# 5 The relevant markets

## Contents

## Introduction

5.1. This chapter starts by considering the wholesale market for gas followed by the retail markets for gas. It then considers the different types of flexibility and aspects of the market for flexibility, including market definition, market shares, entry barriers and data on the use made of the different sources of flexibility. The final section considers whether the merger gives Centrica the incentive to withhold gas from the market in order to increase prices.

5.2. Table 5.1 summarizes the UK supply and demand for gas since 1998. In each year, UK production has exceeded UK demand. Exports have been made through the interconnector to the Republic of Ireland (opened in 1995) and from Bacton to Zeebrugge (opened in October 1998), and also from two UKCS fields which are connected to the infrastructure on the mainland of Europe. There has also been a small amount of imports, principally at times of peak UK demand, through the Bacton interconnector and through the Vesterled pipeline from Norwegian fields to St Fergus.

5.3. In 2002, just over one-third of UK demand was accounted for by domestic customers and one-third by power generation. The I&C sector accounted for just over one-quarter of demand.

TABLE 5.1 **UK supply and use of natural gas**

| | | | | | *TWh* | *%* |
|---|---|---|---|---|---|---|
| | *1998* | *1999* | *2000* | *2001* | *2002* | *2002* |
| *Supply* | | | | | | |
| Production | 1,048 | 1,152 | 1,259 | 1,230 | 1,199 | 108 |
| Imports | 11 | 13 | 26 | 30 | 60 | 5 |
| Exports | –32 | –84 | –146 | –138 | –151 | –14 |
| Total supply | 1,027 | 1,081 | 1,138 | 1,123 | 1,109 | 100 |
| *Demand* | | | | | | |
| Power generation | 268 | 315 | 325 | 312 | 330 | 33 |
| Domestic | 356 | 358 | 370 | 379 | 364 | 36 |
| I&C* | 294 | 283 | 290 | 291 | 272 | 27 |
| Other† | 28 | 54 | 61 | 47 | 48 | 5 |
| Total of above | 945 | 1,010 | 1,046 | 1,028 | 1,014 | 100 |
| Energy industry use‡ | 76 | 77 | 79 | 91 | 92 | |
| Total demand§ | 1,021 | 1,087 | 1,125 | 1,119 | 1,106 | |

*Source:* Digest of UK Energy Statistics.

*Includes agriculture and miscellaneous non-domestic final users.
†Includes non-energy use and heat generation sold to other users.
‡Mainly oil and gas extraction.
§Difference from supply accounted for by stock changes, transfers and statistical discrepancy.

## Wholesale gas market

5.4. The main UKCS producers of gas include Total Fina Elf, BP, Shell, Centrica, ConocoPhillips, ExxonMobil and BG. Centrica's equity interest in UKCS production is about 11 to 12 per cent, of which some 90 per cent is accounted for by the Morecambe Bay fields, which it owns and operates, and the remainder by other fields in which Centrica has an equity interest (see paragraph 4.29).

5.5. Producers may supply gas directly to very large power generation or industrial customers, transfer the gas to a downstream affiliate with a supply licence for sale to smaller I&C and domestic customers, or sell it (directly or indirectly) through the wholesale market to other gas suppliers. Centrica is a substantial net purchaser of gas since the amount needed to meet its share of total demand (about 36 per cent during the gas year 2001/02) is considerably higher than its share of production less net exports, which would be about 12 to 13 per cent (assuming exports at about 10 per cent of produc-

tion). Producers may sell gas on the wholesale market through long-term contracts, shorter-term contracts or on the spot market. Since domestic gas users have full flexibility about how much gas they use on the day (and most I&C and power station users of gas also have some contractual flexibility over level of use), shippers with supply commitments buy/sell gas on the spot market to reduce their end-of-day imbalance (see Appendix 4.3).

5.6. Most gas is traded at the NBP, the seller (or a previous seller) having obtained entry capacity on to the NTS. Entry capacity is sold by Transco through a series of auctions which are held both well ahead of and on the day. There is also a secondary market for entry capacity.

5.7. Traded markets for gas in Great Britain include the following:

*(a)* the OCM market (see paragraph 4.29) through which traders, shippers and Transco buy and sell gas for the current day and the day ahead;

*(b)* an OTC market for the day ahead, weekdays ahead, weekend ahead, current month, forward months and forward quarters and seasons, extending out about five years (although liquidity reduces further out). Price assessments are reported by Platts, Argus Media Limited and Heren Energy Ltd for all these periods; and

*(c)* the International Petroleum Exchange (IPE) on which gas futures are traded. In addition, derivatives such as options and swaps are traded bilaterally.

It has been suggested that the gas markets are relatively illiquid compared with traded markets for oil products and some other commodities, in particular due to the withdrawal from the markets in the last two years of a number of US companies including Enron, Dynegy, TXU Corp, El Paso and Aquila. For instance, The Energy Contract Company states:

> There are now very few traders left of any consequence. In the past these companies bought when the market dropped below a normal trading range and sold when it went above. This served to provide a measure of both liquidity and stability in the gas market. Almost all the significant players left are managing a large physical position … The outlook for the next couple of years seems to be for a high level of volatility in all traded markets.[1]

Centrica told us that other parties, such as banks and European energy companies, had entered or increased their presence in the UK wholesale market and the volumes traded at the NBP had continued to rise despite the exit of US traders. It should also be noted that the NBP market is substantially more liquid than traded markets on the mainland of Europe, where gas market liberalization is not yet developed beyond very large customers and where wholesale gas prices continue to be linked to oil prices.

5.8. Long-term contracts between producers and shippers/suppliers may have prices indexed to prices on traded gas markets or prices may be linked to one or a combination of inflation (usually measured by the producer prices index (PPI)), oil product prices, electricity prices and coal prices. Table 5.2 shows that the proportion of Centrica's purchased gas indexed to traded gas market prices has increased from [✂] per cent in 2000/01 to [✂] per cent in 2002/03 and is projected to rise to [✂] per cent by 2006/07. Table 5.2 excludes Centrica's own Morecambe Bay fields and its other equity gas, which account for around [✂] of its total gas procurement in 2002/03, falling to [✂] per cent in 2006/07: tax payments on Centrica's gas production are also linked to traded gas market prices.

[1] *2003 UK Gas Market Review*, Energy Contract Company, 12 March 2003.

TABLE 5.2 **Indexation in Centrica's gas purchase contracts**

*per cent*

| | *2000/01* | *2001/02* | *2002/03* | *2003/04* | *2004/05* | *2005/06* | *2006/07* |
|---|---|---|---|---|---|---|---|
| *Gas indexed* | | | | | | | |
| Year ahead | | | | | | | |
| Monthly (5 months' average) | | | | | | | |
| Monthly (month ahead) | | | | | | | |
| Day ahead | | | | | | | |
| Total | | | | *Figures omitted. See note on page iv.* | | | |
| Others* | | | | | | | |
| Total | 100 | 100 | 100 | 100 | 100 | 100 | 100 |

*Source:* Centrica.

*Largely indexed to oil or the PPI.

*Note:* The above reflects the total amount of gas contracted by Centrica, not the amount of flexible gas contracted. Centrica's equity gas is excluded.

5.9. Figure 5.1 shows trends in the spot price of gas and in the weighted average price as reported by the DTI. Spot prices were low until 2000 and then increased substantially, although 2002 prices were slightly lower than 2001 prices. In its 2002 response to gas consultation,[1] the DTI attributed the increase in UK wholesale prices to arbitrage (via the Bacton interconnector) between a fully liberalized UK market and a pre-liberalized market on the mainland of Europe where gas prices were still linked to \oil prices. Arbitrage had the effect of increasing UK prices as oil prices increased.

5.10. The DTI noted that trading at hubs on the mainland of Europe represented only a small proportion of the gas used and that the only real competitive trading was at Zeebrugge, when gas from Great Britain was being exported through the Bacton interconnector. Figure 5.2 shows daily NBP prices compared with monthly average Belgian wholesale contract prices.[2] During the year 2000, Belgian wholesale contract prices increased as a result of increases in oil prices and NBP prices also increased broadly in line. This occurred because UK gas producers increased exports through the Bacton interconnector in response to higher prices in Belgium and elsewhere on the mainland of Europe, reducing supply to the NBP and hence increasing the NBP price. Since 2000, NBP prices have been below Belgian prices during the summer but have increased to above Belgian prices on some occasions in the winter. The impact of the Bacton interconnector on price is considered further in paragraphs 5.34 to 5.36.

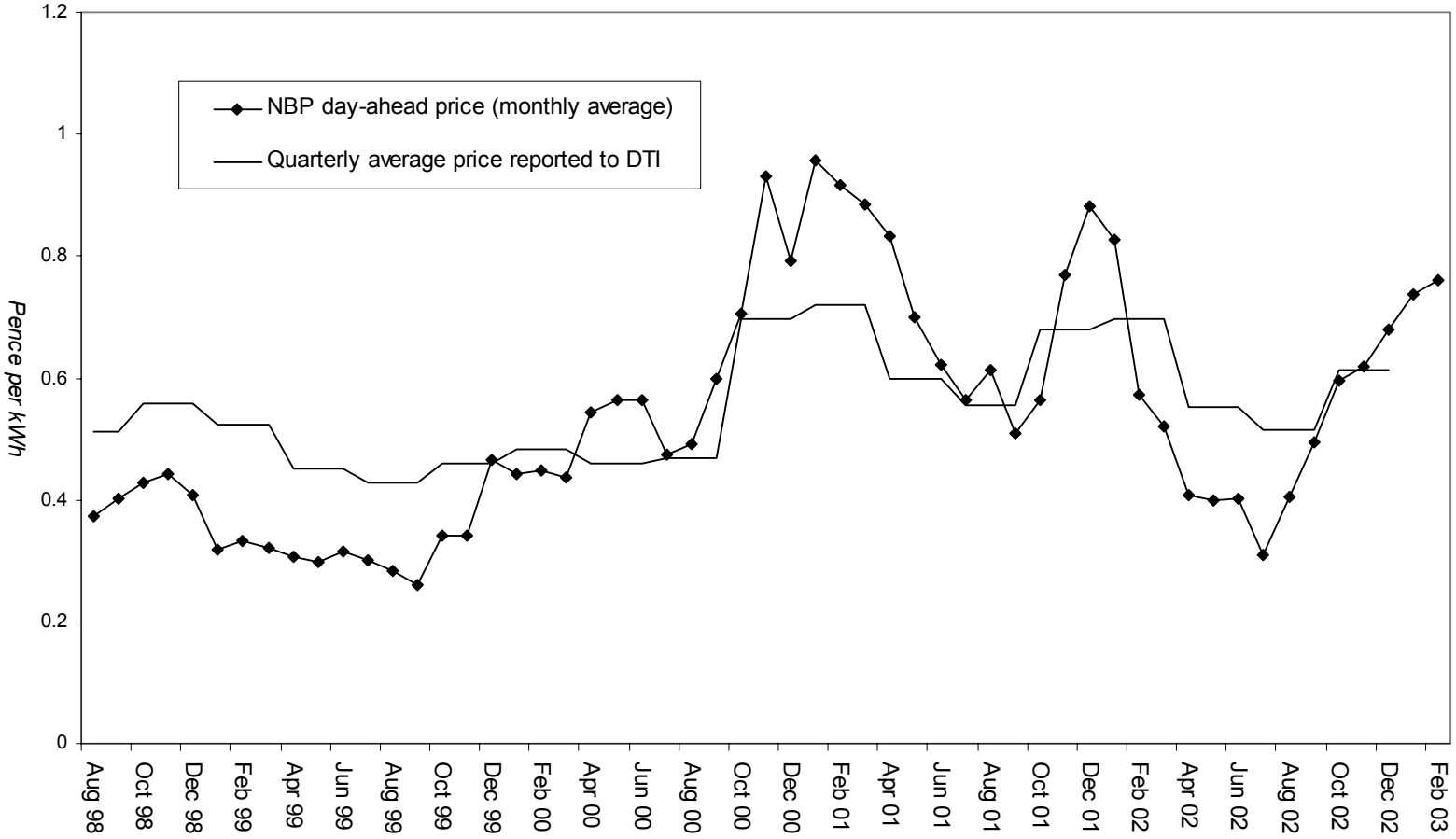
## Retail gas markets

5.11. Retail gas markets may be divided by end-user into power generation, industrial/commercial and domestic. Gas-fired power stations are mostly large consumers of gas connected directly to the NTS and capable of purchasing gas on the wholesale market if they wish to. Larger industrial customers may also purchase directly from the wholesale market. The remainder (ie domestic customers and the majority of I&C customers) are supplied via licensed gas suppliers.

[1]DTI response to consultation on gas issues (URN 02/1306).
[2]Belgian contract prices are based on the Pelig index, representing an average of the different sources of Belgian gas.

FIGURE 5.1

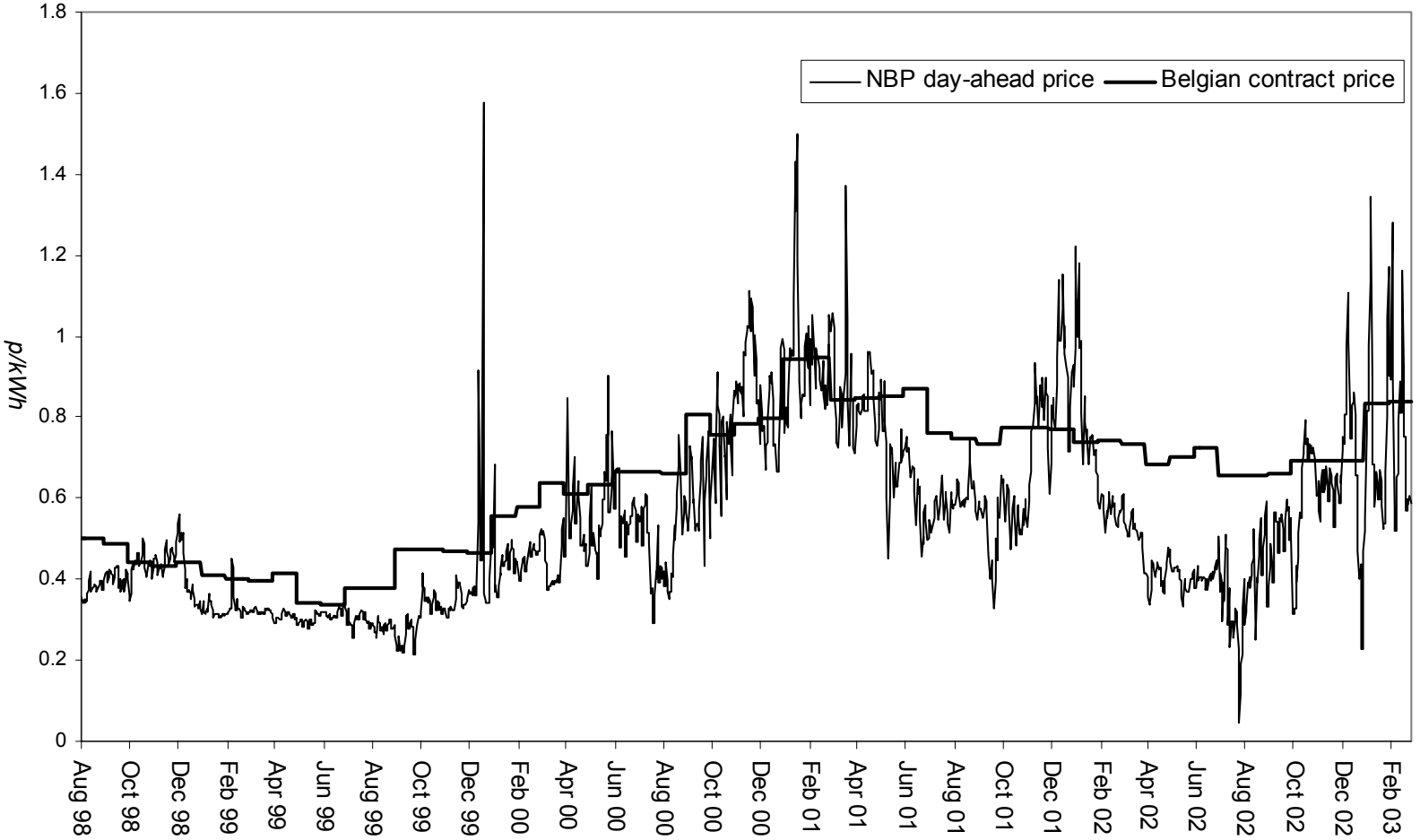
**Wholesale gas prices since August 1998**




*Source:* Centrica and DTI.

FIGURE 5.2

**Comparison of UK prices with Belgian prices**




*Source:* Centrica.

