish the potential extent of response from the power sector. Therefore:

- "Full DSR" is the level of demand expected when demand-side response from the power sector is maximised without adversely affecting electricity demand.

The Full DSR forecast is equivalent to the 'Restricted' forecast referred to in Frontier Economics' report (page 4). Our restricted forecast is our best view of what demand might be given the present forecast of prices in winter 2006/07.

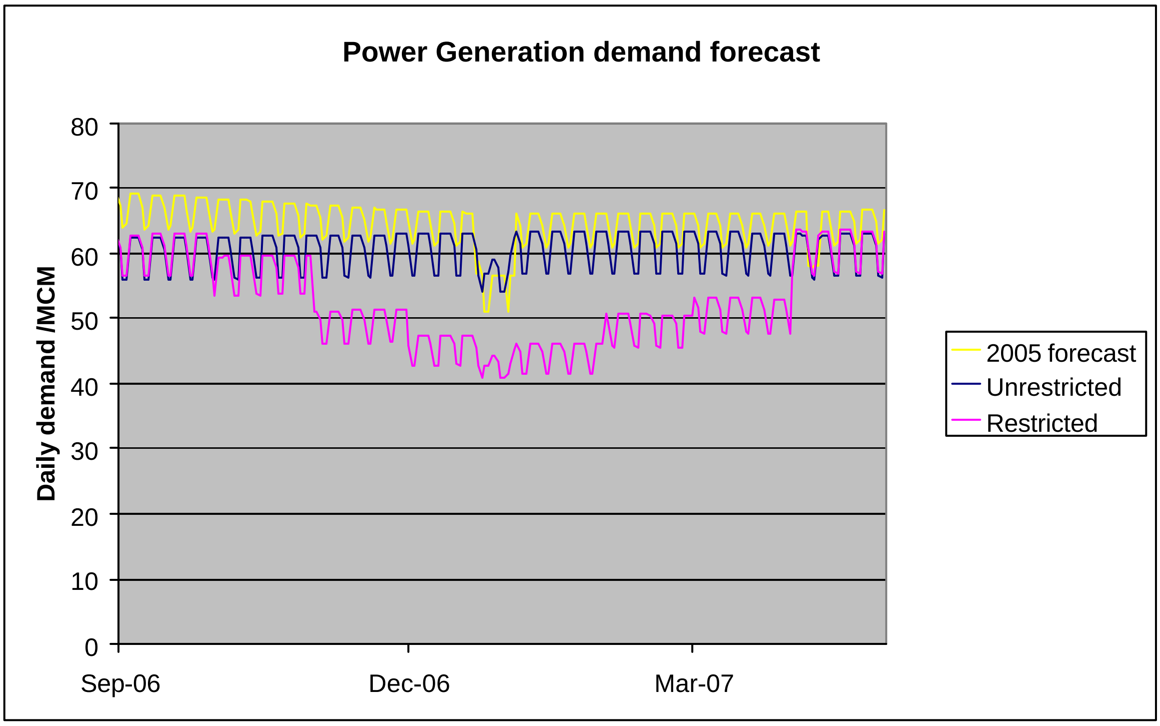
4.1 Power generation

For power generation, our electricity forecasting model allows us to 'rank' power stations to meet various levels of electricity demand using different ranking orders based, for example, on historical patterns of generation or the marginal cost of generation. To obtain the unrestricted forecasts we use ranking orders based on historical generation patterns prior to 2005/06. Restricted forecasts are obtained by using ranking orders based on 2005/06 operation, as our examination of forward spark and dark spreads suggest similar differentials. The experience of 2005/06 can therefore be expected to provide a good approximation for winter 2006/07. The Full DSR forecasts are developed by estimating the reduction in demand that would be possible if the market sought to maximise its response. The assumptions behind this analysis are documented in Chapter 3 of the main body of the document.

Frontier Economics recommended the use of a least cost marginal dispatch model to forecast power generation at different price levels and demonstrated how this could work with assumed price curves and fuel/generation costs per station type. However, they did recognise that this analysis needed to be augmented with additional information on technical and contractual factors that could limit the full extent of potential demand-side response. The approach that we have adopted effectively achieves the same result. To develop the restricted forecasts we have utilised ranking orders observed last winter, while the Full DSR methodology is equivalent to an approach in which severe price curve assumptions are made with technical and contractual limitations overlaid. We believe this approach is an appropriate basis for forecasting the potential demand from the power sector under different price and weather conditions. Advantages of this approach are that forecasts of half hourly prices and the collection of commercially sensitive information on the cost of generation of different stations are not necessary.

To illustrate the effect of these forecasts on power generation demand throughout the winter, figure A.1 compares last year's forecast for 2006/07 with this year's unrestricted and restricted forecasts.

Figure A.1 – Power generation demand forecast

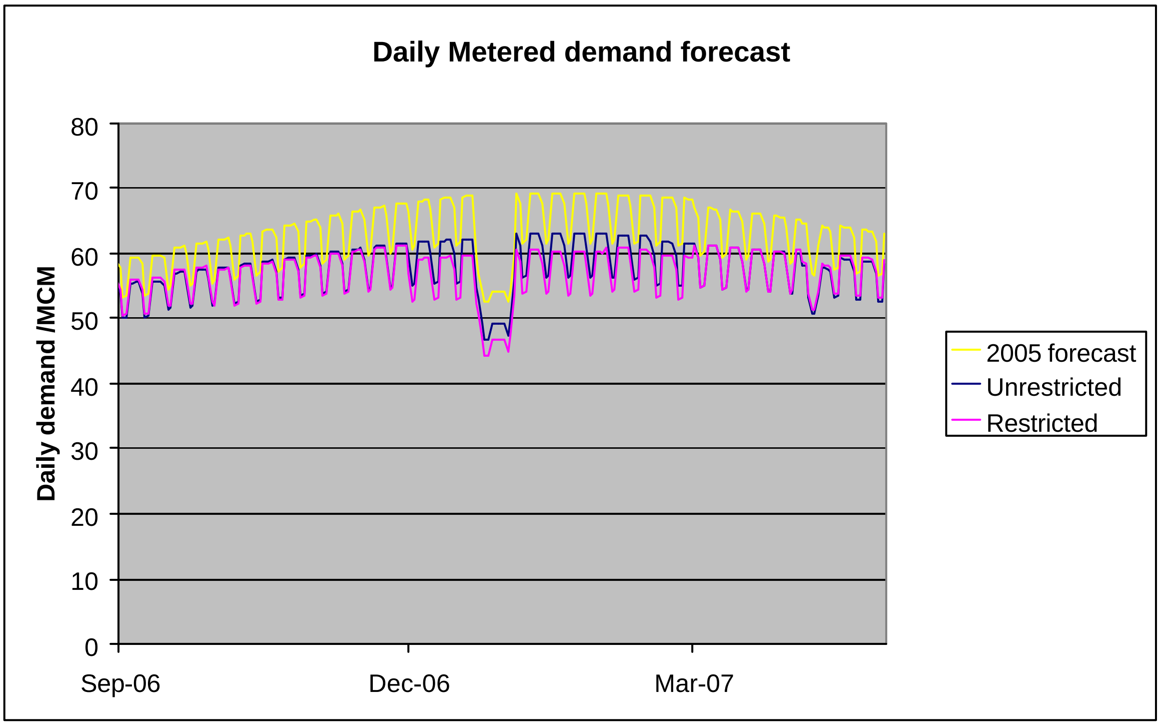


4.2 DM Load

The approach adopted in forecasting DM load and large industrial demand, in particular, followed the same principles as for power generation, i.e. producing unrestricted and restricted forecasts that take account of demand response to underlying average price changes and additional demand-side response, taking account of higher spot prices during the winter. To illustrate the effect of these forecasts on DM demand throughout the winter figure A.2 compares last year's forecast for 2006/07 with this year's unrestricted and restricted forecasts. The restricted demand shows the forecast response during the winter months when prices are at their highest.

As figure A.2 illustrates, a significant element of the DM load isn't exposed to high spot prices on the day (given the relatively small difference between restricted and unrestricted), but is expected to reduce demand in response to increased prices over a longer period (the unrestricted forecast being materially lower than the 2005 forecast). The seasonal nature of some DM load is illustrated by the unrestricted profile through the winter.

Figure A.2 – Daily metered demand forecast



4.3 Validation of power and DM loads

The following charts compare our restricted forecasts for power generation and the DM sectors with the actual demands observed in the present gas supply year to-date. Figure A.3 compares the restricted power generation forecasts with actual daily demands and shows that the forecast would have performed well until mid-March. Subsequently, actual demands were lower than indicated by the forecast as coal-fired generation retained a competitive advantage over gas. One relevant factor here may have been the sharp fall in the price of carbon in the spring.

Figure A.3 – Power generation demand and forecast

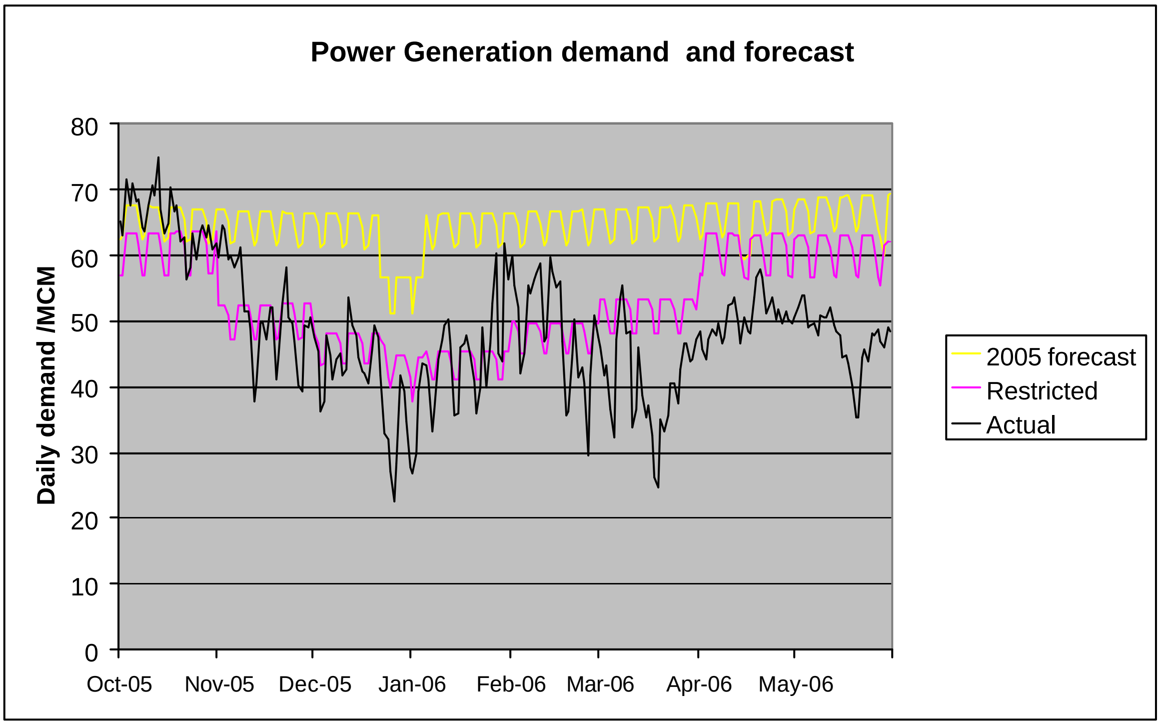
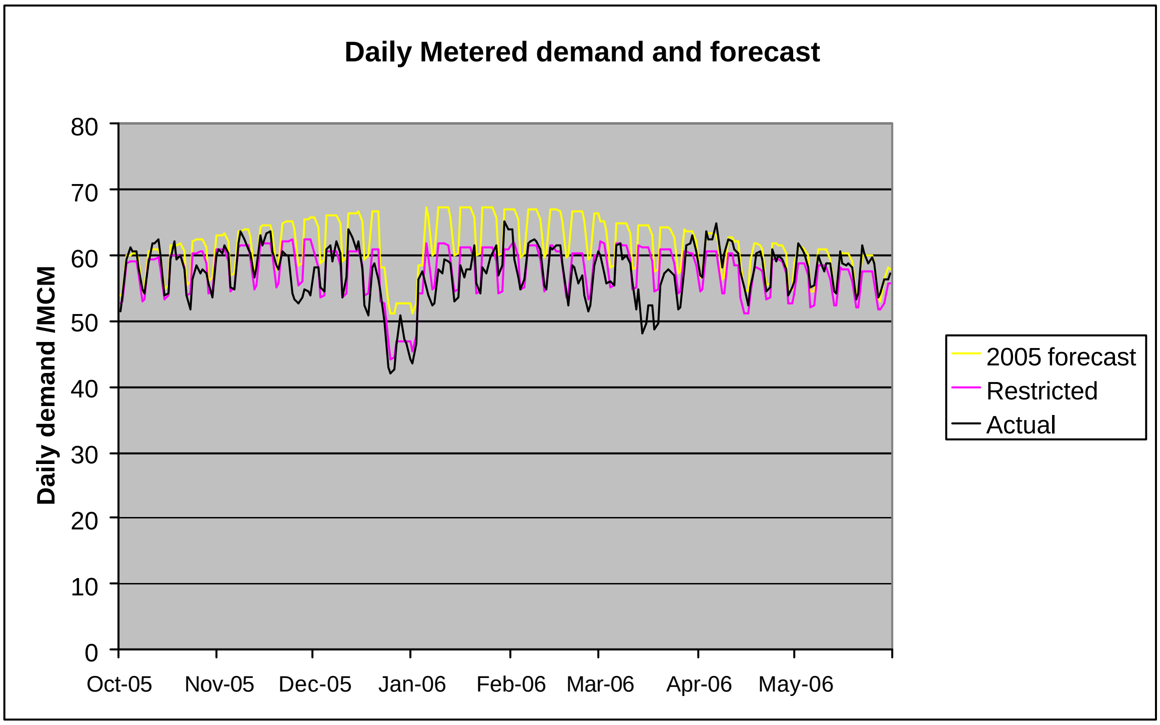


