4 The gas supply system, gas storage and the facilities at Rough and Easington

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Introduction

4.1. In this chapter we describe the gas supply system; the roles and responsibilities of the main types of company in the industry; the uses of storage and other sources of flexible gas; how shippers and suppliers plan their use of flexibility; and the main types of storage facility. Finally we describe the facilities at Rough and the Easington terminal in more detail.

Outline of the gas supply system

4.2. Figure 4.1 shows a schematic representation of the UK gas supply system. Each of the major elements of this system is considered in turn below and in Appendix 4.1.

North Sea and Irish Sea gas fields

4.3. UK gas producers operate offshore rigs in about 100 fields, almost all located in the North Sea and the Irish Sea. Shippers and, to a lesser extent, suppliers (see paragraphs 4.25 to 4.27) purchase gas from these offshore producers (and in much smaller quantities from onshore producers). They can take title to the gas either at the onshore coastal reception terminal (the 'beach terminal'), where the gas is referred to as 'beach gas', or at the national balancing point (NBP—see paragraph 4.16). We describe the contractual arrangements in paragraph 4.71.

4.4. There are imports of gas from Norwegian fields near the UK/Norwegian boundary in the North Sea and via the Bacton interconnector (see paragraph 4.83). With these exceptions, the UK has been self-sufficient in gas for many years and became a significant net exporter of gas when the European and Irish interconnectors became operational (see paragraph 4.83). Transco's forecasts[1] indicate a potential shortfall in future UK supply as a result of the depletion of existing fields, a reduction in new developments on the UKCS and increases in annual demand. Although the short-term annual supply position appears well covered, forecast demand in the medium to long term can only be met by extra UKCS developments and/or further imports. Transco expects that imported gas will contribute one-third of supply by 2010 and about 45 per cent by 2011/12. These imports are likely to be sourced:

(a) through the existing Bacton interconnector;

(b) from Norway, possibly through a new pipeline to the Easington area or another UK beach supply point;

(c) from Holland, probably through a second European interconnector; and

(d) in the form of LNG supplied through new import terminals (see paragraph 4.10 et seq).

The timing of these developments and the likely quantity of gas to be supplied from each of these sources are uncertain at present.

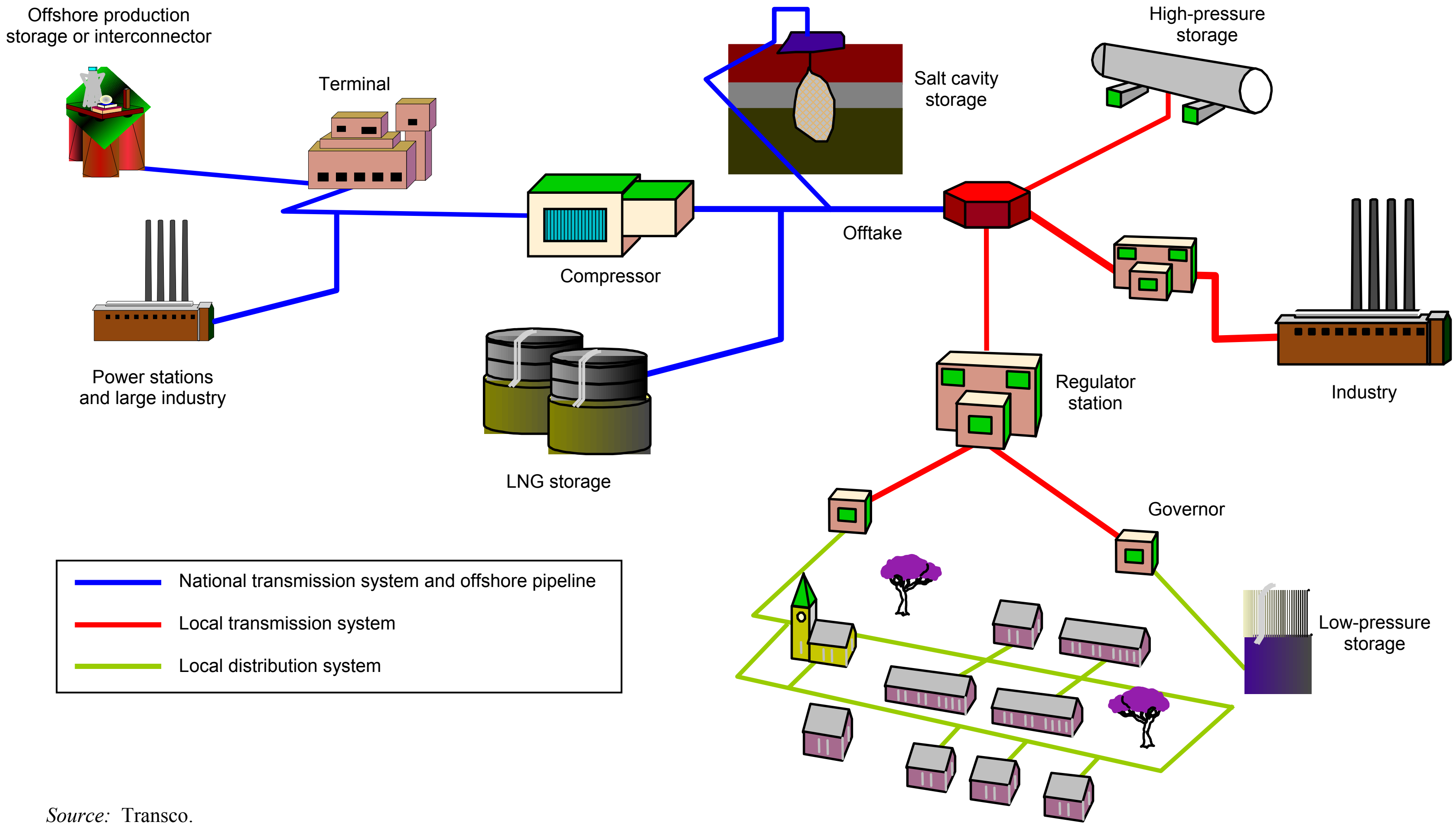
4.5. Centrica estimates that it currently has an 11 to 12 per cent share of equity production of gas from the UKCS. Through a wholly-owned subsidiary, Hydrocarbon Resources Limited (HRL), it owns and operates the North and South Morecambe fields in the Irish Sea. HRL also has equity in and operates the Bains field, which is a small satellite to South Morecambe. Centrica told us that gas had to be transferred between its gas production and retail supply subsidiaries under commercially negotiated arm's length agreements and with pricing terms agreed by the OTO as representing fair value.

4.6. Centrica also has equity interests in the Amethyst, Armada, Galleon, Hewett, Ravenspurn North, Seymour, Thames and Victor production fields (none of which it operates) and in some small development assets including the Rose, Chiswick, Ensign, Goldeneye and York fields (two of which it operates).

[1] *Transportation Ten Year Statement 2002*, Transco.

FIGURE 4.1

The national gas supply system



Source: Transco.

Terminals

4.7. Offshore gas producers deliver gas to seven beach terminals (see Figure 4.2). Each terminal includes processing facilities operated by, or on behalf of, the producers and a Transco facility for receiving gas into the NTS.

4.8. In general the producer is contractually obliged to carry out the processing needed to meet the quality specification required for entry into the NTS. At beach terminals one or more delivery facility operators process gas before transferring it to Transco and the NTS. (Following its purchase of Rough, Centrica is a delivery facility operator at Easington.)

4.9. The functions carried out by Transco's part of each terminal include quality monitoring, metering and providing emergency shut-off facilities. At Bacton and St Fergus, Transco has a manned terminal. At Theddlethorpe, Easington, Teesside, Barrow and Burton Point its equipment is limited to metering and quality monitoring. There are also small onshore terminals at the gas fields at Wytch Farm in Dorset and Caythorpe in North Yorkshire. These feed gas directly into parts of Transco's local transmission system.

Imports of liquefied natural gas

4.10. In its 2002 Ten Year Statement,[1] Transco said that it expected LNG import facilities to play an important strategic role in securing future UK gas supplies from sources such as North Africa, the Atlantic Basin and the Middle East.

4.11. National Grid Transco is planning to build a new import landing terminal at the Isle of Grain and convert part of Transco's LNG storage plant there into import reception facilities (thus reducing storage capacity). This would provide deep-water access for importing gas in the form of LNG from bulk carriers. The terminal could be operational by the end of 2004 and would be able to receive up to 1.2 TWh per delivery.

4.12. Petroplus International NV (a Dutch oil company) and a joint venture between Qatar Petroleum and ExxonMobil group companies are both considering plans for LNG importation terminals at Milford Haven in Pembrokeshire. These could both be operational in 2006/07. The Petroplus terminal, which has planning permission, could have an initial capacity to receive 65 TWh of gas a year. The Qatar Petroleum/Exxon Mobil joint venture is seeking planning permission for its terminal, which could have an initial capacity to import 116 TWh a year. The capacities of these terminals could ultimately rise to 97 TWh a year and 233 TWh a year respectively, together equivalent to around 30 per cent of projected Great Britain demand in 2010.

Onshore transmission and distribution

4.13. We describe Transco's onshore transmission and distribution network in more detail in Appendix 4.1. Gas is input at high pressure into the NTS and, as it is transported through the system, may be compressed further to maintain pressures at the extremities of the NTS. Gas from the NTS is delivered to:

— storage sites;

— large users, such as power stations; and

— Transco's local transmission and distribution systems.

At each stage in distribution the pressure is reduced to ensure safe operation.

4.14. The network is designed to handle the firm demand expected in severe winters. Transco's licence requires it to plan and develop its pipeline system to meet the firm peak demand that is likely to be exceeded (on one or more days) in only 1 year in 20 years. It is also required to plan the system such that it is capable of handling demand in the coldest winter that would be expected in 50 years. These

[1] Op cit.