## *Power generation*

5.12. In 2002, Centrica had about 25 per cent of the supply of gas to power stations, of which 5 per cent was accounted for by supplies to Centrica's own power stations and [✂] per cent by the remaining LTI contracts which were agreed between British Gas plc and new power producers in the 1990s (three of the LTIs were terminated in the period June 2002 to March 2003 because two of the customers went into administration and the other, Brigg power station, was acquired by Centrica). The LTI contracts typically allow a maximum of [✂] days' interruption each year by Transco and Centrica together and an overall number of 300 days of interruption over the contract period. [

*Details omitted. See note on page iv.*

] when the NBP gas price is above the contract price, Centrica has a commercial incentive to interrupt, subject to the total number of interrupted days (including Transco interruption) not exceeding the maximum allowed in any year and over the life of the contract.

## *Industrial and commercial market*

5.13. The I&C market was opened to competition in the 1980s and early 1990s. Following MMC reports in 1988[1] and 1993,[2] there was significant regulatory action to improve competition. In 1999, Ofgem carried out a review which concluded that competition in the I&C gas supply market was continuing to develop very well. Ofgem noted that it had received very few complaints about barriers to entry into the I&C market, and found that there were no significant barriers to suppliers making, and customers obtaining, potentially competitive offers. At that time, Ofgem concluded that further detailed reviews were not necessary. In 2002, in response to customer representations, Ofgem decided that it would conduct a further review of the I&C market, and the first results are due to be published in July 2003.

5.14. Table 5.3 shows that Centrica's market share has continued to decline since 1999 and that, following recent mergers, it is now only the third largest supplier. Centrica's estimated market share in firm supplies is 15 per cent and in interruptible supplies is 10 per cent. Within the market for firm supplies, however, it does have a significantly higher share of supplies to small and medium-size enterprise (SME) customers (Centrica estimated its current share of the SME market sector at 47 per cent by number of customers and 28 per cent by gas supplied).

TABLE 5.3 **Market shares in I&C market**

*per cent*

| | *Jun 1999* | *Dec 2001* | *Nov 2002* | | |
|---|---|---|---|---|---|
| | | | *Total* | *Firm* | *Interruptible* |
| Total Fina Elf* | 20.7 | 22.7 | 23.1 | 22 | 25 |
| Powergen† | 15.8 | 15.9 | 15.6 | 20 | 7 |
| Centrica | 20.9 | 17.1 | 13.1 | 15 | 10 |
| Shell Gas Direct | 9.3 | 13.4 | 12.9 | 14 | 11 |
| BP Gas | 11.4 | 11.5 | 12.0 | 7 | 22 |
| Gaz de France | - | 8.2 | 8.8 | - | - |
| Statoil‡ | 6.7 | 2.9 | 7.1 | - | - |
| Npower | - | 6.0 | 4.1 | 6 | 0 |
| Others | 15.2 | 2.3 | 3.3 | - | - |
| Total | 100 | 100 | 100 | | |

*Source:* DataMonitor, Energy Contract Company and Centrica estimates (for split between firm and interruptibles).

*Includes Mobil Gas Marketing.
†Including TXU Energi.
‡Previously Alliance Gas.

[1] *Gas: a report on the matter of the existence or possible existence of a monopoly situation in relation to the supply in Great Britian of gas through pipes to persons other than tariff customers*, HMSO, Cm 500, October 1988.
[2] *British Gas plc: reports under the Gas Act 1986 on the conveyance and storage of gas and the fixing of tariffs for the supply of gas by British Gas plc*, HMSO, Cm 2315, August 1993.

5.15. Table 5.4 shows the level of prices charged to I&C customers. The largest such customers pay prices about 0.1p per kWh above wholesale prices, presumably reflecting transportation charges, other costs (for example, marketing) and supplier margins. Smaller customers pay higher prices, reflecting in particular higher transportation charges and supply costs. Interruptible prices are considerably below firm prices because of the discount offered for interruption rights (these contracts tend to be taken by the largest customers).

TABLE 5.4 **I&C gas prices**

*£ per kWh*

| | | *By contract type* | | *By size of customer* | | | *Wholesale prices* | |
|---|---|---|---|---|---|---|---|---|
| *Year* | *Quarter* | *Firm* | *Interruptible* | *Small* | *Medium* | *Large* | *Spot* | *Average* |
| 1998 | 3rd | 0.615 | 0.492 | 0.920 | 0.741 | 0.526 | 0.387 | 0.511 |
| 1998 | 4th | 0.647 | 0.503 | 0.920 | 0.754 | 0.538 | 0.426 | 0.559 |
| 1999 | 1st | 0.641 | 0.509 | 0.885 | 0.741 | 0.537 | 0.324 | 0.523 |
| 1999 | 2nd | 0.613 | 0.484 | 0.901 | 0.731 | 0.516 | 0.307 | 0.450 |
| 1999 | 3rd | 0.568 | 0.483 | 0.884 | 0.716 | 0.501 | 0.281 | 0.428 |
| 1999 | 4th | 0.595 | 0.474 | 0.868 | 0.726 | 0.497 | 0.383 | 0.461 |
| 2000 | 1st | 0.620 | 0.486 | 0.903 | 0.728 | 0.512 | 0.443 | 0.482 |
| 2000 | 2nd | 0.597 | 0.491 | 0.931 | 0.748 | 0.509 | 0.557 | 0.461 |
| 2000 | 3rd | 0.593 | 0.536 | 0.974 | 0.739 | 0.541 | 0.521 | 0.468 |
| 2000 | 4th | 0.815 | 0.718 | 0.990 | 0.839 | 0.746 | 0.811 | 0.698 |
| 2001 | 1st | 0.910 | 0.832 | 1.080 | 0.950 | 0.850 | 0.920 | 0.719 |
| 2001 | 2nd | 0.822 | 0.769 | 1.133 | 0.967 | 0.767 | 0.718 | 0.598 |
| 2001 | 3rd | 0.862 | 0.663 | 1.168 | 1.012 | 0.726 | 0.562 | 0.554 |
| 2001 | 4th | 0.922 | 0.754 | 1.226 | 1.040 | 0.796 | 0.739 | 0.679 |
| 2002 | 1st | 0.922 | 0.816 | 1.188 | 1.021 | 0.833 | 0.639 | 0.697 |
| 2002 | 2nd | 0.831 | 0.631 | 1.229 | 1.034 | 0.681 | 0.403 | 0.551 |
| 2002 | 3rd | 0.797 | 0.605 | 1.214 | 0.987 | 0.652 | 0.402 | 0.516 |
| 2002 | 4th | 0.853 | 0.730 | 1.187 | 1.010 | 0.749 | 0.631 | 0.612 |

*Source:* DTI, Centrica (for spot prices).

*Note:* Small customers are those consuming less than 1.5 GWh a year, large those consuming more than 8.8 GWh.

## *Domestic market*

5.16. During the period between April 1996 and May 1998, the regulator lifted the statutory monopoly held by British Gas plc—inherited by Centrica at the demerger in February 1997—over gas supplies to domestic customers (at that time defined as those taking less than 73,268 kWh (2,500 therms)). The similar regional monopolies of electricity supplies were removed slightly later (between September 1998 and May 1999) but incumbent electricity suppliers were not allowed to enter the domestic gas market in their region until their own monopoly had been lifted (although they were allowed to enter the domestic gas market in other regions). The ensuing period has seen considerable switching between suppliers by domestic customers: a survey in the summer of 2001 for Ofgem reported that 37 per cent of gas customers and 38 per cent of electricity customers had switched at least once since competition was introduced. Table 5.5 shows Centrica's share (BGT) had fallen to 71 per cent by September 2000 and has continued to decline since then, although the rate of fall has slowed down. In its 2002 annual report, Centrica referred to a longer-term trend of stabilizing market share (in gas) with losses occurring primarily during the few months following retail price increases.

TABLE 5.5 **Domestic market shares, September 2000 to March 2003**

*per cent*

| | *Sep 2000* | *Sep 2001* | *Dec 2001* | *Jun 2002* | *Sep 2002* | *Dec 2002* | *Mar 2003* |
|---|---|---|---|---|---|---|---|
| BGT | 71.4 | 67.4 | 66.7 | 65.0 | 63.6 | 63.2 | 63 |
| Powergen* | 2.7 | 3.6 | 3.8 | 4.4 | 12.0 | 12.1 | 12 |
| TXU Energi† | 3.2 | 5.6 | 5.4 | 7.2 | - | - | - |
| Npower‡ | 4.1 | 8.9 | 8.8 | 8.7 | 9.2 | 9.3 | 9 |
| Northern Electric | 2.2 | - | - | - | - | - | - |
| Yorkshire | 1.6 | - | - | - | - | - | - |
| Norweb | 2.2 | - | - | - | - | - | - |
| SSE | 4.5 | 5.0 | 5.0 | 5.4 | 5.6 | 5.9 | 6 |
| ScottishPower | 3.3 | 3.7 | 3.7 | 4.2 | 4.3 | 4.6 | 5 |
| LE Group§ | 1.0 | 1.6 | 2.4 | 4.7 | 4.9 | 4.7 | 5 |
| Seeboard | 1.7 | 1.7 | 1.7 | - | - | - | - |
| Others | 1.7 | 2.1 | 2.5 | 0.4 | 0.4 | 0.3 | 0 |
| HHI¶ | 5,175 | 4,718 | 4,627 | 4,437 | 4,346 | 4,307 | 4,280 |

*Source:* Ofgem.

*Includes TXU Energi from September 2002.
†Includes Norweb from September 2001.
‡Includes Northern and Yorkshire from September 2001.
§Includes Seeboard from June 2002.
¶Herfindahl-Hirschman Index.

5.17. In its most recent full review of domestic competition,[1] Ofgem said that competition in gas and electricity supply was highly developed and vigorous and consequently that it was better to rely on competition law than price regulation to control any abuse of market power. All remaining price controls on former monopoly suppliers (caps on standard credit and prepayment electricity prices, and a relative control limiting the difference between Centrica's prepayment and late-pay tariffs on the one hand and its direct debit and prompt-pay tariffs on the other) were lifted in April 2002, direct price controls on direct debit prices having been lifted in 2000 (see Appendix 4.4). Towards the end of our inquiry, Ofgem published an overview paper summarizing market developments in domestic gas and electricity supply.[2] Ofgem stated that competition was continuing to develop well although it noted that, in a number of respects, gas and electricity supply markets were immature. Ofgem noted that switching activity continued at a high level and that incumbent market shares continued to decline, although at a slower rate than previously.

5.18. Centrica's share of the domestic gas market at the beginning of 2003 was about 63 per cent (see Table 5.5). The remaining 37 per cent was almost entirely accounted for by the former electricity monopoly suppliers, which merger activity has now consolidated into five corporate groups. An important feature of the market is that competition is increasingly on a 'dual fuel' basis. Costs are to some extent related to customer numbers, hence it is cheaper to supply one customer with both electricity and gas than two different customers each with a single fuel. Reflecting this cost structure, some domestic suppliers offer price discounts to customers taking both gas and electricity. Centrica told us that at the end of 2002 it supplied about 22 per cent of domestic electricity customers, of whom 75 to 80 per cent took the dual fuel product.

5.19. Changing energy supplier is a more complex decision for customers than, for example, changing a brand of household product at the supermarket. Factors such as the time taken to learn about different suppliers' prices, uncertainty about future prices, inertia, the 'hassle factor' and fear of billing problems are factors that may make customers reluctant to switch energy supplier. As a consequence, suppliers tend to incur high costs in attracting new customers, in particular through direct selling and advertising. High customer acquisition costs mean costs of entry are high into areas where the company does not have an incumbent position in either gas or electricity. Other factors likely to deter entry include that, switchers being the most price-sensitive customers, an entrant would have to charge gas and electricity prices below Centrica and the electricity incumbent respectively and that, at any plausible rate of customer acquisition, it would take time for an entrant to build its customer base to minimum efficient scale. The sales, during 2002, of the UK supply businesses of TXU Corp (Eastern and

[1] *Review of domestic gas and electricity competition and supply price regulation: conclusions and final proposals*, Ofgem, February 2002.
[2] *Domestic gas and electricity supply competition: recent developments*, Ofgem, June 2003.

North Western) and of Seeboard yielded about £300 a customer:[1] since supply businesses require relatively few fixed assets, this illustrates the value of incumbents' existing customer base. Centrica and the electricity incumbents have about 80 per cent of total gas and electricity customers in each region (see Appendix 5.1). This suggests that competition in each region is largely between these two firms. In competition with electricity incumbents, Centrica benefits from the value of the British Gas brand and more generally from its heritage being national rather than regional (although the majority of the electricity incumbents now compete in each region using a national brand).

5.20. Concentration in the domestic market remains very high. The HHI for domestic gas supply is about 4,300 although it has declined with Centrica's market share (see Table 5.5). The OFT states in its guidelines that it is likely to regard any market with an HHI in excess of 1,800 as highly concentrated. Competition between Centrica and incumbent electricity suppliers may soon reach the point where it is more meaningful to consider domestic gas and electricity markets together. On this basis the average HHI in regional markets would be at least 3,400 (see Appendix 5.1), which is still a very high level.

5.21. Figure 5.3 illustrates Centrica's gas prices relative to a simple average of its competitors[2] and also to the lowest price of its competitors. Centrica's prices have typically been about 9 per cent above the average of its competitors reflecting the advantages of incumbency, although this reduced to 7.5 per cent in June 2003. Incumbent electricity suppliers similarly have higher electricity prices so higher gas prices do not disadvantage Centrica in relation to competition for dual fuel customers with its main regional rival. As illustrated in Figure 5.3, Centrica increased its domestic gas prices by about 5 per cent in both April 2001 and January 2002 and a further increase of about 2.5 per cent took effect in April 2003. Ofgem told us that in 2001 and 2002 price increases had typically been announced first by Centrica, with competing suppliers then announcing their price increases shortly afterwards. Although Centrica was among the first companies to announce a price increase in 2002, its 2001 and 2003 price increases followed announced increases by a number of its main competitors. Centrica told us that its domestic gas prices were based on its published tariffs, that it did not offer more favourable tariffs to new than existing customers and that it had national gas prices. Its regional electricity tariff differences reflected distribution costs rather than the strength of competition in particular regions. The primary reason for this was that non-cost-reflective price differences might be found under the Competition Act to be an abuse of its dominant position in domestic gas supply (both in regard to gas-only supply and for dual fuel supply).

5.22. Responses to our questionnaire (see Appendix 5.1) suggested that overall (incumbent and non-incumbent) margins in gas supply are lower than in electricity. Ofgem noted recently that margins in domestic gas supply have been extremely low or negative, that links between gas and electricity markets appear significant and that stronger margins for electricity (where wholesale prices have fallen markedly in the last few years) have helped mitigate increases in domestic gas prices.[3] Centrica appears to earn higher margins than other suppliers in both gas and electricity: in gas because of higher prices and economies of scale; and in electricity because its electricity purchase prices are lower than those of the other (electricity-incumbent) suppliers, which have legacy high-priced contracts.

## Types of flexibility

5.23. Gas suppliers have a demand for flexibility in their supplies for two main reasons: first, to meet variations in demand over the course of the year (these are partly predictable and partly unpredictable, since winters vary in temperature); second, to meet unpredictable shorter-term variations in the demand/supply balance, for example due to a cold snap or to temporary production problems. There exist spot and forward traded markets for gas (see paragraph 5.7) and gas suppliers might obtain all their flexibility requirements from the traded markets, but the traded markets themselves rely on physical sources of flexibility. The traded markets are a means of efficiently bringing together the demand and supply for flexibility, not an additional source of flexibility. Suppliers, unable to vary their prices on a day-to-day basis, are likely to wish to purchase flexibility in advance, especially given the concerns about the liquidity of the traded markets (see paragraph 5.7). We were told that typically suppliers did not wish to rely on a single source of flexibility; rather, they wished to have a portfolio of flexibility sources.