Figure A.4 compares the restricted (Non-Power) DM forecasts with actual daily demands and shows that the forecast would have performed well in predicting the level of demand response in the 2005/06 winter.

Figure A.4 - Daily metered demand forecast



5. NDM Demand Forecasts

5.1 Forecast drivers

Non-Daily Metered (NDM) demand forecasts are underpinned by econometric modelling of various factors including fuel prices, economic growth, efficiency measures, taxes and Government policy. Consequently, the large price increases seen last year along with the forward price curve for next winter, have resulted in a projection of falling demand in 2006/07 and therefore significantly lower forecasts than last year's forecast for 2006/07, which underpinned the analysis in the May Winter 2006/07 Consultation Document. Those forecasts were produced before the unprecedented price increases seen in 2005/06.

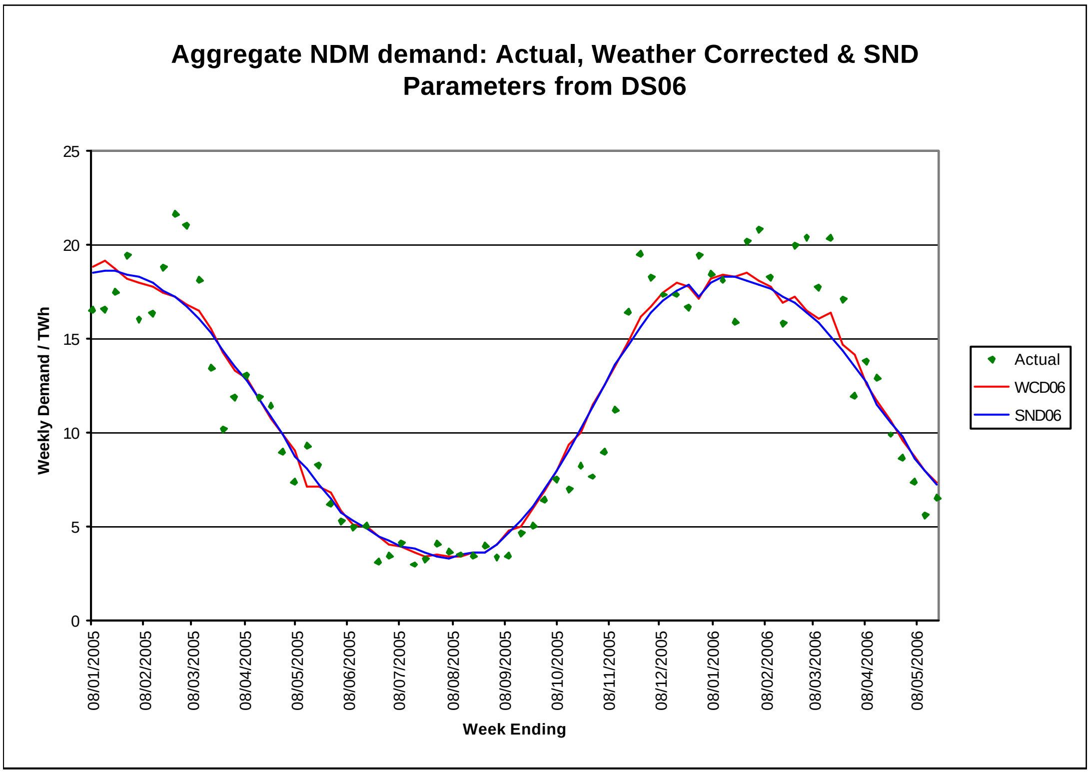
Weather corrected NDM demand in 2005 was 1.4% lower than in 2004 whilst we had forecast a very slight rise of 0.1%. Our latest forecast is for NDM demand in supply year 2006/07 to be 1.5% lower than in 2005/06, 7.9% lower than last year's forecast for 2006/07, with the fall in domestic demand being the most significant factor

5.2 Validation of NDM forecast

We continually review our forecasting processes and methodologies and monitor how accurate the forecasts have been. Figure A.5 compares the actual aggregate weekly NDM demand, weather corrected demand and our seasonal normal demand forecast (SND). It shows that the forecasts have performed well except for one cold week in mid-March when domestic demand was higher than the forecasts indicated.

The final section of this Annex explores possible behavioural explanations for the recent reductions observed in NDM demand and highlights the risks and issues associated with our revised NDM forecast.

Figure A.5 – Aggregate NDM demand: actual, weather corrected & SND parameters from DS06 (Demand Statement 2006)



6. Validation of total demand

Table A.3 summarises forecasting performance in the gas supply year to-date and also shows year-on-year changes. Over the eight months to date (1 October 2005 to 31 May 2006) weather corrected demand is 5.4% lower than last year and when compared to our latest (restricted) forecast is 0.5% higher for LDZs and 0.3% lower for total demand, both of which are well within the historical average levels of accuracy of our forecasts. With eight months gone, including the winter period, this forecast variation is unlikely to change substantially. We therefore have confidence that our forecasts are robust based on the historical data available to us.

Table A.3 – Forecasting performance

Category	Weather corrected demand Oct 05-May 06	Last year	This year vs. Last year	Forecast Oct 05-May 06	Actual vs. Forecast
NDM	484,079	489,109	-1.0%	479,082	1.0%
DM	153,064	160,775	-4.8%	153,756	-0.4%
Power Gen	129,643	160,526	-19.2%	141,368	-8.3%
Total ex. IUK	766,786	810,410	-5.4%	774,206	-1.0%
IUK	28,665	24,436	17.3%	23,749	20.7%
Total	795,451	834,846	-4.7%	797,955	-0.3%
of which: LDZ	*579,647*	*593,865*	*-2.4%*	*576,732*	*0.5%*

7. Risks to forecast outturns

As with any forecast, there are a number of risks associated with the accuracy of our revised demand forecasts. In this case they can be characterised into two main categories; those that relate to econometric variables like price and the economy, and those relating to behavioural issues, for instance, domestic customers' response to high prices and cold weather.

The main uncertainties associated with econometric variables relate to the forecast energy prices. While our 2006/07 price forecasts for both oil and gas are reasonably accurate when compared with actuals to-date and forward prices, outturn prices could be affected by many factors, including developments in the global oil and gas markets and the emerging gas supply-demand outlook in the UK.

Our econometric models include price elasticities that have successfully explained historical behaviour. However, these have been based on many years of history, in which price changes have mostly been significantly smaller in magnitude than those seen recently. Consequently, there is a risk that the price elasticities could be non-linear and large price changes could affect gas demand by more or less than suggested by the elasticities implicit within the modelling.

A particular risk relates to the domestic sector, where we have little evidence with which to predict consumer behaviour in very cold conditions. The lower level of NDM demand within our revised forecasts suggests that a recent change has occurred in consumer behaviour. Possible behavioural explanations include:

- systematic reductions in the temperature settings on thermostats;

- greater use of thermostatic radiator valves to avoid heating rooms that are not often used;
- setting timers so that boilers are on for shorter periods;
- energy efficiency improvements, such as improved loft insulation and cavity wall insulation.

Under very cold conditions, it is possible that behaviour may revert, for example:

- consumers may leave their boilers on all the time in order to keep their houses warm;
- boilers may struggle to maintain temperatures at the level of the thermostat setting, in which case the fact that the thermostat was set lower than before would have reduced impact.

We are keen to gather evidence as broadly as possible in order to inform this question. This consultation process is an important element of our further research, and we would be very grateful for views on the behavioural issues set out above. In addition, we are investigating whether there is any evidence in Europe in relation to domestic consumer behaviour under high prices and very cold conditions, and we are seeking to engage relevant industry experts to garner their views.

Annex B - Overview of Gas Transporter capacity issues

This Annex provides information on issues associated with capacity on the gas transportation system. It builds on Annex E in the May document, which gave an overview of the arrangements under which Gas Transporters may interrupt certain large loads for capacity management purposes. Here we set out further data on the potential for interruption by Gas Transporters and outline the analysis that we have undertaken to explore the possibility of entry constraints arising on the gas transmission network.

Analysis of Gas Transporter interruption

For a precise understanding of the commercial arrangements for interruption by Gas Transporters, the reader should refer to the relevant section of the Uniform Network Code (UNC).

Gas Transporters have rights under the UNC to interrupt Interruptible Supply Points (referred to here as “interruptible sites”) in order to assist with the management of capacity on their networks. A site is eligible for interruptible status if it consumes at least 5,860,000 kWh (200,000 therms) per annum.

Gas Transporters’ interruption rights are mirrored in the interruptible sites’ contracts with their suppliers. We understand that the majority of such contracts only permit interruption where a Gas Transporter (National Grid Gas NTS or the relevant Distribution Network) has requested it. Some supply contracts, however, still permit interruption at the instigation of the supplier.

In return for being interruptible, the relevant shipper is not required to pay NTS (TO) Exit Capacity Charges or Local Distribution Zone (LDZ) Capacity Charges. In addition, the shipper is entitled to a transportation charge credit if interruption is required at the interruptible site on more than 15 days in any price control formula year.

There are approximately 1400 interruptible sites, most of which are connected within the Distribution Networks. The great majority of these have interruptible arrangements that permit interruption for up to 45 days per annum. Twelve interruptible sites, known as (Transporter Nominated Interruptibles) TNIs, are interruptible for more than 45 days to reflect particular transportation constraints. Approximately 80 interruptible sites are known as Network Sensitive Loads (NSLs). NSLs have a higher probability of interruption as a result of their particular location on the gas transportation system.

In our May document, we noted that Gas Transporters have licence obligations to develop their networks to provide capacity to meet anticipated 1 in 20 peak day demand, taking account of any interruption rights. We reproduced an extract from the Gas Transportation Ten Year Statement 2005, showing the 2005 forecasts of 2006/07 1 in 20 peak day firm demand, to provide an indication of the level of capacity within the respective Distribution Networks (DNs).

