

Ofgem's probe into wholesale gas prices

Appendices

October 2004

232/04b

This report contains Appendices 1 to 5 to the main report on Ofgem's probe into wholesale gas prices. These Appendices expand on the information and the analysis presented in the main report and can be read as stand alone documents.

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Appendix 1. October/November 2003 probe:

Analysis of causes of reduced UK gas supply

1.1 This chapter presents a summary of Ofgem's further analysis of the causes of the reduced UKCS gas supply availability in October/November 2003. The section begins by summarising the position in the Interim Report,¹ presents Ofgem's further analysis for each sub-terminal and provides key conclusions.

Interim report

1.2 From analysis presented in Ofgem's Interim Report it was evident that the volumes of gas supplied via six beach terminals (in minimum, maximum and average terms) were significantly lower in October and November 2003 than in the same period of the previous year; both in terms of the total volume of gas delivered and in terms of maximum flow rates.

1.3 At five sub-terminals (Bacton-Tullow, Bacton-Shell, Bacton-Perenco, St Fergus-Shell and Teesside-BP Amoco), flows during October or November 2003 were significantly lower than the same months of 2002 and/or an assessment of the maximum deliverability for Winter 2003/04. Ofgem therefore considered it necessary to assess deliveries at these sub-terminals in more detail.

1.4 Ofgem contacted the relevant sub-terminal and field operators, on an informal basis, to request that they assist it in its enquiries by providing information concerning available gas supplies during the period in question and details relating to any operational difficulties and planned/unplanned maintenance.

1.5 Views previously presented to Ofgem suggested, but did not demonstrate conclusively, that beach supplies during this period were lower as a result of problems with offshore fields (as a result of planned and unplanned maintenance) and lower than winter 2002/03 as a result of the above and depletion of UKCS fields. This analysis addresses these views in more detail.

¹ 'Gas Prices in October and November 2003:Interim Report'; Ofgem, May 2004

Further analysis

- 1.6 In order to further analyse the reasons for the observed reductions in beach flows during October and November 2003, we have considered evidence on the magnitude of the decline in UKCS availability and information provided by sub-terminal and field operators on the level of planned and unplanned maintenance during this period.
- 1.7 Below is a summary of the evidence on the extent of the UKCS decline, followed by a summary of the analysis of planned and unplanned maintenance and of the impact of contracts and nominations on actual gas flows. The next section of this appendix presents detailed analysis of maintenance, flows and capability on a sub-terminal basis, for the sub-terminals identified above.

UKCS Decline

- 1.8 One of the factors highlighted by respondents to the Interim Report was the impact of the ongoing decline of UKCS capability on the reduction in beach supplies during this period.
- 1.9 Information was available from both NGT, collected as part of its Transporting Britain's Energy consultation, and from the respondents to the informal information request.

Information from NGT

- 1.10 NGT, in both its 2003/04 and 2004/05 Winter Outlook Reports, has published information about the lower expected and actual maximum beach deliveries as a result of declining production levels from the UKCS. In 2003 NGT forecast that maximum beach supplies for 2003/04 would be 401mcm, 2mcm lower than maximum beach availability for winter 2002/03, with production from new (generally small) fields broadly cancelling out the decline in production from existing UKCS fields.
- 1.11 In 2004 NGT revised its view of maximum beach supplies for winter 2003/04.² Its revised forecast of maximum beach supplies is now 377mcm, 24mcm lower

² Figures presented at the Transporting Britain's Energy forum in July 2004 and in its preliminary Winter Outlook report published in May 2004

than its 2003 forecast for Winter 2003/04. NGT provided the following explanation for the variation in beach delivery:

- ◆ Development Slippage (10 mcm/day) - In its 2003 forecast, NGT assumed 10 mcm/day for new developments and 5 mcm/day from the expansion plans of other recently developed fields. Of this total of about 15 mcm/day, NGT believed that at least 5 mcm/day was not producing by the end of the winter and about a further 5 mcm/day had commissioning problems or started later in the winter;
- ◆ Production decline (15 -21 mcm/day) – Data provided to NGT has shown that the UKCS is in general decline. This is particularly the case amongst many of the larger fields including Alywn, Brent, Britannia, Bruce, ETAP and Shearwater, some of which had material drops in peak output capability across last winter; and
- ◆ Loss of Brent (6 mcm/day) – whilst Brent Alpha and Delta returned online before the Winter peak, Brent Charlie did not return until late February.

Information provided by respondents

- 1.12 In responding to Ofgem's informal information request, two field operators documented their views on the decline in UKCS productivity and on the year-on-year decline of the Brent and the Armada fields. The companies which have Brent's and Armada's operational responsibility reported that these fields had witnessed some productivity decrease year-on-year.
- 1.13 Perenco also stated that production from its Leman and Indefatigable fields had decreased by around 20 per cent due to deterioration in UKCS productivity, Tullow estimated that flows into the Bacton sub-terminal had decreased by approximately 25 per cent. The volume of gas available to them as a buyer had declined by 10-15 per cent at the Bacton-Shell sub-terminal.

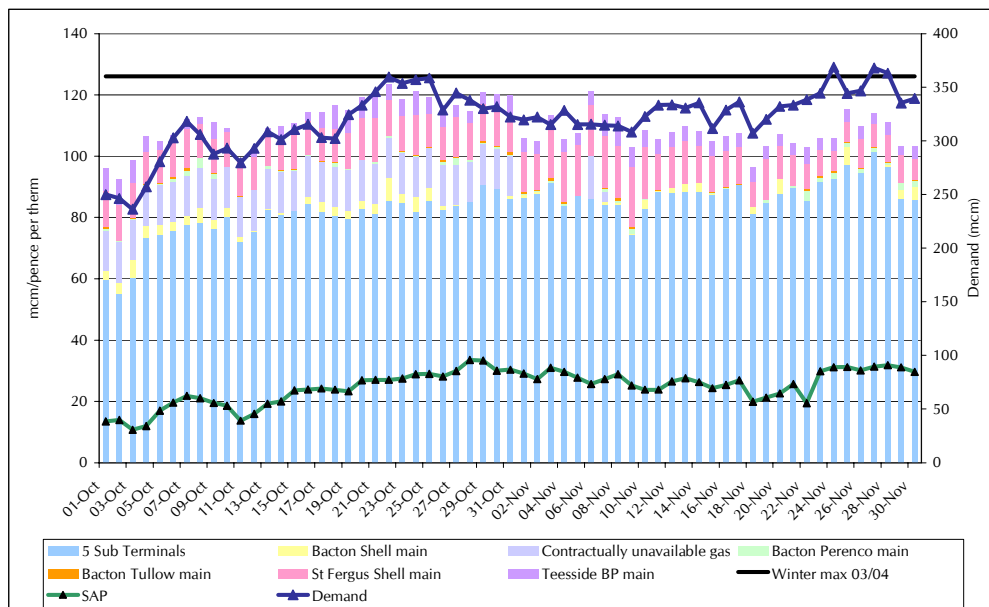
Winter 2003/04 maintenance

- 1.14 In the Interim Report, Ofgem compared the levels of gas delivered by each sub-terminal to an estimate of the maximum available gas supply through that sub-

terminal. The analysis showed that theoretically flows from the UKCS could have been 31.5mcm higher than those observed over October and November 2003.

1.15 Figure A1.1 shows actual flows through each of the five sub-terminals selected for further analysis (Bacton-Shell, Bacton-Perenco, Bacton-Tullow, St-Fergus-Shell and Teesside-BP Amoco) and the maintenance-affected flows at each of these sub-terminals during October and November 2003. Total system demand and the average market price are also plotted to indicate where flows may have been lower than capability for reasons of lower UK gas demand and/or price.

Figure A1.1: Actual and maintenance-affected flows by sub-terminal during October and November 2003



1.16 Figure A1.1 reconciles gas flows up to a measure of field capability (shown as the horizontal black line).

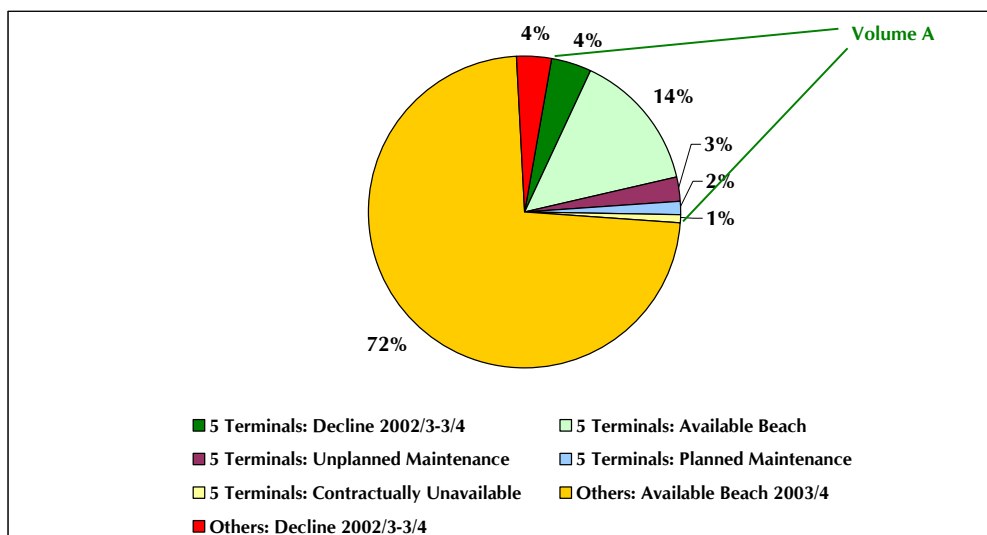
1.17 In the first half of October 2003, observed gas flows are below capability, due to relatively low system demand and prevailing prices. During the second half of October, gas flows can be reconciled to capability with reference to the levels of planned and unplanned maintenance.

1.18 During November 2003, the analysis highlights that it is not possible to reconcile observed flows to capability solely with reference to planned and unplanned maintenance. Information provided to Ofgem highlights that some

fields were physically available but did not deliver gas to the system due to the contracts covering the delivery of gas and/or the nominations made against these contractual rights.

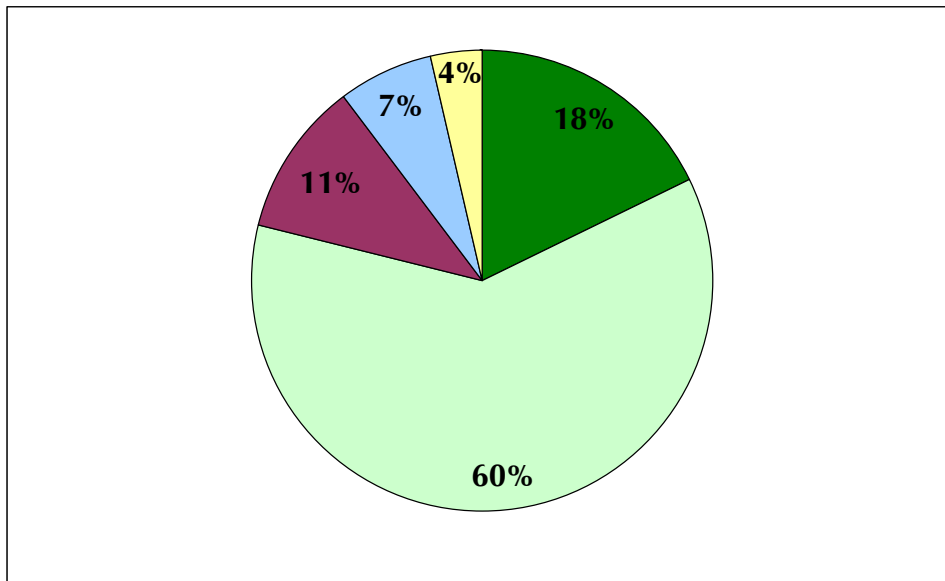
1.19 Figure A1.2 reconciles actual flows during October and November 2003 to beach capability in winter 2002/03 (the preceding gas year). It shows that there has been an 18 per cent decrease in beach supplies flowing through the five sub-terminals as a consequence of declining UKCS productivity, with available beach supplies during October and November 2003 representing 60 per cent of the 2002/03 maximum.

Figure A1.2: Reconciliation between 2002/03 beach capability to observed gas flows in October and November 2003



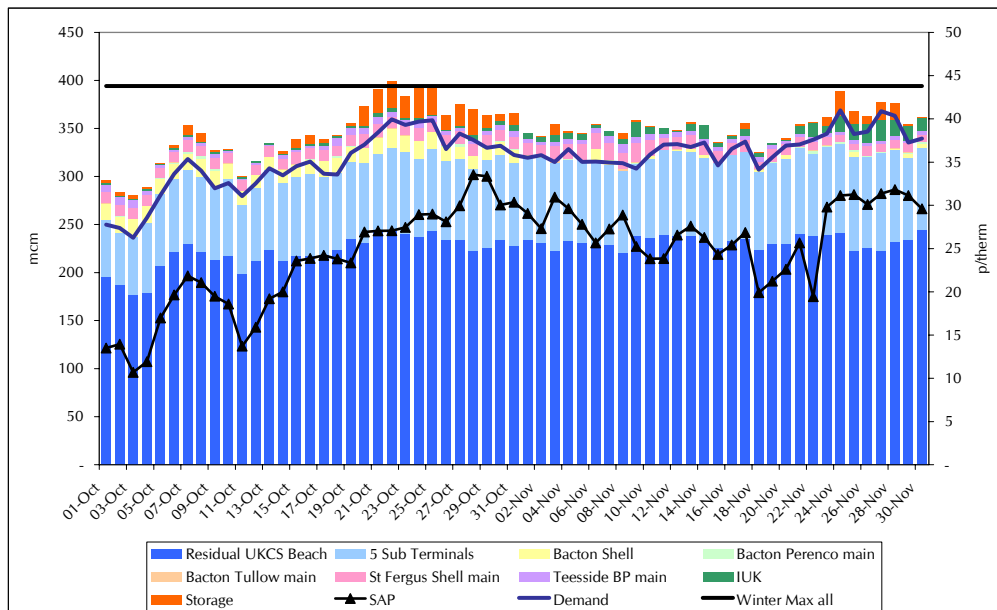
1.20 Figure A1.3 breaks down winter 2003/04 maximum capability (as measured by the maximum observed flows) into its various components, as they relate to the five sub-terminals that were subject to further analysis (this volume is highlighted as 'volume A' in Figure A1.2).

Figure A1.3: Reconciliation of the capability of the five sub-terminals (volume A) to observed flows during October and November 2003 (same key as Figure A1.2)



- 1.21 Actual beach throughput at the five sub-terminals totalled 60 per cent of the maximum possible flow during October 2003 and November 2003. Flows affected by unplanned maintenance totalled 11 per cent, while reduced flows as a result of planned maintenance accounted for 7 per cent of the maximum possible during the two months. The remaining 4 per cent of potential capability, can be explained by gas that is physically available but did not reach the market due to the contractual arrangements and/or the nominations made against these contracts.
- 1.22 Figure A1.4 combines the information detailed in Figure A1.1 with flows at the remaining main beach terminals and storage, presenting this information on a daily basis. This chart shows that had the fields affected by maintenance been available:
- ◆ Storage gas would likely not have been withdrawn in mid-October 2003;
 - ◆ Demand would have likely been met in late November by beach and IUK supplies with minimal withdrawals from storage in late November.

Figure A1.4: Comparison of actual and maintenance-affected supplies³.



1.23 Planned maintenance was taken to be any maintenance planned in advance in connection with statutory inspections/maintenance either for health and safety reasons or in line with plant manufacturer’s guidelines. Unplanned maintenance was taken to be unanticipated maintenance, for example, resulting from equipment failure.

1.24 The information submitted on planned and unplanned maintenance was analysed to consider whether the maintenance was appropriately explained and was carried out in a timely manner. In all cases, satisfactory answers were received from the companies involved; based on the information provided all of the maintenance was explained and was completed in a timely manner.

Contractual constraints

1.25 There are a significant number of fields from which the gas is sold under buyer nominated contracts. These fields tend to be dry gas fields and so are concentrated in the Bacton area. At fields covered by such contracts, the buyer decides (on a day to day basis) the volume of gas to be delivered to the beach, via a nomination to the field operator. Evidence available suggests that a

³ Actual and maintenance-affected flows from other beach sub-terminals, storage and IUUK

significant proportion of these contracts include contract prices that are not linked to the prevailing market price of gas.

- 1.26 Typically, prior to the gas year, the seller indicates to the buyer the annual volume of gas (Annual Contract Quantity (ACQ)) which they believe to be available for delivery. This ACQ is then divided by 365 to calculate the Daily Contract Quantity (DCQ) available for nomination by the buyer, subject to scaling factors which adjust the DCQ on a monthly/quarterly basis to give maximum daily contract quantities, giving the contract a seasonal shape.
- 1.27 Buyer nominated contracts typically include provisions to allow for the nomination of gas in excess of the maximum daily contract quantity. However, the delivery of this gas is usually at the discretion of the seller and is priced at a premium (anecdotal evidence suggests 30 per cent) to the contract price. In deciding whether to deliver excess gas, the seller will trade off the revenues from delivering excess gas at a premium earlier in the winter against the increased risk of under delivery later in the winter.⁴

Individual sub-terminal analysis

- 1.28 The analysis presented above provides a reconciliation, at an aggregate level, between the observed gas flows and the capability at the five sub-terminals identified in the Interim Report.
- 1.29 In this section the five sub-terminals analysed above are considered in turn, with explanations provided for the reduction in observed flows on a sub-terminal basis.
- 1.30 Given the data provided by field and/or sub-terminal operators regarding planned/unplanned maintenance, field decline and contractual constraints, Ofgem sought to reconcile actual flows to an assessment of 2003/04 capability. Ofgem also sought to establish any significant reductions between 2002/03 and 2003/04 capability as a result of field decline.
- 1.31 A summary of the results of this analysis is presented in the following table. This highlights the extent to which the differences between observed flows and

⁴ The penalty for under delivery is usually to provide gas at a discount to the contract price at a later date.

capability can be explained by maintenance, field decline and the structure of contracts and/or nominations made at the relevant fields.

Sub-terminal	Field Decline	Deviations from Winter 2003/04 Maximum Explained by Maintenance	Deviations from Winter 2003/04 Maximum Explained by Contracts/Nominations	Estimated Decline at sub-terminal	Other Comments
BACTON-PERENCO	✓	✓	✓		20 % field decline at Indefatigable & Leman
BACTON-SHELL	✓	✓	✓	11%	
BACTON-TULLOW	✓	✓		25%	Lengthy maintenance at Orwell
ST FERGUS-SHELL	✓	✓		20-30%	Brent Complex and Gannet underwent maintenance repairs
TEESSIDE-BP AMOCO	✓	✓			Decline in Armada Production Maintenance at Armada/Seymour fields & J-Block

	BACTON-PERENCO	BACTON-SHELL	BACTON-TULLOW	ST FERGUS-SHELL	TEESSIDE-AMOCO
Beach Throughput as % Winter Max 02/03	64	48	64	40	70
Beach Throughput as % Winter Max 03/04	86	54	92	48	88
Planned Maintenance as % of Winter Max 03/04	0	0	0	1	3
Unplanned Maintenance as % of Winter Max 03/04	5	19	3	37	14
Throughput & Maintenance as % of Winter Max 03/04	92	74	95	87	104
Maximum of Winter 03/04 as % of Maximum of Winter 02/03	75	88	70	83	80

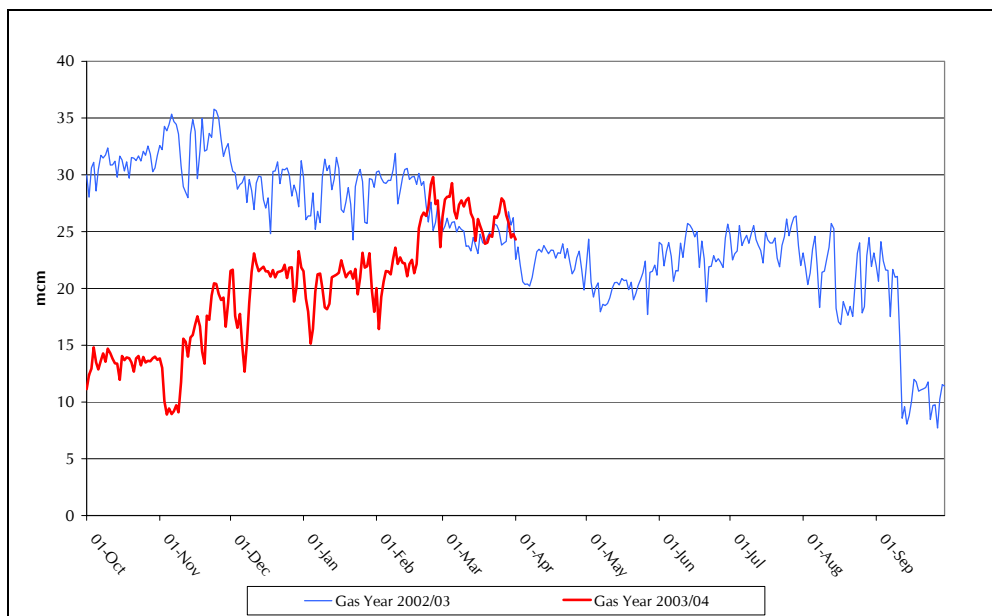
St Fergus-Shell sub-terminal flows

1.32 The most significant reduction in flows was noted at the Shell sub-terminal at St Fergus. Figure A1.5 shows the daily flow levels through this sub-terminal between October 2002 and March 2004. Flows observed during October 2003

and November 2003 were around 20mcm per day lower than those observed during the same months of the previous year.

- 1.33 In the Interim Report, Ofgem made reference to an unplanned outage at the Brent complex of fields, which continued throughout October 2003. It also noted that whilst flows increased later in the winter of 2003/04, the maximum observed flow was still approximately 6mcm lower, than that observed during the winter of 2002/03.

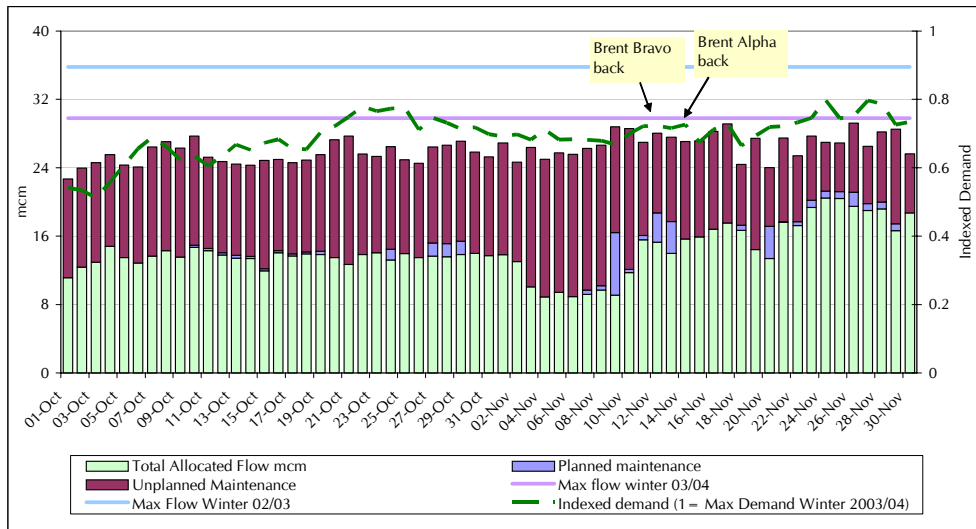
Figure A1.5: Flows into the St Fergus-Shell sub-terminal



Maintenance

- 1.34 Figure A1.6 shows the total flows going into the St Fergus-Shell sub-terminal on each day in October and November 2003 with maintenance-affected flows on each gas day. Also plotted are the maximum sub-terminal flows recorded during winter 2003/04 and the maximum flows for winter 2002/03.
- 1.35 An index of demand over the winter 2003/04 period is also included to establish the response of sub-terminal flows to changes in demand.

Figure A1.6: Actual and maintenance-affected flows through the St Fergus–Shell sub-terminal



- 1.36 It was suggested in the Interim Report that an unplanned outage at the Brent complex of fields, reported during September 2003, contributed to a significant reduction in field flows arriving at the St Fergus-Shell sub-terminal throughout October 2003 and November 2003.
- 1.37 Figure A1.6 highlights the impact of these outages, in particular the phased return of the Brent fields during the period and the ongoing outage at one of the Brent fields throughout the whole period under consideration.
- 1.38 An unplanned outage at the Gannet field contributed to a reduction in total flows and prompted unplanned maintenance between 2 November 2003 and 17 November 2003. Once the impact of maintenance reduced flows is considered, total flows are closer to those originally forecast by the operator during their annual planning round.

Field decline

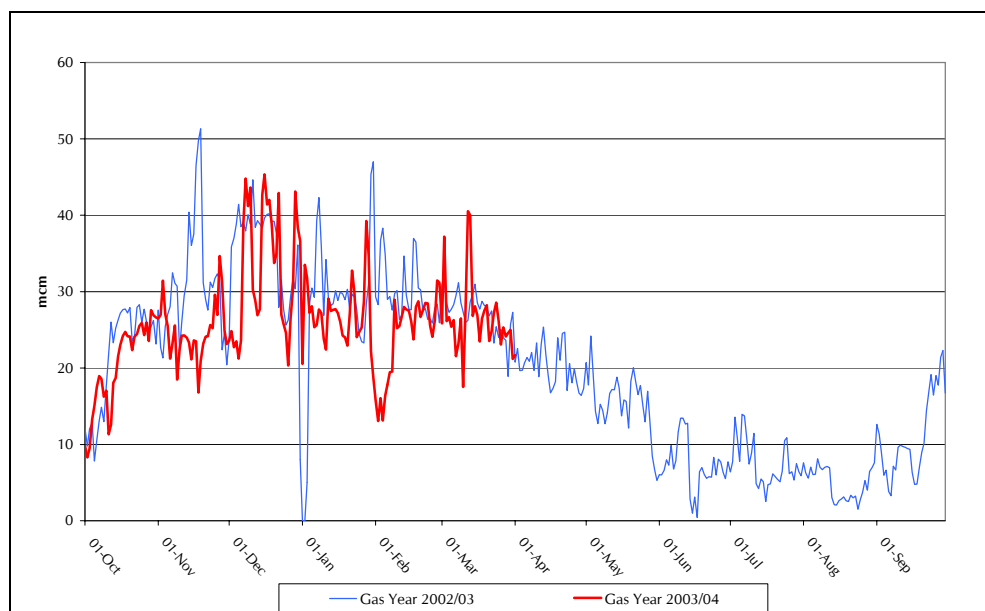
- 1.39 Flows into St Fergus-Shell are of associated gas on seller-nominated (must-take) gas contracts. Given the relative value of the oil over this period, the production strategy of the operator over this period was planned to maximise daily gas flows.
- 1.40 There has been a year on year decrease in the maximum flow recorded at the St Fergus-Shell sub-terminal. Maximum flow recorded during winter 2003/04

was just under 30mcm. This represents a reduction of around 6mcm/day from winter 2002/03.

Bacton-Shell sub-terminal flows

1.41 The flows observed at the Bacton-Shell sub-terminal (Figure A1.7) during October 2003 were similar to those of October 2002. Flows through the sub-terminal in November 2003 were significantly lower than those observed during November 2002. However, the significantly higher (8mcm) flow levels achieved in December 2003 suggest that the reduction in flow rate in November 2003 was probably due to a temporary problem offshore, or some other factor, rather than linked to the decline in the production capacity of the UKCS.