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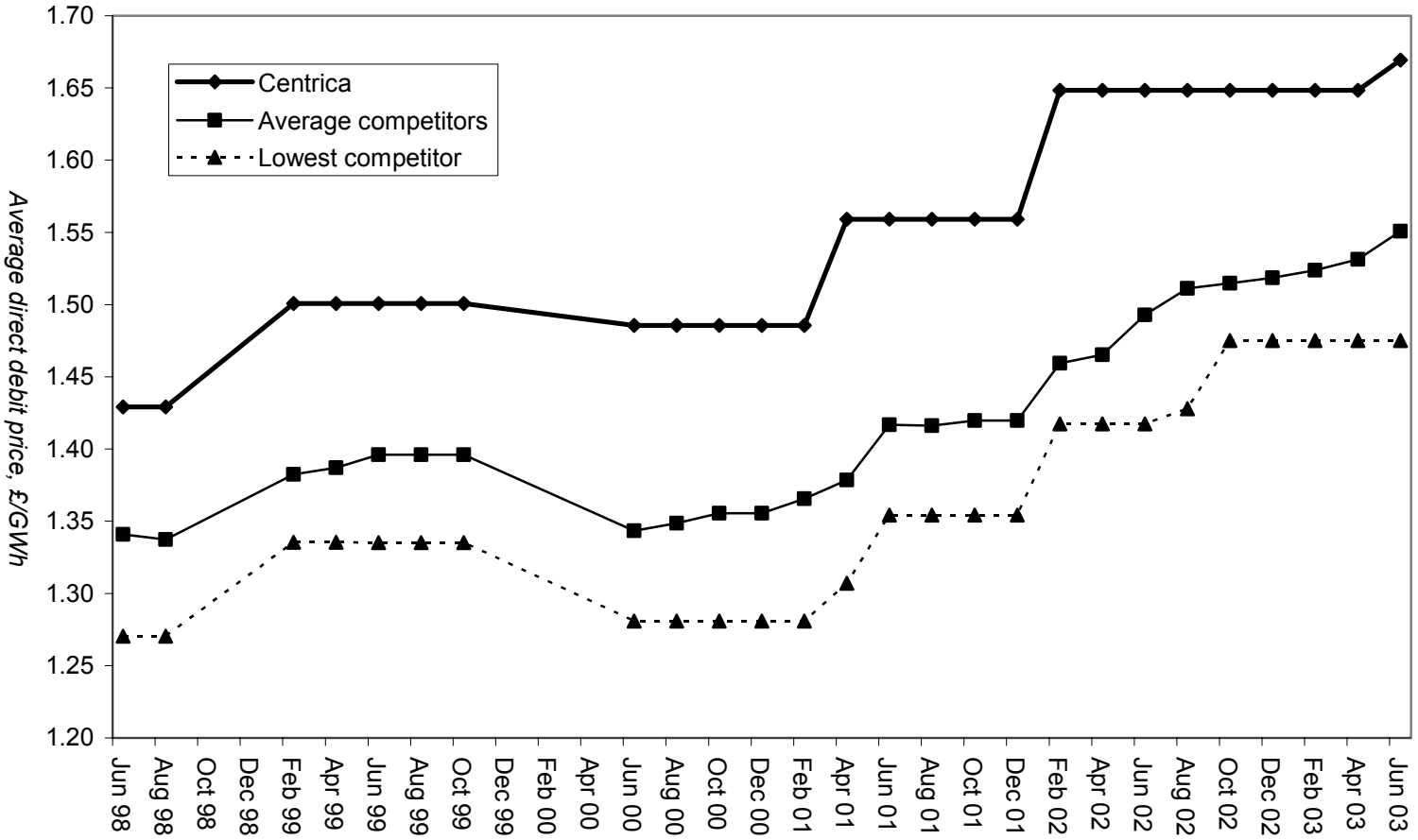
[1]Source: Cheuvreux.
[2]Competitor figures are based on incumbent electricity suppliers only.
[3]*Electricity supply competition: an Ofgem occasional paper*, Ofgem, 16 December 2002.

FIGURE 5.3

**Gas price for household consuming 19,050 MWh a year**




*Source:* Ofgem.

5.24. The main sources of flexibility have been described in Chapter 4 and are:

*(a)* storage (including Rough);

*(b)* beach swing;

*(c)* the Bacton interconnector; and

*(d)* demand-side substitution (interruption and self-interruption).

## *Storage*

5.25. As discussed in Chapter 4, all storage facilities are able to respond rapidly to changes in gas suppliers' requirements. Beyond this, different storage facilities have different physical attributes. In particular, Rough has 67 days' duration (space relative to maximum deliverability), much more than Hornsea (18 days), or LNG (five days) and also more than the two smaller facilities, Hatfield Moor and Hole House. This explains why Rough can be used on a greater number of winter days than the other storage sites. Rough also has higher injection to deliverability than Hornsea (ratio of 0.35 compared with 0.11) and LNG (where injection is at Transco's discretion and is usually in summer only) and is thus more suited to cycling gas between low- and high-price days in winter.

5.26. Table 5.6 shows prices of an SBU at the main existing storage sites. An SBU gives the rights to withdraw 1 kWh per day (as well as a fixed amount of space and rights to injection capability) during a year or a longer period (for longer contracts the price is the price that must be paid each year and can be fixed or indexed to inflation or other indices). The price per bundled unit for Rough is higher than for Hornsea and LNG, presumably reflecting its greater duration and cycling advantages. However, the implied price per kWh of space at Rough is lower, presumably reflecting the fact that customers tend to withdraw gas from Hornsea and LNG on the highest-price days.

TABLE 5.6 **Weighted average price for storage capacity**

| | *Rough* | *Hornsea* | *LNG** |
|---|---|---|---|
| *Make-up of bundled unit (kWh)* | | | |
| Space | 66.59 | 17.95 | 5.00 |
| Withdrawal | 1.00 | 1.00 | 1.00 |
| Injection | 0.35 | 0.11 | No firm rights |
| *Price of bundled units (p)* | | | |
| 5-year auction (1999) | 11.07 | 5.63 | - |
| 4-year auction (2000) | 9.89 | - | - |
| 3-year auction (2001) | 10.99 | 7.85 | - |
| 1999/2000 sales | 9.89 | 5.66 | - |
| 2000/01 sales | 9.89 | 5.86 | - |
| 2001/02 sales | 13.87 | 8.13 | 1.59 |
| 2002/03 sales | 15.96 | 10.76 | 1.83 |
| 2003/04 sales | 22.65 | - | 1.80 |
| *Price per kWh of space (p)* | | | |
| 2002/03 sales | 0.24 | 0.60 | 0.37 |
| 2003/04 sales | 0.34 | | 0.36 |
| Commodity charges† | 0.03 | 0.03 | 0.26 |

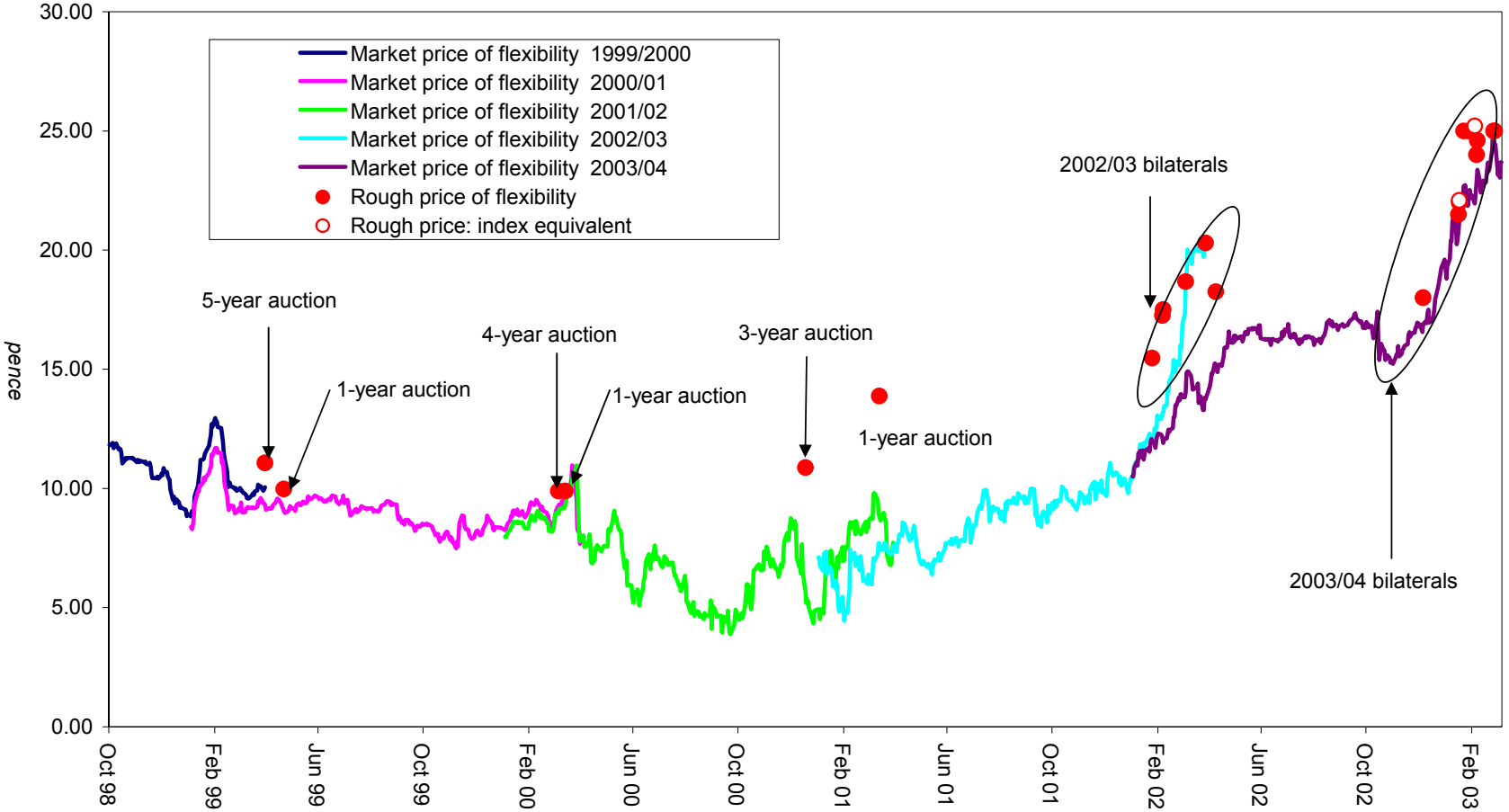
*Source:* Ofgem, Centrica.

*Weighted average for five sites (excluding rebate at constrained sites).
†Cost of cycling 1 kWh. LNG cost reflects summer injection (there is a higher charge for winter injection).

5.27. Table 5.6 and Figure 5.4 show that the price of Rough has increased considerably in the last four years. As also shown in Figure 5.4, the increase in the price of Rough is paralleled by the increase in the spread between forward prices for summer and Q1 (January to March) of the following year (Figures 5.1 and 5.2 illustrate the increase in the spread between summer and Q1 spot prices). The price of Rough has tended to exceed the summer/Q1 forward market spread, despite the commodity charges for using Rough (equivalent to 1.862p per SBU assuming injection for 190 days and withdrawal for 67 days) and the need to purchase entry capacity at Easington when withdrawing gas from Rough.

FIGURE 5.4

**Price of Rough compared with traded market spreads**




*Source:* Centrica.

5.28. The value of a storage facility such as Rough is conventionally attributed to two factors, known as the intrinsic and extrinsic values:

*(a)* The intrinsic value is the risk-free return that can be locked in upon purchase of Rough capacity by buying the forward summer contract (summer being when gas is injected into Rough) and selling the forward Q1 contract (Q1 being the closest proxy to when gas is withdrawn from Rough).

*(b)* The extrinsic value is the value (in addition to the intrinsic value) that can be extracted through the use of Rough over the storage year. As the 67 top-priced days of the year trade at a premium to Q1, withdrawing gas on those days creates additional value for customers. Customers can also cycle (ie inject and withdraw) gas through Rough more than once a year, the second (partial) cycle providing additional value not accounted for in the intrinsic valuation. The extent to which it is profitable to cycle gas in any year depends on the volatility of gas prices. Centrica told us that typically customers could recycle the use of 20 per cent of space, giving them an equivalent availability of 80 days rather than Rough's single cycle of 67 days. Customers may also derive option value from the ability to renominate during the day, for instance in response to unexpected price or demand fluctuations.

5.29. Reasonably full use has been made of Rough and Hornsea in recent years: December 2002 to March 2003 outflows were about 91 per cent of space for Rough and 84 per cent for Hornsea,[1] which suggests that by the end of the winter available gas was reduced to close to the minimum level. This is not the case for LNG: December 2002 to March 2003 outflows were only about 28 per cent of space. Much less use has been made of LNG for two reasons. First, Transco was unable to sell all the capacity it offered to third parties for the 2001/02 and 2002/03 years (although it has sold all of the smaller amount of capacity offered for 2003/04). Second, Centrica told us that, given the high commodity charges for cycling gas, users found it attractive to retain LNG storage as an option for future winters: in relatively warm winters it was more economical to keep gas in store than withdraw remaining gas at the end of winter.

## *Beach swing*

5.30. Where technically feasible, beach swing can be provided by production fields producing less than the maximum quantity of gas in the summer months. Fields tend to produce at maximum during the peak winter months; hence beach swing is less likely than storage to be used as a source of day-to-day flexibility in winter (although flexible gas fields can still generally assist with daily balancing through within-day changes). An exception to this is Sean, a high-cost field which is contracted to Centrica and used only at times of highest demand or price. As discussed in Chapter 4, gas fields typically take longer to respond than storage: Centrica's contracts typically require it to give between 6 and 24 hours' notice to vary its offtake.

5.31. Where production from a field has been sold on a depletion contract, the purchaser (for example, Centrica) often has contractual rights to vary the rate at which gas is extracted and, in order to minimize cost, may wish to use the field flexibly between summer and winter. Where production is controlled by the operator, decisions on summer production, and hence the extent to which the field is used flexibly, would tend to be determined by technical parameters and market prices (and the operator's contractual agreements with its customers regarding minimum take). We were told by one gas producer that reducing summer production was unlikely to be commercially attractive, although we note that this must depend on the level of summer gas prices.

5.32. As shown in Figure 5.5, Centrica operates Morecambe with higher swing than average for Great Britain supply. Supply from the other fields contracted to Centrica also shows somewhat higher swing than the remaining Great Britain supply. Table 5.7 shows that, in the year to end March 2003, Centrica's equity and contracted fields accounted for about 60 per cent of total swing (Appendix 5.2 and Table 5.10 also show flows for the years ending March 2001 to 2003).

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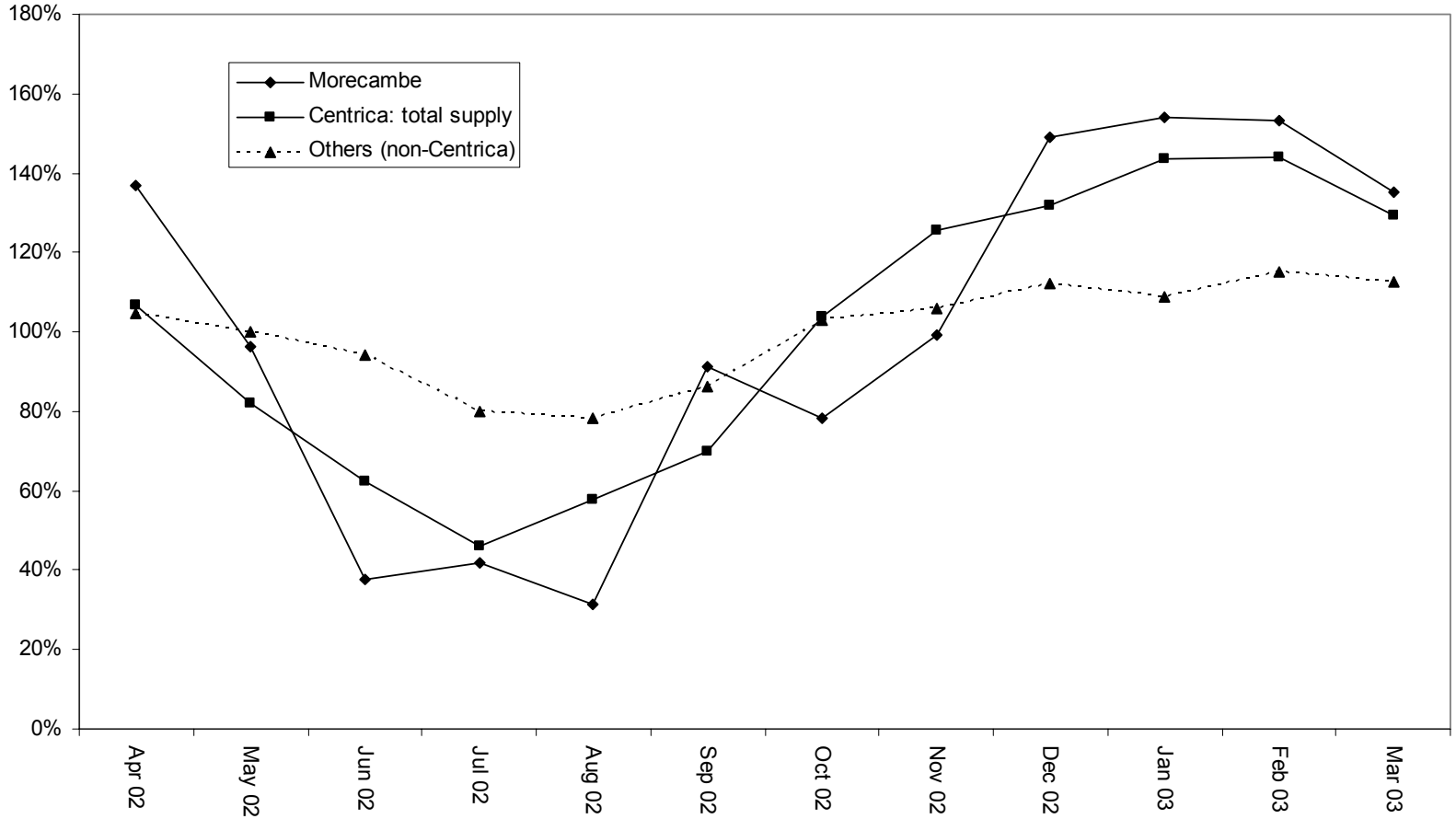
[1]December to March flows are shown in Appendix 5.1 and total space in Table 4.1.