As part of the consultation, we sought data from the DNs on the demand levels at which interruption might be expected, both in relation to NSLs/TNIs and to the other interruptible sites on their networks. Their replies are summarised in the following table.

Table B.1 – Indicative trigger levels for DN Gas Transporter interruption

LDZ (or NTS)	# NSLs[2]	Range of NSL Triggers (% firm peak day)[3]	Non-NSL Trigger (% firm peak day)[2]
SC	19	78 - 97	92
NO	4	>77	Not provided by DN
NW	14	78 - 98	96
NE	12	>83	Not provided by DN
WA	1	Unavailable[4]	Not provided by DN
WM	0	N/A	96
EM	12	80 - 96	96
EA	0	N/A	97
NL	21	83 - 98	96
SE	0	N/A	92
SO	0	N/A	92
SW	0	N/A	Not provided by DN

The trigger levels show the level of total LDZ demand above which it is estimated that interruption may be required. It should be noted that these are provided purely for illustrative purposes, and that interruption in practice will be subject to the particular circumstances prevailing at the time. These estimates are all based on 2005/06 data. The Distribution Networks are in the process of updating their analysis and we expect to publish 2006/07 trigger levels in our Winter Consultation Report in September.

In relation to the NTS, subject to plant failure or unexpected supply-demand patterns, the only part of the system potentially subject to demand-side constraints is the South-West. Here, there is sufficient capacity to transport forecast 1in 20 undiversified firm peak day demand in that part of the country. In practice, as total demand approached that level, we would consider the need for interruption based on prevailing operational circumstances.

Gas Transmission Entry Capacity

The rapidly changing profile of gas supplies in the UK will naturally lead to new patterns of gas flow on our transmission system. We have been asked

[2] Includes any TNIs

[3] Trigger levels are from 2005/06 winter

[4] Not available for reasons of commercial sensitivity as there is only one such site

whether we envisage constraints arising as a result of this in the 2006/07 winter. This question is, of course, one that we examine regularly in our role as system operator.

With the arrival of new gas sources at Bacton, Easington and Teesside, there is the potential for greater flows on the East Coast of the country. The prime focus of our analysis, therefore, has been to investigate the potential for constraints to arise in this part of the system. In response to market signals, we have invested significantly over the last few years in anticipation of this shift in flow patterns. In addition, we are in the process of constructing a new pipeline across the Pennines, which will be commissioned prior to the 2007/08 winter, coincident with the anticipated arrival of gas from the giant Ormen Lange field into Easington.

Entry capacity is made available to Shippers commercially through a system of auctions, ranging from long-term (up-to 17 years ahead) to on-the-day. While the purchase of entry capacity (apart from short-term interruptible purchases) provides shippers with a firm financial product, the possibility of constraints is recognised in the framework through a set of arrangements in which National Grid may buy capacity back from the market if necessary. We are incentivised to minimise the cost of buy-back actions. There is therefore a clear distinction between commercial capacity (which is made available to shippers) and physical capacity on the transmission system.

Physical capacity availability in relation to any particular entry point is a function not only of the transmission system but, critically, of the pattern of gas flows elsewhere on the network. Our analysis has centred on the following:

- Capacity availability under anticipated gas supply profiles at given demand levels;
- The range of capacity physically available at each entry point given variations in demand and supply profiles;
- Interactions and trade-offs between the capacity availability at different entry points;
- Network configuration options for maximising capacity under a variety of flow supply and demand conditions.

Given the commercial framework under which entry capacity is sold, and the associated buy-back regime, it is not appropriate for us to provide quantified details of this analysis. However, in summary, our analysis has confirmed that there is sufficient network capacity to meet anticipated flow patterns at all demand levels this winter. Furthermore, there is flexibility to meet other flow patterns, the extent of which is variable according to demand and other variables. Our expectations of flow patterns are based on an assumed ‘merit order’ taking account of the relative economics of the various supply sources and previous experience.

No transmission network has infinite capacity. It is therefore to be expected that constraints could arise given circumstances sufficiently different from expectations. For example, a material offshore supply loss affecting a non-East Coast terminal such as St Fergus or Barrow could potentially lead to such a situation if the market replaced this gas with additional East Coast supplies. In this event, the actual occurrence of a constraint would depend on the level of demand, the precise profile of supplies and the prevailing operational circumstances.

Annex C – Study into the feasibility of blending at Bacton

Introduction

The UK's gas import dependency is forecast to grow rapidly as UKCS sources decline. The resulting convergence of the UK and European markets has highlighted differences in gas quality specifications and focused attention on potential measures that would enhance the interoperability of the respective systems.

In this context, National Grid has already taken a number of steps to change the gas quality arrangements to facilitate imports, where appropriate:

- Harmonisation of Ten Year Statement (TYS) Wobbe Number limits with limits set out in the Gas Safety (Management) Regulations 1996 (GS(M)R);
- UNC Mod 49 – to amend the UNC to allow the inert gas limits at sub-terminals to be revised in line with European (EASEE-gas) recommendations;
- UNC Mod 69 – widening of IUK's Wobbe range (within GS(M)R limits) and aligning its sulphur limits with European (EASEE-gas) recommendations.

A further measure that has been identified by some parties as having the potential to facilitate additional supplies of gas to the UK could be for National Grid to accept gas with specifications outside those permitted in the UK and blend it within its beach terminals to ensure that gas delivered from the terminal is GS(M)R compliant. In particular, the Bacton terminal has been identified as having the potential to blend additional supplies of non-compliant gas due to the scale of flows through the terminal and its proximity to continental Europe. For this reason, Ofgem requested National Grid to undertake a review of the technical and operational feasibility of providing gas blending at that facility, potentially for winter 2006/07.

The review did not include consideration of any commercial arrangements which might apply to such a service, including how the costs of providing a blending service should be determined and applied to customers. Consideration of the commercial arrangements will therefore need to be progressed in parallel to the identification and implementation of the technical and operational changes required at Bacton to facilitate the provision of a blending service.

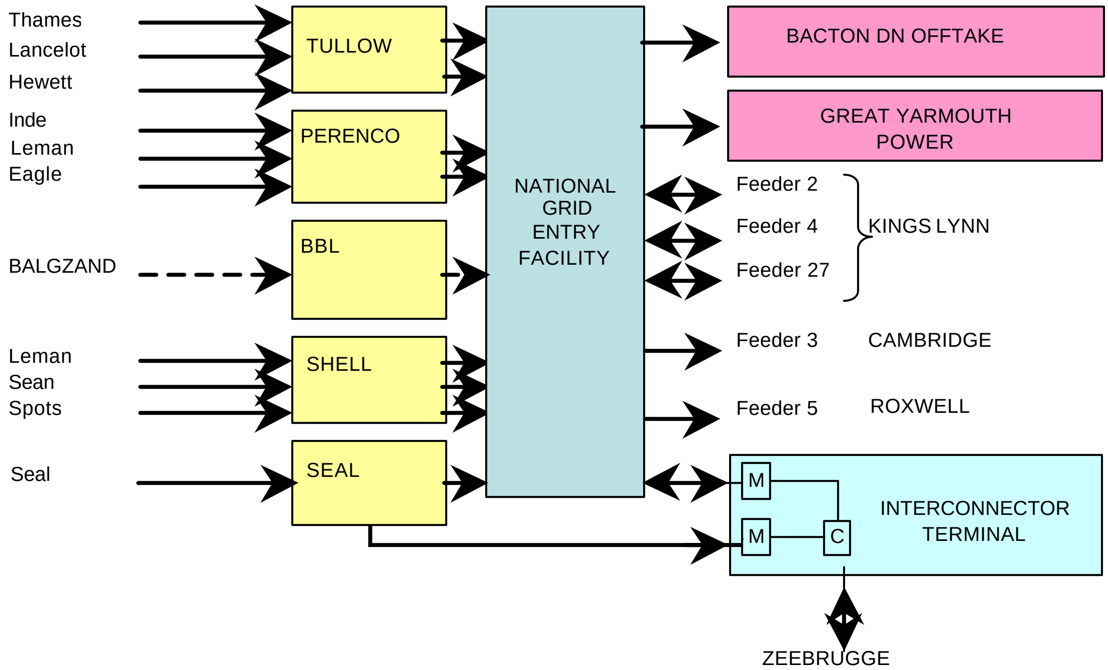
This Annex describes the various elements of the review carried out by National Grid and explains why we have concluded that it is not feasible to provide a blending service at Bacton for this coming winter. The Annex also sets out the proposed next steps in this area.

Background

The National Grid Bacton gas entry terminal, situated close to the village of Bacton in Norfolk, currently acts as a collection point for incoming gas from four UKCS sub terminals and imports through the Belgian Interconnector. From winter 2006/7, it will also receive additional gas imports via the Bacton-Balgzand Interconnector.

The gas exits the terminal through five major NTS inland pipelines (NTS feeders) and the Belgian Interconnector, when operating in export mode. Gas leaving the terminal via NTS feeders is conveyed to several NTS/DN offtakes, which are situated downstream of the terminal, and the Great Yarmouth Power Station.

The simplified schematic diagram below shows the points of entry and exit to and from the Bacton terminal.



In accordance with GS(M)R, National Grid must only convey gas that complies with the gas quality limits set out in GS(M)R within its network. To ensure compliance with these requirements, National Grid requires all gas delivered via the incomers to the National Grid terminal to be within the gas quality limits specified in the GS(M)R. The specific gas quality limits, to which each Delivery Facility Operator (DFO) must adhere, are set out in the relevant entry agreement with National Grid. As such, it currently falls to the offshore producers and DFOs to ensure that, as required, gas is processed and/or blended so as to meet the GS(M)R gas quality limits prior to its delivery to the National Grid terminal.

If National Grid were to offer a blending service, the requirement for all gas delivered to the terminal to be compliant with the GS(M)R gas quality limits would need to be revised. However, the obligation to ensure that non-GS(M)R compliant gas does not enter the gas transportation network would remain. Accordingly, as a necessary pre-condition to offering any such service, National Grid would have to be confident that:

i) At any particular moment in time, there would be sufficient quantities of GS(M)R compliant gas against which to blend any non-compliant gas so as to ensure that the combined stream would be compliant with GS(M)R;
ii) the design of the terminal allows such "balancing" sources of gas to be commingled i.e. any non-compliant incoming gas stream could not pass through the terminal without mixing with one or more alternative incoming streams of gas; and
iii) that where two or more streams of gas commingle, the terminal hardware ensures that the resulting gas stream is fully mixed such that it is of a homogeneous composition i.e. there is no risk of "stratification" whereby gas quality could vary across the pipe. For example, where two streams of gas of different compositions commingle at a T-Junction, under some circumstances it is possible that one of the gases could be entrained along one side of the pipe, thereby resulting in a non-homogeneous mixture of gas that would vary in quality from one side of the pipe to the other. If such conditions existed at the point at which the quality of gas entering the NTS feeders is measured, this could result in an incorrect reading and possibly lead to National Grid taking inappropriate action, such as either allowing non-GS(M)R compliant gas to enter the network, or unnecessarily curtailing inputs of gas to the terminal.

Furthermore, National Grid would have to ensure that it had the necessary measurement and control arrangements in place to prevent non-GS(M)R compliant gas entering the transportation network.

Bacton terminal technical evaluation

Earlier this year, National Grid contracted Advantica to carry out a study to determine:

(i) whether sufficient mixing of gas takes place within the Bacton terminal (utilising existing hardware) to ensure that a homogeneous gas mixture is delivered to each of the NTS feeders; and

(ii) the potential range in the composition of gases (expressed in terms of the proportions of gas delivered from each sub-terminal) exiting the terminal into each of the NTS feeders.

In the event that confidence in the complete mixing of gases using the existing assets at Bacton was not established, Advantica were requested to recommend changes to terminal configuration at the engineering level to ensure such confidence.

To carry out the study Advantica used a number of tools including its Stoner Pipeline Simulator package (SPS) and Computational Fluid Dynamics (CFD). The analysis was performed over a range of flow rates and for a number of different flow route scenarios.