Figure A1.7: Flows at the Bacton-Shell sub-terminal, October 2002 – March 2004



Maintenance

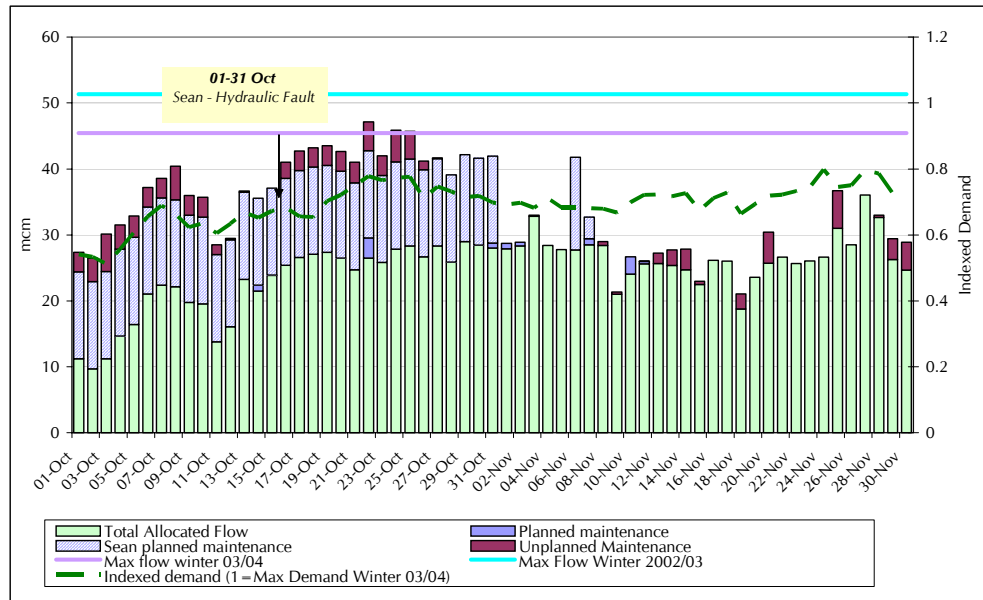
1.42 Figure A1.8 illustrates the impact of maintenance on flows into the Bacton-Shell sub-terminal. On average, flows were reduced by 16mcm; 13mcm of which was due to a hydraulic fault at the Sean field⁵ which took a number of weeks to resolve⁶. In part, this is because Sean is an unmanned platform and had not been nominated to deliver gas by its buyer in October 2003.

⁵ Owned by BP, Exxon Mobil and Shell (www.dti.gov.uk)

⁶ This maintenance was somewhat discretionary and was agreed between the buyer and sellers to be undertaken during October. This decision was taken well ahead of the maintenance period.

1.43 However, maintenance cannot explain the level of flows observed in November 2003. The volume of gas flown from the fields is largely due to buyer nominations.

Figure A1.8: Actual and maintenance-affected flows at the Bacton-Shell sub-terminal



Contracts in place at Bacton-Shell

1.44 As is the case at a number of the fields flowing into the Bacton sub-terminal, the field operator effectively acts as a “service provider” to the buyer, who has exclusive rights to the gas flows from the field, over a defined period. As such, the field operator has minimal control over the volume of gas that is produced; with gas flows responding to nominations made by the buyer(s) and the physical availability of the fields. The contracts in place at these fields have a mixed structure – some are priced to the NBP, whilst others are linked to a basket of commodities.

1.45 An analysis of throughput by shipper through the Bacton-Shell sub-terminal may be used as an indication of who owns buyer nomination rights. The analysis has shown that Centrica was the most significant shipper of gas from this sub-terminal over the Winter 2003/04 period.

1.46 Centrica indicated that they had at least maximised their contractual nomination rights over this period, including taking significant volumes of excess gas during

late October 2003. Ofgem's analysis of nominated flow rates and contractual entitlements at Leman, Sole Pit and Galleon supports this assertion.

- 1.47 A significant volume of the capability of fields flowing into the Bacton-Shell sub-terminal relates to the Sean fields. These flows are covered by a buyer-nominated contract between Centrica, the buyer, and the equity holders (Shell, BP and Exxon Mobil).⁷
- 1.48 Flows from the Sean fields reflected the contractual conditions put in place covering these fields. In particular, this involves a series of pre-agreed contract prices and nomination limits that affect the periods in which it is economic for the buyer to nominate gas to flow from these fields. Consequently, it appears that a significant amount of the difference between observed flows and total capability at the Bacton-Shell sub-terminal can be explained by the contractual arrangements put in place and the resulting nominations made by the buyer, against these contractual rights. These arrangements meant that gas was not delivered from the remaining available fields.

Field decline

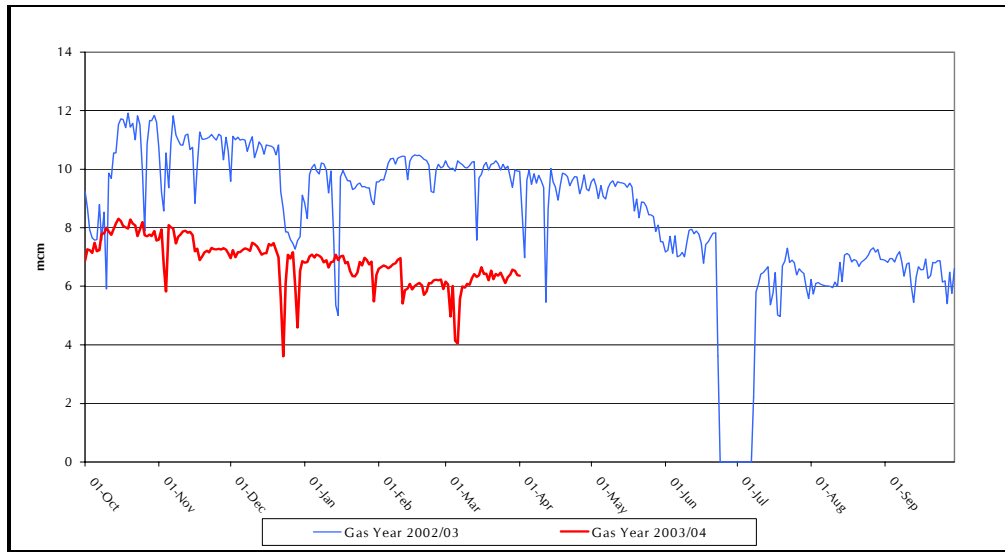
- 1.49 Maximum winter flows observed at the Bacton-Shell terminal were 6mcm lower year on year – a decline of 11.5 per cent: this is lower than the decline observed at the other Bacton sub-terminals into which older dry gas fields flow. The volume of gas available to the buyer at this terminal had decreased by 10-15 per cent year on year.

Bacton-Tullow sub-terminal flows

- 1.50 Flow rates at the Bacton-Tullow sub-terminal, as illustrated by Figure A1.10, have exhibited a steady decline over the past eighteen months (October 2002 to March 2004). In particular, the maximum flows during the last winter (2003/04) were 8mcm, this was 4mcm lower than the maximum observed during the winter of 2002/03. However, it should be noted that the maximum rates achieved this winter were achieved during October and November 2003. In the May Interim Report Ofgem suggested that the reduction in flows year-on-year may be attributable to a longer term cause.

⁷ Source: www.dti.gov.uk; 'Electronic book – Upstream', Wood Mackenzie

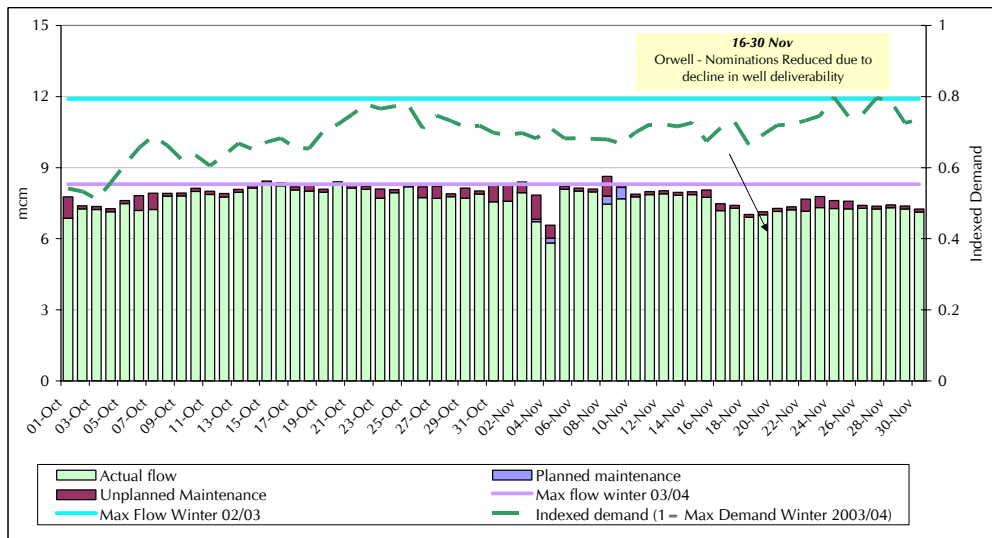
Figure A1.10: Flows into the Bacton-Tullow sub-terminal



Maintenance

1.51 Figure A1.11 illustrates the impact upon daily flows of maintenance either carried out at the sub-terminal or at the fields which flow into the sub-terminal.

Figure A1.11: Actual and maintenance-affected flows through the Bacton-Tullow sub-terminal



1.52 Figure A1.11 shows that total allocated flow was frequently within 1mcm/day of the maximum winter 2003/04. Maintenance volumes were generally low, although a significant reduction in flows was recorded on 3 and 4 November 2003 at the time of a compressor shutdown at the Bacton-Tullow sub-terminal.

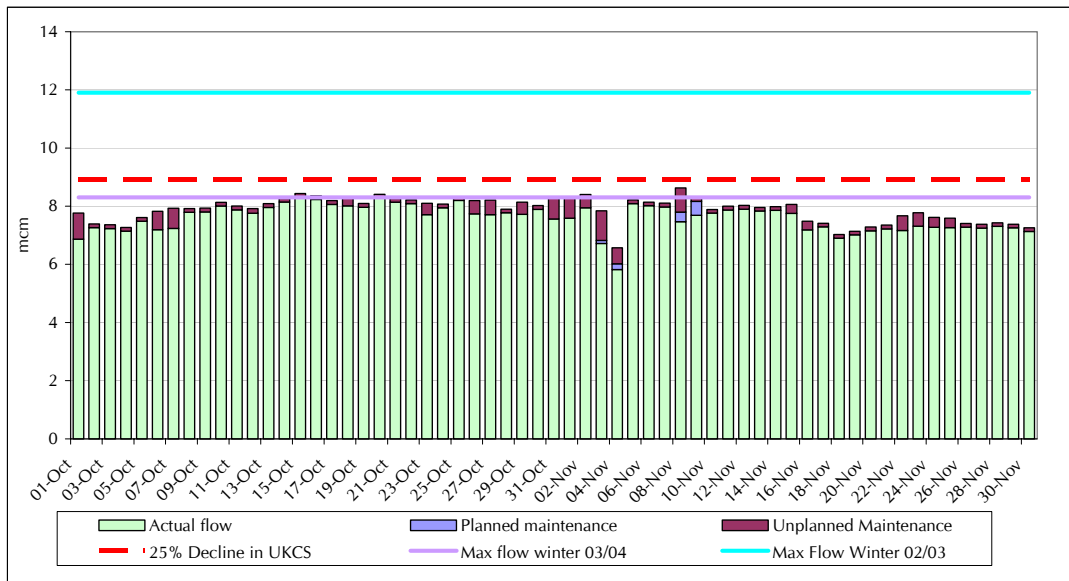
Information provided to Ofgem suggests that an outage at the sub-terminal resulted in reductions in field production on 3 and 4 November and on subsequent days, in response to indications of a longer outage than eventually occurred. Whilst the volume indicated as affected by the sub-terminal operator is higher than the volume of flows indicated as affected by maintenance, this may be because the field operators' view was that the compressor would take longer to return and they adjusted their field production strategy accordingly.

- 1.53 There are a number of days (particularly at the start of October and towards the end of November) where there is a difference of over 1mcm/day between the maximum winter flow and daily total flows. However, given the information available on the economics of production at the relevant fields and the materiality of the difference, Ofgem has not pursued this further.

Field Decline

- 1.54 As suggested by the Interim Report, there has been a decrease in winter flows recorded at the Bacton-Tullow sub-terminal. The maximum flow recorded during Winter 2003/04 was 8.3mcm/day, which represents a reduction of around 3.6mcm/day from the maximum recorded during winter 2002/03.
- 1.55 Tullow has estimated that, on average, fields flowing into this sub-terminal have declined by approximately 25 per cent year on year. Figure A1.12 illustrates the impact upon the winter 2002/03 maximum of a 25 per cent decline in flows (red line). The remainder of the reduction in capability can be attributed to operational difficulties at one field, which reduced flows below their expected level. Information provided to Ofgem explains this reduction.

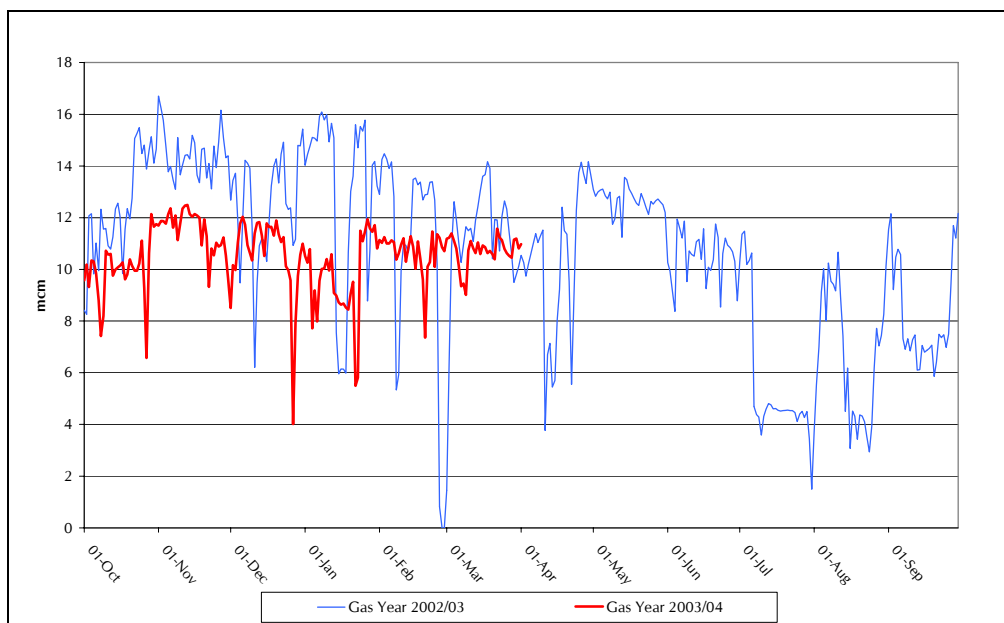
Figure A1.12: Impact of a 25 per cent decline in maximum field deliverability (Bacton-Tullow sub-terminal)



Bacton-Perenco subterminal

1.56 The daily flows through the Bacton-Perenco sub-terminal are illustrated on Figure A1.13. Whilst there was a year-on-year reduction in winter flows at this sub-terminal, it was less marked than that observed at the Bacton-Tullow sub-terminal. Maximum winter 2003/04 flows were just under 13mcm, around 4mcm lower than the maximum observed during the same period in 2002.

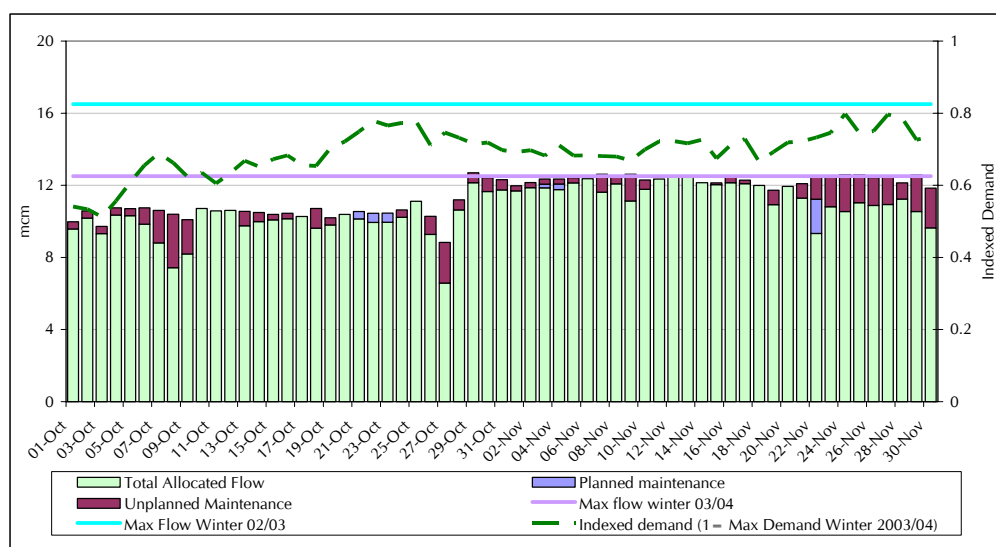
Figure A1.13: Flows into the Bacton-Perenco sub-terminal



Maintenance

1.57 Figure A1.14 illustrates the impact upon daily flows of maintenance either carried out at the sub-terminal or at the fields which flow into the sub-terminal.

Figure A1.14: Actual and maintenance-affected flows through the Bacton-Perenco sub-terminal



1.58 For the majority of days during October 2003, the Transco throughput numbers (inclusive of any reduced flows due to planned or unplanned maintenance) are below the winter 2003/04 maximum, and showed no reaction to the increase in demand in the second half of October. The most noticeable of these occurred on 27 October 2003. Whilst there were offshore problems reported at three fields on this date, the reduced flows due to maintenance do not cover all of the difference.

1.59 A number of fields are covered by buyer-nominated supply contracts, which include pre-agreed contract prices and nomination limits (see above for more information). Information provided to Ofgem shows that these fields had physical capability to deliver more gas, but that additional gas did not reach the market on some days.

1.60 Field flows into the Bacton-Perenco sub-terminal are close to the winter 2003/04 maximum (12.5mcm/day) for much of November, with a large proportion of differences between the theoretical maximum and Transco's throughput numbers explained by planned and unplanned maintenance.

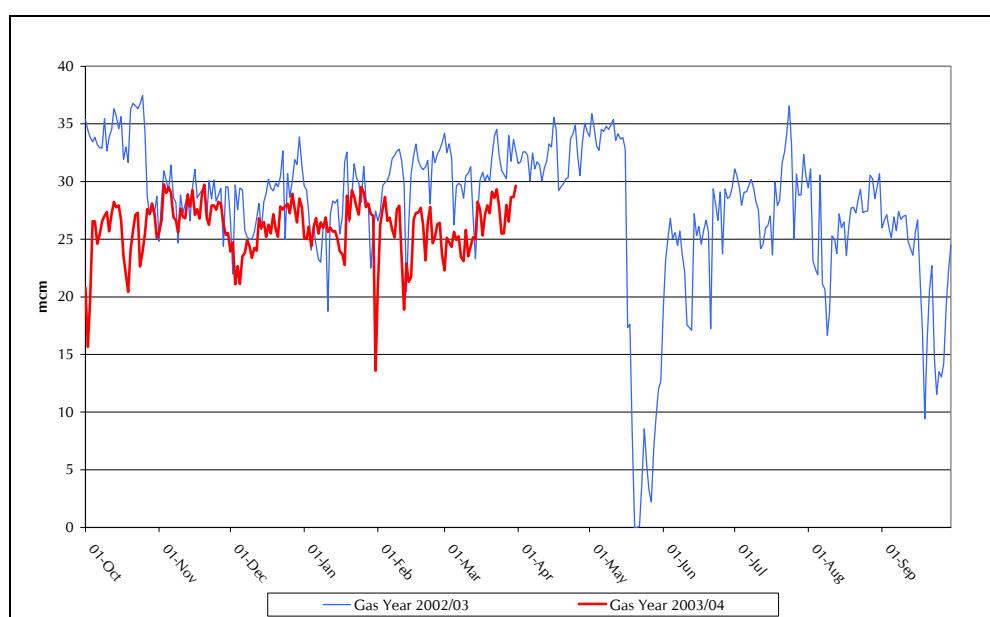
Field Decline

- 1.61 When comparing the maximum flow through this sub-terminal (as a proxy for field capacity) in winter 2002/03 with winter 2003/04, there has been a marked decrease of approximately 4.2mcm/day in maximum flows year on year (Figure A1.13).
- 1.62 The field operator indicated that two fields declined by approximately 2mcm. However, the volume of gas that can be produced from neighbouring fields is related to the volume of flows from these two field complexes. This accounts for as much as 4mcm/day of the reduction in flows.

Teesside–BP Amoco sub-terminal

- 1.63 The daily flows through the Teesside-BP Amoco sub-terminal are illustrated by Figure A1.16. The flows observed at this sub-terminal during October 2003 were around three quarters of the level achieved in October 2002. However, the flows observed in November and December 2003 were of a similar level to those observed during November and December 2002.
- 1.64 In the Interim Report, Ofgem indicated that it considered that the reduction in flow rate in October 2003 may have been due to a temporary problem offshore rather than linked to the decline in the productive capacity of the UKCS.

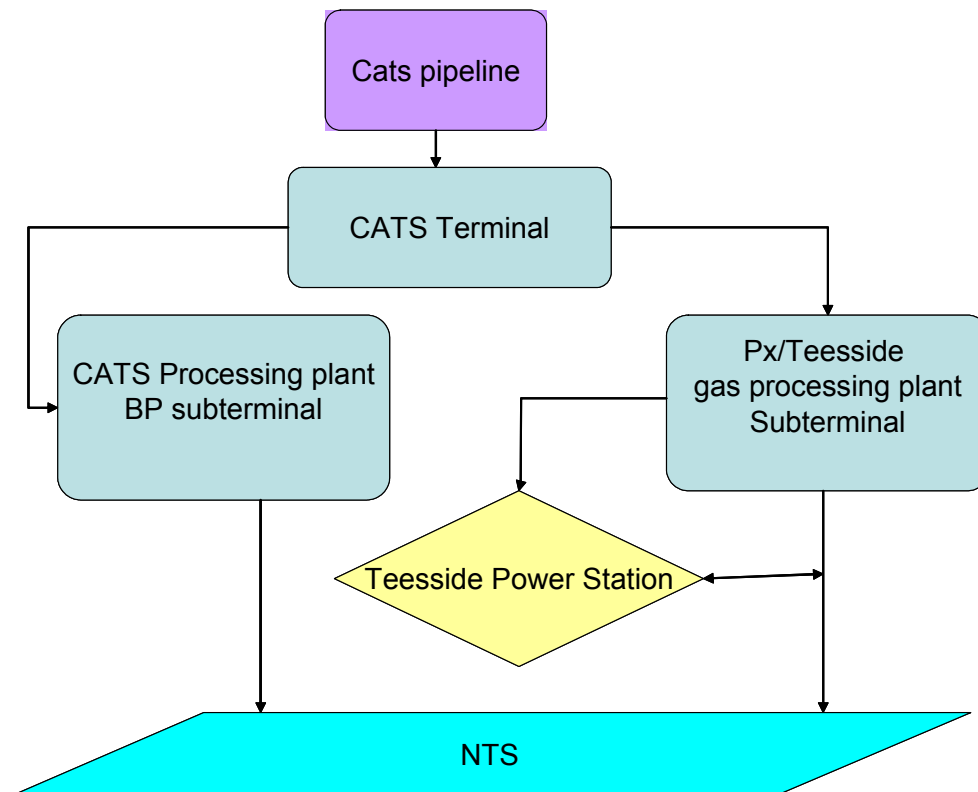
Figure A1.16: Flows into the Teesside –BP Amoco sub-terminal



Teesside Terminal

1.65 The CATS pipeline begins at a riser platform adjacent to the BP operated Everest gas field in the Central North Sea and transports gas to the CATS processing terminal in Teesside (the “Teesside-BP Amoco” sub-terminal). However the shippers then have a choice as to how their gas is treated. The gas can either be processed through the CATS facilities, or CATS can transfer the gas to the adjacent processing facilities operated by PX/Teesside. (Figure A1.17)

Figure A1.17: Schematic of gas flows from the CATS pipeline onto the NTS

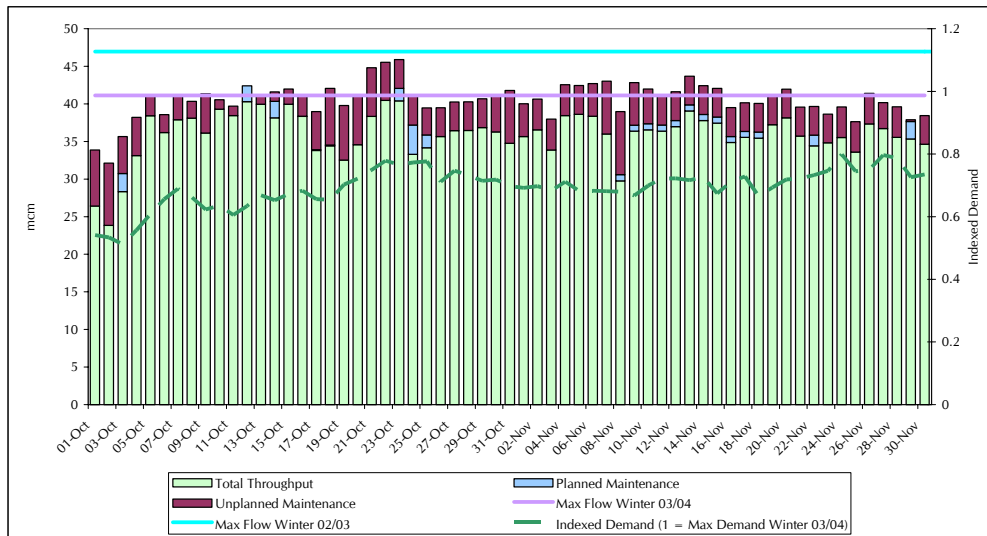


1.66 The ability to direct gas flows between the two sub-terminals has resulted in the consideration of the gas flows through both sub-terminals rather than solely flows through the BP Amoco sub-terminal when considering the reasons for variations from winter maximum flows (both for 2002/03 and for 2004/05).

Maintenance and field decline

1.67 Figure A1.18 illustrates the impact upon the aggregated daily flows through both processing facilities of maintenance either carried out at the sub-terminals or at the fields which flow into the sub-terminal.

Figure A1.18: Actual and maintenance-affected flows through the processing facilities at both Teesside Terminals



1.68 Figure A1.18 would suggest that there had been little reduction in capability year-on-year however:

- The maintenance-affected flows were calculated at the field level and thus would include liquids (and other contaminants) which would be removed by processing at the sub-terminal – thus the maintenance-affected flows are likely to be overstated;
- October 2002 was a month close to the end of the plateau peak period for the Armada field. According to the field operator, Armada is no longer on plateau, but in decline. It has been estimated that production levels at Armada declined by approximately 2 mcm/day year on year as between Q4 2002 and Q4 2003.
- The decline of the level of production of the Armada fields has been partially offset by the ability of other fields to access capacity not previously available in the past.

1.69 The pattern of flows observed over this period can largely be explained by maintenance at Armada and Seymour fields, and J-Block group and by changes in demand.

Summary and Conclusions

- 1.70 As a result of the provision of information concerning available gas supplies and details regarding any operational difficulties Ofgem has been able to provide an explanation of the reduction in beach supplies evident during winter 2003/04 and more particularly, during October and November 2003, at each of the five sub-terminals highlighted for further consideration.
- 1.71 Information provided by both field and sub-terminal operators has illustrated that beach gas supplies were reduced at the Bacton-Tullow, St Fergus-Shell and Teesside-BP Amoco sub-terminal due to the notable impact of maintenance. Had these maintenance-affected flows been available, throughput at these sub-terminals would be close to the winter 2003/04 maximum.
- 1.72 Although maintenance-affected flows accounted for much of the reduction in supplies available at the sub-terminals mentioned above, the structure of existing contracts proved an additional factor at both the Bacton-Perenco and Bacton-Shell sub-terminals.