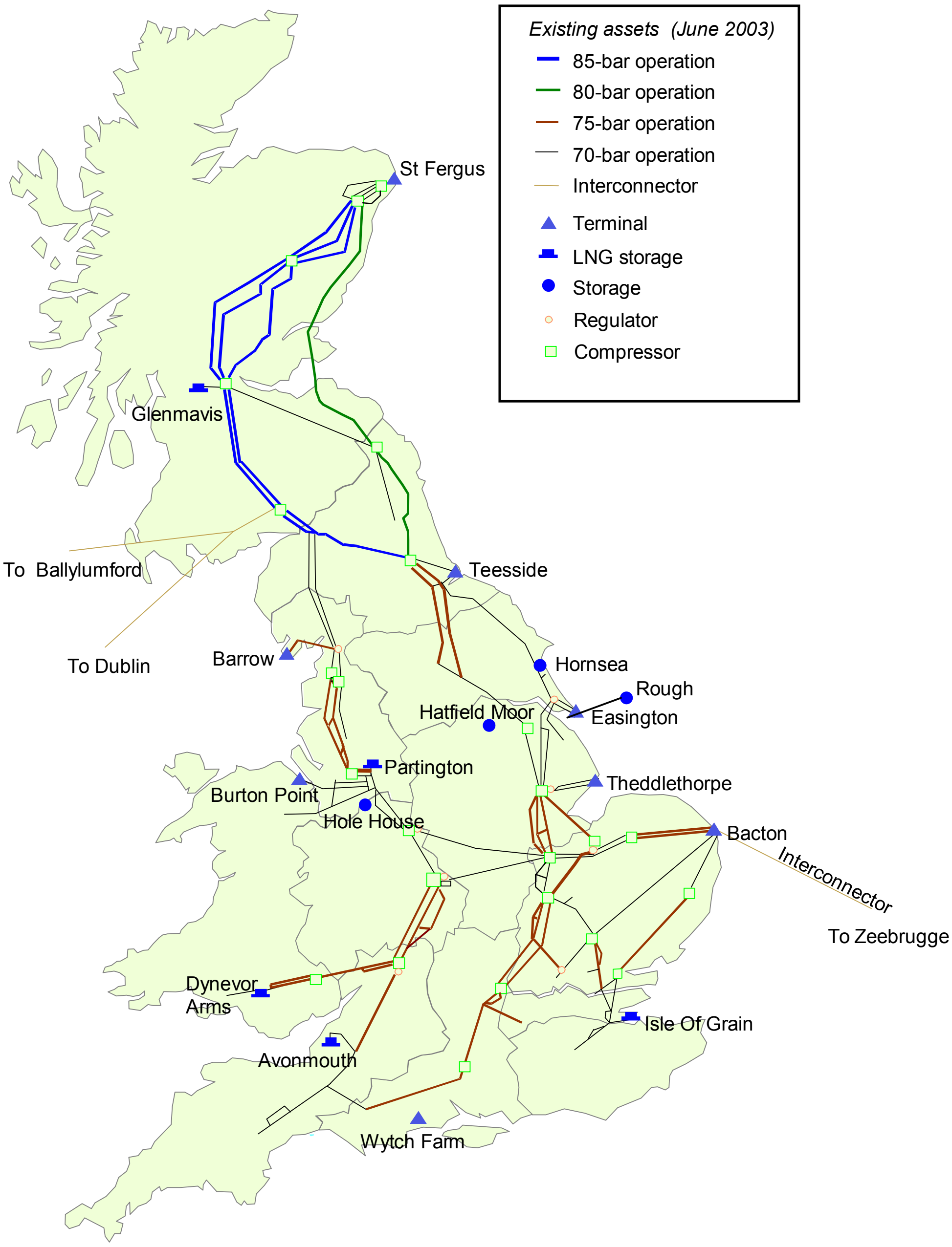
standards are known as the 1-in-20 peak day and 1-in-50 severe year security criteria. If, having taken account of all sources of flexible gas, Transco estimates that insufficient storage capacity has been booked and filled nationally to achieve the two security criteria, it is required to book and fill the remaining capacity requirement (this is known as top-up storage).

The national transmission system

4.15. Figure 4.2 shows the network of NTS pipelines and the location of the major storage installations.

FIGURE 4.2

The national transmission system and storage facilities



Source: Transco.

4.16. Gas transportation is charged for through commodity (throughput) charges and NTS entry and exit charges. The service provided therefore enables a shipper to input gas to the NBP and to output gas from the NBP to its customers. (The NBP is a notional point anywhere within the NTS, defined for the purpose of shipper balancing but also used to provide a place of transfer for gas traded through the on-the-day commodity market (OCM) or other trading mechanisms.)

4.17. The NTS has over 140 offtake stations (offtakes) which supply 12 local distribution zones (LDZs). They also supply the main storage facilities, power stations and a few very large industrial consumers directly.

Local distribution zones

4.18. An LDZ is a distribution area operated by Transco that is supplied by one or more NTS offtakes. Each LDZ contains a local transmission system (LTS), a network of pipelines generally operating at pressures up to approximately half those of the NTS, that transports gas to local distribution systems. Both the NTS and the LTS provide linepack storage (see paragraph 4.123), which is primarily used to aid daily balancing. The low-pressure local distribution systems are the most extensive parts of the transportation system. Transco manages the diurnal profile of customer requirements in them by using local storage, including low-pressure gas holders (see paragraph 4.123).

The roles of the main types of company in the industry

4.19. In addition to storage operators, the main types of company in the industry are producers, gas transporters, shippers, suppliers and traders.

Producers

4.20. Producers (frequently in consortia) explore for gas and develop and operate gas fields (see paragraph 4.3). They deliver their gas to the terminals (see paragraph 4.7) via undersea (or underground) pipes that are often owned by different consortia of producers. At each terminal, one or more delivery facility operators process the gas and deliver it to Transco for input into the NTS (or sometimes for direct delivery to end-users).

Gas transporters

4.21. Transco (along with several small gas transporters) is licensed by Ofgem to transport gas on behalf of shippers to consumers. Transco operates nearly all of the transmission and distribution system that transports gas from the terminals to the consumers. Its gas transportation licence requires Transco:

(a) to plan and develop its system to meet the 1-in-20 peak day and 1-in-50 severe year criteria (see paragraph 4.14);

(b) to operate its pipeline network in an efficient, economical and safe manner; and

(c) to establish a Network Code that sets the commercial rules governing shippers' and Transco's rights and obligations in the use of the transportation system.

4.22. In addition, as part of its licence obligations, Transco has to submit a safety case to the Health and Safety Executive (HSE) that sets out the physical rules ensuring the safe operation of the system

4.23. Within Transco, a top-up manager is required to ensure (subject to the availability of empty storage space) that enough stored gas is available in total to provide for a severe winter and to meet demands caused by extreme weather. Some small gas transportation companies have built their own local distribution networks (each with its own network code).

4.24. Transco also operates LNG storage plants (see paragraph 4.117 et seq) and provides other storage in the form of linepack and local diurnal storage facilities (see paragraph 4.122) for its own use in balancing the system.

Shippers and suppliers

4.25. Around 90 companies are licensed by Ofgem as shippers and/or suppliers. A company granted a shipper's licence by Ofgem can buy gas from producers, traders or other shippers, sell it to suppliers or other shippers, and employ Transco and other gas transporters to transport the gas to the suppliers' customers. It may also store gas with storage operators to help it manage the balance between its supplies and its customers' demand. Its licence requires it to be reasonable and prudent in the way it uses the Transco pipeline network. Paragraph 2 of standard licence condition 3 requires shippers not knowingly or recklessly to pursue any conduct likely to prejudice:

(a) the safe and efficient operation of the pipeline system;

(b) the safe, economic and efficient balancing of the system; and

(c) the due functioning of the Network Code.

Centrica told us that withholding supplies of flexible gas to increase prices could fall foul of the second of these requirements, potentially leading to financial penalties or behavioural directions under section 28 et seq of the Gas Act (as amended). A company with a supplier's licence contracts with shippers to ship gas through the network to its consumers. (A supplier that is not also a shipper has no direct relationship with Transco.) Only suppliers licensed by Ofgem can sell gas to small consumers; no licence is needed to supply customers using over 2,200 GWh a year. In practice, many suppliers are also licensed as shippers.

4.26. The gas day starts at 06.00. By 13.00 on the preceding day, each shipper must make its gas nominations to Transco for supplies to its daily metered sites. By 16.00 each day each shipper must make its nomination for the gas to be input at each NTS entry point. These nominations inform Transco how much gas the shipper wishes to transport on the following day and enable Transco to plan and control the daily operation of the pipeline system. Then, during the day, the shipper can modify its nominations to take account of changes in supply or demand.

4.27. Centrica is the largest shipper and supplier. It is engaged in these activities through two licensed wholly-owned subsidiaries, BGT, which supplies domestic, commercial and industrial customers (and holds both a shipper's and a supplier's licence), and Accord Energy Limited (Accord), which acts as a shipper and an energy trader (and holds a shipper's licence).

Gas traders

4.28. Gas traders buy and sell gas before it reaches the consumer. (To a limited extent some traders also supply gas to large users, such as power stations.) They trade in the OCM (see paragraph 4.29) and forward over-the-counter (OTC) markets, primarily in NBP gas. Although traders do not need a licence from Ofgem, they are regulated by the FSA. Appendix 4.2 considers the circumstances under which the activities of a trader, or a shipper trading gas, could amount to market abuse under the FSMA. While most of their transactions are short term, traders sometimes also enter into longer-term deals.

4.29. The OCM provides a screen-based anonymous gas trading market in which shippers, traders and Transco can post bids and offers to buy or sell gas. Gas can be sold for delivery either at the NBP or at specific locations on the gas network. A contract for delivery to the NBP can have the advantage of avoiding certain risks to the seller, for example the risk of plant failure at a particular terminal. Although Transco has to use the OCM for its gas purchases and sales, other parties can also make use of several other markets including trading at the beach, the OTC market, futures markets and derivatives markets (see paragraph 5.7).

The responsibilities of the players

4.30. The responsibilities of shippers and Transco are set out in Transco's Network Code (see paragraph 4.34) and in their respective licences. Many of them concern the need to keep the transportation system in balance. We discuss daily balancing and the Network Code in more detail in Appendix 4.3.

Daily balancing

4.31. To maintain the safe operation of the transmission and distribution system, the gas that is put into it by shippers must consistently balance the gas used by consumers every day, after allowing for exports and changes in the amount of stored gas. Although each shipper has an incentive to try to balance its inputs against its own customers' consumption (see paragraph 4.33), it does this on the basis of imperfect information and it is not, therefore, feasible for its supply and demand to be in balance at all times.

4.32. The Network Code makes Transco responsible for maintaining the physical balance of the network. If the shippers' combined supply and demand are out of equilibrium, Transco must restore the balance. Usually Transco achieves this through adjustments to linepack (see paragraph 4.123) and by buying or selling gas through the OCM (see paragraph 4.29). It also holds gas in store, known as top-up gas (see paragraph 4.14) and operating margins gas. Operating margins gas is the gas used by Transco to maintain system security under unforeseen circumstances including offshore supply, plant or network failure. It also allows for the orderly run-down of the system when there are major supply failures.

4.33. These measures may incur additional costs. Each shipper is financially responsible for the costs incurred in managing an imbalance in its supply and demand or a difference between its gas nominations and actual flows.

Transco's Network Code

4.34. Transco's Network Code is the legal document which forms the basis of arrangements between Transco and each shipper whose gas it transports. These parties are bound to the terms of the Network Code by entering into a framework agreement. The code provides financial incentives to ensure that each shipper gives Transco the necessary information about its gas flows and honours its gas flow nominations. The Network Code requires the commercial balancing process to be carried out on a daily basis and sets out the actions that are required before the day concerned, during the day and after the day.