Within the study, Advantica:

- Built an SPS model of the Bacton terminal.
- Validated the SPS model using historical flow data under a number of conditions where input and output compositions were known.
- Used SPS to model whether full mixing would take place within the terminal, using determination of Reynolds Number (i.e. a measure of the extent of turbulent flow within the terminal) for a number of flow routes and flexes of flow.
- Where SPS modelling did not give confidence that full mixing had been established, CFD analysis was performed to simulate mixing headers and determine distances from the point of commingling to the point where "full" mixing was indicated to occur. These distances were then compared with actual distances measured at Bacton between the last commingling point within the terminal (prior to entry to each NTS feeder) and the relevant point at which the quality of gas entering an NTS feeder is measured.
- Used the SPS model to determine the composition of exit gas, expressed as a proportion of gas from each sub-terminal, under a range of flow routes and flexes of flow.

The key preliminary findings and recommendations arising from the study are as follows:

- Gas flow appears to be, under all reasonable conditions, turbulent, with Reynolds Numbers two orders of magnitude greater than those assumed for transition from laminar to turbulent flow.

- Consequently, mixing of any two gases is assumed to be rapid. However velocities of gases in the pipe are likely to range from $1ms^{-1}$ to $10ms^{-1}$, for total feeder flows between 5 mcm/d and 50 mcm/d, i.e. the realistic range for a single outgoing feeder.

- With analysis points between final mixing and gas composition measurement being from 35m to 75m, this means that gas could travel from mixing points to measurement points within periods of a few seconds.

- CFD analysis was used to determine whether, even with turbulent flow, full mixing of gases can be assumed in these short transit times. CFD simulations used a simple mixing header with gases of disparate compositions, and initialisation parameters designed to match as closely as possible, ideal pipeline conditions at Bacton, which would give lowest or worst case mixing rates.

- CFD simulations indicated that under all modelled circumstances, homogeneous mixing was complete to within a homogeneity of 1% within a pipe length of 20m, independent of the velocity or pressure, or whether an equi-mixture or an unbalanced mixture of gases was used. As indicated above the distances between points of final mixing and gas quality measurement at Bacton range from 35m to 75m. This is in excess of the 20m which analysis suggests is required to achieve mixing within a homogeneity of 1%.

- Transient analyses using SPS indicate that if incomer flows drop to zero, spikes in gas composition of as little as 30 seconds can be observed. With sampling times typically of the order of several minutes, these are unlikely to be measured using standard analytical equipment (chromatography).

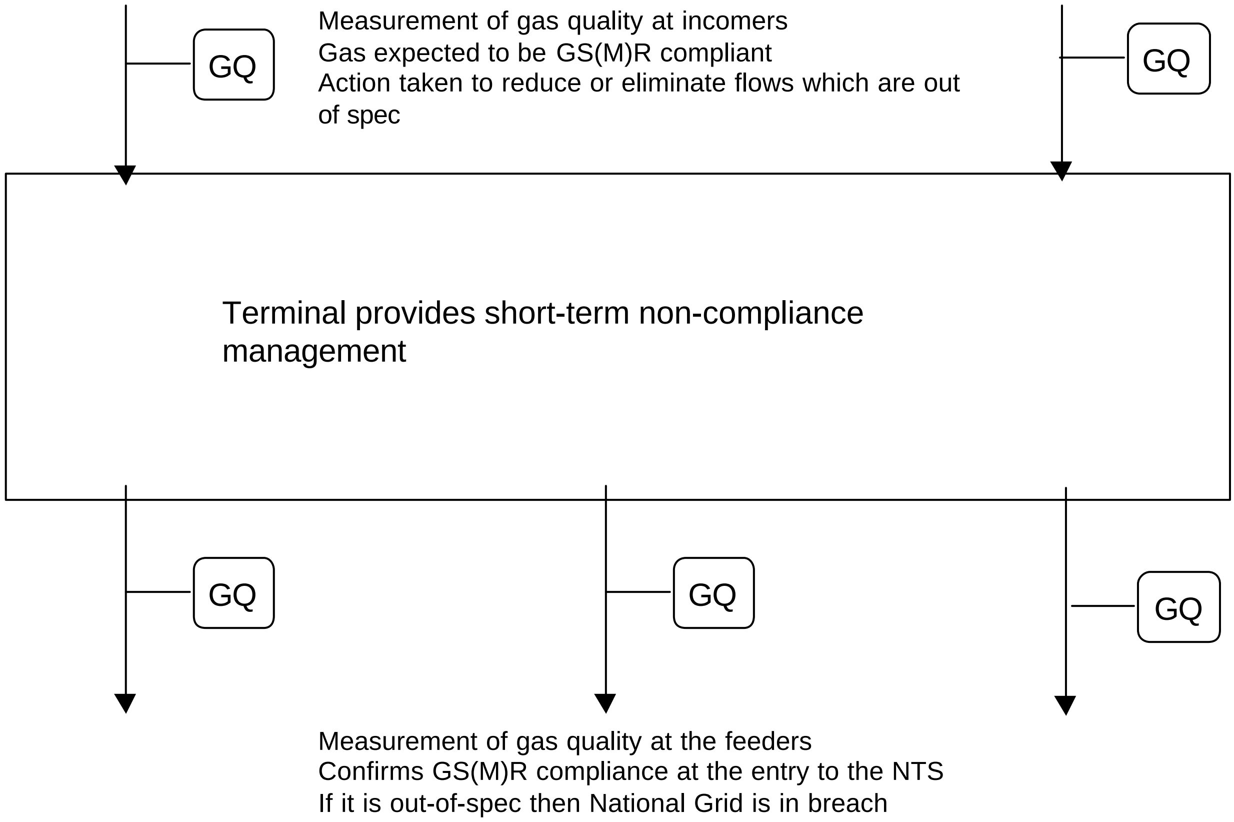
- SPS has proved able to give validated information on flow compositions both steady state and transient, across the Bacton reception terminal. SPS is also capable of mapping gas quality parameters such as Wobbe Index and relative density. Advantica recommended that SPS and the model of Bacton be employed to map the acceptable envelopes of gas composition under all likely operational modes, static and transient.

- Although simulations give some confidence that near-complete gas blending is taking place inside 20m of mixing, Advantica notes that this cannot be taken as a guarantee that such blending will take place. Validation is recommended where there is any doubt that blending will take place, particularly in safety critical situations. There are simple in-pipe mixing devices, which can be incorporated to reduce mixing lengths and increase the probability of mixing.

Safety and operational issues

In parallel to the Advantica study, National Grid has separately carried out an assessment of the safety and operational issues associated with providing a blending service at Bacton.

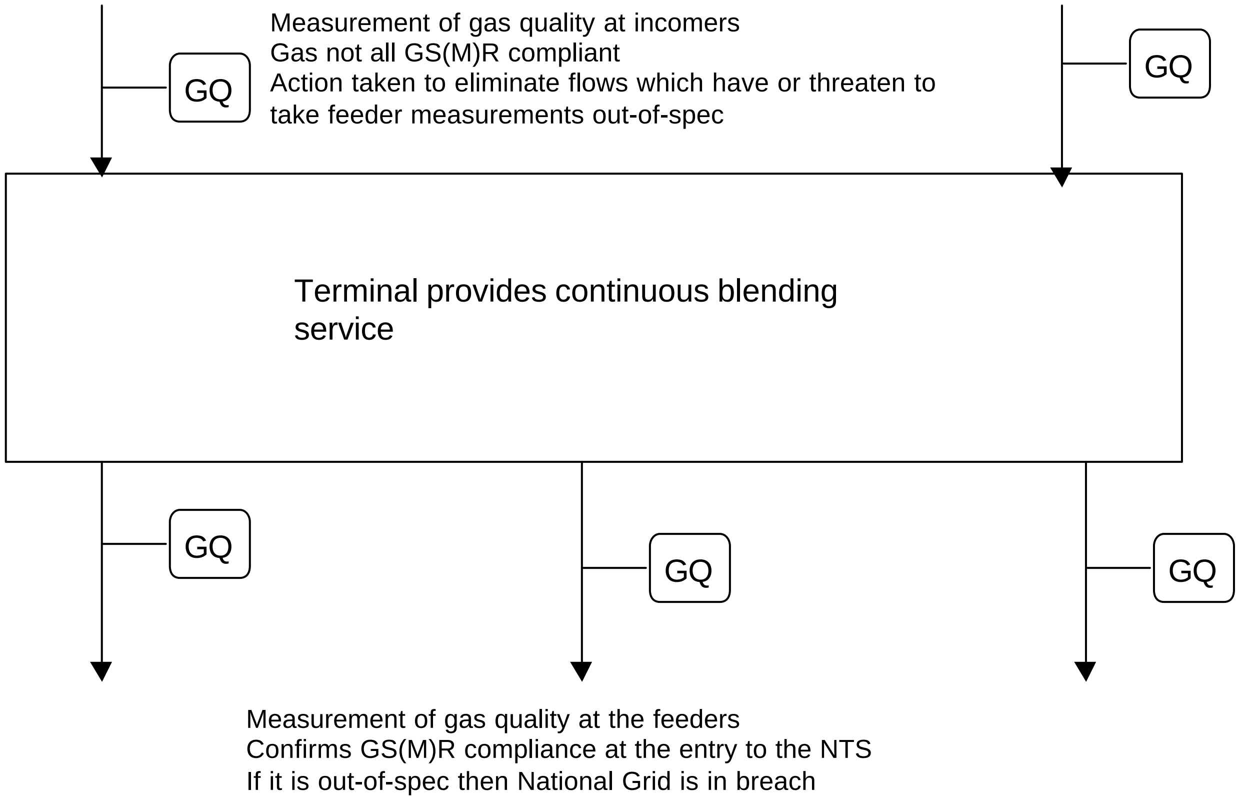
As described above, National Grid must operate Bacton terminal so that all gas delivered to the NTS feeders is compliant with GS(M)R. To this end, in common with other terminals, a set of compliance management arrangements are used to ensure that only GS(M)R compliant gas reaches the NTS. The arrangements are shown below:



Effectively, there is a three-layer structure to the arrangements:

- The primary measurement and control layer lies at the incomers. Gas quality is measured at each incomer and is expected (in line with current obligations on DFOs) to be compliant with GS(M)R and other contractual gas quality limits. If a limit is breached, then National Grid will control the non-compliant gas by either reducing flow or requiring the complete cessation of flows through the issuing of “Terminal Flow Advice” (TFA) notifications.
- The second layer lies in mixing that occurs in the terminal as a result of dilution due to the diverse quality of gases present.
- The final layer of measurements at the feeders acts as confirmation of the operation of the other two control mechanisms.

National Grid has considered what impact the introduction of gas blending would have on these management arrangements. The new arrangements would become as shown below:



With these revised management arrangements, the primary line of measurement moves to the feeders. If there is a possibility that gas entering the NTS feeders is non-compliant then action would still have to be taken at the incomers. Hence, the diversity that exists under the current management arrangements that permits the effective management and mitigation of short-term gas quality excursions would be removed as the terminal would now be operating in a “blending mode”. So the management arrangements would effectively change to a two-layer approach.

In this regime, time of flight issues within the terminal become more important since in order to ensure that non-compliant gas does not reach the NTS, changes in feeder gas quality will need to be reacted to immediately. Similarly, there would need to be a rapid response to changes in incomer volume flows and/or gas quality that could affect gas quality on the NTS feeder.

To ensure that these revised arrangements do not have an adverse effect on safety, a number of changes will need to be made to the measurement and control systems at Bacton as follows:

- The gas quality measurement system at Bacton requires upgrading to provide a higher frequency of readings so that it can be demonstrated that it is possible to respond in a timely fashion to variations in incomer gas quality and flow that could result in non-compliant gas reaching the NTS.