Appendix 2. October/ November 2003 probe: European gas supply and the interconnector

Introduction

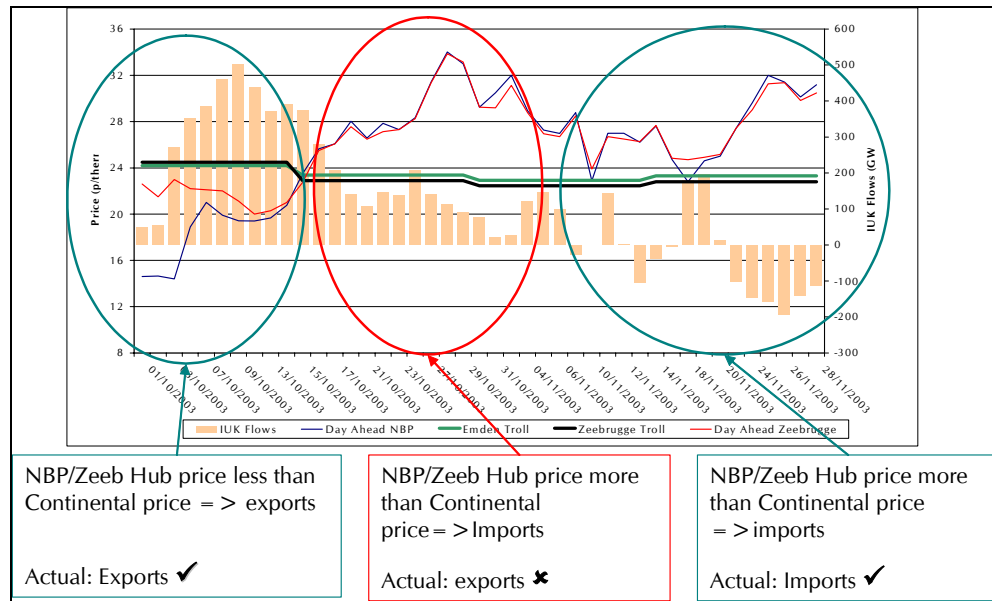
- 2.1 Based on analysis in the Interim Report, Ofgem concluded that no interconnector shipper in isolation was responsible for keeping the interconnector in export mode during late October/early November 2003. Ofgem noted that most of the export nominations were placed well in advance of the relevant gas days and relatively few were changed after placement.
- 2.2 Ofgem also noted concerns that, although exports clearly decreased as GB spot gas prices increased, no net import took place until 9 November 2003. The analysis suggested that the pattern of flows across the interconnector during the relevant period was not consistent with reported price differentials between the NBP and European oil indexed gas prices. Further, that the failure of the interconnector to provide additional supplies to the UK at a time when the supply/demand margin was tight is likely to have been, at least in part, a reason why the high prices were experienced over a sustained period.
- 2.3 Ofgem therefore wrote informally to a number of interconnector shippers requesting their assistance by asking them to explain the reasons why they were not able to or did not choose to reduce their export and increase their import nominations sooner. Ofgem asked the relevant interconnector shippers to provide information on the prices and availability of gas and transportation capacity in the relevant European gas markets during the period when the interconnector remained in export mode. Responses were received from all interconnector shippers. In addition, meetings were held with a number of market participants at which further questions regarding their submissions and other issues, which came to light since the May analysis, were discussed.

Further analysis

- 2.4 Ofgem has carried out a detailed analysis into why the gas interconnector between the UK and Belgium continued to export gas for some time after the GB

gas prices (NBP) exceeded reported prices in Europe. Ofgem has focused on the period from when the NBP price rose above the Emden and Zeebrugge Troll prices until the time that the interconnector switched to importing gas. This is the period from 15 October 2003 until 9 November 2003 and is highlighted in red in Figure A2.1.

Figure A2.1: Interconnector flows and market prices – October and November 2003



2.5 Ofgem’s analysis can be separated into two areas:

- ◆ The flows of gas across the interconnector in response to the prices prevailing at Bacton/NBP and Zeebrugge; and
- ◆ The availability of gas for transit from other Northern European locations towards Zeebrugge and ultimately supply into Great Britain.

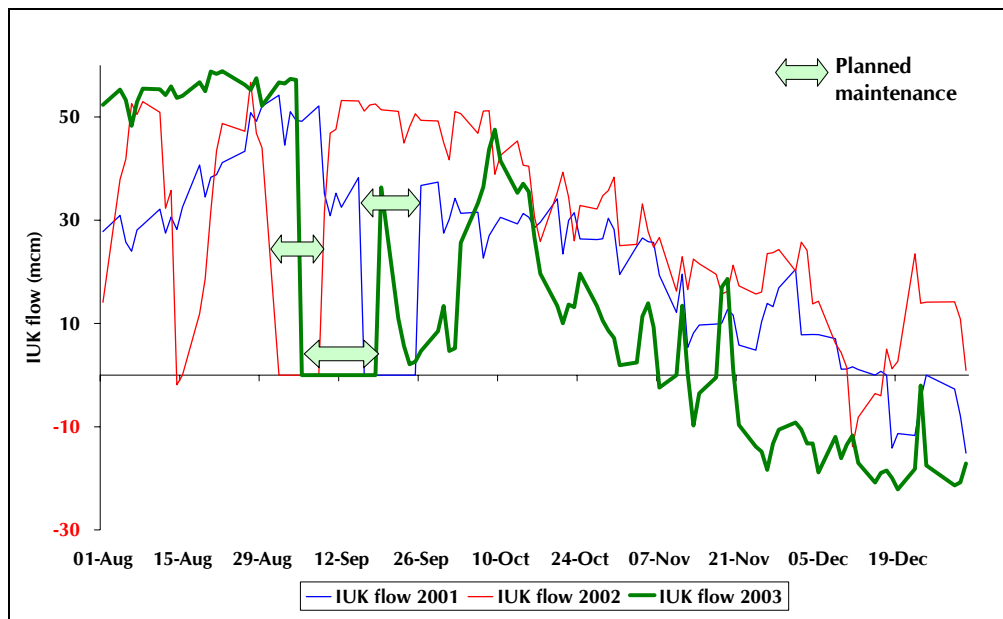
Interconnector flows

2.6 In this section, Ofgem first conducts an analysis of the interconnector’s response to changes in supply, demand and price differentials in the autumns of 2001, 2002, and 2003. Ofgem then considers whether access to capacity was a barrier to efficient arbitrage and whether interconnector shippers’ behaviour was consistent with price differentials.

A comparison of autumn 2003 with autumn 2001 and 2002

2.7 In order to understand if the operation of the interconnector in October and November 2003 (Table A2.1) was consistent with the prevailing market conditions, Ofgem analysed the same periods (autumn leading up to winter) for 2001 and 2002. This period includes the annual maintenance periods which are scheduled in September as shown by Figure A2.2.

Figure A2.2: IUK Flows – August to September 2001, 2002 and 2003



2.8 Table A2.1 summarises characteristics of the three periods and shows that the situation in autumn 2003 was broadly comparable with that of autumns 2001 and 2002.

2.9 In addition, Figures B2.3, B2.4 and B2.5, present information on prices and interconnector flows. These figures highlight periods in which reported price differentials do not appear consistent with the direction of flow. In each case, Figure 'a', presents the Zeebrugge and NBP prices whilst Figure 'b' converts this to a price differential.

Table A2.1: Comparison of autumn 2003 characteristics of the interconnector with corresponding periods in 2001 and 2002

Characteristics	2003	2002	2001
Interconnector Direction	Export	Export	Export
NBP > Troll	Yes	Yes	Yes
Differentials Between NBP and Zeebrugge Hubs Figures A2.3a/A2.4a/A2.5a	Positive Small	Positive Narrower than 2003's values	Positive Small
Export volume assessments Figures A2.3b/A2.4b/A2.5b	Gas export for a significant time before the period (Europe injecting gas in storage)	Gas export for a significant time before the period (Europe injecting gas in storage)	Gas export for a significant time before the period (Europe injecting gas in storage)
Demand	Increasing, 300-350 mcm	Increasing, 300-350 mcm	Increasing, 300-350 mcm

Figure A2.3a: Interconnector flows and market prices – August to December 2003

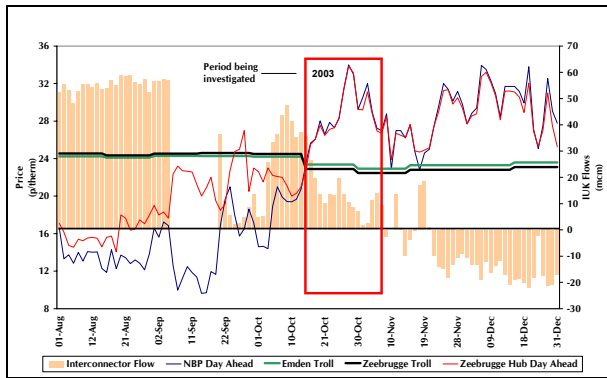


Figure A2.3b: Interconnector flows and price differentials – August to December 2003

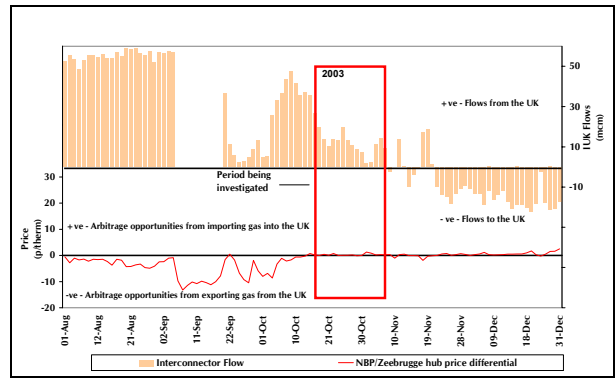


Figure A2.4a: Interconnector flows and market prices – August to December 2002

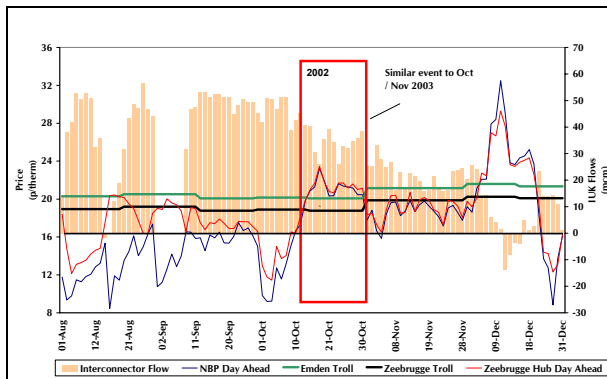


Figure A2.4b: Interconnector flows and price differentials – August to December 2002

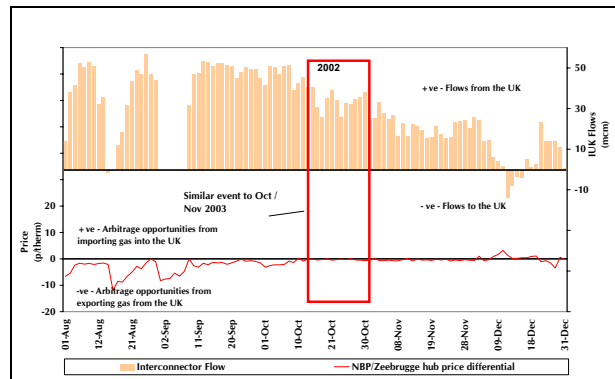


Figure A2.5a: Interconnector flows and market prices – August to December 2001

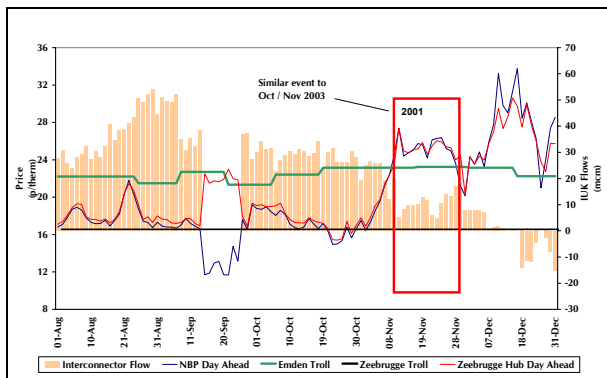
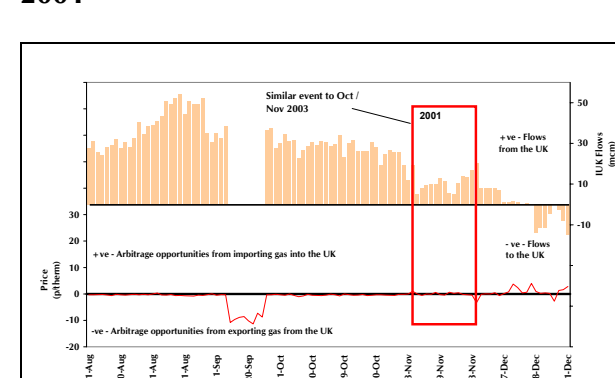


Figure A2.5b: Interconnector flows and prices differentials– August to December 2001



2.10 This analysis highlights that each year, from August through to October/November, the interconnector has historically flowed from the UK to Europe (export mode). For the past 3 years, the earliest that the interconnector

has reversed flow (import mode) has been 9 November 2003 (i.e. during the period being investigated).

- 2.11 The above analysis also shows that during each of the three previous years, the interconnector continued to export gas when circumstances were similar to the period in question (high UK prices, low European prices), although the price differential between NBP prices and European prices was not as marked as was the case in 2003.
- 2.12 In 2001 and 2002, operations at the interconnector to change the direction of the flow were less flexible due to the rules prevailing at the time providing an explanatory factor for the price differentials observed in these periods.
- 2.13 Changes in Rules for Flow Transitions in September 2003⁸ have contributed to a more flexible pipeline flow transition process. The main change is to remove the forecast element from the process so that decisions are based only on firm transportation nominations at the day-ahead stage. There are hurdles to avoid unnecessary transitions; however these are set at very low levels (0.925 mcm for forward to reverse and 0.13 mcm for reverse to forward).⁹

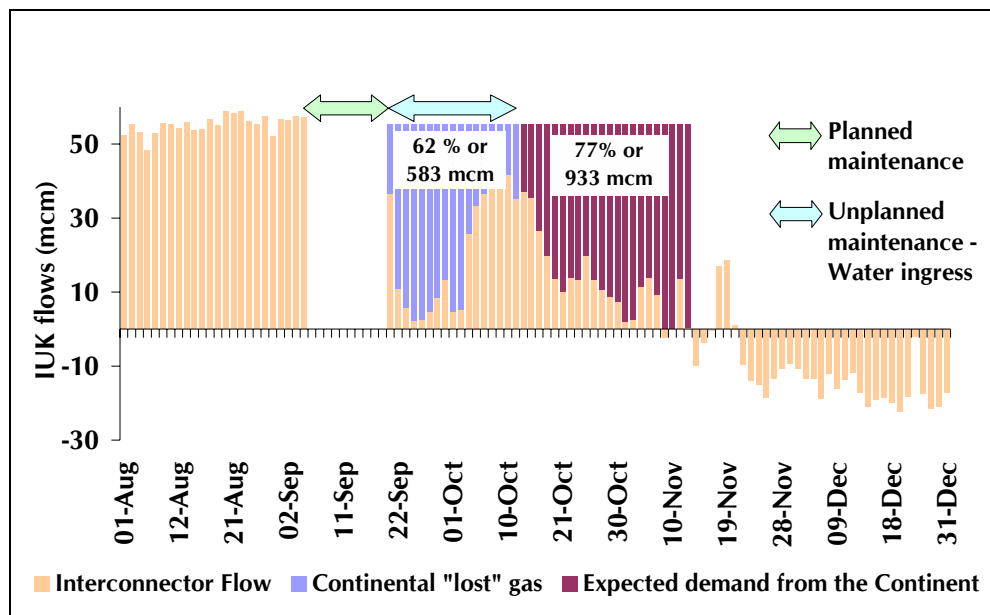
Impact of unplanned outages

- 2.14 As Figures A2.3 – A2.5 show, there have been a number of planned and unplanned outages affecting interconnector flows. In most cases, following the resumption of flows actual exports returned to levels comparable to the pre-outage levels.
- 2.15 However, analysis of the flows in 2003, and other market factors, suggest that the interconnector may have provided significant volumes of flexibility that are understated by observing export flows alone, as shown in Figure A2.6.

⁸ Flow reversals are now based on the pipeline Directional balanced Flow on D-1 rather than on a aggregate forecast.

⁹ Source IUK

Figure A2.6: Interconnector flows and volume losses – October and November 2003



- 2.16 Following the planned outage, the interconnector experienced problems relating to water ingress, reducing export capability and reducing the supplies of gas to Zeebrugge. Assuming that exports would have returned to the pre-planned-outage level, this represents a reduction of around 62 per cent, or 583mcm.
- 2.17 Information provided to Ofgem shows that this reduction in flows reduced the level of injections into storage facilities in northern Europe, compounded by lower than expected deliveries at the LNG terminal at Zeebrugge.
- 2.18 Therefore, in the absence of any other factors, the interconnector could have been expected to continue to export large volumes of gas during October 2003. Figure A2.7 highlights the extent to which the observed flows potentially represented a significant volume response, as continental storage operators would have supported export flows to compensate for the earlier maintenance affected flows.

Capacity holdings

- 2.19 The analysis of interconnector capacity shows that no individual interconnector shipper can restrict access to significant shares of capacity. Figures B2.7 and B2.8 illustrate which interconnector shippers held rights to capacity or sublet rights to capacity on the interconnector, on an anonymous basis.

Figure A2.7: Ownership of forward capacity on the Interconnector

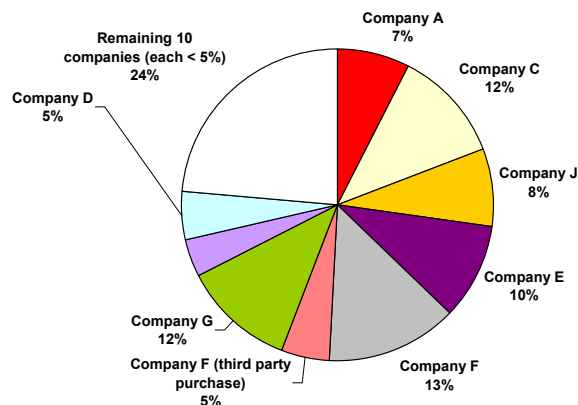
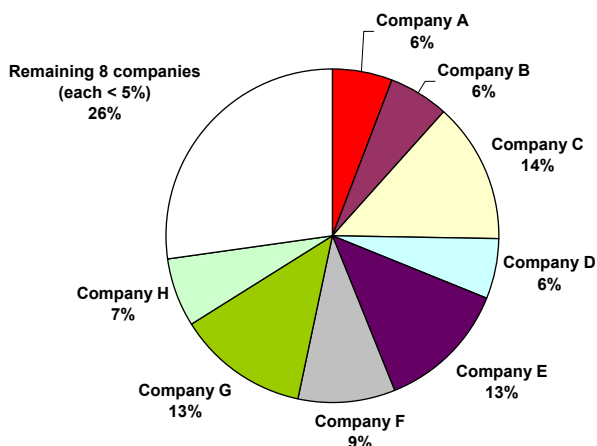


Figure A2.8: Ownership of reverse capacity on the Interconnector



- 2.20 No individual interconnector shipper held more than 19 per cent of available capacity rights. As such, no individual interconnector shipper can dictate the direction of the flow, through their capacity holdings.
- 2.21 The analysis of interconnector capacity shows that during the period being analysed there is no evidence that any interconnector shippers withheld or restricted access to capacity on the interconnector. There is a secondary market for interconnector capacity, although capacity trades tend to be concluded on a long term basis in order to supply long term contracts. Arbitrage of price differentials between the GB and Belgian market therefore tends to be conducted in the energy and not in the capacity market
- 2.22 An important factor explaining this is the presence of transaction costs. A few respondents reported that they prefer to arbitrage gas between the UK and

Zeebrugge markets using their own capacity, rather than selling this capacity to other companies in the short term. The physical flow from either capacity or gas arbitrage should be the same.

Shipper nominations

2.23 Ofgem's analysis of prices on European hubs and their comparison to NBP prices show that the nominations made were appropriate considering the conditions of the UK and Zeebrugge Hub markets over the period. The evidence supporting this is outlined below.

2.24 Zeebrugge Sell and Buy prices were reported by interconnector shippers and Ofgem calculated a volume weighted average of these trades. Ofgem used Heren day-ahead prices to calculate price differentials between NBP and Zeebrugge Hub. There are a number of reasons why actual, observed prices differ from those quoted by Heren:

- ◆ Heren price assessments are a snapshot at the end of the day, whereas completed transactions occur throughout the day, during which time prices can move;
- ◆ It appears that a proxy value can be used for the Zeebrugge price when there is not enough data on Zeebrugge Hub trades; and
- ◆ Ofgem only has trade data from interconnector shippers, and so Ofgem's calculated prices will not reflect all of the transactions concluded.

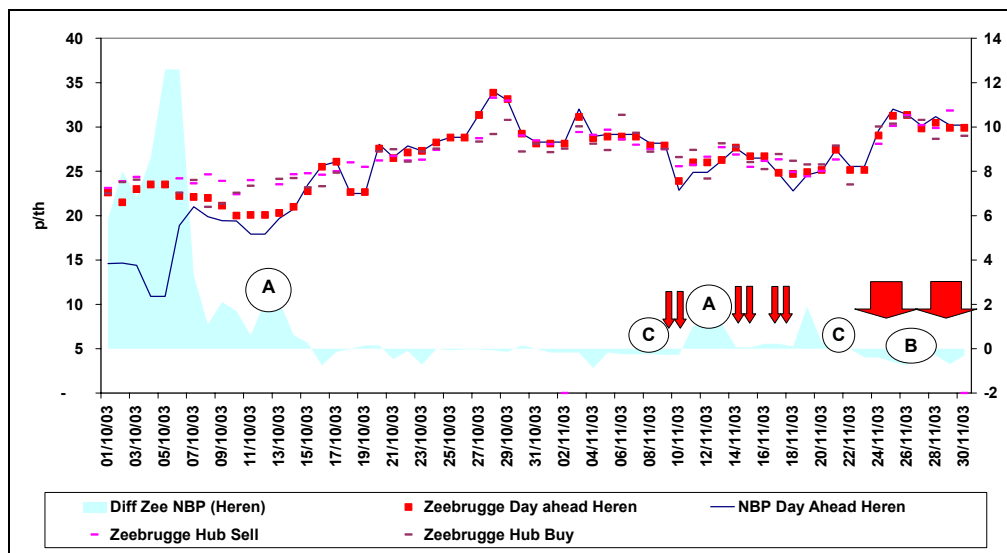
2.25 Figure A2.9 shows the price differential reported by Heren (blue area), reported prices at Zeebrugge (red squares) and the NBP (blue line) and compares these to the Zeebrugge buy and sell prices reported to Ofgem.

2.26 This figure highlights the following:

- ◆ The high price differential at the beginning of the period results from the shutdown of the interconnector.
- ◆ For the majority of the time the price differentials supported exports of gas to Europe (periods A).

- ◆ The negative price differential starting on 20 November was followed by flow reversal on 22 November (period B).
- ◆ Flow reversals for 9-10 November, 14-15 November and 17-18 November occurred after a negative differential, albeit with some lag. These show that there were some limited opportunities to arbitrage by selling into the UK from the Zeebrugge Hub. The opportunities were few and the differentials did not persist over time (period C).

Figure A2.9: Comparison of traded and reported price



2.27 Ofgem undertook a detailed analysis of individual interconnector shipper nominations. This included a consideration of their nomination behaviour in light of prevailing prices and contractual obligations in the UK and Europe. The information collected showed that all interconnector shippers nominated in response to price signals.

2.28 In addition, no individual interconnector shipper's nominations dictated the direction of the interconnector flow. On 20 of the 25 days where gas was exported to the UK, between 15 October and 9 November, at least four interconnector shippers nominated for exports. On four of the remaining five days three interconnector shippers nominated for exports. The remaining day was the final day before the interconnector began importing gas. Highlighting that, at most, an individual shipper delayed the switch of direction by one day.

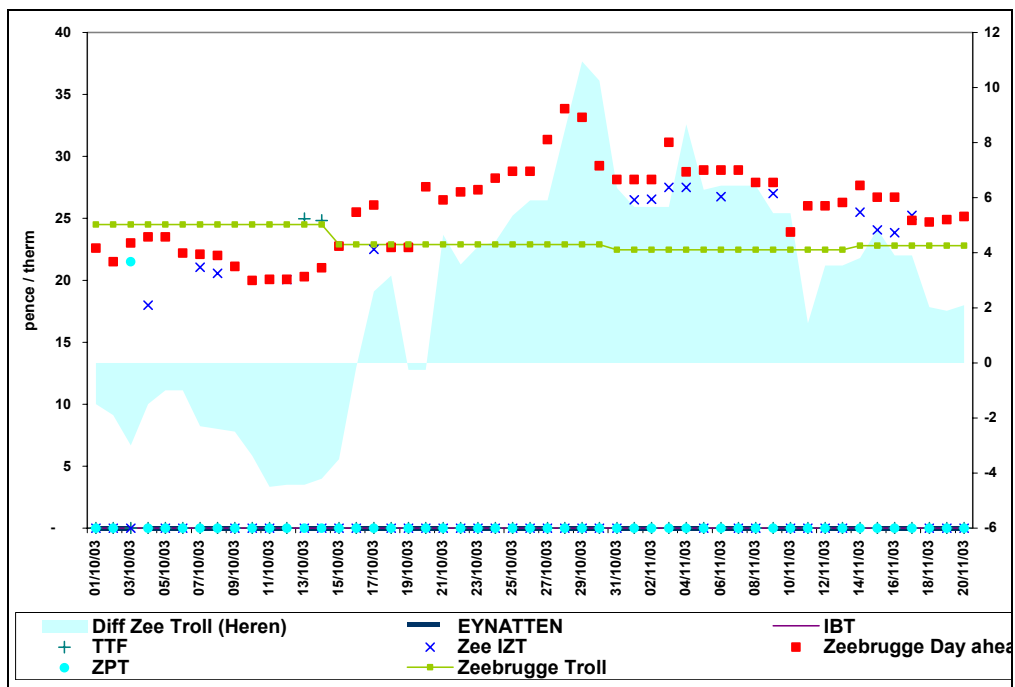
A number of interconnector shippers nominated for exports to the UK throughout the period.

- 2.29 Removing nominations from the company with the most significant forward nominations shows that the interconnector would have remained in export mode until the actual day of switching to importing gas. Furthermore the company nominated gas in the reverse direction throughout the period responding to pricing signals in November.
- 2.30 A few respondents have indicated that where they have long term contracts in place for supplying companies in Europe the payments that they would be obliged to make for under delivery are sufficiently penal so as to ensure that it is economic for them to pay extremely high prices for gas in the UK and Europe rather than cease deliveries to customers.
- 2.31 One respondent, that did not nominate in the reverse direction despite holding reverse capacity, commented that it did not nominate to deliver gas to the UK as its contracted gas was being put into storage to fulfil its Public Service Obligations (PSOs).
- 2.32 Ofgem concluded from the evidence above that the behaviour of the interconnector was consistent with past events and with economic signals at the time.

Traded prices and access to gas

- 2.33 Price differentials existed between the Zeebrugge and Emden Trolls and Zeebrugge Hub prices and remained quite significant throughout the period as shown by Figure A2.10. Troll prices remained higher than Zeebrugge prices for the first two weeks of October. Prices on the Zeebrugge Troll were on average 5.5 p/therm below those observed at the Zeebrugge Hub over the following period 20 October to 30 November 2003.

Figure A2.10: Reported European prices



- 2.34 If companies had taken advantage of this arbitrage opportunity, Ofgem would expect that Zeebrugge gas price would have decreased, which should have then created a sufficient price differential with the NBP price to have interconnector shippers nominate for the interconnector to import gas.
- 2.35 Whilst prices in Europe indicated that this should have occurred, analysis of the Troll prices and the Zeebrugge Hub prices indicate that this did not occur because minimal gas from the Zeebrugge and Emden Trolls was actually delivered to the Zeebrugge Hub. There was limited access to capacity to transport gas purchased at the Zeebrugge and Emden Trolls to the Zeebrugge Hub because the majority of capacity was owned by two market participants.
- 2.36 The above diversion of gas from the competitive market raised the Zeebrugge Hub gas prices and impacted the UK market because the differential did not widen as expected, preventing a switch in interconnector flows.
- 2.37 The analysis of trades reported by interconnector shippers and responses received shows that:

- ◆ most of them trade significantly only at the Zeebrugge Hub;

- ◆ that the hub is not very liquid (relative to the NBP);
- ◆ that there were price differentials between European hubs; and
- ◆ that the price differential did not close due to very limited availability of gas from these hubs.