FIGURE 5.5

**Monthly gas supply as percentage of average for 2002/03**




*Source:* Centrica and Transco as recorded by Centrica.

TABLE 5.7 **Estimates of flexibility from beach swing**

*GWh/d*

| | *Centrica* | | *Great Britain* |
|---|---|---|---|
| | *Morecambe* | *Total* | *Total** |
| *Average supply per day* | | | |
| Apr 02 | | | 3,272 |
| May 02 | | | 2,917 |
| Jun 02 | | | 2,592 |
| Jul 02 | | | 2,124 |
| Aug 02 | | | 2,216 |
| Sep 02 | | | 2,506 |
| Oct 02 | | | 3,201 |
| Nov 02 | | | 3,494 |
| Dec 02 | *Figures omitted. See note on page iv.* | | 3,689 |
| Jan 03 | | | 3,737 |
| Feb 03 | | | 3,872 |
| Mar 03 | | | 3,667 |
| December 02–March 03 | | | 3,738 |
| April 02–March 03 | | | 3,102 |
| *Estimated flexibility for December 02–March 03* | | | |
| Per day† | | | 636 |
| Total for 121 days‡ | | | 76,900 |

*Source:* Centrica and Transco figures recorded by Centrica.

*Great Britain total includes Norwegian imports via Vesterled pipeline but excludes imports via Bacton interconnector and also excludes deliveries direct to UK end-users which do not enter the NTS.

†Difference between average production for December–March and that for whole year (April–March).

‡Flexibility per day multiplied by 121.

5.33. Although beach swing is a source of flexibility impacting on prices in the traded markets, it is not sold in a similar way to storage, ie as a product giving contractual rights to flexibility over a year. Gas contract prices reflect the extent of flexibility in the contract and the value of that flexibility at the time the contract was agreed, but there is no ongoing price for beach swing other than the summer/winter differential from traded markets.

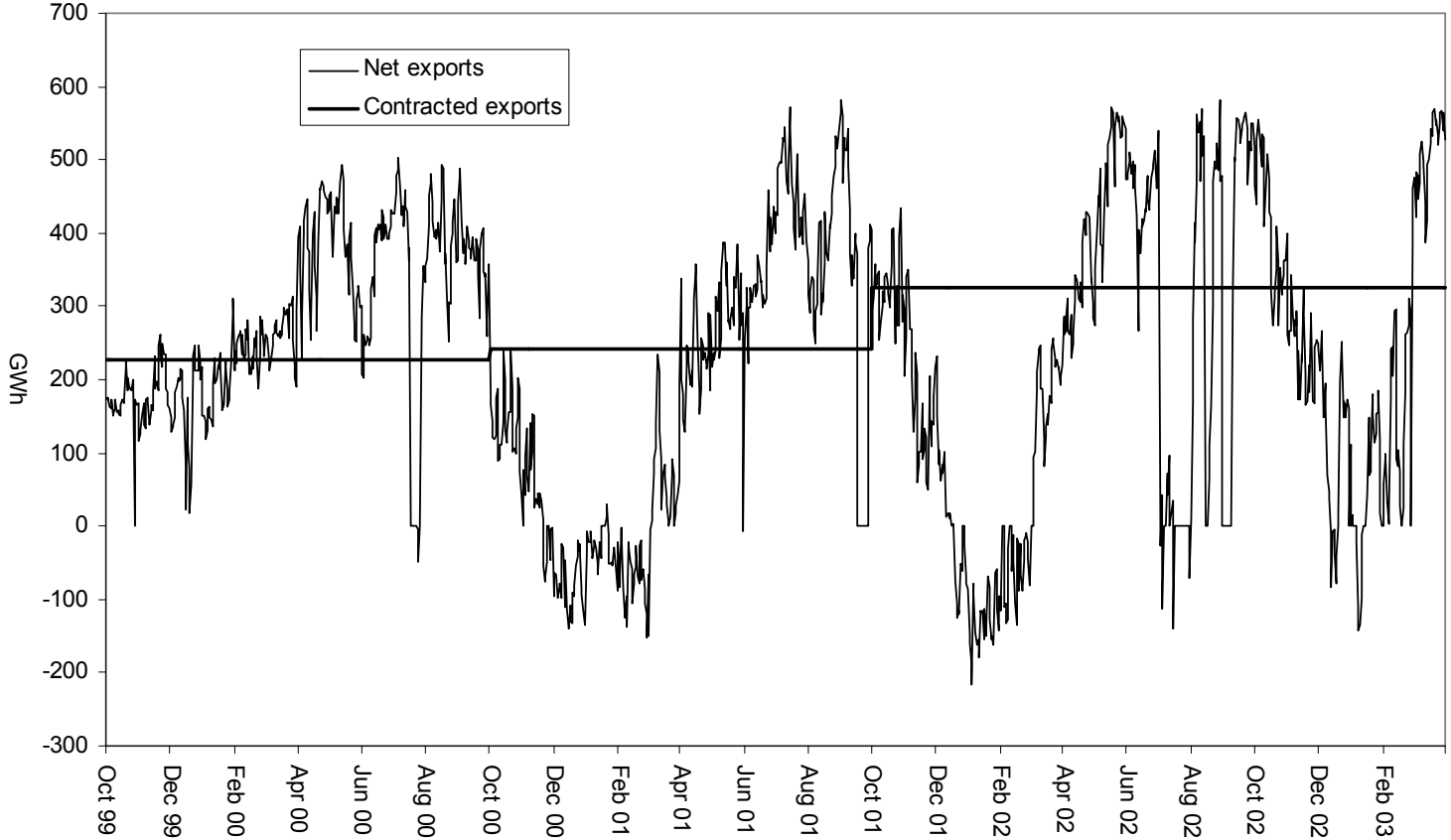
## *The Bacton interconnector*

5.34. As discussed in Chapter 4, the interconnector is an important additional source of flexibility to the UK market. The interconnector is used to arbitrage prices between the NBP and the Zeebrugge spot markets. When NBP prices are lower, gas is exported from the UK to the mainland of Europe and when NBP prices are higher gas is imported into the UK. Figure 5.6 shows that actual net exports through the interconnector have been much higher in summer than winter; if contracted exports are stripped out to reveal spot sales, the flow of spot gas is from UK to mainland Europe in summer and vice versa in winter. Thus, in practice the interconnector has been a source of summer/winter flexibility as well as flexibility to deal with production outages or particularly cold weather in the UK (where it leads to a particularly high level of gas demand in the UK but not on the mainland of Europe). This pattern of interconnector use reflects lower seasonal variation in mainland European wholesale gas prices than UK traded market prices, which typically makes spot exports profitable in summer and spot imports profitable in winter. A study by Global Insight[1] suggests that a principal reason for this is a surplus of storage capacity in France, Germany, Italy and the Netherlands. Although the tariffs charged for third-party access to this excess storage capacity are not necessarily lower than the price of storage in the UK, it appears that the owners of the gas in storage find it profitable to withdraw the gas and sell it on the spot market rather than keep it in storage. This may be because they have relatively onerous take-or-pay commitments regarding the purchase of gas. Those with the rights to Bacton interconnector capacity and storage capacity on the mainland of Europe do not offer to UK shippers a product similar to that offered by Rough—ie one giving rights to storage space, injection and withdrawal—even though such a product would seem to be theoretically possible.

[1] *2002 European Gas Storage Report*, Global Insight (previously trading as DRI-WEFA).

FIGURE 5.6

**Net interconnector flows, October 1999 to March 2003**




*Source:* Net exports: IUK as recorded by Centrica.
Contracted exports: The Energy Contract Company.

5.35. Limitations to the use of the interconnector as a source of flexibility include the fact that one day's notice is generally needed to reverse the flow from exporting to importing mode (although flexibility can be provided more rapidly when changes in flow direction are not required—see paragraph 4.87) and that there must be supply of/demand for the gas on the mainland of Europe. As illustrated in Figure 5.2, flows through the interconnector do not necessarily prevent NBP prices from increasing above Belgian contract prices for short periods. There were 121 days between August 1998 and March 2003 when the NBP price was more than 0.085p per kWh (2.5p per therm) above the Belgian contract price. Although the rules of the interconnector have been changed to make it easier to reverse flow, such periods have continued. As illustrated in Figure 5.7, between 7 and 13 December 2002, the NBP day-ahead price exceeded the Belgian contract price by more than 0.085p per kWh (2.5p per therm) on each day, with the NBP price peaking at 1.1p per kWh (32.5p per therm) on 11 December. The interconnector went from exports of 150 GWh on 6 December to imports of 84 GWh on 13 December (still well below its maximum import capacity of 271 GWh), a total increase in flow of 234 GWh over seven days. By comparison, Rough flows increased from 68 GWh on 6 December to 450 GWh (close to maximum) on 10 December, an increase of 382 GWh over four days, and increased by 225 GWh on a single day (8 December). A further period of high Great Britain prices occurred between 6 and 9 January 2003 when interconnector net imports went from zero on 5 January to 140 GWh on 8 January, still well below its maximum; Rough was at maximum throughout. The limited response of the interconnector suggests that large amounts of gas are not necessarily available at very short notice on the mainland of Europe for export to the UK (one reason for this is that short-term demand changes on either side of the Channel are likely to be weather-related and hence correlated).

5.36. There are currently 17 shippers that have contracts with IUK, including Centrica which has [✂] per cent of long-term capacity in the interconnector. There is a secondary market in interconnector capacity: prices are not transparent but Centrica told us of [✂] purchases of capacity it had made on the secondary market between October 2001 and February 2003. Prices averaged about [✂]p per kWh per day of capacity (both import and export), and the highest price Centrica paid for import capacity was [✂]p per kWh a day. The implied price for 67 days of flow is only [✂]p per kWh, which compares to 15p to 25p for the Rough bundled unit (which also gives 67 days of flow) in the last two years (see Table 5.6). Thus, interconnector capacity on its own appears relatively cheap. One possible explanation for this is that, whilst it may be valuable when combined with access to winter gas on the mainland of Europe (since the combination of the two is a substitute for Rough), the bulk of this value lies in the access to winter gas on the mainland of Europe rather than in access to the interconnector itself.

### *Demand-side substitution*

5.37. In principle, gas users might respond to changes in spot prices by altering their level of use, just as producers and importers respond by changing their supplies. In practice, contract prices do not tend to vary with daily changes in spot prices and thus most users do not have the incentive to vary their use in response to daily fluctuations in market prices. Flexibility is, however, provided in the following ways:

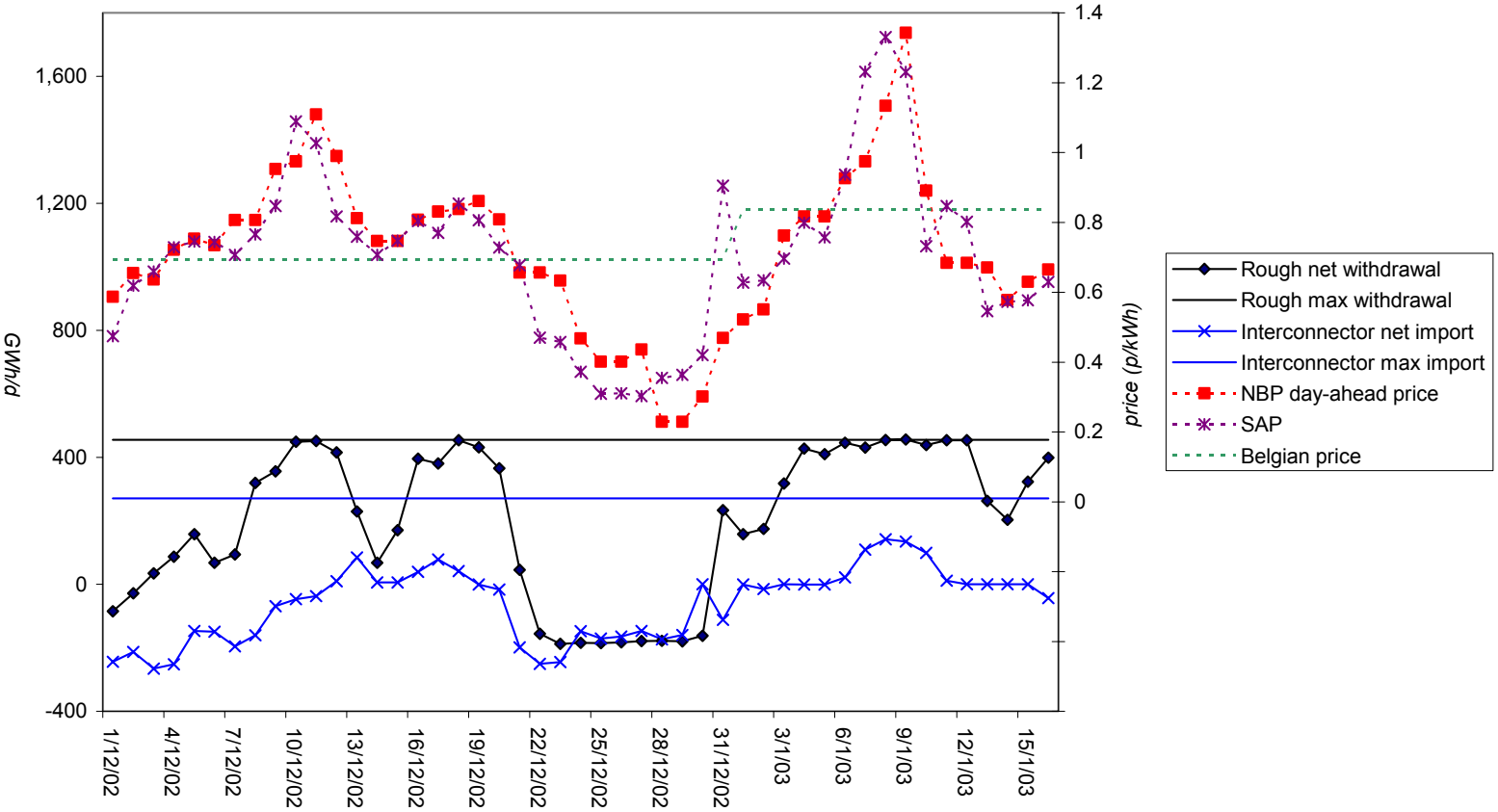
*(a)* Power generation and I&C users may have contracts allowing for interruption by Transco.

*(b)* Such contracts may also provide for interruption by the supplier which can then use the gas to supply its other customers on firm (non-interruptible) contracts or sell it on the spot market. It should be noted, however, that users with such contracts which are connected directly to the NTS have the ability to purchase gas on the spot markets and thus undo the effects of interruption on the market as a whole. (Centrica told us that all its LTI customers were able to purchase gas on the spot market and it estimated that they did so around 65 per cent of the time they were interrupted.)

*(c)* Some users, mainly operators of large power generation sites, have the ability to sell contracted gas on to the spot market (or use it to supply their domestic or I&C gas customers), rather than burning it, as long as they have not been interrupted by Transco. This may be profitable if the cost of generating from gas is higher than from alternative fuels or if the price of electricity is so low that generating from gas is unprofitable. This is sometimes described as self-interruption, which is considered further in Appendix 5.3.

FIGURE 5.7

**Net gas flows from 1 December 2002 to 16 January 2003**




*Note:* The upper three lines on the chart are price series in p per kWh (right-hand scale). The lower lines show Rough and interconnector flows and capacities in GWh per day (left-hand scale).

*Source:* Transco and IUK as recorded by Centrica.

5.38. As described in Chapter 4, interruptible contracts may provide for interruption by Transco and/or by the supplier. In recent years, Transco has required relatively few interruptions (due to warmer than average winters). With the exception of Centrica's LTI contracts, there now appear to be relatively few contracts giving suppliers, as well as Transco, the right to interrupt: Centrica has a few such contracts as do some other suppliers but they now appear to account for a small part of the market. This may reflect the logistical and/or environmental difficulties customers now face when required by interruption to stop production or shift to alternative fuels: unlike Transco, suppliers would be likely to interrupt relatively frequently to justify the discounts offered.

5.39. Interruptible contracts are priced at a discount to equivalent firm contracts. This discount depends on the number of days that the user may be interrupted. The discount per kWh will also depend on the user's ratio of maximum consumption to average consumption (at times of interruption, users are likely to be consuming at the maximum, so interruption rights are more valuable the higher is this ratio). The discount for interruption offered by Transco is currently an administered price reflecting the average cost of exit capacity from the NTS and suppliers tend to pass this discount on to their customers (it might be profitable for suppliers to offer a larger discount to reflect the fact that prices on days when Transco interrupts are likely to be high and probably above the contract price charged to the customer). The discount for supplier interruption is set in the competitive market but, as noted above, there are now relatively few contracts which provide for supplier interruption. Table 5.8 shows the discounts offered by Centrica to an average large I&C customer. The fourth column shows the extent to which prices fall as the length of interruption increases: this appears to be roughly constant as the price reduction offered per day of supplier interruption is similar to that offered for Transco interruption. The fifth column shows the price of flexibility on a similar basis to the price of a Rough bundled unit (pence per kWh of peak flexibility): on this basis Transco-only interruption gives 45 days of flexibility at a price of [✂]p per kWh and Transco plus 45 days interruption gives 90 days of flexibility at a price of [✂]p per kWh. Transco plus 25 days gives 70 days of flexibility, similar to Rough, at a price of [✂]p per kWh, which is only slightly lower than that of Rough. In order to make such discounts profitable, suppliers would need to use their interruption rights actively. As noted above, this is unlikely to be attractive to customers and consequently there are relatively few customers on supplier-interruptible contracts.