- The control system at Bacton itself would need to be upgraded to provide an integrated management system capable of facilitating gas blending. It would have to ensure that National Grid operators have the capability to manage flows and capacity at the terminal without creating problems with the gas quality leaving the terminal.
- Any new control system will also need to provide for automatic shutdown capability on sources of gas in order to ensure that non-GS(M)R compliant gas does not reach the feeders. To do this safely would require a detailed HAZOP review and could result in a requirement to install a high integrity measurement system to ensure reliable operation. The impact that an automatic shut-down system could have on upstream operations also needs to be assessed.
- HSE approval would be required for changes to GS(M)R compliance management arrangements. National Grid will have to demonstrate that any new arrangements do not increase the risk of non-GS(M)R compliant gas being transported onto the NTS.

Blending service for winter 2006/07

With regard to implementing the required changes at Bacton, as a next step it will be necessary to initiate a design and engineering study to identify, evaluate and specify a suitable measurement and control system to facilitate the provision of a safe, reliable blending service. It is anticipated that such a study could take up to five months to complete. In parallel, and feeding into such a study, National Grid would specify the necessary upgrades to the Bacton gas measurement system.

In terms of HSE approval, as far as possible National Grid would seek to engage with the HSE whilst the measurement and control study is being carried out. However, given its criticality to the safe operation of the system under a blending arrangement, National Grid would not be in a position to present its full proposal in support of a change to its safety case until such time as this study has been completed. It is not possible to give a definitive time period in which the HSE will complete its assessment of National Grid's proposal but it is likely that the process would involve the standard 90 day consultation plus time for the HSE to consider responses.

Subject to the HSE approving the required changes to its safety case, National Grid would then move on to the construction phase. The timing of this phase will be dependant on the scale of the changes identified though the design and engineering study.

In view of the above, it is not possible to implement the required technical modifications and changes to operational practices at Bacton in time to offer a blending service for winter 2006/07. However, National Grid proposes to continue to assess the potential for blending services at Bacton and elsewhere on the NTS (e.g. St Fergus) with a view to establishing the feasibility of offering such a service in winter 2007/08. In particular, the immediate focus will be to seek to resolve the identified measurement and control issues.

Next steps

National Grid will continue its review of the findings and recommendations set out in the Advantica study, including the need for on-site validation of the mixing results provided by the CFD analysis and will consider whether there is a requirement to install in-pipe mixing devices to increase the level of confidence that full mixing of gas is achieved within the terminal.

National Grid will also commission specialist engineering and design studies to identify, evaluate and specify a suitable measurement and control system to facilitate the provision of a safe and reliable blending service at Bacton.

Subject to the identification of an appropriate technical solution and confirmation of industry demand for a blending service, it will be necessary to define and agree with the industry and Ofgem the proposed scope and terms (including charges) of any such service. In relation to the question of whether there is demand for the service, we note that Ofgem intend to hold an industry workshop to consider gas quality issues later in the year and that there may be an opportunity to explore this issue at that time.

An update on progress will be provided in the Winter Consultation Report.

Annex D – Load duration curve and monthly cold spell analysis data

Load duration curve data

The following table provides the demand data used in the load duration curves in Figures 2, 3 and 4 in Chapter 1. It should be noted that this data is National Grid's 2006 demand forecasts.

Table D.1 – Demand data for Figures 2, 3 and 4

All data in mcm/d

	Average				1 in 10				1 in 50			
	Restricted demand				Restricted demand				Restricted demand			
Day no.	Domestic	Other DM	DM	Additional DM demand for unrestricted demand	Domestic	Other DM	DM	Additional DM demand for unrestricted demand	Domestic	Other DM	DM	Additional DM demand for unrestricted demand
1	246	86	119	17	269	93	123	18	291	99	125	18
2	225	80	118	17	263	91	123	18	281	96	124	19
3	217	78	118	17	258	90	122	17	274	94	123	19
4	213	77	118	17	254	88	122	17	268	93	122	19
5	209	76	117	17	250	87	121	17	264	91	121	19
6	207	75	116	17	246	86	121	17	260	90	121	18
7	204	74	117	16	243	85	120	17	258	90	121	17
8	203	74	117	16	241	85	120	17	256	89	121	17
9	202	74	117	16	238	84	119	17	254	88	121	17
10	200	73	116	17	236	83	119	17	252	88	121	17
11	199	73	116	17	234	83	119	17	250	87	120	17
12	198	72	116	17	232	82	118	17	248	87	120	17
13	196	72	115	17	230	81	118	17	247	86	120	17
14	195	72	115	17	228	81	118	17	245	86	120	17
15	194	71	115	17	227	80	118	17	244	85	120	17
16	193	71	114	18	225	80	118	17	243	85	120	17
17	191	70	114	18	224	79	117	17	241	84	120	17
18	190	70	114	18	222	79	117	17	240	84	119	17
19	189	69	115	17	221	78	117	17	239	83	119	16
20	188	69	116	16	220	78	117	17	238	83	119	16
21	187	68	116	15	219	77	117	17	237	82	119	16
22	186	68	116	15	217	77	117	17	236	82	119	16
23	186	68	116	15	216	76	117	17	234	82	118	16
24	185	68	116	15	215	76	116	17	233	81	118	16
25	185	68	116	15	214	76	116	17	232	81	118	16
26	184	67	116	15	213	75	116	16	231	80	118	16
27	183	67	115	15	212	75	116	16	230	80	118	16
28	183	67	115	15	211	74	116	16	229	80	118	16
29	182	67	115	15	210	74	116	16	228	79	117	16
30	182	66	115	15	209	74	116	16	227	79	117	16
31	181	66	115	15	208	73	116	16	226	79	117	16
32	181	66	115	15	207	73	116	16	226	78	117	16
33	180	65	115	15	207	72	116	16	225	78	117	16
34	180	65	115	15	206	72	116	16	224	77	117	16
35	179	65	115	15	205	72	116	16	223	77	117	16
36	179	65	115	15	205	72	116	16	222	76	116	16
37	178	64	115	15	204	71	116	16	221	76	116	16
38	177	64	115	15	203	71	116	16	220	76	116	17
39	177	64	115	15	202	71	116	16	220	75	116	17
40	176	64	114	15	202	70	116	16	219	75	116	17
41	176	63	114	15	201	70	116	15	218	74	116	17
42	175	63	114	15	200	69	116	15	217	74	116	17
43	175	63	114	15	199	69	116	15	217	73	115	17
44	174	62	114	15	199	69	116	15	216	73	115	17
45	174	62	114	15	198	68	116	15	215	73	114	18
46	173	62	114	15	197	68	116	15	214	72	113	17
47	173	61	114	15	197	68	115	15	213	71	114	17
48	172	61	114	15	196	67	115	15	211	71	114	16
49	172	61	114	15	195	67	115	15	210	70	115	16
50	171	61	114	15	195	67	115	15	209	70	115	16

	Average				1 in 10				1 in 50			
	Restricted demand				Restricted demand				Restricted demand			
Day no.	Domestic	Other DM	DM	Additional DM demand for unrestricted demand	Domestic	Other DM	DM	Additional DM demand for unrestricted demand	Domestic	Other DM	DM	Additional DM demand for unrestricted demand
51	170	60	114	15	194	66	115	15	208	70	115	16
52	170	60	114	15	193	66	115	15	207	69	115	16
53	169	60	113	15	192	66	115	15	206	69	115	15
54	169	60	113	15	191	65	116	15	205	68	115	15
55	168	59	113	15	191	65	116	15	205	68	115	15
56	168	59	113	15	190	65	116	14	204	67	115	15
57	167	59	113	15	190	65	115	14	203	67	115	15
58	166	59	113	15	189	64	115	14	202	67	115	15
59	166	58	113	15	188	64	115	14	201	66	115	15
60	165	58	113	15	188	64	115	14	200	66	115	15
61	165	58	113	15	187	63	115	14	199	66	115	15
62	164	58	113	15	187	63	115	14	198	65	115	15
63	164	57	113	15	186	63	115	14	197	65	115	15
64	163	57	113	15	185	63	115	14	196	65	115	14
65	162	57	113	15	185	62	115	14	195	64	115	14
66	162	57	113	15	184	62	115	14	194	64	115	14
67	161	56	113	15	183	62	115	14	193	64	116	14
68	161	56	114	14	183	62	115	14	192	63	116	14
69	160	56	114	14	182	61	115	14	191	63	116	14
70	160	56	114	14	181	61	115	14	191	63	116	14
71	159	56	114	14	181	61	115	14	190	63	116	14
72	159	55	114	14	180	61	115	14	189	63	116	14
73	158	55	114	14	179	61	115	14	188	62	116	13
74	158	55	114	13	179	60	115	14	188	62	116	13
75	158	55	114	13	178	60	115	13	187	62	116	13
76	157	55	114	13	177	60	115	13	186	62	116	13
77	157	54	114	13	177	60	115	13	185	61	116	13
78	156	54	114	13	176	59	115	13	184	61	116	13
79	156	54	114	13	175	59	115	13	184	61	116	13
80	155	54	114	13	175	59	115	13	183	61	116	13
81	155	54	114	13	174	59	115	13	182	61	116	13
82	154	54	114	13	173	58	115	13	181	60	116	13
83	154	53	114	13	173	58	115	13	180	60	116	13
84	154	53	114	13	172	58	115	13	180	60	116	13
85	153	53	114	13	171	58	115	13	179	60	116	13
86	153	53	114	13	171	58	115	13	178	60	116	13
87	152	53	114	13	170	57	115	13	177	59	115	12
88	152	52	114	12	169	57	115	13	177	59	115	12
89	151	52	114	12	169	57	115	13	176	59	115	12
90	151	52	114	12	168	57	115	13	175	59	115	12
91	150	52	114	12	167	56	115	13	174	58	115	12
92	150	52	114	12	167	56	115	13	174	58	115	12
93	150	52	114	12	166	56	115	12	173	58	115	12
94	149	51	114	12	165	56	115	12	172	58	115	12
95	149	51	114	12	165	56	115	12	171	57	115	12
96	148	51	114	12	164	55	115	12	171	57	115	12
97	148	51	114	12	163	55	115	12	170	57	115	12
98	147	51	114	12	163	55	115	12	169	57	115	12
99	147	51	114	12	162	55	115	12	168	57	115	12
100	146	50	114	12	161	54	115	12	167	56	115	12

Monthly Cold Spell Analysis Data

The following tables provide the supply and demand data for the Monthly Cold Spell Analysis used in Figures 5 and 6 in Chapter 1.

Table D.2 – Supply and demand data for monthly cold spell analysis for 2006/7 assuming maximum physical supply capacity

Maximum physical capacity (all data in mcm/d)	Oct	Nov	Dec	Jan	Feb	Mar
UKCS	267	267	267	267	267	267
Norwegian	104	104	104	104	104	104
Isle of Grain	17	17	17	17	17	17
Belgian Interconnector	48	48	68	68	68	68
Dutch Interconnector			30	30	30	42
Rough	42	42	42	42	42	42
Medium Range Storage	32	32	32	32	32	32
LNG Storage	49	49	49	49	49	49
Excelerate			11	11	11	11
1 in 20 daily demand	346	410	440	485	481	438
1 in 20 average weekly demand	302	358	388	422	425	380
1 in 20 average monthly demand	278	334	369	402	410	355

Table D.3 – Supply and demand data for monthly cold spell analysis for 2006/7 assuming revised base case supply conditions

Split winter (all data in mcm/d)	Oct	Nov	Dec	Jan	Feb	Mar
UKCS	240	240	240	240	240	240
Norwegian	48	48	48	48	48	48
LNG Imports	13	13	13	13	13	13
Belgian Interconnector	25	25	25	40	40	40
Dutch Interconnector				20	20	20
Rough	42	42	42	42	42	42
Medium Range Storage	32	32	32	32	32	32
LNG Storage	49	49	49	49	49	49
1 in 20 daily demand	346	410	440	485	481	438
1 in 20 average weekly demand	302	358	388	422	425	380
1 in 20 average monthly demand	278	334	369	402	410	355

Annex E – Summary of May winter 2006/07 consultation responses

We received 33 responses to our Winter 2006/07 Consultation Document issued in May 2006. The responses provided us with valuable additional information relating to the forthcoming winter, which has helped us to shape the analysis contained within this consultation update document and identify where further information is required.