4.35. The Network Code provides all system users with equal access to transportation services and has the further objectives that gas transportation should meet market requirements on a non-discriminatory basis; that system security and safety should be safeguarded; and that transportation pricing should reflect the costs of the services concerned.

The role of storage in providing flexibility

4.36. Access to gas storage is one means of obtaining the flexibility needed to manage fluctuations in gas supply and demand levels, and exposure to movements in gas prices. The demand fluctuations that need to be managed include those associated with normal seasonal and daily variations and those generated by more extreme conditions. We estimate that storage provides about 16 per cent of the summer/winter flexibility available to shippers (see Table 5.9) and around one-quarter of the summer/winter flexibility used in recent mild winters (see Table 5.10). The main use of storage is to ensure that sufficient supply is available to meet demand on high demand days. The contribution that each type of storage facility makes is constrained by its capacity, duration and cost structure. It is generally desirable to inject gas in the summer, when gas prices are low, and to deliver it in the winter, when prices are higher. Through users' ability to vary daily injection and withdrawal, storage is able to assist both in daily balancing and in providing for the seasonal swing in demand.

4.37. Long-duration storage mainly used to manage normal seasonal fluctuations is often referred to as seasonal storage, and short-duration storage used chiefly to manage extreme conditions is referred to as peak-shaving storage. The maximum volume of gas in seasonal and peak-shaving storage is a small proportion of total gas demand over the year (about 3.5 per cent) but provides for around a quarter of the peak-day demand requirement for gas.

4.38. Storage had three main traditional uses: supply and demand matching, providing operating safety margins and supporting the transmission system. As part of supply and demand matching, storage is now also used to facilitate the arbitrage of the gas price spreads between summer and winter, between days and within individual days.

Supply and demand matching

4.39. Storage facilities, along with other sources of gas flexibility, are used both to meet requirements on particular days, or longer periods, of high demand and to facilitate daily and within-day demand/supply balancing.

4.40. Gas production facilities are designed to adjust their output rates by varying amounts to accommodate variations in the contractual offtake nominated by shippers, usually in response to changes in demand. It would often, however, be uneconomic to provide sufficient production capacity to meet the highest levels of winter demand and then to operate it in the summer at a low level of utilization that reflected demand at that time. Storage helps suppliers, shippers and producers to match supplies to demand more economically throughout the year.

4.41. Storage can also be used to help correct imbalances caused elsewhere in the supply sector, for example as a result of assets being unavailable owing to maintenance or breakdowns.

4.42. Demand fluctuations are particularly pronounced in relation to domestic customers—their peak demand is usually close to 2.5 times average domestic demand. By contrast, peak demand from large firm I&C customers is typically only 1.3 times their average demand. Given this, a gas supplier's demand for flexible supplies is likely to be heavily influenced by the size of its domestic customer base. It will also be affected by the level of demand from the supplier's interruptible industrial customers (see paragraph 4.92).

Security of supply and operating margins

4.43. For the safe and efficient operation of the NTS, pressure levels must be maintained within strict boundaries. This requires a tight balance to be maintained between the amount of gas delivered into the system and gas consumption, both of which vary within the day.

4.44. Transco ensures the safe operation of its system by using storage to deal with operational incidents such as large unexpected changes in demand, sudden losses of offshore supplies, compressor breakdowns and pipeline failures. LNG storage is also used to provide for the orderly rundown of the system in the event of a major supply failure (see paragraph 4.117 et seq).

Transmission support

4.45. LNG storage facilities have been built at the extremities of the network to provide support for high demand increases in the event of problems or network constraints. This both avoided uneconomic investment in extra pipeline capacity and improved security of supply.

4.46. LNG storage sites that provide this service are designated as 'constrained storage facilities' in the Network Code. Although capacity at these facilities is sold to shippers, Transco has the right to order gas flows from them when forecast demand is higher than predetermined triggers. Gas stocks in these storage sites must therefore be maintained at appropriate levels, depending on the time of year, to ensure that gas is available when required. This may affect the ability of users to withdraw their gas from storage. In recognition of this, shippers booking a storage service at these facilities receive a 'transportation credit' from Transco. At present, three of the five LNG storage sites are designated in the Network Code as constrained facilities, although this designation and the extent of the constraint are reviewed annually.

Arbitrage and retiming gas purchases

4.47. Changes in supply and demand over time lead to seasonal, daily and within-day variations in gas prices. A premium is paid for 'winter gas' in the spot and forward markets, to reflect the tighter supply/demand balance at that time of year. Firms that need access to winter gas must either pay this premium or pay for access to flexible supplies, including storage services. The prices of storage and other sources of flexibility and the gap between summer and winter gas prices are therefore strongly interrelated.

4.48. Storage injection capacity (with available space) can be considered to be a put option. In other words, on any given day a storage customer with spare gas has the option of either selling it on the spot market or (if the price on the spot market is lower than would be expected at a later date) injecting the gas into store for withdrawal later. Conversely, withdrawal capacity (with gas in store) can be seen as a call option. That is, on any given day a storage customer short of gas (but with gas in store) can either use withdrawal capacity or buy gas on the spot market.

4.49. It is also open to traders and other gas market players to offer virtual storage services that are equivalent to issuing gas call options and put options. Enron ran such a service (called 'Enbank') and a similar service is now being offered by Innogy as 'Innstore'. Such virtual services may be backed up in a number of ways. These include (but are not limited to) the risk-taker making balancing trades or having the right to access storage, physical gas held in store or some other source of flexibility (such as upstream supplies).

Regulatory framework for storage

Background

4.50. The Rough field was converted into a storage facility by the British Gas Corporation, the former publicly owned utility which operated all onshore aspects of the UK gas industry (as well as owning some offshore production assets including Morecambe). Its business was privatized under the Gas Act in 1986 as a single, integrated company, British Gas plc. Customers purchasing more than 732 MWh (25,000 therms) a year were free to buy from any authorized supplier that could negotiate access to the pipeline system. The Government and the then regulator, Ofgas, subsequently began progressively to remove the company's statutory monopoly over the supply of gas to non-domestic customers consuming between 73 MWh (2,500 therms) and 732 MWh a year.

4.51. In 1993 an MMC report under the monopoly provisions of the FTA concluded that British Gas plc's conduct in undertaking its business in an integrated way, and its failure to provide for neutrality between its trading and transportation interests, might be expected to reduce the effectiveness of competition and to operate against the public interest. In the MMC's view, separation of these businesses was essential to ensure that transportation and storage could be made available to all shippers without undue discrimination and to bring about self-sustaining retail competition. It recommended that British Gas plc be required to divest its trading activities by March 1997. It also suggested that British Gas plc's tariff monopoly—that is, the statutory right to supply premises consuming less than 73 MWh (2,500 therms) a year—could be removed between 2000 and 2002.

4.52. The Secretary of State decided that transportation and storage should be legally separated from gas supply activities within British Gas plc but did not require any divestment of ownership. (The requirement for legal separation between gas transporters' and gas suppliers' activities was implemented in the Gas Act 1995.) He also decided on a much more rapid withdrawal of the tariff monopoly than proposed by the MMC. As a result, competition in supply to domestic customers was introduced in south-west England in 1996 and extended to the rest of Great Britain by May 1998. In the meantime, British Gas plc voluntarily embarked on a demerger, resulting in the formation of BG and Centrica. As competition was steadily introduced throughout the retail market, controls on Centrica's prices were progressively relaxed and finally removed in April 2002. Appendix 4.4 sets out the main steps taken to introduce competition into the domestic gas market and remove price controls.

4.53. Following the demerger in February 1997, BG owned Transco, which operated the former British Gas plc transport and storage activities, and Centrica owned the trading and supply operations. In May 1997, a further MMC report endorsed a proposal from Ofgas that BG's prices for storage should be regulated separately from its prices for transportation. As a result, BG established BG Storage, as a separate legal entity from Transco's transportation business, to own BG's storage operations, which then comprised Rough, Hornsea and the LNG facilities. The LNG storage sites were subsequently transferred to Transco LNG (see paragraph 4.117).

4.54. In 1998, Ofgas carried out a review of the regulation of storage in the new circumstances. As a result, price controls on the Rough and Hornsea storage operations were lifted in favour of a set of non-statutory informal undertakings given by BG (see paragraph 4.59). These undertakings were set to apply from May 1999 to April 2004.

Current regulatory provisions

4.55. Neither the operation nor the ownership of gas storage facilities is a licensed activity under the Gas Act. Under the EC Gas Directive,[1] storage undertakings are prohibited from discriminating between storage users and are subject to requirements regarding third-party access. These EC obligations were implemented in the UK through amendments to the Gas Act and the Petroleum Act, which govern onshore and offshore facilities respectively.

4.56. Section 17D of the Petroleum Act prohibits operators of offshore storage facilities such as Rough from discriminating against applicants for storage rights and requires them to publish annually the main commercial conditions relating to storage rights. Any person seeking the right to store gas at a particular facility may apply to Ofgem to secure that right, providing he or she has first attempted to negotiate in good faith with the storage undertaking for a reasonable period of time. Ofgem is empowered to issue a notice securing storage rights for the applicant or to regulate storage charges, provided it is satisfied that such rights would not prejudice the efficient operation of the storage facility for the purpose of storing, on behalf of its owner, the quantities of gas which the owner requires.

4.57. Section 17C of the Petroleum Act gives Ofgem powers to consider applications made by storage owners for exemption from certain provisions in the legislation regarding third-party access. As neither Centrica nor the previous owners of Rough have applied for an exemption, the provisions of the legislation relating to third-party access apply to Centrica as the owner of Rough. Relevant extracts from the legislation are included in Appendix 4.5.

4.58. Since Rough is an offshore gas field, its operator requires a gas production licence from the Department of Trade and Industry and it is subject to health and safety regulation by the offshore division of the HSE.

Dynegy's undertakings

4.59. Prior to its acquisition by Centrica, Rough was also regulated through the legally binding undertakings Dynegy gave under the FTA to the Secretary of State, in lieu of a reference to the CC, when it purchased Rough and Hornsea from BG in 2001. These undertakings replaced non-statutory informal undertakings given by BG to Ofgem to cover its operation of Rough over the period from 1999 to 2004. BG's undertakings were put in place following a detailed investigation into the market for gas storage and related activities carried out by Ofgas in 1998. The review identified a number of short- to medium-term issues that needed to be addressed to facilitate the transition to a more competitive market in gas storage and allow deregulation of storage prices.

4.60. The Secretary of State's decision on Dynegy's purchase had been informed by advice from Ofgem, including the results of a consultation process. This indicated a number of areas where respondents agreed that undertakings similar to those given by BG were still required. In particular, they agreed that the maximum physical capacity of Rough should continue to be made available on non-discriminatory terms and that there should be a robust separation between Dynegy's storage and trading activities. Dynegy's undertakings to the Secretary of State therefore carried on some of the provisions that previously applied to BG, including the following:

(a) the commitment to make the maximum physical capacity available remained unchanged as did the stipulation that the injection, space and deliverability capacities would not be less than the nominal amounts previously set;

(b) there was an obligation to offer that capacity on non-discriminatory terms;

[1]Directive 98/30/EC.