2.38 A number of factors were identified that explained the pricing at Zeebrugge and the observed price differentials, including:

- ◆ relatively high European demand;
- ◆ storage injections; and
- ◆ lack of access to capacity to transport gas to the Zeebrugge Hub.

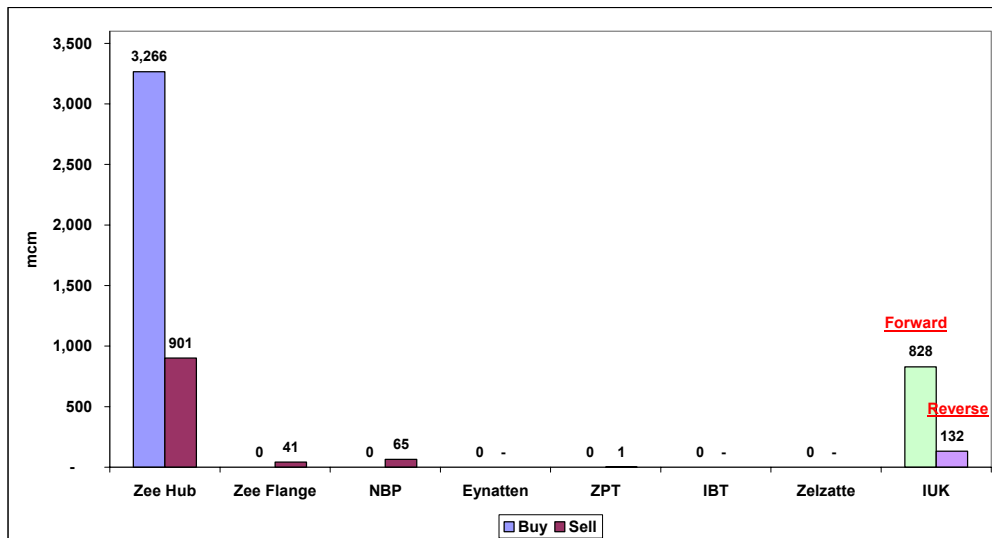
2.39 It is also possible that market sentiment led to a very cautionary approach to trading even though differentials created arbitrage opportunities. All of these points are detailed below.

Traded volumes

2.40 Figure A2.11 shows that the Zeebrugge Hub was the only location that had any significant trading activity over the period.¹⁰ Ofgem could not reconcile buy and sell volumes, as trade data was related to interconnector shippers only. Volumes bought during the period are higher than volumes shipped to the UK through the interconnector as some interconnector shippers have contractual obligations in Europe.

¹⁰ Ofgem asked interconnector capacity holders for details of the trades conducted on the different hubs. Details included volume, price, location, duration and counterparty.

Figure A2.11: Trading volumes reported by location

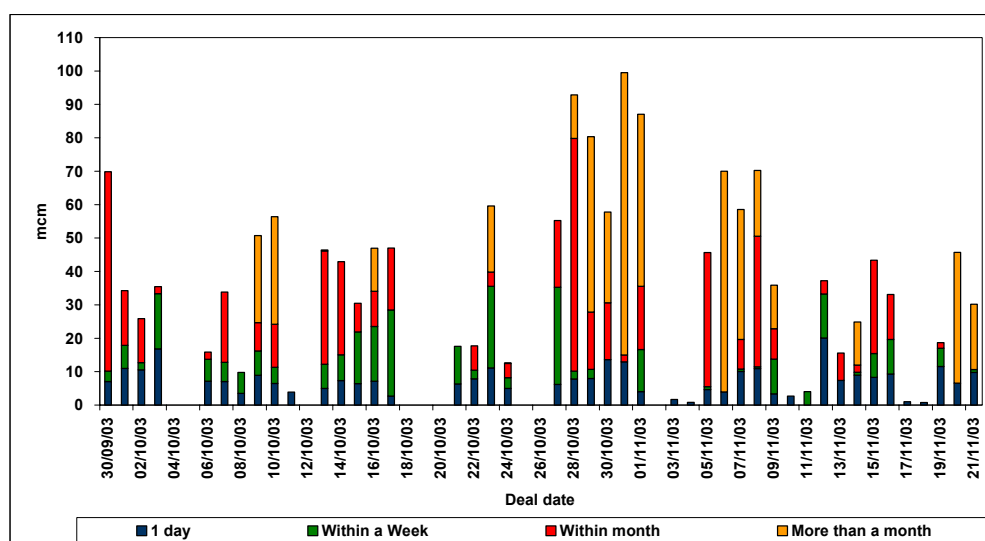


2.41 Furthermore, out of 1,664 buy trades reported over the period by interconnector shippers, 1,592 took place at Zeebrugge Hub, 39 at NBP, 29 at Zeebrugge Flange and one at Eynatten and at Zelzatte.¹¹

2.42 The lack of liquidity in Zeebrugge is furthermore exhibited by the relatively long duration of the trades that were made during this period, which are shown in Figure A2.12. The majority of trades made were for within week or within month for October and for periods longer than a month for November. This indicates that few short term opportunities for arbitrage were taken and that purchases were to fulfil medium to long term supply contracts.

¹¹ The method of data collection will have affected the relative volume of trades.

Figure A2.12: Trade lengths for Zeebrugge Hub Buy transactions



2.43 The above analysis is consistent with the widely reported observation that liquidity, particularly over near-term trading, is limited to the Zeebrugge Hub. This was observed by a number of respondents.

Higher European demand for gas

2.44 Demand for gas was higher in October 2003 in Belgium, France and the Netherlands than in October 2002¹² as shown by Figures A2.13, A2.14 and A2.15 respectively. The increase in demand in the Netherlands was driven by lower temperatures in 2003, when compared to 2002, at de Bilt, at the end of the month. Therefore increasing demand for European gas reduced the amount of gas available for export to the UK. Another respondent reported that demand for gas was higher due to increased demand from CCGTs as a consequence of a dry summer and of problems for shipping barges of coal up the Rhine.

¹² Source: Figaz, DGEMP and KNMI

Figure A2.13: Year on year comparison of monthly demand levels in Belgium (Source Figaz)

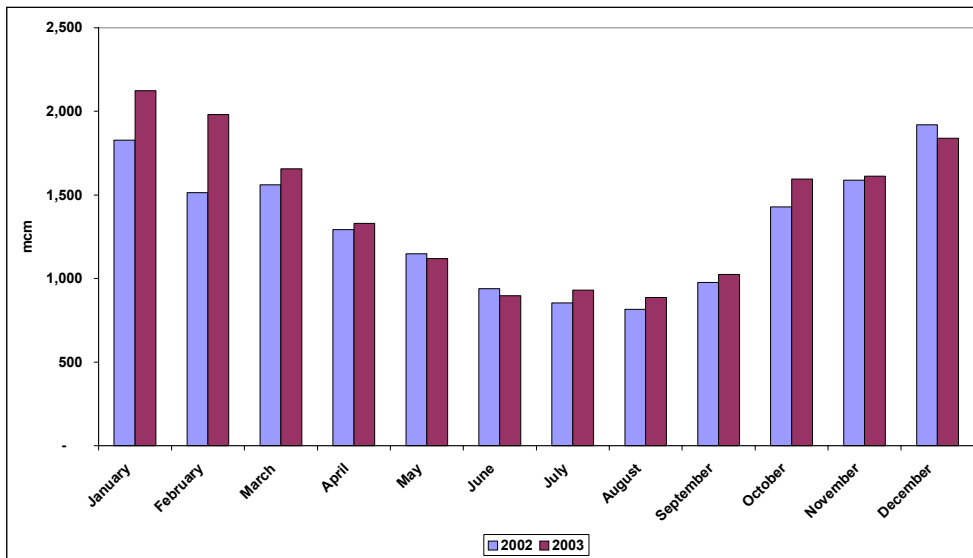


Figure A2.14: Year on year comparison of monthly demand levels in France (source DGEMP)

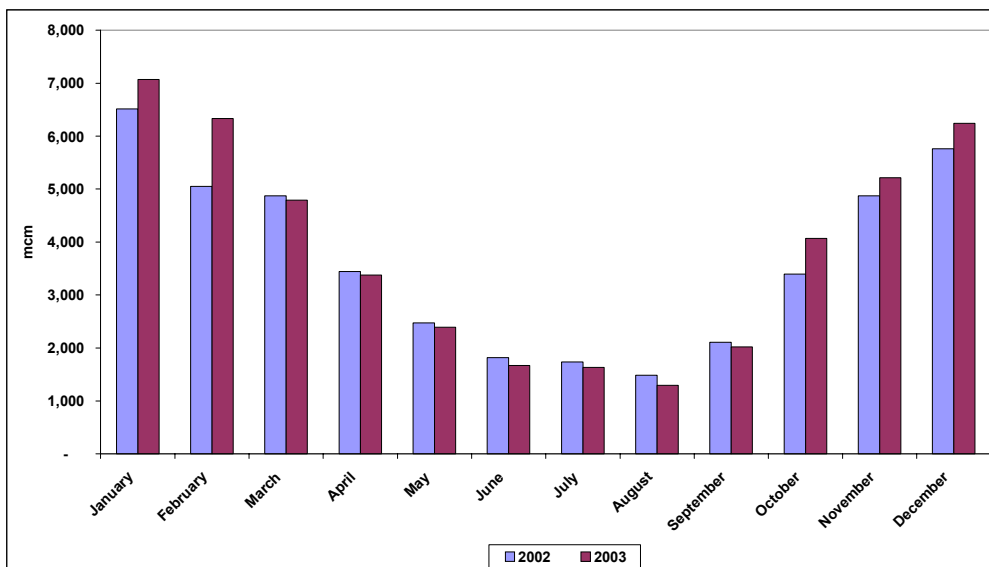
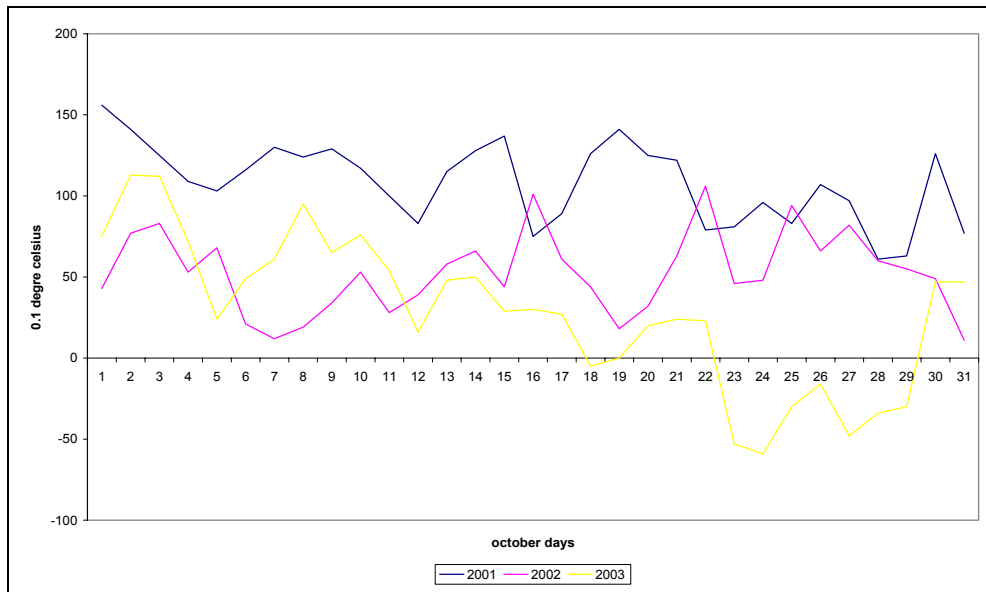


Figure A2.15: Year on year comparison of monthly temperatures in the Netherlands



Storage and LNG

2.45 Two factors that affect the supply and demand of gas at Zeebrugge are:

- ◆ Injections into storage; and
- ◆ Deliveries of LNG at the Zeebrugge terminal.

Therefore these factors will affect the value placed on gas at Zeebrugge and the flows on the Interconnector.

2.46 A respondent commented that it had to continue its injections into storage in order to be able to meet its legal PSO during the following winter. Storage levels were lower than initially planned due to efforts to meet demand on, and support the liquidity of, the Zeebrugge Hub during the planned maintenance period and the subsequent operational problems at the interconnector in September and early October 2003. It appears that the injections into storage diverted gas not needed for Belgian daily demand from the traded market at Zeebrugge Hub increasing the price of gas at Zeebrugge and affecting the flows across the Interconnectors. Belgian storage requirements are discussed in more details in the next section.

- 2.47 As highlighted above, the lower than planned level of storage can be explained by the disruption of the interconnector in early October. Calculations suggest that this may have led to a volume loss of 583 mcm (Figure A2.6).
- 2.48 A respondent reported delays in the delivery of LNG into the LNG terminal at Zeebrugge, reducing the available supply of gas.
- 2.49 These factors appear to have combined to lead to higher Zeebrugge prices. Indeed one respondent reported difficulties sourcing gas at competitive prices on the Zeebrugge Hub.

Limited access to transportation capacity on the Belgian grid

2.50 Whilst lower prices at the Emden Troll than on Zeebrugge Hub and NBP would create arbitrage opportunities, two respondents reported that they were able to use transit capacity to ship gas from neighbouring hubs to the Zeebrugge Hub:

- ◆ One participant was able to use its capacity in the Belgium system through long term and short term agreements to bring gas from neighbouring gas markets to Zeebrugge and the UK,
- ◆ A respondent used its full offtake capacity from a neighbouring hub under its long term supply contracts, which were then nominated for maximum delivery between 16 October and 30 November.

Evidence of any other companies being able to source gas there and to transport it to the hub on a short term basis was limited.

2.51 As such, on the evidence available to Ofgem, it is not possible to fully explain the persistence of price differentials between neighbouring hubs and the apparent lack of arbitrage between them. As such it appears that a number of factors may have contributed to the lack of arbitrage and the resulting response of the interconnector:

- ◆ Access to transportation capacity, at cost reflective prices;
- ◆ Access to gas at price reflecting the prevailing value of that gas.

These issues relate to the liberalisation of European gas markets, which is discussed later in this Appendix.

Gas quality specification issue

- 2.52 Another issue that may limit export to the UK is the quality of the gas to be exported from the Belgian system through the interconnector. None of the respondents mentioned this issue but this was raised during a shipper's meeting.
- 2.53 The interconnector has a standard quality specification for all shippers (see Table A2.2). The single specification applies to both forward and reverse gas flows. In addition, IUK has a quality specification within the Interconnection Agreement with Transco. In renegotiating the specifications, IUK has to ensure that both specifications remain compatible. The quality specification applies to Fluxys, the Belgian system operator, via a legacy agreement that had been signed between British Gas and Distrigas.

Table A2.2: Comparison of some of the key quality specifications (Source DTI)

Parameter	Norwegian	GS(M)R	Typical NTS(10YS)	IUK	EASEE-gas Marcogaz
Gross CV	38.1 to 43.7 MJ/Sm ³		36.9 to 42.3 MJ/Sm ³	38.9 to 44.6 MJ/Nm³	35.01 - 45.18 MJ/Sm ³
Wobbe Index	48.3 to 52.8 MJ/Sm ³	47.2 to 51.41 MJ/Sm ³	48.14 - 51.41 MJ/Sm ³	48.23 - 51.17 MJ/Sm³*	47.0 - 54.0 MJ/Sm ³
Water dewpoint	-18°C at 69 barg	See Note 1	- 10°C at delivery pressure	-10°C at 69 barg	-8°C at 69 barg
Hydrocarbon dewpoint	-10°C at any pressure above 50 barg	See Note 1	-2°C at 75 barg	-2°C at 69 barg	-2°C at any pressure above 69 barg
ICF		Less than 0.48	Less than 0.48		
Soot Index		Less than 0.60	Less than 0.60		Replace with RD 0.5548 - 0.70
Inerts			Not more than 7 mol %		

2.54 The major issues for the interconnector imports are the Upper Wobbe Index limit, the ICF and the Sooting Index. The Upper Wobbe Index limit for the interconnector is 54 MJ/Nm³. This equates to 51.17 MJ/Sm³. This is below the GS(M)R limit of 51.41 MJ/Sm³. There are therefore two issues for the interconnector. The first is that the UK legal limit is generally felt to be restrictive in terms of the gas that can be imported from Belgium. The second issue is whether the contractual limit of 54 MJ/Nm³ can be renegotiated in the event of any raising of the GS(M)R Upper Wobbe limit in the UK. The ICF and SI limits are unique to the UK specification. This can lead to difficulties in negotiations for gas imports, as non-UK gas operators would not normally calculate these factors.

2.55 The quality of gas entering the interconnector is controlled by Fluxys. In order to ensure that it can meet the interconnector specification, Fluxys has imposed a similar quality specification on the RTR-VTN pipeline, which is the main transit

pipeline in Belgium. This pipeline operates at 80barg at the entry point where it receives gas from Wingas and Ruhrgas in the East. Another entry point takes in from Zelzate, Holland in the North.

- 2.56 All gas imported into Belgium has an Upper Wobbe Index limit above the interconnector. All gas could potentially nonetheless have a Wobbe Index between 50.9 and 54.0 and is therefore shippable through the interconnector. Zee pipe usually delivers gas below the interconnector specification. In the absence of statistics on gas volumes and their characteristics, it is difficult to assess the extent to which the maximum Wobbe index limits flows to the UK.

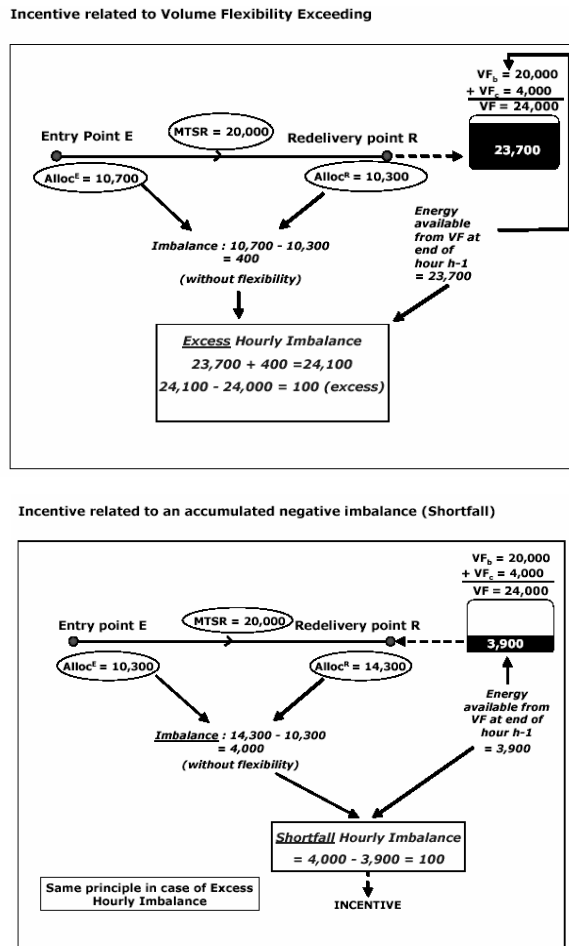
Delivery risk and the cash-out regime in Belgium

- 2.57 Some respondents highlighted that the incidents of early October, and penalties for default clauses on European deliveries created a cautious approach to trading through the interconnector and beyond the Zeebrugge Hub. Several companies had been financially affected by the closure of the interconnector because of high default penalties on supply contracts in Europe. Respondents reported their concerns about the reliability of the physical operation of the pipeline during the period considered. One of them was of the opinion that since the departure of the American trading companies and because of the cash out regime in Belgium it felt that there was a significant risk premium attached to the use of the Interconnector.
- 2.58 In addition, respondents commented that it was difficult to manage the risk associated with speculative/arbitrage trades, as the combination of low liquidity and relatively penal cash-out arrangements meant that any under-delivery risk was very significant.
- 2.59 One respondent added that following the interconnector operational problem, and the associated financial exposures, all new trading beyond the Zeebrugge Hub had been halted, in order to enable risks to be properly assessed.
- 2.60 The cash out regime in Belgium is relatively onerous in cases of imbalances.¹³ Tariff supplements are applied if a grid user does not comply with its hourly nominations on a specific route. There are two components to these balancing

¹³ The imbalance regime was modified on 1 April 2004.

prices: a commodity charge, linked to daily Zeebrugge prices (Fluxys invoices the net user at 130 per cent of Zeebrugge prices in case of shortfall and credits him at 70 per cent of Zeebrugge prices in case of excess) and a capacity charge related to the annual Additional Volume Flexibility tariff and divided by 6. Examples are provided in Figure A2.16.

Figure A2.16: Cash-out calculation examples in Belgium



Other factors

2.61 As noted above, the lack of liquid trading hubs, other than Zeebrugge, in Europe reduces the opportunities for arbitrage. A number of companies indicated to Ofgem that they have not historically traded beyond Zeebrugge due to a lack of internal authorisations and/or difficulties experienced in establishing trading relationships.

- 2.62 The development of standardised terms, including the EFET¹⁴ contracts put in place in January 2004, has improved processes for credit approvals and has contributed to an increase in companies' ability to secure internal trading authorisations.
- 2.63 One respondent also highlighted that the incentives to flow in reverse were limited due to:
- ◆ Entry and exit capacity charges;
 - ◆ NBP commodity charges; and
 - ◆ Fuel gas usage in the interconnector.

Discussion of storage requirements in Europe

- 2.64 As highlighted above, it appears that storage flows in continental Europe may provide an explanation for why additional gas was not imported into the UK. This section provides additional information about the use of storage in Europe.
- 2.65 Information was received from a number of interested parties, including CREG (Belgium), the CRE (France), the DTE (the Netherlands), RWE and Distrigas.
- 2.66 In Belgium, there are currently no legal requirements to store any specific quantity of gas. There is an obligation of continuity of supply to the non eligible market (most distribution customers in the Walloon region and Brussels at the time).¹⁵ This obligation is enshrined in a Royal Decree of 23 October 2003. The injection season into the Loenhout underground storage facility goes from mid April to mid October. The Royal Decree does not give precise guidelines on ways and means to fulfil this obligation of continuity of supply.
- 2.67 Storage at Loenhout (Belgium) represents 525 million cubic meters in the storage year 2003-2004 and the maximum hourly injection rate is 250 000 cubic meters. Storage levels were lower than initially planned due to efforts to meet demand on and support liquidity of Zeebrugge Hub during the maintenance period and the subsequent operational problems in the interconnector in September and early October 2003.

¹⁴ European Federation of European Traders

¹⁵ Flanders has been fully deregulated since July 2003.

- 2.68 Gaz de France did not have regulatory requirements to inject gas during the period considered (autumn 2003) either from the CRE or from the Dideme.¹⁶
- 2.69 In the Netherlands, there are no rules or requirements to fill storage at certain times within the year.
- 2.70 A number of respondents raised concerns about the operation of storage in continental Europe, including:
- ◆ The lack of transparency on what PSOs exist;
 - ◆ The lack of information about storage stocks; and
 - ◆ The inability to gain access to storage facilities.

Liberalisation of gas markets in Europe

- 2.71 Ofgem has two main concerns. The first relates to the lack of effective competition in key European markets that gives rise to the oil price link and its effect on the GB market and customers. Long term supply contracts can provide a valuable contribution to the development of any Market, for example by providing backing for long-term investment in infrastructure projects. However, in the absence of effective competition, such contracts can act to distort prices and potentially foreclose markets from potential entry.
- 2.72 The second relates to specific concerns highlighted in this Appendix. In particular, Ofgem has not been able to satisfy itself fully that all contractually available gas was being released into the market, that the use of storage capacity was appropriate, and that surplus transit capacity was made available.
- 2.73 Ofgem has therefore called on the European Commission to devote sufficient resources to considering competition issues in continental gas markets, and where it identifies infringements to enforce competition law in the energy sector. Ofgem has presented its findings to the Commission and intends to work in collaboration with the Commission and other European competition authorities to identify whether infringements have taken place.

¹⁶ The French Energy Ministry

2.74 Whilst this document highlights a number of issues relating to the operation of the European markets, these are known to regulators and market participants. There is work being undertaken currently to address liberalisation issues, including:

- ◆ The Gas Directive¹⁷ agreed last year
- ◆ Work being carried out by the Madrid Forum on access to flexibility and public service obligations (including storage)
- ◆ Regulation on access to gas transmission networks

2.75 The Gas Directive requires the following:

- ◆ The legal unbundling of transmission and distribution from upstream activities and supply;
- ◆ The ability of Industrial and Commercial and domestic customers to change supplier by 2004 and 2007 respectively;
- ◆ A regulatory function in each Member State, independent from the interests of industry and responsible for ensuring effective competition, non-discrimination and the efficient functioning of the market.
- ◆ Any PSOs adopted by Member States to be clearly defined, transparent and non-discriminatory. Members States must report to the Commission on any PSOs adopted, including their possible effect on national and international competition.

2.76 Regulation on access to gas transmission networks is currently under discussion. This currently requires:

- ◆ Non-discriminatory, transparent and flexible third party access services, in support of competition and trade
- ◆ Measures to facilitate trade of capacity on secondary markets and to prevent the hoarding of capacity

¹⁷ Directive 2003/55/EC

- ◆ Mechanisms to develop further guidelines on network access issues.
- 2.77 Also, the European Commission (EC) is required under the Gas Directive to report by 1 July 2006 on implementation in Member States and progress in creating the internal energy market, and may submit proposals to address issues of market dominance, market concentration and predatory or anti-competitive behaviour.
- 2.78 Ofgem welcomes these moves towards the liberalisation of continental gas markets.

Conclusions

- 2.79 Based upon an analysis of the specific period, Ofgem has concluded that the interconnector was operating efficiently and responded appropriately to the nominations made. Interconnector shippers reduced their export nominations to Belgium and increased their import nominations following price signals given by the NBP Zeebrugge Hub differential. There was adequate access to additional interconnector capacity if it was required.
- 2.80 Whilst Ofgem's analysis has concluded that the interconnector was operating efficiently based upon the observed differential between NBP and Zeebrugge Hub prices, Zeebrugge prices did not appear to reflect arbitrage opportunities with the Zeebrugge and Emden Troll prices.
- 2.81 Respondents highlighted a number of concerns that explain the pricing of gas and the persistence of price differentials, including:
- ◆ Access to gas;
 - ◆ Access to transportation capacity;
 - ◆ Operation of storage facilities and the transparency of the PSOs; and
 - ◆ The nature of the imbalance arrangements during the period.

Appendix 3. October/ November 2003:

Effects of reduced gas supply on prices

3.1 This chapter draws on the analysis presented in Appendices 1 and 2 and quantifies the extent to which observed price movements can be explained by the underlying supply and demand factors identified in relation to the interconnector and UKCS availability.

Introduction

3.2 Ofgem has sought to quantify the factors that could explain the increase in gas prices in October and November 2003. The evolution of forward prices and the outturn prompt prices suggest that there may have been a number of unexpected factors that influenced prices, as any available information about supply and demand fundamentals prior to October 2003 would be expected to have been priced into the prevailing forward price.

3.3 Appendix 1 highlighted that there were a number of potentially unexpected factors that may have reduced the availability of gas in October and November 2003:

- ◆ There had been a significant decline in the production capability of offshore fields (potentially in addition to that previously expected); and
- ◆ There were a number of planned and unplanned outages that reduced UKCS capability during the period (potentially in addition to the level normally expected)

3.4 Appendix 2 highlighted that there were a number of unexpected factors that affected the availability of gas via the interconnector:

- ◆ Higher demand for gas due outturn weather conditions on the continent; and
- ◆ Storage levels were lower than initially planned, due to earlier unplanned interconnector outages and deliveries at the LNG terminal at Zeebrugge

3.5 In addition to determining the range of potential volumes of gas that were affected by the above factors, it is necessary to derive the relationship between any reduction in available supply (or increase in demand) and price in order to assess the degree to which observed price movements can be explained. As such, there are two elements to assessing the observed increase in prices:

- Estimating an appropriate relationship between supply availability and price (the “price elasticity”); and
- Establishing an appropriate volume of gas unexpectedly affected by the factors identified above.