Due to the nature of the information provided a number of the responses were provided on a confidential basis. Therefore this section provides a summary and overview of the issues raised and views expressed without attributing comments to individual organisations.

General comments

Respondents generally welcomed the opportunity to comment upon our May consultation document and a number expressed support for the revised multi-stage process. A few mentioned the additional value of this second consultation document recognising the importance of the inclusion of TBE data providing National Grid with a unique position in its ability to assess the overall supply and demand situation regarding next winter.

Most respondents limited their responses to areas where they felt they were best able to comment. As a result, some of the specific questions raised in the consultation received only a limited number of responses. Most respondents felt they were not in a position to provide quantitative data.

A number of the respondents recognised the particular uncertainties associated with the coming winter, noting that gas supply issues had been given due prominence in the May consultation document. In line with this, most respondents tended to focus their responses on demand-side response and gas supply issues.

Non-CCGT gas demand-side response

Q1. We would welcome views on the extent to which the non-CCGT market is able to provide demand-side response both in volume and duration terms

Responses to this question varied. Many of the respondents focused on the ability / willingness of the non-CCGT market to provide demand side response. A number of the respondents pointed to a potential increased volume of demand-side response in response to price signals and new commercial terms, however some warned that this may not be the case if consumer take-up of fixed price contracts, to mitigate the effect of price volatility, had increased. This resulted in a mixed response with different respondents anticipating increased, the same, or even lower demand-side response from the non-CCGT sector in the forthcoming winter than seen in winter 2005/06, with most recognising it was difficult to quantify.

Those who thought that there may be an increase pointed to the Ofgem survey indicating a willingness to respond, new commercial terms and higher prices.

A couple of the respondents noted the nature of supply to the non-CCGT sector, pointing out that a loss of supply in some instances could lead to a permanent loss of production and that the primary business of the consumer was to honour product supply contracts with their own customers rather than ‘sell gas’.

One respondent criticised the reliance on demand-side response as an effective tool for within-day balancing stating that the market incentives and purchasing mechanisms did not allow for a quick response to demand reduction.

Q1a. The extent to which gas demand-side arrangements were in place for the 2005/06 winter (whether through interruptible contracts or otherwise)

One respondent noted that such response from the non-CCGT sector was significant, albeit small compared to the CCGT sector.

According to responses received the extent to which demand side arrangements were in place last winter varied depending upon the contractual provisions of supply contracts; some criticised shippers / suppliers for failing to facilitate such provisions.

One respondent stated that provisions were not fully utilised due to the fact they were introduced mid-winter without providing time for contractual terms to be revised. Another stated that temporary clauses were put in place, enabling some users to buy and sell gas.

In response to market signals and regulatory concerns, one respondent drew up new contracts which sort to avoid the difficulties in agreeing prices for optionality which have made agreeing Shipper Call Interruption products so difficult. However the uptake on these new contracts was somewhat limited.

Companies exposed to short term prices were incentivised to self-interrupt in response to price, in some cases by taking action such as bringing forward maintenance periods, whereas those on monthly contracts did not reduce consumption.

Q1b. The extent to which such arrangements were utilised, and what triggered them (e.g. shipper v customer driven, contracted interruption v price arbitrage, response to GBA etc)

No detail was provided as to the extent to which such arrangements were utilised however one respondent did state that last year’s behaviour did not indicate future volumes.

The majority of respondents agreed that arrangements were triggered by price. Some respondents suggested that high demand also factored into the decisions made. In addition action was taken by both firm and interruptible consumers in response to the Gas Balancing Alert (GBA). For example; On the GBA day, one respondent's industrial clients responded to within day prices by negotiating a price to reduce demand with shippers. Another respondent, by an initiative to contact consumers, managed to reduce volume by 4% on the GBA day. On subsequent days, there was a reduction of 15% due to high price and not demand-supply fundamentals.

A couple of respondents explicitly noted that utilisation was customer driven, in particular when larger customers curtailed demand to take advantage of contractual terms.

Q1c. The extent to which there is scope for investment prior to the 2006/07 winter to provide back-up capability at non-CCGT DM sites

There was a divergence of opinion as to whether or not there is scope for investment prior to next winter to provide back-up capability at non-CCGT DM sites. A couple of respondents deemed time as the constraining factor but believed that in some cases arrangements could still be made. One respondent stated that if contractual terms were in place in advance there was the opportunity to maximise the potential from sites with alternative fuel capability by the provision of alternative fuel stock. They also stated there was the potential to explore customers' ability to cease consumption for specific periods now that multiple day bids can be accepted. Others disagreed stating back up fuel was uncompetitive and its use constrained by logistical problems associated with its provision.

One respondent stated that it was not economic to invest in back up capability as there was confidence that in future periods prices would be lower.

Q1d. The extent to which the experience of the 2005/06 winter may influence the development of such arrangements and the likely impact on the level of potential demand-side response in 2006/07

Respondents generally agreed that the experience of winter 2005/06 would have increased consumer awareness of supply issues and potential price volatility. On the whole they believed that this would lead to the development of new purchasing strategies. A number of respondents indicated that this awareness might potentially increase those taking up fixed contracts in an attempt to avoid price volatility therefore reducing potential price responsiveness. In contrast others thought that potential demand response would increase due to new contractual provisions and proposed market mechanisms.

Q1e. The extent to which a permanent reduction in non-CCGT gas demand (so-called 'demand destruction') has occurred as a result of recent high energy prices

Opinions as to the extent to which so-called 'demand destruction' has occurred as a result of high prices varied. Some respondents had not seen any 'demand destruction' or considered it 'not significant'. Others quantified within industry investment losses or deferrals amounting to £600m and noted some industry closures (notably in the glass / paper industry) or transfer of production abroad (following a trend of de-industrialisation in the UK). A number of respondents suggested that the demand destruction may be temporary, potentially limited to winter periods. Another noted that consumers had commented that the cost of GBA day may result in demand destruction.

Q2. To what extent can a general reduction in NDM demand be expected in 2006/07, given that NDM demand during the 2005/06 was typically 3-4% below the expected level?

The majority of respondents to this question thought that a similar level of NDM demand reduction to that experienced during winter 2005/06 would be possible in 2006/07. One respondent quantified this by saying that the reduction in demand could be up to 4-5% due to increased prices and customer awareness. Where reasons were provided respondents felt that the demand reduction would be largely due to increased public visibility of gas prices and other costs of energy use (global warming etc). However one of these respondents suggested that consumer efforts to reduce demand would diminish with colder, more prolonged conditions and that high prices would not affect the level of demand on the peak day.

A couple of respondents believed that the reduction compared to expected levels was due to forecasting issues rather than a response to market conditions.

Q3. We would welcome views on expected non-CCGT demand levels for winter 2006/07 under a range of weather conditions and, in particular, on the assumptions that should be made to determine the peak day non-CCGT demand that can be expected in winter 2006/07?

A number of varying responses were received to this question. A couple of respondents used the opportunity to raise the issue of availability of demand side response from the non-CCGT sector with one referring to the survey undertaken by Ofgem arising from the Demand Side Working Group (DSWG) giving some indication of the willingness to respond.

With regards to weather responsiveness one respondent suggested that their customer contracts were affected by longer term pricing signals and that the majority of volume was not weather dependent. This contrasted with another respondent indicating a high correlation between demand volumes and temperature.

In terms of peak day demand one respondent suggested that changes in forecast annual demand would not be translated into a reduction in the forecast peak day.

Q4. At what levels of demand would Distribution Network owners expect interruption to be triggered for capacity management purposes?

Q4a. At what level of demand are Network Sensitive Loads (NSLs) likely to be interrupted?

Q4b. At what level of demand are other interruptible loads likely to be interrupted?

For information provided by the Distribution Network owners in response to these questions please see Annex B.

UKCS supplies

Q5. What assumptions should be made over the maximum UKCS supply availability for 2006/07?

Q5a. What assumptions should be made over the maximum UKCS supply availability from existing fields?

Several respondents expressed a desire / need to consider the outcome of TBE prior to being able to provide an informed response to this question. A couple of respondents explicitly agreed with the drop in supplies from existing fields. Most felt that the assumptions were reasonable / fair with one respondent commenting that they were a ‘more realistic assessment than seen in previous years’. A couple of respondents felt that the assumptions were conservative / prudent with one respondent attributing a potential upside in response to price.

Q5b. What assumption should be made over the commissioning of new UKCS developments?

With regard to new fields one respondent agreed that the assumed 10 mcm/d could be expected however another was more optimistic citing 13 mcm/d with a further 6mcm/d by Q107.

Q6. What implications does the cooler unit issue associated with the Rough storage incident have for UKCS supplies this winter?

Respondents believed that the cooler unit issues were restricted to those already identified at Rough and South Morecambe and they hoped that these should have no further impact on supplies for next winter. One respondent noted that the biggest effect of the Rough problem is likely to be a change in shipper’s behaviour regarding the use of storage with potentially greater emphasis being placed on future operational risk, leading shippers to withdraw earlier in the season.

Q7. What assumptions should be made over the average percentage UKCS supply availability under a period of prolonged severe conditions in 2006/07?

Respondents generally indicated 90% UKCS supply availability was reasonable with only one respondent stating that this was optimistic. However a number of respondents felt that 80-85% would be prudent when considering availability during prolonged poor weather offshore.

Q7a. To what extent would UKCS supply reliability decrease if poor weather is experienced offshore?

A number of respondents indicated that extreme weather offshore decreases availability by hampering operations and extending the time required to repair machinery should problems occur. One respondent further specified that they would not expect a prolonged reduction in output due to weather conditions unless physical damage has occurred.

Q7b. How might UKCS supply availability vary across the winter months, and, in particular, should a lower level of availability be expected in the early part of the winter?

With regards to supply availability varying across winter months two respondents indicated that producers historically use swing so that peak delivery coincides with peak demand (Q1).This contrasted with one respondent who felt that due to long periods of high production increasing wear, reliability may actually decrease through the winter.

A couple of respondents noted that the rapid transition to winter 2005/06 in November and production ramping up slowly should have provided a learning experience for forthcoming years.

One respondent noted that in the consultation document and last year's outlook report that the days of individual terminal maxima rarely coincide with the maximum demand days nor the maximum beach days.

Gas imports

Q8. We would welcome views on whether similar monthly variations to those observed last year can be expected in winter 2006/07 from the various import sources

Generally respondents agreed that similar monthly variations from the various import sources to those observed last year can be expected. The majority of respondents attributed this behaviour to the use of gas storage on the continent; with increased flows to the UK later in the winter corresponding to the release of Continental European storage gas once holders are comfortable with the levels of gas in store.

One respondent stated that the recent focus on liberalisation of the European market should lead us to expect a more predictable response to high gas prices and available infrastructure. Another welcomed increased transparency in this area.

One respondent considered the need to treat gas supplies on a month by month basis in order to account for capacity projects coming on line. Their later comment regarding the importance of utilisation rather than just capacity was mirrored by another respondent.

Q9. What assumptions should be made for levels of imported gas through the Belgian Interconnector for winter 2006/07?

No firm quantitative data was provided in response to this question. A couple of respondents stated they thought flows would be higher than 2005/06 whereas another assumed they would be similar to 2005/06 flows but potentially 20% higher.

One of the respondents who believed that assuming similar flows to last winter was pessimistic stated this was due to EU pressure on energy companies on the Continent to be less protectionist and the fact that last year much of Northern Europe was bitterly cold.

A few respondents said they accepted the logic of flows being lower in Q4 than Q1 as domestic supply took precedent and storage stocks were reserved on the continent during Q4.

One respondent listed the key factors (some of which were also raised by other respondents) summarising the difficulties in accurately forecasting an exact level of imports over winter 2006/07: the price differential between the NBP and Continental European markets, specifically the price at Zeebrugge; the demand for gas in Continental European markets; the contractual and public service commitments of gas suppliers in some Continental European markets; any pre-existing contracts to supply gas to UK Shippers; the physical and contractual availability of gas that meets UK GS(M)R specifications at Zeebrugge.