(c) Dynegy was obliged to publish an auctions procedure document, a standard SSC and a future operations statement;

(d) Dynegy could only change the terms of the auctions procedure and the SSC with the consent of the DGFT; and

(e) Dynegy was obliged to maintain a robust financial and informational separation between the storage business and the rest of its trading activities.

4.61. An additional requirement that respondents considered necessary was the provision of one-year storage rights to help new entrants to the gas market to secure capacity. The undertakings, therefore, placed a further obligation on Dynegy to offer 20 per cent of the capacity at Rough on a one-year basis, either through bilateral sales or subsequent auctions.

4.62. As Dynegy's storage business would have market sensitive information about storage customers' injection and withdrawal patterns, Dynegy voluntarily promised in its future operations statement that the storage business would trade gas only for operational purposes.

4.63. Given that most of the capacity for the period ending in April 2004 had already been sold, Dynegy, unlike BG, was permitted to sell by methods other than auctions. Dynegy was, however, required to offer any unsold capacity for sale by auction at least 30 days before the start of each storage year. Any capacity still remaining unsold at the start of the storage year then had to be offered for sale at the reserve price set in the most recent auction.

4.64. Dynegy was also required to facilitate the development of a secondary market by enabling capacity rights to be transferred and ensuring that injection, space and withdrawal rights could be traded separately.

4.65. Dynegy's undertakings do not apply to Centrica as the new owner of Rough. Centrica nonetheless volunteered to act as required by the undertakings while the OFT—and subsequently the CC—considered the current merger. During our inquiry, the manner in which Centrica operates has been subject to interim undertakings that it has given to the OFT. These cover the period of the reference and are designed to suspend further integration of the acquired business and to avoid prejudicing the outcome of our inquiry.

The overall annual planning of flexibility

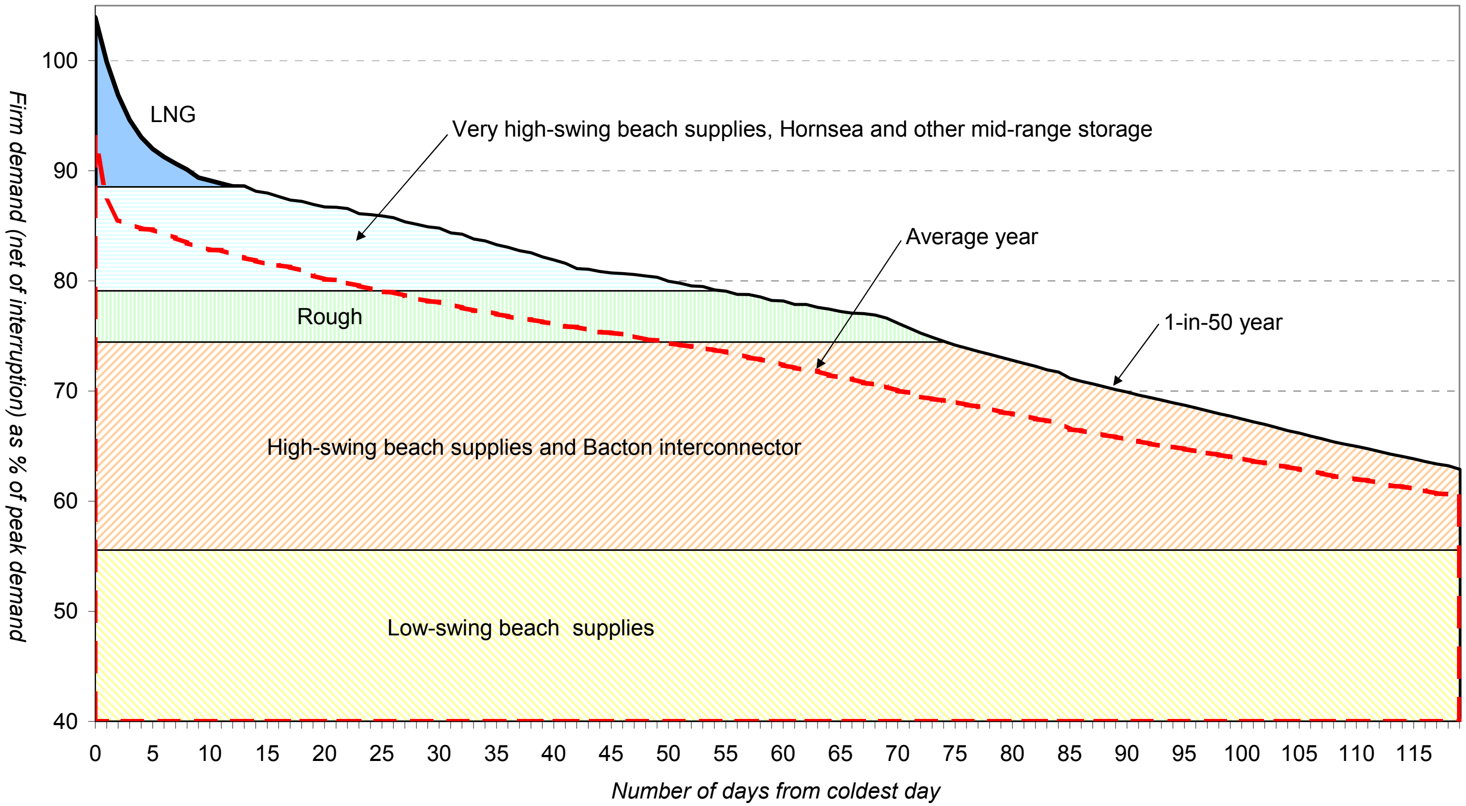
4.66. The storage of gas is one of several means by which the gas industry as a whole secures flexibility. Other physical sources of flexibility include beach swing in gas supply agreements with producers, gas supplied to or from mainland Europe via the Bacton interconnector, and interruptible supply contracts with some large industrial customers and gas-fired power stations.

4.67. For planning their portfolios of seasonal flexibility, the shippers and Transco find it useful to represent the demand for gas as a graph that shows the days of a year ranked in order of daily gas demand. This tool is known as the load duration curve. Figure 4.3 shows a national load duration curve for a 1-in-50 winter.

4.68. The load duration curve shows the order in which suppliers in aggregate would use the various sources of flexibility in a hypothetical severe winter. Thus in the summer months demand would normally be met by low-swing beach gas. In the early autumn and late spring, the increased demand would typically be met by progressively adding supplies from high-swing gas fields. As the seasonal weather became more severe, further supplies would be added in turn from other sources including the Bacton interconnector, Rough, Hornsea and other storage facilities. Finally, if severe cold periods occurred, LNG storage would be used to make up the additional supplies needed for a few peak days. The sources of flexibility also provide cover for breakdowns and daily fluctuations in demand. The order in which they are actually used may be modified in practice to take into account their relative prices and, for limited duration sources of flexibility such as storage and interruption, their potential values later in the winter.

FIGURE 4.3

Load duration curve for a 1-in-50 years



Source: CC based on analysis from Centrica and Transco.

Alternative sources of flexibility

4.69. We now consider in more detail the roles of the sources of flexibility other than storage.

Beach swing

4.70. Swing is a measure of a shipper's ability to vary the contracted supply nominated from a producer each day. Seasonally variable supply contracts (known as high-swing contracts) provide an alternative source of seasonal flexibility to storage. They play a key role in shippers' ability to meet the varying loads placed on them, accounting for nearly half the total available volume of summer/winter flexibility (see Table 5.9) and a higher proportion of the flexibility used in recent mild winters (see Table 5.10). The swing is agreed as part of each contract negotiation for gas supplies. In gas purchasing contracts, the swing factor is calculated as the ratio of peak to average supplies, expressed as a percentage.

Types of supply contract

4.71. Shippers' agreements to purchase gas from producers differ in detail but are of two basic types: buyer's option and seller's option. The type of contract determines the level of swing available to the shipper. Appendix 4.6 outlines how each type operates.

Low-swing supplies

4.72. The St Fergus and Teesside terminals receive gas associated with the production of oil and other liquids (associated gas) from fields in the northern and central basins of the North Sea. At these fields, the producer normally wishes to produce oil at a relatively constant rate. The production of gas is, therefore, likely to follow a comparatively flat profile and have a low swing. Furthermore, where such gas is supplied on a seller's-option contract, the level of peak day supply cannot be guaranteed.

4.73. Producers are, however, able to offer an increased level of swing from such fields if they invest in the equipment needed to reinject gas back into the field. Although adding to production costs, this may also help producers to optimize their pattern of oil production.

4.74. As gas production is increasingly coming from the northern basin or from imports, the overall level of beach swing available to the UK market is expected to decline.

High-swing supplies

4.75. Terminals other than St Fergus and Teesside generally receive high-swing gas from dry fields (that is, fields that do not produce any oil). Producers with dry gas fields may be prepared to vary output levels. However, in agreeing to do so they will either have to install additional plant and transport capacity to meet peak, rather than average, levels of output, or for a given level of production and transport capacity will have to accept an overall lower level of annual production—because output in summer is below maximum capacity—and thus a longer depletion time for the gas reserves. In either case, the ability to vary production results in higher costs per unit of output. Consequently gas produced under high-swing contracts normally commands a higher price than gas with a flat production profile. In particular, where gas is transported over long distances offshore (for example, in the northern North Sea), an increase in swing would require investment in additional pipeline capacity or compression to meet peak transmission needs; this would cost more than the additional investment that would be needed at a similar high-swing gas supply close to shore.

4.76. Flexible gas purchase contracts where supplies can be varied to take into account the higher demand in winter include Centrica's contracts with its own Morecambe fields and the independent Sean field. For Sean, Centrica pays a flat fee for the benefit of having the capacity readily available at times of peak winter demand and commodity charges for the actual gas supplied. Both Sean and the Morecambe fields are capable of varying their output on 6 hours' notice but require 48 hours' notice to start up production. Centrica told us that it held a declining amount of beach swing, due to a considerable extent to the falling production of its Morecambe fields.

4.77. If the summer/winter price differential were to widen sufficiently to justify the extra investment needed, additional beach swing could be introduced by gas producers and made available to the market.

The overall availability of swing

4.78. The potential flexibility that could be provided by beach swing is difficult to determine, given the commercial confidentiality of supply contracts. However, an indication can be gained from examining variations in observed beach flows. Ofgem told us that the difference between peak and annual average aggregate flows at the six largest terminals (excluding the Bacton interconnector and Rough storage flows) over the past two years had been approximately 1,000 GWh a day.