3.6 These are discussed in turn below.

Estimating the price elasticity

3.7 Ofgem has undertaken a range of analysis of the likely impact of changes in supply on the level of prices. Four sources of information are presented:

- ◆ Source 1 – Changes on interconnector availability following planned maintenance (representing continental supplies not being available);
- ◆ Source 2 - The Competition Commission’s report into Centrica’s acquisition of the Rough Storage facility¹⁸; and
- ◆ Source 3 - The price effects of interconnector imports.

3.8 The first two sources are useful and suggest that price rises of 0 – 3 p/therm were possible for each 10 mcm per day reduction in supply (Table A3.1). Analysis from the sources is presented below.

¹⁸ Centrica plc and Dynergy Storage Ltd and Dynergy Onshore Processing UK Ltd – A report on the merger situation, http://www.competition-commission.org.uk/rep_pub/reports/2003/480centrica.htm#full

Table A3.1: Sources for data on price elasticities

Source	Description	Potential price changes
Source 1	The price effects when the interconnector is not available due to planned maintenance (representing continental supplies not being available)	1.3 to 1.5 p/therm for each additional 10mcm of supply being available
Source 2	The conclusions regarding the price increases of withholding gas supplies from the Competition Commission's report.	A 1 p/therm price increase would result from withholding 9.7mcm per day for 90 days A 3 p/therm price increase would result from withholding 13.5 mcm per day for the top 30 days of peak demand
Source 3	The price effects of interconnector imports	No conclusions drawn as the analysis showed that there was no significant relationship between quantity and price – the highest R squared was only 0.19.

Source 1 – Changes on interconnector availability following planned maintenance

3.9 The periods being investigated relate to the following planned maintenance periods:

- ◆ **2001:** 17 September to 26 September
- ◆ **2002:** 31 August to 9 September
- ◆ **2003:** 8 September to 22 September

3.10 The price and quantity changes that occurred during these planned maintenance periods are set out in Table A3.2.

Table A3.2: Elasticity results (Interconnector availability)

Year	Number of days affected	Average export flow lost (additional gas to the UK) (mcm per day) ¹⁹	NBP Price Before (p/therm) ²⁰	NBP Price After (p/therm) ²¹	Price Difference (p/therm) ²²	Price decrease for additional supply of 10 mcm per day (p/therm) ²³
2001	10	34	16.7	11.7	5.0	1.5
2002	10	49	17.4	10.8	6.6	1.4
2003	15	56	16.9	9.6	7.2	1.3

3.11 These results show that for a 10mcm decrease in the UK Supply – Demand balance the gas price would change by 1.3 - 1.5 p/therm. This relationship can be used to construct an estimate of the price elasticity of supply, assuming demand is perfectly inelastic. This implies that a 10mcm decrease in supply to the UK would result in the gas price increasing by 1.3-1.5 p/therm.

3.12 In order to test for consistency, price and quantity changes were also assessed when the interconnector was under unplanned maintenance such as the period from 23 September 2003 to 13 October 2003 when it was affected by water ingress. During this period, the change in flow (max during period minus min during period) was 45mcm. The change in price (max during period minus min during period) was 6.6 p/therm. This equates to roughly 1.5 p/therm for each 10 mcm, which is consistent with the conclusion from the analysis of the planned maintenance periods.

Source 2 - The Competition Commission's report

3.13 In order to quantify price increases due to reduced supply, Ofgem considered the estimates given by the Competition Commission in its report on Centrica's acquisition of Dynegy Storage²⁴, which were based on analysis by Lexecon.

3.14 As part of its analysis, Lexecon estimated that a total of 329 million therms (879mcm) of capacity would need to be withheld over the 90 days of Q1

¹⁹ Average flow for the five days before the planned maintenance

²⁰ NBP Price immediately before the planned maintenance

²¹ Minimum NBP Price during the planned maintenance

²² NBP Price Before minus NBP Price After

²³ Price difference divided by average flow lost multiplied by 10 mcm per day

²⁴ All calculations are based on figures available in the public version of the Competition Commission report, Centrica plc and Dynegy Storage Ltd and Dynegy Onshore Processing UK Ltd – A report on the merger situation, http://www.competition-commission.org.uk/rep_pub/reports/2003/480centrica.htm#full. Lexecon's analysis is included in Appendix 5.

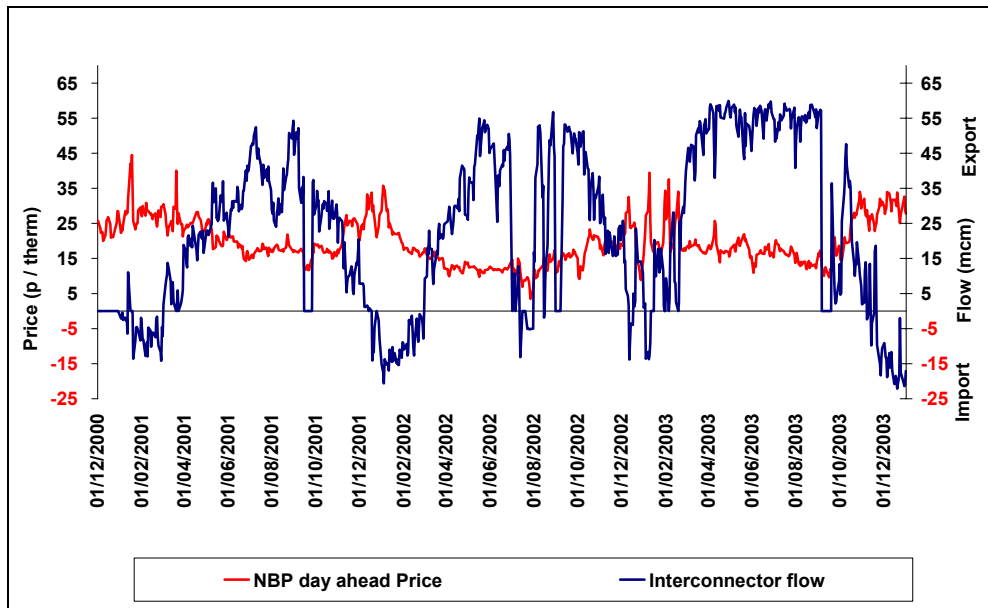
(January – March) in a given year in order to generate an average increase in the wholesale price of about 1 p/therm over that period. The 879 mcm over 90 days corresponds to a daily flow of 9.7 mcm.

- 3.15 As an alternative strategy, Lexecon assumed that a total of 150 million therms (405 mcm) would need to be withheld over the top 30 days of peak demand in Q1 to generate a 3 p/therm increase in the average wholesale price over that 30 day period. The 405 mcm over 30 days corresponds to a daily flow of 13.5 mcm.
- 3.16 These relationships reflect the fact that as prices rise, reflecting the tightening of the supply/demand position during the winter, supply can be expected to become more inelastic resulting in larger price increases than would be expected under normal conditions.
- 3.17 These results suggest an elasticity equivalent to a 10 mcm per day reduction in supply resulting in a 0 - 3 p/therm increase in price.

Source 3 – Imports from the interconnector

- 3.18 The last source of information on elasticity was historical price changes that occurred when the interconnector was importing gas. Price and interconnector flows from December 2000 till December 2003 are displayed in Figure A3.5.

Figure A3.5: NBP day ahead gas prices vs. interconnector flows December 2000 to December 2003



3.19 It is interesting to note that:

- ◆ There are only limited occasions on which the interconnector had been importing gas. For the majority of the time the interconnector remains a net exporter; and
- ◆ There were only a few occasions where the interconnector was importing gas near full capacity (approximately 25mcm). When this did occur, the flows only sustained for a few days.

3.20 Import quantities were assessed against NBP day ahead, NBP two days ahead, NBP three days ahead and NBP six days ahead prices. The analysis considered a variety of interconnector flows ranging from flows under 5mcm to flows at near full capacity (greater than 15 mcm) to understand whether the size of the interconnector flow affects prices. The results are shown in Table A3.3.

Table A3.3: Price elasticity results (Imports from the interconnector)

Difference between (NBP- 2 days ahead) and (NBP- 1 Day ahead)					
Price change (p / per therm)					
Flow	Max	Min	Ave	Std Dev	R^2
0-5 mcm	3.75	-6.90	-0.19	2.44	0.00
5-10 mcm	4.05	-6.40	-0.06	2.01	0.10
10-15 mcm	6.15	-13.30	-0.45	3.17	0.00
>15 mcm	7.20	-27.78	-1.44	6.53	0.01

Difference between (NBP- 3 Days ahead) and (NBP- 2 Days ahead)					
Price change (p / per therm)					
Flow	Max	Min	Ave	Std Dev	R^2
0-5 mcm	5.05	-1.93	1.29	1.75	0.05
5-10 mcm	10.00	-3.20	0.28	2.72	0.00
10-15 mcm	6.15	-13.30	-0.45	2.90	0.00
>15 mcm	30.18	-6.68	0.06	7.31	0.01

Difference between (NBP- 3 Days ahead) and (NBP- 1 Day ahead)					
Price change (p / per therm)					
Flow	Max	Min	Ave	Std Dev	R^2
0-5 mcm	7.48	-4.80	1.09	2.56	0.03
5-10 mcm	14.05	-9.15	0.22	3.83	0.02
10-15 mcm	10.83	-19.70	-0.90	4.37	0.00
>15 mcm	5.60	-8.73	-1.39	3.20	0.19

Difference between (NBP- 6 Days ahead) and (NBP- 2 Days ahead)					
Price change (p / per therm)					
Flow	Max	Min	Ave	Std Dev	R^2
0-5 mcm	16.55	-10.85	3.13	5.79	0.08
5-10 mcm	8.30	-9.00	0.32	2.98	0.01
10-15 mcm	5.50	-20.93	-1.94	4.63	0.03
>15 mcm	2.70	-10.85	-3.13	3.62	0.02

Difference between (NBP- 6 Days ahead) and (NBP- 1 Day ahead)					
Price change (p / per therm)					
Flow	Max	Min	Ave	Std Dev	R^2
0-5 mcm	16.25	-10.65	2.85	5.65	0.08
5-10 mcm	6.80	-8.23	0.26	3.44	0.06
10-15 mcm	4.60	-19.85	-2.39	4.50	0.05
>15 mcm	2.63	-10.35	-3.37	3.58	0.01

1

3.21 The results indicate that none of the combinations tested showed any significant statistical relationships.

3.22 No conclusions were drawn from this analysis.

Estimating the volume of gas affected

3.23 Now that a measure of price elasticity has been developed, the next step is to assess the volume of gas that was *unexpectedly* not available.

3.24 The volume of gas that was unexpectedly not available depends on a range of assumptions relating to:

- ◆ The volume of gas affected by unexpectedly high levels of planned and unplanned maintenance; and
- ◆ The volume of gas affected by higher demand for gas on the continent in order to increase storage injections.

3.25 In both cases Ofgem has made an assessment of the extent of these two factors and also presented a (potentially extreme) case where all of the possible volumes affected are included. This information is presented in Table A3.4.

Table A3.4: Gas volume reduction under the different scenarios

Scenario	Unexpected reductions in supply / increases in demand	Volume reduction (mcm/day)	Cumulative volume reduction (mcm/day)
Supply A	Unexpected maintenance at UKCS fields	24 – 31 ²⁵	24-31
Supply B	Increased continental gas demand to replace the gas affected by the unplanned interconnector outage	26	50-57
Supply C	Increased continental gas demand based on average interconnector import flows ²⁶	22	72-79
Supply D	All other UKCS maintenance	12-19	84-98
	Total	91-98	91-98

Supply A - Unexpected maintenance at UKCS fields

- 3.26 The 24-31 mcm represents an estimate of the level of unexpected maintenance at UKCS fields.
- 3.27 An estimate of October maintenance can be constructed by using the difference between the winter maximum for 2003/04 (394 mcm) and the maximum for October 2003 (351 mcm)²⁷. This gives an estimate of 43 mcm.
- 3.28 In the absence of historical statistics on field maintenance rates, Ofgem used data from winter 2002/03 as a proxy for “normal” maintenance levels. This gives the following estimates of unexpected maintenance:
- ◆ 31 mcm for October - the difference between the winter maximum for 02/03 and the maximum for October 2002; and
 - ◆ 24 mcm for November - the difference between the winter maximum for 02/03 and the maximum for November 2002.

²⁵ This assessment is based on relatively simple analysis of peak monthly flows in October and November 2002, relative to the peak flows throughout winter 2002/03, in order to estimate “expected” maintenance levels.

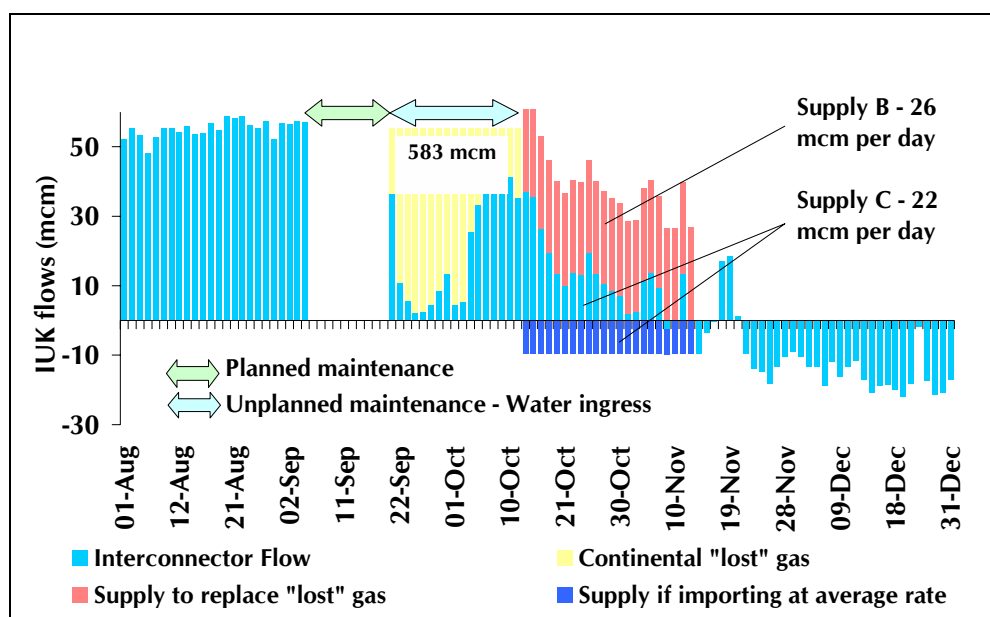
²⁶ This assumes that, in the absence of other continental factors, the interconnector would have imported gas into the GB market at a level equal to the observed average rate following the period being analysed. This is very much an upper case.

²⁷ See Figure 4.4(a) from the Interim Report.

Supply B - Increased continental gas demand to replace the gas affected by the unplanned interconnector outage

- 3.29 The operational problems at the interconnector during September and October 2003 were unexpected. This event appears to have increased the demand for gas on the continent over the second half of October and beginning of November 2003, as flows into continental storage increased.
- 3.30 This increase in demand during October and November 2003 was unexpected and would have affected forward and outturn prices.
- 3.31 Using an estimate of the volume of gas that was affected by the water ingress (583 mcm) at the interconnector gives an average of 26 mcm per day over the following 22 days until the interconnector did import gas. This calculation is illustrated in Figure A3.6. However, this is an estimate of total, and unexpected, maintenance.

Figure A3.6: Gas losses as a result of Supply scenarios B and C



Supply C - Increased continental gas demand based on average interconnector import flows

- 3.32 Supply B gives one estimate of the unexpected increase in demand on the continent. However, it is possible that, in the absence of the factors affecting the European markets, the interconnector would have actually imported gas. Using

average import volumes during the previous 3 years (9.7 mcm/day) together with the actual observed exports gives 22 mcm/day.

Supply D - All other UKCS maintenance

3.33 As an upper case estimate of the level of unexpected maintenance, we have also presented analysis including the estimate of total maintenance. This calculation gives 12-19 mcm/day and is derived from the difference between the estimate of total maintenance and the measure of unexpected maintenance (Supply A).

Conclusions

3.34 Establishing an ex post estimate of a price movement is inherently complex and is inevitably the product of the assumptions made and the information available. Ofgem has sought to present a relatively simple methodology that provides some useful information as to whether the observed price movements were of an order of magnitude that can be understood. Actual pricing will have reflected a vastly greater range of information, some of which might not have been known with any certainty or which might have been known to only a range of participants.

3.35 Against this background, Table A3.5 presents a range of prices implied by the analysis of the price elasticity and the volume of gas affected.

Table A3.5: Implied price impacts of each supply scenario

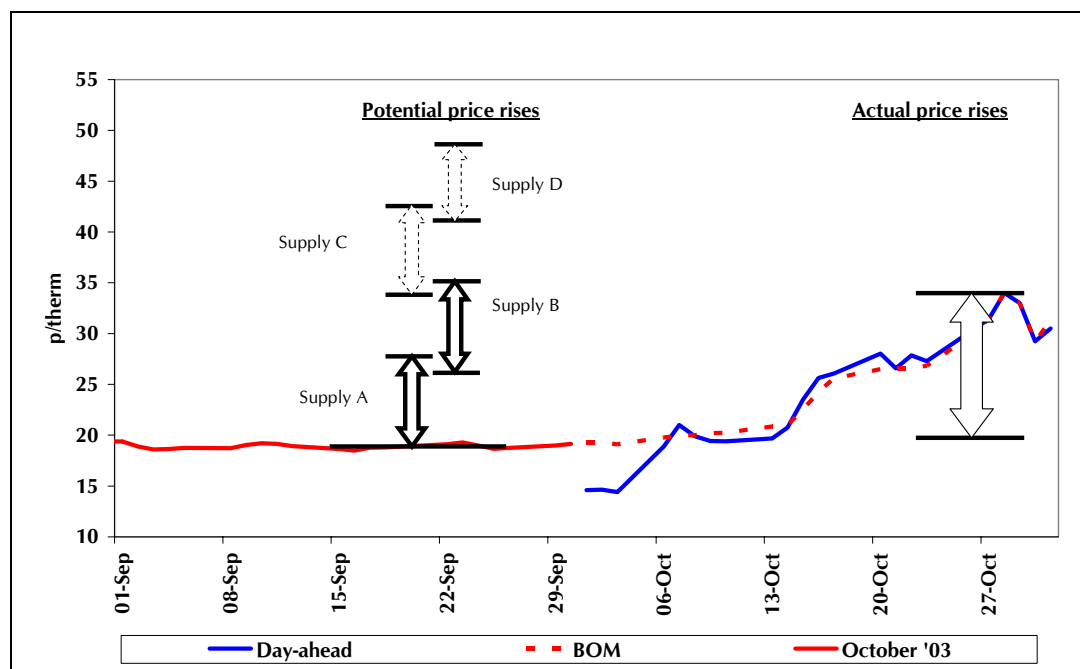
Scenario	Unexpected reductions in supply / increases in demand	Volume reduction (mcm per day)	Price increase (p/therm/mcm)	Overall Price change ²⁸ (p/therm)	Implied Price ²⁹ (p/therm)
Supply A	Unexpected maintenance at UKCS fields	24 – 31	0 – 0.3	7 – 9	26 – 28
Supply B	Increased continental gas demand to replace the gas affected by the unplanned interconnector outage	26		8	34 – 36
Supply C	Increased continental gas demand based on average interconnector import flows	22		7	41 – 43
Supply D	All other UKCS maintenance	12 – 19		4 – 6	45 – 49

²⁸ Range given shows the range of volumes, rather than prices.

²⁹ The initial expected price for October 2003 equals 19 p/therm.

3.36 The actual highest price reached was 34 p/therm which is within the potential price range (Figure A3.7). Consequently, it appears that the actual price rises are likely to be explicable given the availability of gas supplies and the level of GB and continental demand.

Figure A3.7: October 2003 price and potential price increases



3.37 It is worth noting that this analysis is sensitive to the assumptions made. For example, the analysis would have suggested lower outturn prices if:

- ◆ the level of assumed planned and unplanned maintenance was lower; and
- ◆ the assumed increase in continental demand due to storage injections was lower.

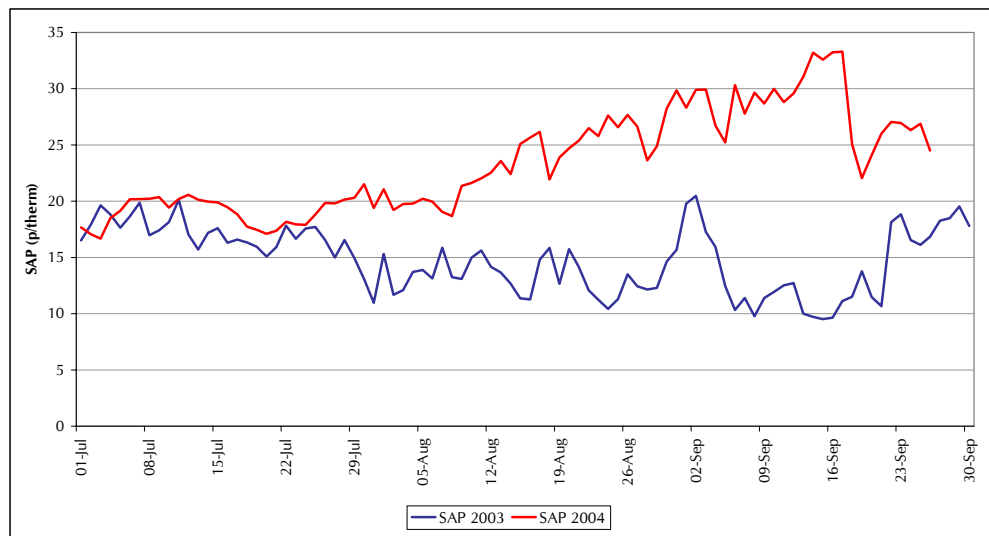
3.38 In these circumstances, less of the increase in prices would be explicable by this analysis.

Appendix 4. August/September 2004: Analysis of gas prices

Background

4.1 During the August and September 2004 period there was a significant increase in National Balancing Point (NBP) day-ahead prices, which reached a peak of 33.4 p/therm on 14 September³⁰. Figure A4.1 shows that prices started increasing in the first half of August, and stayed at these higher levels throughout most of September. This has resulted in a notable increase in prices relative to the price levels observed during August and September 2003.

Figure A4.1 –NBP SAP prices, 1 July to 30 September 2003 and 1 July to 30 September 2004



Ofgem's Analysis

4.2 In response to this price movement Ofgem has conducted some preliminary analysis of market fundamentals in an attempt to establish an explanation for this price movement. This analysis has focussed on both the demand and supply-side of the market

³⁰ Heren Day Ahead

4.3 Ofgem's analysis has focussed on the following factors:

Demand-side

- ◆ GB gas demand, including the impact of interconnector exports;

Supply-side

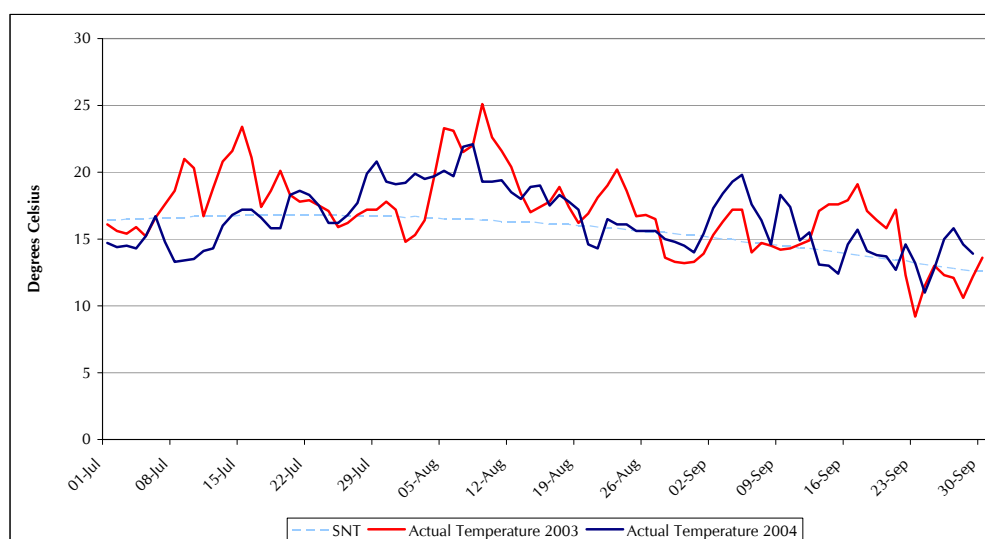
- ◆ UKCS availability; and
- ◆ The impact of increases in the oil price.

4.4 These are discussed in turn, below.

Gas demand

4.5 During August GB Celsius temperatures were on average 2.4 per cent lower in 2004 than during the same period in the previous year, as shown in Figure A4.2. Temperatures in September were broadly consistent with the prior year. As a result, the demand of GB customers (excluding any export demand) was higher in August, and comparable in September, in relation to the previous year.

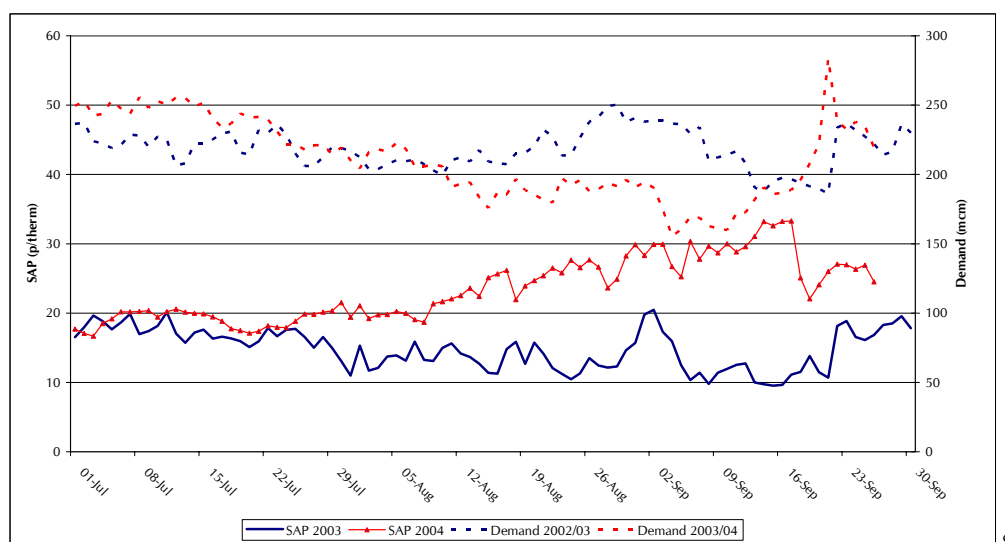
Figure A4.2 – Seasonal Normal Temperatures (2004) and outturn temperatures 1 July to 30 September 2003 and 1 July to 30 September 2004



4.6 However, when interconnector flows are incorporated, to give total system demand, this shows that demand was lower for much of August and September 2004 than in the previous year.

4.7 Figure A4.3 compares both System Average Price (SAP) and total National Transmission System (NTS) gas demand³¹ for the period 1 July to 30 September 2004, with the corresponding period of the previous year. This illustrates that gas prices were significantly higher than during the same period of 2003.

Figure A4.3: Comparison between SAP and demand, 01 July to 30 September 2003 and 01 July to 30 September 2004



Source: Ofgem analysis based on data provided by National Grid Transco

4.8 Figure A4.3 shows that price and demand movements were consistent with the prior year figures during July 2004. However, the rise in SAP from August 2004 onwards does not appear to be readily explainable by movements in the level of gas demand. Indeed, it appears that response from the interconnector may have reduced GB system demand by around 30mcm/d.