Q9a. What assumption should be made over the date at which the second upgrade becomes operational?

All respondents anticipated that the upgrade would be operational by the planned commissioning date of 1st December.

Q9b. How much gas has been contracted by shippers to import through this Interconnector into the UK and what is the nature of these contracts (duration, indexation etc)?

Only one respondent replied to the question regarding gas contracted by shippers to import to the UK. They stated that their limited experience was of optimisation on a short-term basis depending on price signals in the market.

Q9c. To what extent might physical transportation constraints in Europe limit the level of imports into the UK through this Interconnector?

Although unable to provide a quantified response most respondents agreed that the Belgian Interconnector was unlikely to be fully utilised and considered that physical transportation constraints in Europe (in particular in Belgium) would prove to be a limiting factor. German 'debottlenecking projects' were considered positive developments.

Q9d. To what extent have shippers access to the necessary European transportation infrastructure to support gas imports through this Interconnector?

One respondent noted that in relation to short-term capacity on the continent, there appears to be a lack in of liquidity.

Another respondent highlighted the difficulty in obtaining transit capacity within European pipelines, due on some occasions to the physical configuration of the network, as an issue in this respect.

Q9e. To what extent might gas quality issues restrict the level of imports into the UK through this Interconnector?

A couple of respondents stated that they expected gas quality issues on this Interconnector to become more important with time as constraints on the European transmission systems improve. They used the opportunity to reiterate that they expected imports to be restricted by physical and contractual availability of gas from Zeepipe and Zeebrugge LNG.

One respondent stated that due to the UK specification for Wobbe differing from Continental Europe it is possible that UK compatible Norwegian supplies will be diverted through Langeled to the UK and higher Wobbe Index gas will be delivered to Zeebrugge. Therefore gas quality issues would impact on flows through the Belgian Interconnector.

Another respondent stated that an assessment should be made over the installation of ballasting plant at Bacton and that speculation of restrictions due to gas quality issues needed to be overcome.

Q9f. To what extent can net flows on the Interconnector be expected to be depressed by gas export nominations?

There was limited response to this question. One respondent stated that flows could be depressed 'very slightly' due to gas export nominations whilst another stated that it was impossible to forecast as it would be dependent on the aggregate position of all shippers. In line with responses to earlier questions another respondent stated that flows would depend upon relative availability of gas and relative prices.

Q10. What assumptions should be made for levels of imported gas through BBL for winter 2006/07?

Few respondents commented on the base case assumption of an average flow of 20 mcm/d through BBL once it was operational. Two respondents felt that this assumption was appropriate. One thought it "slightly cautious" although no rationale for an alternative assumption was offered.

Q10a. What assumption should be made over the date at which BBL becomes operational initially and the subsequent upgrade to a capacity of 42 mcm/d?

While some respondents had no information on the likely start time for BBL flows other than the planned commissioning date, a number of respondents noted the tight timescale associated with the construction of this Interconnector, highlighting the possibility of delay to commissioning. One of these considered that the situation surrounding BBL flows in 2006/07 was highly uncertain and would remain so until the construction of the infrastructure is substantially complete. Two others identified the possibility of a delay of a month or more.

The only respondent to comment on the upgrade understood the earliest a 3rd compressor would be ready to be 1 March 2007.

Q10b. What utilisation rate should be assumed for the BBL capacity not required to service the Gasunie-Centrica contract?

Only a couple of consultation respondents provided an answer to this question, neither provided quantifiable information. The first stated that as there will be no new gas production sources in NW Europe this winter any extra gas available to release into the UK would come from 'constrained gas' in Holland due to transportation constraints there. Also, given that the supply contracts with Centrica are for delivery at the NBP it is not necessary for gas to flow to the UK to honour these agreements.

The other replied that until the compressor upgrade in March 2007 there will be limited opportunity for third party capacity. No firm capacity will be offered to market participants. The interruptible nature of 3rd party BBL/GTS capacity and high imbalance penalties in the Dutch system mean that it is unlikely that the remaining capacity will be fully utilised.

Q10c. To what extent might physical transportation constraints in Europe limit the level of imports into the UK through this Interconnector?

Three respondents made reference to the Grijpskerk-Workum-Wieringermeer Line (GWWL) connecting Balgzand to Emden, noting that this would not be completed until later in 2007, which could potentially limit the availability of gas through BBL during winter 2006/07.

Q10d. To what extent have shippers access to the necessary European transportation infrastructure to support gas imports through this Interconnector?

No additional information was provided.

Q10e. To what extent might gas quality issues restrict the level of imports into the UK through this Interconnector?

The only respondent to explicitly provide an answer to this question thought that gas quality issues would only have a minor impact with respect to flows on this Interconnector.

Q10f. What is a realistic level for sustained flows via BBL to the UK for winter 2006/07 once it is operational?

Two respondents felt that the 20 mcm/d assumption was appropriate.

Q11. What assumptions should be made for levels of imported gas from Norway for winter 2006/07?

Opinions varied over the level of imported gas from Norway that should be assumed. One respondent suggested that it should be assumed that gas would flow to the highest price market with the easiest access to transportation capacity. Another agreed with the assumptions for flows via Vesterled but anticipated higher incremental flows whereas another concurred with the assumptions regarding Langeled. A couple of respondents noted potential upside on Langeled flows.

Q11a. What assumption should be made over the date at which Langeled becomes operational?

All respondents agreed that the assumption for the operational start date for Langeled should remain 1 October 2006.

Q11b. What level of additional gas supply availability from Norway should be assumed over and above that which we have previously observed through Vesterled?

Respondents’ opinions over the level of incremental flow from Norway varied. One respondent referred to Gassco’s presentation at the Ofgem winter seminar in May 2006, in which they stated that there would only be nominal levels of new gas from Norwegian producers and it was likely that only volume not sold under long-term contracts could be directed to the UK.

A few other respondents saw potential upside in the incremental level of gas with additional volumes suggested (up to a total of 25 mcm/d) via gas swaps and diverted European flows.

Q11c. To what extent might gas quality issues restrict the level of imports into the UK from Norway?

There was significant divergence of opinion between the few responses received to this question. A couple of respondents thought that gas quality issues would have only a minor impact, anticipating the current situation (of gas quality not having caused any problems) to continue. Another respondent considered gas quality parameters, in particular the Incomplete Combustion Factor (ICF) restriction, to be one of the key issues relating to importing gas from Norway. This respondent advocated revising the ICF limit to avoid problems. One respondent suggested avoiding the problem by the provision of ballasting plant.

Q12. What assumptions should be made for the total levels of European imports?

Given their responses to previous questions few respondents used this opportunity to provide additional information. Comments relating to specific import routes have been included in the summaries for questions 9 – 11 above.

Q12a. What interaction between the flows through the various importation routes should we assume, e.g. the extent to which incremental Norwegian imports offset flows via the Belgian Interconnector?

A couple of respondents suggested that producers would switch to flows via Langeled South to reduce transportation costs.

One respondent suggested that there was a possibility of this behaviour reducing flows into Continental Europe thereby resulting in reduced flows on the Belgian Interconnector.

Q12b. What is the total level of flow that could be expected through the Continental Interconnectors (BBL and Belgian Interconnector) given sufficiently high demand in the UK?

One respondent suggested total flow quantities into the UK from Europe would vary according to supply-demand fundamentals. Another responded listing additional factors which would contribute: the price differential between the NBP and Continental European markets; the price at Zeebrugge; the demand for gas in Continental European markets; the contractual and public service commitments of gas suppliers in some Continental European markets; any pre-existing contractual to supply gas to UK Shippers; and the physical and contractual availability of gas that meets UK GS(M)R specifications at Zeebrugge, (normally dependant upon gas from the Zeepipe from Norway and the Zeebrugge LNG Terminal).

Q12c. What are the key risks to the timely completion and commissioning of the infrastructure projects that will facilitate additional gas supplies to the UK for the 2006/07 winter?

Only a couple of responses were received to this question. One used the opportunity to reiterate construction risks associated with the BBL project, stating the importance of keeping the market informed of progress. The other respondent provided a more generic answer citing key risks as planning delays, equipment lead times, Ofgem's rules on the release of entry capacity and prices and exit reform uncertainty.

Q12d. As described in paragraph 175, National Grid is examining the feasibility of potential blending opportunities at the beach terminals. This work is initially focused on Bacton. To what extent do parties consider that, should such blending be possible, additional gas supplies for this winter would emerge?

All respondents to this question agreed the gas quality issue was increasing in importance and needed addressing for the future. One respondent provided further details regarding the risks associated with the current supply situation stating that while this may not be a frequent problem gas quality issues pose a specific risk on high demand days if National Grid have no alternative but to issue a Terminal Flow Advice (TFA) in respect of gas being delivered outside of specification.

A couple of respondents recognised the value of blending services at sub-terminals as increasing the potential availability of gas. However, as one respondent went on to state, it is not possible to say if it would increase supplies but it may enable gas deliverability at times of operational difficulty.

Q13 What assumptions should be made for LNG importation quantities in winter 2006/07?

Q13a. How are flow patterns likely to differ from those observed in 2005/06?

Generally respondents were confident that flows through Grain would be higher throughout winter 2006/07 especially when compared to early winter 2005/06, due to market trends and the UIOLI provisions. A number of respondents warned that the global market would impact on the flows seen, with one respondent noting that LNG cannot be thought of as simply an arbitrage between the NBP and the Henry Hub prices as there are other countries (e.g. Asia and other European countries) that compete strongly for LNG deliveries.

A number of respondents felt that 13 mcm/d flow assumption was reasonable for the base case and excluding Excelerate was prudent. However a couple of responses indicated that this figure was too high, with one respondent stating 100% availability was unrealistic and the other suggesting a revised base case flow figure for Isle of Grain of 11mcm/d.

Storage

Q14. We would welcome views on the likely patterns of use of the various gas storage facilities in 2006/07

It was recognised that the overall pattern of storage use would be an aggregate of individual shipper's usage, which in turn would be dependent on market factors and portfolio considerations. All respondents agreed that the pattern of use of storage would be dependent upon market prices. In addition a few respondents noted secondary variables of weather and supply disruptions. One respondent noted a potential price spike and early draw down of MRS if there was an early cold spell or supply disruption. In terms of pattern of use it was deemed reasonable to assume an overall pattern of use similar to that observed last year with the assumption that Rough problems would not recur.

One respondent used the opportunity to suggest consideration should be given to retrofit peak-shaving plant to be able to receive road deliveries.

Q14a. Likely trigger dates and/or trigger prices for use of storage

As one respondent noted, it was impossible for respondents to indicate specific trigger dates or prices, as different users, with different stock levels within different types of storage facilities, would be driven by different prices. All respondents agreed that the main determinant for withdrawal was price-related with a few expanding on this to state that withdrawal would likely take place if the spot price exceeded the relevant forward price and another stating that the prompt price needed to reach Q1 peak price.

Q14b. The scope for re-injection under different demand and price conditions

Again respondents primarily agreed that when conditions allowed for re-injection (i.e. subject to physical constraints and technical limitations) whether or not re-injection occurred would depend upon price and stock levels. Generally respondents suggested that re-injection would take place if spot prices fell below forward prices.

Q14c. The order in which long, medium and short range storage would be called upon in relation to marginal UKCS fields, interconnectors and LNG imports

As per their answers to previous questions, a couple of respondents indicated that the order in which gas supplies would be called upon would be market-related and optimised based on price. One respondent suggested that storage use would go in the order of LRS, MRS then SRS. One respondent provided a summary of the factors which needed to be considered; with the order in which supplies were used depending on stock levels, the number of days left in the winter, Zeebrugge price drivers, LNG ship availability. Their experience suggested that MRS/SRS would be called upon post-imports unless there was sufficient time to re-inject or it was near the end of winter.