4.79. An indication of shorter-term response capabilities can be gained by examining day-to-day changes in flow levels. Ofgem told us that the biggest daily changes in aggregate beach flows from the six largest terminals in each of the last two years had been between 350 and 400 GWh a day. We estimate that beach swing contributes about 26 per cent of the daily flexibility available to shippers (see Table 5.12).

4.80. Transco's 2002 Ten Year Statement[1] shows the peak supply delivered at the beach reducing from 4,226 GWh a day in 2002/03 to a forecast level of 3,846 GWh a day in 2011/12.[2] By contrast, the annual supply delivered at the beach is forecast to increase from 1,123 TWh to 1,184 TWh over the same period.[3] This implies a reduction in swing from 137 to 119 per cent, reflecting the replacement of depleted higher-swing supplies with lower-swing supplies.

4.81. Some new beach supply contracts (such as that concluded by Centrica with NV Nederlandse Gasunie (Gasunie)) have an in-built seasonal production profile. Although these contracts do not offer the shipper the ability to vary output on a daily basis, they will help to meet the seasonal fluctuations in demand, enabling other sources of flexibility to satisfy more of the daily balancing requirement.

4.82. [

Details omitted. See note on page iv.

]

The Bacton interconnector

4.83. The gas network in Great Britain is connected to mainland Europe, and to both Northern Ireland and the Republic of Ireland, by means of interconnectors. The Bacton interconnector is owned and operated by a consortium known as Interconnector (UK) Limited (IUK). It currently has an export capacity of 217 TWh a year and an import capacity of 92 TWh a year. IUK was formed in 1994 by nine major energy companies. The opening of the Bacton interconnector in October 1998 provided gas producers and marketers with access to mainland European gas markets. The gradual implementation of the EC Gas Directive by EC member states has further facilitated the sale of gas to customers located throughout the European Union.

[1]Op cit.
[2]Table A2.4A excluding storage and Bacton interconnector/LNG imports.
[3]Table A2.3A excluding net Bacton interconnector/LNG imports.

4.84. The Bacton interconnector has also increased the flexibility of UK gas supplies, in particular providing a source of long-duration flexibility through its year-round operation. When UK gas prices are lower than those in mainland Europe (typically in summer), the Bacton interconnector adds to demand for UKCS gas and raises UK prices. When UK prices are higher than those in mainland Europe (typically in part of the winter), export flows via the Bacton interconnector are reduced (that is volumes otherwise destined for export are kept back to supply the UK market), then, if a price differential remains, the interconnector moves into reverse flow and imports gas, reducing UK prices.

4.85. Subject to its capacity limits, the Bacton interconnector consequently increases the flexibility of the UK market, effectively enabling shippers to make some use of storage and swing from mainland Europe. This is possible because storage accounts for a higher share of total gas demand in mainland Europe, which has not traditionally had access to high-swing beach gas (see paragraph 4.130 et seq). Seasonal gas supply requirements and prices in mainland Europe have normally been flatter than those observed in the UK, owing both to greater storage levels and to the preponderance of long-term contracts with oil-indexed prices.

4.86. The extremes of the Bacton interconnector's operational capabilities imply a swing potential of 899 GWh a day (that is, the sum of its maximum export capability of 628 GWh a day and its maximum import capability of 271 GWh a day). Ofgem told us that the difference between peak import and annual average flows (taking an arithmetic average of positive export flows and negative import flows) through the interconnector for 2001/02 was approximately 400 GWh a day. We estimate that the Bacton interconnector provides about 19 per cent of the summer/winter flexibility available to shippers (see Table 5.9) but a smaller proportion of the seasonal flexibility used in recent mild winters (see Table 5.10).

4.87. As regards short-term flexibility, the lead time required for the renomination of flows on the Bacton interconnector is, on average, 2 hours. If the nominations require a change in the direction of flow, one day's notice is generally needed. Such operational and contractual factors therefore limit the daily flexibility that the interconnector can offer at less than one day's notice to a significantly lower level than the sum of its maximum import and export capacities. Centrica told us that the highest observed change in flow into the interconnector on any one day since it became operational was 214 GWh a day.

4.88. As UK beach supply reduces, Bacton interconnector reverse flows from mainland Europe to the UK are expected to increase. Additional interconnector reverse flow capacity is planned for 2005/06. Two extra compressors installed at Zeebrugge will allow a reverse flow of some 179 TWh a year, nearly double the 92 TWh a year currently possible. Consideration is also being given to installing further compression at Zeebrugge, which could allow import capacity to reach about 271 TWh as early as 2006. In the long run, it would be possible to increase capacity further by installing a fourth compressor at Zeebrugge. In its 2002 Ten Year Statement,[1] Transco said that it expected the flow of gas through the Bacton interconnector to and from mainland Europe to remain seasonal.

4.89. Although Centrica has no equity stake in IUK, it holds long-term contracts for Bacton interconnector capacity that last until 2008 and 2018. These currently account for [✂] TWh a year of forward capacity and [✂] TWh a year of reverse capacity (both equivalent to around [✂] per cent of existing capacity) until 2005, [✂] TWh and [✂] TWh respectively ([✂] per cent of existing capacity) from 2005 until 2008, and [✂] TWh and [✂] TWh respectively ([✂] per cent of existing capacity) from 2008 until 2018. It also has rights over [✂] TWh a year of the 87 TWh a year future expansion in reverse capacity.

Further interconnectors

4.90. Centrica has recently signed long-term contracts for imports from Statoil ASA (Statoil) in Norway and Gasunie in Holland. Both are likely to require enhancements to the existing import pipeline

[1]Op cit.

infrastructure. In the case of the Dutch supplies, a new interconnector is likely to be built with potential for more capacity than required for Centrica's contracted flows.

4.91. Norwegian supplies from the Ormen Lange gas field may require a new pipeline from Norway. Centrica's contract with Statoil for these supplies contains no flexibility to vary the amount supplied and the intended 1,200-km pipeline is unlikely to be planned with extra capacity to permit high-swing operation. The Easington area is the preferred landing point for the UK end of this pipeline (see paragraph 4.177).

Interruptible supply contracts

4.92. There are two main types of interruption in interruptible gas sales contracts: supplier rights and Transco rights. A supplier to I&C customers can enter into interruptible contracts containing supplier interruption rights as a means of achieving flexibility. These contracts entitle the supplier to cut off supplies for up to a contractually stipulated maximum number of days in any year (generally 45 days). They provide flexibility by enabling the supplier to interrupt supply in order to support other gas loads (such as domestic peak requirements) or to sell gas in short-term markets when arbitrage opportunities occur. Transco holds most of the interruption rights, although sizeable interruption rights are also available to shippers. Both types of rights have, however, been little used in recent mild winters.

4.93. Contracts with Transco interruption rights allow Transco to initiate interruption in an LDZ when local demand exceeds the capacity of the relevant part of its system and, more generally, in the event of a transportation constraint. Under these arrangements, Transco has the right to interrupt users on 5 hours' notice for up to 45 days a year (and in some cases for more than 45 days) subject to criteria defined in the Network Code.

4.94. Although interruption rights are a demand-side, rather than supply-side, response to peaks in demand, such contracts become more attractive to suppliers as the winter gas premium rises.

4.95. Ofgem told us that users on interruptible transportation terms accounted for 1,123 GWh a day (about two-thirds of total power generation and I&C demand and about one-third of total demand). Ofgem added that there were no reliable estimates of the extent to which customers with either firm or interruptible transportation terms had interruptible supply terms.

4.96. Centrica's interruptible contracts give it a significant amount of flexibility. They include contracts with a number of power stations, including those supplied under legacy 10- to 15-year LTI contracts originally negotiated when British Gas plc was an integrated operation. Although some of its original LTI contracts have terminated early, Centrica told us that it expected the remainder to continue for a further five to eight years, in line with the original contracts. Centrica told us that, in 2002/03, the peak demand of its interruptible customers was between 250 and 300 GWh a day ([*Details omitted. See note on page iv.*]).

4.97. Under its LTI gas sales contracts, Centrica has the right to interrupt for up to a specified number of days ([✂] in most cases) a year. For the most part, however, Centrica shares the interruption rights under these contracts with Transco, that is the maximum number of days' interruption covers both Centrica's and Transco's rights. Centrica's ability to interrupt may, therefore, be restricted through the need to allow scope for possible Transco interruption later in the same gas year. The contracts also incorporate a limit on the aggregate number of days on which Centrica can interrupt over their entire life. Centrica provided information showing that these limits would allow it to interrupt up to the annual ceiling under each contract for at least the next five years.

4.98. Centrica's remaining interruptible contracts are one- to three-year contracts and are for smaller volumes. Where these contracts contain Transco interruption rights, they typically have shipper and Transco interruption rights that are exercisable separately.

4.99. In addition to supplier interruption rights, some customers may respond to price movements by themselves 'self-interrupting' and supplying their contracted gas purchases back into the market at a profit. In particular, gas-fired power generators may respond to high gas prices, relative to the value of gas in power generation, by supplying their gas back into the gas market rather than using it to generate electricity (see Appendix 5.3).

Liquefied natural gas imports

4.100. The future use of terminal facilities to import gas in the form of LNG (see paragraph 4.10) could introduce a new source of seasonal and daily flexibility. To provide seasonal flexibility, varying volumes could be imported at different times and cargoes could be rerouted to different geographical markets as required or according to relative price levels. Daily flexibility could increase if plant with high gasification rates were to be installed. Ofgem told us, however, that it had been informed that the planned LNG supplies were intended to meet baseload requirements.

Types of storage facility

Summary of UK facilities

4.101. There are currently nine major gas storage sites in Great Britain, including Rough, Hornsea and the five LNG facilities that were originally owned and operated by British Gas plc. The ownership of these facilities was transferred by BG to BG Storage, a ring-fenced subsidiary, after the demerger in 1997. The LNG facilities were regarded as being essential to the management of the transportation system; consequently, when Transco was demerged from BG Group in December 2000 to become the main subsidiary of the newly-formed Lattice, the LNG facilities were transferred from BG Storage to a separate unit within Lattice called Transco LNG (see paragraph 4.117). BG Storage then comprised the Rough and Hornsea facilities. In November 2001, Dynegy purchased BG Storage. SSE purchased the Hornsea site from Dynegy in September 2002. The remaining major storage capacity consists of recent entrants: ScottishPower's storage site at Hatfield Moor, and the Electricité de France Trading (EdFT) site at Hole House Farm (Hole House).

4.102. The size of gas storage facilities is generally defined by three parameters:

(a) the rate at which gas can be injected (injectability);

(b) the rate at which gas can be withdrawn (deliverability); and

(c) space, that is the total amount of deliverable gas that the facility can hold when full.

4.103. Related operational and commercial features that stem from these characteristics are the minimum time that it takes to fill a site from empty (that is, space divided by injectability), and the length of time that the site can discharge at maximum deliverability from fully charged (that is, space divided by deliverability—referred to as the site's 'duration').