UK gas supply availability

4.9 It is possible to build up a picture of beach supply availability using information on planned and unplanned maintenance. This information is presented below on an aggregated basis.³²

4.10 As can be seen from Figure A4.4, there was a significant volume of planned maintenance being undertaken during August and September 2004. Information is not available on whether this level of maintenance is materially different from

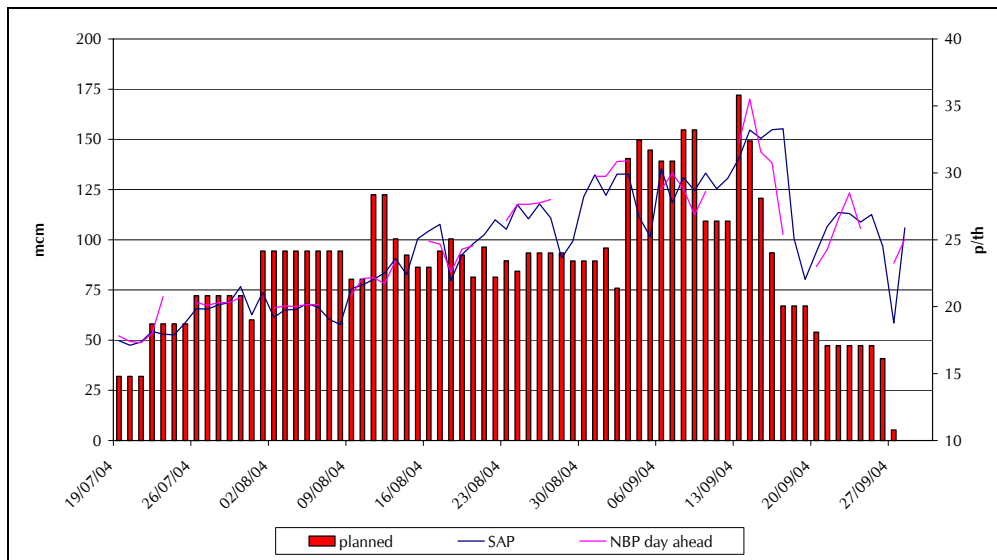
³¹ Underlying (residual) demand was higher year on year due to lower interconnector exports and storage injections.

³² Similar information, on a slightly less aggregated basis, will be released to the market under Phase III of the offshore information release project, commencing in October 2004.

previous periods. Respondents provided mixed views on whether the level was greater than in previous periods, with one expressing the view that it was broadly comparable, whilst another explained that they thought that some maintenance had been unexpectedly delayed from July into August and September.

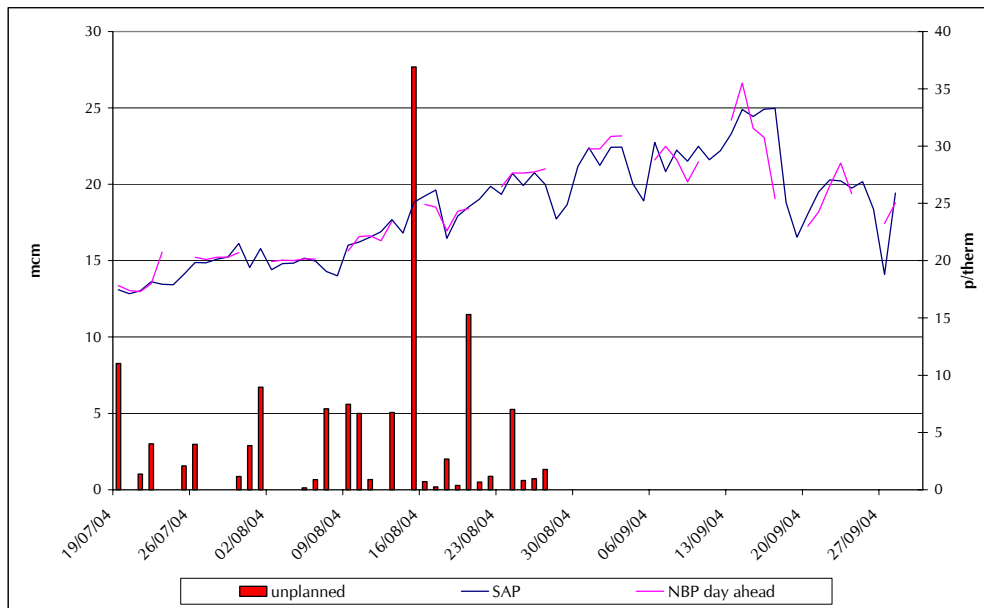
- 4.11 Ofgem approached UKOOA and the DTI for aggregated maintenance information in order to establish whether the observed levels were high by historic standards but both parties were unable to provide this information. Ofgem did not seek this information directly from field operators, due to the volume of work and time that this would have required.

Figure A4.4: Planned maintenance volumes, 19 July 2004 - 28 September 2004



- 4.12 Information is also available to Ofgem on levels of unplanned maintenance. This information is presented in Figure A4.5, and shows some notable outages, in particular on the 15 August. Historic information is not available for the same reasons as given above, so it is not possible to ascertain whether these levels are high or low by historic standards.

Figure A4.5: Unplanned maintenance volumes, 19 July 2004 - 28 September 2004³³

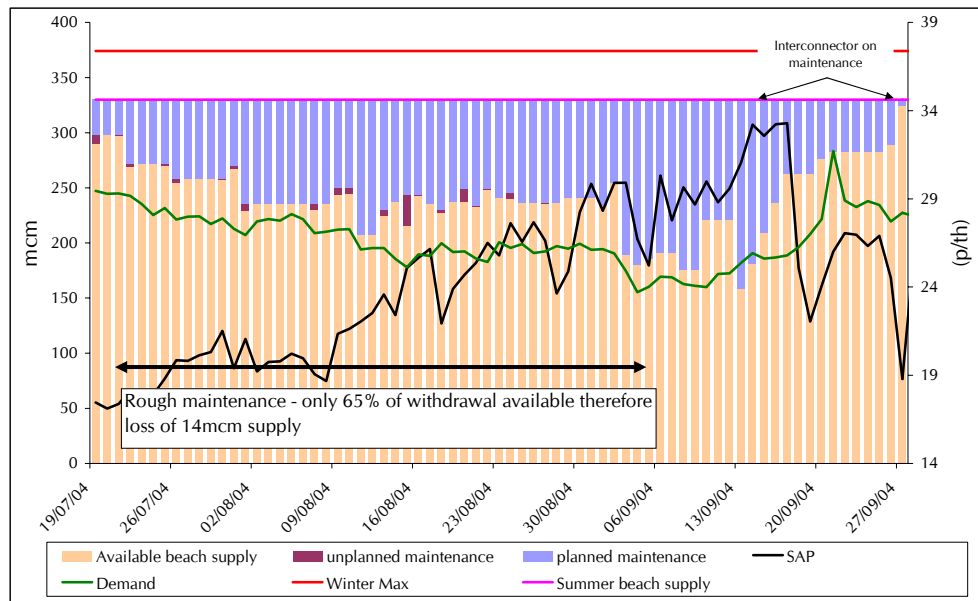


4.13 Combining the effects of planned and unplanned maintenance shows that beach availability was reduced significantly during this period, although whether this level of reduction is abnormal is not known. Figure A4.6 presents a measure of beach availability by subtracting planned and unplanned maintenance from a measure of beach capability (taken as 330mcm).

4.14 Figure A4.6 shows that although beach availability was lower as a result of outages at offshore fields (due to planned and/or unplanned maintenance) it is difficult to fully explain the observed price movements in relation to the margin between beach availability and observed demand.

³³ September data on unplanned maintenance is not available.

Figure A4.6: Maximum and actual flows including maintenance affected volumes, 19 July 2004 until 28 September 2003



Sub-terminal analysis

4.15 Additional information is available by analysing the flows at individual sub-terminals during July, August and September 2004 and comparing these to the corresponding months in 2003.

4.16 Tables A4.1, A4.2 and A4.3 summarise Ofgem’s analysis of a year on year comparison of flows from offshore fields at the main beach sub-terminals. These figures show that:

- ◆ On average, sub-terminal flows were higher in July 2004 (248mcm) than in July 2003 (232mcm), while maximum flow remained similar;
- ◆ Minimum, maximum and average flows were lower in August 2004 than in the same month of 2003;
- ◆ Maximum and average flows were lower in September 2004 than in the corresponding month of 2003, while the minimum flow remained unchanged.

Table A4.1: Changes in sub-terminal flows, July 2003 versus July 2004

Sub-terminal	Jul-03			Jul-04			% Change July 03 to July 04		
	Min	Max	Average	Min	Max	Average	Min	Max	Average
BACTON - PERENCO	1.5	11.5	5.5	2.7	8.8	5.7	78	-23	2
BACTON - SHELL	6.1	20.4	12.4	4.0	22.7	15.3	-35	12	24
BACTON - TULLOW	0.0	7.3	4.7	4.8	5.7	5.3	0	-22	12
BACTON SEAL SUBTERMINAL	11.3	22.5	18.1	19.4	25.8	22.2	72	15	23
BARROW - BGE&P	4.0	17.3	10.0	15.2	29.6	23.9	285	71	139
EASINGTON - BG AMETHYST	0.6	3.6	1.1	0.6	1.3	1.2	5	-64	13
EASINGTON - BP	2.7	3.8	3.6	2.8	3.6	3.3	6	-7	-9
EASINGTON - BP DIMLINGTON	8.3	14.7	13.0	10.8	13.9	12.8	31	-6	-1
ST FERGUS - MOBIL	19.6	47.9	34.9	34.7	48.0	42.5	77	0	22
ST FERGUS - SHELL	21.9	26.4	24.2	16.6	25.7	22.4	-24	-3	-7
ST FERGUS - TOTAL OIL MARINE	32.6	54.5	42.9	19.3	56.6	38.0	-41	4	-11
TEESSIDE - AMOCO	23.6	36.6	29.2	25.1	31.3	28.6	6	-14	-2
TEESSIDE - ENRON	4.6	14.7	11.1	6.4	12.9	10.3	40	-12	-7
THEDDLETHORPE - CONOCO	3.4	26.8	21.1	8.6	19.1	16.7	155	-29	-21
Total (mcm) or Average (%)	140.0	308.0	231.7	171.0	305.0	248.3	22	-1	7

Source: Ofgem analysis based on data provided by National Grid Transco

Table A4.2: Changes in sub-terminal flows, August 2003 versus August 2004

Sub-terminal	Aug-03			Aug-04			% Change Aug 03 to Aug 04		
	Min	Max	Average	Min	Max	Average	Min	Max	Average
BACTON - PERENCO	2.9	10.7	6.6	5.4	7.8	7.0	85	-27	5
BACTON - SHELL	4.3	12.0	8.2	13.0	25.3	21.8	202	111	165
BACTON - TULLOW	5.7	7.3	6.6	0.0	5.8	4.0	-100	-21	-40
BACTON SEAL SUBTERMINAL	0.0	28.6	18.4	12.1	27.3	22.8	0	-4	24
BARROW - BGE&P	2.9	12.0	7.0	4.7	8.8	7.9	66	-26	13
EASINGTON - BG AMETHYST	0.0	1.3	0.6	0.8	3.7	2.0	0	184	214
EASINGTON - BP	0.0	4.2	3.3	0.8	3.6	2.9	0	-16	-14
EASINGTON - BP DIMLINGTON	8.9	12.2	10.9	8.9	13.3	12.1	0	9	12
ST FERGUS - MOBIL	20.2	47.4	36.9	30.1	47.5	41.6	50	0	13
ST FERGUS - SHELL	16.8	25.7	21.1	9.8	24.8	18.4	-42	-4	-13
ST FERGUS - TOTAL OIL MARINE	37.7	56.5	47.0	7.8	24.0	16.0	-79	-58	-66
TEESSIDE - AMOCO	16.7	31.1	26.2	13.0	29.4	22.9	-22	-5	-13
TEESSIDE - ENRON	4.1	13.3	10.2	6.1	12.7	9.0	51	-4	-11
THEDDLETHORPE - CONOCO	15.9	26.5	23.1	0.0	20.9	12.5	-100	-21	-46
Total (mcm) or Average (%)	136.0	288.7	226.0	112.6	255.1	200.8	-17	-12	-11

Source: Ofgem analysis based on data provided by National Grid Transco

Table A4.3: Changes in sub-terminal flows, September 2003 versus September 2004

Sub-terminal	Sep-03			Sep-04			% Change Sep 03 to Sep 04		
	Min	Max	Average	Min	Max	Average	Min	Max	Average
BACTON - PERENCO	5.9	12.2	8.3	4.0	9.1	6.7	-32	-26	-19
BACTON - SHELL	4.8	25.1	13.0	0.0	28.2	22.0	-100	12	70
BACTON - TULLOW	5.4	7.2	6.6	17.6	26.6	22.7	227	270	246
BACTON SEAL SUBTERMINAL	17.8	28.1	26.5	3.6	5.2	4.5	-80	-81	-83
BARROW - BGE&P	2.3	25.9	11.3	7.7	33.9	20.9	231	31	85
EASINGTON - BG AMETHYST	0.0	3.3	1.1	2.6	3.4	3.1	0	2	177
EASINGTON - BP	1.5	3.8	3.1	0.0	12.4	2.2	-100	228	-29
EASINGTON - BP DIMLINGTON	0.0	11.6	6.6	0.0	1.7	0.1	0	-85	-98
ST FERGUS - MOBIL	22.1	50.1	43.2	10.3	51.1	29.7	-53	2	-31
ST FERGUS - SHELL	7.7	24.1	14.1	0.0	40.6	19.4	-100	68	37
ST FERGUS - TOTAL OIL MARINE	23.1	51.5	39.9	14.0	19.9	16.6	-39	-61	-58
TEESSIDE - AMOCO	9.4	27.4	21.9	0.0	24.7	16.6	-100	-10	-24
TEESSIDE - ENRON	0.0	9.5	4.9	0.0	11.4	6.0	0	20	23
THEDDLETHORPE - CONOCO	19.2	26.8	24.6	11.2	24.3	18.3	-41	-9	-25
Total (mcm) or Average (%)	119.2	306.5	224.9	71.0	292.6	189.0	0	-5	-16

Source: Ofgem analysis based on data provided by National Grid Transco

4.17 Table A4.2 shows that the reduction in sub-terminal flows from August 2003 to August 2004 was most significant at the St Fergus–Total Oil Marine and Theddlethorpe–Conoco sub-terminals. The volume of gas delivered to the NTS

through these sub-terminals is usually determined by gas producers and shippers, albeit subject to technical constraints of the sub-terminal facility.

- 4.18 Table A4.3 illustrates a notable year on year reduction in September flows at the St. Fergus-Total Oil Marine, Theddlethorpe-Conoco, Bacton-Seal, St.Fergus-Mobil and Teesside-BP Amoco sub-terminals.
- 4.19 It is also possible, using the data from these tables, to compare flows during July with flows during August 2004. The data shows a considerable decrease, month on month, in the minimum, maximum and average flows recorded at the main sub-terminals. Whilst month on month reductions were registered in 2003, the order of magnitude was lower.
- 4.20 Of the sub-terminals shown here, Barrow demonstrated the largest month on month reduction in flows, with the St Fergus–Total Oil Marine and Theddlethorpe–Conoco sub-terminals also registering significant reductions.
- 4.21 The above analysis provides some evidence that maintenance is likely to have been higher than in the comparable periods in the previous year, although this picture is complicated as maintenance and field decline cannot be separated. However, comparisons between July and August flows suggest that there is likely to have been an unusually high level of maintenance, in particular at the three sub-terminals highlighted above.
- 4.22 It is also possible to analyse the flows at each of the sub-terminals highlighted above in more detail. This is presented below.

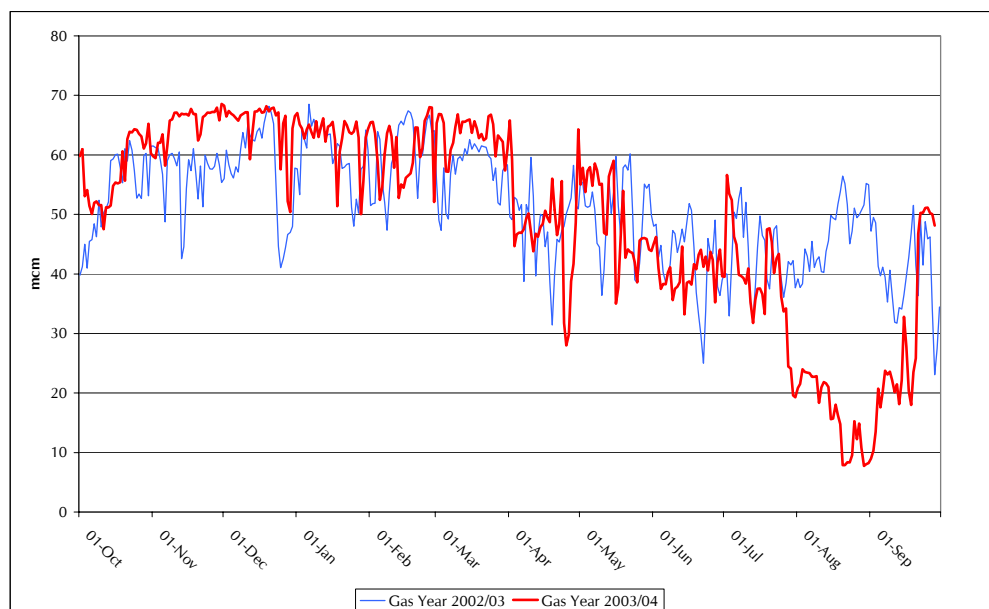
Analysis of individual sub-terminals

St Fergus – Total Oil Marine

- 4.23 The most significant reduction in year on year flows, when comparing August 2003 and 2004, was at the Total Oil Marine sub-terminal at St Fergus. Figure A4.7 shows the daily flow levels through this sub-terminal between October 2002 and 15 September 2004.
- 4.24 Flows are similar during the majority of the period shown but there is a sharp reduction from 26 July 2004, to a low of around 8mcm. The initial reduction in flows, from around 40mcm/day to around 35mcm/day, is reportedly due to the

impact of planned maintenance on the Frigg UK transportation and processing system which collects flows from fields including Alwyn and Bruce.

Figure A4.7: St Fergus – Total Oil Marine sub-terminal flows, 1 October 2002 – 27 September 2004



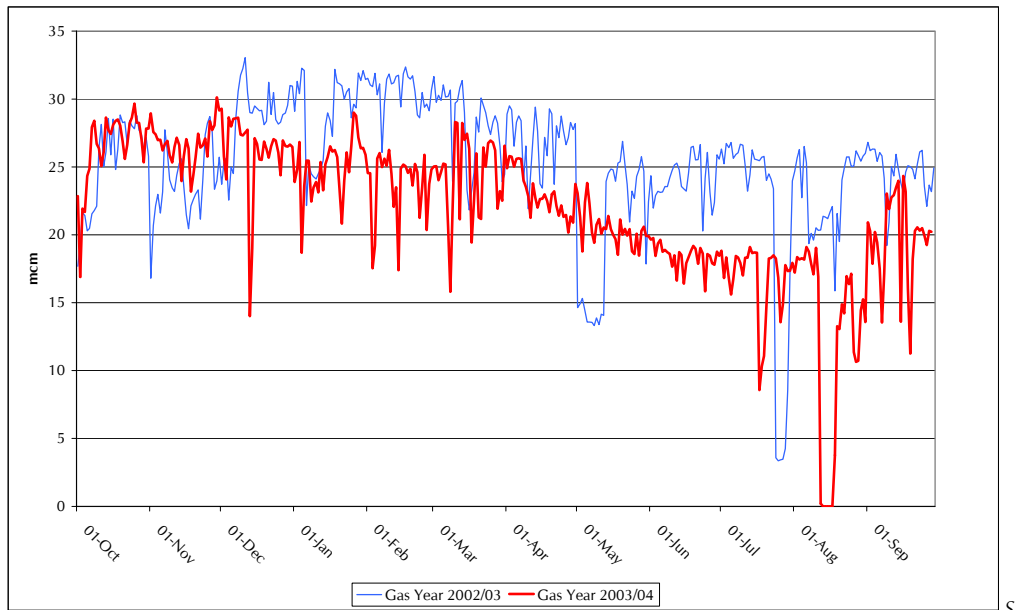
Source: Ofgem analysis based on data provided by National Grid Transco

- 4.25 Based on the information currently available to Ofgem it is not possible to account fully for the further reduction in flows. Although there has been maintenance reported at the BP operated Bruce field, it is described as being intermittent, rather than constant, for the remainder of August 2004. This maintenance is reported to have reduced the flows from this field to around 19mcm/day on the days when work was being carried out.
- 4.26 Flows started to increase through the first two weeks of September 2004, returning back towards the level of throughput observed during September 2003.

Theddlethorpe – Conoco

- 4.27 Flow rates at the Theddlethorpe – Conoco sub-terminal, as illustrated by Figure A4.8, have also shown a notable decrease from the corresponding period of 2003, particularly from the start of 2004. Flows at this sub-terminal appear to be consistently around 5mcm/day lower from the start of the year, perhaps symptomatic of a decline in the productive capability of the UKCS rather than a direct result of planned/unplanned maintenance.

Figure A4.8: Theddlethorpe – Conoco sub-terminal flows, 1 October 2002 – 27 September 2004



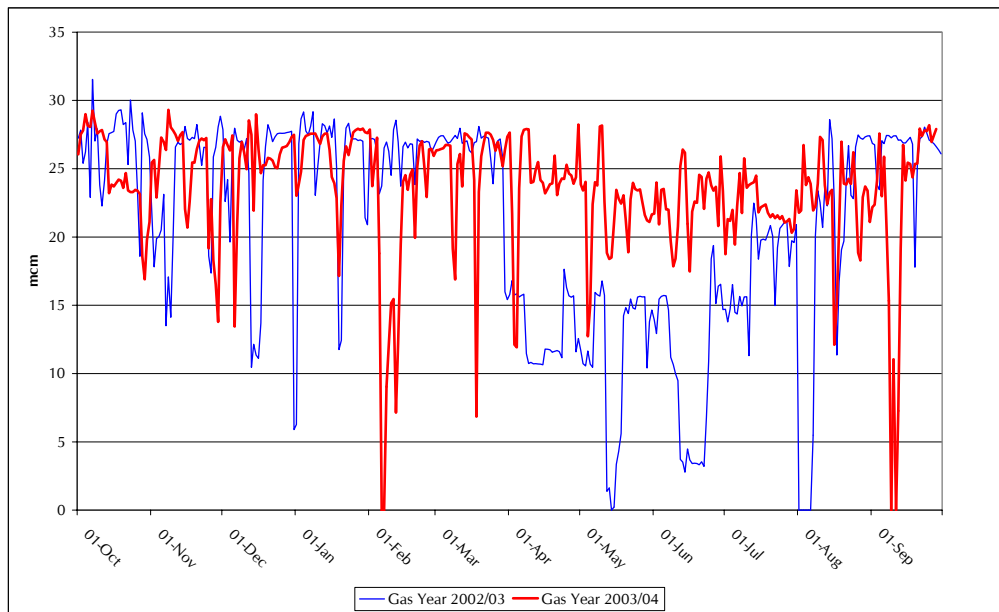
Source: Ofgem analysis based on data provided by National Grid Transco

4.28 The sharp reduction in sub-terminal flows from 11 to 23 August 2004 corresponds with a period of planned maintenance on ConocoPhilips' Lincolnshire Offshore Gas Gathering System, which acts as a hub, receiving gas from the V-fields amongst others.

Bacton Seal

4.29 The daily flows through the Bacton Seal sub-terminal are illustrated by Figure A4.9 and were chosen for further analysis due to a reduction in the September rates. Flows through this sub-terminal were similar during July and August 2004 and the corresponding months of 2003, but showed a large reduction from average at the start of September 2004.

Figure A4.9: Bacton Seal sub-terminal flows, 1 October 2002 – 27 September 2004



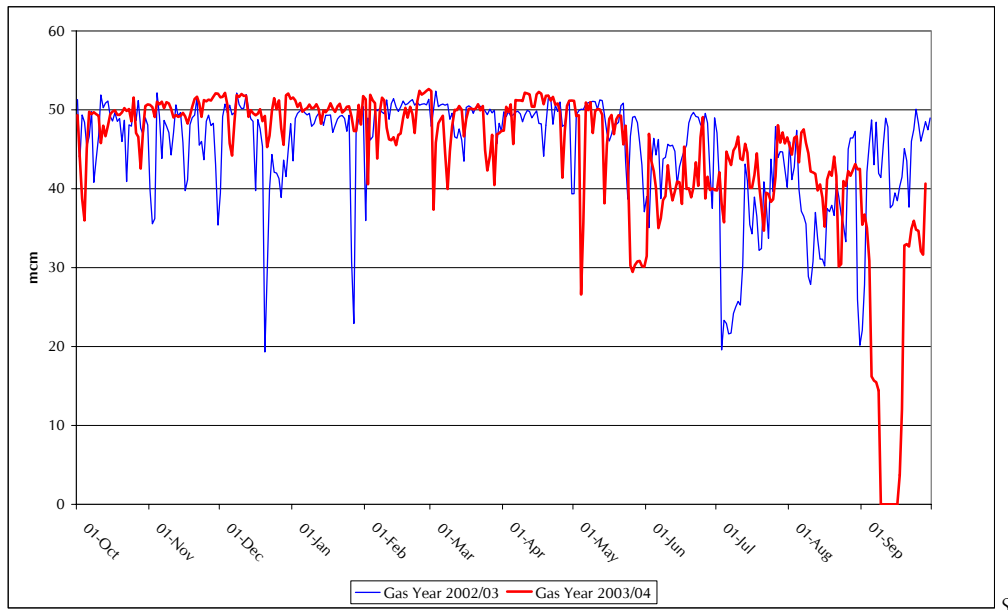
Source: Ofgem analysis based on data provided by National Grid Transco

4.30 Figure A4.9 shows that there was a substantial reduction in sub-terminal flows during the first two weeks of September which, given information currently available to Ofgem, can largely be attributed to planned maintenance of the Shearwater Elgin Area Line (SEAL). This pipeline underwent a full shutdown on 8 September before registering zero flows again on 10 September, contributing to a substantial reduction in flows during the first two weeks of September 2004.

St Fergus-Mobil

4.31 Figure A4.10 presents flow rates through the St Fergus-Mobil sub-terminal. It illustrates that throughput has been similar through much of the period shown with the exception of September 2004.

Figure A4.10: St Fergus-Mobil sub-terminal flows, 1 October 2002 – 27 September 2004



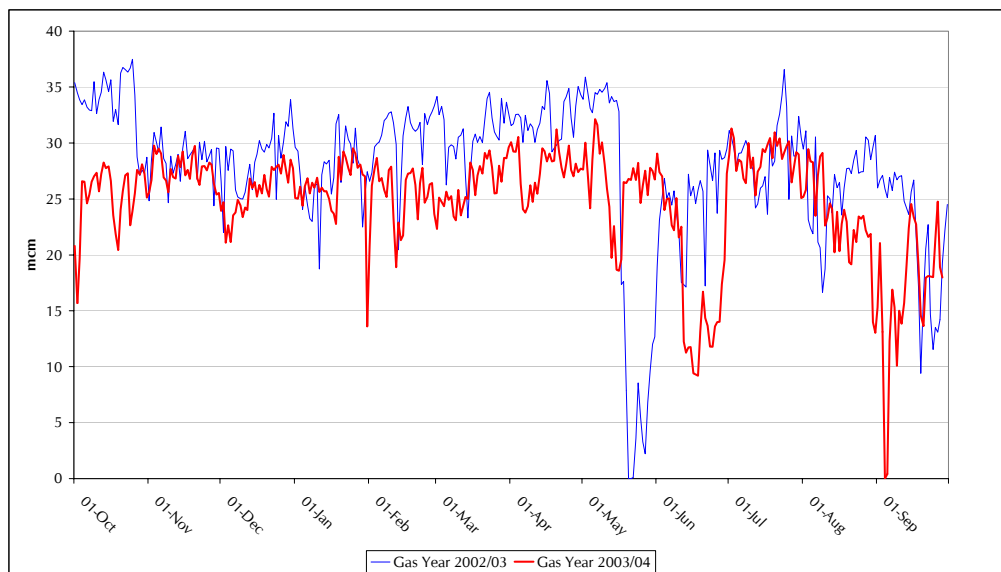
Source: Ofgem analysis based on data provided by National Grid Transco

4.32 Flow rates decrease sharply from 3 September 2004. This is explained by planned maintenance of the Scottish Area Gas Evacuation (SAGE) pipeline and the Britannia field.