TABLE 5.8 **Typical prices for interruptible contracts**

*pence*

| *Type of interruption* | *Maximum days of interruption* | *Contract price per kWh of annual supply* | *Difference from firm supply per kWh of annual supply* | *Implied price of flexibility per kWh per day of peak flexibility* |
|---|---|---|---|---|
| None (firm supply) | 0 | *Figures omitted. See note on page iv.* | | |
| Transco only | 45 | | | |
| Transco + 10 days | 55 | | | |
| Transco + 15 days | 60 | | | |
| Transco + 25 days | 70 | | | |
| Transco + 45 days | 90 | | | |

*Source:* Centrica (typical offer to large customer with 182 per cent swing).

*Note:* [

*Details omitted. See note on page iv.*

]

## Definition of the flexibility market

5.40. There are two aspects to market definition: product market definition and geographic market definition.

5.41. The usual approach to product market definition is to start by considering each product (narrowly defined) that is produced or sold by each of the merging firms. The product is considered to

be a market if a hypothetical monopolist in that product could profitably impose a small but significant non-transitory increase in price (SSNIP), usually of the order of 5 per cent. If the price increase would lead consumers or suppliers to substitute other products for it, the product market is expanded to include those other products. The procedure is repeated until a hypothetical monopolist could profitably impose an SSNIP.

5.42. A suitable starting point for applying the hypothetical monopolist test could be the storage products sold by Rough. Attempting to apply the test raises a number of issues:

*(a)* Rough has hitherto marketed a number of interrelated products, including bundled units for the year ahead, bundled units providing rights for longer periods, interruptible services and incremental space. In future, it may also be expected to market similar products and potentially others as well, such as disaggregated units of deliverability.

*(b)* For the past two years, the operator of Rough has been required to auction any capacity still uncontracted 30 days before the beginning of the storage year, so customers may anticipate that the result of a price increase is to leave unused storage units which might be purchased at the auction. Consequently their response to a price increase may be to delay purchases of Rough capacity rather than purchase substitute sources of flexibility.

*(c)* Some of the other sources of flexibility, principally other storage facilities, are similarly sold as products but this is not currently the case for all the substitutes. As discussed above, beach swing and interconnector flexibility (which involves the right to use the interconnector and storage on the mainland of Europe) are not sold as products and there does not currently appear to be an identifiable equivalent price for these services.

*(d)* On the other hand, there exist forward markets for NBP gas and transactions in these markets can be a substitute for Rough and other physical sources of flexibility: shippers (including producers, traders and suppliers) may use transactions in these markets as a substitute for Rough or may offer a 'virtual storage' product. However, forward market prices are themselves influenced by the expected available capacity of Rough and other sources of flexibility, whilst the price of Rough and other sources of flexibility will be influenced by forward market prices. The nature of the impact is likely to depend on the type of flexibility. In the case of Rough, evidence (see paragraph 5.27) suggests that its price is related to the summer/Q1 differential (the difference between the forward market price for April to September and that for January to March of the following year) and its available capacity is likely to impact on the summer/winter differential. In the case of shorter duration flexibility, available capacity is more likely to impact on the highest price winter days—when the flexibility is most likely to be used—and hence the relationship is likely to be with winter volatility as much as the summer/winter differential.

5.43. In the light of these factors, we have found it difficult to carry out the hypothetical monopolist test, as was also noted by Ofgem and Centrica. In the context of this inquiry, our analysis needs to focus on the extent to which the merger leads to a reduction in competition between Rough and other sources of flexibility. Although we do not consider that all types of flexibility are equally good substitutes for one another, we have not been able to identify a robust basis for excluding any sources of flexibility from the market definition. We broadly accept Centrica's argument that all sources of flexibility contribute to some extent to the summer/Q1 spread which constrains the price of Rough.

5.44. As discussed above, the different sources of flexibility are imperfect substitutes for one another and for Rough. Hence, not all sources of flexibility are equally good substitutes for Rough. In particular, we note:

*(a)* LNG storage has been relatively little used recently, apparently being saved for the very cold days that have not been experienced in recent relatively warm winters. Additionally, LNG storage is expensive as a simple alternative to Rough, for instance as a source of summer/winter flexibility: assuming all injected gas is withdrawn in the subsequent winter, Table 5.6 suggests

that the average 2003/04 (2002/03) cost of using Rough would be 0.37p (0.27p) per kWh of space compared with 0.62p (0.62p) per kWh for LNG including transmission benefit at constrained LNG sites.[1] (The Rough price increased significantly between 2002/03 and 2003/04 whereas the LNG did not which might be an indication that the products are not in the same market.) Additionally, LNG cannot be used as flexibly as Rough (since it is not necessarily possible to inject gas in winter) and part of LNG capacity is retained by Transco for its own use. These considerations suggest that customers do not regard LNG as a close substitute for Rough and hence that competition from LNG is a relatively weak constraint on the price of Rough. Centrica argued that price comparisons of the type shown above could not be expected to be meaningful as different sources of storage bundled together different proportions of space, withdrawal and injection. We do not accept this argument: to the extent that different types of storage are used in totally dissimilar ways they are not likely to be close substitutes; to the extent that they are capable of being used in similar ways, it is meaningful to compare the level of prices and direction of price changes.

*(b)* Likewise, interruption of I&C customers has been relatively little used recently: Transco has required few interruptions due to the relatively warm winters while there now appear to be relatively few I&C contracts with supplier interruption. Moreover, the favourable current terms for Transco interruption (a substantial price discount for a small probability of being interrupted) make it seem unlikely that an increase in the price of Rough or the summer/Q1 spread would cause customers to purchase more Transco interruption and hence reduce demand for other types of flexibility. As with LNG storage, these considerations suggest that interruption of I&C customers is not a close substitute for Rough and hence that competition from interruption is a weak constraint on the price of Rough. Centrica suggested that the apparent high level of Transco interruptible contracts indicated that there was potential scope for more supplier interruptible contracts and that increased supplier interruptible contracts could be envisaged in future if flexibility became more valuable so that discounts offered by suppliers to customers for interruption rights increased. Hence, Centrica argued, interruptible contracts would continue to provide real constraint on Rough pricing. However, Rough's price has more than doubled since 2000/01 (see Figure 5.4) while in this period it is likely that supplier interruptible contracts have declined substantially (shipper interruptions for December 2002 to March 2003 were only 16 per cent of the level two years earlier even though Transco interruptions increased over the same period[2]). This suggests that interruption of I&C customers is not a close substitute for Rough and does not constrain Rough's prices. The discussion in this subparagraph does not necessarily apply to self-interruption by power stations or to interruption under Centrica's LTI contracts, when not offset by interrupted power stations purchasing on the spot market.

For practical purposes, we have included LNG and interruption of I&C customers in our definition of the market but recognize that they are likely to be less of a constraint on Rough prices than other sources of flexibility.

5.45. With regard to geographic market definition, we consider that the geographic market for flexibility is Great Britain. No one suggested to us that the geographic market should be defined as wider than Great Britain. Great Britain has three links to other countries: the Bacton interconnector (see paragraphs 5.34 to 5.36), the Irish interconnector and the Vesterled pipeline from St Fergus to Norway. The two interconnectors carry processed gas while the Vesterled pipeline carries unprocessed gas. As noted above, the Bacton interconnector is, in combination with surplus storage capacity on the mainland of Europe, an important source of flexibility to the British market. On the other hand, the Irish interconnector is a user of Great Britain flexibility, exports from Great Britain being higher in winter than summer. The link from St Fergus to Norway, which has capacity of about 300 GWh per day, was a major source of gas to the British market up to the late 1980s, and remains a potential avenue for future supplies of Norwegian gas. It is at present a potential source of Great Britain flexibility if surplus gas is available in the Norwegian continental shelf. Competition between suppliers of flexibility is on a Great-Britain-wide basis and consequently there appears no need to consider local markets (for example, for entry capacity on to the NTS).

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[1]These figures are based on the estimated price per kWh of space plus the commodity charges from Table 5.6.
[2]Source: Transco.

## Market shares

5.46. Market shares may be measured in monetary terms (based on each firm's revenue) or in physical terms (based on each firm's production volume or capacity). Unfortunately, it is difficult to measure the flexibility market in monetary terms due to the absence of data on the price, and hence revenue, attributable to beach swing and the Bacton interconnector. We have therefore concentrated on physical measures. We have looked at market size and shares both on the basis of maximum flexible capacity and actual use of flexibility in recent years.

5.47. Table 5.9 shows estimates of market size and Centrica's market share based on two measures of flexible capacity for the most recent winter:

*(a)* Based on the maximum that can be made available within a single day: in the case of the storage sites, this is the daily deliverability and in the case of beach swing and the interconnector it is the maximum amount that can be supplied during a single day less the average daily supply for the year (this is consistent with the storage measure since the average net supply during the year from each storage site is approximately zero—deliveries less injections).

*(b)* Based on the maximum that can be made available during the main winter months (December to March, 121 days): in the case of the storage sites, given that none has a duration of more than 121 days, this is the storage volume; in the case of beach swing and the interconnector, this is the maximum daily flexibility for 121 days.

5.48. We have assessed Centrica's pre-merger market share on the basis of its long-term position, ie including its equity and contractual share of beach swing, its long-term rights to use of the interconnector and its share of interruptible capacity from its LTI contracts (which are long term in nature). We have not included Centrica's shorter-term sources of flexibility since these would not necessarily add to its market power. Moreover, as far as Centrica's booked capacity at Rough (pre-merger), Hornsea and the LNG sites is concerned, Centrica's position at Hornsea and LNG is that of customer and this was also its pre-merger position at Rough.

5.49. As Centrica has different shares of the different types of flexibility, its share of total maximum capacity depends on whether daily or December to March maximum capacity is used. Shares of daily capacity relate only to requirements for the expected coldest day (which determines the amount of daily capacity) and consequently are influenced more by LNG, which does not appear to be a close substitute for Rough (see paragraph 5.44*(a)*). Moreover, as illustrated in Figure 5.4, the bulk of Rough's value is accounted for by the summer/Q1 spread. It may therefore be appropriate to put more weight on the December to March period. Table 5.9 shows that Centrica's pre-merger share of December to March maximum flexible capacity is 34 per cent and increases to 46 per cent as a result of the merger. On the basis of maximum daily flexibility, Centrica's pre-merger share is 24 per cent rising to 34 per cent after the merger.

5.50. If LNG storage is excluded from the market on the grounds that it is a weak constraint for Rough, Centrica's pre-merger share of December to March flexible capacity would be 35 per cent, increasing to 47 per cent post-merger, and its share of daily flexible capacity would be 29 per cent, increasing to 42 per cent post-merger. If interruption is also excluded on similar grounds, Centrica's pre-merger share of December to March flexible capacity would be 38 per cent, increasing to 53 per cent post-merger, and its share of daily flexible capacity would be 33 per cent, increasing to 52 per cent post-merger.

TABLE 5.9 **Market for flexibility: maximum flexible capacity, winter 2002/03**

| | *Maximum daily flexibility** | | *Maximum Dec–Mar flexibility†* | |
|---|---|---|---|---|
| | *GWh* | *Share %* | *GWh* | *Share %* |
| ***Market size*** | | | | |
| *Storage* | | | | |
| Rough | 455 | 10.4 | 30,344 | 12.1 |
| Hornsea/MRS‡ | 284 | 6.5 | 5,055 | 2.0 |
| LNG§ | 813 | 18.6 | 3,846 | 1.5 |
| *Supply* | | | | |
| Beach | 1,145 | 26.2 | 117,645 | 47.1 |
| Interconnector | 560 | 12.8 | 48,754 | 19.5 |
| *Demand* | | | | |
| Interruption¶ | 1,120 | 25.6 | 44,305 | 17.7 |
| Total | 4,376 | 100.0 | 249,948 | 100.0 |
| ***Centrica (pre-merger)*** ¤ | | | | |
| *Storage* | | | | |
| Rough | *Figures omitted. See note on page iv.* | | *Figures omitted. See note on page iv.* | |
| Hornsea/MRS | | | | |
| LNG | | | | |
| *Supply* | | | | |
| Beach | | | | |
| Interconnector# | | | | |
| *Demand* | | | | |
| Interruption | | | | |
| Total (pre-merger) | 1,040 | 23.8 | 85,483 | 34.2 |
| Total (including Rough) | 1,495 | 34.2 | 115,827 | 46.3 |

*Sources:* Centrica, Ofgem and Transco (data supplied by Centrica).

*Daily flexibility is defined as the difference between maximum daily capacity and daily average of net supplies in a full year. For storage, average net supply is zero (since, over the longer term, withdrawals are equal to injections). For beach and interconnector, average net supply has been based on net supply in the year to 31 March 2003 (see Appendix 5.2). For interruption, net supply has been taken to be the amount interrupted: in calculating maximum daily capacity, average net supply assumes one day's interruption, hence flexibility is interruptible capacity less potential average daily interruption if maximum use were made of the rights to interrupt (interruptible capacity divided by 365).

†Dec–Mar flexibility is defined as the difference between maximum capacity for the Dec–Mar period and average 121-day net supply over a full year (daily average times 121 days, the length of the Dec–Mar period). Maximum storage capacity is based on total space (in all cases duration is less than 121 days) and average net supplies are zero. In calculating maximum Dec–Mar flexibility, beach and interconnector are assumed to operate at maximum for the full 121 days of the Dec–Mar period (except for Sean which is assumed to produce at maximum for 100 days). Interruptible capacity assumes 45 days' interruption. Average net supply for beach, interconnector and interruption is adjusted for effect of maximum rather than actual use over Dec–Mar (hence ratio of Dec–Mar to daily flexibility is less than 121).

‡Medium-range storage: Hornsea, Hatfield Moor and Hole House. Maximum daily flexibility is based on figure in Transco ten-year statement 2002 and differs slightly from that in Table 4.1.

§Includes capacity retained by Transco for its own use. Maximum daily flexibility is based on figure in Transco ten-year statement 2002 and differs slightly from that in Table 4.1.

¶Excludes self-interruption.

¤Excludes Centrica's pre-merger bookings at Rough, Hornsea and LNG and its short-term interruptible contracts.

#Assumes Centrica has [✂] per cent of interconnector capacity.

5.51. Table 5.10 shows estimates of the use of flexibility in the last three years. On this basis, Centrica's share of flexibility was around 60 per cent in the last two years if the whole of Rough is attributed to Centrica. There has been some fluctuation in the use of different types of flexibility. In particular, use of Rough and Hornsea was lower in the exceptionally warm winter of 2001/02 and apparent flexible use of the interconnector was lower (and beach swing higher) in 2002/03 than in the two previous years. Reasons for the lesser flexible use of the interconnector in winter 2002/03 (compared with average use in the year to 31 March 2003) may include greater self-interruption (see Appendix 5.3) and the high level of gas prices on mainland Europe early in 2003 which made exporting through the interconnector more attractive. Higher net exports (in December to March 2002/03 than 2001/02) through the Bacton interconnector occurred despite higher demand in Great Britain and were possible because beach supplies were about 30 TWh higher (see Appendix 5.2). Centrica estimated that increased imports via the Vesterled pipeline (which we have treated as beach supplies) accounted for just over one-quarter of this increase, with the remainder accounted for by increased UKCS beach supplies.

TABLE 5.10 **Market for flexibility: use of different types of flexibility**

| | *Year to March 2001 GWh* | *Share %* | *Year to March 2002 GWh* | *Share %* | *Year to March 2003 GWh* | *Share %* |
|---|---|---|---|---|---|---|
| ***Market size*** | | | | | | |
| *Storage* | | | | | | |
| Rough | 24,990 | 19.6 | 20,693 | 18.3 | 25,998 | 22.0 |
| Hornsea/MRS | 2,485 | 1.9 | 1,877 | 1.7 | 3,003 | 2.5 |
| LNG | 501 | 0.4 | 512 | 0.5 | 1,109 | 0.9 |
| *Supply* | | | | | | |
| Beach* | 69,883 | 54.8 | 64,108 | 56.6 | 76,900 | 65.0 |
| Interconnector | 26,217 | 20.5 | 25,516 | 22.5 | 10,532 | 8.9 |
| *Demand* | | | | | | |
| Interruption | 3,531 | 2.8 | 573 | 0.5 | 1,071 | 0.6 |
| Total | 127,607 | 100.0 | 113,279 | 100.0 | 118,259 | 100.0 |
| ***Centrica (pre-merger)***† | | | | | | |
| *Storage* | | | | | | |
| Rough | | | | | | |
| Hornsea/MRS | | | | | | |
| LNG | | | *Figures omitted. See note on page iv.* | | | |
| *Supply* | | | | | | |
| Beach‡ | | | | | | |
| Interconnector§ | | | | | | |
| *Demand* | | | | | | |
| Interruption¶ | Not available | | | | | |
| Total (pre-merger) | 65,402 | 51.3 | 46,171 | 40.8 | 47,717 | 40.3 |
| Total (including Rough) | 90,392 | 70.8 | 66,864 | 59.0 | 73,715 | 62.3 |

*Sources:* Centrica, Transco. Figures may differ slightly from those in Appendix 5.2 due to inclusion here of some additional minor supply points.