4.104. Table 4.1 shows the main operational characteristics of the principal UK storage facilities.

4.105. Rough is substantially larger than the other sites in terms of space. Consequently its duration is also greater than that of the other high-deliverability storage sites. In particular, the duration of Rough is far greater than that of the LNG facilities. Whilst the combined deliverability of the five LNG sites is very substantial (769 GWh a day), this level could only be sustained for five days and the sites would take 192 days to refill. By contrast, Rough could be nominated by customers at its nominal full deliverability (455 GWh a day) for 67 days and could then be refilled in approximately 190 days. This difference, together with the fact that the LNG injection process is considerably more costly per unit of gas stored and less flexible than that at Rough, makes Rough much more suitable than the LNG sites for seasonal storage and gives rise to very different usage patterns. The space provided by each of Hornsea, Hatfield Moor and Hole House is significantly less than that of Rough; the characteristics of these mid-range facilities fall broadly between those of Rough and the LNG sites.

TABLE 4.1 **Capacity of principal UK storage facilities**

Facility	*Owner*	*Space*		*Injection*			*Withdrawal*			*Time to cycle†*
		GWh	*%*	*GWh/d*	*%*	*Time to fill* Days*	*GWh/d*	*%*	*Duration* Days*	*Days*
Depleted field										
Rough	Centrica	30,344	76.2				455	21.6	67	4
Hatfield Moor‡	ScottishPower	1,260	3.2				55	2.6	23	2
Salt cavity										
Hornsea	SSE	3,495	8.8		*Figures omitted. See note on page iv.*		195	9.3	18	10
Hole House	EdFT§	300	0.8				30	1.4	10	2
Five LNG sites	Transco	3,846	9.7	¶			769	36.5	5	39
Diurnal storage**#**	Transco	600	1.5				600	28.5	1	2
Total		39,845	100.0				2,104	100.0		

Sources: Centrica, Ofgem, Transco and operators.

*At nominal daily withdrawal or injection rate.
†One day of withdrawal nominal rate plus time to replace withdrawn gas.
‡Injection rate for Hatfield Moor is an approximate CC estimate and withdrawal rate is taken from Transco's Ten Year Statement.
§Owned and operated through its subsidiary Energy Merchant Gas Storage (UK) Ltd.
¶LNG injection rates vary by site.
#CC estimate.

4.106. Other significant characteristics are location, which may, for example, allow a facility to be used to relieve constraints in the transportation system (most relevant for LNG facilities); and (for all storage facilities) lead times for injection and withdrawal, which determine how quickly a facility can respond to new customer or Transco requirements. Lead times to vary the rate or direction of flow for a particular facility can vary according to its current state, for example whether it is actively injecting or delivering gas. Table 4.2 shows the physical lead times at each of the main UK storage facilities and compares them with lead times for other flexible sources of gas. In some cases, contracts may specify a slower response, with any quicker service being subject to the operator's reasonable endeavours.

TABLE 4.2 **Lead times for storage and other sources of flexible gas**

Facility	*Injection lead time*	*Withdrawal lead time*
Storage		
Depleted field		
Rough*	2–12 hours	2–12 hours
Hatfield Moor	1 hour	1 hour
Salt cavity		
Hornsea*	2–6 hours	1–6 hours
Hole House*	Over 1 hour	Over 1 hour
5 LNG sites*	12 hours–10 days	1–8 hours
Diurnal storage	Immediate	Immediate
	Supply/interruption lead time	
Other sources of flexibility		
Beach swing*	6–4 hours	
Bacton interconnector*	2–48 hours	
Interruptible contracts	3–5 hours	
LNG imports†	1–10 days	

Source: Centrica, Transco and operators.

*Lead time dependent on operational status. For Rough and Hornsea, the longer lead times may be needed if a change in direction of flow is required. For LNG, lead times depend on system configuration and linepack position. LNG injection may need to be pre-booked. For beach gas renomination lead times normally exceed 6 hours but vary depending on flow rates and contract terms. For the Bacton interconnector, although shippers are only required to give 2 hours' notice, Transco operational requirements can result in 5 to 8 hour lead times. Renominations needing a change in direction require a lead time of 48 hours.

†CC estimate: dependent on availability and location of ships.

4.107. Third-party access to storage services is currently available at Rough, Hornsea and the LNG facilities in SBUs that give customers a fixed ratio of injection, space and withdrawal capacity based on each particular facility's maximum capacities. Customers of storage services receive:

(a) the right to inject gas into the store at a specified rate;

(b) the right to a specified volume of space in the store for the injected gas; and

(c) the right to withdraw gas from the store at a specified rate.

Different storage facilities offer distinct specifications of injection, space and withdrawal according to their size and operational characteristics.

4.108. We now consider the individual types of storage facility.

Depleted gas and oil fields

4.109. Depleted offshore gas fields, such as Rough, may be converted into storage facilities by installing compressors to force gas back into the fields to be stored. We discuss Rough in paragraphs 4.134 to 4.172. Depleted onshore gas and oil fields can also be used in the same way.

4.110. ScottishPower, in association with Edinburgh Oil & Gas plc, operates a gas storage facility using a depleted gas field at Hatfield Moor in Yorkshire. Although Hatfield Moor is the first onshore facility of its type in the UK, the technique is widely used in Germany and the USA. The site was commissioned in September 1999 and the gas reservoir is a layer of porous sandstone about 440 metres underground. It provides storage with a duration of 23 days. ScottishPower told us that the facility enabled it to manage variation in demand from gas customers and to buy additional gas to store when prices were low. Gas stored at Hatfield Moor may also be used for electricity generation at the company's gas-fired power stations. Star Energy has proposals to develop further small storage facilities of this type using the depleted oil fields at Humbly Grove and Welton (see paragraph 4.126).

4.111. Centrica told us that there were several offshore gas fields that were suitable for conversion into storage facilities. [*Details omitted. See note on page iv.*] whether the South York field could be converted into an extension to Rough (see paragraph 4.172). [

Details omitted. See note on page iv.

]. Centrica estimated that such developments would become viable if forecast prices of long-duration storage were above the equivalent of [✂]p per Rough SBU on a sustained basis. We discuss the potential for further development at Rough in paragraph 4.169.

Salt cavities and other underground storage facilities

4.112. Salt-cavity storage offers mid-range storage with characteristics between those of Rough and the LNG facilities. Following its purchase from Dynegy (see paragraph 4.101), SSE owns nine operational salt cavities located at Hornsea in east Yorkshire. These were created by dissolving and removing part of a thick underground salt stratum approximately 1,800 metres below ground. Hornsea has a total usable storage space capacity of 3,495 GWh. A similar quantity of gas must remain in the cavities as 'cushion gas' that maintains the integrity of the store but cannot be extracted. Gas passes out of the cavities under its own pressure. The cavities are refilled using electrically-driven reciprocating compressors.

4.113. Hornsea has duration of 18 days, but, given the quick response time and ease of switching from output to intake, it is increasingly being used as an arbitrage tool by gas shippers and traders, and is consequently oversubscribed.

4.114. Aquila Energy Storage Ltd started developing a salt cavern gas storage facility at Hole House near Crewe in Cheshire in 1997. Hole House, which was sold to EdFT in 2002, provides 300 GWh of storage space and has a maximum deliverability of 30 GWh a day, resulting in a mid-range duration of ten days. Further development which could ultimately double the existing capacity is due to start shortly.

4.115. The duration of Hornsea and Hole House is greater than that of LNG, but much less than that of Rough. Considerable attention is typically paid to the short-notice flexibility of these sites, and the value that this flexibility can provide for the management of end-of-day balancing positions.

4.116. Transco owns two smaller salt-cavity installations that provide 40 GWh of local diurnal storage. These cavities are at relatively shallow depths, operate at much lower pressures than those at Hornsea and are only used by Transco for operational purposes. Pressure cycling (withdrawal/injection) is done on a daily rather than seasonal basis.

Liquefied natural gas storage

4.117. LNG storage fulfils two major roles: peak shaving and providing an emergency supply to cover for such eventualities as line breaks or major temporary losses of offshore supplies. In the former mode, it is used to meet extreme peaks of demand during cold weather. Under average winter conditions the LNG sites were traditionally expected to be used on only two or three days, such that the stock would only be partially depleted; in a severe winter they were expected to operate over a longer period and potentially to become fully depleted. Under emergency conditions the pattern of usage is likely to be significantly different. LNG facilities are generally located at the extremities of the system and, because evaporation plant is relatively cheap, are designed to provide gas at high deliverability.

4.118. At present, Transco operates five LNG storage sites—at Glenmavis, Partington, Avonmouth, Dynevor Arms and the Isle of Grain—as a ring-fenced business unit, called Transco LNG. The terms of their services are included in the Network Code. These sites store gas in liquid form at a density about 600 times greater than gas at standard temperature and pressure. Their total maximum deliverability is 769 GWh a day, and the maximum refill rate is about 20 GWh a day. Thus LNG storage could be emptied in five or six days but takes all summer to refill.

4.119. Transco LNG offers a storage service both to Transco and to other market participants. 30 per cent of available LNG space is currently booked for Transco's use to provide operating margins gas (see paragraph 4.32). Any shipper that is short of gas on a peak day will be exposed to balancing costs, probably at high prices: LNG provides insurance against this possibility. Capacity at the LNG facilities has typically been sold through annual auctions with a minimum reserve price. Any LNG capacity remaining unsold after the auction is offered to the market at the auction clearing price plus a small uplift.

4.120. Transco's Avonmouth, Isle of Grain and Dynevor Arms sites offer shippers a constrained service (see paragraph 4.46) which may affect their ability to withdraw gas at peak periods. (Ofgem told us that Dynevor Arms was, however, effectively unconstrained in practice.) The LNG sites at Partington and Glenmavis offer an unconstrained service. Shippers using these sites are able to withdraw previously injected gas whenever they wish. (Glenmavis also has a tanker-loading facility that is used to supply gas to relatively remote towns in Scotland by road tanker.)

4.121. With effect from 2004, part of the Isle of Grain site will be converted into an LNG import reception facility and its storage capacity will be reduced (see paragraph 4.10 et seq).

Diurnal storage

4.122. Although gas demand at night is much lower than during the day, the system is designed to enable gas to be supplied by offshore producers at a rate that is kept constant as far as possible. Diurnal storage is therefore needed to deal with the variation in customers' demand within the day. This is largely provided from low-pressure gas holders, high-pressure storage and linepack.

4.123. Low-pressure gasholders still provide approximately 40 per cent of local diurnal storage requirements, although they are progressively being decommissioned. In addition, there are a relatively small number of high-pressure local storage installations and two low-pressure salt-cavity installations in the North-West of England (see paragraph 4.116). Linepack is a cheaper form of diurnal storage that is provided by varying the pressure in high-pressure pipelines. The LDZs generate some 290 GWh of storage space by this means and the NTS provides about 96 GWh.