Teesside-BP Amoco

4.33 Figure A4.11 shows flows at the Teesside-BP Amoco sub-terminal. It illustrates that there has been a gradual decline in flows since the beginning of July 2004, with a reduction to zero for some days in September. These flows suggest an outage during this period, as flows rapidly recover to their previous level.

Figure A4.11: Teesside-BP Amoco sub-terminal flows, 1 October 2002 – 27 September 2004

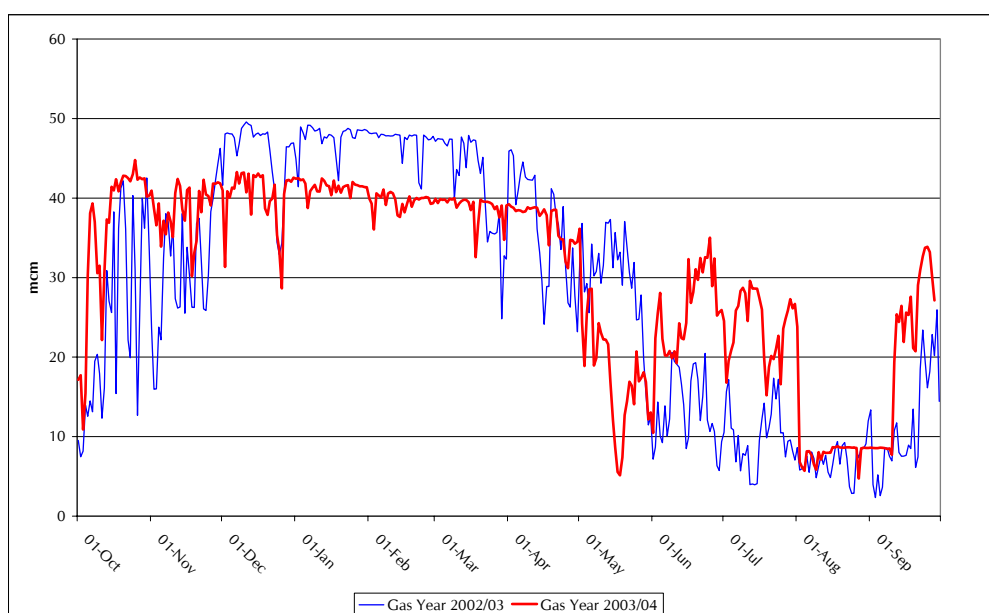


Source: Ofgem analysis based on data provided by National Grid Transco

Barrow

- 4.34 The daily flows through the Barrow sub-terminal are illustrated by Figure A4.12. This sub-terminal was chosen for further analysis because it displayed a 67 per cent reduction in average flows between July and August 2004, with large reductions also shown in minimum and maximum flows.
- 4.35 The abrupt drop in flows during August 2004 is clearly illustrated by the red line in Figure A4.12 and corresponds with the start of planned maintenance at the South Morecambe field on 1 August 2004. This lasted for 40 days and reduced flows to zero from this field.

Figure A4.12: Barrow sub-terminal flows, 1 October 2002 – 27 September 2004



Source: Ofgem analysis based on data provided by National Grid Transco

4.36 However, it can also be noted that flows during August 2004 are similar to the preceding year while flows during June and July 2004 were substantially higher (up to 10mcm/day) than during the same months of 2003. This perhaps suggests that flows during July were higher than usual, making the reduction in August appear larger.

Oil prices and Interconnector flows

4.37 Movements in prices may also be explained by changes in the oil-indexed prices prevailing in Europe and the operation of the interconnector, which links the UK to European prices. Analysis presented below shows that the interconnector appears to have responded appropriately to the NBP-Zeebrugge Day Ahead price differentials during summer 2004 (Figure A4.13). It also appears to have reacted to the NBP-Zeebrugge Troll price differential (Figure A4.14).

Figure A4.13: Interconnector flows and price differentials (Zeebrugge Hub and NBP), 1 December 2003 to 28 September 2004

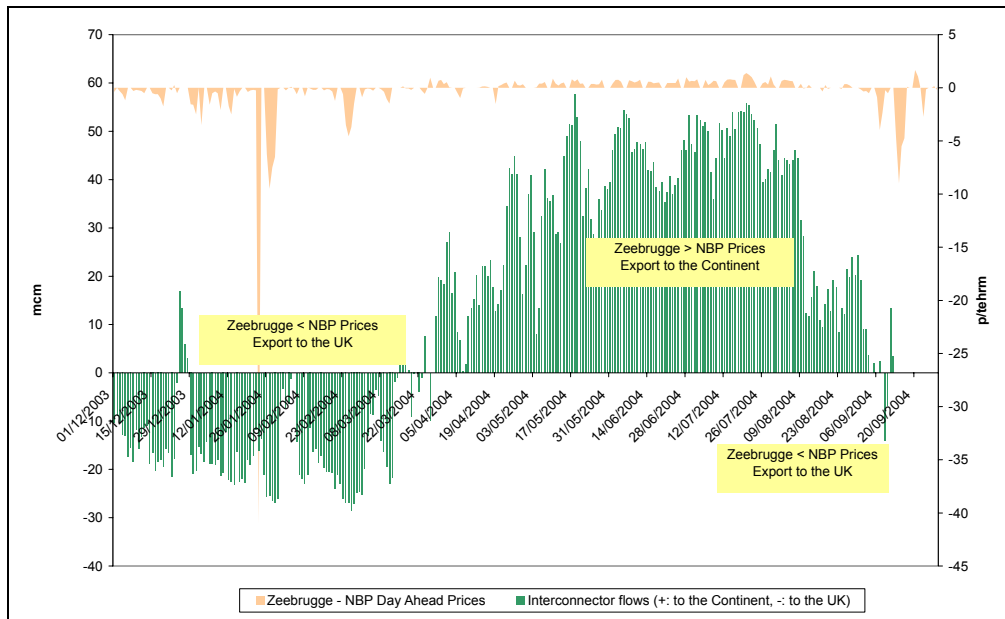
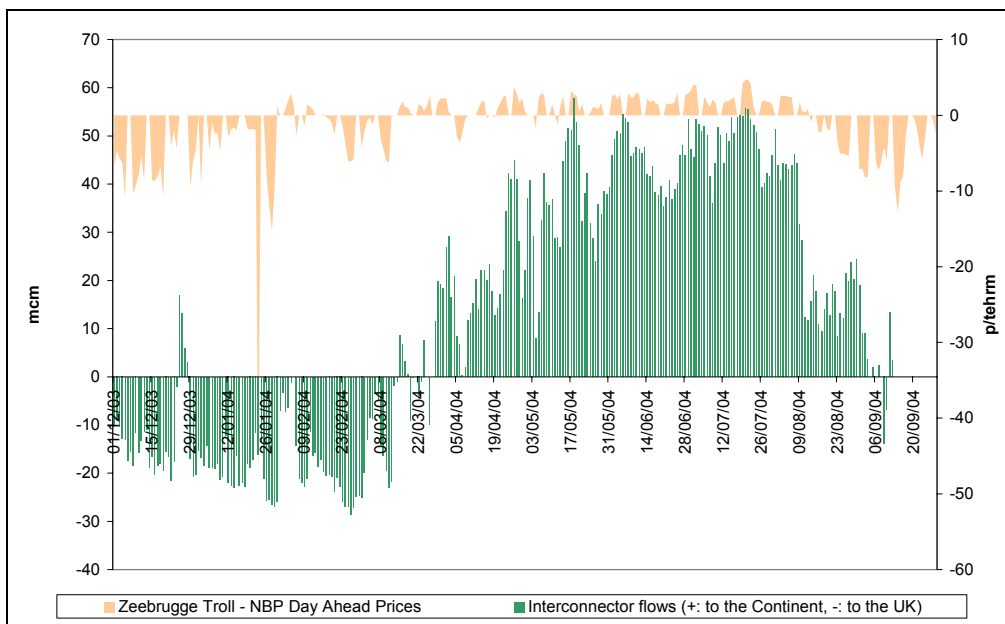


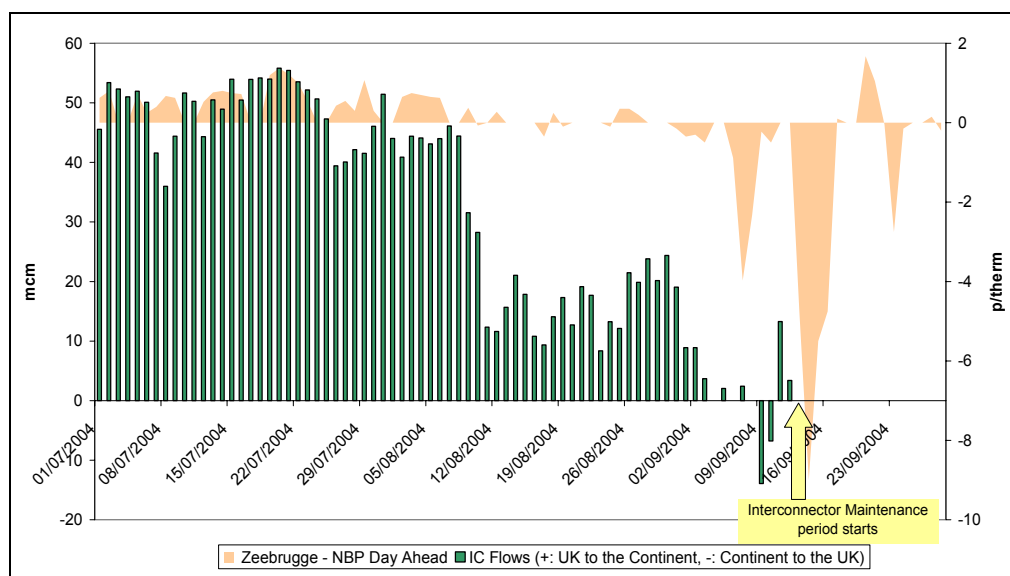
Figure A4.14: Interconnector flows and price differentials (Zeebrugge Troll and NBP), 1 December 2003 to 28 September 2004



4.38 Figure A4.15 shows the period from July 2004 in more detail. This shows significant price differentials only existed where interconnector flows were very close to maximum capability.

4.39 Figure A4.15 also highlights the period in which the interconnector went into reverse mode. From 9 September until 10 September, 20.7 mcm of gas was imported into the UK.³⁴

Figure A4.15: Interconnector flows and price differentials, 01/07/2004-28/09/2004



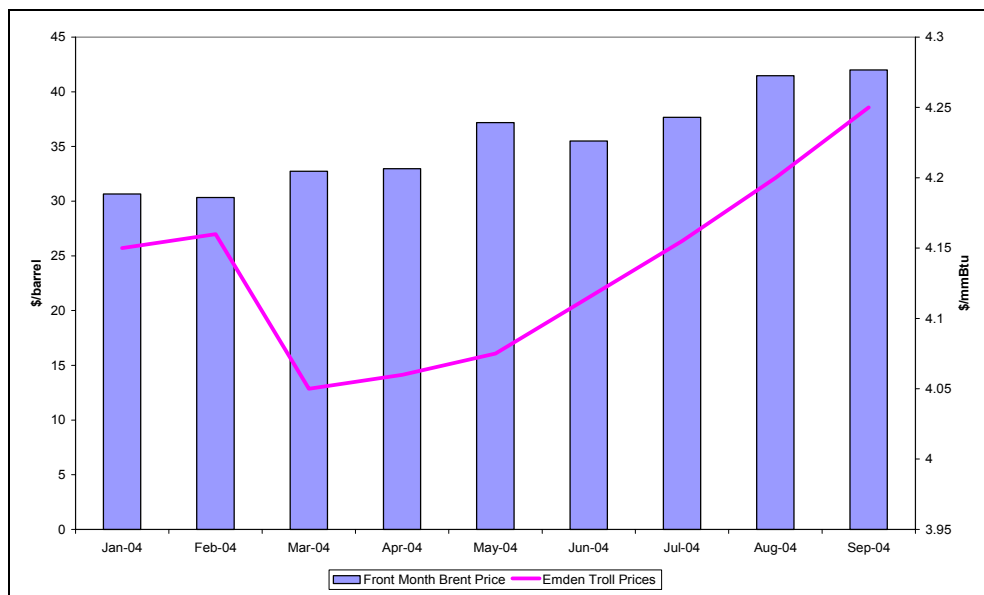
4.40 Figure A4.15 also highlights that during August 2004 there was a significant reduction in export flows, at a time when historically the interconnector has been on full export.

4.41 Consequently, during August and September the effect of a higher oil price was felt in the UK. In previous years this direct link has only been present during autumn and winter months, explaining some of the year-on-year increase in prices.

4.42 As shown in Figure A4.16, Brent front-month-ahead prices remained above 30 \$/barrel for most of 2003 but reached 41.48 \$/barrel in August 2004. They have remained at historically high levels, and at significantly higher levels than in 2003.

³⁴ It is worth noting that once both countries were disconnected, due to the planned interconnector maintenance on 13 September 2004, the price differential increased significantly.

Figure A4.16: 2004 Oil and Emden Troll prices



- 4.43 The indexation of European supply contracts to oil prices, and other oil-related commodities, has resulted in continental prices that have been very high relative to historic levels.
- 4.44 In recent years, the interconnector has exported near to maximum volumes for much of the summer, reflecting the lower-cost UKCS production relative to the oil-indexed prices prevailing in much of Europe. When the interconnector is at maximum export the Zeebrugge and NBP prices de-link, with GB prices trading at a discount to continental ones.
- 4.45 As such, in 2004 it appears that a reduction in beach availability, due to a combination of declining UKCS production and higher than normal levels of maintenance, has resulted in a reduction in export flows to the continent and a re-coupling of the NBP price to the European price at a much earlier stage than in previous years. The movements in oil prices, and the associated movements in European gas prices, has compounded this affect as the NBP has re-coupled to a higher summer gas price than in previous years.

Conclusions

4.46 Between the middle of July and the middle of September there was a notable increase in NBP day-ahead gas prices which does not appear directly attributable to changes in demand.

4.47 It appears that a number of factors have contributed to the price movements, including:

- ◆ A reduction in sub-terminal flows that appears to be driven by both the ongoing decline in UKCS production and higher than normal levels of outages; and
- ◆ Increases in European gas prices, driven in part by increases in the oil price.

The combined effect of the above factors resulted in the re-coupling of the Zeebrugge and GB markets, increasing the GB summer gas price.

Appendix 5. Winter 2004/05 forward gas prices: Analysis

- 5.1 In this section Ofgem looks at the extent to which winter 2004/05 forward gas prices have increased over the past few months, summarises market participant's concerns regarding the high winter forward prices and analyses three causes for this increase: high oil prices, a tightening of the supply and demand balance and increases to storage charges.³⁵

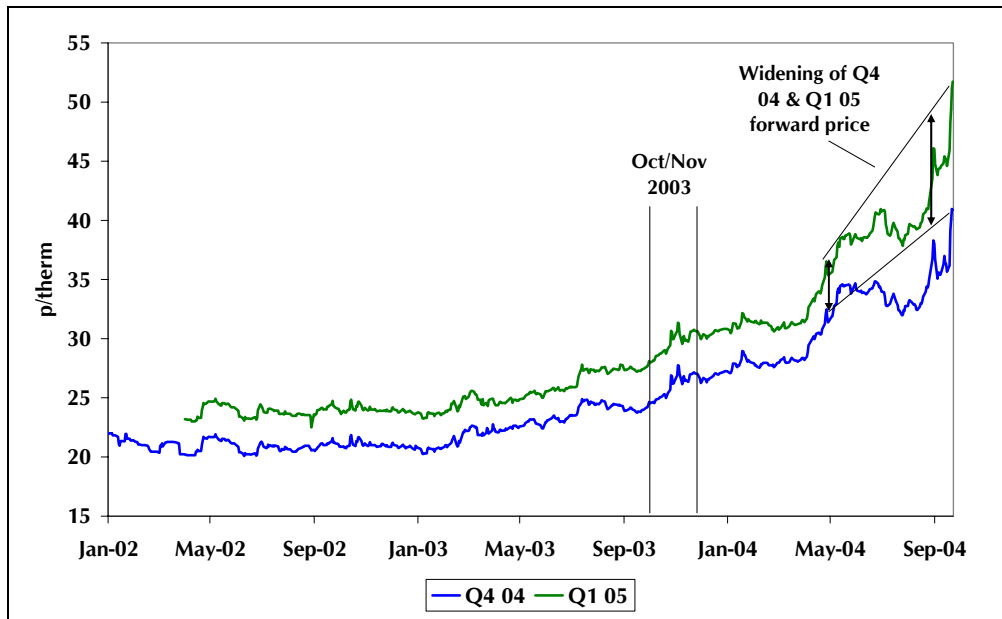
Winter 2004/05 prices

- 5.2 In its Interim Report, Ofgem noted that winter 2004/05 forward prices had increased significantly since the summer of 2003. The evolution of 2004/05 winter forward prices³⁶ (the fourth quarter 2004 (Q4 04) and the first quarter 2005 (Q1 05)) is outlined in Figure A5.1.
- 5.3 This shows that although Q4 04 and Q1 05 forward prices remained fairly stable through much of 2002, prices started to rise from the beginning of 2003. After maintaining a fairly stable differential since January 2002 the spread between Q4 04 and Q1 05 has widened since June 2004 with increases in Q1 05 prices not fully mirrored in Q4 04 prices. This might be explained by the reduced uncertainty associated with factors influencing Q4 04 prices as delivery date for this contract approaches. In particular, any affect of oil-indexation will cease to directly influence Q4 04 as the relevant European prices will vary with observed outturn oil prices, rather than forward oil prices.

³⁵ Storage charges will reflect the expected summer-winter differential and are therefore a measure of increased winter prices rather than a cause per se.

³⁶ Winter is considered to run from October to March, whilst summer runs from April to September.

Figure A5.1: Evolution of Q4 04 and Q1 05 forward prices



Summary of market participants' concerns over winter 2004/05 forward prices

- 5.4 The majority of respondents expressed concerns over the large increases in forward gas prices for the winter ahead and the adverse effects this may have on markets and end customers. The reasons for the increases were partly attributed to the combined effects of recent sharp increases in oil prices and the tight supply/demand margin for the coming winter.
- 5.5 Most respondents suggest that neither of these two effects nor the market fundamentals, provide a sufficient explanation for the increases in the forward gas prices for the coming winter.

Increase in oil prices

- 5.6 Index linked gas prices, which usually follow oil prices with a 3 to 9 month lag, are considered by almost all respondents as a strong underlying factor influencing forward gas prices in the UK. However, UK winter forward gas prices are now considered by some respondents to be at an unrealistic premium above oil-linked European forward gas prices. In addition some respondents suggest that this linkage is tenuous and sometimes inconsistent given the de-

coupling of European forward gas prices with certain oil indices such as LFO (Light sulphur Fuel Oil) and HFO (Heavy fuel oils).

- 5.7 The majority of respondents have commented on the nervousness of the market regarding the level of oil prices, with some suggesting a \$4-8 per barrel premium in the price of oil. Respondents suggest that there is an inevitable feed-through to the gas spot market, but also to forward markets for gas prices for the coming winter.

A tightening of the supply and demand balance

- 5.8 Transco's data indicates that this winter is expected to have the tightest supply/demand margin in recent years, which is causing some concern to market participants. However, respondents believe that winter prices have risen well above the levels that might reasonably be expected on the basis of currently anticipated levels of supply and demand.
- 5.9 A number of respondents have suggested that there is an overvaluation due to a premium being placed on winter forward gas prices, but query whether this explains all of the winter gas price increases.

Market manipulation by large gas producers

- 5.10 A number of respondents commented on the current structure of the market and the impact of the loss of a number of trading companies over the last few years. Some respondents stated that the reduced number of market participants has led to the possibility of market manipulation.

Ofgem's analysis

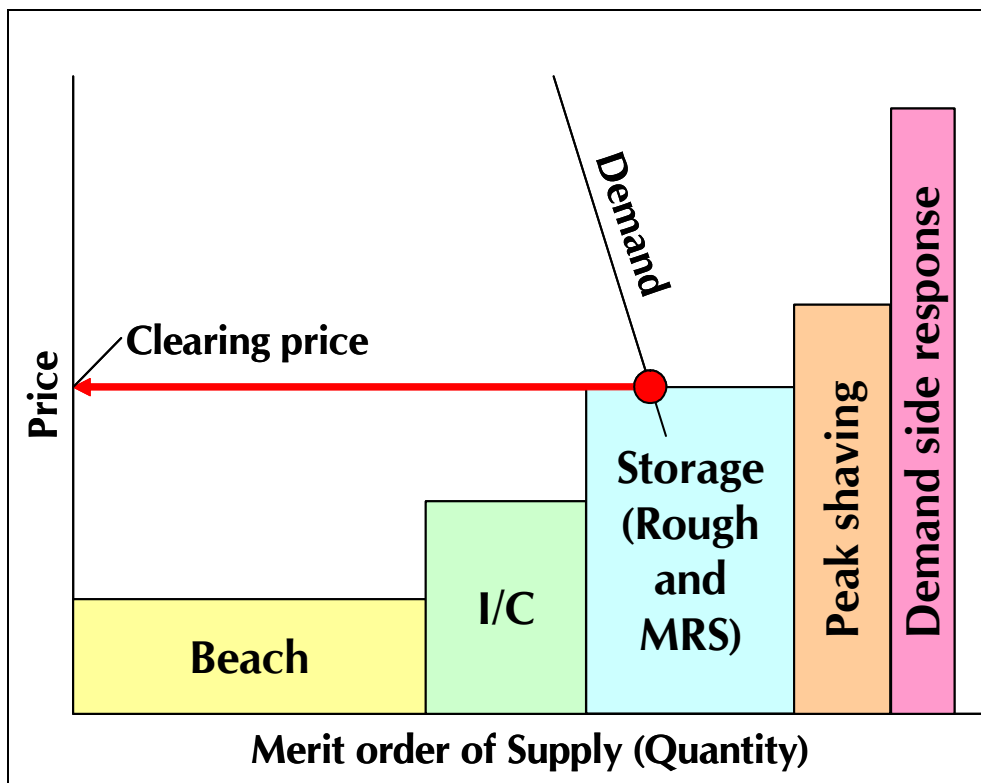
- 5.11 Any analysis of forward prices is inherently complex and any conclusions will tend to be, to a great extent, functions of the set of assumptions made. This is in contrast to analysis of outturn prices, where reconciliations can be made between demand, supply and underlying supply capability.
- 5.12 As such, this analysis seeks to identify the potential primary drivers of forward prices and attempts to establish approximate orders of magnitude associated with each.

Methodology

- 5.13 Ofgem's approach is based upon the theory that in a competitive market, the prompt price should reflect the marginal cost of the marginal supplier³⁷ (the cost of supplying the last unit of gas to meet demand sets the gas price).
- 5.14 The UK gas supplies (in approximate increasing order of cost) are:
- ◆ **Beach gas** - Gas from the United Kingdom Continental Shelf (UKCS)
 - ◆ **Interconnector gas** - Gas supplied from Europe via the interconnector
 - ◆ **Rough Storage gas** - Gas supplied from the Rough storage facility
 - ◆ **MRS Storage gas**- Gas supplied from medium range storage (MRS) storage facility (the Hornsea storage facility has been used to represent this)
 - ◆ **Peak shaving**: either Liquid Natural Gas peak shaving, gas supplied from LNG storage facilities or other high cost UK gas sources
 - ◆ **Demand side response** – Increased supply due to large customers reducing their demand (usually in response to high gas prices and proper incentives)
- 5.15 Beach gas is the first source of gas used (as it is the cheapest) until demand exceeds beached gas supply. Interconnector gas (the next cheapest) is then used to meet any excess demand. The clearing price is then set by the higher marginal cost of gas from the interconnector. When demand exceeds the combined supply from the beach and interconnector gas, Rough storage gas (the next cheapest) is used to meet the excess demand. The clearing price is then set by the marginal cost of the Rough storage gas, etc.
- 5.16 Figure A5.2 illustrates the assumed merit order of UK supply, i.e. how the clearing price is set by the marginal cost of supply (in increasing order of cost).

³⁷ However, in an over supplied market prices will tend to fall to short run marginal costs, just covering the cash costs of marginal production. Then as supply/demand come into balance price will move towards, and potentially beyond, long run marginal cost including a return on investment in marginal production and may rise to, or above, new entrant cost. In addition, marginal gas may also be sourced from storage and so price may also reflect storage costs.

Figure A5.2: Merit order and clearing price



5.17 In order to produce an estimate of the Q1 05 forward gas price, it is necessary to quantify the following:

- ◆ Marginal cost changes: Changes to the marginal cost of each source of supply
- ◆ Timing changes: Changes to the number of days that the source of supply sets the price over Q1 05.

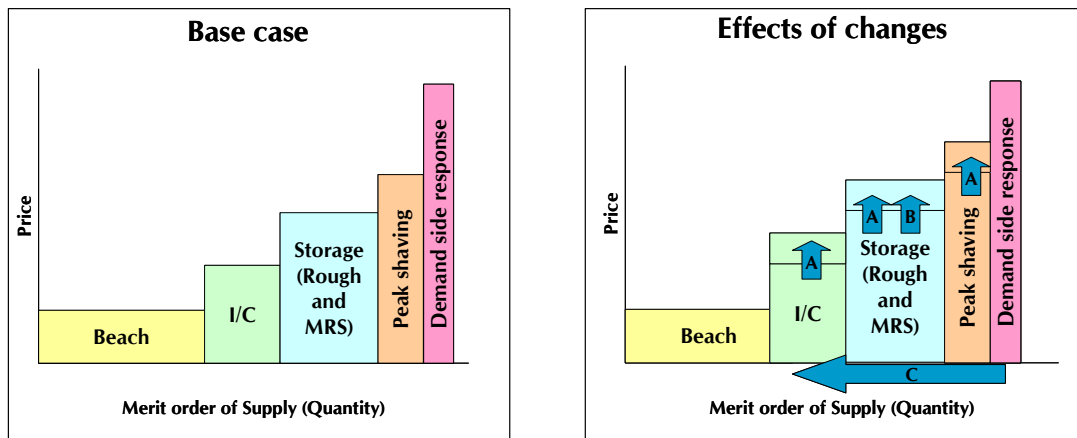
5.18 Ofgem has identified the following as drivers of overall price changes for each source of supply as illustrated in Table A5.1.

Table A5.1: Changes to sources of supply for winter 2004/05

Source of supply	Marginal cost changes	Timing changes
Interconnector gas	Higher European prices, due to higher oil prices	Decrease due to larger number of days that demand side response sets the price
Storage gas - Rough	Higher summer UK gas prices (mainly due to oil) and increases to storage charges	N/ A
Storage gas - MRS	Higher summer UK gas prices (mainly due to oil)	N/ A
Peak Shaving	Higher summer UK gas prices (mainly due to oil)	Increased due to the increasing likelihood that this would be required to compensate for reduced supply
Demand side response	N/ A	Increased due to the increasing likelihood that demand side response would be required to compensate for reduced supply

5.19 The effects of these changes on the merit order are outlined in Figure A5.3.

Figure A5.3: The UK gas sources merit order for Q1 05.