*Includes imports from Norway via Vesterled pipeline.
†Excludes Centrica's pre-merger bookings at Rough, Hornsea and LNG and its short-term interruptible contracts.
‡Centrica's long-term physical supplies.
§Centrica's actual flows through the interconnector.
¶Interruption data for Centrica not available on comparable basis to that for total market. It is likely that Centrica's LTI contracts account for the bulk of interruption in the last two years and hence that, if these were included, Centrica's market share would be about 0.5 per cent higher in 2001/02 and 2002/03.
*Note:* Flexibility is measured as difference between actual supply for December to March period and average for 12 months to end of March (average daily net supply times 121—see Table 5.7 and Appendix 5.2).

5.52. There are both advantages and disadvantages to basing market share on actual use rather than maximum capacity:

*(a)* An advantage is that use reflects market decisions and excludes capacity for which customers are unwilling to pay. Transco's ten-year statement shows that existing capacity, including the interconnector, exceeds expected demand on a 1-in-20-year coldest day (see Appendix 5.4).

*(b)* A disadvantage is that use reflects weather conditions in that particular year and does not include capacity that customers are willing to pay for and have purchased to meet expected demand in colder weather. Typically, customers purchase a portfolio of sources of flexibility and would not expect to use everything they had purchased in a normal winter.

5.53. Centrica's market shares in Tables 5.9 and 5.10 are calculated on the basis of its ownership of, or long-term contractual right to use, flexibility sources. Centrica pointed out that it did not necessarily have the right to withhold from the market all the flexibility sources included in its market share. In particular, it could not withhold beach swing on supplier, rather than depletion, contracts nor its share of the interconnector which is subject to 'use-it-or-lose-it' provisions. If these sources were excluded, Centrica's pre-merger share of December to March flexible capacity would be 24 per cent, increasing to 36 per cent post-merger, and its share of daily flexible capacity would be 17 per cent, increasing to 27 per cent post-merger.

5.54. The market shares in Tables 5.9 and 5.10 do not include self-interruption by large users. This is inherently difficult to measure since self-interruption represents the difference between the amount of gas used under one set of circumstances (for example, that with low gas prices) and that used in another set (with higher gas prices). Appendix 5.3 provides some analysis of self-interruption and suggests that allowing for it would cause a modest reduction in Centrica's market share of flexibility by use.

5.55. Beach swing currently accounts for more than half of the actual use of flexibility and Centrica's share of beach swing is currently around [✂] per cent. The extent to which Centrica has any current and future market power may, however, be affected by the following points:

*(a)* Centrica's high share of beach swing reflects the low production of its owned or contracted fields outside the winter period. Centrica's overall share of gas production is about 36 per cent and Centrica told us that its share of gas from dry gas fields (those which in most cases are potentially flexible) is about 41 per cent. Thus its high share of swing partly reflects its decisions or contractual arrangements to produce relatively less gas outside the winter period than other producers.

*(b)* As shown in Table 5.11, total beach swing is projected to decline after 2004/05 while that owned by or currently contracted to Centrica is already declining. Even if Centrica's share of beach swing remains high, these projections imply that its currently contracted share of total flexibility will decline. (Although these projections only reflect Centrica's current contracts, it is these that are relevant to a merger assessment since Centrica only benefits from exploiting its post-merger position to the extent that it owns or has already contracted for flexibility.)

*(c)* As noted in paragraph 5.8, an increasing proportion of Centrica's contracts for beach supply is indexed to gas market prices. In as far as Centrica's market share is attributable to these contracts, Centrica would not necessarily have the incentive to increase prices and would not have market power. Centrica's incentives are considered further below (paragraphs 5.69 to 5.81).

TABLE 5.11 **Projected beach swing to 2011/12**

*GWh/day*

| | *UK total* | | | *Centrica* | | | |
|---|---|---|---|---|---|---|---|
| | *Peak* | *Average* | *Swing* | *Peak* | *Average* | *Swing* | *Centrica swing as per cent of total* |
| 2001/02 | 4,380 | 3,145 | 1,235 | | | | |
| 2002/03 | 4,226 | 3,077 | 1,149 | | | | |
| 2003/04 | 4,297 | 2,992 | 1,305 | | | | |
| 2004/05 | 4,262 | 2,942 | 1,320 | | | | |
| 2005/06 | 3,983 | 2,940 | 1,043 | | | | |
| 2006/07 | 3,951 | 3,022 | 929 | *Figures omitted. See note on page iv.* | | | |
| 2007/08 | 3,913 | 3,101 | 812 | | | | |
| 2008/09 | 3,904 | 3,145 | 759 | | | | |
| 2009/10 | 4,014 | 3,186 | 828 | | | | |
| 2010/11 | 4,027 | 3,214 | 813 | | | | |
| 2011/12 | 3,846 | 3,244 | 602 | | | | |

*Source:* Transco, Centrica.

*Note:* Projections include Norwegian imports to St Fergus or through new pipelines to Bacton/Easington but exclude imports through the Bacton interconnector and through any LNG import facilities. Centrica figures include Gasunie contract.

5.56. Table 5.12 illustrates the implications of the projections in Table 5.11 for Centrica's share of maximum daily capacity. Table 5.12 is based on Transco's projections in its ten-year statement and has not been extended to December–March maximum capacity which is not projected by Transco, but the proportionate decline in Centrica's share of December–March maximum capacity would be similar. As well as the decline in Centrica's beach swing, Table 5.12 reflects also that Centrica's currently contracted share of the interconnector declines.

TABLE 5.12 **Projected maximum winter flexible capacity**

*GWh*

| | *Maximum daily flexibility* including LNG* | | | *Maximum daily flexibility* excluding LNG and interruption* | | |
|---|---|---|---|---|---|---|
| | *2002/03* | *2006/07* | *2010/11* | *2002/03* | *2006/07* | *2010/11* |
| ***Market size*** | | | | | | |
| *Storage* | | | | | | |
| Rough | 455 | 455 | 455 | 455 | 455 | 455 |
| Hornsea/MRS† | 284 | 284 | 284 | 284 | 284 | 284 |
| New MRS | | 378 | 526 | | 378 | 526 |
| LNG | 812 | 813 | 813 | | | |
| *Supply* | | | | | | |
| Beach | 1,145 | 929 | 813 | 1,145 | 929 | 813 |
| Interconnector & LNG imports | 560 | 387 | 387 | 560 | 387 | 387 |
| *Demand* | | | | | | |
| Interruption‡ | 1,120 | 1,120 | 1,120 | | | |
| Total | 4,376 | 4,366 | 4,398 | 2,443 | 2,443 | 2,443 |
| ***Centrica existing contractual position (pre-merger)***§ | | | | | | |
| *Storage* | | | | | | |
| Rough | | | | | | |
| Hornsea/MRS | | | | | | |
| New MRS | | | | | | |
| LNG | | | | | | |
| *Supply* | *Figures omitted. See note on page iv.* | | | *Figures omitted. See note on page iv.* | | |
| Beach | | | | | | |
| Interconnector¶ | | | | | | |
| *Demand* | | | | | | |
| Interruption | | | | | | |
| Total (pre-merger) | 1,040 | 819 | 419 | 803 | 582 | 345 |
| % (pre-merger) | 23.8 | 18.8 | 9.5 | 32.8 | 23.9 | 14.0 |
| Total (including Rough) | 1,495 | 1,274 | 874 | 1,258 | 1,037 | 800 |
| % (post-merger) | 34.2 | 29.2 | 19.9 | 51.5 | 42.6 | 32.5 |

*Source:* Centrica, Transco ten-year statement.

*Daily flexibility is defined as the difference between maximum daily capacity and daily average of net supplies in a full year. For storage, average net supply is zero (since, over the longer term, withdrawals are equal to injections). For beach and interconnector, average net supply has been based on net supply in the year to 31 March 2003 (see Appendix 5.2). For interruption, net supply has been taken to be the amount interrupted: in calculating maximum daily capacity, average net supply assumes one day's interruption, hence flexibility is interruptible capacity less potential average daily interruption if maximum use were made of the rights to interrupt (interruptible capacity divided by 365).

†Medium-range storage: Hornsea, Hatfield Moor and Hole House. Maximum daily flexibility is based on figure in Transco ten-year statement 2002 and differs slightly from that in Table 4.1.

‡Excludes self-interruption.

§Excludes Centrica's pre-merger bookings at Rough, Hornsea and LNG and its short-term interruptible contracts.

¶Assumes Centrica has [✂] per cent of interconnector capacity.

*Note:* Interruptible peak capacity is not projected by Transco and in this table has been assumed constant at the same level shown in Table 5.9.

5.57. Transco's projections in its ten-year statement (see Appendix 5.4) assume new non-beach capacity comes from new mid range storage facilities (for example, salt cavities) and LNG import facilities. Transco's projections cover peak demand and capacity for a 1-in-20-year coldest day, which is relevant to planning its transmission and distribution system. Transco projects a small shortfall of capacity relative to peak demand in 2010/11 (see Appendix 5.4), but a shortfall of longer duration flexibility may emerge at an earlier date if new capacity is mainly MRS. An alternative or possibly additional source of additional capacity is a new interconnector with the Netherlands (through which, for example, Centrica expects to import gas under its contract with Gasunie). This might provide longer-duration flexibility, as use of a Netherlands interconnector might be combined with use of excess flexibility in the Netherlands.

## Entry barriers and prospects for new entry

5.58. As noted above, new peak capacity may come from increases to the import capacity of the Bacton interconnector, new LNG import capacity, new MRS facilities (for example, salt cavities) and new links connecting Great Britain with Norway and the Netherlands. The balance of evidence suggests that LNG import capacity and any new pipeline from Norway would not be a source of flexible capacity as they would be likely to be used throughout the year (although if under-used initially they might be a temporary source of flexible capacity). Increases in Bacton interconnector capacity, new MRS capacity and any new interconnector with the Netherlands are more likely to be a source of flexible capacity.

5.59. All of these are major projects involving long lead times and in most cases require large capital expenditure and planning permission. Such projects are being pursued in the light of projected reductions in gas supply, and particularly flexible gas supply, from the UKCS. This type of entry is not likely to emerge simply as a response to price increases by existing suppliers of flexibility to the UK market. An additional factor potentially deterring entry is that new projects may involve a significant increment to the supply of flexibility and hence lead to a fall in price.

## Use of different sources of flexibility

5.60. In general, the pattern of use of different types of flexibility reflects their operational characteristics, including duration and, in the case of storage facilities, the commodity charges for injecting and withdrawing gas and also the rate at which gas can be cycled (ratio of injection to withdrawal capability).

5.61. As illustrated in Figure 4.3 and reflected in Tables 5.9 and 5.10, most summer/winter flexibility is provided by beach swing, Rough and the interconnector. Hornsea and especially LNG and interruption tend to be used only on the days with the highest demand (which also tend to be the days with the highest prices).

5.62. Not all sources of flexibility in practice respond similarly to day-to-day variations in price. Based on an analysis of daily data, Table 5.13 shows the correlation between the change in supply and the change in price. The table suggests that supply from Rough and Hornsea is more responsive to price changes than are supplies from beach terminals and the interconnector. As regards beach entry points, the table suggests that supply from Barrow (which comes from Centrica's Morecambe fields), and to a lesser extent Bacton, is more responsive to price changes than supplies from the other beach entry points.

TABLE 5.13 **Correlation* between change in daily supply and system average price (SAP)**

| | *Nominated supply†* | | *Actual net supply‡* | |
|---|---|---|---|---|
| | *2000/01* | *2001/02* | *2000/01* | *2001/02* |
| Rough | 0.2634 | 0.3018 | 0.3088 | 0.3480 |
| Hornsea | 0.2948 | 0.3249 | 0.3191 | 0.3671 |
| Interconnector | 0.0016 | 0.0058 | 0.0245 | 0.0029 |
| *Beach* | | | | |
| Bacton | 0.1575 | 0.0740 | | |
| Barrow | 0.1536 | 0.2322 | | |
| Easington | 0.0494 | 0.0318 | | |
| St Fergus | 0.0049 | 0.0001 | | |
| Teesside | 0.0137 | 0.0334 | | |
| Theddlethorpe | 0.0285 | 0.1056 | | |

*Source:* Ofgem and CC analysis of data provided by Centrica for gas year (to 30 September).

*Correlation is measured by $R^2$. The 1 per cent critical value for $R^2$ with 365 observations is 0.018, ie there is a less than 1 per cent chance that a value of more than 0.018 is generated by chance.

†Nominated withdrawals from storage, interconnector imports and beach supply.

‡Actual withdrawals from storage net of injections and interconnector imports net of exports. No figure for beach is shown as beach supplies flow only on to the NTS (there is no equivalent of injections and exports taking gas from the NTS).

5.63. The results in Table 5.13 may reflect the fact that gas fields tend to produce at maximum throughout winter and thus beach supplies are not very responsive to price changes. Table 5.13 suggests that Centrica's Morecambe fields may be a partial exception to this: it appears that Centrica operates these fields so that their output is more responsive to price changes than output from other fields. Table 5.13 also suggests that the interconnector is unresponsive to on-the-day price changes and this may reflect the factors discussed in paragraph 5.35, including the time taken to change flow direction, the effects of any correlation between weather-related demand changes in Great Britain and mainland Europe and that, given the illiquid nature of mainland European gas spot markets, it takes time for flows to change.

5.64. Similarly, Table 5.14 shows the correlation between the change in supply from Rough and the change in supply from other sources of flexibility. The table suggests that changes in supplies from Rough are more correlated with changes in supplies from Hornsea and Barrow (Centrica's Morecambe fields) than from the aggregate of other UK fields or the interconnector. Together with Table 5.13, this suggests that flexible use of Rough is more similar to that of Hornsea and the Morecambe fields than to that of other UK fields or the interconnector. This may suggest that Hornsea and the Morecambe Bay fields are closer substitutes for Rough.

TABLE 5.14 **Correlation* between change in Rough's daily supply and daily supply of other sources of flexibility**

| | *Nominated suppply* | | *Actual net supply* | |
|---|---|---|---|---|
| | *2000/01* | *2001/02* | *2000/01* | *2001/02* |
| Hornsea | 0.2411 | 0.3137 | 0.1581 | 0.2234 |
| Interconnector | 0.0088 | 0.0506 | 0.0540 | 0.0067 |
| Barrow | 0.0455 | 0.1750 | 0.0751 | 0.1997 |
| Other beach† | 0.0054 | 0.0002 | 0.0053 | 0.0021 |

*Source:* Ofgem and CC analysis of data provided by Centrica for the gas year (to 30 September).

*Correlation is measured by $R^2$. The 1 per cent critical value for $R^2$ with 365 observations is 0.018, ie there is a less than 1 per cent chance that a value of more than 0.018 is generated by chance.
†Bacton, Easington, St Fergus, Teesside, Theddlethorpe.