Q14d. The extent to which UK storage stocks are reserved for UK usage, and what events may lead to them being traded on the continent

As one respondent noted, under the current UK regulatory regime, there is no reservation of UK storage stocks for UK use. As such, there would appear to be nothing to stop UK storage being traded as freely as any other UK source of gas. This would imply that it would be dependent on price arbitrage levels, the relevant cash-out regime and the availability of Interconnector capacity. All but one of the respondents agreed with this stating that the decisions regarding the trading of storage stocks would be based upon economic rationale with flows responding to price. On this basis, one respondent suggested that due to the current forward prices they would expect UK storage stocks to be used for the UK.

Only one respondent categorically stated that all their storage capacity will be reserved for UK use.

Q14e. The extent to which European storage stocks are reserved for continental use, and what events may lead to them being traded in the UK

Respondents' views as to the extent to which European storage stocks are reserved for Continental use varied considerably. One player considered them to be 100% reserved for use on the Continent (in early winter) whereas another felt that flows would depend upon economic rationale. However the respondent who stated that flows were dependent on economic rationale noted that this would be subject to practical constraints (gas being within GS(M)R, long term contracts governing the use of gas, public service obligations).

A number of respondents commented on the likely pattern of flows of gas from Continental storage, proposing that on the basis of previous experience they would expect more gas to be released later in the winter once players were comfortable with the supply position on the Continent. Continental players would be unlikely to release gas in early winter due to the need to ensure they met their own security standards. One used the opportunity to reiterate that due to this the forecasting of a split winter was sensible.

One respondent suggested increased transparency was required in this area and another stated that they would welcome any political pressure brought by the UK to encourage a market-based approach by the Europeans.

Q15. We would welcome views on the appropriate basis for setting the 2006/07 safety monitors

Of those respondents to the May consultation who commented on the appropriate basis for setting the monitor levels, one felt that the base case was "erring towards the conservative", while another took the view that there was "a much greater probability of potential downside…..than potential upside". Another respondent suggested that the assumptions surrounding the isolation process should be revisited, while a further respondent was concerned by the approach to the 2005/06 monitors, when we reflected supply-side uncertainty by the inclusion of a 'supply risk allowance', which was focused on the long-range storage monitor.

Other comments concerned the system of safety monitors more generally, with the need for transparency a common theme.

Electricity market

Q16. We would welcome views on the extent to which electricity demand response might be expected given high electricity prices

Q16a. How much more response might be seen compared to winter 2005/06 estimates?

It was noted from 2005/06 that a demand response of approximately 1GW per day is achievable for a number of days. Most respondents did not expect electricity demand response to increase materially compared to this level seen last year. A few respondents stated that those with the capability to alter demand were already active at reducing demand at peak times to avoid high prices and possible triads, and therefore increases in demand response would be limited. However a couple of respondents did note that there might be additional market incentives in place as a result of changes to the electricity cash-out pricing mechanism.

Q17. What assumptions should be made over the extent to which mothballed generation will become available, and when?

A number of respondents agreed with the assumptions set out in the May consultation document. Respondents thought short-term mothballed plant with TEC (Transmission Entry Capacity) would return subject to appropriate market conditions. Other respondents felt that time considerations were important and that plant was likely to return if a prolonged cold spell was expected. One respondent did warn that the decision would also be impacted by developments in clustering and access product charging and that compared to previous winters P194 would add additional risk to the commercial decision over whether or not to return.

Q18.To what extent is there scope for investment prior to the 2006/07 winter to provide back-up capability at existing power stations?

The majority of respondents felt that there was no scope for investment prior to the 2006/07 winter to provide back-up capability at existing power stations. A number of respondents suggested that were there an economic case for investment there was limited scope within the timeframe due to all the factors that would need to be taken into account (planning, environmental authorisations, physical modification to infrastructure). One respondent stated they were in the process of undertaking investment to increase output at one of their sites. Another said that some infrastructure remains in place at one site but had never been commissioned, was not stocked with fuel and no action was planned prior to the coming winter.

Q19. What assumptions should be made over the availability of nuclear generating plant?

Despite a couple of respondents agreeing with the assumption used in the modelling, the majority of respondents to this question felt that an 80% availability factor from nuclear generating plant was low compared to historic averages.

Q20. What assumptions should be made over the level and direction of flows on the UK-France Interconnector given cold weather in both UK and Europe?

Respondents' opinions varied as to the assumptions that should be made on UK-France Interconnector flows given cold weather in both the UK and Europe. One respondent felt the 2 GW assumption was prudent however agreed with other responses that any curtailment would reduce availability. Others stated that the Interconnector would flow in response to relative prices, and that with high demand in both the UK and the Continent the Interconnector could flow at float.

CCGT demand-side response

Q21. We would welcome views on the ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests might be theoretically achievable in a severe winter

Respondents' opinions regarding the ability of the electricity market to deliver in practice the level of CCGT response the analysis suggested might be theoretically achievable varied from believing that the projected response was broadly sensible (and potentially up to 3.5 bcm response could be achieved) to another respondent who considered that the response suggested by our analysis may not be possible. It was anticipated that CCGT response suggested could be met under average conditions, could feasibly be met under 1 in 10 conditions but was questionable whether it could be met under 1 in 50 conditions. A couple of respondents noted that the level of response it was possible to achieve would vary dependent on a number of factors such as alternative fuel stock supply plus other constraints and could be significantly lower. One respondent did note concern that the level of response suggested could potentially threaten electricity security of supply.

Q21a. Our assumptions relating to the generation running order under cold weather conditions and the associated availability factors

Respondents generally agreed with the assumptions relating to generation running order with gas likely to remain the marginal fuel, coal at high load factors and oil running ahead of gas for an extended day time period. One respondent questioned whether or not non-NTS CCGTs would operate as baseload due to last years usage and suggested that 2.7 GW of NTS CCGTs would run as baseload.

With regards to CCGTs one respondent questioned the 95% availability factor and suggested two-shifting would increase plant failure rates.

Other respondents generally thought other assumptions with regards to availability factors to be reasonable. However this was caveated in part by requests for more detailed information on the assumptions (e.g. at what capacity the pump storage was assumed to run).

Q21b. The extent to which relative market prices will signal the requirement for CCGTs to continue to burn gas at peak electricity demand periods

All respondents agreed that price would be a factor. As CCGTs are operated as marginal generation they will be operated according to the prevalent spark spread. Carbon costs also need to be factored in. One respondent pointed out that if generation units are not flexible they will be priced against baseload market price and will therefore either be on or off rather than responding to price signals.

Q21c. The ability and willingness of CCGT generators to switch to distillate

A number of respondents suggested that the willingness of CCGT generators to switch to distillate would be dictated by price and it may need to be shown to be economical to switch for a matter of days. One respondent suggested that switching may take place earlier due to tax breaks introduced in the second half of last winter whereas another respondent stated that the risk of switching at a time of high market prices would mean that generators add a potentially high risk premium to the switching cost. The premium would reflect direct costs and reliability risks from switching (with a couple of respondents agreeing that these would be potentially higher than last year due to P194).

Respondents suggested a range of issues affecting the ability of CCGT generators to switch to distillate with one respondent suggesting that only 50% of CCGTs with back-up capability in principle could successfully switch and therefore that the assumed demand response may not be possible. Issues raised included environmental (sulphur) limits, supply (logistical and stock availability) constraints, operational considerations such as switch / start up time and increased maintenance costs (with one respondent referring to BSC mod 195).

Q21d. Whether and for how long CCGTs could generate on distillate back-up and any restrictions to the replenishment of distillate stocks

There was a mixed response to this question, some provided anticipated distillate stock levels at particular sites, another agreed with the assumptions and another respondent used the opportunity to outline restrictions on distillate generation and stock replenishment. The main issue raised regarding distillate generation was environmental limitations.

Ability to replenish distillate was outlined as being dependent on distillate market liquidity and stock levels in the UK, delivery and processing issues.

Q21e. The ability and willingness of the market to replace gas-fired generation by coal and oil fired generation

A number of issues were raised in response to this question.

Respondents generally agreed that there was limited scope for gas to coal switching as coal generation was already scheduled ahead of gas, however, subject to environmental constraints, there was further scope for gas to oil switching.

A number of respondents mentioned issues associated with fuel stocking as potential constraints, warning of potential low stocks. Another considered that a heavy two-shifting regime might lead to excessive wear on plant.

The majority of respondents mentioned generation limits indirectly imposed via environmental restrictions with a number suggesting that, as per last year, derogation / dispensation may be required.

Respondents noted that ‘willingness’ to respond would be based on the price differential, a decision process that worked well last winter and was expected to do so again. One respondent suggested it was becoming necessary to make CCGTs more responsive to economic incentives (noting that of 25 GW only 9.5 GW was fully responsive last year).

The final comments related to CHP installation, with one respondent criticising grid access constraints for hindering CHP installation.

Q21f. The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints, carbon emissions and fuel stocks

The majority of respondents focused their answer to this question on fuel stocks and environmental constraints. They reiterated that coal was likely to run ahead of gas with the main switch therefore being from gas to oil and distillate.

It was acknowledged that economic incentives were in place to maximise reliability.

With regards to environmental limits, respondents stated the importance of derogations provided last year, noting that similar requirements would be needed again this year. One respondent suggested that sulphur dioxide emission limits should not directly prevent power stations operating at the level assumed but some transfer of limits may be required. Levels could also limit the output expected for the rest of the year with operators needing to consider output over the 15 month period from October 2006 for implementation of the LCPD in 2008.

Carbon was deemed a price issue (rather than a physical constraint issue) and unlikely to price coal-fired generation above gas at peak times. One respondent believed that generators will be able to obtain any additional EU ETS allowances required if the prevailing power and carbon prices make it economical to do so and if the carbon market is sufficiently liquid.

One respondent stated that they understood generators may be increasing their fuel stocks. Others raised a number of issues regarding fuel stocks, with concerns that there would be pressure on the coal supply chain coupled with a continued high load factor from last year potentially leading to reduced contingency stocks.

Q21g. How the level of CCGT response may compare with that experienced in 2005/06

Respondents were generally optimistic regarding the level of CCGT response available compared to last year. Last year's response was anticipated to be available as a minimum with a few respondents suggesting scope for increased levels given the appropriate market incentivisation, last winter's encouragement, and a supportive regulatory regime (especially helping to increase levels in an emergency or during severe weather conditions).

One respondent quantified their answer. They suggested that demand response would be broadly similar to the 2.5 bcm observed last winter with a potential further 1 bcm if the market was incentivised. They suggested a level of 50 mcm/d was feasible provided there was not a coincidental high on both the gas and electricity markets.

Longer-term outlook

Q22. In addition to the questions relating to winter 2006/07, we would also welcome any views on the market outlook for winter 2007/08 and/or subsequent winters

Views over a longer-term outlook varied. One respondent believed that the market was not bringing investment forward due to a lack of uncertainty in long term forward prices. However this view directly contrasted with another respondent who stated that the market is responding to signals, but needed to ensure a stable, long term energy policy framework with appropriate signals remained in place.

A couple of respondents stated that they believed gas quality issues would become increasingly important.

Respondents

We would like to thank the following for responding to the Winter 2006/07 Consultation Document published in May.

The Association of Electricity Producers (AEP)
Alcan Smelting & Power UK
British Energy Group
BG Group
BP Gas Marketing Limited
British Gas Trading Limited
Centrica Storage Limited
Chemical Industries Association
E.ON UK
EDF Energy Plc
Energywatch
Environment Agency
Gaz de France ESS
Global Insight
INEOS Chlor Ltd
International Power plc
Interconnector (UK) Limited
Magnox Electric Limited
Met Office
The Mineral Wool Energy Savings Company
National Grid Gas Plc (in its capacity as a Gas Distribution Licence holder)
Northern Gas Networks
RWE Npower plc
Scotia Gas Networks
Scottish and Southern Energy
Scottish Power Energy Management
Shell Energy Europe
SEPA (Scottish Environment Protection Agency)
Statoil (U.K.) Limited
Total Gas and Power Limited
UKOOA
Wales & West Utilities Limited
Warwick Energy Limited