- A – High Oil Prices
- B – Rough storage charges
- C – Reduced supply

Key factors affecting prices

5.20 Using the above methodology, it is then necessary to estimate the impact of recent changes in supply and demand fundamentals in the marginal cost and the duration of any price effects. This analysis is outlined for three areas: the impact of:

- ◆ High oil prices;
- ◆ UKCS decline; and
- ◆ Storage costs.

High Oil Prices

Impact of changes in oil prices on UK gas prices

5.21 Figure A5.4 shows winter 2004/05 forward gas prices by month and three-month lagged oil prices. The graph shows that there is some correlation between oil and gas prices, particularly from March 2003. The spike in oil prices from November 2002 reflected concerns in the build up to war in Iraq, and thus did not reflect concerns over longer-term supply, which could have fed into forward gas prices.

Figure A5.4: Evolution of Winter Q4 04, Q1 05 forward gas and Brent oil prices since January 2002



5.22 The strength of the pound against the dollar and euro, particularly since 2000, has offset some of the impact of the higher oil prices.

5.23 High oil prices can affect UK gas prices via three main transmission mechanisms:

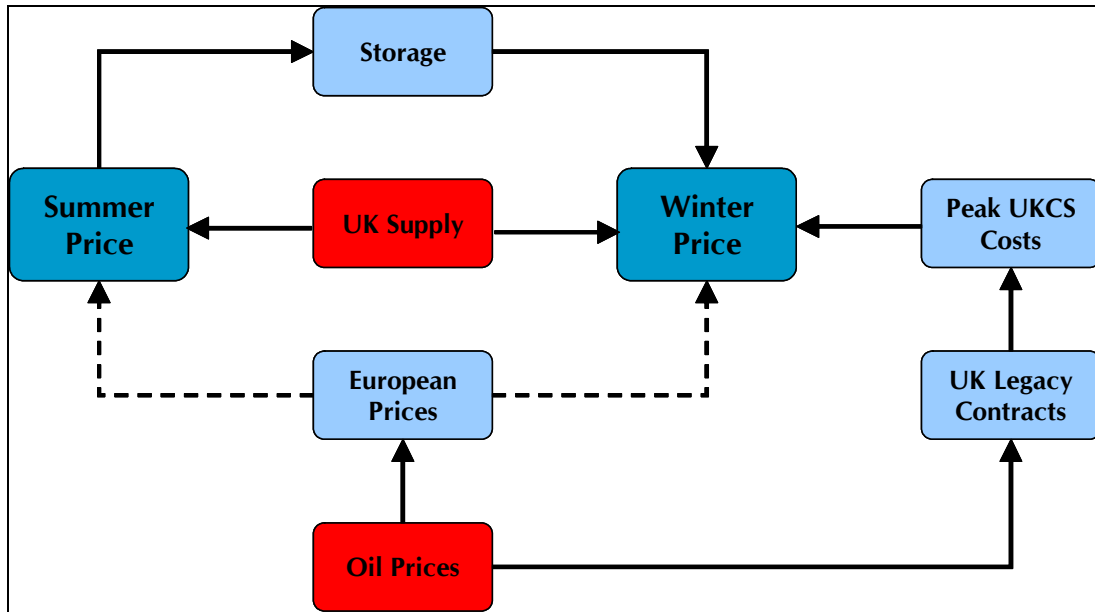
- ◆ **European gas** - The majority of European gas contracts are still indexed to oil prices. Hence, the exposure of European gas contracts to movements in oil prices is the most significant component in determining the extent of any pass-through of higher oil prices to UK gas prices.³⁸
- ◆ **UKCS oil indexation** - In GB some long-term gas contracts are still linked to indices that include oil prices. However, the amount of gas that is linked to oil indices is gradually declining. In addition, the extent to which such oil-indexation will affect GB prices is limited to the degree to which the gas is the marginal source of supply.
- ◆ **Associated gas** - A rise in oil price could actually dampen rises in wholesale gas prices due to gas-oil production (“Associated gas”). If an increase in oil prices induces an increase in oil supply then because associated gas is a by-product of oil extraction, this can lead to an increase in gas supply. However, since most North Sea gas associated fields have been producing at

³⁸ This analysis ignores the presence of any fixed price contracts between European and UK gas suppliers.

maximum output for some time, the impact of this effect appears to be very limited.

5.24 These relationships are shown diagrammatically in Figure A5.5 and explored in more detail below.

Figure A5.5: Impact on UK gas price of oil price movements



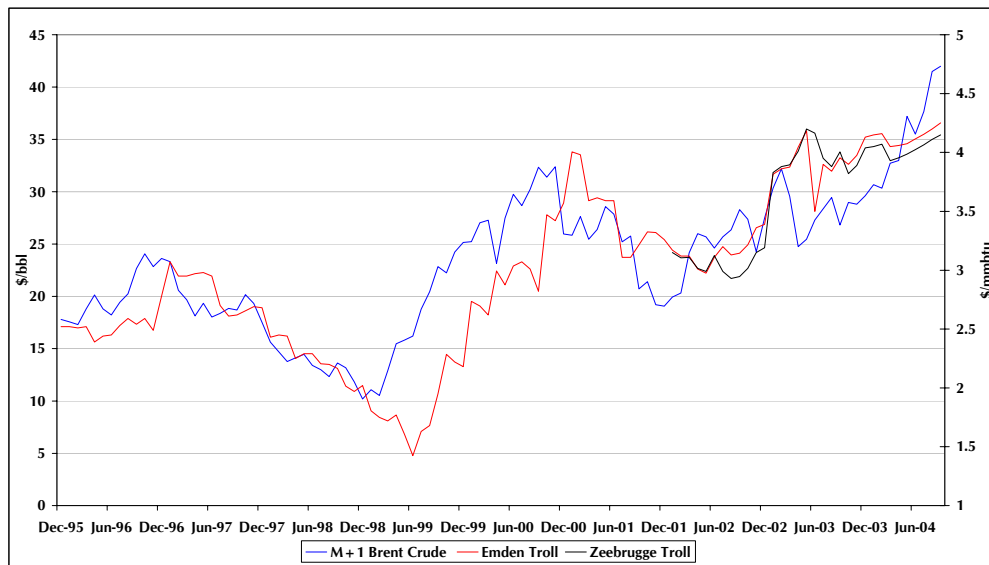
5.25 UK gas prices are affected by European gas prices through the **summer effect and winter effect**.

5.26 **Summer effect:** Higher European prices during summer will tend to increase UK gas exports across the interconnector, as UK suppliers seek to arbitrage between the two markets. This pushes up UK summer gas prices, which in turn increases the price of gas that is injected into storage for use during the following winter. The cost of this higher priced gas, added to storage and cycling costs, can push forward winter prices higher to the extent that storage is expected to be the marginal source of gas.

5.27 **Winter effect:** During winter, GB gas demand is typically greater than UKCS supply, with European imports, via the interconnector, and storage providing the balance of supplies. When this occurs, the price of the European gas will influence the GB gas price, either directly, when imports are the marginal source of supply, or indirectly, when storage is the marginal source of gas. The impact of the latter being as above.

5.28 Figure A5.6 shows movements in quarterly oil prices and Emden Troll³⁹ prices since December 1995. The graph shows that movements in Emden prices are closely correlated with changes in oil prices (both are expressed in dollars); with a correlation coefficient of 0.8. Statistical analysis of the relationship shows that 3-6 month lagged Brent oil prices are significant (at the 5 per cent level) in explaining movements in Emden prices (expressed in GBP). This analysis shows that European gas prices appear to closely track oil prices.

Figure A5.6: Oil prices and European gas prices expressed in dollars



Quantifying the summer effect

5.29 The implied effect of increases to storage gas costs due to oil on the Q1 05 forward gas price has been estimated to be up to 3 p/therm. This is based upon:

- ◆ The limit of the impact of oil on storage prices being 5.5 p/therm⁴⁰. This affects the stored gas at Rough, MRS and the LNG peak shaving plants.
- ◆ Storage gas setting the clearing gas price on 44⁴¹ of the 90 days of Q1 05
- ◆ $3 \text{ p/therm} = 5.5 * 44 / 90$ (rounded up to the nearest pence).

³⁹ Emden prices were chosen as the hub is one of the closest hubs to the UK and reflects oil linked continental prices.

⁴⁰ The difference between 2004 and 2003 average summer gas price (April to September)

⁴¹ Q1 storage gas deliverability was estimated at two thirds of overall deliverable capability

5.30 The 3 p/therm explains approximately 15 per cent of the 20.175⁴² p/therm forward price rise since 1 April 2004⁴³.

Quantifying the winter effect

5.31 The key mechanism by which higher oil prices affect UK gas prices is through the interconnector. In summer, European gas prices influence NBP price since the UK is usually exporting gas to the continent, due to the price differentials. Conversely, during winter, UKCS gas supply is insufficient to meet UK demand and storage and European gas is used to meet the shortfall.

5.32 Using econometric analysis Ofgem estimated that the implied impact of oil on Q1 05 forward prices to be approximately 3 p/therm. This was based upon:

- ◆ The change in oil price between April 2004 and September 2004 was 5.3 £/barrel. Econometric analysis estimated the impact of oil prices on Emden prices, giving a coefficient of 1.2. This implied that the impact on gas prices is approximately 6.4 p/therm ($5.3 * 1.2$).
- ◆ The interconnector is setting the clearing price on 40 of the 90 days over Q1 05.
- ◆ Thus there is an impact of 3 p/therm = $6.4 * 40 / 90$ (rounded up to the nearest pence).

5.33 The 3 p/therm explains approximately 15 per cent of the 20.175 p/therm forward price rise.

Verification of the impact of high oil prices

5.34 In the Utility Journal, NBP year-ahead gas prices from May 03 to June 04 are correlated to oil in various currencies: In sterling the correlation factor equals 0.71, in Euros it equals 0.8 and in US Dollars 0.9.

5.35 One of the conclusions reached was that for a \$1/barrel increase in the oil price, the gas price would increase by 0.95 p/therm over the following 3 month

⁴² The 20.175 p/therm is the difference between the Q1 05 forward price on 24th September 2004 of 51.727 p/therm and the Q1 05 forward price on 1st April 2004 of 31.55 p/therm (source: Heren).

⁴³ Ofgem's analysis assessed changes since April 2004 as this represents the time before the impact of each of the above was known.

period. For Ofgem's analysis, the oil price increase was \$9/barrel. Using the Utility Journal relationship, this would result in a 8.5 p/therm increase in gas prices, suggesting that Ofgem's implied increase of up to 6 p/therm might be conservative.

The impact of UKCS decline

5.36 The impact of the reductions in UKCS availability involved estimating:

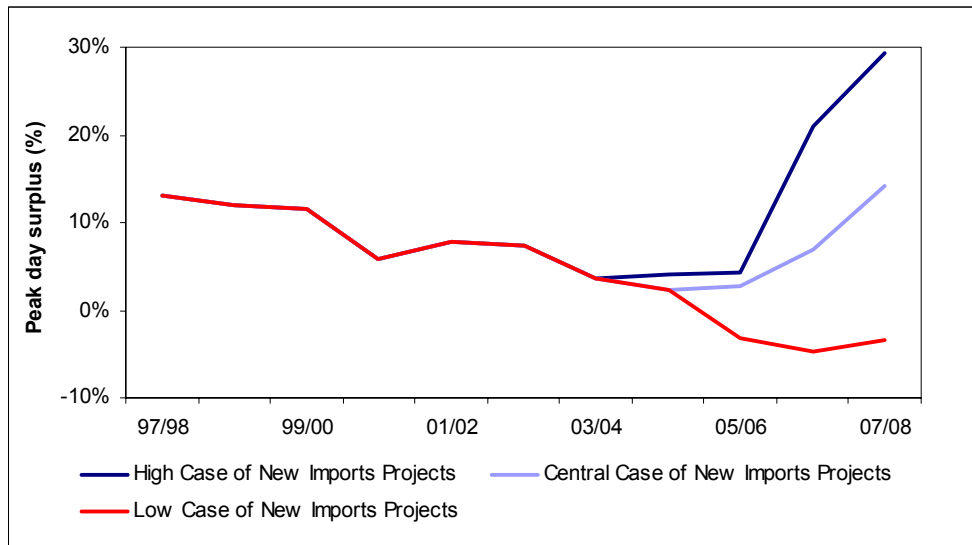
- ◆ The volume of reduced beach supply;
- ◆ The increased likelihood that the more expensive sources of supply-demand balancing (including demand side response) would be required over Q1 05; and
- ◆ The cost of the different supply sources (the demand side for instance).

5.37 In 2003, NGT forecast that maximum beach supplies for 2004/05 would be 402 mcm. In 2004 (both at its Transporting Britain's Energy Forum in July 2004 and in its Preliminary Winter Outlook Report 2004/05 published in May 2004) they revised its view of maximum beach supplies for the Winter 2004/05. Its revised forecast of maximum beach supplies became 364mcm, 13 mcm lower than their 2003 forecast for Winter 2004/05. NGT's Winter Outlook Report, released on 29 September 2004,⁴⁴ provided a revision of its views with maximum beach at 377 mcm, which represents a 9 per cent change from the 2003 forecast.

5.38 Figure A5.7 illustrates historic and forecast supply margins. The winter 2004/05 margin is currently expected to be 2.25 per cent whilst the winter margins for 2003/04 and 2002/03 were 3.64 per cent and 7.46 per cent respectively.

⁴⁴ Information from this document was published on 29 September. The final document is expected in October 2004.

Figure A5.7: Transco's Peak Day Supply Margin⁴⁵



5.39 Ofgem has quantified the tightening of the supply and demand balance by considering its impact on the use of demand side response and peak shaving gas.⁴⁶

5.40 These are explained further below.

Demand side response

5.41 The demand-side is able to respond to high gas prices by selling pre-contracted gas back into the market, or by ceasing to consume gas contracted at NBP-linked prices.

5.42 Response from the demand-side typically comes from gas-fired generation, which arbitrages between the cost of gas and the value of electricity, and large energy users, who may be able to cease, or postpone, production in response to high prices.

5.43 The implied impact of demand side response on the Q1 05 forward price has been estimated at 2.5 p/therm. This is based upon:

- ◆ Demand side response setting prices on 3 of the 90 days.

⁴⁵ Transco's 10 Year Statement 2003

⁴⁶ This assumes that the interconnector is constrained on maximum import and that Rough and LNG storage are fully utilised.

- ◆ The cost of demand side response averaging 75 p/therm. This is an average of:
 - 50 p/therm, representing the price where combined cycle plants reduce or curtail their use of gas⁴⁷; and
 - The 100 p/therm, representing an estimate of the cost of demand side response, based upon the highest price observed during the outage at Rough in January 2004.⁴⁸
- ◆ The overall change in the Q1 05 forward price is approximately 2.5 p/therm (75*3/90).

5.44 The 2.5 p/therm explains approximately 12 per cent of the 20.175 p/therm forward price rise as described in footnote 37.

Peak gas

5.45 The implied impact of the increased use of peak gas has been quantified by assessing the increased likelihood that peak gas facilities would be used during periods of high demand. This has been quantified using the same method that was used for demand side response. The implied impact has been estimated at approximately 1.5 p/therm. This is based upon:

- ◆ Peak shaving gas setting the clearing price for 3 of the 90 days;
- ◆ The cost of the supply averaging 39 p/therm⁴⁹; and
- ◆ Approximately 1.5 p/therm = 39*3/90.

5.46 The 1.5 p/therm explains approximately 7 per cent of the 20.175 p/therm forward price rise.

Storage

5.47 The Rough storage facility, which is the largest storage complex in the UK, can deliver 42 mcm/day for up to 75 days.⁵⁰ Recently Centrica increased the charges

⁴⁷ Joint Energy Security of Supply (JESS) May 2004 report. Page 13.

⁴⁸ Ofgem's Security of Supply October 2003 to March 2004 Six month Retrospective report (September 2004 – 217/04). Page 29.

⁴⁹ Ofgem estimate based on observed prices and the impact of oil.

for injecting, storing and withdrawing gas from Rough, reflecting the widening summer-winter price differential. The cost of storage provides a proxy for the expected summer-winter differential.

- 5.48 As such, the storage costs at Rough can be used to provide an estimate of the Q1 gas price, as implied by the prices prevailing during periods in which gas is typically injected into store.
- 5.49 The impact of stored gas on the Q1 price is estimated using the cost of stored gas and the number of days that gas delivered from Rough is likely to be the marginal supply source.
- 5.50 The implied impact has been quantified using the increased likelihood that demand side response and peak shaving facilities would be required in Q1 05 to meet periods of high demand.
- 5.51 The implied affect of increases to storage gas charges at Rough on the Q1 05 forward gas price has been estimated to be up to 1 p/therm. This is based upon:
- ◆ The Rough storage charge increasing by approximately 2.6 p/therm;
 - ◆ Rough setting the clearing gas price on 37 of the 90 days of Q1; and
 - ◆ $1 \text{ p/therm} = 2.6 * 37 / 90$ (rounded to the nearest pence).
- 5.52 The 1 p/therm explains approximately 5 per cent of the 20.175 p/therm forward price rise (cf. footnote 37).

Incorporating weather expectations

- 5.53 The forward price for winter will reflect the expectations held about the likely distribution of outturn weather conditions, and the prices that would prevail under each of the possible weather outcomes. Other uncertainties are incorporated into the forward price in a similar manner.
- 5.54 The analysis above presents one implied price based on an implicit assumption about outturn weather conditions.

⁵⁰ Transco's Preliminary Winter Outlook Report 2004/05

- 5.55 The above analysis utilises historic demand/supply balance data for 2003/04 which was a particularly warm winter i.e. 1 in 7 warm winter. Consequently, it is likely that the implied price will underestimate the forward price.
- 5.56 In order to take account of this, and to produce a range of potential outcomes, the analysis has been repeated using Transco's latest 1 in 50 load duration curve for 2004/05.
- 5.57 The key differences/assumptions behind this analysis are outlined in the Table A5.2.

Table A5.2 Key assumptions relating to the 1 in 50 scenario

Source of supply	Days supply sets clearing price Q1 05		Marginal Cost - p/th
	Initial Analysis	1 in 50	
Interconnector	40	28	6.3
Rough	37	24	8.1
Medium (MRS)	7	12	5.5
LNG	0	2	5.5
Demand Side Response	3	21	75
Peak Shaving	3	3	39

- 5.58 The three factors: increases in oil prices, tighter supply and demand balance and increases to storage charges - under 1 in 50 winter conditions - have led to an implied increase in the Q1 05 forward price of 23.8 p/therm. If we add the 23.8 p/therm increase to the forward price on 1 April 2004 of 31.5 p/therm this gives an implied price of approximately 55.6 p/therm.
- 5.59 This is broadly similar to current Q1 05 forward prices of 54 p/therm.

Summary of the effects

5.60 The three factors: increases in oil prices, tighter supply/demand balance and increases to storage charges have led to an implied change to the Q1 05 forward price of up to 11 p/therm, under the initial (mild weather) scenario.

- ◆ Increases in oil prices contribute up to 6 p/therm:
 - The summer effect - 3 p/therm
 - The winter effect - 3 p/therm
- ◆ A tightening of the supply and demand balance contribute up to 4 p/therm:
 - 2.5 p/therm due to the increased likelihood of demand side response
 - 1.5 p/therm due to the increased likelihood of peak shaving gas being required
- ◆ Increases in storage charges contribute up to 1 p/therm

5.61 The 11 p/therm explains approximately 54 per cent of the 20.175 p/therm forward price rise.

5.62 These three factors: increases in oil prices, tighter supply and demand balance and increases to storage charges - under 1 in 50 winter conditions - have led to an implied increase in the Q1 05 forward price of 23.8 p/therm

Trade and risk

5.63 A number of market participants have suggested that some of the movements in forward prices have been affected by the degree to which market participants are able to open up short positions in the forward market⁵¹.

5.64 A commonly used risk management tool is the use of Value at Risk (VAR) limits, which set a limit on the extent to which a company is financially exposed to movements in energy prices.

⁵¹ In this context, a short position is where a market participant has sold gas forward in excess of their contractual rights to deliver gas to the market to meet these commitments.

- 5.65 It has been suggested that a number of market participants may have opened up short positions for winter 2004/05, reflecting their view that the prevailing forward price was in excess of their expected outturn price. As forward gas prices have risen the measured VAR will have increased, potentially reaching the authorised trading limits. This would have forced these participants to reduce their exposure by reducing their short position by buying gas at the now higher prices.
- 5.66 It has also been suggested that the impact of this effect has been magnified by the relative illiquidity in the forward market. If a market has relatively few participants or a relatively small number of trades, the possibility of significant movements in prices increases.
- 5.67 In the interim report, Ofgem analysed market liquidity by assessing traded volumes in the wholesale market on a number of different platforms, including trade nominations to Transco, within-day trading on the OCM and day-ahead trading on the Spectron platform. The analysis showed that whilst traded volumes have remained fairly flat since 2002, there have been no significant reductions in traded volume during 2003 or 2004.

Price premium on winter 2004/05 forward prices

- 5.68 There are a number of factors, that result in market participants placing a premium on winter 2004/05 forward prices, especially considering the uncertainties surrounding the tightness of the supply and demand balance.
- 5.69 These include:
- ◆ **The extent and rate of further decreases in UK gas production.**
 - ◆ **The amount of unplanned maintenance on UK gas supplies.** It is possible that the market expects that the amount of unplanned maintenance will increase.
 - ◆ **The extent to which gas from Europe will be imported, as there is uncertainty surrounding the interconnector's ability to respond to UK price signals, the availability of European supply and transit capacity.** Appendix 2 has investigated the October / November 2003 period when the

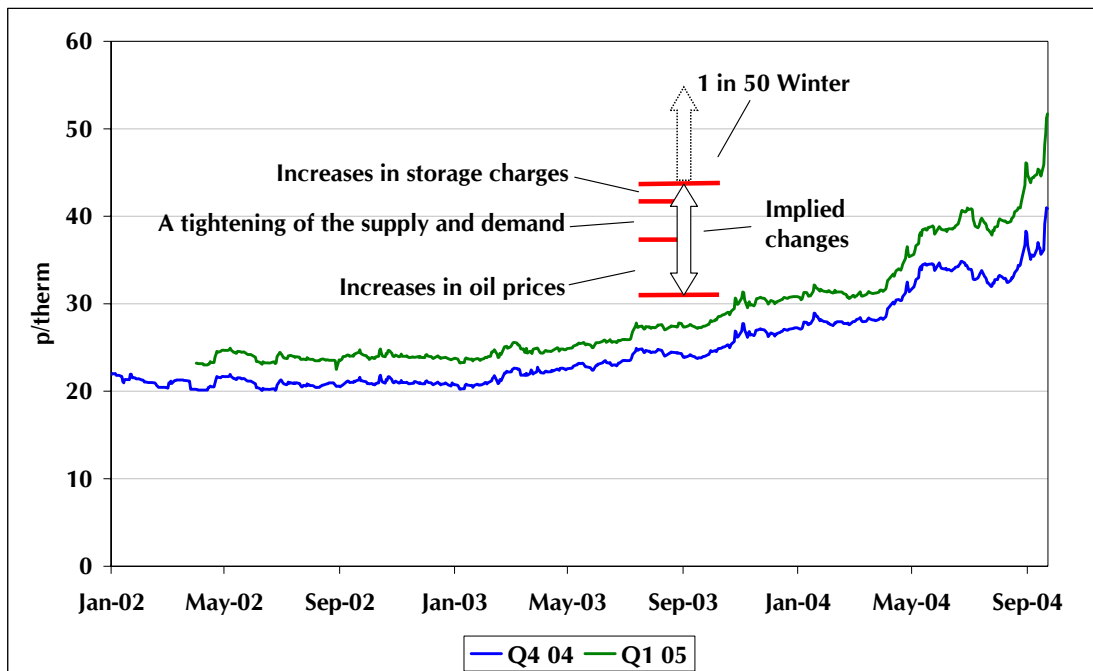
interconnector continued to export gas when it was expected to be importing. A number of issues resulted from the analysis, all of which contribute to the uncertainty of accessing European gas.

- ◆ **The introduction of the emission trading scheme (EU ETS).** The implementation of the EU ETS on 01 January 2005 is another factor that may contribute to the upward pressure on Q1 05 forward prices. It is anticipated that since the EU ETS is likely to increase the marginal cost of using coal to generate electricity, generators will switch to gas. This substitution away from coal to gas will increase demand for gas from 1 January 2005 and increase forward gas prices.

Conclusions

- 5.70 Based on the analysis presented above, Ofgem has constructed an implied Q1 05 winter forward price. The analysis implies that winter 2004/05 forward gas prices could increase by up to 11p/th under a base (warm weather) scenario. Whilst the 1 in 50 winter scenario, implies an increase in the winter 04/05 forward gas price of 23.8 p/therm.
- 5.71 On 1 April 2004 the Q1 05 forward price was 31.55 p/therm. Adding the 11 p/therm increase gives an implied price of approximately 43 p/therm. The recent maximum Q1 05 winter forward price of 54.45 p/therm is 20 per cent higher than this implied price. Similarly, adding the 23.8 p/therm increase implied by the 1 in 50 conditions gives an implied price of approximately 55.6 p/therm. This is slightly higher than the current forward Q1 05 price.
- 5.72 This analysis is summarised in Figure A5.8, which highlights that whilst the forward price is within the range implied by the two scenarios, it is closer to the price implied by the cold weather (1 in 50) scenario.

Figure A5.8: Predicted vs. actual prices



5.73 This analysis highlights that the set of factors identified goes some way to explaining the movements in forward gas prices. However, there are a number of factors that were not quantified, which may offer some explanation of the discrepancy between the implied and current winter 2004/05 forward prices.

5.74 Inevitably, more detailed analysis can be performed based on outturn data and Ofgem will continue to monitor the levels and movements in forward gas prices closely.

Future winter forward prices

5.75 Whilst future prices are high for this winter, looking forward there are a number of projects that are likely to improve the supply/demand margin, and which may result in the fall of forward prices from 2005/06 onwards.

5.76 Table A5.2 details these projects and their impact on future supply.

Table A5.2: New import and storage projects under development or planned⁵²

Import Project	Developer	Location	Size	Date	Status
Interconnector Comp (Phase I)	IUK	Zeebrugge to Bacton	extra 8 bcm	2005/6	Under construction
Interconnector Comp (Phase II)	IUK	Zeebrugge to Bacton	further 8 bcm	2007/8	Under review
Ormen Lange	OL Partners	Ormen Lange field via Sleipner to Easington	15-25 bcm	2006/7	Pipeline contract awarded, government approval sought, import treaty principles agreed
Other Norwegian	Numerous possibilities.	Use of existing UKCS infrastructure	10+ bcm	2007+	Use of FLAGS for Statfjord agreed (~ 10 mcm/d)
BBL pipeline	GTS	Balgzand to Bacton	8-15 bcm	2006/7	Project approval sought, capacity assessment underway, import treaty required
Isle of Grain LNG	NGT	Isle of Grain	4 bcm	2005	Under construction, capacity sold to BP / Sonatrach
Isle of Grain LNG	NGT	Isle of Grain	Further 10+ bcm	2006+	Planning permission sought for further storage
Milford Haven (Petroplus/BG Group)	Petroplus	Milford Haven	10 bcm	2007	Planning permission granted for 3rd tank, prelim site constructed
Milford Haven (Qatar Petroleum / ExxonMobil)	Qatar Petroleum / ExxonMobil	Milford Haven (North Hook)	10 bcm expansion to 20 bcm	2007 2009	Planning application granted, project approval sought
Aldbrough (South)	Statoil	Aldbrough	140 mcm	2007/8	Combined development agreed, planning permission granted
Aldbrough (North)	SSE	Aldbrough	280 mcm	2007/8	Combined development agreed, planning permission granted
Cheshire	Scottish Power	Byley	~ 300 mcm	2007/8	Planning Permission still to be granted
Humbly Grove	Star Energy	Humbly Grove	280 mcm	2005/6	Planning agreed
Welton	Star Energy	Welton	280 mcm	2006/7	Conceptual engineering
Lancs	Canatxx	Fleetwood	400-500 mcm	2006/7	Conceptual no planning submitted

⁵² From Transco's 10 Year Statement 2003