5.65. Ofgem suggested that an analysis of supply and demand shocks could provide useful information about the comparative response of different types of flexibility and hence about the extent to which different sources of flexibility were substitutes for each other. Ofgem told us that it had, through its prior knowledge, identified a number of events that might provide useful information. Ofgem thought useful conclusions could be drawn from three of these:

*(a)* a lightning strike at Easington terminal (affecting supply from Rough) in December 1999;

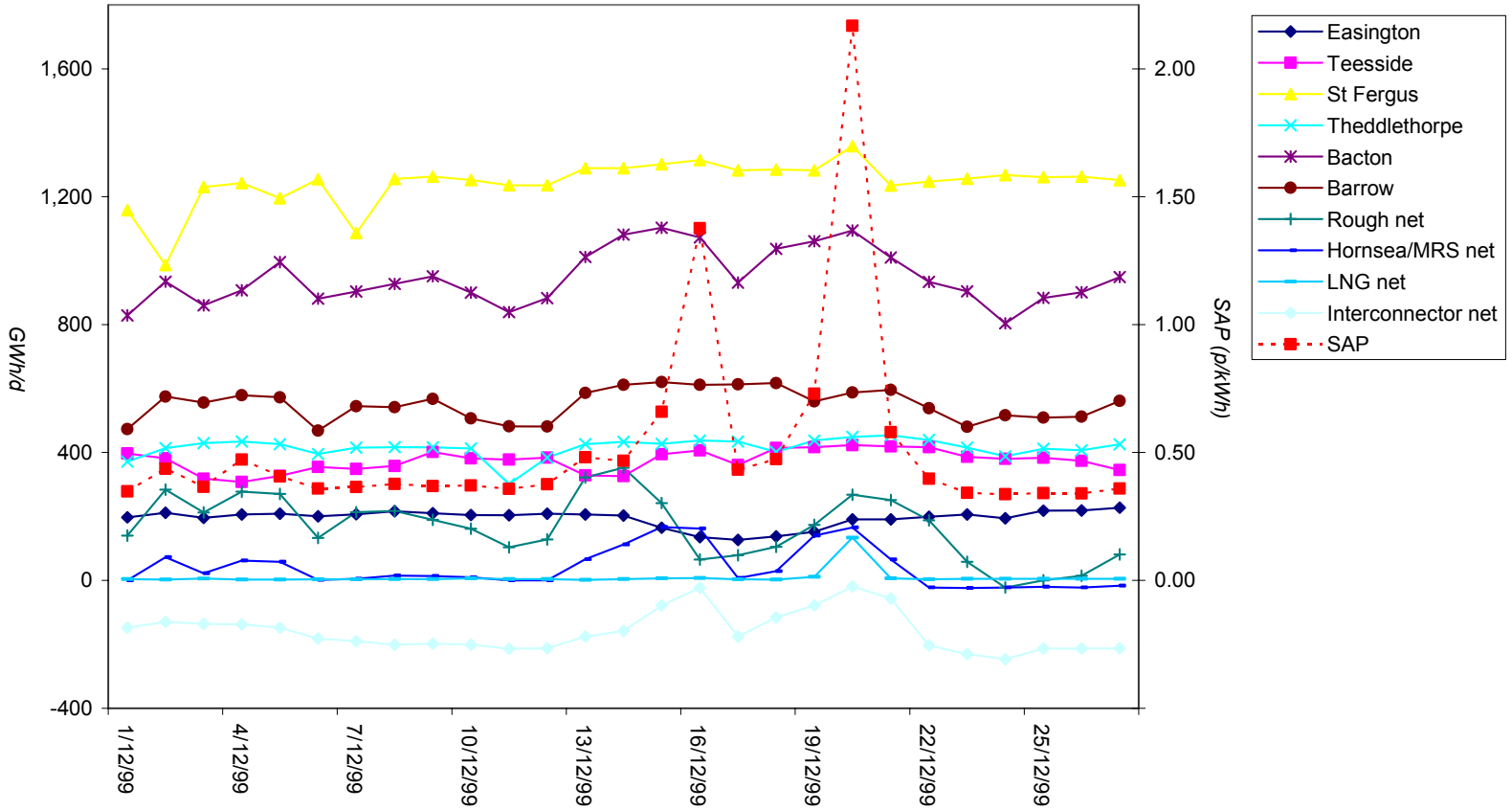
*(b)* production difficulties at the Britannia field in June 2002; and

*(c)* constrained flows from Barrow in October 2002.

5.66. Figure 5.8 shows price (SAP) and net supplies on the days before and after the lightning strike on 15 December 1999. The immediate effect was a large reduction in net withdrawals from Rough (which had been at a fairly high level) and some reduction in beach supplies from Easington. This resulted in a sharp price spike on 16 December but there was little increase in supplies from the other beach terminals (apart from a modest increase at Teesside), possibly because they were already close to capacity. Hornsea net withdrawals increased on 15 December and net interconnector exports reduced significantly on 16 December. There was a further price spike a few days later (20 December) when SAP increased to its highest ever level: this was a particularly cold day when Rough was back on stream but constrained to about 70 per cent of its withdrawal capacity. Centrica argued that the interconnector responded very sharply to the price changes but we note that, on both 16 December and 20 December, while net interconnector exports declined, the interconnector did not reverse direction to start importing. The delays involved in reversing interconnector direction may therefore have contributed to higher prices.

FIGURE 5.8

**Net gas flows during December 1999**




*Note:* SAP is shown on the right-hand scale and the other series on the left-hand scale.

*Source:* Transco and IUK as recorded by Centrica.

5.67. With regard to the other events mentioned in paragraph 5.65:

*(a)* Towards the end of the gas day on 31 May 2001, technical problems resulted in the closure of the Britannia field resulting in a significant reduction in supplies from St Fergus on 1 June. Ofgem's analysis showed that, in response, supplies from Bacton and Barrow increased and Rough net injections reduced. Centrica argued that this episode occurred in summer and was not particularly informative about substitutability between flexibility sources in winter.

*(b)* [

*Details omitted. See note on page iv.*

]

5.68. Centrica argued that analysis of these episodes was not particularly informative about the factors influencing customers' decisions at the time they were contracting for capacity in Rough. We consider, however, that analysis of the use that is made of the different types of flexibility has some value as customers' purchasing decisions are likely to be influenced by the use they expect to make of flexibility.

## Centrica's post-merger incentives

5.69. It was suggested to us that, as a result of the merger, Centrica would have the incentive to withhold some of the gas supplies under its control from the market. In general, the profitability of such a strategy to a firm with market power depends on whether the additional revenue from higher prices exceeds the loss of profit from lower sales. This in turn depends on two important factors:

*(a)* the extent to which demand for the firm's product declines as price rises—this is known as the price elasticity of residual demand, where residual demand is total demand less supply by other firms. The higher the price elasticity of residual demand, the greater the loss of sales and revenue for any given rise in price and hence, other things equal, the less profitable is a strategy of withholding supply; and

*(b)* the extent to which price exceeds avoidable cost of supply. The greater the difference between price and avoidable cost, the greater the loss of profit per unit of sales and hence again, other things being equal, the less profitable is a strategy of withholding supply.

5.70. Centrica operates in both retail and wholesale markets and its contracted supplies and equity gas are intended to meet demand from its retail customers. So, if Centrica pursued a hypothetical strategy of withholding supply from the market, it would be reducing its own supplies and consequently it would have to increase purchases of gas from the spot market to meet the demand of its retail customers (which would be unchanged except to the extent that any effect of higher wholesale prices on retail prices led retail customers to use less gas). As a result of withholding its own supply, Centrica would therefore tend to experience higher gas purchase costs instead of, or as well as, reduced profits from lower sales (Centrica would also tend to experience higher gas purchase costs because some of its gas purchase contracts are indexed to forward or spot prices—see paragraph 5.8). On the other hand, Centrica would benefit from a reduction in Q1 supply through higher prices for Rough (which tend to move with the summer/Q1 spread) and it might also benefit from higher retail prices (it would do so if retail prices increase more than its own costs).

### *Financial effects of Centrica withholding supply*

5.71. Centrica commissioned a study by its economic consultants, Lexecon, of whether a hypothetical strategy of withholding supply would be profitable for Centrica. The Lexecon study (see Appendix 5.5) considered two variants of a hypothetical consistent strategy of withholding supply to increase average Q1 spot prices and Q1 forward prices for future years by 0.034p per kWh (1p per therm):

*(a)* In order to increase spot prices by 0.034p per kWh (1p per therm) across Q1 as a whole, Lexecon estimated that Centrica would need to withhold about 9.5 TWh (325 million therms) in each Q1 (see Appendix 5.5, Table 4), which over the period 2004 to 2007 would reduce Centrica's profits in the base case by an NPV of £25 million (see Appendix 5.5, Table 12).

*(b)* In order to increase spot prices by 0.102p per kWh (3p per therm) on the 30 highest-price days (which would increase the unweighted average Q1 price by 0.034p per kWh (1p per therm)[1] since there are 90 days in Q1), Lexecon estimated that Centrica would need to withhold about 4.3 TWh (150 million therms) on the relevant days in each Q1 (see Appendix 5.5, Table 4), which over the period 2004 to 2007 would reduce Centrica's profits in the base case by an NPV of £12 million (see Appendix 5.5, Table 13).

The Lexecon study concluded that it would not be profitable for Centrica to withhold Q1 supplies in order to increase the price of gas.

5.72. We have made our own projection of the profitability to Centrica of withholding gas supply in Q1, concentrating on the case (*(a)* in the previous paragraph) where price is increased throughout Q1. This is summarized in Table 5.15, which is based on the following volume assumptions:

*(a)* The amount of gas supplied by Centrica to its retail and wholesale markets is as projected by Centrica and used in the Lexecon study and is assumed to be unaffected by any changes in retail prices. Centrica's projected Q1 supply of gas is shown in the first four lines of Table 5.15.

*(b)* As well as supplies to domestic, I&C and LTI customers and its own generation volumes, Centrica also expects to make sales to the wholesale market (fifth line of Table 5.15). Centrica told us that it procured sufficient gas to meet its expected requirements in a cold winter and, consequently, in a normal winter it sold gas on the spot market.

*(c)* In order to increase prices by 0.034p per kWh (1p per therm), Centrica needs to withhold about 9.5 TWh (325 million therms) in each Q1 (see seventh line of Table 5.15), or around one-quarter of the 2003/04 maximum flow from the Morecambe fields. This is based on Lexecon's estimate of Centrica's residual demand elasticity of [✂] (see Table 3 of Appendix 5.5) which combines two components: the residual supply elasticity of [✂] and the aggregate demand elasticity of 0.1. More specifically, the increase in the spot price of 4.5 per cent is assumed to increase non-Centrica supply by [✂] per cent (assumed residual supply elasticity of [✂] times increase in price of 4.5 per cent), or about [✂] TWh; and reduce total demand by 0.45 per cent (assumed price elasticity of total demand of –0.1 times increase in price of 4.5 per cent), or about [✂] TWh. Total demand might be expected to decline, even if retail demand did not, due to increased self-interruption. We made our own analysis (see Appendix 5.6) of Centrica's data on supply over the past three years. Our analysis suggested a residual supply elasticity of [✂], similar to but slightly lower than Lexecon's estimate. Adopting our estimated residual supply elasticity, and continuing to assume a demand elasticity of –0.1, implies a residual demand elasticity of [✂] and a slightly lower volume withheld (see Table 5.16).

5.73. The estimated financial effects on Centrica are also shown in Table 5.15:

*(a)* We have assumed that Centrica withholds gas from Sean and Morecambe, as these are fields which Centrica controls. The Lexecon study states that in an average year Centrica would expect to use Sean at maximum flow on [✂] days in Q1, and we have estimated avoidable cost on the assumption that Centrica withholds gas from Sean for [✂] days (the highest-price days) and from South Morecambe for the remaining [✂] days of Q1. We used the cost figures in the Lexecon study, but adjusted for the effect on tax (the main element of cost at South Morecambe) of average price on those [✂] days being lower than the average for Q1 as a whole. This gives a weighted average avoidable cost of [✂]p per kWh ([✂]p per therm). Centrica's costs avoided (eighth line of Table 5.15) are based on this figure times the amount of gas withheld. Alternative assumptions on costs avoided are discussed in paragraph 5.76*(c)*.

[1]Since supply is greatest on the highest-price days, the weighted average Q1 spot price would increase by more than 0.034p per kWh (1p per therm). However, the unweighted average spot price is relevant to Q1 forward prices in future years since the Q1 forward price is the price of gas for each day in Q1.

*(b)* In order to supply its customers and its own power stations, Centrica incurs costs buying gas from the market to replace the amount assumed to be withheld from its own sources (ninth line of Table 5.15). Centrica's cost of buying gas from the market is based on the spot price (including the assumed 0.034p per kWh increase) times the amount of gas purchased, which is simply equal to the amount withheld since Centrica's own retail demand is assumed not to decline.

*(c)* Since some of Centrica's purchase contracts are indexed to spot or forward prices, an increase in prices would increase its gas purchasing costs. Its tax payments on the Morecambe fields would also be increased by a price increase. On the other hand, lower production from Morecambe, consequent on withholding supply, would reduce tax payments. What we have called the indexation effect (shown in the tenth line of Table 5.15) is the net effect of these factors.

*(d)* An increase in the forward price would also increase the cost of purchasing storage capacity in future. Centrica is assumed to incur additional costs of purchasing storage at Hornsea and LNG sites (11th line of Table 5.15). In the absence of the merger, Centrica would incur additional costs for Rough (12th line of Table 5.15, as Centrica is assumed to use 25 per cent of Rough's capacity). There is no effect from storage capacity that has already been purchased for the next two winters.

*(e)* Centrica would obtain additional revenue to the extent that it passes through increased wholesale prices to its domestic customers. In Table 5.15 (13th line), we have assumed that Centrica obtains net additional revenue from domestic customers of 0.017p per kWh (0.5p per therm) in 2004 and 0.034p per kWh (1p per therm) thereafter. This broadly reflects the assumptions that forward prices for future years increase once supply has been withheld in 2004 and that Centrica (and its competitors in the domestic market) reflect this increase in their domestic prices by early to middle 2004. As a consequence of these assumptions, for 2005 and future years, we assume Centrica obtains additional revenue equivalent to a 0.034p per kWh (1p per therm) increase on its Q1 domestic supplies (domestic prices do not vary between seasons and thus the increase would be a weighted average of 0.034p per kWh for Q1 and zero for the rest of the year). As far as 2004 is concerned, allowing also for the delay in domestic customers paying higher prices, Centrica obtains additional revenue in the remainder of 2004 approximately equal to half of the full year effect. Alternative assumptions about pass-through to the domestic market are considered below (see paragraph 5.76).

*(f)* In the I&C market, contract negotiations generally take place once a year and, as in the domestic market, it would be difficult for Centrica to increase prices before Q1 2004 (prior to Q1 2004 no gas would have been withheld and consequently forward prices would not be higher). We have assumed that contract negotiations reflect the higher price during 2004 and consequently that half of the 2004 wholesale price increase is reflected in higher retail prices and that, from 2005, all the wholesale price increase is reflected in higher retail prices. The projected additional revenue is shown in the 14th line of Table 5.15.

*(g)* Centrica's LTI contracts [ *Details omitted See note on page iv.* ] (15th line of Table 5.15).

*(h)* As regards Centrica's own generation (16th line of Table 5.15), it is assumed (as in the Lexecon study) that Centrica recovers through higher revenue the proportionate increase in its own costs (indexation effect).

*(i)* Centrica also receives increased revenue from its sales to the wholesale market (17th line of Table 5.15) due to the assumed 0.034p per kWh increase in spot prices.

TABLE 5.15 **Effects on Centrica of withholding gas from the market during Q1 assuming pass-through of 50 per cent in 2004 and 100 per cent in 2005–2007**

| | *Line no* | *2004* | *2005* | *2006* | *2007* | *NPV ([✂]%)* |
|---|---|---|---|---|---|---|
| *Centrica gas volume (TWh)* | | | | | | |
| Domestic | 1 | | | | | |
| I&C | 2 | | | | | |
| LTIs | 3 | | *Figures omitted. See note on page iv.* | | | |
| Own generation | 4 | | | | | |
| Sales to wholesale market* | 5 | | | | | |
| Total | 6 | | | | | |
| Volume withheld† | 7 | 9.6 | ( | ✂ | ) | |
| *Effects on Centrica (£m)‡* | | | | | | |
| Costs avoided | 8 | ( | | ✂ | | ) |
| Cost of buying gas from market | 9 | –75.6 | | | | |
| Indexation effect | 10 | ✂ | | *Figures omitted. See note on page iv.* | | |
| Additional cost of Hornsea and LNG | 11 | | | | | |
| Additional cost of Rough | 12 | 0.0 | –2.6 | –2.6 | –2.6 | ( ✂ ) |
| Domestic revenue | 13 | | | | | |
| I&C revenue | 14 | | | | | |
| LTIs revenue | 15 | | *Figures omitted. See note on page iv.* | | | |
| Own generation revenue | 16 | | | | | |
| Sales to wholesale market | 17 | | | | | |
| Total effect on Centrica (pre-merger) | 18 | | | | | |
| Profits from Rough | 19 | 0.0 | 10.4 | 10.4 | 10.4 | ( ✂ ) |
| Total effect on Centrica (post-merger) | 20 | ( | | ✂ | | ) 16.6 |
| *Assumptions* | | | | | | |
| Price before gas withheld from market (p/kWh) | | 0.751 | 0.751 | 0.751 | 0.751 | |
| Price after gas withheld from market (p/kWh) | | 0.785 | 0.785 | 0.785 | 0.785 | |
| Avoidable cost (p/kWh) | | | | | | |
| Indexation ratio§ | | | *Figures omitted. See note on page iv.* | | | |
| Elasticity of residual demand | | | | | | |
| Pass-through to domestic market (%) | | 50 | 100 | 100 | 100 | |

*Source:* CC analysis based on data provided by Centrica.

*Sales (in a normal winter) of gas Centrica has procured to meet demand in a cold winter.

†Amount of gas Centrica needs to withhold from market to increase price by 0.034p per kWh. This is equal to total demand (excluding sales to wholesale market) times elasticity of residual demand times percentage change in price.

‡A positive number indicates a benefit to Centrica, a negative number a cost to Centrica. See text.

§Effect (in £) on Centrica's procurement costs of £1 increase in prices on spot and forward markets. The figure relates to the situation before any hypothetical strategy of withholding supply changes the pattern of procurement.