4.124. At present, linepack is only used to provide Transco with operational flexibility and to ensure system safety. There may in future, however, be proposals that some of this capacity should be unbundled from transportation and sold to shippers through an auction system. The storage provided by linepack capacity would be of very short duration.

Projects under consideration

4.125. In addition to the existing storage facilities, several storage projects have been proposed by Star Energy, Statoil, SSE, ScottishPower and Canatxx Gas Storage Ltd (Canatxx). These plans include the expansion of Hole House and new sites at Humbly Grove, Welton, Aldbrough, Byley and Fleetwood.

4.126. Star Energy has two projects to convert small onshore depleted fields, at Humbly Grove and Welton, into storage facilities. The Humbly Grove project near Alton in Hampshire would provide an additional storage volume of about 3,100 GWh with an average injection rate of approximately 72 GWh a day and an average deliverability of about 35 GWh a day. Subject to planning permission, which has been sought, Humbly Grove could be operational in 2005. Star Energy expects the capacity of the project at Welton in Lincolnshire to be similar to that of Humbly Grove.

4.127. Plans have also been announced for four salt-cavity storage projects. Statoil has planning permission for a facility at Aldbrough, close to the existing salt cavities at Hornsea. This could be complete in 2007 and, subject to engineering studies, could provide between 1,800 and 2,500 GWh of space with a deliverability of around 238 GWh a day. As part of its acquisition of Hornsea, SSE acquired a different site at Aldbrough. This site also has planning permission for another storage facility, which would provide 1,842 GWh of space with a deliverability of 184 GWh a day and could begin operating in 2006. ScottishPower is seeking planning permission for a facility at Byley in Cheshire that could be complete in 2007 and would provide about 1,800 GWh of space with a deliverability of 176 GWh a day. Finally, Canatxx has proposed a storage project at Preesall near Fleetwood in Lancashire but has not yet sought planning permission; this project would provide over 5,000 GWh of space (deliverability figures are not available at present).

4.128. If all these developments are carried out, they could add additional storage space of approximately 17,000 GWh, which is over half the space capacity of Rough. The service offered by these projects is likely, however, to be of medium duration, more comparable to that provided by Hornsea than that provided by Rough. We consider the possible further development of Rough in paragraph 4.169.

4.129. Ofgem told us that it was not aware of any proposals of a size comparable to the large scale of Rough. In particular, it knew of no proposals to develop another substantial partially-depleted gas field into a large storage facility. Experience with new storage developments suggests that they can take a considerable period of time to realize: some are currently subject to planning delays and may not proceed; others may not be economic at current storage price levels.

Interaction with gas flexibility in other countries

4.130. The amount of storage capacity in most mainland European countries is much higher, as a proportion of demand, than in the UK. In its detailed 2002 European Gas Storage Report,[1] Global Insight estimated a storage requirement for each country. This requirement was based on a detailed analysis of needs including supplying seasonal demand; supporting short-term peaks in demand; supplying interruptible customers on all but a limited number of days; storing excess gas purchased on take-or-pay contracts; supporting transportation systems; providing strategic reserves to cover against the failure of high-risk sources of supply; permitting more flexible trade in LNG; and supporting price arbitrage and market hubs. This analysis was carried out on a standard basis for all countries.

4.131. After allowing for other sources of flexibility and comparing these needs with existing and planned capacity, Global Insight concluded that there was an excess supply of storage volume and seasonal flexibility in mainland Europe that it attributed to a heritage of monopolistic planning based on high security of supply margins. In particular, it estimated that there were in varying degrees surpluses of storage (both of volume and deliverability) in France, Germany, Italy and the Netherlands. In these countries Global Insight considered that storage was either under-used or being used for purposes, such as excessive strategic support and security of supply, that would not today justify the development of storage. Table 4.3 shows Global Insight's estimates of the actual and projected surpluses of storage capacity by country.

TABLE 4.3 **Global Insight's analysis of storage needs**

TWh

	Actual and projected surplus of volume by country				
	2000	*2005*	*2010*	*2015*	*2020*
Mainland Europe					
Belgium	–7.8	–9.2	–11.8	–13.6	–15.4
France	29.7	31.0	3.5	–38.0	–74.6
Germany	130.9	149.3	155.2	149.3	141.0
Italy	68.5	67.0	63.1	47.2	30.2
Netherlands	21.5	12.6	11.5	9.3	7.1
Spain	–20.0	–40.6	–41.2	–53.7	–59.4
Total	222.8	210.2	180.3	100.4	28.9
UK	18.3	9.5	–32.5	–57.4	–57.8

Source: Global Insight.

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

4.132. Subject to the Bacton interconnector's capacity constraints and the willingness of the mainland European storage operators to offer services, this underused storage capacity may effectively be available to users in the UK as a result of gas trading via the Bacton interconnector (see paragraph 4.83).

4.133. Mainland European gas prices have not traditionally shown such pronounced seasonal variation as those in the UK. Wholesale gas prices in mainland Europe are generally linked to oil prices. Before the Bacton interconnector opened, they were normally higher than wholesale prices in the UK, particularly in the summer. Following the opening of the Bacton interconnector, UK prices moved towards mainland European levels (see paragraphs 5.9 and 5.10). The UK/mainland European price differential now varies over the year, gas tending to be exported to mainland Europe in the summer and imported into the UK for part of the winter.

The Rough gas storage field

4.134. Rough is by far the largest gas storage facility in the UK and is capable of supplying over 7.5 per cent of peak day demand. It is located about 26 miles off the Humber Estuary. Gas is generally put into Rough when its price is low (typically in the summer) and withdrawn when its price is high (normally in the winter). It is injected into Rough using offshore compressors and withdrawn using the internal pressure of the reservoir.

4.135. The Rough 47/8 Alpha offshore facilities and Easington terminal were originally developed to produce and process natural gas from the Rough field in October 1975. The British Gas Corporation acquired the assets in 1980. Following an assessment of the Rough reservoir's potential, it developed and converted the offshore and terminal facilities into a storage facility that commenced operation in 1985, enabling gas to be stored within the reservoir and withdrawn at short notice to meet peaks in demand. Centrica acquired the facility in November 2002 (see paragraph 3.2).

4.136. The services provided to customers comprise the right to inject gas into store, hold it there and then withdraw it back for injection into the NTS. Rough is operated by CSL, a wholly-owned subsidiary of Centrica. Around 160 staff and contractors are employed within the operation, both onshore and offshore.

Plant and equipment

4.137. Rough includes two offshore installations—47/3 Bravo and 47/8 Alpha (the numbers refer to the North Sea licensing block numbers that identify where the fields are located). Licences to develop these blocks were awarded by the Department of Trade and Industry (DTI). 47/3 Bravo is the main manned complex, typically operating with a minimum of 36 and a maximum of 134 staff on the facility at any one time. It comprises three separate bridge-linked platforms.

4.138. 47/8 Alpha is a manned platform used to maintain deliverability of gas from the field during peak demand days. Up to 27 staff can work and live on the platform.

4.139. Gas is contained within sandstone rock strata some 2,700 metres under the seabed. The reservoir is approximately 10 km long by 3 km wide and varies in thickness from 24 to 36 metres. Gas can be withdrawn from the reservoir to the platforms through 30 wells; it undergoes several processes offshore to separate it from liquids before being sent via a 914-mm (36-inch) subsea pipeline to Easington. The same wells are used to reinject gas back into the reservoir.

4.140. Centrica told us that when it purchased Rough its assets were in poor condition and a 47,000-hour maintenance backlog had built up. The HSE commented that it considered that, when purchased by Centrica, the Rough offshore assets were in average condition for their age. It added that a maintenance backlog had built up on the offshore platforms during BG Group's ownership of Rough. In July 2001, just before the sale to Dynegy, the HSE had served an improvement notice on BG Group. Dynegy subsequently complied with this improvement notice which related to maintenance of electrical junction boxes. Dynegy agreed that it had inherited an offshore maintenance backlog, which it had subsequently reduced to a level that it considered to be within accepted UK offshore operator norms. The HSE told us that, by the time of Rough's sale to Centrica, the offshore maintenance backlog had been reduced substantially.

4.141. Meanwhile, in October 2002 the HSE had issued a deferred prohibition notice on Dynegy that could, if made final, have required Rough to close in November 2002. The HSE issued this notice because Dynegy had proposed to reduce staffing to a level that would, in the HSE's view, have resulted in insufficient competent staff remaining to operate the installations safely. Dynegy commented that this notice related to voluntary redundancies that were part of the transition to a new organizational structure already agreed by the HSE in the context of a revised safety case. Dynegy added that, as a result, it had temporarily retained key staff beyond their planned termination dates while arrangements with contractors were finalized. Dynegy said that it had received no other censure from the HSE regarding the operations of DSL. The HSE told us that during November 2002 Dynegy had arranged for staffing levels acceptable to it. The prohibition notice was not therefore enforced. After its purchase of Rough, Centrica gave the HSE a commitment to comply with the notice served on Dynegy. The prohibition notice was lifted earlier this year.

4.142. Rough's commercial operations are run by 16 full-time employees now based in Staines.

Capacity: space, injection and withdrawal

4.143. Rough is a 24-hour operation and can feed gas into the NTS normally within approximately 2 hours of notice being given. It has a total storage capacity of 30 TWh at pressures of over 200 bar. Rough operates under a contractual obligation to meet customers' maximum withdrawal nominations for about 67 days. Under the undertakings given by BG and Dynegy (see paragraph 4.59 et seq), its deliverability capacity was defined to be at least 455 GWh a day. Both operators were obliged to make this maximum deliverability rate available under the terms of their undertakings.

4.144. A certain amount of gas (known as 'cushion gas') remains in the reservoir at all times. This gas maintains sufficient pressure within the Rough field to achieve the required rate of deliverability at times of peak customer demand. However, under BG Group's ownership some of the cushion gas was used or sold. Centrica told us that, given the depletion dynamics of its reservoir, Rough was now physically unable to sustain the nominal deliverability rate of 455 GWh a day over the entire withdrawal season: Rough's actual deliverability was higher when it was full and dropped off steadily as the reservoir volume declined. The shortfall could be up to [✄] GWh on any given day.

4.145. Gas can be injected into the reservoir at an average of 160 GWh a day, depending on the reservoir pressure.

Types of primary market contract

4.146. Rights to use capacity at Rough are sold for a standard 'storage year' that starts on 1 May. Any company is allowed to purchase storage capacity at Rough, provided that it signs the SSC and a credit agreement. Rough's customers have included producers, transporters, shippers, suppliers, traders, speculators and end-users. The SSC was the result of a lengthy industry-wide consultation and negotiation process. We summarize its main terms in Appendix 4.7.

4.147. Firm capacity at Rough is sold in SBUs consisting of fixed proportions of injectability, space and deliverability that are equivalent in total to its nominal capacity. This requirement was originally set out in the undertakings given by BG and subsequently continued when Dynegy acquired Rough. One SBU is equivalent to 1 kWh a day of withdrawal, 66.593407 kWh of storage space and 0.351648 kWh a day of injection capacity. SBUs can be unbundled and the components sold separately in the secondary market (see paragraph 4.157 et seq).

4.148. Before the present acquisition DSL offered SBUs for sale throughout the year through a variety of sales processes including auctions, tenders and bilateral negotiations. DSL regularly contacted potential customers to update them, review their existing bookings and discuss/negotiate prices for additional bookings.

4.149. SBUs remaining unsold 30 days before the start of the new storage year were required to be offered for sale by auction. Auction/tender documents were posted, with the date by which bids had to be submitted, to all SSC signatories. Capacity was then awarded to the highest bidders, on a pay-as-bid basis.

4.150. CSL told us that it intended to sell SBUs using the same methods as DSL. There would be a combination of bilateral negotiations, auctions and other sales processes (such as invitations to bid). CSL said that customers wanted to continue to have multiple ways and opportunities to purchase storage, rather than being limited to a yearly auction (as occurred when Rough was owned by BG Group).

4.151. The SSC requires CSL to offer all space, injection and withdrawal capacity that is unused by customers on any given day to other customers on an interruptible basis (see paragraph 4.155). Rough's maximum physical capacity is therefore offered to the market at all times.

4.152. The current SSC is due to expire on 30 April 2004. CSL told us that as the SSC was developed through lengthy consultation it provided protection for both the operator and its customers. CSL added that both it and the customers it had consulted thought that it would be preferable to extend the current SSC indefinitely, rather than open a fresh negotiating process.

4.153. CSL told us that some customers had approached it expressing interest in multi-year deals, lasting from 2 to 15 years. Whilst CSL was interested in offering these terms, it had agreed with Ofgem before the acquisition was referred to the CC to postpone any sales beyond those in the 2003/04 storage year. After the reference to the CC, Centrica gave undertakings to the OFT that it would take no action which would lead to the integration of the Dynegy business with the Centrica business or would either prejudice the reference to the CC or impede the taking of any action under the FTA that might be warranted by the CC's report. Centrica believed that this would have allowed it to sell some capacity for the 2004/05 storage year and beyond. CSL told us, however, that since such sales contracts could be overturned following the CC's report, it had not pursued any.

4.154. The movement of gas either into or out of the reservoir is based on daily injection and withdrawal nominations which customers make by placing them on CSL's web-based customer interface, known as STORIT. Customers are also able to renominate within day in response to fluctuations in demand and price. The maximum lead times for renominations range from 2 to 12 hours, depending on Rough's operational status.

Interruptible capacity

4.155. Injection, space and withdrawal rights are subject to a 'use-it-or-lose-it' rule. Any firm capacity rights that are not nominated by their owners on a particular day are made available by CSL on an unbundled interruptible basis. Under the terms of the SSC, all customers can book a standard interruptible service (SIS). Although not required by the SSC or any undertakings, CSL also offers a lower-priced, lower-priority interruptible service called 'bronze' which is available to all customers. CSL has the right to interrupt either type of service if nominations for firm capacity increase during the gas day, for example owing to customers with unused firm capacity rights deciding to use them.

4.156. Customers can book SIS capacity by placing a nomination on STORIT. The SSC sets a maximum price for SIS which operates on a 'pay-as-used' basis. Customers book bronze capacity by submitting an application to CSL by fax. As bronze is interrupted before SIS and operates on a 'pay-as-booked' basis, it is sold at a discount to SIS. The actual discount set by CSL depends on price differentials in the gas market.

Secondary market

4.157. In addition to buying firm and interruptible capacity from CSL, potential customers can also trade firm capacity with other storage customers either directly or via brokers. In this secondary market, storage is traded both in the form of SBUs and as unbundled space, injection and withdrawal rights. These secondary market deals are implemented by transferring capacity between accounts on the STORIT system.

4.158. Under Dynegy's ownership, DSL sometimes acted as an intermediary in facilitating anonymous secondary trades of capacity if the counter-parties desired. CSL told us that it had also facilitated such trades and was willing to continue to do so.

4.159. CSL told us that approximately 16 per cent of Rough's 455 million SBUs for 2002/03 had been traded on the secondary market before the start of the storage year. A further 21 per cent was traded later in the year after Dynegy withdrew from the UK market and sold its storage capacity to third parties. By 31 March 2003, approximately 23 per cent of the capacity for the 2003/04 storage year had been traded on the secondary market.

4.160. CSL added that it would continue to provide the web-based platform on which customers could post bids and offers for bundled and unbundled storage capacity.

Supply of information to the market

4.161. When Rough experiences certain operational problems (that is when, under the terms of the SSC, CSL declares force majeure, an injection/withdrawal cancellation or a maintenance day), its customers may be forced to use the traded market, and other sources of short-term flexibility, to balance their supply and demand. Centrica's gas procurement, supply and trading operations could therefore have a commercial advantage were they to gain information about these operational issues before other storage customers. CSL told us that its code of conduct ensured that operational staff did not pass commercially sensitive operational information to Centrica supply staff.

4.162. Centrica told us that employees working at Rough and Easington who also provided operational support elsewhere (for example, at Morecambe) had been 'designated' under its code of conduct and had signed a letter confirming that they were aware of the consequences of such designation. Their designation required these staff to hold commercially sensitive operational information relating to Rough only for the purpose of giving advice or support to Centrica's storage operations and not to release such information to other parts of Centrica engaged in gas procurement, supply, trading and storage procurement.

4.163. CSL said that it notified all customers simultaneously about outages via STORIT and telephone calls. It added that, following an incident in May 2002 when a fishing boat struck one of the Rough platforms, causing DSL to declare force majeure under the terms of the SSC, the market did not move until after customers had been informed about the incident. This demonstrated that the traders at Dynegy (which then owned Rough) were not provided with this commercially sensitive information ahead of the market. CSL said that its code of conduct would also operate in this way in such circumstances.

4.164. A number of shared services provide support to CSL as well as to other parts of the Centrica group. These include legal, regulatory and human resources. Centrica also intends to secure efficiency gains by managing aspects of the operation of the Rough platforms and the Easington terminal jointly with its gas production operations. The areas concerned relate to health, safety, environmental and quality matters as well as the sharing of operational best practice on asset performance, the development of long-term plans for reservoir development and the use of single third-party contractors for the provision of, for example, engineering support, helicopters, boats and catering.

4.165. Centrica told us that these shared services would all be handled within the terms of the code of conduct by designating the personnel (whether Centrica employees or contractors) that provided them. Such designated persons would be in the same position as CSL employees when they became aware of any commercially sensitive information relating to CSL.

Customer confidentiality

4.166. The information handled on a daily basis by commercial storage staff concerning both the sale of storage capacity and customer nominations for the injection and withdrawal of gas is commercially sensitive. Centrica told us that it had established strong separation arrangements immediately after the acquisition of Rough to prevent CSL from disclosing this information to other parts of Centrica engaged in gas procurement, shipping, trading, supply or storage procurement (supply employees). It added that the due diligence on the acquisition of Rough had been carried out in a manner that ensured the protection of commercially sensitive information. Centrica was confident that this ring-fencing could continue to protect sensitive customer data by ensuring robust physical, financial, information and systems separation.

4.167. Centrica told us that, to achieve this, commercial storage employees were located in a separate building (in Staines) from supply employees (who were located in Slough). The Staines building did, however, contain other Centrica employees engaged in group human resources support and information technology support; the part of the building which housed the commercial storage staff was, therefore, within a restricted access area.

Scope for further development

4.168. As demand grows, the supply of indigenous high-swing gas produced on the UKCS reduces and the UK becomes more reliant on lower-swing UKCS and imported gas, it is likely that there will be an increasing requirement for replacement sources of flexibility, which may include more UK storage.

4.169. CSL told us that it had embarked on a programme of initiatives to maintain and enhance asset performance at Rough. This included the following items:

(a) It had evaluated a project to allow gas produced by the 47/8A platform to bypass the 47/3B platform dehydration unit. This could increase deliverability at high reservoir levels and was currently being implemented on a trial basis to assess its effect on asset integrity.

(b) It was reviewing the instrumentation and process used to measure the maximum sand-free production rates from each well. Subject to any asset integrity issues, there might be potential to raise the maximum production rates from some wells thereby raising the overall maximum deliverability. Trials were under way.

(c) It was investigating the selective reperforation of some wells with downhole flow constraints to increase withdrawal and injection capacity.

(d) A programme to replace major safety-critical equipment was being developed to obtain the benefit of current technology and ensure that equipment could continue to be supported.

4.170. Centrica added that it was preparing a ten-year development plan. This would consider potential asset enhancements over a longer period. Possible projects included additional drilling potential, optimizing compression, installing injection facilities at the 47/8A wells, the early recovery of cushion gas and performance optimization to reduce fuel gas usage. Centrica told us that it had offered to share information on its development plans with Ofgem on a regular basis.

4.171. Centrica is a development partner, together with Amerada Hess and Gaz de France, in the York fields. The South York field lies immediately north of the north-west extremity of the Rough reservoir, and is separated from it only by a geological fault. Because leakage of gas across this fault is possible, the York fields (South, North and East) have remained undeveloped since they were discovered in 1991. A pre-development study is taking place to establish how to minimize the risk of leakage by developing York in such a way that the South York field is only depleted to a pressure close to the operating pressure of the Rough field.

4.172. Centrica added that, following the initial York development, it might be possible to convert the partially depleted South York field into additional storage capacity. The pressures in the Rough and South York fields would then cycle up and down together through the injection and withdrawal seasons, eliminating the leakage issue. [

Details omitted. See note on page iv.

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The Easington terminal

4.173. The onshore gas-processing terminal at Easington is approximately 27 miles south-east of Hull near the Humber Estuary. It processes gas before it enters the NTS through an adjacent Transco entry point and is staffed by approximately 80 employees and 20 to 25 contractors. The terminal can handle up to 750 GWh of gas a day, compared with Rough's rated maximum withdrawal rate of 455 GWh a day.

4.174. Easington's main functions are to receive and process gas from Rough and the BP-operated Amethyst field and to withdraw gas from the NTS for injection into Rough to be stored.

4.175. The product arriving at Easington from Rough is a mixture of condensate (a light oil similar to paraffin) and gas. The gas and liquid have to be separated before the condensate can be treated, stabilized and sent by underground pipeline via the BP Easington terminal to BP Chemicals at Saltend.

4.176. Easington also receives a mixture of condensate and gas direct from the BP-operated Amethyst and Helvellyn fields; this mixture is processed, the gas passed into the NTS and the condensate transported to Immingham by pipeline.

4.177. Easington is a possible location for the reception of substantial new supplies of gas from Norway (see paragraph 4.4). [

Details omitted. See note on page iv.

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