5.74. Table 5.15 suggests that, before the acquisition of Rough, it would not have been profitable for Centrica to withhold supply. An increase of 0.034p per kWh in the Q1 forward price would increase the summer/Q1 spread and hence increase the profits of Rough. Once the additional profits from Rough are included, Table 5.15 suggests that it would be profitable for Centrica to withhold supply. Nevertheless, it should be noted that the projected financial costs (net costs of buying gas in the market, increased purchasing costs due to indexation on existing contracts, additional costs of Hornsea and LNG) are substantial at an NPV of £126 million and are only narrowly exceeded by the projected additional revenue which has an NPV of £142 million.

5.75. Appendix 5.7 summarizes the differences between our projection in Table 5.15 and that in the Lexecon study (90-day strategy). Differences occur in the following areas:

*(a)* We have assumed that avoidable costs are a weighted average of Sean and South Morecambe, whereas the Lexecon study took only the South Morecambe costs for the 90-day strategy (increases NPV by £4.7 million).

*(b)* We have allowed for the impact of lower tax payments, due to lower production at South Morecambe, on the indexation effect (increases NPV by £2.9 million).

*(c)* We have allowed for the impact of higher Q1 prices on the cost of storage at Hornsea and the LNG sites (reduces NPV by £1.9 million).

*(d)* We have also allowed for Centrica not obtaining additional revenue from the 25 per cent of Rough that it is assumed to retain for its own use (reduces NPV by £[✂] million).

*(e)* We have assumed that the full increase in wholesale prices is passed through to domestic customers after 2004, with 50 per cent pass-through in 2004, but the Lexecon study assumes that Centrica's retail prices only increase in line with the indexation effect of wholesale prices on Centrica's procurement cost (increases NPV by £48.6 million).

*(f)* Similarly, we have assumed full pass-through after 2004 to I&C customers whereas the Lexecon study assumes that Centrica's retail prices only increase in line with the indexation effect of wholesale prices on Centrica's procurement cost (increases NPV by £[✂] million).

*(g)* We have allowed for Rough capacity already having been sold for the 2003/04 storage year and hence that no additional revenue would occur in Q1 2004 (reduces NPV by £10.4 million).

5.76. Table 5.16 shows the effect of varying some of the assumptions used in the analysis. In each case only one of the assumptions is varied at a time, with the others remaining as in Table 5.15:

*(a)* The first panel of Table 5.16 shows the projected total effect (post-merger and pre-merger) under different assumptions about the timing as to when Centrica could pass through the wholesale price increase to domestic customers. If there were no pass-through, rather than 50 per cent, in the first year, the strategy becomes unprofitable. Table 5.16 is based on a four-year analysis and thus does not take into account any profits after 2007, which might offset the losses in 2004 and 2005 that occur if pass-through is delayed.

*(b)* The second panel of Table 5.16 shows the effect of assuming a lower level of pass-through in 2005 to 2007, while maintaining the assumption that half of the full year pass-through occurs in 2004. Post-merger NPV becomes negative if 2005 to 2007 pass-through is less than 84 per cent.

*(c)* The third panel of Table 5.16 shows the effect of different assumptions about average avoided costs. The avoided costs in Table 5.15 of [✂]p per kWh were based on a weighted average for Sean ([✂] highest-price days) and South Morecambe ([✂] lowest-price days) with the South Morecambe cost based on a notional tax payment estimated from the pattern of prices over Q1 2001 to 2003 (the implied price for the [✂] lowest price days in Q1 was [✂]p per kWh ([✂]p per therm)). [ *Details omitted. See note on page iv.* ], South Morecambe tax is based on [ *Details omitted. See note on page iv.* ]. Centrica calculated an average price of [✂]p per kWh ([✂]p per therm). Calculating tax on this higher price increases the weighted average cost avoided[1] to [✂]p per kWh ([✂]p per therm), reducing the net cost of, and increasing the profits from, withholding supply. Given the tax agreement, it may not be plausible to assume South Morecambe production is withheld only on the [✂] lower-price days. If, instead, South Morecambe production is withheld on all 90 days, with no effect at Sean, the average cost avoided is [✂]p per kWh ([✂]p per therm) which Centrica considered to be the appropriate figure. This increases the cost of, and reduces the profits from, withholding supply.

[1]The weighted average cost avoided is d*S+(1-d)*M where d is proportion of Q1 that Sean operates ([✂] days out of 90), S is cost of Sean ([✂]p/kWh or [✂]p/therm), M is cost of Morecambe and M=c+v+t where c is production cost, v is long-run marginal value ([✂]p/kWh or [✂]p/therm—see section 5.1 of Appendix 5.5), t is tax payment and t=0.7*(p–c) where p is the price discussed in the text.

TABLE 5.16 **Profitability of withholding gas under different assumptions**

| | *Total effect on Centrica* | | | | | | |
|---|---|---|---|---|---|---|---|
| | *Post-merger (including Rough profits) £m* | | | | | *Pre-merger (excluding Rough) £m* | *Gas withheld 2004 TWh** |
| | *2004* | *2005* | *2006* | *2007* | *NPV ([✂]%)* | *NPV ([✂]%)* | |
| *Different assumptions about delay to pass through to domestic customers* | | | | | | | |
| 100% throughout | | | | | 33.7 | | 9.64 |
| 75% in 2004 then 100% | | | | | 25.2 | | 9.64 |
| 50% in 2004 then 100% | | | | | 16.6 | | 9.64 |
| 25% in 2004 then 100% | | | | | 8.1 | | 9.64 |
| zero in 2004 then 100% | | | | | –0.4 | | 9.64 |
| zero in 2004, 50% in 2005 then 100% | | | | | –15.5 | | 9.64 |
| *Different assumptions about size of pass-through† to domestic customers* | | | | | | | |
| 50% in 2004 then 100% | | | | | 16.6 | | 9.64 |
| 45% in 2004 then 90% | | | | | 6.5 | | 9.64 |
| 40% in 2004 then 80% | | | | | –3.6 | | 9.64 |
| 35% in 2004 then 70% | | | | | –13.7 | | 9.64 |
| 30% in 2004 then 60% | | | | | –23.8 | | 9.64 |
| 25% in 2004 then 50% | | | | | –34.0 | | 9.64 |
| *Different assumptions about average avoided costs* | | | | | | | |
| As in Table 5.15 | | | | | 16.6 | | 9.64 |
| S Morecambe tax based on average Q1 price | | | | | 27.3 | | 9.64 |
| S Morecambe costs only | | | | | 12.4 | | 9.64 |
| *Different assumptions about residual supply elasticity (RSE) and demand elasticity (DE)* | | *Figures omitted. See note on page iv.* | | | | ✂ | |
| RSE of [✂], DE of –0.1 | | | | | 16.6 | | 9.64 |
| RSE of [✂], DE of –0.1 | | | | | 26.5 | | 7.33 |
| RSE of [✂], DE of –0.0 | | | | | 46.2 | | 2.71 |
| RSE of [✂], DE of –0.2 | | | | | 6.8 | | 11.96 |
| *Different assumptions about Q1 price (before gas withheld from market)* | | | | | | | |
| Q1 price of 0.614p/kWh (18p/therm) | | | | | 22.1 | | 11.78 |
| Q1 price of 0.751p/kWh (22p/therm) | | | | | 16.6 | | 9.64 |
| Q1 price of 0.853p/kWh (25p/therm) | | | | | 11.9 | | 8.48 |
| Q1 price of 1.024p/kWh (30p/therm) | | | | | 1.6 | | 7.07 |
| *Different assumptions about amount of gas withheld from market* | | | | | | | |
| Price increase of 0.009p/kWh (0.25p/therm) | | | | | 5.8 | | 2.41 |
| Price increase of 0.017p/kWh (0.5p/therm) | | | | | 10.5 | | 4.82 |
| Price increase of 0.034p/kWh (1.0p/therm) | | | | | 16.6 | | 9.64 |
| Price increase of 0.051p/kWh (1.5p/therm) | | | | | 18.5 | | 14.45 |

*Source:* CC analysis based on data provided by Centrica.

*Amount withheld in subsequent years is slightly less (see Table 5.15).
†First year effect assumed to be half of full year effect.

*(d)* The fourth panel in Table 5.16 shows the effect of different assumptions about Centrica's residual demand elasticity. Using our estimated residual supply elasticity of [✂] (see Appendix 5.6) and continuing to assume a demand elasticity of –0.1 reduces the quantity that needs to be withheld in order to increase price by 0.034p per kWh (1p per therm) to 7.33 TWh and increases the NPV of profits to £26.5 million. We also considered the effect of lower and higher assumptions about the responsiveness of supply and demand to price changes. The lower figure assumed residual supply elasticity of [✂] (two standard errors below our central estimate of [✂]—see Appendix 5.6) and demand elasticity of zero, while the upper figure assumed

residual supply elasticity of [✂] (two standard errors above our central estimate) and demand elasticity of –0.2.

*(e)* The fifth panel of Table 5.16 shows the effect of varying the price assumption. A lower price implies that a slightly higher volume of gas needs to be withheld in order to increase price by 0.034p per kWh (the lower the price, the larger the percentage of that price represented by 0.034p per kWh) but a lower price increases the profits from withholding supply. Profits increase with a lower price because avoided cost declines less than pro rata with price.

*(f)* The sixth panel of Table 5.16 shows the effect of varying the size of the price increase and hence the volume of gas withheld. As the volume withheld increases, profits from withholding supply increase less than pro rata and, beyond a price increase of 0.051p per kWh, incremental profits become negative. This occurs because the cost of buying gas from the market to replace that withheld increases more than pro rata with the volume withheld.

The projected profitability of withholding supply is highly sensitive to assumptions about domestic pass-through. It is also sensitive to assumptions about avoided costs and elasticities, but to a lesser extent—even with our smaller assumed elasticities ([✂] residual supply and zero demand elasticity), withholding supply is unprofitable if domestic pass-through from 2005 is less than 54 per cent. We noted that the projected profitability of withholding supply declines as the projected Q1 price increases: withholding supply is less profitable at a projected price of 0.853p per kWh (25p per therm), approximately the current Q1 forward price, than at 0.751p per kWh (22p per therm), the average Q1 price for the previous three years which has been used in Table 5.15.

## *Pass-through to domestic retail prices*

5.77. Assuming that 40 per cent of domestic gas is used in Q1, fully passing on a 0.034p per kWh increase in Q1 wholesale prices requires annual average domestic prices to be 0.014p per kWh (about 1 per cent) higher than they otherwise would have been. Thus, for the wholesale price increase to be passed through in full to domestic customers, it is necessary for any domestic retail price increase in 2004 to be about 1 per cent more than it otherwise would have been (and subsequent 2005–2007 price increases to sustain the higher price level).

5.78. To the extent that pass-through is delayed because retail prices are sticky, suppliers would be expected to hedge their exposure to market prices. Centrica said that it did not know its competitors' hedging positions, but it did not expect that these were very different from its own. It therefore suggested that there was little reason to expect retail prices to move with the (unhedged) wholesale market price, rather than the (hedged) procurement cost. Hedging occurs both through contractual commitments and through forward market transactions. As regards contractual commitments, we note that Centrica's competitors in the domestic market do not have their own UK production of gas, and that their exposure to fixed-price contracts tends to be less than that of Centrica (see Appendix 5.1). Long-term contracts not indexed to gas market prices (both those of Centrica and its competitors) tend to be a legacy of earlier gas market conditions and/or associated with electricity generation rather than a result of hedging short-term exposure to wholesale prices. As regards hedging more generally, all suppliers to the domestic market told us that their domestic businesses were required to hedge short-term (up to two or three years) exposure to market prices, but the percentage of expected domestic supply required to be hedged declined as the time period lengthened. The extent of hedging varied between suppliers, as discussed in paragraph 11 of Appendix 5.1.

5.79. Centrica made two other points regarding pass-through of wholesale price increases to the domestic market:

*(a)* In the domestic market, there were direct costs and other disadvantages, such as adverse publicity and the resultant brand damage, of implementing a price increase. Centrica tended to lose customers, even if its price increase was smaller than those of its competitors, as any price increase was a trigger for consumer bodies to encourage customers to move away from Centrica (the most expensive gas supplier) to cheaper suppliers. Centrica pointed out that Ofgem had stated recently that 'suppliers seem keen to avoid price rises, and in some cases have seen

strongly negative public reactions when raising prices'.[1] Centrica said that these factors tended to reduce both the frequency and the size of any price increases that Centrica made. Centrica said that the loss of customers was financially significant: for instance, it estimated that its 2003 price increase (of 2.5 per cent) would lead to a loss of about [✂] customers, worth about £[✂] million if each customer was valued at £300 as suggested in paragraph 5.19.

*(b)* During 2000, annual average wholesale prices increased from about 0.41p per kWh (12p per therm) to about 0.85p per kWh (25p per therm), subsequently falling back to about 0.68p per kWh (20p per therm), but the retail price increased only by 12.5 per cent up to spring 2003. Centrica argued that if all of the increase in retail price between 2000 and 2003 was taken to reflect gas costs (rather than, say, general inflation), the retail price increase represented only 27 per cent of the wholesale price increase during 2000 and 41 per cent of the change in wholesale prices between early 2000 and the end of 2002. Centrica's reluctance to increase retail prices was illustrated by the fact that it had increased prices by only 2.5 per cent in 2003 whereas its competitors had increased prices by between 3 and 6.2 per cent. Centrica pointed out that Ofgem had accepted that 'margins in domestic gas supply have, over the last two years, been extremely low or negative'; that 'for whatever reasons, customers have not borne the brunt of large increases in wholesale gas costs since 2000' and that 'suppliers have chosen to smooth prices in part through offsetting lower gas margins with electricity margins that are higher by historical standards'.[2]

5.80. Ofgem said that it thought Centrica had significantly overstated the difficulties it would experience in passing through wholesale price increases to domestic customers. Ofgem said that it thought it reasonable to assume that increases in the costs of procuring gas on the wholesale market would be passed on to customers, by both Centrica and its competitors. At a late stage in the inquiry, Ofgem provided us with an analysis which, it said, showed that the movement in Centrica's domestic prices, when taken with countervailing factors, was fully consistent with Centrica passing through the observed wholesale gas price increase to domestic customers. The countervailing factors identified in Ofgem's analysis were:

*(a)* The extent of observed wholesale price increases had been affected by Transco's entry capacity auctions in April–September of 2000 and 2001, which had resulted in very substantial over-recovery of revenue compared with that allowed for in Transco's price controls (subsequently dispersed through reductions in other transportation charges). Increases in entry capacity prices would be expected to increase SAP, other things being equal, but the subsequent dispersal through other transportation charges did not affect NBP prices and was likely to benefit domestic customers disproportionately.

*(b)* Transportation charges to domestic customers had also declined for other reasons: leaving aside the impact of the entry capacity auctions, movements in transportation charges since October 1999 had resulted in a reduction of about £8 in the cost of supplying a typical medium-usage domestic customer.

*(c)* LNG storage prices had declined significantly since April 2000, which had reduced Centrica's costs by 60p to £1.00 per domestic customer.

*(d)* Intensified supply competition since 2000 might have resulted in tighter margins in gas supply even in the absence of increases in wholesale prices.

Ofgem added that, even if it were concluded that there had been significant stickiness in terms of the pass-through of wholesale price increases since 2000, this did not automatically imply that this stickiness provided an adequate safeguard in terms of Centrica's acquisition of Rough.

5.81. We put these countervailing factors to Centrica, which made the following points:

*(a)* Entry capacity charges would be expected to have only a slight impact on SAP since gas supply decisions were not significantly affected by entry capacity charges, particularly at St Fergus where gas production was associated with oil production (over 95 per cent of the increase in

[1] *Electricity supply competition*: an Ofgem occasional paper, 16 December 2002.
[2] Op cit.

entry capacity charges in the summers of 2000 and 2001 occurred at St Fergus). Moreover, even in 2001, overrecovery of entry capacity charges was not material to the Great Britain market as a whole, representing less than 0.03p per kWh on the quantity of gas supplied that year.

*(b)* Although the transportation costs associated with supplying domestic customers had fallen, other costs (environmental levy, supply costs) had increased. As a result, Centrica's own total non-gas costs had increased somewhat over the period.

*(c)* The impact of lower LNG storage prices was negligible and, in any case, more than offset by increases in the prices of storage at Rough and Hornsea.

*(d)* As regards supply competition, Centrica disputed any suggestion that competition was inadequate in 2001. It pointed out that Ofgem had decided in February 2001 to remove all remaining price-cap controls from the domestic market, suggesting that Ofgem believed competition to have been sufficiently strong to help keep margins to a reasonable level. Centrica added that, in any event, as net margins were low (typically below 5 per cent), the strength of competition could have only a small impact on its pass-through calculations. For instance, if intensifying competition had resulted in a one percentage point margin reduction, its calculated percentage pass-through (see paragraph 5.79*(b)*) in 2000 would only be increased from 27 to 29 per cent and its calculated percentage pass-through since 2000 from 41 to 44 per cent.

Centrica also referred us again to statements previously made by Ofgem about low margins in domestic gas supply and suppliers choosing to smooth domestic prices (see paragraph 5.79*(b)*).